

**Yukon Utilities Board
(YUB)**

1 **TOPIC: Actual Versus Forecast**

2
3 **REFERENCE:** Application, Tab 7 – Financial Schedules. PDF pages 277 to 292

4
5 **PREAMBLE:** The referenced schedules have the following column headings: “Actual
6 2016,” “Forecast Existing” for each of 2017 and 2018 and “Forecast
7 Proposed” for each of 2017 and 2018.

8
9 **QUESTION:**

10
11 a) Please confirm that any column identified as “Actual 2016,” includes 12 months of
12 actual data. If not confirmed, please explain.

13
14 b) Please clarify the difference between columns identified as “Forecast Existing” and
15 columns identified as “Forecast Proposed.” Do either of these columns contain
16 data on actuals for 2017?

17
18 c) If the columns referred to in question (b) do not include 2017 actuals, please
19 provide 2017 actuals based on information available to date.

20
21 d) Please clarify if any information provided in the columns identified as “Forecast
22 Existing” has been previously provided to the Board. If so, under what
23 circumstances was this information provided.

24
25 e) Please clarify whether YEC is seeking approval for 2017 and 2018 revenue
26 requirement under “Forecast Proposed” columns. If confirmed, please explain why
27 the “Forecast Existing” information was provided.

28
29 **ANSWER:**

30
31 **(a)**

32
33 Confirmed.

1 **(b)**

2
3 These columns contain only forecast numbers and do not include any actuals. The
4 “Forecast Existing” columns reflect forecasts based on the assumption that YEC did not
5 apply for a General Rate Application. The “Forecast Proposed” columns reflect forecasts
6 based on the assumption that YEC has applied for a General Rate Application and the
7 proposals by YEC are approved.

8
9 **(c)**

10
11 YEC is not able to provide a full update to Tab 7 tables as requested.

12
13 YEC has Q2 year to date actuals that have been reviewed and approved by management
14 and the Board of Directors. In order to properly update Tab 7, the utility would need to re-
15 forecast financial results for the last six months of the year. While this forecasting is not
16 particularly onerous, the impact of updating 2017 forecasts for half-year actuals would
17 effectively require YEC to revise and refile its entire General Rate Application based on
18 these new forecasts.

19
20 It is not clear that this is the Board's intention and refiling would be a material update to
21 the document and requires much time and effort from the applicant.

22
23 2017 actual results are provided in response to the following interrogatories:

24

Interrogatory #	Financial Category
CW-YEC-1-14	Secondary sales
UCG-YEC-1-41	Hearing costs
YUB-YEC-1-26 & 46	LNG purchases
YUB-YEC-1-27	Diesel purchases
YUB-YEC-1-39	LNG/Diesel generation
YUB-YEC-1-59	Energy sales

25
26 **(d)**

27
28 Information in YEC's prior GRAs (e.g., the 2012-13 GRA) was provided using the same
29 format for test years (i.e., “Forecast Existing” and “Forecast Actual”) in order to provide

1 the same analysis regarding GRA impacts. YEC has not filed with the Board prior to the
2 GRA Application any of the specific forecast information relating to 2017 and 2018.

3

4 **(e)**

5

6 YEC is seeking approval for 2017 and 2018 revenue requirement under the “Forecast
7 Proposed” columns. As in past General Rate Applications, YEC has provided the
8 “Forecast Existing” columns to highlight the impacts that the general rate application would
9 have if approved.

1 **TOPIC:** Increased Operating Expenses since 2012-2013 GRA

2
3 **REFERENCE:** Application. PDF page 25, lines 28 to 29. PDF page 26, lines 1 to 2

4
5 **QUOTE:** “As noted in Section 1.1, material labour operating expense increases
6 occurred in 2013 above the approved forecast and have continued to
7 be a key cost driver since that time. The increase in labour expense
8 reflects negotiated wage increases, changes in capital/non-capital
9 allocations, and other increased costs without a major change in the
10 overall number of Full Time Equivalent [FTE] positions.”

11
12 **QUESTION:**

- 13
14 a) Please provide the date(s) at which the negotiation of wages were concluded, the
15 length of the negotiated term and the per cent associated with the increase in
16 wages.
17
18 b) Please clarify whether there were any non-negotiated wage increases and if so,
19 indicate the per cent associated with the increase in wages and the date on which
20 the increase came into effect.
21
22 c) Please clarify whether YEC has a vacancy rate with respect to its FTEs and if so,
23 provide the rate for the years 2013 through to 2018. Please also indicate in which
24 operational area¹ the vacancies occurred or are anticipated.
25
26 d) Please provide a table summarizing approved, actual and forecast key
27 assumptions, escalation (or inflation) factors or any other indices² examined or
28 used by YEC in its application for items such as labour (in scope and/or out of
29 scope), contractors, other labour cost categories, direct operating and
30 maintenance costs, non-direct operating and maintenance costs, and capital
31 costs.

¹ For example, using the categories identified on YEC 2017-2018 General Rate Application, Table 3.4, PDF page 55.

² For example, the Consumer Price Index (CPI) for Whitehorse.

ANSWER:

(a)

The only completed collective bargaining agreement during this period was for the period commencing January 1, 2014.

- i. Arbitration award was received on February 5, 2015
- ii. 3 year term
- iii. 2014 – 2%; 2015 2%; 2016 1.75%

(b)

The Management and Professional Group (non-union) was granted the same increments specified in (a) on the same dates.

(c)

Vacancy rates are shown in Table 1 below. YEC does not allocate forecast vacancies.

Table 1: Vacancy Rates

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018
President	0.0	0.3	-0.3	-0.1		
Human Resources & Info. Mgmt.	-0.1	-1.2	-1.2	-0.1		
Resource Planning and Environment	-1.0	0.0	0.6	-0.1		
Finance, Cust. Acctg. & Purchasing	-0.2	1.0	0.7	-0.1		
Operations	-1.9	-0.6	-1.7	-1.2		
Engineering Services	-1.2	-0.1	0.0	-0.3		
Unallocated					-2.0	-2.0
Total	-4.4	-0.6	-1.9	-1.9	-2.0	-2.0

(d)

YEC has assumed the following labour related changes (Table 2):

Table 2: Key Labour-related Assumptions

	2017	2018
Overtime hours	4%	-2%
Standby wage increase	\$0.16/hour	\$0.16/hour
Standby hours	-15%	1%
Other Benefits	5%	-3%

In addition to the factors in Table 2 above, YEC also included a general provision for forecast negotiated wages. The specific rate included cannot be provided at this time as this would compromise YEC's negotiations with the unions as part of the collective bargaining process. However, YEC can confirm that rates used in lieu of the actual wages increase were developed consistent with awards granted in arbitration in the last two collective agreement settlements.

YEC did not assume any general increase for non-labour costs.

1 **TOPIC:** Wholesale Sales to ATCO Electric Yukon, Section 2.2.1

2
3 **REFERENCE:** Application, page 2-4, PDF page 33, lines 11 to 13

4
5 **QUOTE:** “Subsequent to finalizing YEC’s forecast for this Application, Board
6 Order 2017-01 was issued on the AEY GRA and AEY filed its
7 Compliance Filing response for review by the Board and interveners.”
8

9 **QUESTION:**

- 10
11 a) Given the above quote and the issuance of Board O[r]der 2017-03 wherein the
12 Board accepted “the calculations and revisions to YECL’s 2016 through 2017
13 revenue requirement as submitted by AEY in its compliance filing”¹, please provide
14 an updated forecast for this Application.
15

16 **ANSWER:**

17
18 **(a)**

19
20 YEC’s forecast firm wholesales forecast for 2017 as referenced in this question is 309.0
21 GW.h, which is 8.7 GW.h higher than AEY’s initial GRA forecast, and 5.2 GW.h lower than
22 AEY’s approved Compliance Filing forecast of 314.2 GW.h in response to Board Order
23 2017-01.
24

25 Section 2.4 of YEC’s Application sets out the basis for this firm wholesale forecast for
26 2017. Please see the response to YUB-YEC-1-59 for an additional review of the basis for
27 YEC 2017 forecast firm wholesales, and the response to CW-YEC-1-11 for additional
28 background information.
29

30 YEC does not have the information used by AEY to prepare its Compliance Filing forecast,
31 or the details on this 2017 forecast by month as regards firm wholesales.
32

33 In response to this question, an updated 2017 firm wholesales forecast consistent with the
34 314.2 GW.h accepted by the Board in Order 2017-03 is provided in summary as follows
35 based on the information currently available to YEC:

¹ Board Order 2017-03, PDF page 3.

- Updated Sales (Table 2.1) is attached below, based on the following changes from the Application:
 - AEY firm wholesales for 2017 as per AEY Compliance Filing as approved by Order 2017-03 (increase of 5,234 MW.h, with related increase in revenues of \$0.434 million).
 - Assumed same increase for 2018 firm wholesales.
 - Assumed increase in Rider J revenues (approximately \$0.083 million increase in each test year).
 - Total revenue increase of approximately \$0.518 million in each test year.
- Updates re: firm generation required (Table 2.2) are summarized below:
 - Firm load generation (assumes 8.8% average losses added to sales):
 - 426,093 MW.h in 2017 (increase of 5,695 MW.h)
 - 426,879 MW.h for 2018 (increase of 5,695 MW.h)
 - LTA thermal generation (based on updated firm load generation and Table 3.4-1 of the Application):
 - 16,714 MW.h for 2017 (increase of 2,568 MW.h)
 - 17,100 MW.h for 2018 (increase of 2,620 MW.h)
- Based on the updated firm sales and LTA thermal generation, the following material changes in forecast costs are estimated (i.e., addresses two specific costs as noted without updating all revenue requirement numbers as would be required for a compliance filing):
 - LTA thermal fuel costs (assumes average thermal fuel cost of \$0.1584/kW.h per the Application fuel prices and 90/10 LNG/diesel split - excludes fuel costs for annual maintenance):
 - \$2.647 million for 2017 (increase of \$0.407 million)
 - \$2.708 million for 2018 (increase of \$0.415 million)
 - Mayo Flexible Debt interest (approximate increased interest costs based on 5.46% interest impact of 5.7 GW.h added generation, based on terms for this debt - assumed to be reflected in rate base return debt cost increase)
 - Approximate added interest of \$0.083 million for 2017
 - Approximate added interest of \$0.088 million for 2018
 - Overall added costs from the above two items:
 - \$0.490 million increase for 2017
 - \$0.503 million increase for 2018

- An updated Table 4.1 of the Application is attached below. In summary, overall net impacts of this update are estimated as follows:

- Increase of the revenue requirement
 - \$0.490 million increase for 2017
 - \$0.503 million increase for 2018
- Increase of revenues at existing rates
 - \$0.518 million increase for 2017
 - \$0.518 million increase for 2018
- Net decrease on additional firm rate revenue required
 - \$0.027 million increase for 2017
 - \$0.014 million increase for 2018

- An updated Table 4.2 of the Application is attached below. In summary, the overall impact of this update on the required Rider J increase is affected by the related estimated increase of approximately \$0.756 million in each year's consolidated revenue at existing base rates [before impact of changes in Rider J and Rider R revenues]. Overall changes to the total consolidated revenues at existing rates are affected by the lower final AEY Rider R as approved by Order 2017-03 (8.3% versus the 11.62% assumed in the YEC Application). Updated Table 4.2 shows the following:

- Rider J increase required in 2017 of 8.876% (decrease of 0.159% from the Application)
- Rider J increase required in 2018 of 2.070% (no change)
- Cumulative Rider J increase required by 2018 of 10.95%
- Total cumulative 2017 and 2018 rate increase required over existing rate revenues [including Rider J and Rider R revenues] is 9.19% (versus 9.08% in YEC's Application).

It is noted that the above estimates are subject to refinements in a full compliance filing update. However, the analysis addresses the main impacts of the wholesale sales update as requested in the question.

**Table 2.1 - Revised to reflect AEY Compliance Firm Wholesales for 2017
Summary of Customers, Energy Sales and Revenues**

Line No.	Description	2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual	Forecast	Forecast
							2017	2018
1	Residential							
2	Customers	1,536	1,559	1,561	1,588	1,609	1,624	1,635
3	Sales in MWh	12,408	13,385	13,327	13,121	13,390	13,622	13,719
4	MWh sales per customer	8.1	8.6	8.5	8.3	8.3	8.4	8.4
5	Revenue (\$000s)	1,815	1,943	1,938	1,913	1,956	2,002	2,016
6	Cents per KWh	14.6	14.5	14.5	14.6	14.6	14.7	14.7
7	General Service							
8	Customers	467	470	475	480	488	490	490
9	Sales in MWh	22,620	22,283	23,616	24,551	24,994	25,318	25,436
10	MWh sales per customer	48.4	47.4	49.8	51.1	51.2	51.7	51.9
11	Revenue (\$000s)	3,735	3,621	3,894	4,048	4,180	4,036	4,054
12	Cents per KWh	16.5	16.3	16.5	16.5	16.7	15.9	15.9
13	Industrial							
14	Sales in MWh	40,592	40,513	36,302	37,186	41,169	38,219	38,219
15	Revenue (\$000s)	4,787	4,595	3,958	4,159	4,478	4,198	4,198
16	Cents per KWh	11.8	11.3	10.9	11.2	10.9	11.0	11.0
17	Street lights							
18	Sales in MWh	279	281	290	290	256	225	214
19	Revenue (\$000s)	88	89	92	92	88	58	56
20	Cents per KWh	31.5	31.6	31.6	31.6	34.5	26.0	26.0
21	Space lights							
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	26.7	26.5	26.6	25.9	26.0	22.5	22.5
25	Total Company - Firm Retail & Ind.							
26	Customers	2,003	2,029	2,036	2,068	2,098	2,114	2,126
27	Sales in MWh	75,914	76,476	73,549	75,162	79,823	77,395	77,599
28	Revenue (\$000s)	10,429	10,252	9,886	10,214	10,705	10,297	10,327
29	Cents per KWh	13.7	13.4	13.4	13.6	13.4	13.3	13.3
30	Wholesale sales							
31	Sales in MWh	307,147	307,927	295,284	297,961	301,207	314,234	314,753
32	Revenue (\$000s)	25,487	25,546	24,503	24,725	24,994	26,075	26,118
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3	8.3	8.3
34	Total Company - Firm							
35	Sales in MWh	383,061	384,403	368,833	373,122	381,030	391,629	392,352
36	Revenue (\$000s)	35,916	35,798	34,388	34,939	35,700	36,372	36,445
37	Cents per KWh	9.4	9.3	9.3	9.4	9.4	9.3	9.3
38	Secondary							
39	Sales in MWh	0	3,959	5,415	7,030	4,835	11,464	11,464
40	Revenue (\$000s)	0	275	410	544	371	642	642
41	Cents per KWh	0.0	6.9	7.6	7.7	7.7	5.6	5.6
42	Total Company							
43	Sales in MWh	383,061	388,363	374,248	380,152	385,865	403,093	403,816
44	Revenue (\$000s)	35,916	36,073	34,798	35,483	36,071	37,014	37,087
45	Cents per KWh	9.4	9.3	9.3	9.3	9.3	9.2	9.2
46	Rider J (\$000s)	6,163	6,288	6,167	6,172	6,342	6,447	6,456
47	Total Sales Revenues¹	42,079	42,360	40,966	41,655	42,413	43,461	43,543
48	Total Sales Revenues excluding secondary sales	42,079	42,086	40,556	41,111	42,042	42,819	42,901

Note:

1. Excludes revenues from other revenues.

Table 4.1: YEC 2017/18 GRA
Yukon Energy Revenue Required from Rates (\$000s)
Revised to reflect AEY Compliance Firm Wholesales for 2017

	2017	2018
Revenue Requirement	\$49,034	\$50,367
Less: Other Revenues	\$ 253	\$ 253
Less: Secondary Sales	\$ 642	\$ 642
Revenue Required from Firm Rates	\$48,139	\$49,472
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	<u>\$ 42,819</u>	<u>\$ 42,901</u>
Additional Firm Rate Revenues Required	\$5,321	\$6,571

Table 4.2: Calculation of Required 2017 and 2018 Rate Increases (Rider J)
Revised to reflect AEY Compliance Firm Wholesales for 2017

Line #			Forecast 2017	Forecast 2018
1a	Consolidated Firm Retail Sales Revenues - Base Rates ¹	\$000	55,746	55,830
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	\$000	4,198	4,198
2a	Consolidated Rider J Revenues ²	\$000	6,447	6,456
2b	AEY Rider R Revenues ³	\$000	4,975	4,982
3=1+2	Total Consolidated Firm Sales Revenues at existing rates	\$000	71,366	71,466
4=Table 1	Retail Revenue increase required in 2017	\$000	5,321	
5=4/3	Required Rate Increase	%	7.46%	
6=3+4	Total Consolidated Firm Sales Revenues with 2017 Increase	\$000	76,687	76,795
7=Table 1	Total Revenue increase required in 2018	\$000		6,571
8=6-3	To Be Recovered from 2017 Increase	\$000		5,328
9=7-8	Total net increase required in 2018	\$000		1,243
10=9/6	Required Rate Increase in 2018	%		1.62%
11=9+6	Total Consolidated Firm Sales Revenues with 2018 Increase	\$000		78,037
12	Total Cumulative 2017 and 2018 Rate Increases (compounded)			9.19%
	Rider J Required			
13a=4/(1a+1b)	Rider J Increase Required	%	8.876%	
13b=9/(1a+1b)	Rider J Increase Required	%		2.070%
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	%	19.89%	21.96%
17=13+15	Total Rider J with increases - industrial	%	16.24%	18.31%
18	Total Consolidated Firm Sales Revenues with increases	\$000	\$76,687	\$78,037

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 existing 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 final (Order 2017-03) 2018 Rider R at 8.3% for firm retail and industrial base rate sales of YEC and AEY.

TOPIC: Increase in 2017 Forecast for LTA Wind Generation

REFERENCE: Application, PDF page 47, Table 2.2

QUOTE: LTA Wind Generation

2013 Approved	2013 Actual	2014 Actual	2015 Actual	2016 Actual
238	238	238	238	238

Existing Forecast 2017	Proposed Forecast 2017	Existing Forecast 2018
238	580	238

Proposed Forecast 2018
580

PREAMBLE: Explanation needed for the increase of LTA wind generation from 238 MWh under the existing forecast column to 580 MWh under the proposed forecast column for the test years.

QUESTION:

- a) Considering that the LTA wind generation has not changed from the years 2013 to 2016 and that the existing forecast for the test years is the same as the actuals for the years 2013 to 2016, please explain the significant increase in LTA wind generation for the proposed forecast and the assumptions and factors underlying the proposed forecast for the test years is based.

ANSWER:

(a)

LTA wind generation is different from actual wind generation. LTA Wind generation for the years 2013 to 2016 is fixed and is based on the approved amount in YEC's last General Rate Application. LTA wind generation is used for the calculation of Diesel Contingency Fund costs.

1 YEC is seeking approval to adjust the LTA wind generation from 238 MWh to 580 MWh,
2 based on a change in actual circumstances.

3
4 As shown at Line 11 of Table 2.2 in YEC's current Application, under the section "Actual
5 Generation – MWh" (as opposed to the section "LTA Generation – MWh"), actual wind
6 generation for the years 2013 to 2016 was:

7

	2013	2014	2015	2016
Actual wind generation (MWh)	277	337	650	509

8
9 Generation in 2015 increased over previous years due to changes made to the turbine
10 blades, greatly increasing efficiency. The noted increase in LTA wind generation to 580
11 MWh is based on the average of the actual wind generation for the years 2015 and 2016.

1 **TOPIC:** **Proposed Increases to 2017 and 2018 Revenue Requirement**
2 **Forecasts**

3
4 **REFERENCE:** Application. Page 3-2 and PDF page 50, lines 16 to 21 and Tab 7,
5 Schedule 5, line 14, PDF page 286
6

7 **QUOTE:** “In general, Yukon Energy’s forecast 2017 and 2018 revenue
8 requirements primarily reflect proposed adjustments to thermal
9 generation requirements and fuel prices, changes to labour and non-
10 labour costs, increases in rate base, as well as changes in the proposed
11 return on equity (ROE) relative to 2013 GRA approved forecast (“2013
12 approved”) numbers, the last test year reviewed by the Board during
13 Yukon Energy’s 2012/2013 GRA application.”
14

15 **PREAMBLE:** The Board requires summary information for the 2017 and 2018 test
16 years, which identifies the reasons contributing to the proposed
17 revenue requirement increase of \$5.9 million¹ (13.7 per cent) over the
18 2016 actual revenue requirement and \$1.3 million² (2.7 per cent) over
19 the 2017 proposed forecast revenue requirement.
20

21 **QUESTION:**
22

- 23 a) Please provide a table for each of the test years summarizing the main reasons
24 for the proposed forecast requirement increases over the 2016 actual and 2017
25 proposed forecast revenue requirement amounts. The tables should provide a high
26 level summary justifying the revenue requirement increase of \$5.9 million and \$1.3
27 million while at the same time providing a breakdown of the related increase or
28 decrease amount by each major contributing factor, such as inflation, full-time
29 equivalent (FTE) additions, wage increases, capital/non-capital allocations, capital
30 expenditures or those factors identified in the referenced quote.

¹ Calculated as: 2017 proposed forecast revenue requirement of \$48.544 million less 2016 actual revenue requirement of \$42.686 million equals \$5.678 million.

² Calculated as: 2018 proposed forecast revenue requirement of \$49.864 million less 2017 proposed forecast revenue requirement of \$48.544 million equals \$1.32 million.

b) Please explain what is meant by “proposed adjustments to thermal generation requirements.”

ANSWER:

(a)

Please see Tables 1 and 2 below.

Table 1: Summary of Key Revenue Requirement Increases – 2016 to 2017

	Revenue Requirement (\$000)				
	2016	2017	Change		Major Factor for Change
Fuel and Purchased Power (Table 3.2)	\$ 2,159	\$ 2,381	\$ 222	10.3%	
Expected thermal generation (GW.h) (Table 2.2)	10.5	14.1	3.6	34.3%	Increased firm grid load
Average fuel cost (\$/kW.h)	0.206	0.158	(0.048)	-23.3%	Lower LNG cost, and higher LNG share of expected generation
Non-Fuel Operating and Maintenance (Table 3.1)	\$ 20,470	\$ 22,060	\$ 1,590	7.8%	
Brushing Costs (Table 3.6.1)	\$ 502	\$ 1,487	\$ 985	196.2%	Expensing all brushing related costs, deferral account impacts
Non Labour Administration (Table 3.9)	\$ 2,726	\$ 3,149	\$ 423	15.5%	Env. Management, General, Union, Information Systems
Depreciation and Amortization (Table 3.14)	\$ 7,816	\$ 10,814	\$ 2,998	38.4%	
Fixed asset depreciation net of customer contrib.	\$ 6,497	\$ 7,194	\$ 697	10.7%	\$941k increase re: deferred costs brought into rate base with GRA
Amortization of deferred charges	\$ 1,581	\$ 3,883	\$ 2,302	145.6%	\$1,731k increase re: deferred costs brought into rate base with GRA
Return on Rate Base (Table 3.1)	\$ 12,242	\$ 13,289	\$ 1,047	8.6%	
Mid-year Rate Base (Table 3.13)	\$ 258,060	\$ 274,459	\$ 16,399	6.4%	\$8,955k increase re: deferred costs brought into rate base with GRA
Return on Equity (Schedule 4B)	\$ 9,002	\$ 9,711	\$ 709	7.9%	Rate base growth and ROE increase from 8.69% to 8.82%
Cost of Debt (Schedule 4B)	\$ 3,239	\$ 3,578	\$ 339	10.5%	Rate base growth and Av. Debt cost increase from 2.10% to 2.18%
Revenue Requirement	\$ 42,687	\$ 48,544	\$ 5,857	13.7%	

1 **Table 2: Summary of Key Revenue Requirement Increases – 2017 to 2018**

	2017	2018	Change	Major Factor for Change
Fuel and Purchased Power (Table 3.2)	\$ 2,381	\$ 2,407	\$ 26	1.1%
Expected thermal generation (GW.h) (Table 2.2)	14.1	14.5	0.3	2.4% Increased firm grid load
Non-Fuel Operating and Maintenance (Table 3.1)	\$ 22,060	\$ 22,016	-\$ 44	-0.2%
Non Labour Administration (Table 3.9)	\$ 3,149	\$ 3,001	-\$ 148	-4.7% Expected decrease in union, general, and env. Management costs
Labour (Table 3.3)	\$ 11,770	\$ 11,823	\$ 53	0.5%
Non Labour Production Costs (Table 3.5)	\$ 1,750	\$ 1,799	\$ 49	2.8% Hydro and LNG plant increases
Depreciation and Amortization (Table 3.14)	\$ 10,814	\$ 11,094	\$ 280	2.6%
Fixed asset depreciation net of customer contrib.	\$ 7,194	\$ 7,465	\$ 271	3.8% Rate base growth
Amortization of deferred charges	\$ 3,883	\$ 3,891	\$ 8	0.2%
Return on Rate Base (Table 3.1)	\$ 13,289	\$ 14,348	\$ 1,059	8.0%
Mid-year Rate Base (Table 3.13)	\$ 274,459	\$ 291,627	\$ 17,168	6.3%
Return on Equity (Schedule 4B, 4C)	\$ 9,711	\$ 10,290	\$ 579	6.0% Rate base growth
Cost of Debt (Schedule 4B, 4C)	\$ 3,578	\$ 4,058	\$ 480	13.4% Rate base growth and Av. Debt cost increase from 2.18% to 2.32%
Revenue Requirement	\$ 48,544	\$ 49,865	\$ 1,321	2.7%

(b)

The reference to “proposed adjustments in thermal generation requirements” is that forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 90% LNG and 10% diesel generation. (This is reviewed in Section 3.2 and Appendix 3.4 of the Application, and in response to YUB-YEC-1-25).

1 **TOPIC:** **Proposed Increases to 2017 and 2018 Non-Fuel Operating and**
2 **Maintenance**

3
4 **REFERENCE:** Application, Table 3.1. PDF page 50

5
6 **PREAMBLE:** With respect to non-fuel operating and maintenance costs, the Board
7 requires summary information for the 2017 and 2018 test years, which
8 identifies the reasons contributing to the proposed increase of \$1.59
9 million¹ (7.8 per cent) over the 2016 actual non-fuel operating and
10 maintenance costs and -\$0.044 million² (0.2 per cent) under the 2017
11 proposed non-fuel operating and maintenance costs.
12

13 **QUESTION:**
14

- 15 a) Please provide a table for each of the test years summarizing the main reasons
16 for the proposed forecast non-fuel operating and maintenance cost increase or
17 decrease over the 2016 actual and 2017 proposed forecast revenue requirement
18 amounts. The tables should provide a high level summary justifying the revenue
19 requirement increase of \$1.59 million and decrease of \$0.044 million while at the
20 same time providing a breakdown of the related increase or decrease amount by
21 each major contributing factor, such as inflation, full-time equivalent (FTE)
22 additions, wage increases, capital/non-capital allocations, or any other factor
23 identified by YEC.
24

25 **ANSWER:**
26

27 **(a)**
28

29 Please see the response provided to YUB-YEC-1-5(a).

¹ Calculated as: 2017 proposed non-fuel operating and maintenance costs of \$22.060 million less 2016 actual non-fuel operating and maintenance costs of \$20.470 million equals \$1.59 million.

² Calculated as: 2018 proposed non-fuel operating and maintenance costs of \$22.016 million less 2017 proposed non-fuel operating and maintenance costs of \$22.060 million equals -\$0.044 million.

1 **TOPIC: Capital/Maintenance Allocation**

2
3 **REFERENCE:** Application. PDF page 54, lines 19 to 23

4
5 **QUOTE:** “The 2013 approved revenue requirement forecasts included an
6 allocation set at 23% capital and 77% maintenance. Actual results over
7 the 2013 to 2016 period varied between 20:80 and 16:84. The
8 allocation for the 2017 and 2018 forecasts have been adjusted to align
9 with historical results and are set at 18:82.”

10
11 **QUESTION:**

- 12
13 a) Please clarify which years were included in the “historical results” used to
14 determine the 2017 and 2018 forecast capital to maintenance allocation ratio.
15
16 b) Why does YEC consider that a forecast based on a span of years of historical
17 results would be more representative than a forecast based on the most recent
18 year’s actual results? Please explain.
19
20 c) In general, to what does YEC attribute the variation in capital to maintenance
21 allocation ratios between the approved (23:77) and the proposed (18:82)?
22
23 d) Please provide the 2016 actual capital to maintenance allocation ratio. In general,
24 to what does YEC attribute the variation in capital to maintenance allocation ratios
25 of capital to maintenance between the 2016 actual allocation ratio and the
26 proposed (18:82)?
27

28 **ANSWER:**

29
30 **(a) through (d)**

31
32 Please see Table 1 below. The historical results for the years 2013 to 2016 were used to
33 determine the 2017 and 2018 forecast capital to maintenance ratio allocation. The actual
34 results for the previous five years are shown below. 2017 and 2018 are based on an
35 average of 2013 to 2016 actuals.

Table 1: Actual Results: 2012 to 2016

	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2013 -2016 Average
Capital	31%	17%	17%	20%	16%	18%
Maintenance	69%	83%	83%	80%	84%	82%

Actual results in any given year can be impacted by different factors such as one-time large projects that may increase or decrease the ratio. 2017 and 2018 were not forecast based on 2016 results as different projects will be worked on. Based on the variability of actual results each year, 2017 and 2018 forecasts were based on the average of historical results.

In general, YEC attributes the variation in capital to maintenance allocation ratios to a combination of factors including:

- Variability of projects worked on in any given year;
- Variability of labour time that is required on a specific project;
- Variability of maintenance issues that may arise that may delay capital work; and
- General availability of internal resources.

1 **TOPIC: Allocation of Employee Complement to YDC**

2
3 **REFERENCE:** Application. PDF pages 54 to 56 and Table 3.4, PDF page 55

4
5 **PREAMBLE:** YEC discusses labour expense, FTE's and labour complement
6 beginning at PDF pages 54 and ending on 56 of its application.

7
8 Further, Table 3.4 indicates that the employee complement history
9 provided therein, is "net of allocation to YDC."

10
11 **QUESTION:**

12
13 a) Please clarify that, with the exception of Table 3.4, all other information provided
14 by YEC in PDF pages 54 to 56 is similarly, "net of allocation to YDC." If not
15 confirmed, please explain.

16
17 b) Please prepare a table showing total actual 2016 employee complement history
18 (before allocation to YDC) and actual 2016 allocation of employee complement to
19 YDC and net actual 2016 allocation of employee complement after allocation to
20 YDC.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Confirmed.

27
28 **(b)**

29
30 Please see Table 1 provided below.

1

Table 1: 2016 Employee Complement History

Before Allocation to YDC

President	5.1
Communications	1.0
Human Resources & Info. Mgmt.	5.2
Resource Planning & Environment	6.0
Finance, Cust. Acctg. & Purchasing	17.1
Operations	44.1
Engineering Services	13.0
Health, Safety	2.0

Total Before Allocation to YDC	93.5

Allocation to YDC

Finance, Cust. Acctg. & Purchasing	-0.2

Net Allocation

President	5.1
Communications	1.0
Human Resources & Info. Mgmt.	5.2
Resource Planning & Environment	6.0
Finance, Cust. Acctg. & Purchasing	16.9
Operations	44.1
Engineering Services	13.0
Health, Safety	2.0

Total After Allocation	93.3

2

TOPIC: Production Costs

REFERENCE: Application, Table 3.5. PDF page 56

QUESTION:

- a) For the line item cost categories of labour, diesel, LNG and hydro, please provide reasons for differences between 2016 actual costs and 2017 proposed forecast costs, and differences between 2017 and 2018 proposed forecast costs.

ANSWER:

(a)

Please see Table 1 and Table 2 below.

Table 1: Production Costs Changes (2016/2017)

(\$000's)	Actual 2016	Forecast 2017	Change	Reasons for differences
Labour	\$ 4,133	\$ 4,010	\$ (123)	Overall change in capital/maintenance labour allocation from 16/84 to 18/82
Diesel	\$ 548	\$ 436	\$ (111)	Reduction in heating fuel
LNG	\$ 224	\$ 155	\$ (69)	Bi-annual maintenance schedule
Hydro	\$ 1,058	\$ 1,075	\$ 17	Not significant

Table 2: Production Costs Changes (2017/2018)

	Forecast 2017	Forecast 2018	Change	Reasons for differences
Labour	\$ 4,010	\$ 4,109	\$ 99	Additional maintenance mechanic
Diesel	\$ 436	\$ 425	\$ (11)	Not significant
LNG	\$ 155	\$ 196	\$ 41	Bi-annual maintenance schedule
Hydro	\$ 1,075	\$ 1,093	\$ 17	Not significant

TOPIC: General Operating and Maintenance Costs

REFERENCE: Application, Table 3.8. PDF page 59

QUESTION:

a) For the line item cost categories of labour, transportation and maintenance, please provide reasons for differences between 2016 actual costs and 2017 proposed forecast costs.

b) For the cost category identified as maintenance of company owned properties, please provide reasons for the differences between 2017 and 2018 proposed forecasts.

ANSWER:

(a) and (b)

Please see the Table 1 below.

Table 1: Changes in Labour, Transportation and Maintenance Costs (2016/2017)

(\$000's)	Actual 2016	Forecast 2017	Change	Reasons for differences
Labour	\$ 366	\$ 394	\$ 29	Not significant
Transportation	\$ 459	\$ 501	\$ 42	Expected increase in vehicle fuel costs
Maintenance of Company Owned Properties	\$ 501	\$ 535	\$ 35	Increased staff housing repairs and maintenance in Dawson and Mayo

Table 2: Changes in Labour, Transportation and Maintenance Costs (2017/2018)

(\$000's)	Forecast 2017	Forecast 2018	Change	Reasons for differences
Maintenance of Company Owned Properties	\$ 535	\$ 508	\$ (27)	Not significant

1 **TOPIC: Administrative costs**

2
3 **REFERENCE:** Application, Table 3.9. PDF page 61

4
5 **QUESTION:**

6
7 a) For the line item cost categories of labour, customer accounting, environmental
8 management, general, information systems, training, recruitment, board of
9 directors, union, regulatory affairs and professional development, please provide
10 reasons for differences between 2016 actual costs and 2017 proposed forecast
11 costs.

12
13 b) For the line item cost categories of labour, environmental management, general,
14 information systems, recruitment and union, please provide reasons for
15 differences between 2017 and 2018 proposed forecast costs.

16
17 **ANSWER:**

18
19 **(a) and (b)**

20
21 Please see Table 1 and Table 2 below.

Table 1: Administration (2016/2017)

(\$000's)	Actual 2016	Forecast 2017	Change	Reasons for Differences
Labour	5,783	5,961	\$ 178	Increase in forecast wage rate, additional IT costs
Customer Accounting	208	224	\$ 16	Expected increased Atco Electric Yukon fees
Environmental Mgmt	166	278	\$ 112	2016 was abnormally low, as well as one-time \$0.040M of Hazardous Waste costs
General	613	705	\$ 92	Increased Engineering external consulting
Information Systems	576	631	\$ 55	Increased IT external consulting and license fees
Training	143	175	\$ 32	Annual budget of \$0.175M, however, in 2016 YEC received government funding
Recruitment	231	244	\$ 13	Nothing significant
Board of Directors	160	182	\$ 22	Increased training costs
Union	0	95	\$ 95	2016 Collective Bargaining
Regulatory Affairs	99	33	\$ (66)	Reduction in external consulting
Professional Development	3	15	\$ 12	Employment contract specifies \$0.015 of training

Table 2: Administration (2017/2018)

(\$000's)	Forecast 2017	Forecast 2018	Change	Reasons for Differences
Labour	5,961	5,911	\$ (50)	Elimination of receptionist position
Environmental Mgmt	278	238	\$ (40)	Reduction in one-time Hazardous Waste costs
General	705	662	\$ (43)	Reduction in Finance external consulting
Information Systems	631	645	\$ 14	Additional data circuits
Recruitment	244	229	\$ (15)	Nothing significant
Union	95	20	\$ (75)	Completion of 2016 Collective Bargaining

1 **TOPIC:** **Deferral and Reserve Accounts**

2
3 **REFERENCE:** Application. PDF page 64, lines 6 to 9, PDF page 66, lines 9 to 13, and
4 Schedule 1, lines 6, 8, 9 and 18, PDF page 279

5
6 **QUOTE:** “Yukon Energy’s rate base includes all investment providing service to
7 ratepayers, as well as components of necessary working capital. It
8 comprises property, plant and equipment (net of depreciation), deferred
9 study and other costs, reserves set aside for various regulatory
10 purposes and working capital as indicated in Schedule 1 of Tab 7 of
11 this submission.”

12
13 “The largest component of deferred charges relates to planning and
14 study costs, regulatory hearing costs and licensing costs related to
15 maintaining licenses of YEC’s hydro facilities and air emission permits.

16
17 “The amortization of planning costs is the largest component of
18 deferred costs, which is primarily studies of the existing system and
19 options for expanding the quantity of renewable generation, as well as
20 studies related to the safety and reliability of the system, and other
21 small projects.”

22
23 **PREAMBLE:** The Board has examined Schedule 1 (lines 6, 8, 9 and 18) of Tab 7 and
24 requires information with respect to the sub-categories of costs that
25 comprise all deferral and reserve accounts included in YEC’s rate base
26 calculations.

27
28 **QUESTION:**

- 29
30 a) Please prepare a continuity schedule for each sub-category of costs comprising
31 YEC’s deferral and reserve accounts for the years 2013 to 2018. The schedules
32 should detail the transactions for each individual sub-category of deferral account
33 or provision for reserve and should correspond, when totalled, to the amounts
34 shown on the lines referenced in the preamble. For each sub-category of costs,
35 please also provide a brief explanation of any approval YEC is seeking with respect
36 to the costs identified (for example, elimination of the deferred balance) and the
37 basis for any annual amortization calculation.

b) Please clarify whether any other Tab 7 schedules contain amounts for deferral or reserve accounts, and if so, please provide on a sub-category basis, the same information as requested in part (a).

ANSWER:

(a)

The continuity schedule for Miscellaneous Reserves is provided in Table 1 below.

Table 1: Miscellaneous Reserves

	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast Existing 2017	Forecast Proposed 2017	Forecast Existing 2018	Forecast Proposed 2018
Reserve for Injuries and Damages (as per Table 3.11.1)								
Opening Balance	-\$152	-\$330	-\$300	-\$267	-\$1,059	-\$1,059	-\$1,136	-\$847
Annual Appropriation	226	226	226	226	190	479	190	479
Annual Costs	-404	-196	-193	-1,018	-267	-267	-267	-267
Closing Balance	-\$330	-\$300	-\$267	\$1,059	-\$1,136	-\$847	-\$1,213	-\$635
Deferred Gain on Fire Insurance Proceeds								
Opening Balance	\$6,276	\$6,014	\$5,752	\$5,490	\$5,228	\$5,228	\$4,966	\$4,966
Annual Amortization	-262	-262	-262	-262	-262	-262	-262	-262
Closing Balance	\$6,014	\$5,752	\$5,490	\$5,228	\$4,966	\$4,966	\$4,704	\$4,704
Miscellaneous Reserves (Schedule 1, Line 6)								
Closing Balance	\$5,684	\$5,452	\$5,223	\$4,169	\$3,830	\$4,119	\$3,491	\$4,069

YEC is seeking approval of the following as per the Application, Page 3-15:

- Line 3: amortize the 2016 RFID balance of -\$1.059 million over a five-year period (\$0.212 million per year). The amortization period proposed is consistent with Board Order 2013-01 which approved amortization of the 2011 balance over a five-year period).

- Line 5: increase the appropriation to the RFID from \$0.190 million to \$0.267 million based on the ten-year average of actual expenses from 2006 to 2015 as shown in Table 3.11.

The continuity schedule for Deferred Study Costs is provided in Table 2 below.

Table 2: Deferred Study Costs

(\$000's)	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast		Forecast	
					Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Vegetation Management (as per Table 3.14.2)								
Opening Balance	\$0	\$0	\$917	\$1,644	\$2,215	\$2,215	\$3,200	\$1,994
Annual Deferred Cost	\$0	\$917	\$727	\$571	\$985	\$0	\$990	\$0
Annual Amortization	\$0	\$0	\$0	\$0	\$0	-\$222	\$0	-\$222
Closing Balance	\$0	\$917	\$1,644	\$2,215	\$3,200	\$1,994	\$4,190	\$1,772
Feasibility and Licensing								
Opening Balance	\$23,160	\$21,196	\$22,116	\$18,792	\$23,338	\$23,338	\$27,319	\$25,817
Net Additions	\$1,239	\$2,685	-\$1,557	\$5,131	\$4,647	\$4,647	\$17,006	\$17,006
Net Amortization	-\$3,202	-\$1,766	-\$1,766	-\$586	-\$666	-\$2,168	-\$666	-\$2,303
Closing Balance	\$21,196	\$22,116	\$18,792	\$23,338	\$27,319	\$25,817	\$43,660	\$40,521
Dam Safety Review								
Opening Balance	\$71	\$47	\$24	\$144	\$148	\$148	\$152	\$118
Net Additions	\$0	\$0	\$144	\$3	\$4	\$0	\$3	\$0
Net Amortization	-\$24	-\$24	-\$24	\$0	\$0	-\$30	\$0	-\$30
Closing Balance	\$47	\$24	\$144	\$148	\$152	\$118	\$155	\$89
DSM								
Opening Balance	\$1,183	\$1,400	\$1,783	\$2,080	\$2,484	\$2,484	\$2,884	\$2,445
Net Additions	\$217	\$383	\$298	\$403	\$400	\$210	\$600	\$625
Net Amortization	\$0	\$0	\$0	\$0	\$0	-\$248	\$0	-\$269
Closing Balance	\$1,400	\$1,783	\$2,080	\$2,484	\$2,884	\$2,445	\$3,484	\$2,801
Hearing Cost Reserve Account (as per Table 3.14.1)								
Opening Balance	\$0	-\$106	-\$224	-\$561	-\$973	-\$973	-\$1,523	-\$1,028
Annual Appropriation	-\$550	-\$550	-\$550	-\$550	-\$550	-\$55	-\$550	-\$55
Annual Costs	\$444	\$432	\$213	\$138	\$0	\$0	\$818	\$818
Closing Balance	-\$106	-\$224	-\$561	-\$973	-\$1,523	-\$1,028	-\$1,255	-\$266
Other Regulatory								
Closing Balance	\$1,569	\$0	-\$143	\$0	\$0	\$0	\$0	\$0
Deferred Study Costs (Schedule 1, Line 8)								
Closing Balance	\$24,106	\$24,615	\$21,957	\$27,212	\$32,031	\$29,346	\$50,232	\$44,917

1 YEC is seeking approval of the following as per the Application:

- 2
- 3 • Page 3-19, Line 25-Page 3-20, Line 1: amortize the 2016 vegetation management
- 4 deferral account balance of \$2.215 million over a ten-year period (\$0.222 million
- 5 per year). The amortization period of ten years is proposed to be consistent with
- 6 YEC policy of amortizing deferred costs greater than \$1 million over ten years.
- 7
- 8 • Page 3-20, Lines 1-2: elimination of the requirement to defer brushing costs in
- 9 excess of 2011 actual brushing costs.
- 10
- 11 • Page 5-30, Lines 14-19: transfer approximately \$13.9 million of deferred costs to
- 12 rate base at the start of 2017 (includes closing of projects as well as deferred costs
- 13 carried over from the last GRA at the direction of the Board, including DSM).
- 14
- 15 • Page 5-43, Lines 16-17: project related DSM costs are proposed to be closed out
- 16 and amortized each year over a ten-year period.
- 17
- 18 • Page 3-19, Lines 14-15: amortize the 2016 hearing cost reserve account balance
- 19 of \$0.973 million over a five-year period (\$0.195 million per year). The amortization
- 20 period of five years is proposed to be consistent with YEC policy of amortizing
- 21 deferred costs less than \$1 million over five years.
- 22
- 23 • Page 3-19, Lines 16-17: decrease the annual provision to the hearing cost reserve
- 24 account, starting 2017, to \$0.250 million per year.
- 25

26 The continuity schedule for Studies in Progress is provided in Table 3 below.

1

Table 3: Studies in Progress

(\$000's)					Forecast		Forecast	
	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Feasibility and Licensing (as per Tables 5.3-5.8)								
Opening Balance	\$12,169	\$11,914	\$14,496	\$16,432	\$21,394	\$21,394	\$25,435	\$15,350
Net Additions	\$2,098	\$2,582	\$2,448	\$5,154	\$4,387	\$4,387	\$16,021	\$16,021
Net Transfers	-\$2,354	\$1	-\$511	-\$193	-\$346	-\$10,431	-\$370	-\$1,512
Closing Balance	\$11,914	\$14,496	\$16,432	\$21,394	\$25,435	\$15,350	\$41,086	\$29,859
Dam Safety Review (as per Tables 5.3-5.8)								
Opening Balance	\$0	\$0	\$0	\$144	\$148	\$148	\$148	\$0
Net Additions	\$0	\$0	\$144	\$3	\$0	\$0	\$0	\$0
Net Transfers	\$0	\$0	\$0	\$0	\$0	-\$148	\$0	\$0
Closing Balance	\$0	\$0	\$144	\$148	\$148	\$0	\$148	\$0
Regulatory (as per Tables 5.3-5.8)								
Opening Balance	\$1,410	\$1,704	\$2,277	\$2,493	\$3,187	\$3,187	\$4,110	\$818
Net Additions	\$758	\$1,177	\$440	\$694	\$923	\$923	\$0	\$0
Net Transfers	-\$464	-\$604	-\$224	\$0	\$0	-\$3,292	-\$818	-\$818
Closing Balance	\$1,704	\$2,277	\$2,493	\$3,187	\$4,110	\$818	\$3,292	\$0
Other¹								
Closing Balance	\$0	\$0	\$0	\$0	\$3,933	\$0	\$5,544	\$0
Studies in Progress (Schedule 1, Line 9)								
Closing Balance	\$13,618	\$16,773	\$19,070	\$24,728	\$33,625	\$16,167	\$50,069	\$29,859

Note 1: The 2017 and 2018 Existing Forecasts on Schedule 1 incorrectly included certain assets in WIP

2

3

4 The continuity schedule for Mid-Year Regulatory Deferral is provided in Table 4 below.

1

Table 4: Mid-Year Regulatory Deferral

(\$000's)					Forecast		Forecast	
	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Rate Case Assets								
Opening Balance	\$2,742	\$643	\$2,091	\$1,922	\$2,200	\$2,200	\$3,120	\$2,693
Net Change	-2,099	1,448	-169	278	920	493	-331	-972
Closing Balance	\$643	\$2,091	\$1,922	\$2,200	\$3,120	\$2,693	\$2,789	\$1,722
Mid-Year Regulatory Deferral (Schedule 1, Line 18)								
Balance	\$1,693	\$1,367	\$2,007	\$2,061	\$2,660	\$2,447	\$2,955	\$2,208

2

3 **(b)**

4

5 Schedule 3, Tab 7 includes a reconciliation of the Reserve for Future Removal and Site
6 Restoration. As per the direction of the YUB in Order 2005-12, there are no further
7 appropriations to this account. YEC is not requesting any changes to this account.

TOPIC: Two-Part Solution to Reserve Account Balances

REFERENCE: Application. PDF pages 63 and 67

PREAMBLE: For each of the hearing cost reserve account and RFID account, YEC is seeking approval of a “two-part solution” to the growing account balances.

For the RFID account, YEC proposes to:

“1. Amortize the 2016 negative balance of \$1.059 million over a 5-year period (\$0.212 million per year).

“2. Increase the annual appropriation to the RFID, starting in 2017, to \$0.267 million per year. This is based on the 10-year average of actual expenses as shown in Table 3.11 below.”

**Table 3.11.1:
RFID Continuity Schedule
(\$000)**



	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast		Forecast	
					Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Opening Balance	-\$152	-\$330	-\$300	-\$267	-\$1,059	-\$1,059	-\$1,136	-\$847
Annual Appropriation	226	226	226	226	190	479	190	479
Annual Costs	-404	-196	-193	-1,018	-267	-267	-267	-267
Closing Balance	-\$330	-\$300	-\$267	-\$1,059	-\$1,136	-\$847	-\$1,213	-\$635

For the hearing cost reserve account, YEC proposes to:

“1. Amortize the forecast 2016 credit balance of \$0.973 million over a 5-year period (\$0.195 million per year).

“2. Decrease the annual provision to the hearing cost reserve account, starting 2017, to \$0.250 million per year.”

**Table 3.14.1:
Hearing Cost Reserve Account Continuity Schedule
(\$000)**



	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast		Forecast	
					Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Opening Balance	\$0	-\$106	-\$224	-\$561	-\$973	-\$973	-\$1,523	-\$1,028
Annual Appropriation	-550	-550	-550	-550	-550	-55	-550	-55
Annual Costs	444	432	213	138	0	0	818	818
Closing Balance	-\$106	-\$224	-\$561	-\$973	-\$1,523	-\$1,028	-\$1,255	-\$266

1 **QUESTION:**

- 2
- 3 a) Table 3.11.1 and Table 3.14.1 show that each of the accounts have negative
- 4 closing balances in the year 2016 in the amounts of -\$1.059 million for the RFID
- 5 account and -\$0.973 million for the hearing cost reserve account, yet are referred
- 6 to in the referenced quotes as “2016 negative balance of \$1.059 million” and “2016
- 7 credit balance of \$0.973 million.” Please provide an explanation for this
- 8 discrepancy.
- 9
- 10 b) Please explain why the annual costs shown in the two tables are in opposing
- 11 directions. For example, the annual costs in the RFID account are shown as
- 12 negative amounts, whereas the annual costs in the hearing cost reserve account
- 13 are shown as positive amounts.
- 14
- 15 c) Please confirm the calculation of the annual appropriation for each of the accounts
- 16 given that the amortization of the -\$1.059 million RFID appears to increase the
- 17 total annual amortization amount by \$0.212 million and the amortization of the -
- 18 \$0.973 million hearing cost reserve appears to decrease the annual amortization
- 19 amount by \$0.195 million.
- 20
- 21 d) Has YEC requested in past applications, this same two-part solution, for any other
- 22 deferral or reserve account balances? If so, please explain.

23

24 **ANSWER:**

25

26 **(a)**

27

28 The negative balances have different meaning.

29

30 The RFID is over-subscribed, i.e., the costs incurred exceed the sum of the annual

31 appropriations. Therefore, this account is in a debit balance which is due from ratepayers.

32 The Hearing Reserve Account is undersubscribed, i.e., the costs incurred are less than

33 the sum of the annual appropriations. This account is in a credit balance – due to

34 ratepayers.

1 **(b)**

2
3 The annual costs are in opposing directions as the annual costs for the RFID increase the
4 asset position while the annual costs for the hearing cost reserve account reduce the
5 liability position.

6
7 **(c)**

8
9 YEC confirms the amortization of the RFID balance increases the total annual amortization
10 by \$0.212 million and the amortization of the hearing cost reserve account decreases the
11 total annual amortization by \$0.195 million.

12
13 **(d)**

14
15 Yes. In YEC's 2012/2013 GRA, YEC applied for a similar solution with regard to YEC's
16 RFID account. The Board approved the approach and the amortization of the balance over
17 a five-year period. There was no similar approach for the hearing cost reserve account in
18 the 2012/2013 GRA as this account was created subsequent to the GRA at the direction
19 of the Board.

1 **TOPIC: Property Tax Increase**

2

3 **REFERENCE:** Application. PDF page 63, lines 20 to 21 and Table 3.12. PDF page 64

4

5 **QUESTION:**

6

7 a) Please confirm whether the increases in property taxes between the years 2014-
8 2015 and 2015-2016 is “due primarily to the additional property for the LNG plant.”
9 If not confirmed, please explain.

10

11 **ANSWER:**

12

13 **(a)**

14

15 Confirmed.

1 **TOPIC: Increases in Rate Base**

2
3 **REFERENCE:** Application, Schedule 3. PDF page 282, line 3

4
5 **QUESTION:**

- 6
7 a) For each of the years 2013-2018, please identify the three largest projects
8 contributing to the increases in rate base for that year. As part of the response,
9 please provide the dollar value of the project capitalized to rate base.

10
11 **ANSWER:**

12
13 **(a)**

14
15 The Request by the Board specifically refers to rate base, however, the Reference by the
16 Board refers to increases to PPE on the Schedule 3 of the Application. Increases to PPE
17 do not directly relate to increases to rate base as additions to rate base do not occur until
18 projects are completed. YEC is assuming that the Board would like further details on the
19 additions to rate base as this is what impacts rates; therefore, YEC's response below
20 relates to increases in rate base. Schedule 1 in the Application references the impact of
21 PPE on rate base.

22
23 Table 1 below summarizes the three projects each year which have the largest impact on
24 rate base. The assessment takes into account the following:

- 25
26
 - Total project costs.
 - Year when project came into service.
 - All offsets against capital costs due to contributions.
 - Impacts on mid-year rate base in each year – as is evident from the table, project costs affect rate base over two years owing to the mid-year rule; this is not evident for all projects in table 1, depending on the relative dollars involved in each year.

27
28
29
30
31

**Table 1: Three Largest Project Impacts Each Year on Mid-Year Rate Base
(2013-2018)**

	2013	2014	2015	2016	2017	2018
	(\$ millions)					
Accounting Software Conversion	1.2					
Aishihik Elevator Shaft Structural Steel					5.1	5.1
Faro Diesels Switchgear		0.4				
Gladstone					2.3	2.3
LNG Plant			11.8	11.8		
Mayo Head Gate Repairs	1.0					
Mayo Substation Enhancements	5.2					
Takhini Substation Upgrade			1.8	1.8		
WAF Transmission Upgrades		0.6				
WH4 Major Overhaul					2.1	2.1
Whistlebend Takhini Subdivision Supply			3.9	3.9		
Whitehorse Spillway Improvements		0.8				

1 **TOPIC: Amortization and Retirements of Contributions**

2
3 **REFERENCE:** Application. PDF page 19, lines 25 to 26

4
5 **QUOTE:** "These contributions continue to reduce ongoing annual
6 depreciation/amortization and return costs for the affected projects."
7

8 **QUESTION:**
9

10 a) Please provide a high level explanation describing the basis for YEC's amortization
11 of contributions.
12

13 b) Please explain if and how YEC retires contributions, once the associated capital
14 asset has been retired.
15

16 **ANSWER:**
17

18 **(a)**
19

20 The principle behind the basis of amortization of contributions is one of matching. The
21 intent is to amortize the contribution at the same rate as the underlying asset that the
22 contribution relates to. In many cases, the constructed project will include different classes
23 of assets with different depreciation rates. In this case, the utility will calculate a weighted-
24 average rate based on the relative dollars assigned to each asset class. This combined
25 rate is then used to draw down the contribution over time. The objective is to ensure that
26 the depreciation of the contribution and the underlying asset are essentially the same so
27 that the utility income for the period is unaffected (and therefore ratepayers are not
28 affected by the cost of this invested capital).
29

30 **(b)**
31

32 Contributions would be retired at the same time as retirement of the related asset. The
33 accounting entry is:
34

35 dr. Contributions

36 cr. Accumulated amortization – contributions

1 **TOPIC: Depreciation and Amortization of Contributions Expense –**
2 **Proposed Forecasts**

3
4 **REFERENCE:** Application, Schedule 6 (lines 7 and 8). PDF page 287

5
6 **QUESTION:**

7
8 a) Please provide detailed calculations supporting each depreciation and
9 amortization expense as shown on lines 7 and 8 of Schedule 6 of Tab 7 for the
10 years 2017 and 2018 – proposed forecasts. Please ensure that the calculation for
11 the amortization of fire insurance recoveries is disclosed separately from the
12 amortization of contributions.

13
14 b) As part of the response to (a) above, please include in separate columns, the
15 currently approved depreciation parameters (and resultant depreciation rates) on
16 an account by account basis.

17
18 c) Please provide reason(s) for the difference in depreciation expense for the years
19 2017 and 2018 between the “Existing Forecast” versus “Proposed Forecast”
20 columns.

21
22 d) Please provide reason(s) for the difference in amortization of contributions for the
23 years 2017 and 2018 between the “Existing Forecast” versus “Proposed Forecast”
24 columns.

25
26 e) Please provide reason(s) for the difference in amortization of fire insurance
27 recoveries for the years 2017 and 2018 between the “Existing Forecast” versus
28 “Proposed Forecast” columns.

29
30 **ANSWER:**

31
32 **(a) and (b)**

33
34 Please see Table 1 and Table 2 below.

Table 1: Proposed Depreciation (Schedule 6, Line 7)

(\$000's)	2017			2018			Depreciation Period
	2016 Assets	New Assets	Total	2016 Assets	New Assets	Total	
Land	2	-	2	2	-	2	0-48
Hydro	3,071	502	3,573	3,071	766	3,837	10-103
Diesel	567	594	1,160	567	599	1,165	5-72
Distribution	426	9	434	423	25	449	20-55
Wind	95	-	95	95	-	95	26-30
Transmission	3,981	14	3,995	3,978	67	4,046	12-65
Buildings & Equipment	1,452	159	1,610	1,093	341	1,434	5-55
Transportation	310	17	327	308	56	365	9-31
LNG	1,021	-	1,021	1,021	7	1,027	30-72
Total	10,922	1,294	12,217	10,558	1,861	12,419	

Table 2: Proposed Amortization of Contributions and Fire Insurance Recoveries (Schedule 6, Line 8)

(\$000's)	2017	2018	Amortization Period
Residential	137	149	40
General Service	62	62	40
Industrial	15	15	40
Street & Sentinel Lights	1	1	40
Other Customer	3	3	40
Minto Exploration 138Kv Line	129	129	56
Minto Spur 25Kv Line	900	900	12
Yukon Development Corporation	1,674	1,674	40
Yukon Government	212	212	40
Government of Canada Green Infrastructure	991	991	60
Feasibility and Licensing	786	705	5
Regulatory	99	99	5
Total Contributions	5,007	4,938	
Fire Insurance Recoveries	262	262	45
Total Contributions and Fire Insurance Recoveries	5,269	5,200	

1 **(c)**

2
3 The primary reason for the difference in depreciation between the existing and proposed
4 columns is due to the proposal to transfer Deferred Overhaul costs carried over from the
5 last GRA to rate base at the start of 2017.

6
7 **(d)**

8
9 The primary reason for the difference in amortization of contributions between the existing
10 and proposed columns is due to the proposal to transfer Deferred Feasibility and
11 Regulatory Contributions carried over from the last GRA to rate base at the start of 2017.

12
13 **(e)**

14
15 The referenced line represents amortization of contributions and fire insurance recoveries.
16 The variance between “Existing Forecast” and “Proposed Forecast” relates to
17 contributions on deferred projects that were delayed from addition to rate base at the
18 direction of the YUB in 2012/13 GRA, pending the next GRA proceeding.

1 **TOPIC:** **Approved Depreciation Parameters (and resultant depreciation**
2 **rates)**

3
4 **REFERENCE:** Application. PDF page 65, lines 1 to 4
5

6 **PREAMBLE:** YEC describes increases to 2017 mid-year net plant in service as
7 reflecting the “LNG plant” and “Aishihik elevator” in the year 2017.
8

9 **QUESTION:**
10

- 11 a) Please clarify if, in any Tab 7 calculations, YEC has used depreciation parameters
12 (and resultant depreciation rates) that have not been presented in a depreciation
13 study or tested in a general tariff application, or specifically approved by the Board.
14
15 b) If (a) is confirmed, please identify the specific asset accounts impacted by the
16 described action and provide an explanation of YEC’s rationale for using those
17 specific depreciation parameters (and resultant depreciation rates), for the
18 purposes of its forecast 2017 and 2018 depreciation expense calculations.
19

20 **ANSWER:**
21

22 **(a)**
23

24 Two assets capitalized since the last GRA are using rates not previously reviewed by the
25 YUB nor supported by a depreciation study:
26

- 27 • LNG storage; and
- 28 • LNG fencing.
29

30 The majority of the LNG project was classified into the same depreciation groupings as
31 diesel equipment. That is, YEC assessed that these new assets were similar in nature and
32 therefore use the same depreciation rates (see (b) for asset groupings and related rates).
33

34 With respect to LNG storage, there is no similar category to assign to. Discussions with
35 the equipment supplier indicated that this equipment should last approximately 20-30
36 years. Based on the relatively light usage by YEC, the rate was set at 32 years. With
37 respect to LNG fencing, YEC has a category of assets for fencing (depreciation rate – 20

years). The fence surrounding the LNG compound is constructed to a much higher standard, so the rate was set at 30 years.

(b)

Table 1 below outlines the categories for LNG assets established by YEC. This also includes the depreciation period and rationale for using the depreciation period.

Table 1: LNG Depreciation parameters

LNG Category	Depreciation	
	Years	Rationale
Structures and improvements	72	This is the same life as the diesel plant structures and improvements
Fuel Holders	32	The manufacturer indicated that the life would be 30 or more years
LNG Generator	40	This is the same as the diesel generator life
Accessory Electric Equipment	45	This is the same as the diesel accessory equipment life
Misc Power Plant Equipment	30	This is the same as for the diesel misc power plant equipment
Fencing	30	The life of a substation fence is 20 years. As the LNG fence used higher quality materials, the life of this asset is expected to be longer.

1 **TOPIC:** Yukon Energy Vegetation Management Policy

2
3 **REFERENCE:** Application, Appendix 3.1 – Yukon Energy Vegetation Management
4 Policy, PDF pages 75 to 79

5
6 **QUESTION:**

- 7
8 a) From whom will YEC receive approval when it states “If approved for use, the
9 following herbicide methods will be considered for use by YEC...”?
10
11 b) Under what circumstances might a herbicide application method be considered for
12 use by YEC.
13
14 c) Please describe YEC’s process for studying the use of herbicides for transmission
15 vegetation management in the Yukon.
16
17 d) Has YEC contemplated a ranking of the assessment criteria in order to select a
18 specific brushing method for a given area?
19

20 **ANSWER:**

21
22 **(a)**

23
24 The application of a registered herbicide requires a Pesticide Use Permit from
25 Environment Yukon. The Minister will determine if a technical review is required. As well,
26 herbicides are classified as restricted or non-restricted. Restricted herbicides would likely
27 also be subject to review under the *Yukon Environmental and Socio-economic*
28 *Assessment Act (YESAA)*.
29

30 **(b)**

31
32 Yukon Energy might consider a herbicide application program in the case that:

- 33
34 • The program is considered to be safe by regulators;
35
36 • The program achieves the required vegetation management to safely maintain
37 transmission line right of ways;

- The herbicide program is cost effective in comparison to traditional mechanical methods or as a combination of traditional mechanical methods and herbicide program; and
- The program has stakeholder acceptance.

The past studies (filed with YUB as part of 12/13 GRA) demonstrated that herbicide application could be a very effective and cost-efficient approach to vegetation management. This has also been demonstrated in numerous jurisdictions in North America. The challenge to implement chemical vegetation management is a resistance from stakeholders. A recent application for a Pesticide Use Permit in the territory was met with “significant public and First Nation concerns regarding the potential contamination of drinking water and harvestable flora and fauna” – this concern resulted in a permit denial. As described above in a), the regulatory environment requires significant study and concrete support for this use. From a utility and ratemaking perspective, herbicides provide the best solution. However if stakeholder acceptance is not achievable, the company will continue with traditional mechanical methods.

(c)

YEC has partnered with Yukon College to study this approach in Yukon. A number of potential herbicides have been identified and field tests are being conducted over multiple years to determine the effectiveness and impacts.

(d)

The assessment criteria have not been ranked as part of the policy and therefore, the listed order does not imply relative importance or consideration. Depending on the specific characteristics of the sites to be brushed in a given year, the relative importance of a given criteria may change (e.g. FN considerations would be higher for brushing on settlement land v. crown land).

1 **TOPIC: Reserve For Injuries and Damages (RFID) Policy**

2
3 **REFERENCE:** Application, Appendix 3.2 – Reserve for Injuries and Damages (RFID)
4 Policy. PDF pages 80 to 82

5
6 **QUESTION:**

- 7
8 a) Given that the policy was issued in March 2012 and reviewed in February 2015,
9 please clarify whether it is YEC's intention that this policy be updated each time
10 YEC proposes to adjust its annual appropriation amount.

11
12 **ANSWER:**

13
14 **(a)**

15
16 Please note that prior to filing the 2017/18 GRA, the policy was updated as follows to
17 reflect the outcomes of the 2012/13 GRA and Board Order 2013-01:

- 18
19 • **Section 2 – Background:** was updated to reflect the outcomes of the 2012/13
20 General Rate Application and more specifically directions provided in Board Order
21 2013-01 regarding the 2013 approved appropriation amount of \$0.190 million.
22
23 • **Section 3 – Annual Appropriation to the RFID:** this section was revised to note
24 that “subject to the approval of any increase in the annual appropriate to the RFID
25 by the Board as part of future Yukon Energy General Rate Applications, the RFID
26 will be funded and raised through an approved annual appropriation of \$0.190
27 million, with no specific limits on surpluses or deficits.”

28
29 As the policy specifically references the annual appropriation, the policy will be updated if
30 this amount changes (and is approved by the YUB).

1 **TOPIC: Measures to Defer the Requirement for the Application**

2
3 **REFERENCE:** Application, page 2. PDF page 3

4
5 **QUOTE:** "... and adjusted thermal fuel costs related to Diesel Contingency Fund
6 operation ..."

7
8 **QUESTION:**

- 9
10 a) Please explain in greater detail how adjusted thermal fuel costs related to the
11 Diesel Contingency Fund operation have helped defer the requirement for a GRA.
12 Please quantify this impact for each of the non-test years 2014-2016 inclusive.

13
14 **ANSWER:**

15
16 **(a)**

17
18 The DCF operation has enabled YEC thermal generation fuel costs to be adjusted in
19 response to load changes.

20
21 In the 2014-2016 non-test years, when loads fell below the forecasts approved in the last
22 GRA for setting YEC's rates, the reduced loads reduced YEC's revenues. The DCF in
23 2014 and 2016 in particular reduced YEC thermal generation fuel costs based on LTA
24 assessments as approved by the Board (changes in system losses in 2015 moderated the
25 DCF assessments for that year relative to the sales changes).

26
27 Table 1 below summarizes related information from the Application.

1

Table 1: Changes in YEC Sales, Revenues and Fuel Costs 2014-2016

2

	2013 Approved	2014	2015	2016
Firm Rate Revenues (\$000)	42,079	40,556	41,111	42,042
Change from 2013 Approved		-1,523	-968	-37
Fuel Costs (\$000)	3,160	1,528	2,720	2,114
Change from 2013 Approved		-1,632	-440	-1,047
LTA Thermal Generation (MW.h)	11,006	5,288	10,011	10,536
Change from 2013 Approved		-5,718	-995	-470
Firm Generation (MW.h)	416,387	396,502	410,304	412,812
Change from 2013 Approved		-19,885	-6,083	-3,575
Firm Sales (MW.h)	383,061	368,833	373,122	381,030
Change from 2013 Approved		-14,228	-9,939	-2,031

3

1 **TOPIC: Energy Reconciliation Adjustment (ERA)**

2
3 **REFERENCE:** Application, page 7. PDF page 8

4
5 **QUOTE:** “No proposal regarding the Rate Schedule 42 Energy Reconciliation
6 Adjustment (ERA) is provided at this time in the Application as the ERA
7 is currently the subject of an appeal to the Court (the Appeal) from the
8 Board's Order 2015-06 of August 18, 2015. At such time as the Court's
9 decision is provided, Yukon Energy will review the ERA and provide the
10 Board with a filing as required on this matter.”

11
12 **QUESTION:**

13
14 a) Does the exclusion of the ERA from this application indicate that the DCF and ERA
15 are separate and discernible entities?

16
17 b) Can the DCF operate without any finding in regards to the ERA? Please explain.

18
19 **ANSWER:**

20
21 **(a)**

22
23 Determination of the DCF has never been dependent on the ERA. However, determination
24 of the ERA has in the past been affected by DCF determinations (when DCF
25 determinations affect YEC changes in thermal generation costs related to changes in
26 wholesales).

27
28 **(b)**

29
30 Yes, the DCF can operate without any findings in regards to the ERA. This has been
31 demonstrated by all DCF filings since the 2012/13 GRA.

32
33 As demonstrated in Appendix 3.5, DCF operation relies on the following variables (none
34 of which require any ERA determinations related to wholesales and/or cost recoveries
35 from AEY):

- 1 • Total actual grid load excluding secondary sales (YEC firm grid load plus AEY Fish
2 Lake hydro).
3
- 4 • Actual grid generation by sources (specifically re: AEY Fish Lake Hydro, YEC
5 diesel and LNG generation, YEC wind generation), with exclusion of thermal
6 generation for activities not related to firm loads, e.g., capital, RFID and
7 maintenance).
8
- 9 • Expected LTA thermal generation for the actual grid load (determined based on
10 the approved DCF Term Sheet table and actual firm grid load less expected wind
11 and expected Fish Lake Hydro).
12
- 13 • Approved thermal fuel costs per kW.h.

TOPIC: Secondary Sales

REFERENCE: Application, page 1-4. PDF page 20, lines 7 to 9

QUOTE: "... and annual secondary sales from 2013 to 2016 have ranged between 3.9 GW.h and 7.0 GW.h with revenues as follows: \$0.275 million in 2013; \$0.410 million in 2014; \$0.544 million in 2015; \$0.371 million in 2016."

QUESTION:

- a) Please provide the corresponding volumes for secondary sales for each of the years 2013-2016 inclusive.

ANSWER:

(a)

Please see Table 1 below for the requested information.

Table 1: YEC Secondary Sales

Unit	2013	2014	2015	2016
Sales (MWh)	3,959	5,415	7,030	4,835
Revenues (\$000)	\$275	\$410	\$544	\$371

1 **TOPIC: Mine Closure and Capacity**

2
3 **REFERENCE:** Application, page 1-7. PDF page 23, lines 11 to 13

4
5 **QUOTE:** “Looking beyond the test years, updated load forecasts and the
6 anticipated end of Minto mine operations within a few years highlight
7 ongoing pressure for added dependable capacity notwithstanding
8 limited growth opportunities for new energy requirements unless new
9 mine connections occur.”

10
11 **QUESTION:**

- 12
13 a) Please explain how the closure of a mine (reduced load and capacity) relates to
14 the requirement for additional dependable capacity.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The referenced quote is making the point that there is ongoing pressure for added
21 dependable capacity after the test years, even though (i.e., “notwithstanding” that) there
22 are expected to be limited growth opportunities for new energy requirements “unless new
23 mine connections occur”. In different words, the closure of a mine is not creating the
24 requirement for additional dependable capacity, i.e., this requirement derives from non-
25 industrial load growth in peak winter demands.

26
27 Mine loads are not currently affecting the requirement for additional dependable capacity
28 (and therefore closure of a mine does not reduce this requirement):

- 29
30 • Under the single contingency (N-1) planning criterion for determining dependable
31 capacity surplus or shortfall, mine loads are excluded from the referenced winter
32 peak demand (and therefore closure of a mine does not provide any reduction in
33 the referenced winter peak demand).
34
35 • Under the LOLE planning criterion for determining dependable capacity surplus or
36 shortfall, overall grid loads are not sufficient with the Minto mine to result in this
37 criterion overriding the single contingency planning criterion.

1 **TOPIC: Thermal Fuel Mix**

2
3 **REFERENCE:** Application, page 3-3. PDF page 51, lines 30 to 31

4
5 **QUOTE:** "... and forecast long-term average thermal requirements for the test
6 years are assumed to be supplied with a combination of 90% LNG and
7 10% diesel generation."
8

9 **QUESTION:**

- 10
11 a) Please provide details as to how the 90:10 LNG: Diesel proportion was
12 established. Is this ratio statistically based? If so, please provide the statistical
13 calculation.
14
15 b) Please show separately the actual and proposed maintenance fuel costs for each
16 of the years 2015-2018 inclusive (include both dollars and forecast litres of fuel).
17
18 c) Please provide actual diesel/LNG ratios for 2015 and 2016.
19

20 **ANSWER:**

21
22 **(a)**

23
24 Details on establishing the 90:10 LNG: Diesel proportion are reviewed in Section 1.3 of
25 Appendix 3.4 of the Application. This ratio is not statistically based, but reflects experience
26 and expectations related to thermal generation to supply the long-term average (LTA)
27 requirement over all water years.
28

29 Key points reviewed on this matter in Appendix 3.4 include:

- 30
31 • YEC's LNG Part 3 Application provided simulations and analysis to support the
32 assumption that the initial two LNG units (8.8 MW) would be expected to displace
33 all LTA diesel generation at LTA thermal requirements of up to 17 GW.h/year. This
34 assessment assumed operation of the LNG units as required during low water
35 conditions (i.e., during the water years accounting for the vast majority of the LTA
36 thermal generation requirement at grid loads then forecast) to enhance hydro
37 storage for use in wintertime.

- 1 • LTA thermal generation requirements on the grid remained below 17 GW.h in 2015
2 and 2016, and remain below 17 GW.h in each of the test years, indicating that an
3 assumption of 100% LNG displacement of LTA diesel generation during these
4 years would be consistent with the Part 3 determinations.
5
- 6 • Addition of a third LNG unit in 2019 will expand considerably the overall LNG
7 capability to displace LTA diesel generation on the grid.
8
- 9 • Actual LNG unit operation to date has been constrained by unit size at 4.4 MW
10 (see response to YUB-YEC-1-38 for review of these constraints); however, these
11 constraints are not considered to have a material impact on the ability of LNG (with
12 operation during low water conditions to enhance hydro storage) to supply overall
13 LTA thermal generation at the grid loads relevant to the Application.
14
 - 15 o Appendix 3.4.2 (Figure 3.4-1 and Table 3.4-4) highlights the extent that
16 LTA thermal is affected by years with below average water levels.
17
 - 18 o At a grid load of 420 GW.h/year, 75% of the thermal generation
19 requirement over 35 water years occurs in the 20% of the 35 water years
20 with the worst drought conditions, and less than 1% of this thermal
21 generation occurs in the 46% of the 35 water years with the best water
22 conditions.
23
- 24 • The Application proposes that LTA thermal generation be assumed, for revenue
25 requirement purposes at this time, to be supplied 90% by LNG-supplied natural
26 gas generation and 10% by diesel generation. This approach is proposed to
27 ensure that revenue requirement costs used to set rates provide some recognition
28 of the current limits on actual LNG ability to displace all diesel generation.
29

30 **(b)**

31
32 The available information on actual and proposed maintenance costs is summarized
33 below in Table 1.

Table 1: Actual and Proposed Thermal Generation Maintenance: 2015-2018

	Actuals		2017/18 GRA Forecast	
	2015	2016	2017	2018
<u>MW.h</u>				
Diesel	224.9	319.4	312.5	229.2
LNG	123.6	55.4	133.3	100.0
Total	348.5	374.8	445.8	329.2
<u>Litres of Fuel</u>				
Diesel	60,910	86,584	87,400	64,093
LNG	26,878	12,052	51,914	38,935
	87,788	98,636	139,313	103,029
<u>Cost (\$000)</u>				
Diesel	64.6	91.7	82.3	60.3
LNG	23.3	10.1	19.6	14.7
Total	87.8	101.8	101.8	75.0

(c)

Actual diesel/LNG ratios for 2015 and 2016 are as follows (see Appendix 3.5, Table 1):

- 2015
 - o 27/73 LNG/Diesel including capital and RFID.
 - o 21/79 LNG/Diesel excluding capital and RFID.
 - o LNG was not available until after mid-year, at which point only about 15% of the annual LTA thermal generation would be expected to occur.
- 2016
 - o 53/47 LNG/Diesel including capital and RFID.
 - o 55/45 LNG/Diesel excluding capital and RFID.

1 **TOPIC: LNG Prices and Energy Content**

2
3 **REFERENCE:** Application, page 3-4 and footnote 1. PDF page 52

4
5 **QUOTE:** Footnote 1: "Reflects the September to December 2016 average
6 delivered LNG cost from the Ferus facility in Elmworth, Alberta, and the
7 forecast that test year LNG requirements will be supplied from facilities
8 at no greater distance from Whitehorse than Elmworth. Assumed
9 energy content (HHV) per litre of LNG approximates 0.02369GJ."

10
11 **QUESTION:**

12
13 a) Please provide the average actual delivered cost of LNG for the period January 1
14 to July 31, 2017. Please provide in tabular format indicating volumes acquired,
15 commodity price, delivery price and supply location.

16
17 b) Please provide the actual or realized heat content per litre of LNG for 2015, 2016
18 and January 1 to July 31, 2017. Please show all calculations.

19
20 **ANSWER:**

21
22 **(a)**

23
24 Please see Table 1 below.

1

Table 1: Actual LNG Delivery Costs for 2017 - January to end of July

LNG Source: Fortis BC - Delta, BC

Month	LNG Volume Delivered	LNG Costs	Transportation Costs	Total Cost per Load (LNG & Transportation)	Total Cost per Load (LNG & Transportation)
	[litres]	[\$]	[\$]	[\$]	[\$/Litre]
January	154,247.18	\$ 40,654.04	\$ 56,100.96	\$ 96,755.00	\$0.63
February	80,576.19	\$ 16,216.85	\$ 28,002.31	\$ 44,219.16	\$0.55
March	157,603.13	\$ 27,153.21	\$ 51,024.75	\$ 78,177.96	\$ 0.50
April	0.00	\$ -	\$ -	\$ -	\$ -
May	0.00	\$ -	\$ -	\$ -	\$ -
June	0.00	\$ -	\$ -	\$ -	\$ -
July	0.00	\$ -	\$ -	\$ -	\$ -
August	0.00	\$ -	\$ -	\$ -	\$ -
September	0.00	\$ -	\$ -	\$ -	\$ -
October	0.00	\$ -	\$ -	\$ -	\$ -
November	0.00	\$ -	\$ -	\$ -	\$ -
December	0.00	\$ -	\$ -	\$ -	\$ -
Total	392,426.50	\$ 84,024.10	\$ 135,128.02	\$ 219,152.12	\$ 0.56

LNG Source: Ferus - Elmworth, AB

Month	LNG Volume Delivered	LNG Costs	Transportation Costs	Total Cost per Load (LNG & Transportation)	Total Cost per Load (LNG & Transportation)
	[litres]	[\$]	[\$]	[\$]	[\$]
January	499,161.07	\$ 128,206.55	\$ 100,608.50	\$ 228,815.05	\$0.46
February	388,113.31	\$ 91,776.02	\$74,177.14	\$ 165,953.16	\$ 0.43
March	457,684.07	\$ 105,184.58	\$ 85,807.54	\$ 190,992.12	\$ 0.42
April	43,909.67	\$ 10,062.43	\$6,600.00	\$ 16,662.43	\$ 0.38
May	38,436.73	\$ 9,087.20	\$6,600.00	\$ 15,687.20	\$0.41
June	0.00	\$ -	\$ -	\$ -	\$ -
July	0.00	\$ -	\$ -	\$ -	\$ -
August	0.00	\$ -	\$ -	\$ -	\$ -
September	0.00	\$ -	\$ -	\$ -	\$ -
October	0.00	\$ -	\$ -	\$ -	\$ -
November	0.00	\$ -	\$ -	\$ -	\$ -
December	0.00	\$ -	\$ -	\$ -	\$ -

2

(b)

Please see Table 2 below.

Table 2: Calculated Heat Content per Litre of LNG – 2015 to end of July 2017

LNG Source: Fortis BC - Delta, BC			
Year	LNG Mass Delivered [kg]	LNG Volume Delivered [litres]	LNG Heat Content [GJ/litres]
	[A]	[B]	$[A \times HHV_{BC} / B]$
2015	490,915.04	1,121,033.11	0.0241
2016	368,845.00	840,895.42	0.0242
2017	171,609.00	392,426.50	0.0241
Total	1,031,369.04	2,354,355.04	0.0241

LNG Source: Ferus - Elmworth, AB			
Year	LNG Mass Delivered [kg]	LNG Volume Delivered [litres]	LNG Heat Content [GJ/litres]
	[A]	[B]	$[A \times HHV_{AB} / B]$
2015	N/A	N/A	N/A
2016	335,427.00	783,847.13	0.0237
2017	610,778.00	1,427,304.85	0.0237
Total	946,205.00	2,211,151.98	0.0237

LNG High Heating Value

FortisBC	0.0551 GJ/kg	(HHV _{BC})
Ferus	0.0554 GJ/kg	(HHV _{AB})

TOPIC: Diesel Prices

REFERENCE: Application, pages 3-4 to 3-5. PDF pages 52 to 53

QUESTION:

- a) Please provide actual diesel prices for the period January 1, 2017 to July 31, 2017 for each of Whitehorse, Faro, Dawson and Mayo. Please include purchase volumes with the prices for each location.

ANSWER:

(a)

Please see Table 1.

Table 1: Diesel Purchased (Litres & Prices) - January 1, 2017 to July 31, 2017

FUEL PURCHASES LITRES		(Actual units purchased)						
	JAN	FEB	MAR	APR	MAY	JUN	JUL	TOTAL
Faro	30,100	0	24,962	0	9,816	0	38,001	102,877
Dawson	48,113	0	0	0	0	47,223	0	95,335
Mayo	0	0	0	0	7,010	0	0	7,010
Whitehorse	168,846	178,866	250,427	0	0	18,349	0	616,487
Total	247,058	178,866	275,388	0	16,826	65,571	38,001	821,710

FUEL PURCHASES DOLLARS		(Actual Cost paid for purchases not including GST)						
	JAN	FEB	MAR	APR	MAY	JUN	JUL	TOTAL
Faro	\$ 27,797.17	\$ -	\$ 22,777.37	\$ -	\$ 8,858.49	\$ -	\$ 32,737.52	\$ 92,170.55
Dawson	\$ 47,237.15	\$ -	\$ -	\$ -	\$ -	\$ 43,765.91	\$ -	\$ 91,003.06
Mayo	\$ -	\$ -	\$ -	\$ -	\$ 6,453.68	\$ -	\$ -	\$ 6,453.68
Whitehorse	\$ 154,670.47	\$ 151,374.13	\$ 219,198.58	\$ -	\$ -	\$ 15,803.65	\$ -	\$ 541,046.83
Total	\$ 229,704.79	\$ 151,374.13	\$ 241,975.95	\$ -	\$ 15,312.17	\$ 59,569.56	\$ 32,737.52	\$ 730,674.11

FUEL PURCHASES PER LITRE		(Actual cost/L)						
	JAN	FEB	MAR	APR	MAY	JUN	JUL	TOTAL
Faro	\$ 0.9235	\$ -	\$ 0.9125	\$ -	\$ 0.9025	\$ -	\$ 0.8615	\$ 0.8959
Dawson	\$ 0.9818	\$ -	\$ -	\$ -	\$ -	\$ 0.9268	\$ -	\$ 0.9546
Mayo	\$ -	\$ -	\$ -	\$ -	\$ 0.9206	\$ -	\$ -	\$ 0.9206
Whitehorse	\$ 0.9160	\$ 0.8463	\$ 0.8753	\$ -	\$ -	\$ 0.8613	\$ -	\$ 0.8776
Total	\$ 0.9298	\$ 0.8463	\$ 0.8787	\$ -	\$ 0.9100	\$ 0.9085	\$ 0.8615	\$ 0.8892

1 **TOPIC: Labour Rates**

2
3 **REFERENCE:** Application, page 3-6. PDF page 54

4
5 **QUOTE:** “The average annual negotiated increase in wages approximates 1.9%
6 from 2013 approved to 2016, and is forecast to increase at
7 approximately this same annual rate to 2018.”

8
9 **QUESTION:**

10
11 a) Please provide the latest edition of the Yukon Economic Outlook.

12
13 b) How does the YEC forecast labour escalation compare to the latest forecast from
14 the Yukon Economic Outlook?

15
16 **ANSWER:**

17
18 **(a)**

19
20 Please see YUB-YEC-1-28 Attachment 1.

21
22 **(b)**

23
24 The Yukon Economic Outlook forecasts Whitehorse CPI to be up 1.9% in 2017 and 1.8%
25 in 2018. The specific rate for negotiated wages cannot be provided at this time as this
26 would compromise YEC’s negotiations with the unions as part of the collective bargaining
27 process. However, YEC can confirm that rates used in lieu of the actual wages increase
28 were developed consistent with awards granted in arbitration in the last two collective
29 agreement settlements. See also, YUB-YEC-1-2.

YUKON ECONOMIC OUTLOOK

APRIL 2017



CONTENTS

Economic Forecasting and Risk	3
The World in Brief	3
A Closer Look at Yukon.....	5
Signs of strength in economy, despite flat GDP growth	5
• GDP to remain flat, then regain ground.....	5
• Slow and steady population growth	8
• Continued strength in the labour market.....	9
• CPI edging upward after a 2015 decline	11
Sector performance varies	11
• Mining to pick up steam in 2018, 2019.....	11
• Energy potential abounds	14
• Tourism performing well	16
• Construction gains with public sector spending.....	18
• Strong gains in retail trade.....	20
Assumptions and Risks	21
Key Economic Indicators.....	23
Data Sources for Key Economic Indicators.....	24
Endnotes.....	25

ECONOMIC FORECASTING AND RISK

The forecast discussed in this document, examines medium term expectations for Yukon's economy, focusing on the anticipated performance of key economic indicators and sectors. As with all forecasts, the results are dependent on the information available at the time the forecast was completed and the key assumptions incorporated into the forecast. Assumptions such as the level and timing of mining development activity, estimates around annual mineral production and estimates around construction spending can all impact the forecast results, particularly for an economy as small as that of Yukon.

While best efforts are made to develop assumptions that capture Yukon's potential economic performance in the near term, there is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. For a more detailed discussion of key assumptions and risks, please refer to the last section.

THE WORLD IN BRIEF

The Road to Recovery

Elevated levels of public and private debt, an aging population and political uncertainty in a number of countries continues to weigh on the near term outlook for global economic growth.

While the current outlook is clouded by uncertainty around U.S. policy under the new administration, the International Monetary Fund (IMF) is projecting stronger near term global growth. Following estimated growth of 3.1% in 2016, the IMF's January 2017 update¹ to the World Economic Outlook includes projections of growth of 3.4% in 2017 and growth of 3.6% in 2018. The forecast is unchanged from the IMF's October 2016 Outlook, but the update did note that key assumptions of the forecast should be clearer in the April 2017 World Economic Outlook*, specifically noting the expectation of more clarity around policies of the new U.S. administration.

Growth in emerging markets and developing economies² is expected to continue to drive global growth projections with the IMF growth forecasts of 4.5% in 2017 and 4.8%

*Not released at time of writing.

in 2018, building on estimated growth of 4.1% in 2016. While remaining strong, growth prospects have marginally worsened for many of the economies in question due to tightening financial conditions.

China's economy remains in a period of transition, moving from an economy supported substantially through manufacturing activities and large scale industrial development to development of services and retail in support of its domestic demand. Even with a recent slowdown, China (along with India) will continue to lead the way for emerging market countries. Following estimated growth of 6.7% in 2016, China's economy is expected to grow 6.5% and 6.0% over the next two years. India's growth is forecast to be even stronger with growth of 6.8% in 2016, followed by growth of 7.2% and 7.7% in 2017 and 2018, respectively.

Following growth of 1.7% in 2016, advanced economies are forecast to grow by 1.9% and 2.0% annually over the next two years. The near term outlook for advanced economies has improved, reflecting stronger activity in the last six months of 2016 as well as the expectation of U.S. stimulus spending.

U.S. growth is expected to be the prominent driver of growth in advanced economies with U.S. growth rates in both 2017 (2.3%) and 2018 (2.5%) exceeding the overall growth rates of advanced economies. Strong growth forecasts for the U.S. are related to the assumption of fiscal stimulus in the form of reduced taxes and increased infrastructure spending. The IMF's January update does note that the U.S. outlook has a wide range of possible scenarios given uncertainties surrounding future policy choices of the new U.S. administration.³

The Canadian economy continues to adjust to lower oil prices and a generally weaker global economy. Canada's estimated GDP growth of 0.9% in 2015 was the worst performance since a contraction of 3.2% in 2009. Growth in 2016 was only marginally stronger, estimated at 1.4%.

Much of recent performance is related to weaker commodity prices, particularly the price of oil, which has declined significantly in the last 18-20 months as a result of oversupply in the global market, falling below \$30 per barrel in early 2016. Prices for many key mineral exports are also down substantially from recent levels which has contributed to mine closures, layoffs, reduction in mineral exports and lower levels of investment in Canada's mining sector. The IMF's January 2017 update includes forecasts of stronger Canadian growth of 1.9% and 2.0% in 2017 and 2018, respectively.

Growth forecasts from the Bank of Canada are very similar to that of the IMF. The January 2017 *Monetary Policy Report** notes that Canada's GDP will grow by 2.1% in both 2017 and 2018. The Bank notes that the Canadian economy continues to adjust to past declines in commodity prices with the worst appearing to be over for resource-related industries.

At the same time, investment and employment are being reallocated to other sectors of the economy which are growing, in particular the service sector.⁴ Like the IMF, the Bank of Canada notes that the current outlook is subject to considerable uncertainty, given the unknowns around policy

actions by the incoming U.S. administration, particularly concerning trade.⁵

Resource extraction activities continue to be a significant contributor to Canada's economy, and the performance of commodity prices will have a significant impact on growth prospects for the country. Recent modest GDP growth is very much related to weakness in oil and natural gas prices, as well as lower prices for a number of prominent metals, including gold and silver. Lower prices for these key commodities, particularly for oil, have resulted in far lower levels of investment in the resource sector and lower levels of mineral and oil exports, negatively impacting the value of Canada's economy.

While the outlook remains uncertain for gold and silver, the outlook for oil and natural gas prices is generally positive. At the time of writing, the World Bank was calling for oil prices to average US\$55 per barrel in 2017, up from US\$42.80 in 2016.⁶ While expected to remain well below recent record highs, the current outlook from the World Bank was for oil prices to increase in every year, reaching US\$80 per barrel by 2030.

The World Bank notes a very similar story for natural gas, with prices expected to average US\$3.00 per MMBTU⁷ (Henry Hub) in 2017, up from US\$2.50 per MMBTU in 2016. The World Bank is projecting the price of natural gas will grow annually, eventually reaching \$5.00 per MMBTU in 2030.⁸

Future growth prospects for Canada are also tied to interest rates. The overnight rate has rested at 1.0% or lower since September 2010. At its rate announcement on January 18, 2017, the Bank of Canada opted to continue to keep the cost of borrowing low, maintaining the overnight rate at 0.5%, a level it has been at since July 2015. Canadian interest rates are expected to remain low throughout 2017, before increasing in 2018, but remaining at relatively low rates.

*April 2017 Monetary Policy Report not released at time of writing.



Outlook for Global, U.S. and Canadian Economies: IMF January 2017



- Global Growth: 3.4% (2017) and 3.6% (2018).
- U.S. Growth: 2.3% (2017) and 2.5% (2018).
- Canadian Growth: 1.9% (2017) and 2.0% (2018).

2016 Highlights

- Real GDP by industry in 2016 is estimated at \$2.295 billion, up 4.6% from \$2.193 billion in 2015.
- Growth in 2016 follows two consecutive years of GDP contraction, and is primarily related to increased mineral production at the Minto mine.
- 2016 population of 37,858 was up 1.4% from 2015 – 13 straight years of growth.
- Labour market continued to perform well in 2016:
 - Average employment 20,200, up 800.
 - Labour force averaged 21,400, up 700.
 - Unemployment rate averaged 5.6% - the lowest in the country.
- Retail sales reported at over \$740 million, up 7.0% from \$692 million.
- A good year for tourism, with international travellers reported up 3.5%.
- At nearly \$171 million, the value of building permits in 2016 was up 45.1% – mostly related to government and institutional projects.
- Consumer Price Index (CPI) for Whitehorse increased 1.0% in 2016, following a contraction of 0.2% in 2015.

A CLOSER LOOK AT YUKON

Signs of strength in the economy, despite flat GDP growth

GDP to remain flat, then regain ground

Gross Domestic Product (GDP) is a widely used measurement of the economic performance of a region. GDP represents the market value of final goods and services produced within a defined region (e.g., country, province, territory) over a specified period of time (usually over the course of a year).

While an imperfect measure of economic progress, an increase in real GDP is generally interpreted as a sign that the economy is doing well, while a decrease indicates that the economy is under-performing. In many jurisdictions, gains in real GDP are closely tied to gains in other variables such as employment, population, and retail sales. In Yukon, correlation between GDP changes and other indicators is often not as strong.

Revised data released by Statistics Canada in November 2016 estimates that Yukon's real GDP by industry in 2015⁹ contracted by 6.0% to \$2.193 billion. This was the second consecutive year that real GDP fell after a modest decline of 0.2% in 2014.

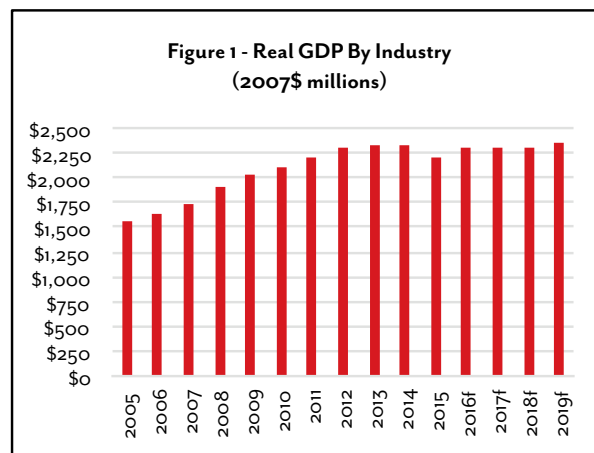
2017 Highlights

- Real GDP in 2017 is forecast to remain flat at 0.1% over 2016, with lower production from the Minto mine offset by increased government investment.
- Population will continue to increase by 1.4%, growing to almost 38,400.
- The number of employed Yukoners and the size of the labour force are both expected to increase to 20,600 and 21,900, respectively.
- The unemployment rate in 2017 is expected to rise slightly to 5.7%.
- Following strong gains in 2016, retail sales are expected to remain strong in 2017, growing about 5% to \$777 million.
- Indications are that 2017 will be another positive year for Yukon's tourism sector.
- Stronger growth in the Whitehorse CPI, expected to be up 1.9% in 2017.

Prior to 2014, Yukon's real GDP had recorded 10 consecutive years of growth, after revisions to 2013 GDP numbers by Statistics Canada which saw Yukon's annual GDP change revised from a 1.2% contraction to 1.5% growth.

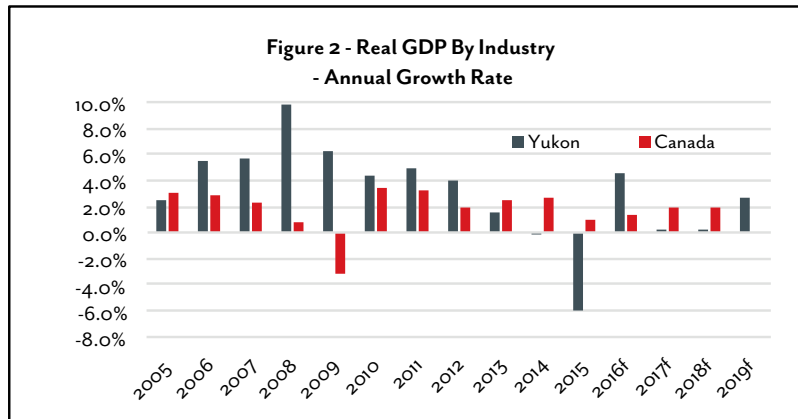
Yukon's contraction of 6.0% represented the lowest performance of all the provinces and territories with Saskatchewan (-1.3%), Newfoundland and Labrador (-1.8%) and Alberta (-3.7%) also posting contractions in 2015.

The primary driver of the 2015 decline was weakness in the mining sector, which included the suspension of production of the Wolverine mine in January 2015. A 42%, or \$198 million, decline in the mining, quarrying and oil and gas extraction component of GDP was noted in 2015 and was the primary contributor to the annual decline in total industry GDP.



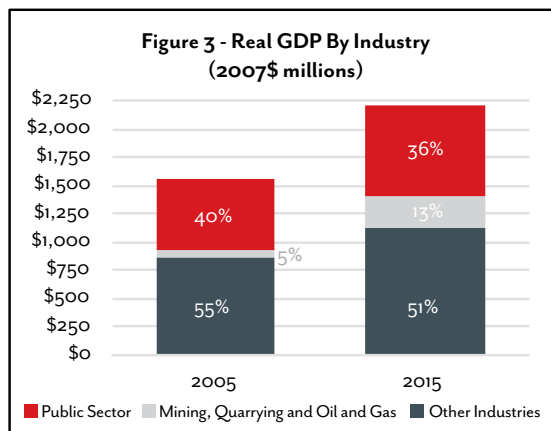
Source: Department of Finance; Statistics Canada

Recent history has seen the percentage contribution of mining in excess of 20% annually, averaging about 22% from 2012/14. While down from recent highs, Figure 3¹⁰ illustrates that the current contribution of mining related activities still remains well above estimates from a decade ago. At almost 13% of total real GDP, the 2015 contribution of mining, quarrying and oil & gas extraction is more than double the contribution of 5.2% noted in 2005.



Source: Department of Finance; Statistics Canada; IMF

Declines in the mining component in 2015 were partially countered by GDP gains in other industries. Supported by a tight rental market and a strong housing market, the finance, insurance, real estate, rental and leasing component grew for the 13th straight year, up 2.6% to \$391 million, and is projected to continue to grow throughout the forecast horizon. Notable growth was also recorded in professional, scientific and managerial component, growing to \$108 million, up 5.3% from 2014; growth is expected to continue through 2019. GDP contribution from health and social services also posted an increase of \$5 million to \$180 million, up 3.1% from 2014.



Source: Department of Finance; Statistics Canada

Most industries are estimated to have experienced GDP growth in 2016, with the largest change related to increased mineral production with development of the Minto North pit. Of the estimated increase of \$100 million in real GDP in 2016, more than 70% is associated with an increase in the mining, quarrying and oil &

Beyond 2017

- GDP expected to contract remain essentially flat at 0.2% for 2018, as a result of the closure of the Minto mine at the end of 2017 offset by government investment.
- Development spending for two new mines (Eagle Gold, Coffee) and the start of production from the Eagle Gold mine expected to drive real GDP growth of 2.6% for 2019.
- Steady population growth to continue with gains of 1.1% in 2018 and 1.4% in 2019.
- Strength in labour market expected to continue, with growth in employment and the labour force, with the unemployment rate expected to remain relatively low.
- Growth in retail sales anticipated in the medium term, increasing to exceed \$790 million in 2018 and nearing \$820 million in 2019.
- Continued growth in the Whitehorse CPI, averaging 1.8% over 2018 and 2019.

gas extraction component. Construction also saw significant gains with growth of 7.7%. Overall, real GDP growth is estimated at 4.6% in 2016, higher than the May 2016 forecast of 2.8%. Preliminary GDP numbers for 2016 will be released by Statistics Canada in early May.

Looking forward, Yukon's GDP performance in the medium term remains very much linked to the performance of Yukon's mining sector. For 2017, mineral production is expected to be stronger than noted in the May forecast as Capstone Mining Corp. has stated that its Minto mine will now likely mill until the end of the year. On an industry basis, construction-related real GDP is forecast to be up 13.6%, increasing to \$207 million in 2017. As a result, real GDP is now expected to increase slightly by 0.1%, a substantial improvement from the May 2016 forecast (-5.7%).

GDP is expected to remain essentially flat in 2018 at +0.2%, primarily the result of lower mineral production due to the anticipated closure of the Minto mine at the end of 2017, offset by government investment. The expected start of development activities at the Eagle Gold mine will counter some of the drag on Yukon's GDP in 2018, which (together with increased government investment) will offset the effect of a year-over-year decline in mineral production.

For 2019, further development spending on the Eagle Gold project, the start of development spending on the Coffee project and the start of Eagle Gold mine production are the largest contributors to forecasted real GDP growth of 2.6%, with most industries expected to continue expansion in 2019.

Outlook for GDP

GDP

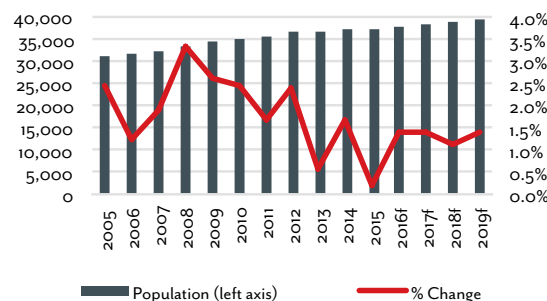
- Revised estimates from Statistics Canada note a second straight decline in 2015 in Yukon's real GDP by industry, with the estimate of \$2.193 billion representing a 6.0% contraction from 2014.
- Growth in mineral production in 2016 is expected to contribute to real GDP gains, with forecasted growth of 4.6%.
- The medium term outlook is mixed, with 2017 and 2018 remaining flat, followed by real GDP growth in 2019.

Slow and steady population growth

The population is estimated to have grown for the 13th consecutive year in 2016. The annual population¹¹ of 37,858 was up 1.4% from 37,343 in 2015.

Whitehorse¹² – at 29,258 – accounted for more than 77% of Yukon's total population in 2016. Serving as Yukon's primary goods and services hub, population gains in Whitehorse have accounted for the majority of Yukon's recent population gains. Growth in the Whitehorse population of 386 in 2016 represented 75% of the total gains of 515.

Figure 4 - Yukon Population (June)



Of the remaining Yukon communities, eight were noted as recording population gains in 2016, led by Dawson City, which added 91 people, and Teslin, which grew by 27. Of these communities, only two had populations above 1,000, Dawson City at 2,158 and Watson Lake at 1,460.

Buoyed by a resilient local labour market and expectations of further mining development, the population is expected to continue to grow. The current outlook¹³ is for population to grow by a further 1.4% in 2017 followed by growth of 1.1% in 2018 and 1.4% in 2019, bringing Yukon's population to more than 39,300 in 2019.



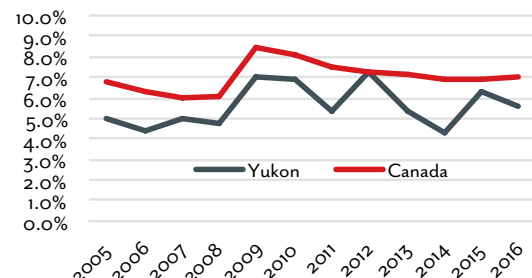
Outlook for Population

- Population is estimated to have grown for the 13th consecutive year in 2016, up 1.4% from 2015.
- Continued population growth is projected in the current outlook, with Yukon's population topping 39,300 by 2019.

Continued strength in the labour market

Yukon's labour market has generally performed well in recent years, with the unemployment rate tracking below the national average for over a decade. During this time, record levels of employment and labour force have been recorded with Yukon's unemployment rate among the lowest in the country.

Figure 5 - Average Annual Unemployment Rate

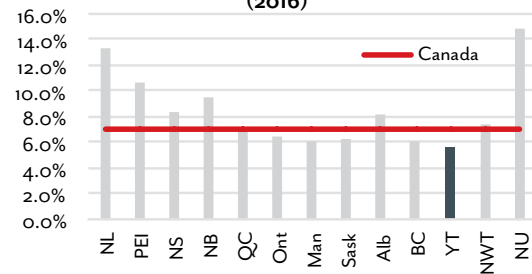


Preliminary data from Statistics Canada¹⁴ suggests that Yukon's labour market remained healthy in 2016, outperforming the previous forecast from May 2016.

Both employment and the labour force were up in 2016 with employment averaging 20,200, up 4.1%, and the labour force averaging 21,400, up 3.4%. As growth in employment outpaced labour force gains, the unemployment rate declined to 5.6%, down from 6.3% in 2015.

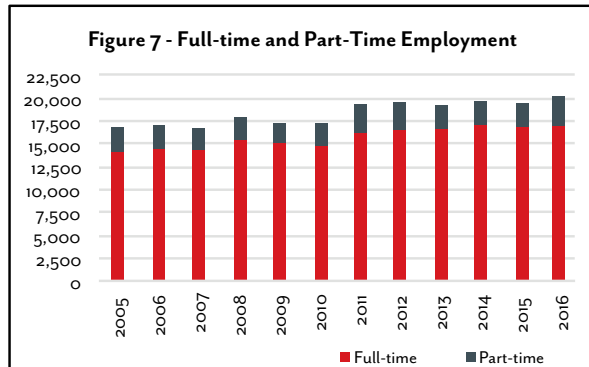
At 5.6%, Yukon's unemployment rate was well below the Canadian average, and the lowest of all the provinces and territories.

Figure 6 - Average Annual Unemployment Rate (2016)



Beyond having the lowest unemployment rate in the country, data for 2016 also shows that Yukon has a higher proportion of workers employed full-time, versus part-time. Last year, there were 17,100 (85.1%) full-time workers and 3,000 (14.9%) part-time workers in Yukon. At 14.9%, Yukon's proportion of part-time workers was the third lowest in the

country, behind NWT (12.4%) and Nunavut (12.6%). The highest proportion of part-time workers in Canada was in B.C. (21.7%).

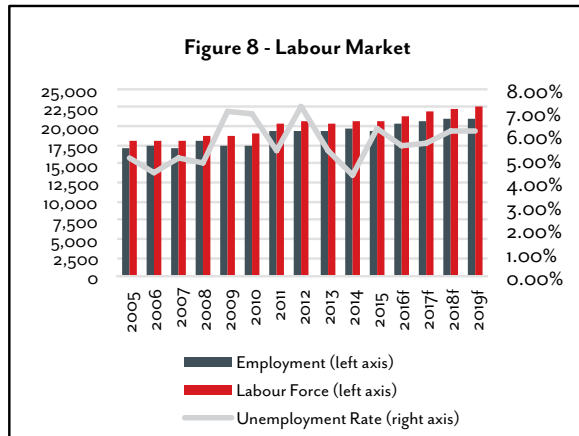


Source: Department of Finance; Statistics Canada

Nationally, the proportion of full-time workers was 80.8%. Since 2002, Yukon's proportion of full-time workers has been higher than of Canada as a whole. Over the 2002 to 2016 period full-time employment in Yukon accounted for an average 85.4% of total employment, while nationally, an average of 81.1%.

Yukon's labour market is expected to continue to perform well in 2017, with forecasts of gains for both employment and the labour force. The current forecast is for employment to grow 2.2% to 20,600, with the labour force growing 2.3% to 21,900. With labour force growth expected to be slightly stronger than employment growth, the unemployment rate is expected to see a slight uptick to 5.7%.

The medium term outlook is also generally positive for Yukon's labour market, with gains expected in employment and the total labour force in both 2018 and 2019.



Source: Department of Finance; Statistics Canada

By 2019, Yukon employment is projected to be 21,100, with a total labour force of 22,500, resulting in an unemployment rate that continues to be relatively low at 6.2%.

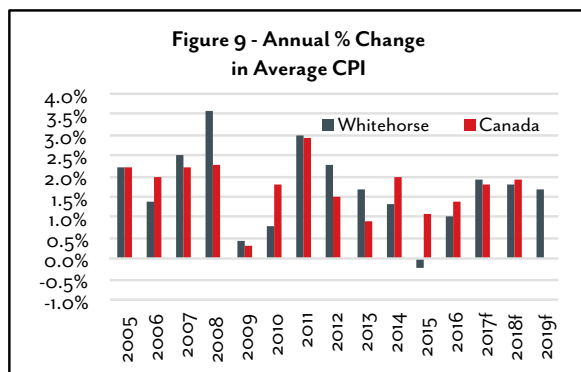
Medium term employment gains are generally expected to be broad based, with gains in a number of key industry classifications¹⁵, including Transportation and Warehousing, Trade, and Professional, Scientific and Management.

Outlook for Labour Market

- Yukon's labour market continued to perform well in 2016 with gains in both employment and the labour force, contributing to a notable decline in the unemployment rate to 5.6%, the lowest in the country.
- The medium term outlook for Yukon's labour market is positive, with gains in employment and the labour force forecast in 2017, 2018 and 2019 and an average unemployment rate of 6.0% over those three years.

CPI edging upward after a 2015 decline

The annual change in the Whitehorse¹⁶ CPI, often used as an indicator of local price inflation, has generally been low in recent years. From 2000 to 2015, the annual change in the Whitehorse CPI averaged about 1.7%, below the 2.0% average for Canada over the same period.



Source: Department of Finance; Statistics Canada; Bank of Canada

Following deflation in 2015, the Whitehorse CPI increased by 1.0% in 2016. Notable gains were recorded in Clothing and Footwear (2.8%), Alcoholic Beverages and Tobacco Products (2.4%), Household Operations, Furnishings and Equipment (2.0%) and Health and Personal Care (1.7%).

Countering some of the growth in 2016 was a reduction in CPI for the Energy component (down 5.7%). The Energy component includes Gasoline, which was down 3.2%. This decline is supported by a 2.9% annual decline in the average price of regular unleaded self-service gasoline in Whitehorse in 2016.

Expectations are for the Whitehorse CPI to increase by 1.9% in 2017, little changed from the May 2016 forecast of 2.0%, and near the Bank of Canada's forecast¹⁷ of 1.8% for Canada in 2017. The Bank's January 2017 *Monetary Policy Report* notes upward pressure on consumer energy prices in 2017, stemming from higher commodity prices and new regulations related to carbon use, but this will be more than offset by falling food prices and excess capacity in the Canadian economy.¹⁸

Beyond 2017, the outlook is for similar levels of growth in the Whitehorse CPI with gains of 1.9% and 1.7% in 2018 and 2019, respectively.

Outlook for CPI

CPI

- Following deflation in 2015, the Whitehorse CPI grew at a modest 1.0% in 2016.
- Moderate growth of the Whitehorse CPI is expected with annual growth to average 1.8% over 2017 to 2019.

Sector performance varies

Mining to pick up steam in 2018, 2019

Mining related activities have been a key driver of Yukon's economic performance with annual gains and contractions, particularly of GDP, often explained by what is happening in the mining sector.

Following a period of high levels of development and exploration spending where three mining projects were brought into production, lower mineral prices in recent years have contributed to decreased spending and mine closures.

Yukon's mining sector will continue to play a prominent role in Yukon's economy in the medium term, with the current outlook for real GDP tied to expectations for the mining sector.

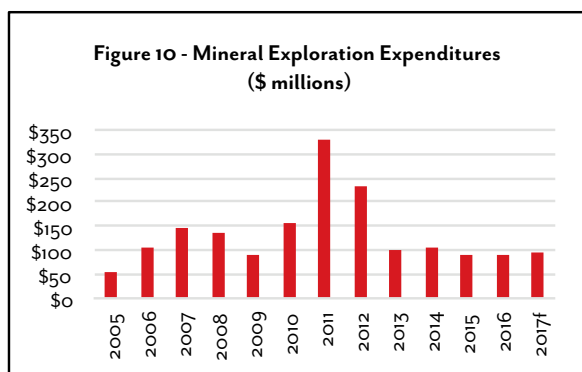
Mineral exploration driven by prices

The fortunes of Yukon's mining sector are invariably linked to the performance of mineral prices, in particular the price of gold. As gold prices saw a rapid run-up, reaching all-time highs in 2012, record annual levels of exploration spending were noted in Yukon.

Following the peak in 2012, gold prices fell in each of the next three years, contributing to notable declines in mineral exploration expenditures. Lower prices made it more difficult for mining companies, particularly junior mining companies, to raise capital to finance exploration activities. With much of the exploration undertaken in Yukon completed by junior miners, this contributed to a dramatic decline in annual exploration expenditures.

Prices for metals of interest for Yukon recovered somewhat in 2016. The average price of gold was up 7.6% from 2015 and silver prices increased by 9.1% in 2016. Copper prices, while down overall in 2016, saw significant gains in the last two months of the year.

Natural Resources Canada's (NRCAN) latest *Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures*, released in February 2017, estimates that exploration spending¹⁹ decreased to \$87.9 million in 2016, down from \$92.2 million in 2015.



Source: Department of Finance; Natural Resources Canada

Recent years have seen a shift from a greater proportion of spending on exploration^a activities to more spending on deposit appraisal^b work. NRCAN's spending estimate for 2016 includes an estimated \$38.2 million related to deposit appraisal and the remaining \$49.6 million for exploration. At \$38.2 million, spending on deposit appraisal accounted for almost 44% of the total spending figure, much higher than during the last exploration boom (2010/12) which saw the share of deposit appraisal spending at about one-quarter^c of the total. Spending intentions for 2017²⁰, as

compiled by NRCAN, have exploration spending in Yukon increasing for the first time since 2014. While remaining well below the robust spending of the 2010/12 period, anticipated spending of \$94.1 million in 2017 would represent an increase of 7.1% from 2016.

An improved outlook for the global mining community, based in part on improved outlooks for global growth and growth in key countries, is fueling hope of increased demand for minerals. Spending by Goldcorp. Inc., owner of the Coffee property, is expected to account for almost a third of total spending in 2017.

Mineral development spending remains low, but is expected to pick up

With no mines in development, expenditures on development remain modest, averaging less than \$20 million over the last three years. Estimates from NRCAN have development expenditures in 2016 at just under \$12 million, up slightly from \$10 million in 2015. Spending by GoldCorp Inc. on its Coffee property accounted for much of the spending in 2016. NRCAN's forecast for 2017 anticipates spending will increase to more than \$28 million, similar to what was recorded in 2014.

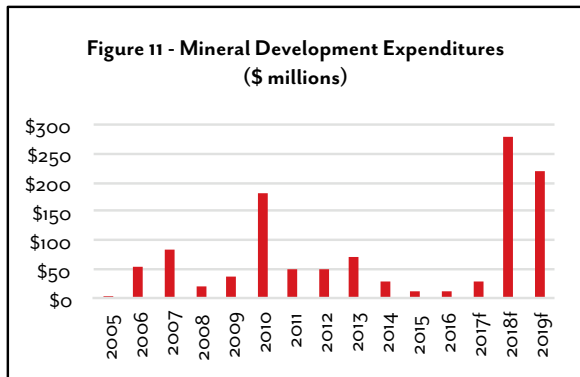
Development spending related to Victoria Gold Corp's Eagle Gold project and the Coffee project account for almost all of the spending expected in 2017.

The current forecast includes the development of the Eagle Gold and Coffee projects, which would result in significant development expenditures over 2018 and 2019, estimated at almost \$500 million.

^a Defined as the search for, discovery and first delimitation of a previously-unknown mineral deposit, or a re-evaluation of a deposit to enhance its potential economic interest.

^b Defined as the steps undertaken to bring a delimited deposit to the stage of detailed knowledge required for a complete feasibility study that will fully justify and support a production decision and the large investment required.

^c \$40.7 million (26%) in 2010, \$76.0 million (23%) in 2011 and \$52.9 million (23%) in 2012.



Source: Department of Finance; Natural Resources Canada

The Eagle Gold project is fully permitted and is currently looking to secure financing to begin construction²¹. Development costs are estimated at about \$370 million, with John McConnell, President and CEO of Victoria Gold noting publicly that the company will need US\$300 million to begin construction.²¹ In January 2017, it was announced that a major French bank, BNP Paribas had committed US\$220 million in financing for the project, and that with Victoria Gold having US\$40 million of its own money, they were looking to raise the remaining US\$40 million.

The Eagle Gold mine is projected to have a ten-year lifespan with production of almost 1.9 million ounces of gold over that period. It is anticipated that the project would employ 350-400 people annually during operation.

GoldCorp Inc. submitted a proposal for the Coffee project to the Yukon Environmental and Socio-economic Assessment Board (YESAB) on March 31, 2017.²² Mine General Manager, Buddy Crill, suggested that construction could begin as early as 2018 with the project producing for 12 years. Timeline in a GoldCorp presentation from February 2017 shows development beginning in the third quarter of 2019 and continuing through to the end of 2020.²³ Crill also noted that construction would support 400 jobs, and the mine would employ 320 people annually during operation.²⁴

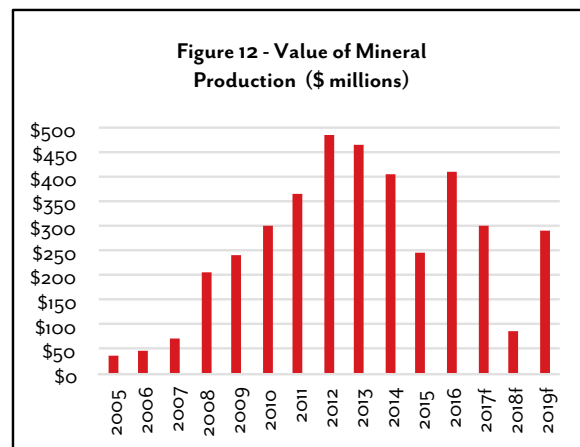
Mineral production to dip in 2018

After reaching a peak in 2012, lower mineral prices and lower annual production contributed to declines in 2013, 2014 and 2015. Closures of the Bellekeno mine in September 2013 and the Wolverine mine in January 2015 account for much of the recent decline.

Production increased markedly in 2016 on the strength of higher production from the Minto mine as well as increased placer gold production. The addition of production from the Minto North pit contributed to significant production gains at the Minto mine. Preliminary estimates from NRCAN have 2016 mineral production at more than \$409 million, up 66% from \$246 million in 2015.

Looking to 2017, expectations for metal prices are mixed. While the outlook for base metals such as copper, zinc, lead and nickel are for growth, the outlook is for a retreat in gold and silver prices. In terms of production, expectations are for underground mining at Minto to continue into early Q4, after which the mill will process stockpiled material, with milling currently scheduled to run at full capacity until the end of 2017.

The value of mineral production in 2017 is expected to be down significantly, in the area of \$300 million.



Source: Department of Finance; Natural Resources Canada

Placer gold mining continues to make significant contributions to Yukon's mining sector, supporting local employment and accounting for a significant portion of annual mineral production. In 2016, there were an estimated 170 placer mine sites that directly employed about 700 people.²⁵ In terms of production, after averaging near \$70 million annually from 2012 to 2015, the value of placer gold production is estimated at about \$90 million in 2016. Estimated at about 70,000 crude ounces in 2016, placer gold production would be the highest since 2004. Placer gold production in 2017 is expected to be similar to the level of production in 2016.

With the Minto mine expected to cease operations in late 2017, mineral production is expected to decline dramatically in 2018, falling below \$100 million, with placer gold accounting for most of the value. There is some upside risk in 2018 as Capstone Mining has indicated that they are continuing to review the economics of additional mining which could extend into 2018 and beyond.²⁶ An additional few months of production in 2018 could boost GDP growth by 1-2%.

With first production from the Eagle Gold project expected in 2019, the value of mineral production is expected to approach the current forecast for 2017.

While not included in the forecast, there is upside risk related to the development of the Kudz Ze Kayah mine, a zinc, lead, copper, gold and silver project. On March 27, 2017 YESAB indicated that BMC Minerals Ltd. had submitted a project proposal and that a 60 day adequacy review of the project had begun. BMC has publically indicated intentions to have a final decision to proceed with construction in late 2019, with commissioning of the mill to begin in late 2021 with commercial production in 2022. The project calls for a two-year construction period at a cost more than \$420 million. The project would employ about 400 people during construction and support approximately 400 jobs annually during operations.²⁷

Outlook for Mining



- Exploration spending in 2017 is expected to be the highest since 2014, increasing 7.1% from 2016.
- Development expenditures are expected to be down in the short term, but development of the Eagle Gold and Coffee projects is expected to boost development going forward.
- Lower production from the Minto mine is the primary contributor to a decline in mineral production in 2017. With Minto expected to cease operations in late 2017, the value of mineral production is expected to dip in 2018, before Eagle Gold production begins in 2019.

Energy potential abounds

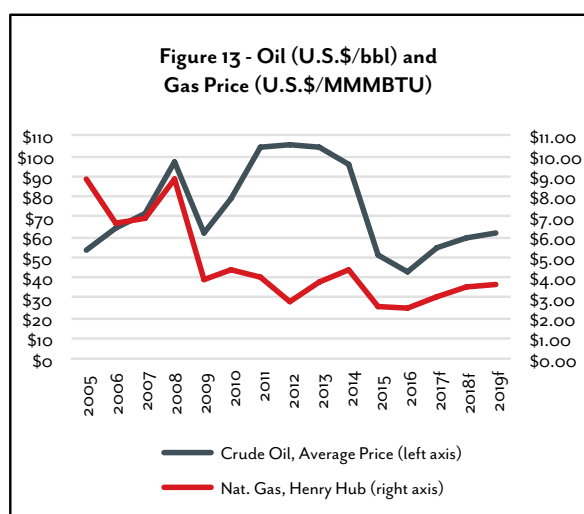
A growing population, a desire for less reliance on imported fuels, and interest in exploring options to provide energy to potential mining projects are all contributing to the ongoing exploration of local options of energy production.

Yukon has been investigating options for renewable power, including development of a biomass energy strategy for district and home heating and an Independent Power Production policy, including a micro-generation program allowing individuals to produce and sell electricity to the grid. The government's platform also committed to explore options for expansion of renewable energy sources.

Oil and Gas

While there has been no commercial hydrocarbon production in Yukon since production ceased at the Kotaneelee field in the Liard Basin in September 2012, there is significant hydrocarbon potential in the territory,

both onshore and offshore. Yukon's onshore sedimentary basins contain an estimated 14.77 trillion cubic feet (Tcf) of conventional natural gas and 663 million barrels (MMbbls) of conventional oil. Offshore conventional resources in the Beaufort Sea include an additional estimated 40 Tcf of natural gas and 4,500 MMbbls of oil.



Interest has also been shown in the hydrocarbon potential of the Kandik and Eagle Plain sedimentary basins in Northern Yukon. The fall 2016 Request for Postings closed on July 13, 2016, and the Yukon Government received 15 requests for oil and gas rights located in the Kandik (13) and Eagle Plain (2) oil and gas basins. Consultation with affected First Nations and a review by government departments is currently being conducted and will be followed by a 60-day public review process.

Concerning Yukon's offshore resources in the Beaufort Sea, in December 2016, Canada designated all Arctic waters as indefinitely off limits to oil and gas licensing, to be reviewed every five years through a climate and marine science-based life-cycle assessment. Existing rights holders can continue to apply for and acquire licenses to undertake oil and gas activity, however, offshore rights will be indefinitely off-limits in the Beaufort Sea (to be reviewed every five years).²⁸ There will be no call for nominations during that time period.

Potential exists for development of local natural gas resources for both export and domestic use. Domestic production could help provide power for future mining projects; there has been interest in the potential of using LNG for the purposes of powering some operations, creating further interest.

Renewable Energy

As well as hydrocarbon, significant geothermal potential has been identified in Yukon. A report released by the Canadian Geothermal Energy Association²⁹ in 2016 noted that Yukon's geothermal energy potential could be more than 1,700 MW of energy, or about 18 times the current energy supplied by Yukon's renewable electrical system. There has also been recent discussion about drilling test wells to assess geothermal capacity in specific areas.³⁰

Hydro generation accounts for almost 95% of Yukon's total annual electricity generation and expansion of hydroelectric capacity is expected to continue in partnership with First Nations, along with considering smaller hydroelectric sites and exploring other forms of renewable energy. Some local efforts are already underway, with a solar project in Old Crow nominated for an Arctic Inspiration Prize³¹, given to projects with real-world applications that benefit the Canadian Arctic.

Outlook for Energy

- Yukon has significant energy potential from a variety of sources. Development of these resources would provide a boost to Yukon's economic prospects, both with an increase to GDP and by improving energy security in the territory, building a stable foundation for future development and potentially higher energy needs.

Tourism performing well

Tourism activities have long been an important contributor to Yukon's economy, often acting as a stabilizing force during times when the mining sector has struggled. Tourism-related activities add to the diversity of the local economy, help promote the territory, and support employment across a wide variety of local goods and services providers. Retailers, grocery stores, restaurants, accommodations providers, providers of sports and recreational activities and providers of arts and culture all benefit annually from the activities of visitors to the territory.

Tourism activities overlap a number of industries, making it difficult to determine the overall economic contribution. Accommodations & Food Services, Retail Trade and Transportation & Warehousing are three industry classifications where tourism activities are reflected strongly. In the 2015 Yukon Business Survey, Yukon businesses estimated that \$226.9 million of their gross revenue in 2014 was attributable to tourism; based on these revenues, total GDP contribution of tourism is estimated at \$95.9 million, almost 4% of Yukon's total GDP in 2014.³²

While an imperfect indicator of tourism performance, international border crossings have often been used as a performance measure for Yukon's tourism sector. Based on reporting from the Canada Border Services Agency (CBSA), Statistics Canada reports that total international travellers³³ to Yukon numbered 419,244 in 2016, an increase of 14,124 (3.5%) from 2015. Since falling to below 360,000 in 2009 during the height of the last global economic downturn, the number of international travellers to Yukon has averaged more than 409,000 annually.



Source: Statistics Canada

The proportion of non-resident travellers is very stable from year to year, at about 80% of all travellers annually. In 2016, non-resident travellers totaled almost 346,000, or 79.7% of the total number of international travellers.

Looking only at the number of international travellers does not provide a complete picture of Yukon's tourism performance, and only when examining other indicators and data sources can one get a better understanding of how the sector is performing. Other indicators also suggest that 2016 was a solid year for Yukon's tourism sector:

- Air arrivals at Erik Nielsen Whitehorse International Airport in 2016 were up 8.6% from 2015, with almost 170,000 passengers arriving at the airport³⁴ – the third consecutive annual increase recorded.
- The Canadian Tourism Research Institute (CTRI) estimates that tourism spending in Yukon rose by 7.0%, including an estimated 6.0% increase in spending by domestic tourists and a 7.6% increase in spending from international travellers. Tourism sector revenues in Yukon are estimated to have increased by 5.1% in Yukon in 2016 – third highest in Canada, behind only B.C. (6.5%) and P.E.I. (5.4%), and 1.2 percentage points higher than the national average.
- Also from CTRI, the growth in revenue from what was classified as tourism activity (6.4%) outpaced

that from non-tourism (local) activity (4.0%) for Yukon.

- CTRI's most recent Travel Markets Outlook³⁵ notes that overnight visitation of about 322,000 was up 5.2% from 2015, with growth coming from all areas, domestic (up 3.3%), U.S. (up 5.0%) and overseas (up 7.6%).
- Related expenditures are also noted as being up in 2016, with spending associated with these overnight visits increasing 6.7% to \$303 million – the fourth highest increase in Canada, behind only P.E.I. (10.1%), B.C. (8.4%), and Ontario (7.0%).
- For both overnight visitation and the spending associated with these stays, Yukon's gains outpace Canadian growth of 3.0% and 6.1% for both measures, respectively.

Looking forward, a number of factors have the potential to affect Yukon's tourism sector, including the performance of the Canadian dollar, gasoline prices, and geopolitical concerns.

After averaging just over US\$0.75 in 2016, expectations are for a further decline in 2017 to about US\$0.73. The persistence of a weaker Canadian dollar makes visitation to Yukon relatively more affordable for U.S. and some overseas visitors, potentially contributing to increased visitation and spending in 2017, as well as giving Canadians an incentive to travel within Canada, as the cost of international travel becomes relatively more costly.

Weakness in oil prices has contributed to lower gasoline prices in the last two years, but oil prices are expected to increase in 2017, putting upward pressure on gasoline prices. With many visitors to Yukon arriving by car (particularly from the U.S.), this could have a negative impact on Yukon's largest source of visitors. Higher fuel prices could also be passed along to customers in the form of higher costs for motorcoach and air travel to Yukon, which could also dampen visitation in 2017.

Geopolitical uncertainty, particularly that associated with potential policy decisions of the new U.S. administration, could impact travel in the near term. Recent policy direction, in the areas of immigration, trade of goods and services and restrictions on travel from certain countries to the U.S., has created significant concern in other countries and may deter travel to the U.S. This, along with Canada's reputation as a safe travel destination resonating with overseas travellers, could bode well for travel to Canada, and possibly Yukon.

CTRI's latest Travel Markets Outlook suggests that 2017 will be another positive year for Yukon's tourism sector. The CTRI forecast has total overnight visits at about 331,000, up 3.0%. Growth is noted in all areas with the strongest gains in overseas visitation, expected to increase 5.1% to 56,000, which may in part be fuelled by the current uncertainty regarding policy direction in the U.S. Expenditures by overnight visitors are forecast to increase 5.9% to \$321 million, but some of these increases are price-related, as a significant increase in the travel price index in 2017 is noted.

Looking beyond 2017, CTRI forecasts increased overnight visitation and associated expenditures in every year out to 2020. Growth is reported in domestic, overseas and U.S. visitation, with the strongest gains noted in overseas visitation.

Outlook for Tourism



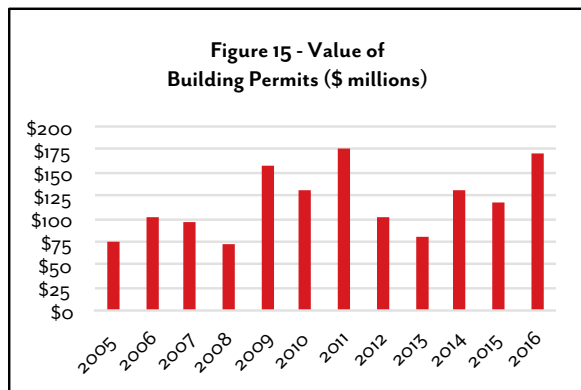
- Indications are that 2016 was another positive year for Yukon's tourism sector with growth noted in the number of international travellers and tourism-related spending and revenues.
- Expectations are that the near term will build on recent positive results.

Construction gains with public sector spending

Given the relatively small size of Yukon's economy, construction of a school or hospital, development of a new retail store or mine development activities can have a large impact on the territory's GDP. Forecast for the construction sector incorporates planned government capital spending in the 2017/18 Budget, which can have a significant effect in an economy as small as Yukon's.

While not all construction activity requires a building permit, the value of building permits can provide valuable information about the performance of the construction sector and is a commonly used indicator of performance.

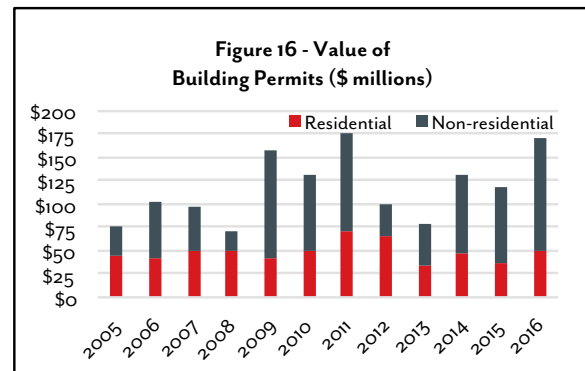
Following a 9.7% contraction in 2015, the value of building permits in 2016 are reported as growing 45.1% to almost \$171 million, the highest value since 2011.



Source: Department of Finance; Yukon Bureau of Statistics

While gains were noted in both residential and non-residential permit value, the majority of the gains were on the non-residential side.

The value of non-residential permits increased substantially in 2016, up 49.0% to \$121.7 million. Non-residential permits continued to account for the majority of building permit value, representing over 71% of the annual total. Since the start of 2010, non-residential building permit value has accounted for 61% of the total of almost \$910 million.



Source: Department of Finance; Yukon Bureau of Statistics

Contributing to the increase in non-residential permits in 2016 was strong growth in the value of government/institutional permits, up 68.9% to \$91.0 million. Commercial permit value also grew in 2016, totalling \$30.7 million, up 13.7% from 2015. Countering a portion of the gains was a small decrease in industrial permit value, which fell from \$769,000 in 2015 to \$0 in 2016.

The value of residential permits also posted strong growth in 2016, up 36.3% to \$49.2 million. For the period 2010 to 2016, residential building permits accounted for 39% of building permit value, totalling more than \$350 million.

Public sector investment has historically been a prominent driver of construction activity in Yukon. Capital spending by the Government of Yukon is estimated at \$306.6 million in 2016/17, up from spending of \$238.5 million in 2015/16. Prominent projects that contributed to this spending³⁶ include:

- Continued work on a 150-bed continuing care facility in Whitehorse (\$42.7 million);
- \$60 million related to transportation infrastructure, including more than \$38 million on improvement and rehabilitation of Yukon highways, \$4.3 million for various bridge work, and almost \$4.1 million for work on Yukon airports;
- Emergency department expansion and MRI at the Whitehorse General Hospital (\$22.0 million);



- Further work on the new Salvation Army building in Whitehorse (\$10 million);
- Work on phase 3 of the Whistle Bend sub-division (\$9.8 million);
- Activities related to investing in affordable housing (\$9.4 million);
- Continued work on the replacement of the Sarah Steele alcohol and drug detox centre (\$8 million);
- Activities related to the continued replacement of the old F.H. Collins school in Whitehorse (\$5.1 million) as well as construction of the new school's technical education wing (\$3.5 million);
- Archives Vault Expansion (\$5.6 million); and
- Replacement of fire hall in Carcross (\$2.6 million).
- Work associated with phases 3 (\$9.8 million) and 4 (\$14.3 million) of Whistle Bend;
- Activities related to construction of a new Francophone school in Whitehorse (\$8.0 million);
- Activities related to investments in affordable housing (\$6.9 million);
- Upgrades to the MacBride Museum (total project cost of \$6 million shared between Yukon and federal governments);
- Activities related to demolition (\$2.9 million) of the old F.H. Collins and development of the track and field and recreation site (\$2.0 million); and
- Construction of 6-plex residential building in Ross River (\$2.4 million).

Construction activity in 2017 will be driven in large part by capital projects identified in the 2017/18 Government of Yukon budget, which notes \$309.4 million in capital spending³⁷. Key projects in the latest budget include:

- Further work on the continuing care facility in Whitehorse (\$68.5 million);
- More than \$57 million related to transportation infrastructure, including more than \$36 million for improvement and rehabilitation of Yukon highways, \$15.3 million for various bridge work, and almost \$6.5 million for work on Yukon airports;
- \$30.3 million for work in various Yukon communities to improve sewage and wastewater services including Whitehorse (\$4.1 million), Haines Junction (\$3.3 million), Ross River (\$3.0 million), Old Crow (\$3.0 million), Mayo (\$2.9 million), Watson Lake (\$2.8 million), Carcross (\$2.8 million) and Dawson City (\$2.2 million);
- Emergency department expansion and MRI at the Whitehorse General Hospital (\$17.8 million);

Beyond capital spending by the Government of Yukon, the City of Whitehorse's building consolidation project is a large capital project that will impact the local economy in 2017. The City of Whitehorse's Capital Budget 2017/20 notes total investment in this project of \$45 million, with more than \$39 million budgeted to be spent in 2017. Driven by spending associated with the consolidation project, the City's total capital budget of \$46.6 million in 2017 is well above estimated capital spending of just under \$16.2 million in 2016.

Local construction activity will continue to be supported primarily by public spending, particularly on key infrastructure such as highways, water and sewage services, hospitals and schools. The development of new mining projects, as noted in the discussion of mining, could also result in substantial levels of private sector spending locally and has the potential to positively impact Yukon's construction industry in the medium term.



Outlook for Construction

- The 2017/18 Government of Yukon Budget notes capital spending of about \$310 million, up from estimated spending of \$306.6 million in 2016/17.
- Spending identified in the most recent budget will support a number of local construction projects.
- Development of new mines in the medium term could result in substantial construction related spending in 2018 and 2019.

Of the total annual increase of more than \$48 million, almost one third of the increase was a \$14.8 million increase in sales from Gasoline Stations. Much of the remaining increase falls within industry classifications with some data suppressed³⁸ in the last two years. These industries represent more than 76% of the total retail sales reported for 2016 with sales from *Motor Vehicle and Parts Dealers* accounting for more than 23% of that value. While the value was suppressed in 2016, historical data suggests that *Food and Beverage Stores* would likely represent 35-40% of the total value of retail sales.

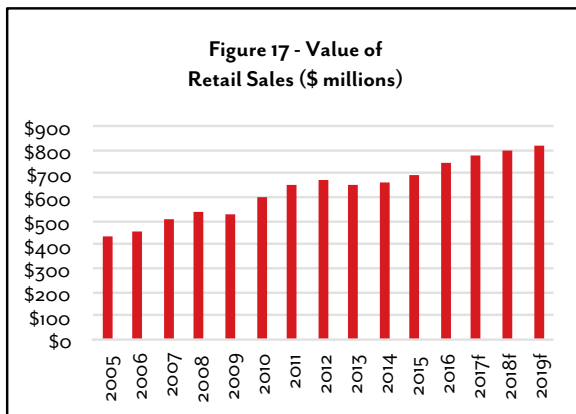
For all categories without data suppression in the past two years, reported sales increased in 2016. Reported sales for *Gasoline Stations* increased 13.8% to \$122.6 million. Sales from *Health and Personal Care Stores* changed little in 2016, with the estimated value of \$37.7 million up slightly from \$37.5 million in 2014. *Furniture and Home Furnishings Stores* sales of \$14.2 million in 2016 were up 10.2% from 2015.

Strong gains in retail trade

Yukon's retail sales have recently been strong, with increasing population, robust employment numbers and growing household incomes contributing to higher sales.

Retail sales for Yukon are estimated to have grown for a third consecutive year in 2016, with more than \$740 million in sales, a 7.0% increase from \$692 million in 2015.

Supported in part by the expectation of population gains, retail sales are anticipated to grow in the medium term. Retail sales are forecast at nearly \$780 million in 2017, with further gains in the following two years, totalling almost \$820 million in 2019.



Source: Department of Finance; Yukon Bureau of Statistics

Outlook for Retail Trade



- Retail sales grew for a third consecutive year in 2016, increasing 7.0% to more than \$740 million.
- Expectations are for further growth in Yukon retail sales in each of the next three years, bringing the value of retail sales to over \$817 million by 2019.

ASSUMPTIONS AND RISKS

As noted at the beginning of this document, forecasts are developed based on the best information available at the time and on the assumptions deemed most realistic. The following highlights some of the key assumptions that helped to shape the current forecast.

Mineral Production – In recent years, Yukon's real GDP performance has been driven by mineral production, and this remains the case for this forecast. Higher production from the Minto mine was a key driver of growth in 2016, and expectations of lower annual production in 2017 and 2018 explain much of the expected weakness in GDP during those years. The development of other mining projects, such as the Eagle Gold and Coffee mines, would also impact Yukon's economic fortunes beyond 2017.

Commodity Prices – Where available, World Bank metal price forecasts are used. If not available, forecasted growth of similar products is applied to historical data to develop a forecast. For energy prices, the U.S. Energy Information Administration's (EIA) long term forecast is used, adjusted in the near term for their short term forecast. Forecasts may be adjusted with reference to other prominent energy forecasts (e.g. Sproule, a leading global petroleum consultant).

Exchange Rates and Interest Rates – Exchange and interest rate forecasts are generated by a Yukon macroeconomic model used to develop this forecast. U.S. interest rates come from publically available sources (e.g. the Organization for Economic Co-operation and Development, or OECD).

Economic Forecasts – The US Energy Information Administration's (EIA) long term forecast is used for U.S. GDP growth, adjusting the short term based on the latest consensus forecast from the survey of professional forecasters of the Federal Reserve Bank of Philadelphia. For other major trading partners the current OECD forecast is generally used.

Capital Spending – As spending on large capital projects can impact GDP growth, this forecast is aligned with

planned upcoming projects (based on information available), including the Government of Yukon's capital plan and the City of Whitehorse's current capital budget. Examples of prominent projects considered in this forecast include the City of Whitehorse Municipal Building and the Whistle Bend Extended Care Facility. Spending related to the development of the Eagle Gold and Coffee mines are also key drivers of the real GDP forecast beyond 2017.

Government – this economic forecast incorporates the government's planned spending as outlined in the 2017/18 Budget. Public sector spending has a significant economic impact in a small jurisdiction such as Yukon, so any changes in the rate of spending would likely have an impact on a number of economic indicators (including GDP).

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There is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. Key risks to consider include:

Global Economy – Yukon's economy is tied to the performance of other economies, such as the U.S., China, Canada, and the global economy as a whole. Economic performance elsewhere affects the demand for Yukon goods and services, including minerals and local tourism activities. Recent developments such as the outcomes of the Brexit vote and the U.S. election could have an impact on Yukon's future economic performance.

Metal Prices – Metal prices are determined on the global market and are a key driver of mining activity. During the last global economic downturn, prices for minerals, particularly gold, saw a rapid increase and record highs, spurring interest in Yukon resources and contributing to record levels of exploration spending and substantial development spending (three mines brought into production). Weaker prices since then have contributed to two mine closures and reduced levels of exploration and development spending. Gold and silver prices were higher in 2016 while the price of copper fell. The outlook for mineral prices is mixed, with prices of



gold and silver expected to fall over the forecast period, but prices of base metals such as copper and zinc are expected to increase. Higher or lower prices would likely impact mining activity and ultimately the GDP forecast.

Energy Prices – Oil and gas prices can influence local economic activity, in particular mining sector activity (fuel for project operations and equipment) and tourism (fuel for travelers' vehicles). Fuel prices also affect construction costs and the cost of local purchases, as most goods are transported in from outside Yukon. This forecast notes a decline in oil and natural gas prices in 2016, before annual gains out to 2019. Higher or lower prices than forecast could impact actual results.

Exchange Rates – The Canadian/U.S. dollar exchange rate can affect spending decisions by tourists and investment decisions by resource-based companies. After a decline in the exchange rate in 2016, this forecast projects a further decline in 2017 to be followed by gains in each of the next two years, which would bring the Canadian dollar to US\$0.77 in 2019. Variation from the current projections could have an impact on actual results.

Interest Rates – Lower interest rates can contribute to increased investment as the cost of borrowing is reduced, and, conversely, higher interest rates may dampen investment spending. The cost of borrowing in Canada has been low for a prolonged period, with the Bank of Canada's daily overnight target for the bank rate not exceeding 1.0% since January 19, 2009. This forecast assumes that interest rates will remain low over the forecast horizon, but unforeseen increases could affect investment in Yukon.

Population and Labour Market – Population and labour market forecasts include the assumption that the proportion of fly-in/fly-out versus resident workers remains the same for future mining projects as in previous experience. If this proportion were to shift significantly (in either direction), there would likely be an impact on the employment forecast in particular.

KEY ECONOMIC INDICATORS

Indicator	2015	2016	2017f	2018f	2019f
Economic Output					
Real GDP by Industry (2007\$ billions)	\$2.193 (r)	\$2.295 (e)	\$2.296	\$2.301	\$2.361
Annual percent change	-6.0%	4.6%	0.1%	0.2%	2.6%
Population					
Population	37,343	37,858	38,380	38,810	39,360
Annual percent change	0.2%	1.4%	1.4%	1.1%	1.4%
Labour market†					
Labour force	20,700	21,400	21,900	22,300	22,500
Employment	19,400	20,200	20,600	20,900	21,100
Unemployed	1,300	1,200	1,300	1,400	1,400
Unemployment rate	6.3%	5.6%	5.7%	6.2%	6.2%
CPI (Annual % Change)	-0.2%	1.0%	1.9%	1.9%	1.7%
Commodity Prices~					
Gold (\$U.S./ounce)	\$1,160	\$1,249	\$1,167	\$1,153	\$1,142
Silver (\$U.S./ounce)	\$15.70	\$17.15	\$16.70	\$16.60	\$16.60
Copper (\$U.S./pound)	\$2.50	\$2.21	\$2.49	\$2.54	\$2.59
Zinc (\$U.S./pound)	\$0.87	\$0.95	\$1.22	\$1.27	\$1.27
Oil – WTI (\$U.S./barrel)	\$48.67	\$43.07	\$50.66	\$53.99	\$57.43
Natural Gas – Henry Hub (\$U.S./MMBTU)	\$2.63	\$2.49	\$3.27	\$3.45	\$3.96
Key Rates					
Three month Treasury Bill rate	0.50%	0.50%	0.50%	0.50%	0.50%
Canada/U.S. exchange rate	\$0.782	\$0.754	\$0.733	\$0.747	\$0.770
Mining					
Value of mineral production (\$ millions)	\$246.2 (r)	\$409.1 (p)	\$303.0	\$86.0	\$291.0
Exploration expenditures (\$ millions)	\$92.2	\$87.9	\$94.1	--	--
Development expenditures (\$ millions)	\$10.0	\$11.9	\$28.6	\$280.0	\$220.0
Construction					
Value of building permits (\$ millions)	\$117.8	\$170.9			
Retail Trade					
Value of retail sales (\$ millions)	\$692.2	\$740.5	\$777	\$792	\$818

e = estimate, f = forecast, p = preliminary, r = revised, -- = not available

^CPI increase for Whitehorse only

† = Annual averages rounded to the nearest 100. Totals may not add due to rounding.

~Annual averages

DATA SOURCES FOR KEY ECONOMIC INDICATORS TABLE

Indicator	Source
Economic Output (Real GDP)	Statistics Canada, Yukon Department of Finance
Population	Yukon Bureau of Statistics
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Finance
Commodity Prices	World Bank, U.S. Energy Information Administration, Yukon Department of Finance
Interest Rates	Bank of Canada, Yukon Department of Finance
Exchange Rates	Bank of Canada, Yukon Department of Finance
Value of Mineral Production	Natural Resources Canada, Yukon Department of Finance
Mineral Exploration Expenditures	Natural Resources Canada
Mineral Development Expenditures	Natural Resources Canada, Yukon Department of Finance
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Finance
Retail Trade	Statistics Canada, Yukon Department of Finance

ENDNOTES

- ¹ World Economic Outlook - Update. (January 2017). International Monetary Fund.
<http://www.imf.org/external/pubs/ft/weo/2017/update/01/pdf/0117.pdf>
- ² Caribbean countries, Latin America, Africa, rest of Asia, parts of Eastern Europe (including Baltic states, Russia, and Turkey), Middle Eastern countries excluding Israel, Oceania excluding Australia and New Zealand.
- ³ World Economic Outlook - Update. (January 2017). International Monetary Fund.
<http://www.imf.org/external/pubs/ft/weo/2017/update/01/pdf/0117.pdf>
- ⁴ Monetary Policy Report (January 2017). Bank of Canada.
<http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf>
- ⁵ Monetary Policy Report (January 2017). Bank of Canada.
<http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf>
- ⁶ World Bank Commodities Price Forecast (January 24, 2017).
World Bank. <http://pubdocs.worldbank.org/en/926111485188873241/CMO-January-2017-Forecasts.pdf>
- ⁷ MMBTU refers to a million British thermal unit (Btu)
- ⁸ World Bank Commodities Price Forecast (January 24, 2017).
World Bank. <http://pubdocs.worldbank.org/en/926111485188873241/CMO-January-2017-Forecasts.pdf>
- ⁹ Real GDP for 2015 represents the most recent data available from Statistics Canada. It is anticipated that preliminary data for 2016 will be released in May 2017.
- ¹⁰ "Public Sector" is an aggregation of industry classifications Public Administration, Educational Services and Health Care & Social Assistance.
- ¹¹ Population as of June 30th is treated as the annual figure.
- ¹² Includes City of Whitehorse and surrounding area as well as the community of Marsh Lake.
- ¹³ The outlook for population is based on the population projections produced by the Yukon Bureau of Statistics.
- ¹⁴ Data is from the Labour Force Survey.
- ¹⁵ Industry classifications are based on the North American Industry Classification System (NAICS). Business establishments are classified to an industry according to the primary business activity of the establishment.
- ¹⁶ Consumer Price Index data is only available in Yukon for Whitehorse.
- ¹⁷ Monetary Policy Report (January 2017). Bank of Canada.
<http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf>

- 
- ¹⁸ Monetary Policy Report (January 2017). Bank of Canada.
<http://www.bankofcanada.ca/wp-content/uploads/2017/01/mpr-2017-01-18.pdf>
- ¹⁹ Exploration and deposit appraisal expenditures include on-mine-site and off-mine-site activities; field work, overhead costs, engineering, economic and pre- or production feasibility studies, environment, and land access costs. Expenditures also include only the search for and appraisal of deposits and do not include work for extensions for known reserves.
- ²⁰ Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures (February 2017). Natural Resources Canada.
- ²¹ Victoria Gold reaches tentative financing deal for Eagle Gold mine near Mayo (January 26, 2017). CBC News.
<http://www.cbc.ca/news/canada/north/victoria-gold-mayo-mine-financing-deal-1.3953490>
- ²² Goldcorp showcases Dawson mine project (February 17, 2017). CKRWg6.1FM.
<http://www.ckrw.com/news/local-news/goldcorp-showcases-dawson-mine-project/>
- ²³ GoldCorp Inc. Corporate Presentation (February 27, 2017).
- ²⁴ Goldcorp showcases Dawson mine project (February 17, 2017). CKRWg6.1FM.
<http://www.ckrw.com/news/local-news/goldcorp-showcases-dawson-mine-project/>
- ²⁵ Yukon Exploration & Geology Overview 2016. Department of Energy, Mines and Resources.
http://ygsftp.gov.yk.ca/publications/yeg/yeg16/overview/YEG_Overview2016.pdf
- ²⁶ Capstone Mining 2017 Operating and Capital Guidance. <http://capstonemining.com/news/news-details/2017/Capstone-Mining-2017-Operating-and-Capital-Guidance/default.aspx>
- ²⁷ Mine would eventually employ 400 people.
<http://whitehorsestar.com/News/mine-would-eventually-employ-400-people>
- ²⁸ <http://pm.gc.ca/eng/news/2016/12/20/united-states-canada-joint-arctic-leaders-statement>
- ²⁹ In partnership with Canadian Northern Economic Development Agency, the Government of Yukon's Department of Energy, Mines and Resources' Energy Branch (the Energy Solutions Centre), Yukon Energy and the Yukon Geological Survey: <http://www.energy.gov.yk.ca/pdf/Yukon-Geothermal-Opportunities-and-Applications-Report.pdf>
- ³⁰ <http://www.cbc.ca/news/canada/north/yukon-geothermal-energy-1.4009917>
- ³¹ <http://www.arcticinspirationprize.ca/finalists/2016finalists.php>
- ³² Yukon Business Survey 2015. Yukon Bureau of Statistics.
http://www.eco.gov.yk.ca/stats/pdf/2015_Business_Survey_Report.pdf
- ³³ Cansim Table 427-0001. Statistics Canada.
- ³⁴ Department of Tourism and Culture.



³⁵ Travel Markets Outlook – National Focus (Autumn 2016). Canadian Tourism Research Institute. Conference Board of Canada

³⁶ Spending figures rounded to the nearest one decimal.

³⁷ Spending figures rounded to the nearest one decimal.

³⁸ Data for the following is suppressed, but is included in the total for retail sales: Motor Vehicle and Parts Dealers; Electronics & Appliance Stores; Building Material & Garden Equipment; Clothing & Clothing Accessories Stores; Sporting Goods, Hobby, Book & Music Stores; General Merchandise Stores; and Miscellaneous Store Retailers, and Supplies Dealers.

APPENDIX 5.3

MAYO B FLEXIBLE NOTE

1 **APPENDIX 5.3: MAYO B FLEXIBLE NOTE**

2 **PRIOR COMMITMENTS**

3 Yukon Energy, when seeking approval to proceed with the Mayo B Project, committed in the Mayo B Part
4 3 Application that it would secure (via Yukon Development Corporation [YDC]) flexible debt financing for
5 the Mayo B Project (i.e., measures to reduce overall return on rate base in order to mitigate specific near-
6 term rate impact concerns), and at that time outlined as follows the rationale and broad approach for this
7 financing.

8 The Mayo B flexible debt will allow the interest rate on the debt to change, based on the IS [Integrated
9 System] grid generation load, as required to prevent, in any fiscal year during the short-term, the cost of
10 Mayo B net generation used to displace diesel generation from exceeding a 10 to 11 c/kW.h range
11 (2012\$). [YEC's Mayo B Project Part 3 Application, page 45].

12 Additional commitments for this flexible debt included in the Mayo B Part 3 Application (page 45) were as
13 follows:

- 14 • YDC funding at no cost to YEC for the additional interest rate reductions (including cash injections
15 through 'negative' interest rate payments) required in this regard (i.e., to prevent net generation
16 cost from exceeding the stipulated unit cost range) to mitigate any delays in connecting the
17 Carmacks Copper mine load to the grid – these no cost arrangements for YEC were to apply in
18 the short-term for years before the Carmacks Copper assumed operating load of approximately
19 50 GW.h/year was to be supplied from the grid.
- 20 • The face interest for this flexible debt (i.e., the rate charges when no interest rate reductions
21 apply) will be set above YEC's then applicable long-term borrowing costs in order to enable YDC
22 an opportunity to earn an overall return on the load over its life equal to YDC's long-term
23 borrowing costs when the flexible debt is established.

24 The specific methodology for implementation of the above financing was not developed at the time of the
25 Part 3 hearing. The YUB noted in its Report and Recommendations to the Minister following the Mayo B
26 hearing (page 45) that it expects "...the complete details of the flexible debt financing with YDC and
27 illustrative examples of how the flexible debt financing works will be provided by YEC in its next GRA."

28 **OVERVIEW OF FLEXIBLE DEBT NOTE**

29 The YDC Mayo B Flexible Debt (long-term promissory note – the "Note") with YEC for \$21.9 million¹ that
30 was concluded effective December 31, 2011 is attached at Attachment 5.3. Illustrative examples of how
31 the flexible debt financing works are provided in Schedule 2 of the Note.

¹ The budget for the Mayo B project is \$120 million. The majority of the financing for the Mayo B project is derived from other sources (Federal Infrastructure Fund payments of \$53.35 million and Yukon Government Contributions of \$30.15 million), resulting in this project being expected to add \$36.5 million to YEC's asset base. In keeping with the 60:40 debt:equity structure, this asset addition requires a debt component of \$21.9 million (60% of \$36.5 million). At the time that the Note was concluded in November/December 2011, commissioning of Mayo B was scheduled for completion during December, 2011, and this Note was therefore required to be in place by December 31, 2011.

Simplified terms for the Mayo B Flexible Debt have been established that in summary reflect the following. The simplified terms and other revisions are summarized below:

- **Debt Amount** – The Note is for the full \$21.9 million, assuming that the ultimate net rate base for Mayo B is \$36.5 million.
- **Term** – 40 years (reflects maximum term of other flexible debt in the past for YDC with YEC). The following are noted with regard to the Term:
 - o Flexible interest terms extend to the Expiry Date, which is January 1, 2021 if the Mayo Lake Project is in service, and otherwise is January 1, 2023.
 - o Annual principal repayment is calculated based on an assumed 65 year project life (depreciation), with a balloon payment for the outstanding balance at the end of the Term.
- **Interest Rate** – The 5.46% annual rate was determined as the rate estimated to achieve a forecast interest IRR of 5% over the Term, taking into account forecast Maximum Interest Payable under grid loads as currently forecast by YEC assuming connection of Victoria Gold by late 2014, and assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load (compared to forecast Minto and Alexco loads) at the start of 2012 and remaining for six years (i.e., to the end of 2017).
- **Simplified Approach to determine Maximum Interest Payable Prior to the Expiry Date**
 - The simplified approach follows the Canada Flexible Debt mechanics that rely on readily available grid generation records, and avoids the complexities of requiring annual reviews of actual YEC costs and estimates of annual net generation used to displace diesel or other fossil fuel generation on the grid.
 - o The simplified approach assumes a ceiling on interest payments in any year at 11 cents/kW.h in 2012\$ (adjusted after 2012 by annual Yukon CPI escalation) times the estimated grid diesel generation displaced by Mayo B based on the actual grid generation load and long term average annual grid hydro generation at that load assuming renewable generation capability in place and as licensed in December 2012, i.e., no Mayo Lake project and Aishihik FAA as at this time².
 - o “Actual Grid Generation” is to be determined for this purpose after adding back the estimated reduction, if any, in grid generation in that years due to DSM/SSE (as defined in the Note) undertaken since December 31, 2012³.
 - o The assessments of maximum and minimum grid loads adopted in the simplified approach (Schedule 1 attached) were calibrated and tested using detailed model calculations of the applicable **maximum grid load** (i.e., load at which full interest payable) and **minimum grid load** (i.e., load at which no interest payable) based on

² The Note is not varied in the event that new renewable generation is added to the grid, or the existing licences are modified, after December 31, 2012, i.e., the assistance that was committed related solely to load-related risk affecting diesel displacement by Mayo B and was independent of impacts on such diesel displacement as a result of subsequently approved new generation projects.

³ The Note is not varied by the impacts of DSM/SSE, i.e., the assistance that was committed related solely to load-related risk independent of impacts of DSM/SSE.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

- 1 forecast annual Mayo B operating and maintenance costs, 65 year depreciation of the
- 2 assumed \$36.5 million net rate base cost, and equity at 40% of rate base with an
- 3 allowed ROE of 8.49%/year.
- 4 o Figures 5.3A-1 and 5.3A-2 provide further information on this analysis.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

Figure 5.3-1

Mayo B Grid Load at Full Interest, at 5%, no more than 11 cents/kW.h in \$2012

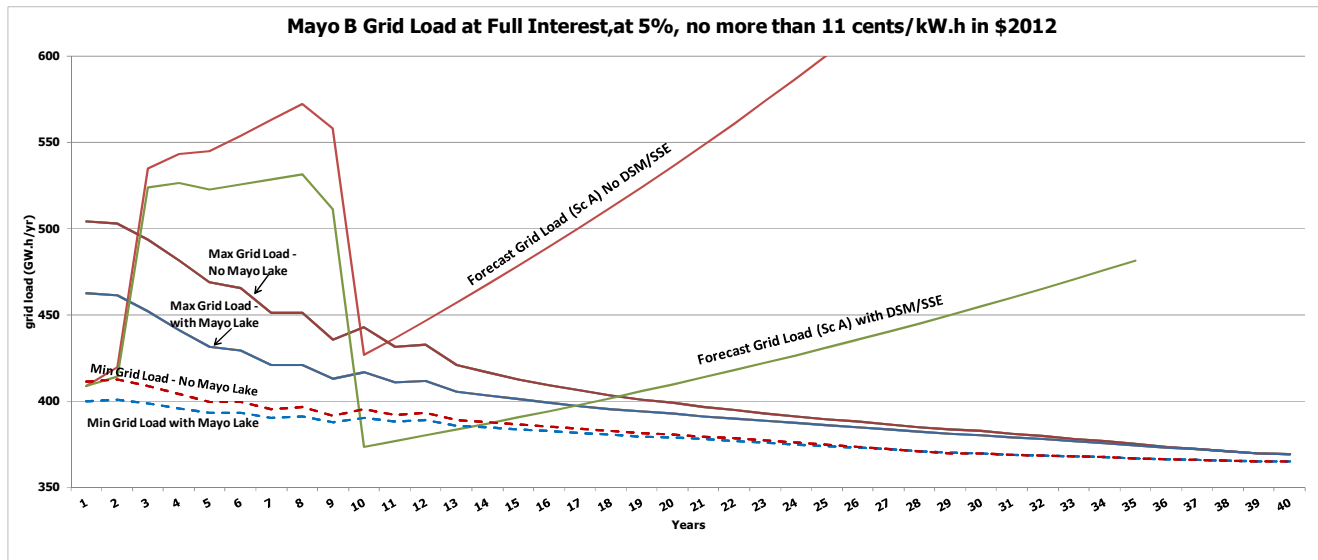


Figure 5.3A-1 shows detailed calculated estimates (i.e., not using the simplified approach) by year (year 1=2012) of **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), assuming interest is constrained as required to ensure Mayo B annual costs do not exceed 11 cents per kW.h (2012\$) of net generation (diesel displaced) by Mayo B, and based on assumed forecast annual Mayo B costs for O&M, depreciation and return on equity. Max and Min Grid Loads are shown by year both (a) with no Mayo Lake Project and (b) with Mayo Lake Project enhanced storage (1 metre lower bottom storage) – including the Mayo Lake Project reduces the Max and Min Grid Loads. Figure 5.3-1 also shows forecast grid loads by year, indicating years when full interest is expected to be paid versus years when interest is expected to be reduced. Current [as at November/February 2011] forecast loads are shown for the first two years (2012 and 2013); after 2013, the forecast shows the current [as at November/February 2011] longer-term planning YEC grid generation forecast with Victoria Gold. Separate grid load forecasts are provided with no DSM/SSE, as well as the lower loads with maximum DSM/SSE as assumed in current long-term resource planning forecasts.

In summary, Figure 5.3A-1 shows that full interest would be paid each year that Victoria Gold is on the grid, as well as each year after 2021 with only non-industrial forecast grid loads, i.e., no mines connected to the grid, assuming no reductions for DSM/SSE are considered. Without Victoria Gold loads, however, only minimal interest would be paid for many years prior to 2022. Further, if DSM/SSE impacts materially reduce grid loads the period with no or reduced interest would be greatly extended in the absence of new mine loads and/or adjustment to remove the effects of DSM/SSE when determining Mayo B Flexible Debt interest payments.

The Mayo B Flexible Debt commitments were made based only on Mayo B and the grid resources and licences at the time of the Mayo B commitment, and are not intended to reflect changes due to subsequent resource investments such as DSM/SSE or new renewable generation resources on the grid.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

Figure 5.3-2
Mayo B Grid Load at 40 Years Flex Term Debt (lump sum payment in year 40),
65 years depreciation, no more than 11 cents/kW.h in \$2012

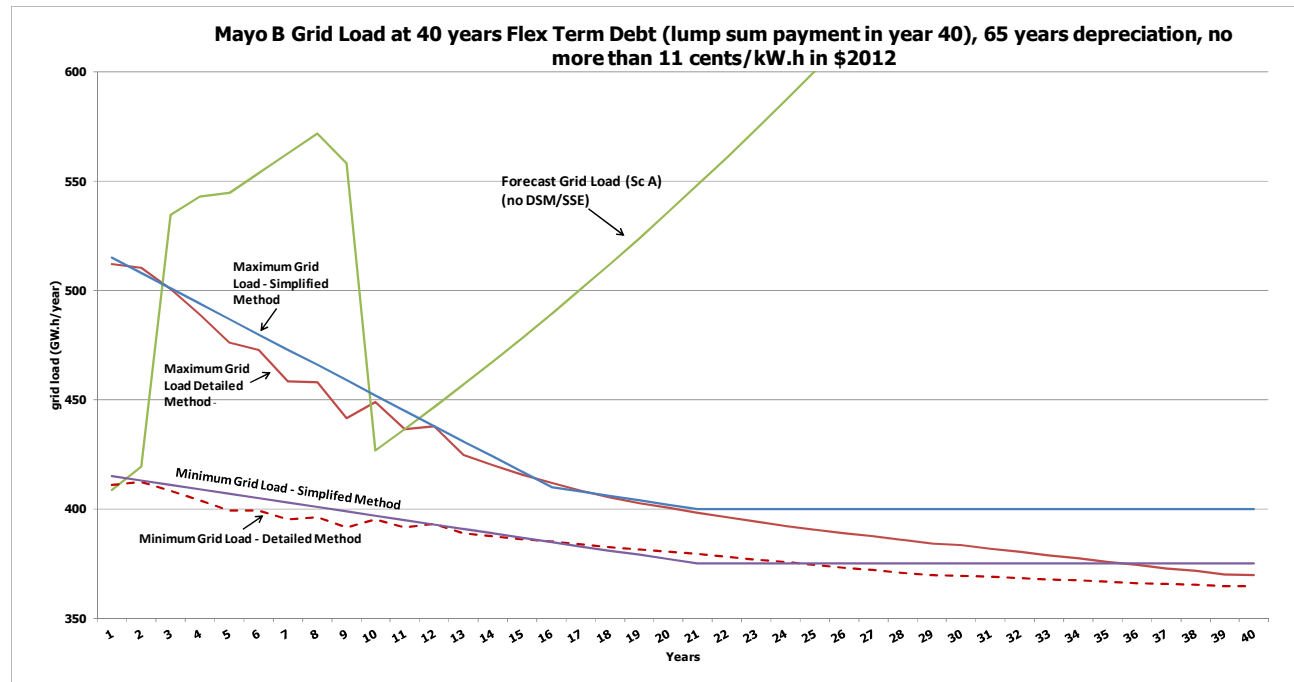


Figure 5.3-2 shows **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), comparing the Simplified Method and the Detailed Calculation Method (see Figure 5.3-1). Forecast grid loads are also shown by year assuming no DSM/SSE (the current [as at November/February 2011] YEC forecast loads are shown for the first two years [2012 and 2013]; after 2013, the forecast shows the current [as at November/February 2011] long-term resource planning grid generation forecast with Victoria Gold).

Figure 5.3-2 shows that the Simplified Method in almost every year results in Max and Min Grid loads that are equal to or higher than those determined with the Detailed Calculation Method.

The Interest Rate of 5.46% was determined as the rate estimated to achieve a forecast interest IRR of 5% over the 40-year term, taking into account forecast Maximum Interest Payable under the grid loads shown in Figure 5.3-2 (with "Carmacks Copper" minimum loads assumed in 2012 and 2013 per commitments by YEC in the Part 3 proceeding, i.e., assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load [compared to forecast Minto and Alexco loads]) at the start of 2012 and remaining for six years [i.e., to the end of 2017]). In the event that the Mayo Lake Project is approved, Figure 5.3-1 demonstrates that the 11 cent per kW.h cost ceiling would be met by 2020/21 at grid loads with no mines connected.

ATTACHMENT 5.3: MAYO B PROMISSORY NOTE

December 31, 2011

\$21,900,000

Due in installments

1. Promise to Pay

1.1 Effective as of December 31, 2011, in consideration of the advance by way of loan of the sum of \$21,900,000 from Yukon Development Corporation (“**YDC**”) to Yukon Energy Corporation (“**Yukon Energy**”) Yukon Energy promises to pay to YDC, the principal amount of, and interest on, \$21,900,000 in lawful money of Canada as follows:

- (a) 40 equal annual installments of principal of \$336,923.07 each, payable on December 31 of each calendar year commencing on December 31, 2012 and continuing up to and including December 31, 2051; and
- (b) a final payment of principal of \$8,423,078, payable on December 31, 2051;
- (c) subject to Sections 1.2 below, interest at the Interest Rate, calculated annually, and not in advance, on the principal amount from time to time remaining unpaid as of December 31 of each calendar year of this Note prior to the payment of principal in that calendar year. Such interest is to accrue from January 1 to December 31 and include each calendar year of this Note. Interest is payable on December 31 of each calendar year commencing on December 31, 2012 up to and including December 31, 2051.

1.2 **Limitation on Interest.** Notwithstanding Section 1.1(c), prior to the Expiry Date, the amount of interest payable in each calendar year of this Note will not be more than the Maximum Interest Payable in that year (as defined below), determined as of December 31 of each calendar year of this Note. If the Interest Rate exceeds the Maximum Interest Payable in a calendar year then the terms set out in Section 3.1 will apply. For greater certainty, if the Maximum Interest Payable under this Note is a negative number then YDC will pay to Yukon Energy the positive dollar amount of that number on or before March 31 of the next calendar year.

1.3 **Application of Payments.** Payments received will be applied firstly in payment of unpaid interest and the balance, if any, in reduction of principal.

1.4 **Sample Calculation.** A sample calculation of the annual interest payment (Maximum Interest Payable) is attached to this Note as Schedule 2.

2. Definitions and Interpretation

2.1 Definitions. In this Note the following terms have the following meanings:

- (a) **“Actual Grid Generation”** means in any calendar year commencing with 2012, the total GW.h in that year of Yukon Energy generation and purchased power on the electrical grid system connected with Mayo B based upon metered readings (or based upon reasonable estimates thereof consistently applied from year to year where it is unreasonable or impractical to base grid generation or purchased power upon metered readings), plus the estimated reduction, if any, in such grid generation in that year due to DSM/SSE undertaken since December 31, 2012;
- (b) **“Business Day”** means any day other than a Saturday, Sunday, or a statutory holiday in the Yukon Territory;
- (c) **“DSM/SSE”** means the estimated amount by which Actual Grid Generation in any calendar year has been reduced due to demand side management and supply-side enhancement measures undertaken by the Yukon Territorial Government, Yukon Energy, or Yukon Electrical Company Limited since December 31, 2012, based on reasonable estimates thereof by Yukon Energy consistently applied from year to year; for this purpose,
 - (i) **“demand side management”** measures include any load reduction measures undertaken specifically by the Yukon Government, Yukon Energy or the Yukon Electrical Company Limited to reduce the electrical sales to customers required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B; and
 - (ii) **“supply-side enhancement”** measures include any generation or transmission efficiency improvement measures undertaken specifically by Yukon Energy or the Yukon Electrical Company Limited, other than demand side management measures, to reduce the electrical generation required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B;
- (d) **“Expiry Date”** means the earlier of:
 - (i) if the Mayo Lake Project is in service, January 1, 2021; or
 - (ii) January 1, 2023.
- (e) **“Interest Rate”** means in each calendar year of this Note that annual rate of interest equal to **[5.46%]**;
- (f) **“Mayo Lake Project”** means the enhancement of the storage upstream of the Mayo B Project by adding additional drawdown to YEC’s authorized storage

range at Mayo Lake beyond the storage range authorized as at December 31, 2011;

(g) **“Maximum Grid Load”** for each calendar year is as established in Schedule 1 to this Note;

(h) **“Maximum Interest Payable”** means for any calendar year:

(i) The Interest Rate if Actual Grid Generation for the calendar year is at or above the Maximum Grid Load established in Schedule 1 of this Note for that calendar year; or

(ii) If Actual Grid Generation for the calendar year is below the Maximum Grid Load established in Schedule 1 of this Note for that calendar year, an amount arrived at by applying the following formula for the Actual Grid Generation, Minimum Grid Load and Range values for that calendar year:

$$\frac{(\text{Interest Rate}) \times (\text{Actual Grid Generation} - \text{Minimum Grid Load})}{(\text{Range})}$$

(i) **“Maximum Interest Payable Statement”** has the meaning set out in Section 3.2;

(j) **“Mayo B”** means Yukon Energy’s Mayo Hydro Enhancement Project;

(k) **“Minimum Grid Load”** for each calendar year is as established in Schedule 1 to this Note;

(l) **“Note”** means this Promissory Note;

(m) **“Parties”** means Yukon Energy and YDC and **“Party”** means any one of them;

(n) **“Range”** for each calendar year is as established in Schedule 1 to this Note; and

(o) **“YUB”** means the Yukon Utilities Board.

2.2 **Headings.** The headings are inserted for convenience of reference only and will not affect the construction or interpretation of this Note.

2.3 **Governing Law.** This Note will be governed by, and construed under the laws of the Yukon Territory.

2.4 **Invalidity of Any Provision.** If any covenant, obligation, or provision contained in this Note is invalid or unenforceable, the remainder of this Note will not be affected and each covenant, obligation, or provision of this Note will separately be valid and enforceable to the fullest extent permitted by law.

2.5 **Amendments.** This Note may only be amended from time to time in writing and any such amendment may be evidenced by a document signed by an authorized officer of each of the Parties.

2.6 **Included Words.** Whenever the singular or the masculine is used the same will be considered to include the plural or the feminine or the body corporate where the context or the Parties so require.

3. **Maximum Interest Payable**

3.1 **Interest Abatement.** The amount of interest, if any, which is payable under this Note as a result of the Interest Rate exceeding the Maximum Interest Payable will abate forever and will not be payable by Yukon Energy to YDC, it being the clear intention of the Parties that the amount of interest payable by Yukon Energy as a result of the Interest Rate payable by Yukon Energy to YDC will not exceed the Maximum Interest Payable.

3.2 **Maximum Interest Rate Statement.** Yukon Energy covenants and agrees to provide YDC on or before March 31 in each year of the Note commencing March 31, 2013 and continuing until the whole of the principal and interest under the Note is paid, with a statement (the “**Maximum Interest Payable Statement**”) certified by the Chief Financial Officer of Yukon Energy as to the Maximum Interest Payable for the preceding calendar year, including explanation of any estimates (including any DSM/SSE estimates) used in the determination of the Maximum Interest Payable. If the Maximum Interest Payable Statement at March 31 of each year differs from the interest paid under Section 1.1 as at December 31 of the preceding calendar year, payment of the difference will be made forthwith by either YEC or YDC, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.3 **Dispute.** If YDC does not object in writing to the Maximum Interest Payable Statement within 30 days of receipt of such statement from Yukon Energy the Maximum Interest Payable Statement will be final and binding on YDC. If YDC does object in writing to the Maximum Interest Rate Statement within such 30 days the Parties will negotiate in good faith a resolution to the dispute for a period of 15 days. If the dispute is not resolved by the Parties the matter will be referred to a single arbitrator under the *Arbitration Act* (Yukon Territory), whose decision will be final and binding on the Parties. If the arbitrator’s decision differs from the Maximum Interest Rate Statement, payment of the difference will be made forthwith by either YDC or Yukon Energy, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.4 **Access to Books and Records.** Yukon Energy will allow YDC and YDC’s representatives access to the books, records, and other documents of Yukon Energy at all reasonable times for the purpose of verifying the Maximum Interest Payable.

4. **General**

4.1 **Disposition of Project.** If Yukon Energy sells, transfers, or otherwise disposes of Mayo B without the prior written approval of YDC, which may be arbitrarily withheld, then YDC may,

at any time thereafter, demand payment of the entire principal and interest owing under the Note, whereupon the entire principal and interest then remaining will become due and payable notwithstanding any other provision of this Note.

4.2 Insurance Proceeds. If there is damage to all or part of the Project for which insurance proceeds are paid to Yukon Energy and which are not used to repair or replace such damage within a reasonable time with work commencing within six months of the damage having occurred, Yukon Energy will be required to pay to YDC the amount of such proceeds first, in reduction of any outstanding interest under the Note and then in reduction of any outstanding principal under the Note.

4.3 Prepayment. The principal amount due under the Note may be paid by Yukon Energy in whole or in part with mutual agreement of the Parties on one year's written notice without bonus or penalty.

4.4 Default. Upon default in payment of any payment when due under this Note, the entire unpaid balance of the principal amount and accrued interest will become immediately due and payable without notice or demand and the undersigned covenants to pay interest on it and on subsequent overdue interest at the Interest Rate, both before and after judgment, until paid in full. The covenants to pay interest will not merge on the taking of a judgment or judgments with respect to any of the obligations stipulated for this Note.

4.5 Interest Act of Canada. For the purposes of the *Interest Act* (Canada), whenever any interest is calculated in respect of this Note on the basis of a period of time other than a calendar year, the annual rate of interest to which each rate of interest determined pursuant to such calculation is equivalent to such rate as so determined multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days used in the basis for such determination.

4.6 Notices. In this Note:

(a) any notice or communication required or permitted to be given under this Note will be in writing and will be considered to have been given if delivered by hand, transmitted by facsimile transmission or mailed by prepaid registered post in Canada, to the address or facsimile transmission number of each Party set out below:

(i) if to YDC:

206A Lowe Street
Whitehorse, YT Y1A 1W6

Attention: President
Fax No.: 867-393-7071

(ii) if to Yukon Energy:

#2 Miles Canyon Road

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

Whitehorse, YT Y1A 6S7

Attention: President
Fax No.: 867-393-5323

or to such other address or facsimile transmission number as any Party may designate in the manner set out above; and

- (b) notice or communication will be considered to have been received:
- (i) if delivered by hand during business hours on a Business Day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next Business Day;
 - (ii) if sent by facsimile transmission during business hours on a Business Day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next Business Day; and
 - (iii) if mailed by prepaid registered post in Canada, upon the fifth Business Day following posting; except that, in the case of a disruption or an impending or threatened disruption in postal services every notice or communication will be delivered by hand or sent by facsimile transmission.

4.7 **Assignment by Yukon Energy.** Yukon Energy may not to assign this Note, except with the prior written consent of YDC.

4.8 **Assignment by YDC.** YDC may assign this Note without the consent of Yukon Energy.

4.9 **Enurement.** This Note and all its provisions will enure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

4.10 **Yukon Energy Waiver.** Yukon Energy waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit, and diligence in taking any action.

4.11 **Set-off.** Yukon Energy will not be entitled to set-off against any payments payable to YDC under this Note any amounts owing or alleged to be owing by YDC to Yukon Energy.

Executed at Whitehorse, Yukon Territory, on December _____, 2011.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

YUKON ENERGY CORPORATION

Per:

Authorized Signatory

Authorized Signatory

YUKON DEVELOPMENT CORPORATION

Per:

Authorized Signatory

Authorized Signatory

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

SCHEDULE 1

	Year	Maximum Grid Load (GWh)	Minimum Grid Load (GWh)	Range
1	2012	515	415	100
2	2013	508	413	95
3	2014	501	411	90
4	2015	494	409	85
5	2016	487	407	80
6	2017	480	405	75
7	2018	473	403	70
8	2019	466	401	65
9	2020	459	399	60
10	2021	452	397	55
11	2022	445	395	50
12	2023	438	393	45
13	2024	431	391	40
14	2025	424	389	35
15	2026	417	387	30
16	2027	410	385	25
17	2028	408	383	25
18	2029	406	381	25
19	2030	404	379	25
20	2031	402	377	25
21	2032	400	375	25
22	2033	400	375	25
23	2034	400	375	25
24	2035	400	375	25
25	2036	400	375	25
26	2037	400	375	25
27	2038	400	375	25
28	2039	400	375	25
29	2040	400	375	25
30	2041	400	375	25
31	2042	400	375	25
32	2043	400	375	25
33	2044	400	375	25
34	2045	400	375	25
35	2046	400	375	25
36	2047	400	375	25
37	2048	400	375	25
38	2049	400	375	25
39	2050	400	375	25
40	2051	400	375	25

SCHEDULE 2 – EXAMPLE: RE ANNUAL INTEREST PAYMENT

Assume for 2012:

- Balance of debt outstanding at start of fiscal year \$21.9 million
- Maximum Grid Load (Schedule 1) 515 GW.h
- Minimum Grid Load (Schedule 1) 415 GW.h
- Range (Schedule 1) 100 GW.h
- Maximum Interest Payable at different Actual Grid Loads:
 - o Assume Actual Grid Load at 520 GW.h
 - Actual Grid Load > Max Grid Load
 - Maximum Interest Payable at 5.44% (full interest)
 - Amount Payable:
 $\$1,195,740.00 = 5.46\% \times \$21.9 \text{ million (paid by YEC to YDC)}$
 - o Assume Actual Grid Load at 450 GWh
 - Actual Grid Load < Max Grid Load
 - Max Interest Rate = $\frac{(\text{Interest Rate}) \times (\text{Actual Grid Generation} - \text{Minimum Grid Load})}{(\text{Range for the year as established in Schedule 1})}$
 - Maximum Interest Payable: $5.46\% \times (450 - 415) / 100 = 0.35 \times 5.46\% = 1.911\%$
 - Amount Payable
 $\$418,509.00 = 1.911\% \times \$21.9 \text{ million (paid by YEC to YDC)}$
 - o Assume Actual Grid Load at 400GWh
 - Actual Grid Load < Max Grid Load
 - Max Interest Rate = $\frac{(\text{Interest Rate}) \times (\text{Actual Grid Generation} - \text{Minimum Grid Load})}{(\text{Range for the year as established in Schedule 1})}$
 - Maximum Interest Payable: $5.46\% \times (400 - 415) / 100 = -0.819\%$
 - Amount Payable
 $-\$179,361.00 = -0.819\% \times \$21.9 \text{ million (indicates YDC amount paid to YEC)}$

1 **TOPIC: Non-Labour Costs**

2
3 **REFERENCE:** Application, pages 3-8 to 3-13. PDF 56 to 61

4
5 **QUESTION:**

6
7 a) Was any escalator applied to non-labour costs in section 3 of the Application?
8 Please explain.

9
10 b) If an escalator (s) was/were applied, please quantify the escalator(s), where it/they
11 were applied and the base numbers it was applied to.

12
13 **ANSWER:**

14
15 **(a) and (b)**

16
17 No escalator was applied to non-labour costs referenced in Tab 3, pages 3-8 to 3-13 of
18 the Application. Costs for these items were individually forecast giving consideration as to
19 what each specific cost would be.

1 **TOPIC: Reserves for Injuries and Damages (RFID)**

2
3 **REFERENCE:** Application, page 3-15, PDF page 63, lines 1-6

4
5 **QUOTE:** "... Yukon Energy is seeking approval of a two-part solution to the RFID
6 [reserve for injuries and damages] account:

7 ...

8 2. Increase the annual appropriation to the RFID, starting in 2017, to
9 \$0.267 million per year. This is based on the 10-year average of actual
10 expenses ..."

11
12 **QUESTION:**

13
14 a) Please provide the 10-year average of actual expenses in relation to the RFIDF
15 for the years 2007 to 2016.

16
17 **ANSWER:**

18
19 **(a)**

20
21 The 10-year average of actual expenses in relation to RFID for the years 2007-2016 is
22 \$306,000 based on the following details:

23

(\$000's)	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	10 Year Average
Annual Charges	\$63	\$101	\$159	\$415	\$302	\$204	\$404	\$196	\$193	\$1,018	\$306

24

1 **TOPIC:** YDC Mayo B Promissory Note

3 **REFERENCE:** Application, page 3-22. PDF 70, lines 1 to 2

5 **QUOTE:** "... which forgives the interest expense if the Integrated Grid is lower
6 than the Minimum Grid Load as set in Schedule 1 of the Mayo B
7 Promissory Note..."

9 **QUESTION:**

11 a) Please provide a copy of the referenced Schedule 1 with respect to the Mayo B
12 Promissory Note.

14 b) Please provide a continuity schedule of interest payments with respect to the Mayo
15 B Promissory Note for the period 2013-2016 inclusive.

17 **ANSWER:**

19 **(a)**

21 Please see YUB-YEC-1-31 Attachment 1, which provides Appendix 5.3 from the 2012/13
22 GRA Application. This includes the Mayo B Promissory note (as well as the referenced
23 Schedule 1).

25 **(b)**

27 Please see the table provided below.

28

(\$000's)	2013	2014	2015	2016
Interest on Mayo B Flex Note	\$ 130	-\$ 112	\$ 128	\$ 167

APPENDIX 5.3

MAYO B FLEXIBLE NOTE

1 **APPENDIX 5.3: MAYO B FLEXIBLE NOTE**

2 **PRIOR COMMITMENTS**

3 Yukon Energy, when seeking approval to proceed with the Mayo B Project, committed in the Mayo B Part
4 3 Application that it would secure (via Yukon Development Corporation [YDC]) flexible debt financing for
5 the Mayo B Project (i.e., measures to reduce overall return on rate base in order to mitigate specific near-
6 term rate impact concerns), and at that time outlined as follows the rationale and broad approach for this
7 financing.

8 The Mayo B flexible debt will allow the interest rate on the debt to change, based on the IS [Integrated
9 System] grid generation load, as required to prevent, in any fiscal year during the short-term, the cost of
10 Mayo B net generation used to displace diesel generation from exceeding a 10 to 11 c/kW.h range
11 (2012\$). [YEC's Mayo B Project Part 3 Application, page 45].

12 Additional commitments for this flexible debt included in the Mayo B Part 3 Application (page 45) were as
13 follows:

- 14 • YDC funding at no cost to YEC for the additional interest rate reductions (including cash injections
15 through 'negative' interest rate payments) required in this regard (i.e., to prevent net generation
16 cost from exceeding the stipulated unit cost range) to mitigate any delays in connecting the
17 Carmacks Copper mine load to the grid – these no cost arrangements for YEC were to apply in
18 the short-term for years before the Carmacks Copper assumed operating load of approximately
19 50 GW.h/year was to be supplied from the grid.
- 20 • The face interest for this flexible debt (i.e., the rate charges when no interest rate reductions
21 apply) will be set above YEC's then applicable long-term borrowing costs in order to enable YDC
22 an opportunity to earn an overall return on the load over its life equal to YDC's long-term
23 borrowing costs when the flexible debt is established.

24 The specific methodology for implementation of the above financing was not developed at the time of the
25 Part 3 hearing. The YUB noted in its Report and Recommendations to the Minister following the Mayo B
26 hearing (page 45) that it expects "...the complete details of the flexible debt financing with YDC and
27 illustrative examples of how the flexible debt financing works will be provided by YEC in its next GRA."

28 **OVERVIEW OF FLEXIBLE DEBT NOTE**

29 The YDC Mayo B Flexible Debt (long-term promissory note – the "Note") with YEC for \$21.9 million¹ that
30 was concluded effective December 31, 2011 is attached at Attachment 5.3. Illustrative examples of how
31 the flexible debt financing works are provided in Schedule 2 of the Note.

¹ The budget for the Mayo B project is \$120 million. The majority of the financing for the Mayo B project is derived from other sources (Federal Infrastructure Fund payments of \$53.35 million and Yukon Government Contributions of \$30.15 million), resulting in this project being expected to add \$36.5 million to YEC's asset base. In keeping with the 60:40 debt:equity structure, this asset addition requires a debt component of \$21.9 million (60% of \$36.5 million). At the time that the Note was concluded in November/December 2011, commissioning of Mayo B was scheduled for completion during December, 2011, and this Note was therefore required to be in place by December 31, 2011.

Simplified terms for the Mayo B Flexible Debt have been established that in summary reflect the following. The simplified terms and other revisions are summarized below:

- **Debt Amount** – The Note is for the full \$21.9 million, assuming that the ultimate net rate base for Mayo B is \$36.5 million.
- **Term** – 40 years (reflects maximum term of other flexible debt in the past for YDC with YEC). The following are noted with regard to the Term:
 - o Flexible interest terms extend to the Expiry Date, which is January 1, 2021 if the Mayo Lake Project is in service, and otherwise is January 1, 2023.
 - o Annual principal repayment is calculated based on an assumed 65 year project life (depreciation), with a balloon payment for the outstanding balance at the end of the Term.
- **Interest Rate** – The 5.46% annual rate was determined as the rate estimated to achieve a forecast interest IRR of 5% over the Term, taking into account forecast Maximum Interest Payable under grid loads as currently forecast by YEC assuming connection of Victoria Gold by late 2014, and assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load (compared to forecast Minto and Alexco loads) at the start of 2012 and remaining for six years (i.e., to the end of 2017).
- **Simplified Approach to determine Maximum Interest Payable Prior to the Expiry Date**
 - The simplified approach follows the Canada Flexible Debt mechanics that rely on readily available grid generation records, and avoids the complexities of requiring annual reviews of actual YEC costs and estimates of annual net generation used to displace diesel or other fossil fuel generation on the grid.
 - o The simplified approach assumes a ceiling on interest payments in any year at 11 cents/kW.h in 2012\$ (adjusted after 2012 by annual Yukon CPI escalation) times the estimated grid diesel generation displaced by Mayo B based on the actual grid generation load and long term average annual grid hydro generation at that load assuming renewable generation capability in place and as licensed in December 2012, i.e., no Mayo Lake project and Aishihik FAA as at this time².
 - o “Actual Grid Generation” is to be determined for this purpose after adding back the estimated reduction, if any, in grid generation in that years due to DSM/SSE (as defined in the Note) undertaken since December 31, 2012³.
 - o The assessments of maximum and minimum grid loads adopted in the simplified approach (Schedule 1 attached) were calibrated and tested using detailed model calculations of the applicable **maximum grid load** (i.e., load at which full interest payable) and **minimum grid load** (i.e., load at which no interest payable) based on

² The Note is not varied in the event that new renewable generation is added to the grid, or the existing licences are modified, after December 31, 2012, i.e., the assistance that was committed related solely to load-related risk affecting diesel displacement by Mayo B and was independent of impacts on such diesel displacement as a result of subsequently approved new generation projects.

³ The Note is not varied by the impacts of DSM/SSE, i.e., the assistance that was committed related solely to load-related risk independent of impacts of DSM/SSE.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

- 1 forecast annual Mayo B operating and maintenance costs, 65 year depreciation of the
- 2 assumed \$36.5 million net rate base cost, and equity at 40% of rate base with an
- 3 allowed ROE of 8.49%/year.
- 4 o Figures 5.3A-1 and 5.3A-2 provide further information on this analysis.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

Figure 5.3-1

Mayo B Grid Load at Full Interest, at 5%, no more than 11 cents/kW.h in \$2012

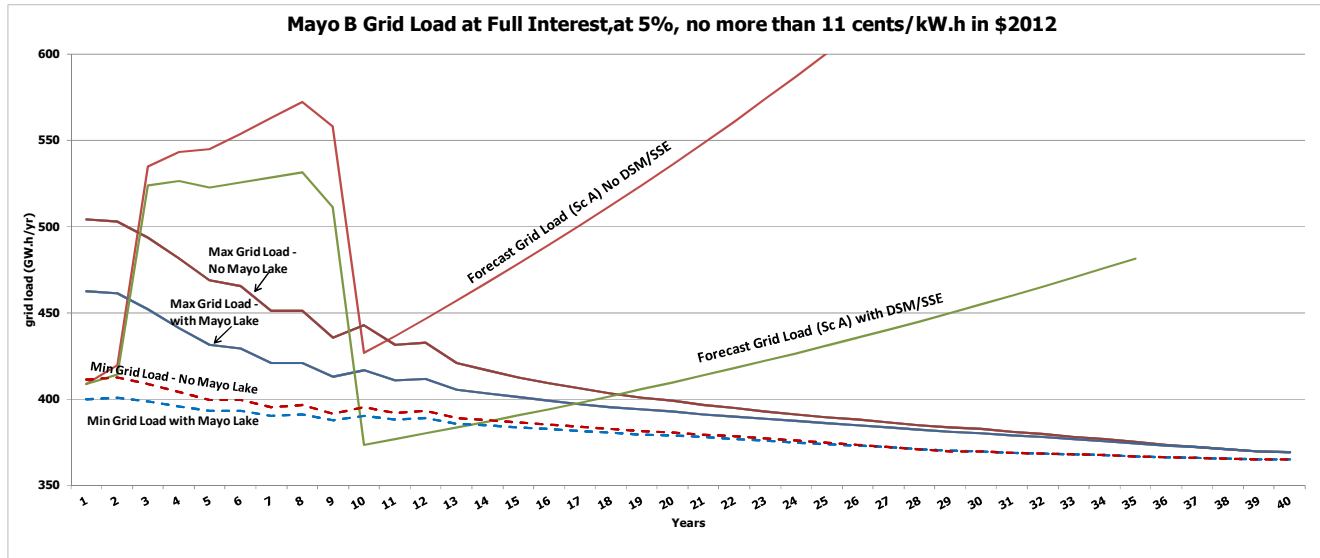


Figure 5.3A-1 shows detailed calculated estimates (i.e., not using the simplified approach) by year (year 1=2012) of **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), assuming interest is constrained as required to ensure Mayo B annual costs do not exceed 11 cents per kW.h (2012\$) of net generation (diesel displaced) by Mayo B, and based on assumed forecast annual Mayo B costs for O&M, depreciation and return on equity. Max and Min Grid Loads are shown by year both (a) with no Mayo Lake Project and (b) with Mayo Lake Project enhanced storage (1 metre lower bottom storage) – including the Mayo Lake Project reduces the Max and Min Grid Loads. Figure 5.3-1 also shows forecast grid loads by year, indicating years when full interest is expected to be paid versus years when interest is expected to be reduced. Current [as at November/February 2011] forecast loads are shown for the first two years (2012 and 2013); after 2013, the forecast shows the current [as at November/February 2011] longer-term planning YEC grid generation forecast with Victoria Gold. Separate grid load forecasts are provided with no DSM/SSE, as well as the lower loads with maximum DSM/SSE as assumed in current long-term resource planning forecasts.

In summary, Figure 5.3A-1 shows that full interest would be paid each year that Victoria Gold is on the grid, as well as each year after 2021 with only non-industrial forecast grid loads, i.e., no mines connected to the grid, assuming no reductions for DSM/SSE are considered. Without Victoria Gold loads, however, only minimal interest would be paid for many years prior to 2022. Further, if DSM/SSE impacts materially reduce grid loads the period with no or reduced interest would be greatly extended in the absence of new mine loads and/or adjustment to remove the effects of DSM/SSE when determining Mayo B Flexible Debt interest payments.

The Mayo B Flexible Debt commitments were made based only on Mayo B and the grid resources and licences at the time of the Mayo B commitment, and are not intended to reflect changes due to subsequent resource investments such as DSM/SSE or new renewable generation resources on the grid.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

Figure 5.3-2
Mayo B Grid Load at 40 Years Flex Term Debt (lump sum payment in year 40),
65 years depreciation, no more than 11 cents/kW.h in \$2012

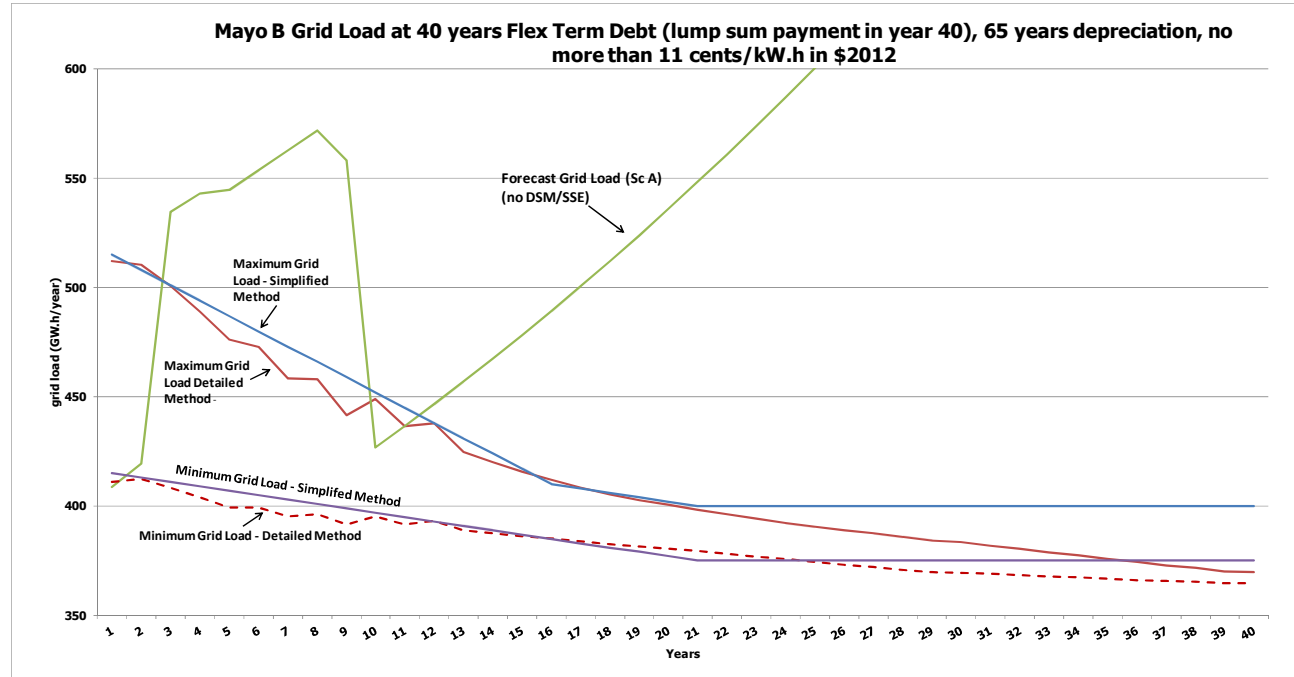


Figure 5.3-2 shows **Maximum Grid Load** (at and above this level full interest is paid) and **Minimum Grid Load** (at this level zero interest is paid, and below this level negative interest is paid), comparing the Simplified Method and the Detailed Calculation Method (see Figure 5.3-1). Forecast grid loads are also shown by year assuming no DSM/SSE (the current [as at November/February 2011] YEC forecast loads are shown for the first two years [2012 and 2013]; after 2013, the forecast shows the current [as at November/February 2011] long-term resource planning grid generation forecast with Victoria Gold).

Figure 5.3-2 shows that the Simplified Method in almost every year results in Max and Min Grid loads that are equal to or higher than those determined with the Detailed Calculation Method.

The Interest Rate of 5.46% was determined as the rate estimated to achieve a forecast interest IRR of 5% over the 40-year term, taking into account forecast Maximum Interest Payable under the grid loads shown in Figure 5.3-2 (with "Carmacks Copper" minimum loads assumed in 2012 and 2013 per commitments by YEC in the Part 3 proceeding, i.e., assuming connection to the grid at a minimum of at least 52 GW.h/year of new mine load [compared to forecast Minto and Alexco loads]) at the start of 2012 and remaining for six years [i.e., to the end of 2017]). In the event that the Mayo Lake Project is approved, Figure 5.3-1 demonstrates that the 11 cent per kW.h cost ceiling would be met by 2020/21 at grid loads with no mines connected.

ATTACHMENT 5.3: MAYO B PROMISSORY NOTE

December 31, 2011

\$21,900,000

Due in installments

1. Promise to Pay

1.1 Effective as of December 31, 2011, in consideration of the advance by way of loan of the sum of \$21,900,000 from Yukon Development Corporation (“**YDC**”) to Yukon Energy Corporation (“**Yukon Energy**”) Yukon Energy promises to pay to YDC, the principal amount of, and interest on, \$21,900,000 in lawful money of Canada as follows:

- (a) 40 equal annual installments of principal of \$336,923.07 each, payable on December 31 of each calendar year commencing on December 31, 2012 and continuing up to and including December 31, 2051; and
- (b) a final payment of principal of \$8,423,078, payable on December 31, 2051;
- (c) subject to Sections 1.2 below, interest at the Interest Rate, calculated annually, and not in advance, on the principal amount from time to time remaining unpaid as of December 31 of each calendar year of this Note prior to the payment of principal in that calendar year. Such interest is to accrue from January 1 to December 31 and include each calendar year of this Note. Interest is payable on December 31 of each calendar year commencing on December 31, 2012 up to and including December 31, 2051.

1.2 **Limitation on Interest.** Notwithstanding Section 1.1(c), prior to the Expiry Date, the amount of interest payable in each calendar year of this Note will not be more than the Maximum Interest Payable in that year (as defined below), determined as of December 31 of each calendar year of this Note. If the Interest Rate exceeds the Maximum Interest Payable in a calendar year then the terms set out in Section 3.1 will apply. For greater certainty, if the Maximum Interest Payable under this Note is a negative number then YDC will pay to Yukon Energy the positive dollar amount of that number on or before March 31 of the next calendar year.

1.3 **Application of Payments.** Payments received will be applied firstly in payment of unpaid interest and the balance, if any, in reduction of principal.

1.4 **Sample Calculation.** A sample calculation of the annual interest payment (Maximum Interest Payable) is attached to this Note as Schedule 2.

2. Definitions and Interpretation

2.1 Definitions. In this Note the following terms have the following meanings:

- (a) **“Actual Grid Generation”** means in any calendar year commencing with 2012, the total GW.h in that year of Yukon Energy generation and purchased power on the electrical grid system connected with Mayo B based upon metered readings (or based upon reasonable estimates thereof consistently applied from year to year where it is unreasonable or impractical to base grid generation or purchased power upon metered readings), plus the estimated reduction, if any, in such grid generation in that year due to DSM/SSE undertaken since December 31, 2012;
- (b) **“Business Day”** means any day other than a Saturday, Sunday, or a statutory holiday in the Yukon Territory;
- (c) **“DSM/SSE”** means the estimated amount by which Actual Grid Generation in any calendar year has been reduced due to demand side management and supply-side enhancement measures undertaken by the Yukon Territorial Government, Yukon Energy, or Yukon Electrical Company Limited since December 31, 2012, based on reasonable estimates thereof by Yukon Energy consistently applied from year to year; for this purpose,
 - (i) **“demand side management”** measures include any load reduction measures undertaken specifically by the Yukon Government, Yukon Energy or the Yukon Electrical Company Limited to reduce the electrical sales to customers required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B; and
 - (ii) **“supply-side enhancement”** measures include any generation or transmission efficiency improvement measures undertaken specifically by Yukon Energy or the Yukon Electrical Company Limited, other than demand side management measures, to reduce the electrical generation required to be supplied by Yukon Energy or the Yukon Electrical Company Limited on the electrical grid system connected with Mayo B;
- (d) **“Expiry Date”** means the earlier of:
 - (i) if the Mayo Lake Project is in service, January 1, 2021; or
 - (ii) January 1, 2023.
- (e) **“Interest Rate”** means in each calendar year of this Note that annual rate of interest equal to **[5.46%]**;
- (f) **“Mayo Lake Project”** means the enhancement of the storage upstream of the Mayo B Project by adding additional drawdown to YEC’s authorized storage

range at Mayo Lake beyond the storage range authorized as at December 31, 2011;

(g) **“Maximum Grid Load”** for each calendar year is as established in Schedule 1 to this Note;

(h) **“Maximum Interest Payable”** means for any calendar year:

(i) The Interest Rate if Actual Grid Generation for the calendar year is at or above the Maximum Grid Load established in Schedule 1 of this Note for that calendar year; or

(ii) If Actual Grid Generation for the calendar year is below the Maximum Grid Load established in Schedule 1 of this Note for that calendar year, an amount arrived at by applying the following formula for the Actual Grid Generation, Minimum Grid Load and Range values for that calendar year:

$$\frac{(\text{Interest Rate}) \times (\text{Actual Grid Generation} - \text{Minimum Grid Load})}{(\text{Range})}$$

(i) **“Maximum Interest Payable Statement”** has the meaning set out in Section 3.2;

(j) **“Mayo B”** means Yukon Energy’s Mayo Hydro Enhancement Project;

(k) **“Minimum Grid Load”** for each calendar year is as established in Schedule 1 to this Note;

(l) **“Note”** means this Promissory Note;

(m) **“Parties”** means Yukon Energy and YDC and **“Party”** means any one of them;

(n) **“Range”** for each calendar year is as established in Schedule 1 to this Note; and

(o) **“YUB”** means the Yukon Utilities Board.

2.2 **Headings.** The headings are inserted for convenience of reference only and will not affect the construction or interpretation of this Note.

2.3 **Governing Law.** This Note will be governed by, and construed under the laws of the Yukon Territory.

2.4 **Invalidity of Any Provision.** If any covenant, obligation, or provision contained in this Note is invalid or unenforceable, the remainder of this Note will not be affected and each covenant, obligation, or provision of this Note will separately be valid and enforceable to the fullest extent permitted by law.

2.5 **Amendments.** This Note may only be amended from time to time in writing and any such amendment may be evidenced by a document signed by an authorized officer of each of the Parties.

2.6 **Included Words.** Whenever the singular or the masculine is used the same will be considered to include the plural or the feminine or the body corporate where the context or the Parties so require.

3. **Maximum Interest Payable**

3.1 **Interest Abatement.** The amount of interest, if any, which is payable under this Note as a result of the Interest Rate exceeding the Maximum Interest Payable will abate forever and will not be payable by Yukon Energy to YDC, it being the clear intention of the Parties that the amount of interest payable by Yukon Energy as a result of the Interest Rate payable by Yukon Energy to YDC will not exceed the Maximum Interest Payable.

3.2 **Maximum Interest Rate Statement.** Yukon Energy covenants and agrees to provide YDC on or before March 31 in each year of the Note commencing March 31, 2013 and continuing until the whole of the principal and interest under the Note is paid, with a statement (the “**Maximum Interest Payable Statement**”) certified by the Chief Financial Officer of Yukon Energy as to the Maximum Interest Payable for the preceding calendar year, including explanation of any estimates (including any DSM/SSE estimates) used in the determination of the Maximum Interest Payable. If the Maximum Interest Payable Statement at March 31 of each year differs from the interest paid under Section 1.1 as at December 31 of the preceding calendar year, payment of the difference will be made forthwith by either YEC or YDC, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.3 **Dispute.** If YDC does not object in writing to the Maximum Interest Payable Statement within 30 days of receipt of such statement from Yukon Energy the Maximum Interest Payable Statement will be final and binding on YDC. If YDC does object in writing to the Maximum Interest Rate Statement within such 30 days the Parties will negotiate in good faith a resolution to the dispute for a period of 15 days. If the dispute is not resolved by the Parties the matter will be referred to a single arbitrator under the *Arbitration Act* (Yukon Territory), whose decision will be final and binding on the Parties. If the arbitrator’s decision differs from the Maximum Interest Rate Statement, payment of the difference will be made forthwith by either YDC or Yukon Energy, as the case may be, together with simple interest at the Interest Rate computed from January 1 to the date of payment.

3.4 **Access to Books and Records.** Yukon Energy will allow YDC and YDC’s representatives access to the books, records, and other documents of Yukon Energy at all reasonable times for the purpose of verifying the Maximum Interest Payable.

4. **General**

4.1 **Disposition of Project.** If Yukon Energy sells, transfers, or otherwise disposes of Mayo B without the prior written approval of YDC, which may be arbitrarily withheld, then YDC may,

at any time thereafter, demand payment of the entire principal and interest owing under the Note, whereupon the entire principal and interest then remaining will become due and payable notwithstanding any other provision of this Note.

4.2 Insurance Proceeds. If there is damage to all or part of the Project for which insurance proceeds are paid to Yukon Energy and which are not used to repair or replace such damage within a reasonable time with work commencing within six months of the damage having occurred, Yukon Energy will be required to pay to YDC the amount of such proceeds first, in reduction of any outstanding interest under the Note and then in reduction of any outstanding principal under the Note.

4.3 Prepayment. The principal amount due under the Note may be paid by Yukon Energy in whole or in part with mutual agreement of the Parties on one year's written notice without bonus or penalty.

4.4 Default. Upon default in payment of any payment when due under this Note, the entire unpaid balance of the principal amount and accrued interest will become immediately due and payable without notice or demand and the undersigned covenants to pay interest on it and on subsequent overdue interest at the Interest Rate, both before and after judgment, until paid in full. The covenants to pay interest will not merge on the taking of a judgment or judgments with respect to any of the obligations stipulated for this Note.

4.5 Interest Act of Canada. For the purposes of the *Interest Act* (Canada), whenever any interest is calculated in respect of this Note on the basis of a period of time other than a calendar year, the annual rate of interest to which each rate of interest determined pursuant to such calculation is equivalent to such rate as so determined multiplied by the actual number of days in the calendar year in which the same is to be ascertained and divided by the number of days used in the basis for such determination.

4.6 Notices. In this Note:

(a) any notice or communication required or permitted to be given under this Note will be in writing and will be considered to have been given if delivered by hand, transmitted by facsimile transmission or mailed by prepaid registered post in Canada, to the address or facsimile transmission number of each Party set out below:

(i) if to YDC:

206A Lowe Street
Whitehorse, YT Y1A 1W6

Attention: President
Fax No.: 867-393-7071

(ii) if to Yukon Energy:

#2 Miles Canyon Road

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

Whitehorse, YT Y1A 6S7

Attention: President
Fax No.: 867-393-5323

or to such other address or facsimile transmission number as any Party may designate in the manner set out above; and

- (b) notice or communication will be considered to have been received:
- (i) if delivered by hand during business hours on a Business Day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next Business Day;
 - (ii) if sent by facsimile transmission during business hours on a Business Day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next Business Day; and
 - (iii) if mailed by prepaid registered post in Canada, upon the fifth Business Day following posting; except that, in the case of a disruption or an impending or threatened disruption in postal services every notice or communication will be delivered by hand or sent by facsimile transmission.

4.7 **Assignment by Yukon Energy.** Yukon Energy may not to assign this Note, except with the prior written consent of YDC.

4.8 **Assignment by YDC.** YDC may assign this Note without the consent of Yukon Energy.

4.9 **Enurement.** This Note and all its provisions will enure to the benefit of and be binding upon the Parties, their successors and permitted assigns.

4.10 **Yukon Energy Waiver.** Yukon Energy waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit, and diligence in taking any action.

4.11 **Set-off.** Yukon Energy will not be entitled to set-off against any payments payable to YDC under this Note any amounts owing or alleged to be owing by YDC to Yukon Energy.

Executed at Whitehorse, Yukon Territory, on December _____, 2011.

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

YUKON ENERGY CORPORATION

Per:

Authorized Signatory

Authorized Signatory

YUKON DEVELOPMENT CORPORATION

Per:

Authorized Signatory

Authorized Signatory

YUKON ENERGY CORPORATION
2012 - 2013 GENERAL RATE APPLICATION

APRIL 2012

SCHEDULE 1

	Year	Maximum Grid Load (GWh)	Minimum Grid Load (GWh)	Range
1	2012	515	415	100
2	2013	508	413	95
3	2014	501	411	90
4	2015	494	409	85
5	2016	487	407	80
6	2017	480	405	75
7	2018	473	403	70
8	2019	466	401	65
9	2020	459	399	60
10	2021	452	397	55
11	2022	445	395	50
12	2023	438	393	45
13	2024	431	391	40
14	2025	424	389	35
15	2026	417	387	30
16	2027	410	385	25
17	2028	408	383	25
18	2029	406	381	25
19	2030	404	379	25
20	2031	402	377	25
21	2032	400	375	25
22	2033	400	375	25
23	2034	400	375	25
24	2035	400	375	25
25	2036	400	375	25
26	2037	400	375	25
27	2038	400	375	25
28	2039	400	375	25
29	2040	400	375	25
30	2041	400	375	25
31	2042	400	375	25
32	2043	400	375	25
33	2044	400	375	25
34	2045	400	375	25
35	2046	400	375	25
36	2047	400	375	25
37	2048	400	375	25
38	2049	400	375	25
39	2050	400	375	25
40	2051	400	375	25

SCHEDULE 2 – EXAMPLE: RE ANNUAL INTEREST PAYMENT

Assume for 2012:

- Balance of debt outstanding at start of fiscal year \$21.9 million
- Maximum Grid Load (Schedule 1) 515 GW.h
- Minimum Grid Load (Schedule 1) 415 GW.h
- Range (Schedule 1) 100 GW.h
- Maximum Interest Payable at different Actual Grid Loads:
 - o Assume Actual Grid Load at 520 GW.h
 - Actual Grid Load > Max Grid Load
 - Maximum Interest Payable at 5.44% (full interest)
 - Amount Payable:
 $\$1,195,740.00 = 5.46\% \times \$21.9 \text{ million (paid by YEC to YDC)}$
 - o Assume Actual Grid Load at 450 GWh
 - Actual Grid Load < Max Grid Load
 - Max Interest Rate = $\frac{(\text{Interest Rate}) \times (\text{Actual Grid Generation} - \text{Minimum Grid Load})}{(\text{Range for the year as established in Schedule 1})}$
 - Maximum Interest Payable: $5.46\% \times (450 - 415) / 100 = 0.35 \times 5.46\% = 1.911\%$
 - Amount Payable
 $\$418,509.00 = 1.911\% \times \$21.9 \text{ million (paid by YEC to YDC)}$
 - o Assume Actual Grid Load at 400GWh
 - Actual Grid Load < Max Grid Load
 - Max Interest Rate = $\frac{(\text{Interest Rate}) \times (\text{Actual Grid Generation} - \text{Minimum Grid Load})}{(\text{Range for the year as established in Schedule 1})}$
 - Maximum Interest Payable: $5.46\% \times (400 - 415) / 100 = -0.819\%$
 - Amount Payable
 $-\$179,361.00 = -0.819\% \times \$21.9 \text{ million (indicates YDC amount paid to YEC)}$

1 **TOPIC: Formula for Calculating Interest Expense, Debt Instruments**

2
3 **REFERENCE:** Application, page 3-22. PDF page 70

4
5 **QUESTION:**

- 6
7 a) Please provide a full explanation of the term “Range for the year” included in the
8 formula for calculating interest expense for the Mayo B Promissory Note.
9
10 b) Please provide a continuity table, listing each debt instrument separately, of all
11 actual and forecast debt instruments for the years 2013 to 2018 inclusive.
12
13 c) For forecast borrowings, please provide the inputs used to determine the forecast
14 debt interest rate of 2.15%.
15

16 **ANSWER:**

17
18 **(a)**

19
20 Please see the response to YUB-YEC-1-31(a) for a copy of Schedule 1 from the Mayo B
21 Promissory Note.
22

23 The “Range for the year” is the difference between the minimum and maximum grid load
24 for the applicable year.
25

26 As per the definitions in the Mayo B Promissory Note, grid generation refers to “the total
27 GW.h in that year of Yukon Energy generation and purchased power on the electrical grid
28 system connected with Mayo B based upon metered readings, plus the estimated
29 reduction, if any, in such grid generation in that year due to DSM/SSE undertaken...”
30

31 **(b)**

32
33 Please see Table 1 for a continuity table of actual and forecast debt instruments.

Table 1: Continuity Schedule of Actual and Forecast Debt Instruments

2013 Actual	Balance, beginning of year	New Debt	Principal repayments	Balance, end of year
YDC \$81.9M	75,891	-	3,000	72,891
TD \$12.4M	3,939	-	993	2,946
YDC \$17.1M	16,411	-	684	15,727
YDC \$2.1M	2,053	-	-	2,053
YDC \$21.9M	21,563	-	337	21,226
TD \$11M	11,000	-	313	10,687
YDC \$5.5M	-	5,471	-	5,471
Minto Decommissioning Reserve	2,522	31	-	2,553
	133,379	5,502	5,326	133,554

2014 Actual	Balance, beginning of year	New Debt	Principal repayments	Balance, end of year
YDC \$81.9M	72,891	-	3,000	69,891
TD \$12.4M	2,946	-	1,033	1,912
YDC \$17.1M	15,727	-	684	15,044
YDC \$2.1M	2,053	-	-	2,053
YDC \$21.9M	21,226	-	337	20,889
TD \$11M	10,687	-	321	10,366
YDC \$5.5M	5,471	-	-	5,471
YDC \$5.5M	-	5,505	-	5,505
Minto Decommissioning Reserve	2,553	33	-	2,586
	133,554	5,538	5,376	133,717

2015 Actual	Balance, beginning of year	New Debt	Principal repayments	Balance, end of year
YDC \$81.9M	69,891	-	69,891	-
TD \$12.4M	1,912	-	1,076	837
YDC \$17.1M	15,044	-	15,044	-
YDC \$2.1M	2,053	-	2,053	-
YDC \$21.9M	20,889	-	337	20,552
TD \$11M	10,366	-	330	10,036
YDC \$5.5M	5,471	-	5,471	-
YDC \$5.5M	5,505	-	-	5,505
YDC \$92.5M	-	92,458	3,684	88,775
YDC \$21.0M	-	20,984	-	20,984
Minto Decommissioning Reserve	2,586	26	-	2,612
	133,717	113,469	97,885	149,301

1 **Table 1: Continuity Schedule of Actual and Forecast Debt Instruments (Continued)**

2

2016 Actual	Balance, beginning of year	New Debt	Principal repayments	Balance, end of year
TD \$12.4M	837	-	837	-
YDC \$21.9M	20,552	-	337	20,215
TD \$11M	10,036	-	339	9,697
YDC \$5.5M	5,505	-	-	5,505
YDC \$92.5M	88,775	-	3,684	85,091
YDC \$21.0M	20,984	-	839	20,145
YDC \$12.1M	-	12,136	-	12,136
Minto Decommissioning Reserve	2,612	23	-	2,636
	149,301	12,159	- 6,036	155,425

2017 Forecast	Balance, beginning of year	New Debt	Principal repayments	Balance, end of year
YDC \$21.9M	20,215	-	337	19,878
TD \$11M	9,697	-	348	9,348
YDC \$5.5M	5,505	-	-	5,505
YDC \$92.5M	85,091	-	3,684	81,407
YDC \$21.0M	20,145	-	839	19,306
YDC \$12.1M	12,136	-	-	12,136
New debt 2017	-	23,828	-	23,828
Minto Decommissioning Reserve	2,636	24	-	2,659
	155,425	23,851	- 5,208	174,068

2018 Forecast	Balance, beginning of year	New Debt	Principal repayments	Balance, end of year
YDC \$21.9M	19,878	-	337	19,542
TD \$11M	9,348	-	358	8,991
YDC \$5.5M	5,505	-	-	5,505
YDC \$92.5M	81,407	-	3,684	77,723
YDC \$21.0M	19,306	-	839	18,466
YDC \$12.1M	12,136	-	-	12,136
New debt 2017	23,828	-	-	23,828
New debt 2018	-	7,004	-	7,004
Minto Decommissioning Reserve	2,659	24	-	2,683
	174,068	7,028	- 5,218	175,877

3

1 **(c)**

2

3 The forecast interest rate of 2.15% was provided to YEC directly from YEC's Relationship
4 Manager at TD Bank.

1 **TOPIC: DCF – LNG Costs**

2
3 **REFERENCE:** Application, page 3-25. PDF page 73

4
5 **QUOTE:** “It in principle addresses all YEC thermal generation requirements (i.e.,
6 includes LNG as well as diesel generation).”

7
8 **QUESTION:**

- 9
10 a) Please provide the direct quotes in Board Order 2015-01 (Appendix A: Reasons
11 for Decision) that specifically make reference to LNG costs.

12
13 **ANSWER:**

14
15 **(a)**

16
17 Board Order 2005-01 approved the DCF amendments as proposed by YEC, which
18 included reference to “thermal generation cost” changes resulting from variations in LTA
19 hydro availability. Section 2.1.1.4 of Board Order 2015-01 (Appendix A: Reasons for
20 Decision) approved the DCF use “...for variations in LTA hydro availability” without
21 specifically making reference to LNG costs.

22
23 Section 2.4 of Board Order 2015-06 (Appendix A: reasons for Decision) subsequently
24 approved the Revised DCF Term Sheet as set out in Attachment 1 of YEC's April 7, 2015
25 Compliance Filing related to Board Order 2015-01. The Revised DCF Term Sheet as
26 approved referenced LNG (see quote below from this Term Sheet's statement re: “function
27 and purpose”):

28
29 **PURPOSE**

30 **& FUNCTION:** The Diesel Contingency Fund (“DCF”) operates to smooth
31 customer rate changes from thermal (diesel, LNG and other
32 thermal) generation cost impacts caused by fluctuation of hydro
33 generation due to water conditions or changes in wind conditions.¹

¹ Appendix A to Board Order 2015-01, section 2.1.1.4, page 11.

1 Yukon Energy Corporation (YEC) manages the DCF as a ratepayer
2 “trust fund”. The Fund is only to be used for variations from long-
3 term average (LTA) water and wind availability.²

² 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.”

1 **TOPIC: DCF**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-3. PDF page 102

4
5 **QUOTE:** “YEC's LTA hydro generation continues to be based on the power
6 benefits system simulation model as used in the last GRA (i.e., the
7 YECSIM model), updated to reflect the load shape for the test years
8 (with basically the same Minto mine loads being forecast in each of
9 these years) and the following information related to Yukon Integrated
10 System hydro operations:” [Footnote omitted]

11
12 **QUESTION:**

- 13
14 a) Two subsequent bullets to the above-noted quote refer to additional water year
15 records and updated reservoir and generation station water flow requirement
16 changes. Please confirm that there were no other changes in the base
17 assumptions or parameters used in the YECSIM model.
18
19 b) If Part (a) cannot be confirmed, please provided a side by side detailed listing of
20 all changes by listing the assumption or input parameter used in the 2012/2013
21 GRA, the similar assumption or input parameter in the 2017/2018 GRA and the
22 reason for the difference.

23
24 **ANSWER:**

25
26 **(a) and (b)**

27
28 Confirmed.

1 **TOPIC: Vista Model**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-3, Footnote 3. PDF page 102

4
5 **QUOTE:** “Yukon Energy continues at this time to use the YECSIM model for the
6 LTA assessments for this Application and the 2016 Resource Plan (see
7 Attachment 3.4.3 for information on the YECSIM model). YEC is
8 currently examining another system planning model (VISTA) for
9 potential future use in assessing LTA hydro and thermal requirements.”

10
11 **QUESTION:**

- 12
13 a) Please explain why YEC is reviewing another system planning model.
14
15 b) What are the potential benefits of the VISTA model?
16
17 c) What are the current shortfalls of the YECSIM model?
18
19 d) If YEC were to convert to the VISTA model, in what timeframe would such a
20 conversion take place?

21
22 **ANSWER:**

23
24 **(a), (b), (c) and (d)**

25
26 YEC continues to examine options for future improvement in its planning. Optimization
27 models such as VISTA offer opportunities to introduce more advanced methodologies,
28 provide higher resolution of outputs (e.g., daily versus weekly outputs), more detailed
29 representation of resources, additional outputs, and support for a wider range of new
30 system resources. These added features can assist in the assessment of new resource
31 options and planning issues. However, broader use of a new model will be considered
32 after gaining experience on the model use and testing the model to confirm its adequacy.

33
34 The 2016 Resource Plan and the current GRA continue to rely on YECSIM for assessment
35 of expected long-term average hydro and thermal generation requirements under different
36 load and system facility conditions. No specific timeframe has been established for
37 potential conversion to use of an alternative model to YECSIM for these purposes.

- 1 YEC will update the Board in future filings on the status of its examinations of planning
- 2 model options.

1 **TOPIC:** DCF – Thermal Generation Requirements

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-4. PDF page 103

4
5 **QUOTE:** “Other thermal generation requirements (i.e., expected generation not
6 addressed by the LTA assessments) that may occur under higher-than-
7 median water conditions will be assessed as required in future GRAs.”

8
9 **QUESTION:**

10
11 a) Please provide a detailed explanation of the above-noted statement.

12
13 **ANSWER:**

14
15 **(a)**

16
17 Prior to the quoted sentence, the paragraph noted that the “LTA thermal requirements as
18 determined pursuant to the YECSIM model and Table 3.4-1 addresses thermal generation
19 requirements for firm loads”. The paragraph went on to explain that this YECSIM
20 determination excludes thermal generation needed for capital projects, emergencies/grid
21 interruptions, RFID requirements, and ongoing maintenance-related run-ups.

22
23 The Application’s separate treatment of ongoing maintenance-related thermal generation
24 recognizes that this separate generation is required even when firm loads are insufficient
25 to require ongoing thermal generation. Higher-than-median water conditions also tend to
26 reduce requirements for thermal generation to supply firm loads - and increase the need
27 for separate thermal generation solely for ongoing maintenance-related run-ups.

28
29 The above-noted statement references ongoing review to assess other possible separate
30 thermal generation that may tend to be needed under higher-than-median water
31 conditions when no thermal generation is otherwise forecast in YECSIM determinations.
32 YEC is not aware of any such specific requirements that could be forecast at this time.

33
34 The basis for ongoing interest in this matter is outlined below, based on recent experience
35 during years with above average water conditions:

- 1 • As reviewed at page 3.4-7 of the Application and Appendix 3.5, actual diesel and
2 LNG thermal generation in 2015 and 2016 during above average water conditions
3 directly affects YEC expenses.
 - 4 o Actual thermal generation required (excluding capital projects and RFID)
5 was 2.8 GW.h in 2015 and 5.1 GW.h in 2016.
 - 6 o These actual thermal generation requirements occurred notwithstanding
7 that actual annual firm grid load (net of expected wind and Fish Lake Hydro)
8 was only 410 to 412 GW.h in these two years and that above average water
9 conditions also existed.
- 10
11 • As reviewed in Appendix 3.4 of the Application, determinations of LTA thermal
12 requirements at any specific firm grid load are based on simulated assessments
13 of thermal generation needed over each of the 35 water years of record.
 - 14 o Figure 3.4-1 and Table 3.4-4 demonstrate the extent to which actual
15 thermal generation is expected to be minimal during above average water
16 conditions when grid loads are less than 420 GW.h/year.
 - 17 o Table 3.4-4 shows, for example, an expectation that under 2015 actual
18 water conditions the thermal generation requirement would approximate
19 only 0.2 GW.h at a grid load of 420 GW.h/year.
 - 20 o Actual thermal generation in 2015, however, was 2.8 GW.h (excluding
21 capital projects and RFID thermal generation requirements), and therefore
22 much higher than expected based on the simulations.
 - 23 o A similar situation appears to have occurred in 2016.
 - 24 o In the event that actual thermal requirements in above average water years
25 are higher than estimated in the LTA simulations, the estimated LTA
26 requirement would be increased above the levels currently estimated.

1 **TOPIC: LNG Cost per kW.h**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-5. PDF page 104

4
5 **QUOTE:** “3. The LNG fuel cost per kW.h to be assumed for DCF cost
6 assessments (equivalent to the 28.7 c/kW.h diesel generation fuel cost
7 used to date for the DCF based on the last approved GRA fuel price
8 and average diesel generation efficiency for the 2012/13 GRA).”

9
10 **QUESTION:**

11
12 a) Please show the derivation of the 28.7 c/kW.h diesel generation fuel cost.

13
14 **ANSWER:**

15
16 **(a)**

17
18 The 28.7 c/kW.h diesel generation fuel cost is the last approved GRA fuel price from YEC's
19 2012/13 GRA. This average diesel fuel cost per kW.h was derived from the following:

- 20
- 21 • Forecast diesel fuel prices for the 2012/2013 test years are \$1.0513 per litre for
22 Whitehorse, \$1.0885 per litre for Faro, \$1.1168 per litre for Dawson (as corrected
23 in CW-YEC-1-15 in that proceeding) and \$1.0966 per litre for Mayo and are based
24 on the (then) most recent fuel prices paid by YEC.
25
 - 26 • YEC average fuel efficiency forecasts of 3.77 kW.h/litre in Whitehorse, 3.83
27 kW.h/litre in Faro, 3.72 kW.h/litre in Dawson and 3.37 kW.h/litre in Mayo based on
28 2011 averages.
29
 - 30 • The resulting cost per kW.h for each location is 27.86 c/kW.h for Whitehorse, 28.42
31 c/kW.h for Faro, 30.02 c/kW.h for Dawson and 32.54 c/kW.h for Mayo.
32
 - 33 • The average diesel fuel cost of 28.71 c/kW.h is the average YEC cost based on
34 the 2012/13 GRA Compliance Filing, and is referenced as such in the DCF Term
35 Sheet as approved in Board Order 2015-06.

1 **TOPIC:** **Capability to Supply LTA Thermal Generation**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-7. PDF page 106

4
5 **QUOTE:** “Emergency thermal loads, which typically require quick response and
6 may continue for only a short duration, are excluded from LTA
7 assessments; and

8
9 “Other small or short duration loads of the type affecting actual current
10 LNG use are not important factors affecting LNG unit ability to supply
11 overall LTA thermal generation at the grid loads relevant for this
12 review.”

13
14 **QUESTION:**

- 15
16 a) For each of the constraints listed in the last paragraph of page 3.4-7 and the above-
17 noted considerations, please explain why LNG is not the preferred generation
18 method.

19
20 **ANSWER:**

21
22 **(a)**

23
24 The last paragraph of page 3.4-6 references the following constraints on actual LNG 4.4
25 MW unit operation (there are two units commissioned at this time):¹

- 26
27 • The manufacturer recommends not running the individual LNG units for loads
28 below 2.6 MW. Therefore, YEC relies on smaller existing diesel units for thermal
29 generation loads less than 2.6 MW and between 4.4 and 5.2 MW, rather than
30 starting up one or both of the 4.4 MW LNG units.
31
32 • Similarly, the manufacturer recommends a minimum run time of 4 hours for LNG
33 units; existing diesel units are relied upon for short duration loads (less than a few
34 hours).

¹ The last paragraph of page 3.4-7, as referenced in the question, does not note any specific constraints related to LNG unit operation.

- These constraints mainly reflect the size and nature of the generation units selected, which are best suited to base load operation, rather than the use of LNG fuel versus diesel fuel. YEC expects peaks to continue to grow on the system, both in terms of the size (MW) and duration; this growth will positively improve the usage of the LNG units.

The two above-noted considerations in the question address a separate matter, namely the extent to which LTA thermal generation requirements (which drive GRA expected thermal generation and fuel cost requirements) are not materially affected by the above noted constraints on actual LNG unit operation of the existing LNG units:

- Emergency thermal loads (where a short-duration and quick response is required) are excluded from LTA thermal forecasts; and
- Overall LTA thermal generation at the GRA forecast grid loads are driven mainly by sustained thermal generation required during low water or drought conditions, and therefore other small or short duration loads of the type affecting current LNG unit use are not important factors affecting LNG unit ability to supply these overall LTA thermal generation requirements.

1 **TOPIC: Limitations on LNG Unit Operation**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-7. PDF page 106

4
5 **QUESTION:**

6
7 a) Please provide a detailed explanation and an illustrative example of how DCF
8 Annual Reporting and GRA Test Year Revenue Requirement determinations limit
9 LNG unit operation.

10
11 b) What was the actual 12 month performance of LNG generation to diesel generation
12 for the period July 1, 2016 to June 30, 2017?

13
14 **ANSWER:**

15
16 **(a)**

17
18 References in Appendix 3.4 to limitations on LNG unit operation reference small and short
19 duration loads, as reviewed in response to YUB-YEC-1-38.

20
21 GRA Test Year Revenue Requirement determinations as provided in this Application
22 specify, starting with the 2017 test year, an assumed 90/10 LNG-diesel share or split
23 related to the forecast LTA thermal generation for each test year. This approach is
24 proposed to ensure that revenue requirement costs used to set rates provide some
25 recognition of the current limits on actual LNG ability to displace all diesel generation (see
26 response to YUB-YEC-1-25 for more detailed review). No such LNG/diesel split was
27 specified in prior GRA Test Year Revenue Requirement determinations (see response to
28 YUB-YEC-1-42).

29
30 DCF Annual Reporting addresses actual diesel and LNG generation as recorded for a
31 fiscal year, and thereby reflects actual limitations on LNG unit operation during that year,
32 including any of the limitations reviewed in Appendix 3.4 and YUB-YEC-1-36. This
33 reporting by itself does not limit LNG unit operation.

1 DCF Annual Reporting also determines the following:
2

- 3 1. LTA (expected) thermal generation for the actual firm load based on the DCF Term
4 Sheet table approved by the Board.
5
- 6 2. The gap for the year between LTA (expected) thermal generation and actual
7 thermal generation that determines the amount that YEC pays into or receives from
8 the DCF for the fiscal year (the “DCF Transfer”).
9
- 10 3. In determining the DCF Transfer amount, it is necessary to specify the portion
11 assigned to LNG versus diesel generation (see response to YUB-YEC-1-40 for
12 examples relating to 2015 and 2016). The current Application proposes that the
13 Board approve rules going forward as of January 1, 2017 for determining the
14 LNG/diesel split for the DCF Transfer. The proposed approach focuses on seeking
15 to set YEC’s annual fuel mix costs as close as possible to the GRA approved
16 assumptions adopted to set the approved revenue requirement and rates. (See
17 response to YUB-YEC-1-42 for more detailed review of the proposed DCF fuel mix
18 determination approach.)
19

20 **(b)**
21

22 Please see Table 1 below.

Table 1: Actual LNG and Diesel Generation

		Diesel	LNG	Total Thermal	% Diesel	% LNG
2016	JUL	507,074	23,950	531,024	95%	5%
2016	AUG	125,687	6,800	132,487	95%	5%
2016	SEP	637,993	1,234,000	1,871,993	34%	66%
2016	OCT	50,968	198,400	249,368	20%	80%
2016	NOV	71,203	-	71,203	100%	0%
2016	DEC	1,113,601	1,480,100	2,593,701	43%	57%
2017	JAN	880,076	1,820,900	2,700,976	33%	67%
2017	FEB	549,099	1,244,800	1,793,899	31%	69%
2017	MAR	980,908	1,478,100	2,459,008	40%	60%
2017	APR	20,667	-	20,667	100%	0%
2017	MAY	110,059	-	110,059	100%	0%
2017	JUN	155,927	-	155,927	100%	0%
		5,203,262	7,487,050	12,690,312	41%	59%

1 **TOPIC:** **Actual LNG Use and Year-end DCF Determinations**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-7. PDF page 106

4
5 **QUOTE:** “The 2016 DCF Annual Report (Appendix 3.5) shows the actual LNG
6 generation in 2015 and 2016, net of capital and RFID generation
7 (based on this Application, future DCF Annual Filing years will also
8 exclude maintenance run-up generation). In each of these years,
9 expected thermal generation exceeded actual thermal generation, and
10 the balance (approximately 7.2 GW.h in 2015 and 5.1 GW.h in 2016)
11 was thermal generation for which YEC transferred fuel cost into the
12 DCF. Due to limits in LNG unit availability, only 15% of the 2015 thermal
13 generation included in the DCF transfer by YEC was assumed to be
14 supplied by LNG - however, in 2016, 100% of the thermal generation
15 included in the DCF transfer by YEC was assumed to be supplied by
16 LNG.” [underlining added]

17
18 **QUESTION:**

- 19
20 a) Why were the amounts of thermal generation referred to above for 2015 and 2016
21 assumed? Why can't YEC calculate actual amounts?

22
23 **ANSWER:**

24
25 **(a)**

26
27 Actual LNG and diesel generation amounts are determined and reported in the year-end
28 DCF Annual Reports for 2015 and 2016.

29
30 DCF final determinations are based on “expected thermal generation” (i.e., LTA thermal
31 generation for the actual grid generation load). Transfers into or out of the DCF at year
32 end address differences between expected and actual thermal generation (with the result
33 that YEC’s final thermal generation cost expense for the year is based on expected rather
34 than actual thermal generation).

35
36 In 2015 and 2016, as noted in the above quote, expected thermal generation exceeded
37 actual thermal generation:

- **2015:** Expected thermal generation at 10.0 GW.h versus actual thermal generation of 2.8 GW.h, resulting in a difference of approximately 7.2 GW.h thermal generation for which YEC transferred fuel cost into the DCF.
- **2016:** Expected thermal generation at 10.536 GW.h versus actual thermal generation of 5.087 GW.h, resulting in a difference of approximately 5.449 GW.h thermal generation for which YEC transferred fuel cost into the DCF. [Note that the 5.1 GW.h referenced at page 3.4-7 of Appendix 3.4 is not correct, and that the correct number from Appendix 3.5 for thermal generation transferred to the DCF in 2016 is 5.449 GW.h.]

These 2015 and 2016 transfers into the DCF were based on the amounts by which expected thermal generation (LTA) exceeded actual thermal generation. Assumptions are therefore required to determine the share of this balance that is assigned to LNG versus diesel generation. The assumptions adopted in the 2015 and 2016 DCF Annual Reports reflected YEC's evidence to the Board at the Part 3 LNG Project proceeding.

In summary, the referenced "assumptions" related in each case to the share of each transfer to the DCF that was assumed to be supplied by LNG generation versus by diesel generation:

- In 2015, due to in-service of the LNG units occurring only after mid-year, only 15% of the 2015 expected thermal generation was assumed to be eligible to be supplied by LNG generation (i.e., only 15% of the 10.0 GW.h expected thermal generation, or 1.5 GW.h); in this instance, the 7.2 GW.h transfer to the DCF was then estimated at 0.909 GWh LNG [1.5 GW.h expected less actual LNG generation] and 6.280 GW.h diesel [the balance equals expected diesel less actual diesel].
- In 2016, 100% of the 2016 expected thermal generation was assumed to be eligible to be supplied by LNG generation (i.e., 100% of the 10.536 GW.h expected thermal generation); expected thermal generation included in the transfer (i.e., 100% of the 5.449 GW.h that expected thermal generation exceeded actual thermal generation) was assumed to be supplied by LNG.

1 **TOPIC:** **Actual LNG Use and Year-end DCF Determinations**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-7. PDF page 106

4
5 **QUOTE:** “The 2016 DCF Annual Report (Appendix 3.5) shows the actual LNG
6 generation in 2015 and 2016, net of capital and RFID generation
7 (based on this Application, future DCF Annual Filing years will also
8 exclude maintenance run-up generation). In each of these years,
9 expected thermal generation exceeded actual thermal generation, and
10 the balance (approximately 7.2 GW.h in 2015 and 5.1 GW.h in 2016)
11 was thermal generation for which YEC transferred fuel cost into the
12 DCF. Due to limits in LNG unit availability, only 15% of the 2015 thermal
13 generation included in the DCF transfer by YEC was assumed to be
14 supplied by LNG - however, in 2016, 100% of the thermal generation
15 included in the DCF transfer by YEC was assumed to be supplied by
16 LNG.”

17
18 **QUESTION:**

19
20 a) Please explain the significance of the above-quoted paragraph.

21
22 **ANSWER:**

23
24 **(a)**

25
26 As reviewed in Section 1.1 of Appendix 3.4, the Board has directed that it is to review
27 procedures for including LNG in the DCF as part of the next GRA.

28
29 In response to this direction, the above-quoted paragraph summarizes for review by the
30 Board the procedures and assumptions adopted for including LNG in the 2015 and 2016
31 DCF Annual Reports. Details related to these procedures and assumptions are reviewed
32 in response to YUB-YEC-1-40.

1 **TOPIC:** Actual LNG Use and Year-end DCF Determinations

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-8. PDF page 107

4
5 **QUOTE:** “YEC’s final fuel expense for annual expected thermal generation after
6 DCF transfers is affected by the LNG/diesel mix for actual thermal
7 generation as well as by the LNG/diesel mix adopted for transfers into
8 or out of the DCF. In 2016, due to the actual generation mix being 45%
9 diesel, YEC’s final expense for all expected (LTA) thermal generation
10 showed 21.8% being supplied by diesel (2.293 GW.h out of 10.536
11 GW.h), notwithstanding that 100% of the thermal generation included
12 in the DCF transfer by YEC (to address the difference between LTA
13 thermal generation and actual thermal generation) was assumed to be
14 supplied by LNG.”

15
16 **QUESTION:**

- 17
18 a) Has the Board previously approved any LNG/diesel fuel mix for expected thermal
19 generation?
20
21 b) Has the Board previously approved any LNG/diesel fuel mix for transfers into or
22 out of the DCF?
23
24 c) How can the assumption for 2016 be made that 100% of the thermal generation
25 included in the DCF transfer by YEC was supplied by LNG?
26

27 **ANSWER:**

28
29 **(a) and (b)**

30
31 The Board has not previously approved any specified LNG/diesel fuel mix for expected
32 thermal generation, or any specific LNG/diesel fuel mix for transfers into or out of the DCF.
33

34 **(c)**

35
36 The referenced assumption reflected the Board’s 2014 review of YEC’s LNG Project.

1 Section 3.1.3 of the Board's May 14, 2014 Report to the Minister on YEC's Part 3
2 Application for the LNG Project accepted YEC's submission that the new LNG units would
3 displace through to 2018 at least 95% of the expected [LTA] grid diesel generation
4 requirements (assuming LTA hydro generation).
5
6 YEC's submissions during that 2014 proceeding estimated 100% LNG displacement of
7 expected diesel generation at grid loads comparable to the actual 2015 and 2016 loads.
8 Prior to the next GRA review, YEC in 2015 retained these prior assumptions as presented
9 to the Board. The 2016 DCF Annual Report retained without review the assumptions
10 adopted in the 2015 DCF Annual Report.

1 **TOPIC:** **Actual LNG Use and Year-end DCF Determinations**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-8. PDF page 107

4
5 **QUOTE:** “As noted under item #1 above, this Application proposes that test year
6 thermal generation be assumed to be supplied 90% by LNG generation
7 and 10% by diesel generation. In order to enable final year-end YEC
8 LTA fuel expense to reflect this same LNG/diesel mix to the extent
9 possible, it is proposed in this Application that subsequent DCF Annual
10 Filings (for 2017 and 2018, and subsequent years until changed by
11 approval of the Board) adjust YEC's year-end DCF payment into (or
12 receipt from) the DCF as required so that YEC's final fiscal year
13 expense for the total expected thermal generation (i.e., YEC expense
14 after all transfers) is 90% LNG and 10% diesel, subject to the constraint
15 that the LNG share of any transfer into or out of the DCF cannot exceed
16 100%. This proposed approach is reflected in the DCF example in
17 Appendix 3.4-1 (Table 3.4-3).”

18
19 **QUESTION:**

- 20
21 a) Please explain why the fuel mix ratio for the DCF needs to be fixed. What is the
22 impact if the actual fuel mix is used versus the assumed fuel mix?
23
24 b) Please explain the situation where the LNG share of any transfer into or out of the
25 DCF could exceed 100%. Provide an example where this is demonstrated.
26

27 **ANSWER:**

28
29 **(a)**

30
31 As reviewed in response to YUB-YEC-1-40, assumptions are required to determine the
32 fuel mix ratio applicable for transfers into and out of the DCF.
33

34 The Application proposes that the fuel mix ratio adopted for the 2017 and 2018 test years
35 be retained for DCF annual determinations starting with 2017. This approach focuses on
36 seeking to set YEC fuel mix costs as close as possible to the GRA approved assumptions
37 adopted to set the approved revenue requirement and rates.

1 Adoption of the actual fuel mix for actual generation versus the assumed 90/10 LNG/diesel
2 fuel mix would have varying impacts depending on the actual fuel mix and its share of
3 expected thermal generation in a fiscal year. The example set out in Tables 3.4-2 and 3.4-
4 3 of Appendix 3.4 looks at a range of such potential situations over five years, indicating
5 the impact of the proposed approach as summarized below to contrast with assuming the
6 actual fuel mix in each year:

- 7
- 8 • Year 1 of example:
 - 9 o Actual fuel mix assume 50/50 LNG/diesel (actual < expected by 9.9 GW.h)
 - 10 o Proposed DCF; yields 90/10 LNG/diesel
 - 11
- 12 • Year 2 of example:
 - 13 o Actual fuel mix assume 25/75 LNG/diesel (actual < expected by 14.4 GW.h)
 - 14 o Proposed DCF; yields 83.7/16.3 LNG/diesel
 - 15
- 16 • Year 3 of example:
 - 17 o Actual fuel mix assume 96.8/3.2 (actual < expected by 19.0 GW.h)
 - 18 o Proposed DCF; yields 90/10 LNG/diesel
 - 19
- 20 • Year 4 of example:
 - 21 o Actual fuel mix assume 71.4/28.6 LNG/diesel (actual > expected by 42.1
 - 22 GW.h)
 - 23 o Proposed DCF; yields 90/10 LNG/diesel
 - 24
- 25 • Year 5 of example:
 - 26 o Actual fuel mix assume 60/40 LNG/diesel (actual > expected by 68.1 GW.h)
 - 27 o Proposed DCF; yields 90/10 LNG/diesel
 - 28

29 **(b)**

30

31 The proposed approach will not allow the LNG share of any transfer into or out of the DCF
32 to exceed 100%. As a result, under certain factual situations (e.g., the year 2 example in
33 Table 3.4-3 as reviewed above), the final fuel mix for expected generation after DCF
34 transfers will not equal the 90/10 LNG/diesel fuel mix assumed for the Application.

1 Absent the proposed procedures, in order to secure a 90/10 LNG/diesel mix would require
2 under certain factual situations an LNG share of any transfer to exceed 100%. Under the
3 above referenced example for year 2:

- 4
- 5 • Assumed actual thermal generation of 4 GW.h, with fuel mix 25/75 LNG/diesel.
- 6
- 7 • Assumed expected thermal generation of 18.446 GW.h.
- 8
- 9 • The transfer of funds to the DCF is based on 14.446 GW.h gap between expected
10 and actual thermal generation.
- 11
- 12 • The target 90% LNG would require 90% of expected, or 16.6 GW.h (or 15.6 GW.h
13 more than actual LNG generation).
- 14
- 15 • To achieve this target, the LNG share of the DCF transfer would need to equal
16 108% of the 14.446 GW.h to be transferred.

TOPIC: Diesel and LNG Fuel Cost per kW.h

REFERENCE: Application, Appendix 3.4, page 3.4-8. PDF page 107

QUOTE: “2015 average delivered LNG fuel cost of 18.83 cents/kW.h assumed 40% energy conversion efficiency as per the LNG Part 3 Application.”

QUESTION:

- a) Please provide the actual energy conversion for LNG for each of 2015, 2016 and January 1 to June 30, 2017.
- b) Please show how the energy conversion costs were calculated for each of the years 2015, 2016 and 2017 inclusive.

ANSWER:

(a) and (b)

Please see Tables 1, 2 and 3 below and related notes.

Table 1: 2015 Actuals Energy Conversion

Month	NG Generation [kWh]	LNG Volume for Generation [Litres]	Fuel Energy [kWh]	Conversion Efficiency [%]
January				
February				
March				
April				
May				
June				
July				
August				
September				
October	112,702	41,834	280,641	40%
November	60,147	27,934	187,390	32%
December	420,100	159,234	1,068,205	39%
Total	592,949	229,001	1,536,236	39%

Fortis BC

LNG Density

HHV

438.634 kg/m³

0.055 GJ/kg

1

Table 2: 2016 Actuals Energy Conversion

Month	NG Generation	LNG Volume for Generation	Fuel Energy	Conversion Efficiency
	[kWh]	[Litre]	[kWh]	[%]
January	135,300	50,554	335,728	40%
February	68,200	27,058	179,694	38%
March	47,900	18,565	123,290	39%
April	36,000	14,490	96,227	37%
May	10,900	4,356	28,930	38%
June	9,650	3,860	25,634	38%
July	23,950	9,215	61,199	39%
August	6,800	2,385	15,837	43%
September	1,234,000	470,089	3,121,858	40%
October	198,400	79,379	527,154	38%
November				
December	1,480,100	562,250	3,733,901	40%
Total	3,251,200	1,242,201	8,249,450	39%

Fortis BC

LNG Density 438.63 kg/m3
HHV 0.055058 GJ/kg
% Volume Delivered in 2016 52%

Ferus

LNG Density 427.92 kg/m3
HHV 0.055353 GJ/kg
% Volume Delivered in 2016 48%

2

3

Table 3: 2017 Actuals Energy Conversion

Month	NG Generation	LNG Volume for Generation	Fuel Energy	Conversion Efficiency
	[kWh]	[Litre]	[kWh]	[%]
January	1,820,900	708,155	4,679,432	39%
February	1,244,800	486,362	3,213,845	39%
March	1,478,100	536,011	3,541,918	42%
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total	4,543,800	1,730,528	11,435,195	40%

Fortis BC

LNG Density 438.63 kg/m3
HHV 0.055058 GJ/kg
% Volume Delivered in 2016 22%

Ferus

LNG Density 427.92 kg/m3
HHV 0.055353 GJ/kg
% Volume Delivered in 2016 78%

4

1 **TOPIC: LNG Haul Units**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-9. PDF page 108

4
5 **QUOTE:** “This has included continuing to pursue licencing and development of
6 larger configurations of LNG haul units that would materially reduce the
7 per unit costs for delivery, as well as opportunities to secure LNG from
8 potential new or enhanced LNG facilities that are much closer to
9 Whitehorse.”

10
11 **QUESTION:**

12
13 a) Please provide a status update on the licensing and development of larger
14 configurations of LNG haul units. When does YEC expect that these larger units
15 will be operational?

16
17 b) Please provide total to date costs by year for the licensing and development of the
18 larger configurations of LNG haul units.

19
20 **ANSWER:**

21
22 **(a)**

23
24 The objective remains to develop a safe, high payload (more efficient) configuration that
25 can be permitted under a bulk haul permit in BC and Yukon. The design of this larger
26 trailer is complete and is fully compliant with bulk haul parameters – specifically to avoid
27 the requirement for a pilot car. The updated King B-Train design was received from the
28 design firm in October 2016 and submitted to the University of Ontario Institute Of
29 Technology (UOIT) for a “Vehicle Dynamic Performance Assessment.” UOIT reported that
30 the configuration passed all performance measures. The BC regulator subsequently
31 reviewed the report and approved the configuration. The next step in the regulatory
32 approval process is to undertake a route analysis which will include an assessment of all
33 bridges and culverts. Analysis of the identified route will give the regulator all the
34 information required for a formal assessment. The updated King B-Train design still
35 provides for a payload of over 85m³ which translates into approximately 2000 GJ, which
36 is 60% more than the largest tridem trailer currently in operation, and more than double a
37 standard tandem trailer. All LNG industry players are watching the King B-Train

development with great interest and at least one LNG supplier is known to be in commercial discussions with CVA (the designer of the King B-Train) for the construction of several units. The King B is now available for commercial development. BC Highways has initiated the route analysis in 2017 and will include the Federal and Yukon Governments for their portion of the highway between Fort Nelson and Whitehorse. YEC expects that these larger units will be operational when LNG volumes increase to meet new markets in Alaska, Inuvik or new mining loads.

(b)

Annual YEC spending in support of trailer design and permitting activities is as follows:

Table 1: Trailer Design & Permitting: 2013-2016

2013	\$32,333
2014	161,244
2015	53,987
2016	<u>30,136</u>
	<u>\$277,700</u>

Note that Table 5.4 shows total spending of \$193,577 for 2014; this reflects the creation of the feasibility study out of the LNG project in that year. Table 1 above reflects the actual spending timing.

1 **TOPIC: LNG Assumptions**

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-9. PDF page 108

4
5 **QUOTE:** “This Application assumes a forecast delivered fuel cost of LNG for the
6 2017 and 2018 test years of \$0.1467 per kW.h, based on a delivered
7 average fuel cost of \$0.3767 per litre and average efficiency for LNG
8 generation of 2.57 kW.h/litre (assumes 0.02369 GJ/litre of LNG [HHV]).
9 This LNG fuel cost reflects the average delivered LNG cost from
10 September to December 2016 from the Ferus facility in Elmworth, and
11 the forecast that test year LNG requirements will be generally supplied
12 from facilities at no greater distance from Whitehorse than Elmworth.”

13
14 **QUESTION:**

- 15
16 a) Please provide the following for the January 1 to June 30, 2017 period:
17 i.) Actual delivered litres of LNG and delivery costs of that LNG and the
18 conversion of those costs to \$/kW.h
19 ii.) The delivered fuel cost in \$/litre
20 iii.) The actual efficiency for LNG generation in kW.h/litre
21 iv.) Actual fuel purchases in litres and \$/litre
22 v.) LNG fuel costs in \$/kW.h.
23
24 b) Please provide the basis of 0.02369 GJ/litre of LNG [HHV].
25
26 c) Please explain the acronym “LNG [HHV]”.
27

28 **ANSWER:**

29
30 **(a)**

31
32 Please see Table 1 below.

Yukon Energy Corporation
2017 – 2018 General Rate Application
YUB-YEC-1-46

Table 1. Actual LNG Delivery Costs for 2017 - January to end of July

Month	LNG Volume Delivered	LNG Costs	Transportation Costs	Total Cost per Load (LNG & Transportation)	Total Cost per Load (LNG & Transportation)	Total Cost per Load (LNG & Transportation)	NG Generation Actuals	LNG Consumption Volume	LNG Consumption Actuals
	[litres]	[\$]	[\$]	[\$]	[\$/Litre]	[\$/kWh]	[kWh]	[Litre]	[kWh/Litre]
January	653,408.25	\$ 168,860.59	\$ 156,709.46	\$ 325,570.05	\$ 0.50	\$ 0.19	1,820,900.00	708,154.70	2.57
February	468,689.50	\$ 107,992.87	\$ 102,179.45	\$ 210,172.32	\$ 0.45	\$ 0.17	1,244,800.00	486,362.40	2.56
March	615,287.20	\$ 132,337.79	\$ 136,832.29	\$ 269,170.08	\$ 0.44	\$ 0.17	1,478,100.00	536,010.80	2.76
April	43,909.67	\$ 10,062.43	\$ 6,600.00	\$ 16,662.43	\$ 0.38	\$ 0.15	0.00	0.00	0.00
May	38,436.73	\$ 9,087.20	\$ 6,600.00	\$ 15,687.20	\$ 0.41	\$ 0.16	0.00	0.00	0.00
June	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
July	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
August	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
September	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
October	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
November	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
December	0.00	\$ -	\$ -	\$ -	\$ -	\$ -	0.00	0.00	0.00
Total	1,819,731.35	\$ 428,340.88	\$ 408,921.20	\$ 837,262.08	\$ 0.46	\$ 0.18	4,543,800.00	1,730,527.90	2.63

1 * Assumes conversion of 2.57 kWh/litre

1 **(b) and (c)**

2
3 The energy content per litre for LNG is as provided by Ferus for its LNG supplied from
4 Elmworth, Alberta. It is calculated as follows:

5
6
$$HHV = 427.92 \text{ kg/m}^3 \times 0.055353 \text{ GJ/kg} = 23.69 \text{ GJ/m}^3 \text{ or } 0.02369$$

7
$$\text{GJ/litre}$$

8
9 The acronym “HHV” represents “Higher Heating Value” which takes into account the latent
10 heat of vaporization of water in a fuel¹; HHV is contrasted with “LHV” representing “Lower
11 Heating Value” which excludes the latent heat of vaporization of water in a fuel. For
12 consistency in comparison of diesel and LNG fuels, costs have been consistently
13 assessed based on HHV. For LNG, LHV per litre approximates 97.7% of the HHV per litre.

¹ The High Heating Value is defined as “the total heat obtained from the combustion of a specified amount of fuel and its stoichiometrically correct amount of air, both being at 60°F when combustion starts, and the combustion products being cooled to 60°F before heat release is measured.”

(<https://www.fortisbc.com/NaturalGas/Business/PriceAndMarketInformation/Pages/Heat-content-values.aspx>).

1 **TOPIC: DCF Cap Update**

2
3 **REFERENCE:** Application, Appendix 3.4, Section 1.4, page 3.4-9. PDF page 108

4
5 **QUOTE:** “No specific option to modify this cap is proposed in the Application.”

6
7 **QUESTION:**

8
9 a) Please explain why YEC is not making any recommendation to modify the DCF
10 cap in this application.

11
12 **ANSWER:**

13
14 **(a)**

15
16 YEC has provided updated information and assessment of the DCF cap, but has declined
17 to provide any specific recommendation on a matter which ultimately addresses ratepayer
18 interests as to the appropriate DCF cap under current grid conditions.

19
20 YEC understands that the prime purpose of the DCF is to enhance long-term rate stability
21 for ratepayers and to reflect the underlying long-term valuation of renewable hydro and
22 wind resources.

23
24 The Board noted in Order 2015-01 (Appendix, page 11) that all Parties to that proceeding
25 agreed that there is a need for a mechanism that effectively protects ratepayers from
26 diesel generation cost impacts caused by fluctuation of hydro generation due to water
27 conditions or changes in wind conditions. The Board noted in this Order that rate stability
28 is achieved by limiting the requirement for separate rider collections/refunds to ratepayers
29 and by enhancing the ability to handle material (drought) changes in hydro availability. In
30 effect, rate stability is achieved by enabling ratepayers (to the extent practical) to pay the
31 same LTA cost during droughts as during floods.

32
33 YEC has provided updated information in Appendix 3.4 (and Attachment 3.4.4) on the
34 adequacy of the existing DCF cap in order that the Board and intervenors can assess
35 options to the current +/- \$8 million cap last approved by the Board. YEC's observations in
36 Appendix 3.4 based on this updated information include the following:

- 1 • There is no reasonable basis today to consider any lower DCF cap.
- 2
- 3 • Potential benefits today of a higher DCF cap include reduced Rider E frequency
- 4 and enhanced robustness of the DCF in dealing with severe drought (with reduced
- 5 rate instability for ratepayers).
- 6
- 7 • A specific comparison of the above potential benefit impacts relative to the current
- 8 \$8 million cap was provided for a \$16 million cap, based on GRA forecast loads of
- 9 approximately 420 GW.h/year and potential higher loads of 450 GW.h/year that
- 10 could occur if an additional mine load is connected.

1 **TOPIC: YEC Expected Thermal Generation**

2
3 **REFERENCE:** Application, Appendix 3.4, Table 3.4-1, page 3.4-17. PDF page 116

4
5 **QUESTION:**

6
7 a) Please recreate Table 3.4-1 removing the 35-year water history, using the previous
8 28-year water history, and removing the restrictions for Mayo that were not
9 included in the 2012-2013 filing of the table. Keep all other assumptions the same.

10
11 b) Please recreate Table 3.4-1 showing only the 35-year water history change (the
12 change from the previous 28-year water history). Keep all other assumptions the
13 same.

14
15 c) Please recreate Table 3.4-1 showing only the change with respect to the Mayo
16 restrictions. Keep all other assumptions the same.

17
18 **ANSWER:**

19
20 **(a)**

21
22 Please see the table provided below.

1

Table 3.4-1 using 28 year water history, without Mayo restrictions

Table 1. Expected YEC Thermal Generation Based on Long-Term Average Hydro Generation

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in		Thermal as % of Increased Load Column F = E/D
				Load (GWh)	Thermal Generation (GWh)	
	Column A	Column B	Column C	Column D	Column E	
1	370.0	368.868	1.132			
2	375.0	373.231	1.769	5.0	0.637	13%
3	380.0	377.410	2.590	5.0	0.821	16%
4	385.0	381.403	3.597	5.0	1.007	20%
5	390.0	385.209	4.791	5.0	1.194	24%
6	395.0	388.827	6.173	5.0	1.382	28%
7	400.0	392.258	7.742	5.0	1.569	31%
8	405.0	395.502	9.498	5.0	1.755	35%
9	410.0	398.564	11.436	5.0	1.939	39%
10	415.0	401.445	13.555	5.0	2.119	42%
11	420.0	404.150	15.850	5.0	2.295	46%
12	425.0	406.684	18.316	5.0	2.466	49%
13	430.0	409.053	20.947	5.0	2.631	53%
14	435.0	411.265	23.735	5.0	2.788	56%
15	440.0	413.327	26.673	5.0	2.938	59%
16	445.0	415.247	29.753	5.0	3.079	62%
17	450.0	417.037	32.963	5.0	3.210	64%
18	455.0	418.706	36.294	5.0	3.331	67%
19	460.0	420.266	39.734	5.0	3.440	69%
20	465.0	421.730	43.270	5.0	3.536	71%
21	470.0	423.111	46.889	5.0	3.619	72%
22	475.0	424.424	50.576	5.0	3.687	74%
23	480.0	425.684	54.316	5.0	3.740	75%
24	485.0	426.907	58.093	5.0	3.777	76%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. 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.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 28 "water years" on record (1981-2008) 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.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m for 2006-2015 period), Mayo Lake operation rule considered during the 2012-2013 GRA (no additional storage, no impact of sedimentation at the outlet of Mayo Lake and no restricted Mayo GS winter flows).
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconnected from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
7. 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 10).
- Step 2. Find the diesel 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 diesel generation at 417 GW.h load is 12.963 GW.h.

2

3 (b)

4

5 Please see the table below.

1

Table 3.4.1 with only the 35 year water history change (from “a”)

Table 2. Expected YEC Thermal Generation Based on Long-Term Average Hydro Generation

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	368.923	1.077			
2	375.0	373.349	1.651	5.0	0.573	11%
3	380.0	377.687	2.313	5.0	0.663	13%
4	385.0	381.917	3.083	5.0	0.770	15%
5	390.0	386.024	3.976	5.0	0.893	18%
6	395.0	389.994	5.006	5.0	1.030	21%
7	400.0	393.816	6.184	5.0	1.178	24%
8	405.0	397.479	7.521	5.0	1.337	27%
9	410.0	400.975	9.025	5.0	1.504	30%
10	415.0	404.298	10.702	5.0	1.677	34%
11	420.0	407.445	12.555	5.0	1.854	37%
12	425.0	410.412	14.588	5.0	2.033	41%
13	430.0	413.200	16.800	5.0	2.212	44%
14	435.0	415.812	19.188	5.0	2.389	48%
15	440.0	418.249	21.751	5.0	2.562	51%
16	445.0	420.519	24.481	5.0	2.730	55%
17	450.0	422.629	27.371	5.0	2.890	58%
18	455.0	424.588	30.412	5.0	3.041	61%
19	460.0	426.409	33.591	5.0	3.179	64%
20	465.0	428.105	36.895	5.0	3.304	66%
21	470.0	429.691	40.309	5.0	3.414	68%
22	475.0	431.185	43.815	5.0	3.506	70%
23	480.0	432.607	47.393	5.0	3.578	72%
24	485.0	433.978	51.022	5.0	3.629	73%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 35 "water years" on record (1981-2015) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m for 2006-2015 period), Mayo Lake operation rule considered during the 2012-2013 GRA (no additional storage, no impact of sedimentation at the outlet of Mayo Lake and no restricted Mayo GS winter flows).
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconnected from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
7. 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 10).
 - Step 2. Find the diesel 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 diesel generation at 417 GW.h load is 12.963 GW.h.

2

3 (c)

4

5 Please see the table below.

1

Table 3.4-1 with only the Mayo restriction change (from “a”)

Table 2. Expected YEC Thermal Generation Based on Long-Term Average Hydro Generation

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	368.545	1.455			
2	375.0	372.824	2.176	5.0	0.721	14%
3	380.0	376.840	3.160	5.0	0.984	20%
4	385.0	380.611	4.389	5.0	1.229	25%
5	390.0	384.153	5.847	5.0	1.458	29%
6	395.0	387.483	7.517	5.0	1.670	33%
7	400.0	390.616	9.384	5.0	1.868	37%
8	405.0	393.565	11.435	5.0	2.051	41%
9	410.0	396.345	13.655	5.0	2.220	44%
10	415.0	398.968	16.032	5.0	2.377	48%
11	420.0	401.446	18.554	5.0	2.522	50%
12	425.0	403.791	21.209	5.0	2.656	53%
13	430.0	406.011	23.989	5.0	2.779	56%
14	435.0	408.119	26.881	5.0	2.893	58%
15	440.0	410.120	29.880	5.0	2.998	60%
16	445.0	412.025	32.975	5.0	3.096	62%
17	450.0	413.839	36.161	5.0	3.186	64%
18	455.0	415.569	39.431	5.0	3.270	65%
19	460.0	417.221	42.779	5.0	3.348	67%
20	465.0	418.798	46.202	5.0	3.422	68%
21	470.0	420.306	49.694	5.0	3.492	70%
22	475.0	421.746	53.254	5.0	3.559	71%
23	480.0	423.122	56.878	5.0	3.624	72%
24	485.0	424.434	60.566	5.0	3.688	74%

Notes:

1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid, excluding actual less expected Fish Lake hydro generation.
2. 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.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 28 "water years" on record (1981-2008) 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.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m for 2006-2015 period), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake and restricted Mayo GS winter flows).
5. The simulation model results are based on the 2018 forecast load distributions, and requires modifications when new mines or industrial loads are connected [or disconnected from] to the grid.
6. This table assumes max load at 485 GW.h and minimum load at 370 GW.h. If the load exceeds these limits then the table needs to be updated.
7. Numbers are subject to rounding.

Example

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 - 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 diesel generation at 417 GW.h load is 12.963 GW.h.

2

1 **TOPIC:** YECSIM Model

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-26. PDF page 125

4
5 **QUOTE:** “Being a planning model, YECSIM is not structured in a way that lends
6 itself to retrospective verification per se. Detailed test year verifications
7 are not typically undertaken as such a verification or “test” would not
8 normally be seen as a verification that is required or appropriate for this
9 type of a planning model. If the model was to be reviewed for an historic
10 test year it would be necessary to use the actual loads and inflows as
11 input, and consider as well any special conditions that could have
12 occurred during the test year.” [footnote omitted]

13
14 **QUESTION:**

- 15
16 a) Has YEC ever retrospectively tested the YECSIM model? If not, please explain
17 why not? If it has, what were the results?
18
19 b) If YECSIM is not structured in a way that lends itself to retrospective verification,
20 how can YEC have confidence in its output? Please explain.
21
22 c) How does YEC test the veracity of the YECSIM model?

23
24 **ANSWER:**

25
26 **(a), (b) and (c)**

27
28 As reviewed in Attachment 3.4.3 (which notes similar hydro planning models such as the
29 Manitoba Hydro SPLASH planning model), detailed retrospective verifications or tests are
30 not typically undertaken for hydro system planning models similar to YECSIM.
31 Accordingly, YEC has not done such tests of YECSIM.

32
33 As described in Attachment 3.4.3, the structure of the YECSIM model was prepared to
34 follow other well-established precedents in the field. Key features related specifically to
35 YECSIM are reviewed at pages 3.4-25 to 3.4-29. “Testing” has focused on verifying the
36 accuracy of individual components of the model, including algorithms that compute power
37 generation at each facility based on differential water levels at each structure. YEC’s

1 confidence in the model's outputs is based on consideration of all of these factors as well
2 as ongoing adjustments to reflect new information affecting specific elements of the hydro
3 grid.

4
5 Actual system operation will differ from planning model simulations in response to operator
6 assessments of, and responses to, specific conditions. Planning models provide a
7 consistent basis to simulate the system operation within the conditions imposed by
8 physics, regulation and operational priorities, in order to supply the estimated loads with
9 the available hydrologic inputs. Such simulations are required for long-term evaluation of
10 system operation under different loads and with varying generation resource options.

1 **TOPIC:** YECSIM model

2
3 **REFERENCE:** Application, Appendix 3.4, page 3.4-26. PDF page 125

4
5 **QUOTE:** “Expected thermal generation as provided by YECSIM based on LTA
6 hydro and wind generation for specified grid loads assumes that
7 thermal generation is dispatched only as required to meet energy load
8 requirements, i.e., it does not include or assess options for thermal
9 generation to enhance hydro storage for wintertime use. The LNG Part
10 3 Application (Appendix D) stipulated specific scenarios for LNG
11 operation in order to assess such potential storage opportunities and
12 impacts.”

13
14 **QUESTION:**

- 15
16 a) Operationally, does YEC avail itself of opportunities to enhance hydro storage for
17 wintertime use? Please explain.
18
19 b) If yes to (a), how often does YEC avail itself of opportunities to enhance hydro
20 storage for wintertime use?
21
22 c) Do opportunities such as hydro storage enhancement affect DCF calculations?

23
24 **ANSWER:**

25
26 **(a) and (b)**

27
28 YEC assesses opportunities to enhance hydro storage for wintertime use through the
29 inflow forecast, load forecast, its ongoing rules of operation, and in response as required
30 to specific circumstance, e.g., capital works and/or interruptions affecting hydro unit
31 operation.

32
33 Given recent load and water conditions, there have been few opportunities to assess
34 hydro storage for wintertime use beyond opportunities defined by normal ongoing rules of
35 operation.

1 **(c)**

2
3 Yes – opportunities such as hydro storage enhancement affect YECSIM calculations, and
4 therefore the LTA assessments of hydro and thermal generation used in the GRA and to
5 establish the DCF Term Sheet table approved by the Board.
6

7 As noted in the above quote, however, the YECSIM model is limited to specific operation
8 rules when it is used for LTA hydro generation assessment related to GRA hydro and
9 thermal generation forecasts, assessment of new generation resource options, and for
10 GRA-related determinations.

1 **TOPIC:** YECSIM Model

2
3 **REFERENCE:** Application, Appendix 3.4, pages 3.4-27 to 3.4-28. PDF pages 126 to
4 127

5
6 **QUOTE:** “The historical operation of the system was revised at the developing
7 stages to obtain a general understanding of YEC’s operation. At those
8 stages, simulations were carried out to verify in general that the model
9 results properly corresponded to the operation of the WAF system.
10 Model results were discussed with YEC at that stage. However, the
11 YECSIM model is not set to replicate the past; but to simulate the
12 system operation within the conditions imposed by physics, regulation
13 and operational priorities, in order to supply the estimated loads with
14 the available hydrologic inputs.”

15
16 **QUESTION:**

- 17
18 a) Does YECSIM mirror day-to-day operational decisions of the YEC system? If yes,
19 please explain. If no, please explain.

20
21 **ANSWER:**

22
23 **(a)**

24
25 YECSIM, as a planning model, includes information and decision rules that affect ongoing
26 operational decisions for operation of the YEC system, such as for example, fish flows
27 and lake elevations as per water use licenses. However, as reviewed in detail in
28 Attachment 3.4.3, a long term planning model such as YECSIM does not set to replicate
29 actual past short term operational decisions or to address future short term operational
30 planning.

1 **TOPIC:** **BCUC Decisions and Orders**

2

3 **REFERENCE:** Application, page 8-3, footnote 9. PDF page 296

4

5 **QUOTE:** “BCUC Generic Cost of Capital (GCOC) benchmark rate as set in
6 BCUC Decision and Order G-129-16.”

7

8 **QUESTION:**

9

10 a) Please provide copies of the BCUC decisions and Orders G-158-09, G-75-13, G-
11 47-14 and G-129-16 for the record of this proceeding.

12

13 **ANSWER:**

14

15 **(a)**

16

17 Please see YUB-YEC-1-52 Attachments 1 through 4.

YUB-YEC-1-52 Attachments 1-4

(Large attachment – please see 2017/2018 General Rate Application
Round 1 Interrogatory Responses Appendix A)

1 **TOPIC: Return on Equity**

2
3 **REFERENCE:** Application, Tab 8. PDF pages 294 to 302

4
5 **QUESTION:**

- 6
7 a) What makes YEC comparable to FortisBC Electric? Please explain.
8
9 b) What makes YEC comparable to PNG West? Please explain.
10
11 c) Since the benchmark utility for the BCUC is FortisBC Energy, how does YEC
12 compare to the BCUC benchmark utility?
13

14 **ANSWER:**

15
16 **(a) and (b)**

17
18 FortisBC Electric and PNG West have been used as comparable utilities for determining
19 the ROE for Yukon Energy since the 2005 Required Revenues and Related Matters
20 review. The following is specifically noted regarding why these are appropriate comparator
21 utilities for determining a fair ROE for Yukon Energy in the context of the BCUC benchmark
22 ROE:
23

- 24 • **Fortis BC (Electric) and PNG-West are BCUC Regulated Utilities:** The Board
25 has repeatedly noted the BCUC model for determining ROE is most appropriate
26 for Yukon; FortisBC Electric and PNG West are each BC-based utilities that have
27 a BCUC approved risk premium over and above the BCUC-approved benchmark
28 ROE of 8.75%. Other utilities outside of BC, and that do not have a BCUC
29 approved risk premium, are not useful comparators.
30
31 • **Fortis BC (Electric) and PNG-West have a BCUC determined Risk Premium:**
32 The BCUC approved benchmark ROE for a low risk utility is 8.75% (approved for
33 FortisBC Energy). FortisBC (Electric) and PNG-West are not considered to be low
34 risk utilities and each have a BCUC-approved risk premium above the low risk
35 utility benchmark of 8.75%. Yukon Energy's comparability to FortisBC Energy (the
36 low risk benchmark utility) is summarized in part (c) below and indicates that Yukon

1 Energy is a small, northern utility with greater operating and business risk
2 compared to the low risk benchmark utility.

3
4 • **Prior Yukon Precedents have considered FortisBC (Electric) and PNG-West
5 to be comparable utilities for determining Yukon Energy's risk premium:**

6 Since 2005, FortisBC (Electric) and PNG-West have been considered to provide a
7 reasonable benchmark range for determining Yukon Energy's risk premium
8 (compared to the low risk benchmark utility). In Order 2005-12 and Order 2009-8,
9 the Board approved a risk premium of 52% for Yukon Energy. In each application,
10 this risk premium was based on being at the mid-point of the range between
11 FortisBC Electric (40%) and PNG West (65%). This range was considered
12 reasonable as Yukon Energy was considered more risky than FortisBC Electric (at
13 the lower end of the range) and less risky than PNG-West (at the top end of the
14 range). As reviewed in the relevant applications and decisions, "risk" has been
15 assessed based on utility size of operations (revenues, rate base, customers) and
16 financial structure (capital structure), and nature of business (e.g., exposure to
17 generation-related risks, including hydroelectric generation, and industrial
18 customer loads).

19
20 Yukon Energy's current comparability to FortisBC Electric and PNG West is summarized
21 in Tab 8, pages 8-4 to 8-7, and Tables 8.1 (Comparison of YEC to BC Utilities Size of
22 Operations and Financial Structure) and Table 8.2 (Comparison of YEC to BC Utilities –
23 Nature of Business).

24
25 **(c)**

26
27 FortisBC Energy is a large, privately owned, southern natural gas distribution utility that
28 owns no generation assets and has 982,000 retail customers, and is regulated using
29 Performance Based Regulation. Based on information available at the time of the AEY
30 2016/17 GRA, FortisBC Electric had a 2014 rate base of \$2.765 billion and 2014 regulated
31 revenues of \$1.489 billion. This is significantly larger than Yukon Energy's rate base and
32 revenues as noted below.

33
34 Yukon Energy is less comparable to FortisBC Energy (and in certain cases more
35 comparable to Fortis BC Electric and PNG-West) for the following reasons:

- 1 • Yukon Energy is a small, northern utility that operates on an isolated grid that has
2 no interconnections to other jurisdictions. Yukon Energy operates in a relatively
3 small market with limited diversity, which carries more risk than a utility serving a
4 large southern Canadian market with greater economic diversity and strength.
5
6 ○ As summarized in Tab 8, Table 8-1, Yukon Energy has a rate base of
7 \$257.6 million and revenues of \$42.7 million. This is significantly smaller
8 than FortisBC Energy (Yukon Energy is also smaller in size compared to
9 FortisBC Electric).
10
11 ○ FortisBC Energy has a more diverse customer base with about 982,000
12 distribution customers. In contrast, about 70% of Yukon Energy load relates
13 to a single wholesale customer and about 12.4% of Yukon Energy's load
14 relates to a single mine (Minto mine). Yukon Energy is subject to risks
15 related to serving large industrial loads on an isolated grid (i.e., mine loads
16 can come on and off the system impacting generation requirements and
17 revenues). In this respect, Yukon Energy may be considered comparable
18 [although likely less risky] to PNG-West which has a greater reliance on
19 industrial customer load.
20
21 • Yukon Energy is a vertically integrated utility with generation, transmission and
22 distribution functions, and must plan and generate the power required to serve the
23 Yukon Integrated System (i.e., it cannot purchase additional power from outside
24 the grid, and cannot sell surplus power to other jurisdictions). In contrast, FortisBC
25 Energy is a distribution gas utility with no generation. In this respect, Fortis BC
26 Electric [a vertically integrated electric utility that meets 45% of its load
27 requirements with its own generation] is more comparable to Yukon Energy.
28 However, it is noted that Yukon Energy carries relatively more risk as it meets
29 100% of its load requirements with its own generation.

1 **TOPIC: Return on Equity, Risk premium**

2
3 **REFERENCE:** Application, Tab 8. PDF pages 294 to 302

4
5 **QUESTION:**

6
7 a) Has YEC's risk profile materially changed since its last GRA in 2012/2013? Please
8 explain.

9
10 b) Please rank the types of risks faced by YEC in order from the greatest risk to the
11 least risk.

12
13 c) For any of the risks listed in (b), what has YEC done to mitigate those risks?

14
15 **ANSWER:**

16
17 **(a), (b) and (c)**

18
19 Yukon Energy's risk profile is influenced by the same factors that have been discussed
20 since the 2005 Required Revenues and Related Matters hearing – with the most notable
21 risk factors being the lack of interconnection with external electricity grids, Yukon Energy's
22 reliance on its own generation, and fluctuating industrial loads.

23
24 The following are noted regarding the types of risk factors identified in YEC submissions
25 since 2005 for determining Yukon Energy's risk profile relative to comparable BC utilities:

- 26
- 27 • **2005 Required Revenues and Related Matters:** Yukon Energy was considered
28 to have roughly similar business risk to FortisBC Electric (related to mix of
29 customers) as at the time the Faro mine was closed and there were no industrial
30 customers connected to the Yukon grid (i.e., Yukon Energy no longer faced risks
31 related to relatively high reliance on large industrial customers). Yukon Energy
32 was considered to have a similar financial risk to FortisBC Electric and a greater
33 business risk based on all measures of utility size (YEC is much smaller), reliance
34 on its own generation and lack of interconnections with external electricity markets.
35 This last set of factors was seen as conclusive evidence that YEC's risk was
36 materially greater than FortisBC Electric.

1 • **2008/09 General Rate Application and 2012/13 General Rate Application:**

2 Yukon Energy noted that many of the risk factors identified compared to FortisBC
3 Electric remained (i.e., no material change in statistics regarding customers, size,
4 revenue or rate base compared to the 2005 Application), Yukon Energy continued
5 to have greater risk than comparable BC utilities based on reliance on its own
6 generation (far higher than FortisBC Electric) and lack of interconnection to
7 external electricity markets. Since the 2005 GRA, Yukon Energy's business risk
8 had increased due to connection of a new Industrial customer (Minto mine). As
9 noted for the 2012/13 GRA, Yukon Energy relied on the AUC benchmark of 8.75%
10 for the test years. While Yukon Energy sought a risk premium of 52% (based on
11 risk premium applied in prior years), the Board did not approve this as the AUC
12 approach did not apply a risk premium.

13
14 The above risk factors have not changed materially since the 2012/13 Application.

- 15
16 • **Comparison of Yukon Energy to BC utilities size of operations and financial**
17 **structure** continues to indicate that Yukon Energy is smaller compared to
18 FortisBC Energy (the low risk benchmark). YEC's customer count and rate base
19 is also smaller than FortisBC Electric's; however the financial structure for both
20 utilities is the same (40% equity).

- 21
22 • **Comparison of nature of business to BC utilities** indicates that Yukon Energy
23 continues to have a greater business risk based on its reliance on its own
24 generation (far higher than FortisBC Electric) and its lack of interconnection with
25 external markets. The business risk related to industrial customers has fluctuated
26 with the connection of new industrial customers in 2008 (Minto) and 2011 (Alexco)
27 and the loss of Alexco after the 2012/13 GRA (after rates were set based on its
28 forecast load). Further, as noted in Tab 1 and Tab 2 of the current Application, in
29 preparing the 2017/18 GRA the forecast for Minto mine load changed significantly.

30
31 There is little that Yukon Energy can do to mitigate risks that arise due to its size, the
32 isolated nature of the Yukon grid (i.e., a grid interconnection is not a feasible, near term
33 risk mitigation measure), its material hydroelectric generation, and its service of industrial
34 customer loads. Negotiation of Power Purchase Agreements (PPAs) with industrial
35 customers to require recovery up front of connection capital costs is one specific mitigation
36 adopted by YEC to remove "hang-over" cost risks related to connecting new industrial
37 customer loads. Flexible debt financing with YDC for the Mayo B project rate base to adjust

1 interest rates based on actual grid loads is another mitigation measure adopted related to
2 generation related capital costs and load related risks. Capital grant contributions and
3 renegotiated interest costs are other mitigation measures adopted to reduce specific risks
4 related to generation and transmission asset costs. Implementation of the DCF to address
5 water-related variability risks for hydroelectric generation, and updating of the DCF to
6 address impacts of changing loads and generation facility capability, is another mitigation
7 measure adopted to address generation and load-related risks.

1 **TOPIC: Generation Risk**

2
3 **REFERENCE:** Application, page 8-7. PDF page 300

4
5 **QUOTE:** “YEC continues to have a greater business risk than the relevant BC
6 utilities based on its reliance on its own generation (far higher than for
7 FortisBC Electric), and its lack of any interconnection with external
8 electricity markets. These material differences have not changed from
9 the assessments provided in 2005 and 2009.”

10
11 **QUESTION:**

- 12
13 a) What is the level of generation of FortisBC Electric versus YEC in terms of absolute
14 level of generation (nameplate capacity) and as a percentage of load?
15
16 b) Is there a linear relationship between level of generation risk and the level of
17 generation (capacity)? Please explain.
18

19 **ANSWER:**

20
21 **(a) and (b)**

22
23 Please see Table 1 below for the information related to level of generation for Fortis BC
24 and YEC.
25

26 Assessments have not suggested a strict linear relationship between level of generation
27 risk and the level of generation (capacity). The nature of the risk can vary depending on
28 the generation and related cost risks (e.g., fixed costs versus variable costs, new versus
29 very depreciated assets, risks related to renewable energy variability, and risks related to
30 load variation and related cost versus revenue variability), and the relative importance of
31 generation and related costs within the total utility revenue requirement. On all related
32 grounds, YEC’s hydro-based generation with new as well as old assets on an isolated grid
33 displays a high level of generation risk.

Table 1: Fortis BC and YEC Generation Levels¹

	2016	
	Fortis BC	YEC
Total Gross Load, GW.h	3,477	413
Own Generation	1,599	413
Own generation as % of total load	46%	100%
Installed Capacity (MW)	225	133
Capacity Factor	81%	36%
Available/Dependable Capacity (MW)	208	110
Capacity Factor	88%	43%

Notes:

1. Information for Fortis BC:

- a. The total load information for Fortis BC is based on Appendix A-2 of Fortis BC Annual Review for 2018 Rates [available at http://www.bcuc.com/Documents/Proceedings/2017/DOC_49776_B-2_FBC_Annual_Review_2018_Rates_Application.pdf]
- b. Own generation is based on response to Information Request #8 [available at http://www.bcuc.com/Documents/Proceedings/2016/DOC_47674_B-5_FBC-Response-to-BCOAPO-IR1.pdf]
- c. Installed capacity based on information from Fortis BC which notes that FortisBC owns four hydro-electric generating plants on the Kootenay River with an installed capacity of 225 MW [available at <https://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ElecFacilitiesOperations/Pages/default.aspx>]
- d. Available generation based on Table 5.1. FBC's 2016 Available Energy and Capacity Resources [available at https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf]
- e. On page 74, Section 5 of the 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan) Fortis BC notes that

¹ The total load information for Fortis BC is based on Appendix A-2 of Fortis BC Annual Review for 2018 Rates [available at http://www.bcuc.com/Documents/Proceedings/2017/DOC_49776_B-2_FBC_Annual_Review_2018_Rates_Application.pdf]; own generation is based on response to Information Request #8 [available at http://www.bcuc.com/Documents/Proceedings/2016/DOC_47674_B-5_FBC-Response-to-BCOAPO-IR1.pdf]; installed capacity available generation based on Table 5.1. FBC's 2016 Available Energy and Capacity Resources [available at https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf]. On page 74, Section 5 of the The FBC Plants supplied about 50 percent of FBC's energy requirements and about 27 percent of the Company's peak demand in 2015.

1 “FBC Plants supplied about 50 percent of FBC’s energy requirements and about 27
2 percent of the Company’s peak demand in 2015.”
3

4 2. Information for YEC:

- 5 a. 2016 load is based on Table 2.2 and includes secondary related load.
6 b. Installed capacity is based on Figure 4-7: Yukon Power Grid and Load Centers, 20-
7 Year Energy and Peak Demand Forecast of the 2016 Resource Plan update.
8 c. Dependable capacity as noted on page 2-16 of Tab 2 of the 2018/19 GRA.

1 **TOPIC: ROE Risk Premium**

2
3 **REFERENCE:** Application, page 8-4. PDF page 297; Appendix A to Board Order 2017-
4 01: Reasons for Decision, page 43.

5
6 **QUOTE:** “As described above, the Board in Order 2005-12 approved Yukon
7 Energy’s proposal to set its fair return at 52 basis points (0.52%) above
8 the BCUC low-risk benchmark utility ROE being the mid-point between
9 FortisBC Electric (40 basis points) and PNG-West (65 basis points).”

10
11 **QUESTION:**

- 12
13 a) What factors did the BCUC consider in determining the equity premium for PNG-
14 West?
15
16 b) In Board Order 2017-01(paragraph 211- Appendix A) the Board concluded that in
17 determining relative risk for AEY, the Board should look at size and generation risk.
18 Please comment on the applicability of this finding to determining YEC’s risk
19 premium.
20

21 **ANSWER:**

22
23 **(a)**

24
25 The BCUC approved an equity level of 46.5% and a risk premium of 75% above the low
26 risk utility benchmark of 8.75% for PNG-West [see Page 113-14 of Decision G-47-14]. In
27 approving the 75% risk premium, the BCUC determined that PNG-West faces significantly
28 more risk than the benchmark with respect to customer growth, market demand and
29 throughput risk. The following factors were specifically noted in Decision G-47-14:

- 30
31 • PNG-West serves customers in 11 municipalities close to its transmission lines
32 which traverses BC from the Westcoast Energy system mainline connection near
33 Summit Lake to Prince Rupert. The total population of the service area is under
34 100,000.
35
36 • The highest weighted risks identified by PNG West were operating and size,
37 demand and throughput, competitive position and regulatory.

- The BCUC noted that PNG-West size and operating risk are higher than Benchmark; PNG West is 1/20 the size of the benchmark and in comparison to FEI it “operates in a northern, mountainous and generally harsher environment, where the company assets are subject to significant weather, geographic and geologic factors.”
- PNG-West experienced negative customer growth for 9 consecutive years (2003-2012) amounting to a close to 10% decline in overall accounts over this period. In contrast, the benchmark experienced steady growth in customer accounts. PNG-West’s throughput has also declined by 87% over the 2003-12 timeframe with a significant part of this decline related to the loss of a major customer; a 42% decline continued over the 2006-2012 timeframe following the loss of this customer.¹

(b)

Yukon Energy agrees that size and generation risk are important risks to consider in assessing the risk premium applicable for Yukon Energy; however, the nature of the operating environment (i.e., isolated northern grid) is also an important factor to be considered. Key factors that have been considered in prior reviews to determine Yukon Energy's risk relative to BC comparable utilities and that remain applicable for determining the risk premium for Yukon Energy at this time are as follows:

- **The isolated nature of the Yukon grid** – i.e., unlike BC utilities, Yukon Energy operates on an isolated grid and cannot purchase power from other electrical systems (or sell surplus power into such systems). This is a critical risk for Yukon Energy that sets it apart from other southern utilities, as well as AEY.
- **Yukon Energy is the main generator and transmission utility in Yukon** – and generation risk is a key risk for Yukon Energy. Yukon Energy has significantly higher generation (100% of supply requirements) than FortisBC Electric (45% of supply requirements) and AEY (9% of supply requirements).
- **Business Risks related to industrial loads** – Yukon Energy has historically been the utility supplying industrial load that connects to the Yukon grid. The business risk related to industrial customers has fluctuated with the connection of new

¹ Decision B-47-14, page 97-98; 102-103.

1 industrial customers in 2008 (Minto) and 2011 (Alexco) and the loss of Alexco after
2 the 2012/13 GRA (after rate were set based on its forecast load). Further, as noted
3 in Tab 1 and Tab 2, in preparing the 2017/18 GRA, the forecast for Minto mine
4 load changed significantly.

5

- 6 • **Size relative to larger, southern utilities** – Yukon Energy is relatively small in
7 terms of customers, rate base and revenues compared to larger utilities such as
8 FortisBC Energy and FortisBC Electric.

9

10 Overall, Yukon Energy is a small, northern utility (similar to AEY), but also carries much
11 higher risks compared to AEY related to generation, related to connected industrial load,
12 and related to being the main transmitter and generator on an isolated northern grid.

13

14 See also the response to YUB-YEC-1-53, YUB-YEC-1-54, YUB-YEC-1-55 and
15 CW-YEC-1-28.

1 **TOPIC: System Sales and Generation**

2
3 **REFERENCE:** Application, page 2-2. PDF page 31, lines 2 to 7

4
5 **QUOTE:** “Industrial sales under Primary Industrial Rate Schedule 39 currently
6 include only sales to the Capstone Mining Corp (Minto mine). No other
7 industrial customer sales are forecast for the test years. Since 2013,
8 firm grid load supplied by Yukon Energy to industrial customers has
9 fallen below the actual and approved forecast load for 2013, except
10 2016, reflecting early shut down of the Alexco Resources Bellekeno
11 mine the last half of 2013. The Whitehorse Copper Tailings industrial
12 load that was forecast to be supplied by AEY in the 2013 YEC
13 Compliance Filing has not to date materialized.”

14
15 **QUESTION:**

- 16
17 (a) Please provide an explanation for why the firm grid load supplied to industrial
18 customers was above the actual and approved forecast load for 2016, while all
19 other years it was below the actual and approved forecast.
20
21 b) Provide a status update regarding the Whitehorse Copper Tailings industrial load
22 that was forecast to be supplied by AEY in the 2013 YEC compliance filing.
23

24 **ANSWER:**

25
26 **(a)**

27
28 It is assumed that the question is referencing the actual and approved forecast industrial
29 load for 2013.

30
31 The actual and approved YEC industrial load for 2013 included load supplied to Alexco
32 Resources Bellekeno mine for the first half of the year. However, due to an early shut
33 down, there has been no subsequent industrial load supplied to Alexco. As a result, the
34 only industrial customer since 2013 has been Capstone Mining Corp (Minto Mine). YEC’s
35 understanding is that Minto’s load for 2016 was abnormally high as they were also
36 considering an upcoming shut down and were trying to produce as much as possible
37 before it was shut down.

1 **(b)**

2

3 YEC has had no recent contact with this proposed customer and has no knowledge of the
4 status of the project beyond what has been publicly reported. The company has
5 acknowledged via its website that the drop in ore price in 2014 made the project
6 unsustainable. No provision has been made in YEC test year forecasts for this customer.

1 **TOPIC:** Installed dependable grid capacity

2
3 **REFERENCE:** Application, page 2-16. PDF page 45, lines 1 to 6

4
5 **QUOTE:** “Installed YEC and AEY 1 dependable grid capacity for the winter peak
6 in both 2017 and 2018, based on existing capacity today and any
7 planned retirements and excluding Fish Lake hydro, is approximately
8 115.0 MW (70.5 MW of YEC hydro, 39.1 MW of YEC diesel, and 5.4
9 MW of AEY diesel).

10
11 For the single contingency (N-1) criterion assessment of the
12 dependable capacity, excluding Fish Lake hydro, to meet the YEC
13 load...”

14
15 **QUESTION:**

16
17 a) Please explain why the dependable grid capacity shortfall calculation does not
18 include Fish Lake hydro.

19
20 **ANSWER:**

21
22 **(a)**

23
24 AEY Fish Lake Hydro is a facility connected to the distribution grid, directly serving the
25 local demand in Whitehorse. As such, YEC is serving the demand net of AEY Fish Lake
26 Hydro contribution.

27
28 Consequently, the load and peak demand forecast completed as part of the 2016
29 Resource Plan and the 2017-2018 GRA Application excluded the contribution of the AEY
30 Fish Lake Hydro. Adding the dependable capacity of AEY Fish Lake Hydro into the single
31 contingency (N-1) criterion would require an increase in non-industrial loads by the same
32 amount to account for the demand it serves as a part of the distribution grid. Considering
33 the added dependable capacity and added demand, the resulting dependable capacity
34 shortfall (or surplus) would be similar to the dependable capacity shortfall (or surplus)
35 calculated for the case without the AEY Fish Lake Hydro contribution. This approach is
36 consistent with past assessments of dependable grid capacity provided to the Board.

1 **TOPIC: Energy Sales**

2
3 **REFERENCE:** Application, Table 2-2, page 2-18, PDF page 47

4
5 **QUESTION:**

- 6
7 a) Please explain the significant increase in total energy sales from 2016 actuals to
8 2017 forecast sales when compared to increases in previous years.
9
10 b) Please provide 2017 actual total energy sales to date.

11
12 **ANSWER:**

13
14 **(a)**

15
16 Total energy sales in Table 2.2 includes secondary sales as well as firm sales. The 12.0
17 GW.h increase in total energy sales from 2016 to 2017 reflects the following:

- 18
19 • 6.6 GW.h increase in secondary sales (which were relatively low in 2016 compared
20 with 2015);
21
22 • 7.8 GW.h increase in firm wholesales (see discussion below – 2016 showed 3.2
23 GW.h increase over 2015, but remained 6.7 GW.h below 2013 actual); and
24
25 • 2.4 GW.h decrease in other firm sales, reflecting a 3.0 GW.h reduction in firm
26 industrial sales.
27

28 As indicated above, the fluctuation in total firm energy sales from 2013 to 2016 actual
29 sales and 2017 forecast sales is due primarily to fluctuations in Wholesale sales.
30 Fluctuations in firm Wholesales sales during this period were caused primarily by
31 fluctuations in temperatures, plus impacts of changing Fish Lake Hydro generation.

32
33 Warmer than normal temperatures in 2014, 2015 and the first half of 2016 reduced
34 Wholesale sales. As reviewed at page 2-5 of YEC's Application, it is estimated that the
35 magnitude of the above normal temperature impact likely reduced AEY's wholesale
36 purchases from YEC by about 6.4 GW.h in 2015 and by a higher amount in 2016 (relative
37 to AEY's original GRA forecast). It was concluded in YEC's Application that actual AEY

1 firm wholesales in 2016 were at least 2 to 3 GW.h below what could be expected based
2 on normal temperatures (indicating a minimum 2016 firm wholesales at normal weather
3 of about 304 GW.h).

4
5 As reviewed at pages 2-5 and 2-6 of YEC's Application, the 2017 Wholesales firm sales
6 forecast has been based on normal long-term average temperatures and a range of model
7 assessments, and also takes into account AEY's expected changes in Fish Lake Hydro
8 generation between 2016 and 2017.

9
10 YEC's forecast firm wholesales for 2017 at 309.0 GW.h is 8.7 GW.h higher than AEY's
11 initial GRA forecast, and 5.2 GW.h lower than AEY's approved Compliance Filing forecast
12 of 314.2 GW,h in response to Board Order 2017-01.

13
14 Please also see response to YUB-YEC-1-3 regarding the difference between YEC's GRA
15 and the AEY Compliance Filing as approved by Board Order 2017-03.

16
17 **(b)**

18
19 The total 2017 actual energy sales to July 31, 2017 is 242.1 GWh, as detailed below, and
20 compared to the GRA forecast in Table 2.1 for the same period.

21

	January to July Actual	GRA Forecast (Table 2.1)
Residential	9.3	8.3
General Service	14.4	14.0
Street Lights	0.1	0.1
Industrial	24.6	22.6
Wholesale	188.6	176.7
Secondary	5.0	6.8
	<u>242.1</u>	<u>228.7</u>

22

TOPIC: Power Generation

REFERENCE: Application, page 2-10. PDF page 39, lines 21 to 22

QUOTE: “Total generation is based on the sum of total sales plus losses. Losses are forecast at 8.8% for each of the test years.”

QUESTION:

- a) Please explain how the forecast level of losses (8.8%) was determined. Please provide actual levels of losses for the years 2012 to 2016 inclusive.

ANSWER:

(a)

As reported in the 2016 Resource Plan (Chapter 4, page 4-17, lines 17 to 19), the forecast level of losses was defined using the average of historical levels of losses for the 2012 to 2015 period. Actual levels of losses for the years 2012 to 2016 inclusive are presented in the table below.

**Table 1: Actual Levels of Losses (% of YEC Sales on Grid)
– 2012 to 2016**

Year	Losses
2012	8.8%
2013	9.0%
2014	7.5%
2015	10.0%
2016	8.3%

1 **TOPIC:** Aishihik AH3, Section 5.2.1.1

2
3 **REFERENCE:** Application, pages 5-6 to 5-7. PDF pages 177 to 178

4
5 **QUOTE:** “The Aishihik hydro facility 7 MW third turbine (AH3) came into service
6 in December 2011. Yukon Energy has incurred \$2.715 million of costs
7 after 2012 for wrap up activities related to this project, including \$2.574
8 million of costs from a dispute with a contractor on this project. Total
9 spending in 2016 was \$2.117 million, the majority being legal costs
10 required to be expensed during the year for accounting purposes.”

11
12 “A decision on the dispute was provided in August 2016 by the Yukon
13 Supreme Court, awarding the contractor a net amount of \$1,623,565
14 plus interest and costs. The amount awarded by the Court included
15 \$1,308,462 that consisted of holdbacks and extra works done where
16 the price had been agreed upon, but not yet paid due to YEC’s claims
17 for set-off rights. The final cost of the claim dispute includes YEC legal
18 fees of \$0.962 million. Based on the advice of legal counsel, YEC has
19 filed the necessary documentation to appeal the court decision.”

20
21 **QUESTION:**

- 22
23 a) Please explain why the amount of \$1,308,462 which consisted of holdbacks and
24 extra works done is being expensed during the 2016 year for accounting purposes,
25 rather than being capitalized to the project.
26
27 b) Please provide any cost-benefit analysis YEC undertook regarding legal fees
28 before proceeding with litigation.
29
30 c) YEC indicates it had a claim for setoff against the contractor of at least \$1,623,565,
31 which was denied by the Yukon Supreme Court. Are the costs that YEC attempted
32 to set-off included in the \$0.665 million capital costs already expensed, or are they
33 in addition to those costs?

1 **ANSWER:**

2
3 **(a)**

4
5 YEC is not at this time seeking to add any amount to rate base in this Application related
6 to this issue. The utility will carry related costs until such time as the legal process has run
7 its course at which time the utility will consider amounts for review by the YUB.

8
9 To help with understanding, the following chronology is provided:

10
11 The AH3 project was put into service effective December 2011. Subsequently, the
12 installation contractor advised Yukon Energy of a dispute under the contract. After several
13 rounds of negotiation without success, the contractor filed a claim with the Yukon Supreme
14 Court. YEC filed its defense and a counter claim. Total claims as filed:

15		
16	Contractor claim	\$3,674,000
17	YEC counter claim	\$2,442,045
18		

19 At this time, the parties had agreed that a total of \$1.165 million (\$0.746 holdbacks; \$0.419
20 change orders) were legitimate claims by the contractor. YEC accrued these amounts to
21 the project, however, withheld payment due to the material counterclaims outstanding
22 against the contractor. Subsequent to commencement of the court action, but prior to the
23 trial, the parties agreed to further change order settlement of \$0.143 million (this amount
24 is not accrued to the project to date and is accounted for in capital WIP; see below for
25 accounting analysis). The sum of these amounts equals \$1.308 referenced in the
26 application (page 5-7, I 10). The case went to trial in early Q2 2016 with judgement issued
27 August 1 2016. The judgement awarded some amounts to both parties, with the net result
28 in favour of the contractor. YEC management reviewed the reasons for decision produced
29 by the court and, in consultation with legal counsel, concluded that several legal errors
30 existed in the judgement. Based on this conclusion, the decision was made to appeal.

31
32 The table below details the components of the settlement, as well as other spending since
33 2011.

<u>Description</u>			<u>\$000's</u>	<u>Notes</u>
Judgement				
Holdback Release			746	1
Change Orders				
Previously agreed		419		1
Pre-Trial settlement		143		2
Awarded at trial		724	1,286	2
Award to contractor			2,032	
Awarded to YEC			- 409	2
Net judgement payment			1,623	
Legal Expenses		962		3
YEC Labour		20		2
Travel		12		2
Contract		161		2
AFUDC		64		2
Misc		2	1,221	2
			<u>2,844</u>	
	1	Amount accrued to project cost at construction; approved into rate base during 12/13 GRA		
	2	Amount held in capital work-in-progress		
	3	Amount written off to income statement at the direction of auditors.		

In summary the accounting for these costs is as follows:

Costs included in original project costs ¹	\$1.164 million
Project costs included in Capital WIP	\$0.718 million
Legal costs expensed per audit direction	<u>\$0.962 million</u>
Total	\$2.844 million

¹ These costs were part of the \$13.8 million of rate base costs approved by the YUB as part of the order on YEC GRA 2012/13.

1 With respect to legal costs, YEC was forced to expense these amounts under GAAP
2 based on the previous disallowance of costs by the YUB with respect to the Mayo-Dawson
3 transmission project contract settlement from the 2005 Required Revenues and Related
4 Matters proceeding. It remains YEC's position that these are valid costs for recovery from
5 ratepayers and these costs will be applied for at the next proceeding following resolution.
6

7 **(b)**

8
9 From the beginning of this dispute, both parties were motivated to find a settlement outside
10 of a court process. Several negotiation sessions were held, including a court-sponsored
11 mediation. Although some progress was made on some of the issues, overall settlement
12 was not achieved.
13

14 **(c)**

15
16 The amount \$1,623,565 is the award from the trial judge issued in 2016 (page 5-7, ll 8-9).
17 This is a net award; the contractor was awarded \$2.091 million and YEC was awarded
18 \$0.408 million for a net award to the contractor of \$1,624 million. The amount identified as
19 capital costs of \$0.665 million does not include any of the YEC claims against the
20 contractor.
21

22 The AH3 project discussed in this GRA is made up of two distinct activities – project wrap-
23 up and the contract dispute. The \$0.665 million represents the amount allocated to these
24 two activities during the years 2013 through 2016. For clarity, the following table breaks
25 down the separate activities and shows total costs including 2012.
26

Activity	2012	2013-2016	Total
AH3 Wrap-up	\$148,695	\$141,135	\$289,830
AH3 Contract Dispute	\$183,510	\$523,703	\$707,213
Total AH3	\$332,205	\$664,838	\$997,043

27
28 AH3 Wrap-up activities involved normal work required to address project deficiencies after
29 the unit was put into service. The total for that activity of \$289,830 was added to rate base
30 at the end of 2014 and YEC is seeking approval of these costs during the current GRA.
31 The total costs of the contract dispute of \$707,213 are being held in WIP. YEC is not
32 seeking approval of these costs during the current GRA.

1 **TOPIC:** Aishihik Elevator Shaft Structural Steel Rehabilitation, Section
2 5.2.1.2
3

4 **REFERENCE:** Application, pages 5-7 and 5-8. PDF pages 178 to 179
5

6 **QUOTE:** “Following the addition in 2011 of a second feeder cable in the Aishihik
7 elevator shaft, the Yukon Workers Compensation Health and Safety
8 Board required YEC to have an independent engineer conduct a
9 comprehensive evaluation of the installation to ensure the elevator
10 meets all applicable codes, acts, and regulations. The engineering firm
11 reviewed the elevator structural frames and support system in 2013 and
12 observed degradation of the steel integrity. The report recommended
13 permanent rehabilitation of the structure and a list of conditions
14 imposed on the use of the elevator to provide a reasonable margin of
15 safety until the work is completed. Since regular elevator access to the
16 underground generator floor is required for continued operation of the
17 plant, and the plant is critical to the operation of the Yukon Integrated
18 System, there was no reasonable alternative to completing this project.”
19

20 “The project is forecast to be completed in 2017 with a forecast cost of
21 \$10.116 million.”
22

23 **QUESTION:**
24

- 25 a) Has this project been completed?
26
27 b) Please confirm that YEC is not asking for approval to put the costs of this project
28 into rate base for the test period.
29
30 c) With respect to the report, were other alternatives provided in the report? If so,
31 please discuss the other alternatives.
32
33 d) Please provide the original forecast cost of this project, and explain any variances
34 between the original forecast cost, and the current forecasted cost of \$10.116
35 million.
36
37 e) When was the elevator installed?

ANSWER:

(a)

Yes, the project is complete and the elevator was returned to service at the end of June 2017.

(b)

Not confirmed. YEC is seeking approval to put the costs of this project into rate base in 2017.

(c)

No other alternatives were provided in the report.

(d)

Table 1 below provides a comparison between the GRA forecast cost of \$10.116 million and the original forecast cost of \$9.512 million. Table 2 and the description below it provide an explanation of variance by project subcomponent.

Table 1 – AH Elevator - GRA vs Original Forecasts (\$000)

	GRA Forecast	Original Forecast (May 2015)	GRA vs Original Forecast
Site Preparation and Modifications	890	425	(465)
Structural Steel	6,163	5,138	(1,025)
Lead Abatement Costs	749	-	(749)
Construction Field Costs:	7,802	5,563	(2,239)
Engineering and Design	482	674	192
Construction Management	637	300	(337)
YEC Owners Costs	759	550	(209)
Construction Financing Cost	198	302	104
Thermal Generation Costs	238	100	(138)
Indirect Costs:	2,314	1,926	(388)
Contingency:	-	2,024	2,024
Total Cost (Project Deficit)	10,116	9,513	(603)

1

Table 2 – AH Elevator - Variance Explanations

	(\$' 000's)
Elevator Contractor	(145)
Other Contractors & Services	(320)
Site Preparation and Modifications	(465)
Construction Change Orders	(787)
Schedule Extension Overhead Costs	(238)
Structural Steel Contract	(1,025)
Lead Abatement Costs	(749)
Engineering and Design	192
Construction Site Manager	(290)
Other Consultants & Engineers	(48)
Construction Management	(337)
Camp Rental	(36)
YEC - Labour	(66)
YEC - Non Labour	(106)
YEC Owners Costs	(209)
Construction Financing Cost	104
Thermal Generation Costs	(138)
Variances from Original Forecast	(2,627)
Contingency within Original Forecast	\$ 2,024
Project Deficit	\$ (603)

2

3

4 The following reviews the variances as reported in Table 2 – AH Elevator Variances
5 Explanation:

6

7 • **Site Preparation and Modifications** – Costs for the elevator contractor to remove
8 from service and return to service the elevator at the beginning and end of each
9 phase were underestimated by \$145k. Other Contractors and Services were
10 greater than forecast by \$320k as the costs were underestimated for preparation
11 for construction, maintenance costs for the camp and crane, and numerous other
12 miscellaneous materials and services that were required during the project.

13

14 • **Structural Steel Contract** – 46 construction change orders were issued for a
15 value of \$787k with the bulk of related costs being incurred to address unforeseen
16 conditions such as additional rock chipping, adjustments to design and changes to
17 work plans to address shaft dimensions and bracing. The additional works also

1 extended the construction schedule resulting in payment to the contractor of an
2 overhead claim in the amount of \$238k.

3
4 • **Lead Abatement Costs** – Early in the project it was determined that the existing
5 structural steel was painted with lead paint which necessitated special handling
6 procedures during removal.

7
8 • **Engineering & Design** – The actual cost was less than forecast by \$192k due to
9 using the same engineer for the preliminary and detailed engineering phase and
10 also due to a construction site manger being on the site for the duration of the
11 project reducing the supervisory and inspection role of the Owner Engineer.

12
13 • **Construction Site Manager** – The project was forecast to be delivered over 2
14 phases each with a duration of 5 months per year. The actual duration for the two
15 phases was 17 months - 7 months for the first year and 10 months for the second
16 year. During the second phase the Construction Manager also fulfilled the
17 regulatory requirement mandated by OH&S regulations that a certified frontline
18 supervisor be in attendance at all times when working underground.

19
20 • **YEC Owner Costs** – Were greater than forecast due to the duration for both
21 phases of the project being longer than forecast resulting in higher camp rental,
22 YEC Labour and YEC Non-Labour costs.

23
24 • **Construction Financing Cost** – There costs were lower than forecast as the
25 outflows as dispersed during Phase 1 were less than forecast resulting in lower
26 financing costs.

27
28 • **Thermal Generation Costs** – A provision was made within the forecast but actual
29 costs exceeded budget by \$138k.

30
31 (e)

32
33 The Aishihik hydro facility with its related elevator was commissioned in 1975.

1 **TOPIC:** **Aishihik Electrical and Control Upgrades, Section 5.2.1.3**

2
3 **REFERENCE:** Application, pages 5-8 to 5-11. PDF pages 179 to 182

4
5 **QUOTE:** “The Aishihik Control Systems and Electrical Upgrades project includes
6 a number of specific control systems and electrical upgrades that are
7 being undertaken to ensure ongoing safe and reliable operation of the
8 Aishihik Generating Station. Approximately \$2.511 million of upgrades
9 are planned to be completed before the end of 2018.

10
11 “In 2014, a formal asset assessment was completed by KGS.”

12
13 “A project to replace equipment and complete a number of specific
14 associated plant control system upgrades and electrical upgrades was
15 developed for execution over multiple years, with most of the upgrades
16 planned to be completed in 2017 and 2018. The need for each planned
17 upgrade (based on currently available upgrade options) was addressed
18 versus the do-nothing alternative.”

19
20 **QUESTION:**

- 21
22 a) Please provide a copy of the assessment that was completed by KGS respecting
23 this project.
24
25 b) For each of the control system upgrades, as well as each of the electrical
26 upgrades, please provide:
27 i.) the report that outlines the upgrade options available at the time.
28 ii.) the original forecasted cost of each alternative that was chosen, and
29 explain any variances between the costs that were originally forecast and
30 the current forecast cost total of \$2.511 million.
31
32 c) Does YEC review control system drawings and operator interfaces on a regular
33 basis? If so, when was the last time that drawings and interfaces were updated?

1 **ANSWER:**

2
3 **(a)**

4
5 Please see YUB-YEC-1-63 Attachment 1.

6
7 **(b)**

8
9 There were no other option reports prepared for this project aside from KGS assessment.
10 Other than a number of minor allocations between project components, there has not been
11 any significant change in the forecast cost.

12
13 **(c)**

14
15 Operator interfaces and system drawings are not reviewed on a regular basis, only when
16 required by a specific issue or shortcoming. In this case, the issues are legacy deficiencies
17 from the original AH3 project.

YUB-YEC-1-63 Attachment 1

(Large attachment – please see 2017/2018 General Rate Application
Round 1 Interrogatory Responses Appendix A)

1 **TOPIC: AH Reactor Cable Replacement**

2
3 **REFERENCE:** Application, page 5-11. PDF page 182, lines 10 to 17

4
5 **QUOTE:** “During the AH3 project in 2011 the cables between the breakers and
6 reactors within the S-167 (AH0) substation were replaced. However,
7 the new cables are undersized and need to be replaced. There is a risk
8 that constant heavy load between the reactors and breakers will
9 eventually result in a cable failure which could damage equipment and
10 cause an unscheduled outage of the Aishihik hydro plant.”

11
12 **QUESTION:**

- 13
14 a) Please provide the average life expectancy of cable installed and used by a utility
15 for AH reactor cables.
16
17 b) Please explain why customers should be paying for undersized cables that were
18 installed in 2011.
19
20 c) Please explain the process used during the AH3 project in 2011 that was used to
21 determine what size was needed for the new cables.
22
23 d) Please explain why the process described in (c) resulted in cables that were
24 undersized, and are in need of replacement six years later.
25
26 e) Notwithstanding the answer to (c) above, please explain the process used to verify
27 that the cables that will be installed in 2017 are now of the correct size.
28

29 **ANSWER:**

30
31 **(a)**

32
33 Average life expectancy is between 25 and 40 years.

1 **(b)**

2
3 See part (d); certain assumptions about the nature of application were proven to be
4 misunderstood at the time of construction.

5
6 **(c)**

7
8 Proper cable size was confirmed with YEC's engineering department.

9
10 **(d)**

11
12 The cable replacement was not part of the original scope of work and was a result of a
13 change order caused by design complications with the pipe bus. A length of wire that was
14 being removed as part of the project was repurposed for the reactor cable and YEC
15 engineering department was asked to determine if it was adequate. The cable was
16 deemed to be adequate for a similar free-air installation, however, the change order
17 resulted in the cable instead being placed underground in conduit. In this arrangement, the
18 cable size was too small.

19
20 **(e)**

21
22 Proper cable size was confirmed with YEC engineering department after ensuring full and
23 accurate information about the installation type and location.

1 **TOPIC:** AH3 Lube Oil Pump Battery Installation

2
3 **REFERENCE:** Application, page 5-11. PDF page 182, lines 18 to 26

4
5 **QUOTE:** "Isolating this pump onto its own backup power supply would enable
6 AH3 to operate independently from the main AH0 backup battery bank,
7 reduce the drawdown and extend the life of the main AH0 backup
8 battery bank during a station service outage. Failure to install this
9 backup increases the risk of the AH0 backup battery bank being drawn
10 down too quickly, which could compromise the ability to recover the AH
11 plant following an extended outage."
12

13 **QUESTION:**

- 14
15 a) Please discuss if the situation described in the quote above (AH0 backup battery
16 bank being drawn down too quickly) has occurred in the past. What is the likelihood
17 of this occurring in the future if a new battery for AH3 is not installed?
18

19 **ANSWER:**

20
21 **(a)**

22
23 The situation described has not yet happened, the batteries are only used during a station
24 service outage. This project is being performed as a preventative action after determining
25 that the AH3 lube oil pump places significant demand on the main AH0 battery bank. The
26 main battery is designed to last 16 hours, however, with the additional draw of the AH3
27 lube oil pump this is reduced to approximately 1 hour. Although even a 1 hour station
28 service outage is unlikely, the consequences of fully discharging the battery are severe.
29 Furthermore, under the current scenario, the plant does not meet its design criteria for
30 battery backup.

1 **TOPIC: Aishihik Black Start Modifications**

2
3 **REFERENCE:** Application, page 5-11. PDF page 182, lines 27 to 33

4
5 **QUOTE:** “The black start generator of the Aishihik plant can be improved in order
6 to take on additional loading to run more efficiently when it is called into
7 service. It would also be beneficial to increase the number of Aishihik
8 station services served by the black start generator. This project will
9 involve first determining the optimal underground station services that
10 could be shifted to the black start diesel, then performing the work to
11 physically relocate them to the centralized underground station service
12 points supported by the black start diesel.”

13
14 **QUESTION:**

- 15
16 a) Please provide the genesis for this project.
17
18 b) Please explain how the number of optimal underground services that can be
19 shifted to the black start diesel will be determined.
20
21 c) Please discuss the impact on black start services if these modifications were not
22 completed.

23
24 **ANSWER:**

25
26 **(a)**

27
28 The Aishihik black start generator was at end of life in 2014 and was replaced with a new
29 and slightly larger unit. This project is required to take advantage of the increased
30 generation capacity and to decrease wear on the asset caused by under loading.

31
32 **(b)**

33
34 Services will be prioritized based on their criticality to plant reliability during a station
35 service outage. Once the list of services is ranked and the load demand of each is
36 determined, as many as possible will be added up to the generator's capacity.

1 **(c)**

2

3 With the generator being significantly under-utilized, there is an increased risk of it not
4 performing during a station service outage. Furthermore, if these modifications are not
5 completed, certain services will continue to rely solely on their own dedicated backup
6 power (batteries, diesel engine, etc.) adding to the risk of failure. These modifications will
7 significantly increase the likelihood that the Aishihik plant will be able to continue operating
8 during a station service outage.

1 **TOPIC:** **Communications Upgrades, Section 5.2.1.4**

2
3 **REFERENCE:** Application, pages 5-12 to 5-14. PDF pages 183 to 185

4
5 **QUOTE:** “The Communications upgrades project includes a number of specific
6 communications network upgrades that will replace end of life
7 communication network infrastructure with new technology and
8 implement a simplified network infrastructure which will increase
9 performance and improve reliability of the network. The new network
10 environment will also support other modernization projects that may be
11 undertaken in the future (e.g., Smart Grid Technology). Approximately
12 \$1.003 million of upgrades are planned to be completed by the end of
13 2018.”

14
15 “In 2016, an independent consultant completed a Communications
16 Needs Assessment and made recommendations to improve critical
17 elements such as Supervisory Control and Data Acquisition (SCADA)
18 system features, and improve network performance, reliability,
19 redundancy and security. A proposed system design was provided with
20 recommendations for staged implementation focusing on the most
21 critical assets or initiatives first, and progressing towards the less
22 critical ones, with the eventual goal of covering the whole YEC
23 communications system.

24
25 “A project to replace communication network infrastructure and
26 complete a number of specific communications upgrades was
27 developed for execution over multiple years, with some of the upgrades
28 planned to be completed in 2017 and 2018. The need for each planned
29 upgrade (based on currently available upgrade options) was addressed
30 versus the do-nothing alternative. Each specific upgrade comes into
31 service (and into rate base) when it is completed.”

32
33 **QUESTION:**

- 34
35 a) Please indicate whether YEC is not asking for approval to put communication
36 upgrade costs into rate base in the test years.

1 b) Please explain what precipitated the need for the above noted Communications
2 Needs Assessment. How often has YEC undertaken such an assessment in the
3 past?

4
5 c) For each of the Communications upgrades, please provide the original forecasted
6 cost of each project, and explain any variances between the original forecasted
7 costs, and the current forecasted costs that total \$1.003 million.

8
9 **ANSWER:**

10
11 **(a)**

12
13 YEC is seeking approval to put communication upgrade costs into rate base as the work
14 will be completed and in service.

15
16 **(b)**

17
18 The previous study was 5 years old at the time the current needs assessment was
19 requested. Within those 5 years, there have been significant changes in communications
20 technology and YEC recognized the need for an update on the current state of the
21 communications assets. A strategic roadmap was required in order to best allocate
22 resources to address future technologies and operational requirements.

23
24 **(c)**

25
26 There have been no cost changes from the estimates provided in the BBA assessment to
27 the YEC forecasts other than the addition of YEC internal labour to support each project.

1 **TOPIC:** Hydro Unit #WH4 Overhaul, Section 5.2.1.5

2
3 **REFERENCE:** Application, pages 5-15 to 5-16. PDF pages 186 to 187

4
5 **QUOTE:** “The Whitehorse #4 (WH4) hydro unit (20 MW installed capacity
6 commissioned in 1984) is a critical hydro generation asset to YEC. As
7 part of YEC’s on-going preventative maintenance program for hydro
8 units, a 10 Year Major Overhaul of the WH4 hydro unit is scheduled for
9 spring 2017 (from April to June) at a forecast total cost of approximately
10 \$4.3 million (\$3.7 million forecast in 2017).”

11
12 “The forecast cost in 2017 for the 10-Year Major Overhaul is
13 approximately \$1.9 million, including \$0.978 million intended to cover a
14 variety of potential contingency events ranging from overruns on key
15 contracts, significant additional “discovery” work and/or thermal
16 generation costs due to extension of schedule.

17
18 “During the 10-Year Major Overhaul process the following two
19 additional replacement activities related to the WH4 hydro unit will also
20 be undertaken as part of this project.

- 21
22 • “WH4 Rotor Spider Replacement – (\$1.439 million) – Stress
23 cracks, which required immediate and extensive repair,
24 were observed on the rotor spider during overhauls and
25 inspections performed in 2007, 2012 and 2016. The original
26 equipment manufacturer (OEM), Andritz Hydro, has
27 confirmed that the original rotor design is flawed and
28 recommended that during the next overhaul YEC install a
29 new replacement rotor spider of more durable design in
30 order to improve the long term reliability of this unit.”
31 • “WH4 Excitation Replacement – (\$0.977 million) –
32 Technical support and parts to maintain the existing
33 excitation system are becoming more difficult to procure. In
34 2014, two outages of WH4 occurred. The post-event
35 analysis of these outages resulted in a recommendation to
36 replace the WH4 excitation system. Subsequently, another

1 outage occurred on February 18, 2017 that was a direct
2 result of a failure of a component of the MH4 exciter.

3
4 “YEC has awarded a contract to Andritz Hydro (the original equipment
5 manufacturer) to install the new rotor spider and to perform the 10-Year
6 Major Overhaul. Andritz will be responsible for providing technical
7 advisory services and for overseeing the mechanical services
8 contractor performing the work.” [footnotes omitted]
9

10 **QUESTION:**

- 11
12 a) Assuming that this project has been completed, please provide the final costs and
13 explain any variances from the above-noted \$4.3 million forecast. If the project is
14 not complete, please indicate the new completion date and the reasons this project
15 was not completed as indicated in the above-noted quote.
16
17 b) Please explain what the 2016 actual costs (\$0.581 million)¹ relate to.
18
19 c) Given that the original rotor design was flawed, was any compensation from
20 Andritz Hydro pursued?
21
22 d) Please discuss the process used to award the contract to Andritz Hydro to install
23 the new rotor spider. Were other equipment manufacturers considered? What
24 factors were evaluated prior to awarding the contract?
25

26 **ANSWER:**

27
28 **(a)**

29
30 The WH4 Overhaul project was substantially completed and returned to service at June
31 28, 2017. At the time of responding to GRA IRs there are some minor deficiency activities
32 that are scheduled for completion in September 2017. The forecast cost to complete the
33 project is presented in Table 1:
34

¹ Application, Table 5.2. PDF page 224.

Table 1: WH4 Major Overhaul Costs

WH4 Major Overhaul (\$,000s)	Forecast To Complete (Aug 2017)	BOD Budget (Nov 16)	Forecast Vs. BOD Budget
Design & Supply of Spider	574	574	0
Installation & Overhaul Services	1,288	1,400	211
Owner's Engineer	285	270	(15)
Exciter System - Supply & Installation	617	703	86
YEC - Labour	370	241	(129)
YEC - Materials & Services	513	100	(413)
Contingency	-	977	977
Construction Financing	31	35	3
Project total	3,678	4,300	721

The project is forecast to be completed as scheduled and within budget. The Forecast to Complete values reflected in the table above are the expected final costs. Provisions were made within Contingency for “discovery works” that could not be determined until the unit was dismantled. The variances reported for the Installation and Overhaul, Labour, and Materials categories reflect the net effect of budgeting for, then completing, the discovery works during the project.

(b)

The 2016 actual costs (\$0.581 million) are as per Table 2:

Table 2: WH4 Overhaul Expenditures for 2016

WH4 Overhaul - Expenditures for 2016	
Fabrication of Rotor Spider	315,678
Owner Engineer Services	64,553
Supply of Exciter System	154,251
YEC – Labour	37,728
YEC - Materials & Supplies	7,190
Construction Financing (AFUDC)	1,587
Total	580,988

(c)

Compensation was not pursued. The original installation was in 1984 and the “flawed” design was only recognizable in hindsight with modern computer modelling.

1 (d)

2
3 With regard to the award of the rotor spider fabrication contract to Andritz, other equipment
4 manufacturers were considered. A significant impediment to proceeding in that direction
5 is that the OEM specifications for an improved design of the rotor would not be available
6 to a non-OEM fabricator. This would have necessitated reverse engineering of the rotor
7 design before tendering the design and fabrication. This approach would have increased
8 the risk that some minor aspect of the rotor design could be overlooked by the non-OEM
9 engineer or fabricator. To go with any contractor other than Andritz would also have
10 resulted in a longer duration to design and manufacture the rotor which would have
11 pushed the overhaul project into 2018. This timeline was not acceptable due to the
12 increased risk of a WH4 failure as the cracks on the existing rotor were getting longer
13 which once hitting a specific size would result in the unit being removed from service until
14 repairs were effected. Choosing Andritz to manufacture the rotor provided assurance the
15 project could be executed in 2017.

16
17 In regard to awarding the Installation and Overhaul contract to Andritz, the alternative
18 approach of YEC hiring multiple contractors for the overhaul still required Andritz
19 participation as a condition of the rotor warranty. YEC negotiated favorable discounted
20 rates with Andritz (20% discount) and the turn-key solution achieved efficiencies in
21 engineering and project management, and also resulted in a one year warranty on the
22 rotor installation and overhaul works performed by Andritz.

1 **TOPIC:** **Hydro Unit #MH2 Overhaul, Section 5.2.1.6**

2
3 **REFERENCE:** Application, pages 5-16 to 5-17. PDF pages 187 to 188

4
5 **QUOTE:** “The Mayo #2 (MH2) hydro unit (2.55 MW installed capacity
6 commissioned in 1952 at the Mayo A facility) was fitted with new
7 runners in 2002 and is currently rated at 2.9 MW. A 10 Year Major
8 Overhaul of the MH2 hydro unit and general facility upgrades is
9 scheduled in 2018 at a forecast total cost of \$1.655 million.”

10
11 “As reviewed in the 2016 Resource Plan (Chapter 5), a study of four
12 options for the future of the Mayo A facility was completed for Yukon
13 Energy by KGS Group in 2016 to address the fact that many
14 components in this facility were coming to end of life. A conceptual, high
15 level cost estimate and economic analysis was prepared for each
16 option (i.e., replacement, refurbishment, removal of the facility with
17 return of site to near greenfield condition, and decommissioning of the
18 facility with abandonment insitu). This study found that the optimal
19 solution in terms of the cost and energy generation would be to replace
20 the existing two units with a new single 2.3 MW unit. The 2016
21 Resource Plan action plan assumes that this Mayo Hydro
22 Refurbishment project will proceed for in-service in 2022.”

23
24 **QUESTION:**

- 25
26 a) Please explain what is meant by the “Mayo A” and “Mayo B” facility.
27
28 b) Do the planned MH2 unit upgrades have continuing value for the future planned
29 refurbishment of the Mayo A facility?
30
31 c) Please explain the operation of MH1 and MH2. Can either of the units, each with
32 an installed capacity of 2.5 MW, be operated at any one time when Mayo B is in
33 operation? Has YEC considered operation of the plan with only one of the existing
34 units, rather than replacement of both units with a 2.3 MW unit?

1 d) Respecting the 2016 Resource Plan action plan assumption that the Mayo Hydro
2 Refurbishment project will proceed for in-service in 2022, please provide the
3 expected completion date and associated costs.
4

5 **ANSWER:**
6

7 **(a)**
8

9 “Mayo A” is the original Mayo hydro facility in service since 1951; this facility contains two
10 hydro units, MH1 and MH2 with total capacity of 5.8 MW. “Mayo B” is the new hydro facility
11 completed in 2011 with two hydro units, MBH1 and MBH2 with total capacity of 10 MW.
12

13 **(b)**
14

15 Yes, this work will have continuing value. The optimal generation configuration in Mayo is
16 two Mayo B units plus one Mayo A unit. Since MH2 has been assessed as the better of
17 the two Mayo A units, YEC intends to complete a standard overhaul in 2018 in accordance
18 with established overhaul policy. Please see page 5-18, lines 4-14 for a description of
19 work that will have continuing value for the future refurbishment.
20

21 In conjunction with the MH2 overhaul, YEC will undertake a condition assessment of the
22 unit. This will determine the scope of work for the refurbishment of the facility (including
23 rebuilding MH2) and what components (if any) can be reused.
24

25 **(c)**
26

27 The Mayo B plant has higher operational efficiency than Mayo A. Therefore, for maximum
28 output, YEC runs the Mayo B plant at maximum. For higher load scenarios, there is
29 enough water available through the Wareham Lake intake to also run one unit at Mayo A
30 (attempts to run two units creates a negative pressure situation that could compromise the
31 penstock). Either of MH1 or MH2 can be operated at any one time when both Mayo B
32 units are in operation. For clarity, YEC does not anticipate installing a brand new unit in
33 2022; the focus of this work will be upgrades to peripheral systems not directly related to
34 the unit overhaul (e.g. switchgear replacement, ...) as well as upgrades to certain
35 components of MH2 to ensure it reaches a target capacity of 2.3MW. These upgrades will
36 be determined as part of the overhaul scheduled for 2018.

1 **(d)**

2
3 The Mayo Hydro Future Facility Options Concept Design Report commissioned as part of
4 the Resource Plan assessed four options for the facility and concluded that a
5 refurbishment of the facility had the greatest economic benefit. The overhaul and upgrades
6 to be performed in the test years will aid in determining the specific scope of work for the
7 refurbishment project. Project timing may also be influenced by load growth over the next
8 2-3 years, however the current forecast is for the plant to be online for the winter of 2022-
9 2023. The forecast cost for the project has not changed from the Resource Plan report
10 (\$28.6 million) and is not expected to be updated until preliminary engineering is
11 performed.

1 **TOPIC: LNG Plant, Section 5.2.1.11**

2
3 **REFERENCE:** Application, pages 5-22 to 5-26. PDF pages 193 to 197

4
5 **QUOTE:** “The LNG Plant project at the Whitehorse Thermal Generating Station
6 (WTGS) came into service July 1, 2015 with two new natural gas
7 engines (8.8 MW), provision for a third natural gas engine, and liquefied
8 natural gas (LNG) offloading, storage, vapourization and other related
9 infrastructure.”

- 10
11 • “The two natural gas-fired units (8.8 MW total capacity) were
12 anticipated to be in service before the end of Q4 2014 to provide
13 capacity and fuel cost savings during the winter of 2014/2015,
14 with an estimated capital cost (2013\$) of \$36.5 million.”

15
16 “The final completion costs for the project were approximately \$41.933
17 million. However, the net impact of the project on ratebase is
18 considerably lower due to YDC contributions of \$18.3 million that were
19 applied to the LNG project in 2015. This reduces the total project costs
20 funded by ratepayers to \$23.63 million.”

21
22 **QUESTION:**

- 23
24 a) Please provide a summary table highlighting the \$5.45-million increase in the final
25 project capital costs. Please ensure that the table shows YEC’s assertions related
26 to construction costs, engineering and management costs, owners’ costs, planning
27 and permitting, demolition and other activities on pages 5-24 to 5-26.

28
29 **ANSWER:**

30
31 **(a)**

32
33 Please see summary table below, which details these costs as provided at pages 5-24 to
34 5-26 of the Application.

1

Table 1: LNG Project – Part 3 Estimate vs. Final Costs

(\$ 000's)	Part 3 (Feb 14 Update)	Costs at Completion	Variance
Construction Contracts			-
<i>Final Tender Costs</i>	6,777	9,256	(2,479)
<i>Firewater Pump & Enclosure</i>	-	572	(572)
<i>Construction Start Delay</i>	-	560	(560)
<i>Additional Works</i>	-	446	(446)
<i>Impoundment Pit</i>	-	403	(403)
<i>Dewatering</i>	-	363	(363)
<i>Vapour Fence</i>	-	90	(90)
<i>Pilings</i>	-	45	(45)
LNG - Site Development	6,777	11,736	(4,959)
<i>Base Contract</i>	10,751	10,751	-
<i>Glycol & E-house Redesign</i>	-	318	(318)
<i>Delays in construction</i>	-	153	(153)
<i>Permitting Requirements</i>	-	60	(60)
<i>Consumables & Miscellaneous</i>	195	339	(144)
LNG Gen - Engines	10,946	11,621	(675)
LNG Plant - Equipment	6,750	6,700	50
Grid Connection	2,033	1,534	499
Contingency	1,000	-	1,000
Construction Contracts - subtotal	27,507	31,591	(4,084)
Engineering & Project Management			
Preliminary Engineering	189	250	(61)
Detailed Engineering	1,244	1,253	(9)
Redesign (Glycol & Site Layout)	-	358	(358)
Construction Support	-	223	(223)
Engineering for permitting	-	219	(219)
Procurement & QA Activities	-	101	(101)
Detailed Engineering	1,244	2,155	(911)
Project Management	1,850	1,876	(26)
Construction Management Services	-	670	(670)
Permitting Support	-	70	(70)
Project Management	1,850	2,616	(766)
Contingency	200	-	200
Engineering & PM - subtotal	3,483	5,021	(1,538)
Owner Costs			
YEC - Non Labour	1,365	1,327	38
YEC - Labour	618	1,145	(526)
AFUDC	450	577	(127)
Owners Costs - subtotal	2,433	3,049	(615)
Planning & Permitting	2,506	2,687	(182)
Demolition	553	-	553
<i>Descope Transportation Costs</i>	-	(326)	326
<i>FN Benefits (offset by YDC)</i>	-	(90)	90
Other Activities - subtotal	-	(416)	416
Total - All Costs	36,482	41,933	(5,451)

2

1 **TOPIC: LNG Third Engine, Section 5.2.1.12**

2
3 **REFERENCE:** Application, pages 5-26 to 5-27. PDF pages 197 to 198

4
5 **QUOTE:** “The LNG Third Engine project will provide a third natural gas-fired
6 generation unit at the Whitehorse thermal plant of approximately 4.4
7 MW to assist in reducing the current capacity shortfall in a cost effective
8 manner by early 2019.

9
10 “The forecast capital cost for this project is approximately \$6.2 million,
11 with \$3.04 million forecast in 2017 and \$2.7 million forecast in 2018
12 (approximately \$0.2 million was spent prior to 2017 for foundation work
13 completed in the first stage of development, and the balance of
14 approximately \$0.5 million is forecast in Q1 of 2019).

15
16 “The 2016 Resource Plan identified a dependable capacity shortfall for
17 the Yukon Integrated System under its single contingency (N-1)
18 capacity reliability criterion that approximates 6 MW in 2017, increasing
19 to 10-11 MW by 2019. Yukon Energy is required to provide sufficient
20 dependable winter capacity to meet the single contingency capacity
21 reliability criterion, i.e., there is no acceptable "do nothing" option...”

22
23 “The 2016 Resource Plan identifies construction of the LNG Third
24 Engine as one of the preferred options for addressing a portion of the
25 dependable capacity gap in a cost-effective manner in the near term,
26 i.e., for use by 2019.”

27
28 “YEC commissioned a small study in late 2016 to review options for
29 commercially available gas-fired engines to meet desired performance
30 requirements with the third LNG engine at the current LNG facility. The
31 results of the assessment will support YEC’s decision with respect to
32 the selection of the single engine or multiple engines with total installed
33 capacity of 4.4 megawatts, and confirm current costs and schedule for
34 commercially available options.

35
36 “The project to design, procure and install a third LNG engine will be
37 completed mainly during 2017 and 2018, with the engine currently

planned to be in service in Q1 2019. Other activities to be completed in 2017 include preliminary engineering, development of equipment specification documents, grid impact study, detailed engineering and procurement of long-lead equipment.”

QUESTION:

- a) Please provide updated costs to design, procure and install the third LNG engine and provide a variance analysis compared to initial forecast costs for this engine.

ANSWER:

(a)

Please see Table 1 provided below.

Table 1: LNG Third Engine Project Budget Update (\$000's)

	Initial Forecast	Updated Forecast	Variance
Engineering and Construction Management	\$520	\$491	\$(29)
Engine Package and Transportation	\$4,100	\$5,769	\$1,669
Balance of Plant Installation	\$975	\$1,372	\$397
Commissioning	\$150	\$160	\$10
YEC – Owner Costs	\$495	\$608	\$113
Contingency	\$260	\$500	\$240
Total Project Cost	\$6,500	\$8,900	\$2,400

The following is specifically noted regarding changes from the initial forecast:

- Engine Package and Transportation* - The updated budget of \$5.769M for supply and installation of the GE Jenbacher engine is based on the fixed price quotation (effectively a Class 1 estimate) provided by Gas Drive in September 2017, whereas the prior budget for this item was based on a Class 4 estimate by the owner's engineer, which was in turn based on a preliminary proposal submitted by the engine supplier in February 2017. The \$1.669M increase in costs for the engine package is largely due to the omission of key cost items from the Class 4 cost

1 estimate including installation, engineering, project management, and
2 commissioning. The owner's engineer had assumed that these items were
3 included in scope of the preliminary proposal submitted by the supplier. Additional
4 cost increases resulted from an increase in shipping costs and the inclusion of
5 spare parts and anticipated change orders in the supplier's final fixed price
6 quotation.

7

8 • *Balance of Plant* – The updated budget of \$1.372M for the Balance of Plant work
9 is based on the updated Class 3 estimate of prepared by the owner's engineer
10 (based on contractor quotations). The increase in Balance of Plant costs is driven
11 primarily by an increase Civil construction costs arising from the inclusion of
12 \$0.213M for Phase 1 foundation costs currently held in Work in Progress (not
13 included in the Stagegate 3 cost estimate), an increase in the electrical installation
14 costs, and the inclusion of a General Contractor premium management of the
15 Balance of Plant contract which was also omitted from the Stagegate 3 estimate.

16

17 • *YEC-Owner Costs* – The \$0.113M increase in Owners Costs is comprised of an
18 increase in forecast labour and the addition of construction support costs, partially
19 offset by reductions in Insurance, Permitting, and AFUDC.

20

21 • *Contingency* – a comprehensive risk-based contingency was developed for the
22 updated project cost estimate, resulting in a \$0.240M increase in the project
23 contingency.

1 **TOPIC:** Projects \$100,000 to \$1 million, Section 5.2.2

2
3 **REFERENCE:** Application, page 5-28. PDF page 199, lines 4 to 7

4
5 **QUOTE:** “Growth in net rate base reflects ongoing need to refurbish old assets
6 and improve grid reliability. Significant re-investment in existing
7 infrastructure has been undertaken since 2013 to ensure that the
8 Yukon integrated grid can continue to meet the unprecedented level of
9 growth on the system in a safe and reliable manner.”

10
11 **QUESTION:**

- 12
13 a) Please explain and provide examples of what YEC means when it refers to an
14 “unprecedented level of growth on the system” in the above quote.

15
16 **ANSWER:**

17
18 **(a)**

19
20 The sentence should be amended as follows for the current GRA: “Ongoing re-investment
21 in existing infrastructure ensures that the Yukon integrated grid can continue to meet loads
22 on the system in a safe and reliable manner.”

1 **TOPIC:** **L170 Line Access**

2
3 **REFERENCE:** **Application, Appendix 5.3, page 5.3-6. PDF page 249**

4
5 **QUOTE:** “YEC requires access to transmission lines for maintenance,
6 inspection, and brushing activities. Currently a number of temporary
7 access points are used that lack the necessary permitting and may
8 not be constructed to an acceptable standard. This project will
9 complete the required assessment process in order to obtain the
10 necessary permits for both new and existing accesses. It also
11 includes the construction of new accesses and upgrades to existing
12 ones, resulting in faster response times for emergency line work
13 and reliable access to key YEC assets.”

14
15 **PREAMBLE:** The Board notes that \$350,000 is to be spent in each of the test
16 years. Further information is required.

17
18 **QUESTION:**

- 19
20 a) Please explain who issues the permits respecting the access points. Please
21 provide a copy of a sample permit.
22
23 b) What does YEC mean when it states that this project “will complete the required
24 assessment process in order to obtain the necessary permits”?
25
26 c) Is YEC completing the assessment? Why has this not been done previously?
27
28 d) Can YEC provide examples where responses times were slow? What is the
29 comparator when YEC says “faster response times”? How long has this been a
30 problem?
31
32 e) How has YEC been able to operate in the past without the necessary permits?

1 **ANSWER:**

2
3 **(a)**

4
5 Please note that this project began in 2016 and included spending of \$350,000. A
6 presentation error occurred in the Application in Table 5.2 and Appendix 5.3. The costs
7 appear on Table 5.2 as “L170 Access Construction Between S164 and Structure 524”
8 under the General Plant & Equipment heading.

9
10 The following permits are required to build a new access point or modify an existing one:

- 11 • Construction or modification of an access – issued by Yukon Highways and Public
- 12 Works;
- 13 • Access Permit Agreement – issued by Little Salmon Carmacks First Nation;
- 14 • Forest Resources Permit – issued by Yukon Energy, Mines and Resources;
- 15 • Land Use Permit – issued by Yukon Energy, Mines and Resources.

16
17 **(b) and (c)**

18
19 In order to obtain the necessary Land Use Permit, a YESAB assessment was required
20 (see YESAB project 2016-0021). This was completed by YEC staff with the assistance of
21 a consultant to perform the heritage assessment work. The assessment was not done
22 previously as YEC had not sought to obtain a Land Use Permit.

23
24 **(d)**

25
26 In 2015 the failure of an insulator caused part of a structure to burn and require
27 replacement. As there was no existing access to this section of line, a road was
28 constructed over the course of 3 days, adding significant time to the replacement of the
29 structure.

30
31 Line access in emergency situations has typically been performed on an ad-hoc basis
32 and has been a challenge since the original construction of the WAF line. Staff have
33 regularly been required to access transmission line structures via unofficial routes that
34 often pose safety (and occasionally environmental) risks. Upon completion of this project,
35 every structure will have a designated access point that is properly constructed and avoids
36 any risk of environmental damage (water crossings, sensitive terrain, etc.).

1 **(e)**

2

3 In the past YEC would access power line right of ways through existing roads or trails
4 without permit. In 2016, as a result of investigations into brushing contractor access
5 issues, the regulator (YG) advised that permits were required for all accesses.

1 **TOPIC:** **Whitehorse-Aishihik-Faro (WAF) Transmission Upgrades**

2
3 **REFERENCE:** Application, Appendix 5.3, page 5.3-7. PDF page 250

4
5 **QUOTE:** “The WAF transmission system allows low cost hydro generation
6 supplied from Aishihik, Whitehorse, or Faro to be transmitted to other
7 locations on the grid. A failure of a transmission line structure would
8 interrupt this supply, potentially resulting in a wider grid collapse. The
9 structures on this transmission line were built in the 1960s through
10 1970s and are in various stages of deterioration. A recently performed
11 test and treat program has identified the structures that are at the
12 highest risk of failure. This project replaces the identified structures,
13 along with any end-of-life cross arms and insulators that are
14 discovered.”

15
16 **PREAMBLE:** The Board notes that \$3.068 million was spent in the period 2013 to
17 2016 (approximately \$750,000 per year). Moreover \$850,000 is to be
18 spent in each of the test years on this project.

19
20 **QUESTION:**

- 21
22 a) Considering that YEC’s test and treat program has recently identified structures
23 that are at the highest risk of failure, please indicate and explain when YEC expects
24 this project to be completed.

25
26 **ANSWER:**

27
28 **(a)**

29
30 Depending on the timing of certain stages of the work, all of the elements of this project
31 are expected to be completed in 7 – 10 years, with costs for each portion being brought
32 into rate base as it is completed. Work on L170 (Whitehorse – Carmacks) will be
33 prioritized, followed by L171 (Whitehorse – Aishihik). Once all structures and components
34 on those lines have been brought up to an acceptable standard, L178 (Carmacks – Faro)
35 will see similar work performed. Note this work differs from T&D Line Replacement which
36 is described in section 5.2.1.8 which addresses other components of these lines.

1 **TOPIC:** **Deferred costs, Section 5.3**

2
3 **REFERENCE:** Application, page 5-30. PDF page 201

4
5 **QUOTE:** “Deferred costs include feasibility studies for a wide range of projects
6 (focused mainly on potential new generation or transmission options
7 and includes the 2016 Resource Plan Update), continued relicensing
8 work (for this Application, this grouping includes water licence renewal
9 activities as well as water licence amendment projects, e.g., Mayo Lake
10 Storage Enhancement Project), regulatory work (includes DSM), and
11 dam safety review work. Overhauls, which in prior GRAs were included
12 as a separate deferred cost, are now included under PP&E capital
13 works (see Table 5.2) as per new accounting regulations.”

14
15 “The Application includes, as appendices to this section for approval by
16 the YUB, Yukon Energy’s Planning Cost Accounting Policy (Appendix
17 5.1) and DSM Accounting Policy (Appendix 5.2) to address
18 amortization of these cost for regulated revenue requirement
19 purposes.” [footnote omitted]

20
21 **QUESTION:**

22
23 a) With respect to YEC Planning Cost Accounting Policy and DSM Accounting Policy,
24 has YEC previously submitted these policies for approval?

25
26 b) If the answer to (a) is yes, please list the changes and the reasons for the change.

27
28 **ANSWER:**

29
30 **(a) and (b)**

31
32 Yukon Energy previously submitted an updated Planning Cost Accounting and a DSM
33 Accounting Policy for the Board’s review and approval as part of the 2012/13 General
34 Rate Application (see Appendix 5.1 of the 2012/13 GRA for the Planning Cost Accounting
35 Policy filed at that time; and Appendix 5.2 for the DSM Accounting Policy filed at that time).
36 The Board in Order 2013-01 noted as follows regarding the approval of these policies [as
37 applied for at that time]:

- The Board did not accept the planning cost accounting policy [see paragraph 405 of Order 2013-01]. The Board specifically noted that the Board and interveners must be given the opportunity to test the prudence of all costs incurred by YEC in respect of deferred costs "... and considered "the policy as proposed would allow the inclusion of these costs without any prior scrutiny by the Board and interveners."
- The Board deferred its findings and directions regarding YEC's DSM Accounting Policy until YEC and YECL have jointly filed a DSM plan [see paragraph 407 of Order 2013-01].

The Planning Cost Accounting policy was subsequently revised to take into consideration the concerns raised by the Board in Order 2013-01. Overall, in many cases wording was changed/ added to provide greater clarity compared to provisions included in the 2012/13 version [this applies to section 2.1 and new section 2.2]. Key changes to the policy compared to the 2012/13 version are as follows:

- **Removal of reference to "Reasonable Assurance Test":** Section 2.3 in the 2017/18 version was altered to review reference to the "Reasonable Assurance Test" for deferral of planning costs without amortization¹ that was included in the 2012/13 version of the Planning Cost Accounting Policy. Reference to this has been removed to address the Board's concerns noted in Order 2013-01.² Section 4 was added to provide greater clarity that while YEC will close out and begin amortization of studies as prescribed by the policy, all deferred costs will be subject to a prudence review by the YUB prior to any change in customer rates.
- **Insertion of new Section 2.3:** Addressing how viability of planning cost projects will be assessed on an ongoing basis.

¹ "planning costs deferred without amortization must meet a "Reasonable Assurance Test": (a) Future expenditures will not be recognized as work-in-progress assets until such time as there is reasonable assurance that a Corporation commitment to construction will be made; (b) in the event a project is abandoned after this step, accrued costs will be amortized over 10 years."

² The 2012/13 version of this provision [including the Reasonable Assurance Test] did not seek, or intend, to include in rates any deferred or other costs that had not been subject to review and approval by the Board. However, there was significant confusion regarding this element at the 2012/13 GRA which led to the amendments included in Appendix 5.1 of the 2017/18 GRA.

- **New Section 2.5:** Added to clarify how planning costs will be amortized in the event a project does not proceed. The 2012/13 version of the policy included provision for a “transition policy for 2012 & 2013 Test Years”. This was considered a “one-time” transition approach for cost in WIP at that time and intended to mitigate rate impacts from 5-year amortization of existing WIP costs for projects incurred that exceeded \$1 million. The current section 2.5 seeks to continue with this approach in order to continue to mitigate rate impacts from projects in WIP that are being closed out and that have costs in excess of \$1 million.

The only change to the DSM Accounting Policy from the version filed in the 2012/13 GRA is an edit to section 2.3 which simply notes “qualifying expenditures will be closed out on an annual basis” as opposed to the wording included in the 2012/13 version which is now deleted: “a. Over each year eligible DSM program expenditures will be deferred. (b) At the end of each year eligible deferred DSM program expenditures will be closed out and amortized over the following ten years.”

1 **TOPIC:** **Stewart Keno City Transmission Line Project, Section 5.3.1.2**

2
3 **REFERENCE:** Application, pages 5-32 to 5-33. PDF pages 203 to 204

4
5 **QUOTE:** “The Stewart Keno Transmission Line (SKTL) project will improve the
6 electrical transmission infrastructure in central Yukon between Stewart
7 Crossing and Keno City; reinforce and strengthen the grid between
8 Stewart Crossing and Mayo; and replace and remove deteriorated and
9 ‘end of life’ transmission infrastructure between Mayo and Keno City.
10 The project is being planned to ensure continued safe and reliable
11 service and to facilitate future economic development within the
12 territory.

13
14 “An initial \$5.3 million tranche of funding was provide by the Yukon
15 Government for the costs required to advance the project to a shovel
16 ready stage by Q4 2016.”

17 ...

18 “...a material component of the Project costing cannot be confirmed
19 with reasonable certainty until the Project is tendered.

20 “Detailed line design and detailed substation design contracts were
21 competitively tendered and awarded in 2016, with this work to be
22 completed in Q1 2017.

23
24 “A decision to advance the project will be undertaken once Yukon
25 Energy has confirmed the project costs and potential funding
26 availability. Yukon Energy is considering options for a staged project
27 development, with the initial stage to remove and replace deteriorated
28 and ‘end of life’ transmission infrastructure between Mayo and Keno
29 City, in the event that third party funding is not available.”

30
31 **QUESTION:**

- 32
33 a) Has YEC made any decision with respect to advancing this project? Please explain
34 any issues, problems or constraints that YEC faces in relation to the above-noted
35 project.

b) YEC states that staged development may take place and refers to an initial stage. Please describe and explain further stages related to this project.

c) Is YEC looking for 100% funding outside of the revenue requirement? Please explain.

d) Will this project require a Part 3 certificate?

e) Please confirm that no costs for the Stewart Keno City Transmission Line Project are forecast to be included in rates for the 2017 to 2018 test period. If not confirmed, please provide a detailed breakdown and explanation of the past actual costs and forecast costs from 2017 onwards for the Stewart Keno City Transmission Line Project.

ANSWER:

(a)

No decision has been made with respect to advancing this project.

The Stewart-Keno Transmission Line Project (SKTP) with extension of the 138 kV grid from Stewart Crossing to Keno City, which would materially expand the Yukon hydro grid capability to accommodate future loads as well as new resource options, is conditional today on government rather than ratepayer funding given current and potential loads to be supplied at this time.

A new line from Mayo to the Keno region, however, is required to replace the end of life existing 69 kV line constructed in the 1950s. The option is to have users in this region (mines as well as non-industrial electricity users) depend solely on local fossil fuel generation. The business case for replacement of this existing line would be strengthened by additional loads required by any major industrial customers in this region. As in the past, the required generation would be supplied by the Mayo hydro facility supplemented by generation from the southern portion of the Yukon Integrated System, and any new renewable generation on the northern portion of the grid.

Full replacement of the Mayo to Keno City line could have a material impact on rate base and therefore rates for all Yukoners. YEC is investigating different replacement

1 configurations and funding options to minimize this impact while maintaining acceptable
2 service levels to affected customers.

3
4 **(b)**

5
6 YEC is evaluating an option for full development of the SKTP in the event that government
7 funding can be secured for the full project, and options for proceeding in the event that
8 government funding cannot be secured for the full SKTP.

9
10 In this context, YEC is examining an option to replace just the Mayo-McQuesten portion
11 of the Mayo to Keno City transmission line, which is at end of life and is considered the
12 worst section of line between Mayo and Keno City. This initial step will ensure reliability of
13 service for the prospective Victoria Gold connection, while addressing the section of line
14 which is in poorest condition. This option ensures reliability of service for customers on
15 this portion of line including the prospective Victoria Gold connection, while addressing
16 the section of line which is in poorest condition. Subsequent to this initial stage of
17 development, YEC could plan the further stages of the project which would involve
18 replacing the line between McQuesten and Keno, and at some time thereafter installing a
19 new 138kV line between Stewart Crossing and Mayo. The objective of this subsequent
20 phase of the project would be to improve reliability along the whole length of line (i.e.
21 replace the McQuesten-Keno section), and increase the total transmission capacity of the
22 line in response to additional (future) industrial load and/or local renewable resource
23 supply development.

24
25 **(c)**

26
27 YEC is investigating options to secure funding for the full SKTP (or portions thereof) up to
28 100% of full revenue requirement impact. A number of Federal infrastructure programs
29 have been identified under which this project could qualify, and YEC expects to work
30 further with YDC and the Yukon government in pursuit of these options within the next six
31 months.

32
33 **(d)**

34
35 The designation as a regulated project under part 3 of the Act is the responsibility of the
36 Commissioner in Executive Council. YEC is not aware today whether the Commissioner
37 will make such a designation.

1 **(e)**

2

3 Confirmed that no costs for the SKTP are forecast to be included in rates for the 2017 to
4 2018 test period.

TOPIC: Aishihik Generating Station Water Use Licence Renewal, Section 5.3.1.2

REFERENCE: Application, pages 5-33 to 5-34. PDF pages 204 to 205

QUOTE: “A licence renewal is required for the continued operation of the 37 MW hydro facility, which provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System. Yukon Energy plans to seek a 25-year licence renewal (the maximum allowed term).

“The total budget for the project is forecast at \$3.569 million spread over five years (2015 – 2019). Total deferred costs to the end of 2018 are forecast at \$2.899 million. The last Aishihik licence renewal project cost approximately \$8.791 million.

“The licence renewal process will include undertaking environmental and socio-economic studies required to support a YESAA Project Proposal (currently targeted for a Designated Office filing in mid-2018), followed by the development and securing of a Yukon Water Board Application and an application for a Fisheries Act Authorization.”

QUESTION:

- a) Please provide a detailed breakdown and explanation of the actual costs from 2015 and 2016 and forecast costs from 2017 onwards for the Aishihik licence renewal project.
- b) Considering that the above is a five-year project, please describe and explain what has been accomplished from 2015 to date, with respect to this project.
- c) Please explain what is meant by a “Designated Office filing”.
- d) Have issues arisen as a result of working with the Champagne and Aishihik First Nations (CAFN) towards a water license use renewal? If so please explain.

1 e) Considering that YEC is almost three years into the project, are there updates to
2 the total forecast cost of \$3.569 million for this project?

3
4 **ANSWER:**

5
6 **(a)**

7
8 Table 1 provides a breakdown of the actual and forecast expenditures per spending
9 category for the Aishihik water use license renewal project. The actual expenditures for
10 2015 and 2016 are combined since the expenditures were minimal in 2015 due to a delay
11 in the project start. The delay was caused by longer than expected negotiations with the
12 Champagne and Aishihik First Nations (CAFN) related to the novel co-management
13 approach in developing the regulator submissions. The co-management approach is
14 discussed in more detailed in answer to YUB-YEC-77(b).

15
16 The total project expenditure forecast, as presented in column 2015-2019 in Table 1, is
17 based on the budget approved by YEC's Board of Directors in September 2015. As
18 discussed in more details in the answer to YUB-YEC-77(e), the 2015-2019 forecast is
19 expected to increase.

20
21 The project management costs are YEC internal costs related to the work on planning and
22 executing the project.

23
24 The CAFN and stakeholder engagement costs are related to: 1) engagement with the
25 CAFN, including funding the Champagne and Aishihik Community Advisory Committee
26 (CACAC) and traditional knowledge project, discussed in more details in the answer to
27 YUB-YEC-77(b); and 2) public engagement, discussed in more details in the answer to
28 YUB-YEC-77(b).

29
30 The Aishihik Advisory Committee (AAC) costs are related to the activities of AAC
31 discussed in more details in the answer to YUB-YEC-77(b).

32
33 The Impact assessment studies costs are related to the planning and execution of the
34 environmental and social impact assessment studies discussed in more details in the
35 answer to YUB-YEC-77(b).

The permitting process costs are related to development of: 1) the project proposal to the Yukon Environmental and Socio-economic Assessment Board (YESAB); 2) regulatory application to the Department of Fisheries and Oceans (DFO); and 3) regulatory application to the Yukon Water Board (YWB).

The CAFN compensation costs are related to: 1) the compensation to the CAFN due to the loss of use of the lake for the duration of the future water use license; and 2) negotiation costs to reach a compensation agreement with the CAFN.

Table 1: Actual and Forecast Expenditures for the Aishihik Water Use License Renewal Project

Expenses in \$'000	Actual 2015-2016	Actual Jan - Jun 2017	Forecast Jul 2017 - Dec 2019	Forecast 2015-2019
Project management	79	34	440	553
CAFN and stakeholder engagement	126	36	222	384
Aishihik Advisory Committee (AAC)	81	6	66	153
Impact assessment studies	703	426	630	1759
Permitting process			300	300
Total	989	502	1658	3149

In addition to the above forecast, YEC anticipates payment of compensation to affected lake users, however, the quantum is not known at this time.

(b)

Project accomplishments since its inception until the end of August 2017 are presented in the following categories: establishment of co-management framework; establishment and activities of the AAC; planning and execution of environmental and social impact assessment studies; public engagement; and building relationship with the CAFN. Each of those categories is discussed in the following paragraphs.

Establishment of co-management framework.

Considering the importance of the Aishihik Generating Station (AGS), the fact that the facility is located at the CAFN traditional territory, and complexities encountered during the previous water use licence renewal process due to misaligned expectations between the CAFN and YEC, YEC deemed it prudent to engage the CAFN at the beginning of the

1 current water use license renewal process. The objective of engagement was to increase
2 participation by the CAFN in the water use relicensing regulatory process, increasing
3 collaboration between YEC and CAFN and reducing the risk of conflict and/or adversarial
4 legal action during the formal regulatory proceedings. As a consequence, CAFN and YEC
5 signed the Aishihik Hydroelectric Power Generation License Renewal Co-Management
6 Protocol Agreement that provided a formal framework for the co-management of the water
7 use licence renewal process between CAFN and YEC. The document stipulates the roles
8 and responsibilities of the parties in the relicensing process, as well as the governing and
9 advisory bodies, such as the Steering Committee, AAC, and CACAC. As a part of the co-
10 management process to develop the assessment and permitting regulatory submissions,
11 CAFN set up the CACAC to provide advice on the introduction of CAFN's values and
12 traditional knowledge to the process to influence the scope and interpretation of the
13 environmental and social impact assessment studies. In the spirit of the co-management
14 agreement, YEC provided funding for the CACAC, as well as the CAFN-led traditional
15 knowledge project that will be a part of the regulatory submissions.

16
17 **Establishment and activities of AAC.**

18 Since, in addition to CAFN, the water use licence renewal process includes external
19 stakeholders, YEC also engaged the major stakeholders in the process through the AAC.
20 The AAC is co-chaired by the CAFN and YEC.

21
22 The AAC's role is to provide ongoing advice and feedback as Yukon Energy and CAFN
23 develop a project proposal targeted for submission to the Yukon Environmental and Socio-
24 economic Assessment Board (YESAB), as well as regulatory applications to the
25 Department of Fisheries and Oceans (DFO) and Yukon Water Board (YWB). In addition,
26 the AAC reconciles potential opposing interests and values of the YEC, CAFN, external
27 stakeholders, and public related to the use of Aishihik Lake.

28
29 Eight AAC meetings have been held since the beginning of the project until the beginning
30 of August 2017, and all the major project activities have been proposed, discussed and
31 approved at AAC meetings.

32
33 The activities of the AAC included:

- 34
35 1. Consideration of the Federal and Yukon Government policies and regulations
36 related to the water use license renewal process;

2. Building a common understanding of inputs, analysis methodologies, and deliverables related to the water use license renewal process;
3. Development of potential AGS operational alternatives;
4. Identification of potential information gaps to define required environmental and social impact assessment studies and their scopes, impact assessment planning, mitigation and monitoring plans;
5. Development of the list of the environmental and social impact assessment studies required for the regulatory submissions;
6. Development of the list of valued components to be used to evaluate operational alternatives; and
7. Preliminary evaluation of the operational alternatives.

Planning and execution of environmental and social impact assessment studies.

As a consequence of the AAC activities, environmental and social impact assessment studies are being executed. To inform the execution of the impact assessment studies, three technical groups were established to execute the decisions made by the AAC. The activities of the technical groups are related to lake issues, downstream river issues and the traditional knowledge project, all of which create a base for development of the documents needed for the regulatory submissions. The technical groups consist of members from YEC, CAFN, and subject matter experts.

Public engagement.

As a part of the public engagement strategy, two public meetings, one in Whitehorse, another in Haines Junction, were jointly planned, organized and held by YEC and CAFN. The goal of the meetings was to inform public on the objectives and progress of the project, co-management process and to solicit feedback.

Building relationship with the CAFN.

In addition to joint YEC and CAFN activities discussed in paragraphs on establishment of co-management framework, establishment and activities of AAC, planning and execution of environmental and social impact assessment studies, and public engagement, as a part of building relationship with the CAFN, YEC participated in two culture camps organized by the CAFN. The objective of the participation was to familiarize with CAFN values related to water, land and fish.

1 **(c)**

2
3 A 'Designated Office Filing' refers to a project proposal submitted to a Designated Office
4 for an assessment pursuant to the Yukon Environmental and Socio-economic Assessment
5 Act (YESAA). In this case, the Haines Junction Designated Office is expected to conduct
6 the project evaluation. This level of assessment differs from a project proposal required to
7 be submitted to the more intensive Executive Committee Screening or Panel Review
8 processes of Yukon Environmental and Socio-Economic Assessment Board.

9
10 **(d)**

11
12 Please refer to the answer to YUB-YEC-77(b) for details related to relationship with the
13 CAFN.

14
15 **(e)**

16
17 Largely due to the known increased quantum and scope of the impact assessment studies
18 required for the project proposal to YESAB, as well as the funding of the CACAC and
19 CAFN traditional knowledge project, the project is expected to exceed the initial budget of
20 \$3.569 million. Due to unknown costs related to potential increase in the scope of
21 regulatory proceedings, and compensation to the CAFN, the final project cost cannot be
22 accurately estimated at this time. YEC will continue to monitor the development of costs
23 related to unknowns and adjust the budget accordingly.

1 **TOPIC:** **Battery Project – Energy Storage System, Section 5.3.1.3**

2
3 **REFERENCE:** Application, pages 5-34 to 5-36. PDF pages 205 to 207

4
5 **QUOTE:** “The Battery project will provide a Battery Energy Storage System
6 (BESS) to assist in addressing the current dependable capacity
7 shortfall in a cost-effective manner by 2020.”

8
9 “Depending on the option selected, the TGS [TransGrid Solutions Inc.]
10 study indicates forecast costs for the Battery project between \$21.7 and
11 \$27.4 million (including costs for planning, permitting and construction)
12 for an initial 15 to 20 year life, after which a replacement battery is
13 estimated to cost between \$17.4 and \$22.1 million (2016\$).”

14
15 **PREAMBLE:** The Board notes that “Completion of environmental and socio-
16 economic base line studies, stakeholder engagement and consultation,
17 preliminary engineering, grid impact study followed by a Stagegate 3
18 project review in the 4th quarter of 2017”¹ were to be undertaken in
19 2017.

20
21 **QUESTION:**

- 22
23 a) Please provide a copy of the TransGrid Solutions Inc. Study.
24
25 b) Can YEC provide examples of utilities, in particular northern utilities, which have
26 employed battery energy storage systems to address dependable capacity
27 shortfall?
28
29 c) Are there limitations, such as limitations related to charging of the batteries, with
30 respect to the use of the battery storage systems? Please explain.
31
32 d) Please provide a detailed year-by-year breakdown, with explanations, of the
33 forecast costs for the battery project.

¹ Application, page 5-36, PDF page 207, lines 10-13.

1 e) Please indicate what has been undertaken to date in relation to the steps identified
2 in the preamble of this question.

3
4 f) Please explain what is meant by a “Stagegate 3 project review.”

5
6 **ANSWER:**

7
8 **(a)**

9
10 The TransGrid Solutions Inc. study can be found on the 2016 Resource Plan website at
11 the link below.

12
13 [http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_o](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf)
14 [f_Energy_Storage_Technologies_\(Transgrid_Solutions_2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf).

15
16 **(b)**

17
18 Yukon Energy is not aware of a northern utility using an energy storage system for electric
19 supply capacity or energy time shift. Examples of energy storage systems used for electric
20 supply capacity, energy time shift or any other usage worldwide can be found on the US
21 Department of Energy Global Energy Storage Database.

22
23 **(c)**

24
25 The project is in early stages of its development. As Yukon Energy completes the planned
26 activities leading up to Stagegate 3, it will investigate operational limitations associated
27 with energy storage systems.

28
29 **(d)**

30
31 Forecast year-by-year costs for the Energy Storage System project are provided in the
32 table below. The costs assume that the 4MW/40MWh Lead-Acid option is chosen;
33 however, work to be completed during the test years will confirm ESS size and technology.
34 The forecast costs are subject to change as the project definition evolves.

Table 1: Forecast Energy Storage System Costs

Costs (\$000)	2017	2018	2019
Preliminary Engineering	\$ 375	\$ -	\$ -
Assessment & Permitting	\$ 100	\$ -	\$ -
Consultation	\$ 25	\$ 25	\$ -
YESAA Review	\$ -	\$ 50	\$ -
Regulatory Authorizations	\$ -	\$ 415	\$ -
Detailed Engineering	\$ -	\$ 2,000	\$ -
Procurement, Construction & Commissioning	\$ -	\$ 5,866	\$ 13,852
Total	\$ 500	\$ 8,356	\$ 13,852

(e)

As of the end of August 2017, YEC has completed internal work on the Energy Storage System Project. Specifically, an updated schedule leading up to the Stagegate 3 project review was prepared and scope of work for the system impact study, preliminary engineering and environmental and socio-economic base line studies were developed.

(f)

YEC uses a Stagegate Project Development Framework (Application, page 5.1-3. PDF, page 240. Appendix 5.1 Planning Cost Accounting Policy) to advance major projects from early planning to commissioning. This approach requires a review of the project by the Board of Directors at each decision point referred to as “Stagegate”. “Stagegate 3” is a Board of Directors review and go/no go decision based on preliminary engineering, socio-economic and environmental assessments, First Nation engagement and public engagement, and defining of a procurement strategy.

For the Energy Storage System, Yukon Energy, as part of the planned activities for the 2017 and 2018 test years, would complete environmental and socio-economic base line studies, stakeholder engagement and consultation, preliminary engineering, and a grid impact study. These studies would provide YEC with an updated business case, schedule and risk register for review by the YEC Board of Directors. A decision to continue advancement or cease further spending on the project would be done as part of the “Stagegate 3 project review”. Planned work is subject to approval of YEC’s overall capital plan and associated access to the necessary debt financing.

1 **TOPIC:** Thermal Plant, Section 5.3.1.4

2
3 **REFERENCE:** Application, pages 5-36 to 5-39. PDF pages 207 to 210

4
5 **QUOTE:** “The Thermal Plant project will provide up to 20 MW of new diesel
6 or natural gas thermal generation capacity to assist in addressing
7 the current dependable capacity shortfall in a cost-effective
8 manner by 2021. Forecast spending during 2017 and 2018 is on
9 planning, preliminary engineering, environmental permitting, and
10 the start of detailed design for this project.”

- 11
12 • “Planning for the 20 MW Diesel Plant option for in-service by
13 2021 involves the following schedule and budget:
14 ○ “2017: Completion of environmental and socio-economic
15 baseline studies, stakeholder engagement and
16 consultation, preliminary engineering and grid impact study
17 (\$0.75 million).
18 ○ “2018: Stagegate 3 project review in the first quarter of
19 2018; subject to the project successfully passing the
20 Stagegate 3 review, followed by the submission of a YESAB
21 proposal, start of detailed design and procurement of long-
22 lead equipment near end of year (\$3.46 million).
23 ○ “2019: Permitting, procurement and start of construction
24 (\$38 million).
25 ○ “2020: Construction and commissioning (\$20.1 million).
26

27 “In addition, the 2017 work plan for the Thermal Plant project will
28 include a final review of all new fossil fuel thermal generation
29 options as required for proceeding on a timely basis ... One of the
30 options to be considered will be a greenfield LNG option with third
31 party gas supply; with LNG storage managed by others, it is
32 possible this option could result in low enough CAPEX to enable
33 use of natural gas in a greenfield facility.

34 “Specifically, the 2017 work will review options to refurbish the
35 existing Whitehorse thermal plant as discussed in YEC's 2013/14
36 Part 3 Application and YUB hearing for the Diesel to Natural Gas
37 Conversion Project (initial LNG Project).”

QUESTION:

a) Please confirm that no costs for the thermal plant project are forecast to be included in rates for the 2017 to 2018 test period. If not confirmed, please provide a detailed breakdown and explanation of the past actual costs and forecast costs from 2017 onwards for the thermal plant project.

b) With respect to the above, has YEC determined whether it will proceed with diesel or natural gas thermal generation capacity to address the current dependable capacity shortfall.

c) Please explain what YEC has learned from its review of the options to refurbish the existing Whitehorse thermal plant that informs its answer to (b).

ANSWER:

(a)

Confirmed.

(b) and (c)

At this time, YEC has not made any decision regarding the primary fuel of the potential thermal plant facility. Since completing the 2016 Resource Plan, YEC was made aware of the potential development of an LNG depot near Whitehorse. The availability of local LNG storage would enable the removal of the storage and processing facilities from the scope of a greenfield thermal plant. Consequently, it could make a new natural gas fired generating plant financially more attractive and bring its capital cost and Levelized Cost of Capacity close to that of a greenfield diesel plant. Part of the planned activities for 2017 and 2018 will assess the impact of removing the LNG storage and processing equipment from the scope of the plant and its impact on the business case.

There are two other options being studied for this new generation in conjunction with the LNG alternative above:

- A greenfield, diesel fired thermal plant at an alternate site within the City of Whitehorse; and

- 1 • YEC will further study the option of removing the two retired Mirrlees engines and
2 a third engine nearing end of life, and replacing them with dual-fuel engines at its
3 existing Whitehorse thermal plant. Since the original BBA study (2013) excluded
4 certain aspects of the plant retrofit, the new study aims at updating and building
5 upon the work completed in 2013 to reduce remaining uncertainties.

6

7 All options will be evaluated as part of YEC's Stagegate process where a decision whether
8 to cease activities or to pursue a specific option for further development will be made.

1 **TOPIC:** **Demand Side Management, Section 5.3.1.5**

2
3 **REFERENCE:** Application, pages 5-39 to 5-41. PDF pages 210 to 212

4
5 **QUOTE:** **“inCharge Program Development and Delivery**

6 “Beginning in 2010, Yukon Energy, in partnership with AEY and in
7 consultation with stakeholders, developed a Five Year Demand
8 Side Management Plan for the Yukon (the Plan).”

9
10 “The programs ... are very beneficial to the participants of the
11 program and the utilities, who are the administrators of the
12 programs.”

13
14 “Yukon Energy plans to continue the delivery of the approved
15 inCharge program for the test years. Funding as proposed for 2017
16 and 2018 reflects that AEY has chosen to discontinue partnership
17 in program delivery resulting in YEC carrying the full cost of these
18 programs.

19
20 “The net cost of conducting initial research into potential for
21 electricity conservation programming, designing the DSM Plan, in
22 consultation with stakeholders and delivering the inCharge program
23 until the end of 2016 was \$1.291 million. The costs for continuing
24 delivery of the inCharge program in 2017 and 2018 are \$0.190
25 million and \$0.290 million for 2018.

26
27 **“New Program Development**

28 “The 2016 Resource Plan recommends that additional DSM
29 programs are a cost effective way to meet energy and capacity
30 demands and should be included in the proposed future portfolio of
31 energy supply projects. These additional DSM programs must be
32 designed prior to submission to the YUB for approval. To have
33 sufficient Yukon-specific data to use in program design, YEC plans
34 to develop residential and commercial customer end use surveys to
35 be conducted by Yukon Bureau of Statistics.”

1 “Using the End-Use Survey data, Capacity DSM Feasibility Study
2 and updated CPR model, the next step will be to design a suite of
3 new DSM programs to complement the existing inCharge program.”
4

5 “The cost of new program development will be \$0.190 million in
6 2018.”
7

8 **“Pilot DSM Projects**

9 “The learnings from these pilots helped to lay the groundwork for
10 the launch of the inCharge program and build capacity within Yukon
11 Energy to administer DSM programs ... Yukon Energy plans to
12 continue to [contribute] to the Yukon Government’s commercial
13 lighting program in 2018.”
14

15 **QUESTION:**
16

- 17 a) Please explain what subsidies are provided through YEC’s DSM program
18 and those provided by the Yukon Government DSM program. Is there an
19 overlap between the two subsidy programs?
20
- 21 b) Please explain YEC’s statement that “DSM programs are a cost effective way
22 to meet energy and capacity demands.” Does this statement apply to all YEC
23 customers or to participants of the program?
24
- 25 c) Please provide YEC’s rationale for its submission that DSM programs are
26 beneficial to the participants of the program and the participating utilities.
27
- 28 d) Please explain how the benefit/cost ratios provided in figure 5.1 are
29 calculated.
30
- 31 e) Please provide figure 5.1 in Excel format with all formulas intact.
32
- 33 f) Please provide a table outlining the annual expenditures (i.e. conducting
34 initial research into potential for electricity conservation programming,
35 designing the DSM Plan, in consultation with stakeholders and delivering the
36 inCharge program) until the end of 2016. In the same table outline the costs
37 included in the continuing delivery of the inCharge program for the test years.

1 g) With respect to new program development and considering YEC's
2 experience, does YEC have any preliminary thoughts as to new programs
3 that may be developed?
4

5 h) Please confirm that the cost of new program development is a deferred costs,
6 which YEC will bring before the Board for approval in its next GRA. Is YEC
7 willing to take the risk that expenses may be denied?
8

9 i) Please explain what YEC means when it states that it "plans to continue to
10 contribute to the Yukon Government's commercial lighting program in 2018."
11

12 **ANSWER:**

13
14 **(a)**
15

16 The following subsidies are provided to homeowners by YEC's inCharge DSM Program:
17

- 18 • Up to \$7 per bulb or lamp on ENERGY STAR® LED bulbs and lamps;
- 19 • Up to \$10 on mechanical block heater timers; and
- 20 • A free energy saving kit that include two LED bulbs, one block heater timer and
21 one smart power bar.
22

23 The following subsidies are provided to homeowners by the Yukon Government's Good
24 Energy DSM Program:
25

- 26 • \$100 to \$250 on a home energy assessment;
- 27 • \$50 per old refrigerator retired, as well as free pick-up and landfill tipping fees;
- 28 • \$100 on ENERGY STAR® washers, refrigerators, freezers, dishwashers and
29 ventless dryers;
- 30 • \$300 to \$1,500 on various energy efficiency home heating systems;
- 31 • Up to \$1,200 on solar domestic hot water heating systems and \$150 on drain water
32 heat recovery systems;
- 33 • \$65 on EPA WaterSense® toilets;
- 34 • \$500 on Heat Recovery Ventilators;
- 35 • \$100 on ENERGY STAR® Zone 3 windows and doors;

- Up to \$2,000 for basic insulation upgrades and up to \$10,000 for high performance insulation upgrades to homes;
- Up to \$10,000 for super-insulated new homes; and
- A free energy saving kit that includes window film, a CFL bulb, a water saving showerhead, a bathroom faucet aerator, a fridge/freezer thermometer, kitchen faucet tap aerator, a shower timer, a hot water gauge, LED night light, Teflon tape for plumbing installations and weather stripping.

The following subsidies are provided to business owners by the Yukon Governments Commercial Energy Incentive Program:

- Up to \$10,000 on LED lighting and lighting controls; and
- Up to \$50,000 on thermal enclosure upgrades.

The Yukon Housing Corporation's Home Repair Loan program allows homeowners to borrow up to \$50,000 at a low interest rate to improve the quality of their homes with energy efficiency upgrades being one of the eligible upgrades.

The only overlap in DSM program subsidies offered from YEC through inCharge and the Yukon Government is the inclusion of an energy efficient light bulb in both the Good Energy and inCharge free energy saving kits. In the design of the inCharge program, care was taken to ensure programs complimented already existing programs.

(b)

DSM programs reduce the amount of electricity customers use and/or shift the timing of when customers need power. Instead of delivering new electricity supply, DSM focuses on changing the demand for electricity as a way of ensuring that the utility is able to meet future load requirements, either replacing the need for, or deferring, the construction of new supply projects. In this way, all Yukon ratepayers benefit from avoiding higher cost new supply at the current time.

At the resource planning stage, to analyze if DSM programs are a cost effective way to help meet electrical and capacity needs, the cost of conserved energy and cost of peak reduction of DSM measures is compared to the levelized cost of energy and levelized cost of capacity of supply projects. During the program design process, the four industry best practice benefit-cost ratios are analyzed. This is a method of analyzing the balance of

1 benefits to costs from a DSM program for various stakeholder groups. In general, the Total
2 Resource Cost (TRC) Test demonstrates the benefit, or detriment, of DSM to the cost of
3 electricity in the service territory. The Participant Cost (PC) Test demonstrates the overall
4 benefit, or detriment, to customers participating in the DSM program. These benefit-cost
5 ratios are used as a design tool to design cost-effective programs.

6
7 **(c)**

8
9 The benefit-cost ratios calculated for the inCharge program and presented in Figure 5.1
10 of the 2017-2018 GRA are an industry best practice method of analyzing the balance of
11 benefits to costs from a DSM program for various stakeholder groups. A ratio greater than
12 1.0 indicates a net benefit. The RIM and TRC both met this objective at 1.1 and 3.1
13 respectively. As well, the results of the Participant Cost (PC) ratio and Program Administer
14 Cost (PAC) ratio results were 3.0 and 9.4 respectively, indicating that the inCharge
15 program is beneficial to both participants and the utilities as program administrator.

16
17 **(d)**

18
19 The benefit/cost ratios are calculated using a proprietary, customized, mathematical
20 model developed by ICF Marbek for the inCharge program. This model is a complex Excel
21 based file that includes multiple project inputs and assumptions. The calculations of the
22 individual benefit-cost tests for each measure originally proposed for the inCharge
23 program was presented in Appendix D of the 2013 Demand Side Management Program
24 Portfolio. The model incorporates individual measure calculations, such as a program
25 uptake, and costs to generate the overall program benefit-cost ratios. ICF Marbek
26 discussed the cost/benefit ratios, also referred to as cost-effectiveness tests, in section
27 1.2 of the 2013 Demand Side Management Program Portfolio as follows “The cost
28 effectiveness results that are presented in this report are consistent with industry best
29 practices and are based on the methods outlined in the California Standard Practice
30 Manual. The four standard tests used were originally developed by the California Public
31 Utilities Commission (CPUC) and defined by the California Standard Practice Manual.”

32
33 The cost-benefit analysis was reviewed and approved by an independent evaluation
34 advisor, Econoler, as part of the 2015-2016 inCharge Evaluation Report. Please see
35 YUB-YEC-1-80 Attachment 1.

(e)

As discussed in (d) above, Figure 5.1 was generated using a proprietary, customized, Excel based model developed by ICF Marbek for the inCharge program. As discussed in (d), the cost benefit analysis was reviewed and approved by an independent evaluation advisor, Econoler, as part of the 2015-2016 inCharge Evaluation Report.

(f)

Please See Table 1 below.¹

Table 1: Annual DSM Expenditures: 2011 (Actual) to 2018 (Forecast)

	2011	2012	2013	2014	2015	2016	2017	2018
inCharge Program Development and Delivery	\$ 427,188	\$ 135,557	\$ 91,337	\$ 220,022	\$ 157,453	\$ 259,080	\$ 190,000	\$ 290,000
Industrial DSM	\$ 23,766	\$ 3,314	\$ 48,847	\$ 2,573	\$ 1,608	\$ 1,569		
Pilot DSM Projects	\$ -	\$ -	\$ -	\$ 8,155	\$ 17,891	\$ 24,806		\$ 20,000
LED Streetlight Retrofits	\$ 61,525	\$ 11,897	\$ 51,274	\$ 12,701	\$ 81,246	\$ 91,130		\$ 80,000
Internal Energy Conservation	\$ 121,301	\$ 58,748	\$ 142,493	\$ 18,950	\$ 6,053	\$ 5,905		\$ 25,000
Administration		\$ 70,503	\$ 179,385	\$ 93,349	\$ 34,567	\$ 19,680	\$ 20,000	\$ 20,000
New Program Development								\$ 190,000

(g)

Yukon Energy has not completed any preliminary design of new programs. The Conservation Potential Review, which had key sections updated as part of the 2016 Resource Plan, will be used as the basis for identifying the potential savings and costs that can be achieved using DSM. As indicated in the Application (page 5-41 ll 3-5), YEC recognizes the challenges with capacity growth on the system; as part of program design, YEC will conduct the necessary studies to quantify what the conservation potential is and what programs could be introduced to achieve these savings.

(h)

Confirmed; similar to the program approved by the regulator as part of the AEY 2013/15 GRA, YEC would invest in program design in advance of review by the regulator. As described in the Application (page 5-43, line 15), Yukon Energy currently intends to file with the YUB in advance of program delivery.

¹ An error in the allocation of contributions was made. It was assumed that a contribution was used prior to 2013, however, it was used from 2011 to 2014. This correction has no impact to revenue requirements or rates.

1 **(i)**

2

3 Yukon Energy contributed to the Yukon Government's Energy Solutions Centre LED
4 Lighting Upgrade for Commercial Buildings Rebate program in 2016. These contributions
5 were not continued in 2017, however, YEC plans to continue contributions to the LED
6 Lighting Upgrade program in 2018.



MEMORANDUM

To: Stephanie Whitehead, Energy Conservation Advisor, Yukon Energy Corporation
From: Marie Couture-Roy, Director – Program Evaluation, Econoler
Date: October 25, 2016

Subject: Approval of the 2015-2016 inCharge Evaluation Report

Econoler was retained by the Yukon Energy Corporation (YEC) to act as an independent evaluation advisor for the 2015-2016 evaluation of its DSM program portfolio. Econoler worked with the Energy Conservation team to deliver high-quality and high-level evaluation of industry standards for the inCharge program.

The scope of work of the assignment was to provide general advice and support for the evaluation, as well as to review the evaluation work plan, data collection instruments, cost-benefit analysis and savings calculations. At the end of this process, the 2015-2016 inCharge evaluation report was submitted to Econoler for review.

Ms. Marie Couture-Roy, team leader for this assignment, confirms that Econoler has reviewed and approved the final 2015-2016 inCharge evaluation report submitted on October 25, 2016.

Sincerely,

Marie Couture-Roy
Director – Program Evaluation
Econoler

1 **TOPIC:** **LED Streetlight Retrofits**

2
3 **REFERENCE:** **Application, page 5-42. PDF page 213, lines 10 to 16**

4
5 **QUOTE:** “In 2015, Yukon Energy decided to move forward with the retrofit of
6 their streetlight assets with LEDs [light-emitting diodes]. A
7 consultant was retained to develop a technical specification that
8 was used in a competitive bidding process. Streetlights in
9 downtown Dawson and Mayo were retrofit in 2016 with plans to
10 retrofit the remaining streetlights in Faro, Mendenhall and
11 Champagne in 2018.

12
13 “The net cost of piloting LED streetlights to 2016 is \$0.142 million
14 and the cost for retrofitting the streetlights in Dawson and Mayo with
15 LEDs in 2016 was \$0.168 million. The cost of completing the
16 retrofits will be \$0.080 million in 2018.”

17
18 **PREAMBLE:** The Board in Board Order 2017-01 (page 57) set out the following:
19 ... the initial light asset cost was contributed by the customer
20 when the light was originally installed in accordance with the
21 approved Terms and Conditions of Service at the time. At the
22 end of useful life when the asset needs replacement the
23 customer is not required to contribute again and the cost
24 becomes a system cost.

25
26 292. Accordingly, the Board directs that all capital costs associated
27 with the end-of-life streetlight conversions be treated as a system
28 cost.

29
30 293. With respect to LED streetlight installations that are not end-
31 of-life conversions, the Board directs AEY to treat the costs related
32 to new installations or requested conversions as capital costs that
33 attract a full customer contribution in aid of construction. [footnotes
34 omitted]

1 **QUESTION:**

2
3 a) With respect to the retrofit of streetlight assets with LED assets prior to their end-
4 of-life, in consideration of the Board's findings in Board Order 2017-01, who should
5 be bearing the costs of retrofitting the streetlights in Dawson and Mayo with LEDs?
6 Please explain fully.

7
8 b) If assets are removed before their end-of-life, who should bear the costs of
9 premature removal?

10
11 **ANSWER:**

12
13 **(a) and (b)**

14
15 With respect to YEC projects to replace streetlights in its franchise area, the utility intended
16 to absorb any existing rate base costs for existing lamp fixtures. This decision was based
17 on the assessment of the vintage of the streetlight asset pool as well as the relatively small
18 size of this asset grouping relative to YEC's total portfolio. Based on a review of asset
19 depreciation records, YEC determined that most of the streetlights in its fleet were at or
20 near end of life. For example, with respect to Dawson, YEC estimated that the value of
21 streetlight fixtures was <\$1,000 in total (lamp head only, not including pole, wiring, civil
22 works etc; approximately 200 lights in service). No further action was taken and the
23 application essentially requests that the system pay for the installed cost of the
24 replacement LED streetlights.

1 **TOPIC: Administration**

2
3 **REFERENCE:** Application, page 5-43. PDF page 214, lines 16 to 17

4
5 **QUOTE:** "Pursuant to the DSM [demand side management] Accounting Policy
6 provided in Appendix 5.2, project related DSM costs are proposed to
7 be closed out and amortized each year over a ten year period."
8

9 **PREAMBLE:** Per YEC's DSM Policy (Appendix 5.2), the Board notes YEC's
10 assertion that the following DSM-related costs shall be expensed as
11 incurred:

- 12 a. Administrative and other general overhead expenditures are
13 expensed unless the expenditure can be directly attributed to a
14 specific DSM program.
15 b. Expenditures related to information programs and advertising
16 unless directly attributed to a specific DSM program.
17 c. Expenditures on training staff shall be expensed.
18

19 **QUESTION:**

- 20
21 a) Please explain YEC's rationale underpinning its proposal related to expensing
22 DSM-related costs as they are incurred.
23
24 b) With respect to its proposal, please explain what opportunity is there for the Board
25 and interveners to review these expenses and how will Board approval of these
26 expenses be sought?
27

28 **ANSWER:**

29
30 **(a) and (b)**

31
32 Prior to any deferred costs being included in rates they will need to be reviewed by the
33 Board and intervenors as part of a General Rate Application.
34

35 This policy addresses only the accounting treatment for DSM costs. Yukon Energy
36 recognizes that in keeping with standard regulatory processes, it is required to file an
37 application with the YUB any time it seeks to adjust rates due to changes in its revenue

- 1 requirement. Any DSM costs not previously approved by the Board to be included in rates
- 2 would be subject to review by the Board and would need to be approved as part of YEC's
- 3 revenue requirement before they could be included in rates.

1 **TOPIC:** **Resource Plan Update, Section 5.3.1.6**

2
3 **REFERENCE:** **Application, pages 5-43 to 5-44. PDF pages 214 to 215**

4
5 **QUOTE:** "In late 2005, Yukon Energy completed a 20-year Resource Plan
6 for the years 2006-2025 and the Yukon Utilities Board
7 recommended that YEC file an update to its resource plan within
8 five years.

9 • "An update was undertaken in 2011 covering the period
10 from 2011 to 2030."

11 • "A second update to the 20-Year Resource Plan was
12 undertaken starting in 2015 and 2016 to address planning
13 requirements for the period from 2016 to 2035."

14 "The 2016 Resource Plan update is forecast to cost \$2.004 million
15 and will be completed in 2017."

16 ...

17
18 "The 2016 Resource Plan document is provided for references as
19 Volume 2 of this filing (absent the Appendices). The 2016 Resource
20 Plan Appendices are available on Yukon Energy's website at the
21 following link: <http://resourceplan.yukonenergy.ca/more/>."

22
23 **QUESTION:**

24
25 (a) Please indicate if the 2016 Resource Plan update filed in this application is the
26 complete update referred to in the above quote. If not, when does YEC expect to
27 complete the update?

28
29 (b) What was the final cost of YEC's first update to the 20-Year Resource Plan?

30
31 (c) Please compare final costs of the second update with the first update and explain
32 variances.

1 (d) Please summarize and explain significant findings of the second update which
2 have arisen since YEC filed its first update, and explain the reasons for any
3 variances which may have risen in respect to the following:

4 i.) Assessment of available resource options for analysis by assigning
5 technical, financial, environmental and socio-economic attributes;

6 ii.) Development of a preferred resource portfolio for the short and long term
7 as well as some contingency portfolio options;

8 iii.) Documentation of external risks and uncertainties and how they could
9 impact preferred options;

10 iv.) Generation of a short-term (five-year), long-term (20-year) and contingency
11 action plan for YEC to act upon in its resource planning activities.
12

13 (e) Please provide the 2016 Resource Plan Appendices which YEC refers to in the
14 above quote.
15

16 **ANSWER:**
17

18 **(a)**
19

20 The 2016 Resource Plan update filed as volume 2 in this Application is the complete
21 update.
22

23 **(b)**
24

25 The final cost of the 2011 Resource Plan update was \$978,388 [see Tab 5, Table 5.3
26 which shows \$740,164 closed in 2013 and amortized over five years; and Table 5.7 which
27 shows \$238,223 in WIP (\$219,615 of this was in WIP at end of 2013) that was closed in
28 2017].
29

30 **(c)**
31

32 The 2016 Resource Plan update cost is approximately \$2.0 million (Application, section
33 5.3.1.6), which compares with the 2011 Resource Plan update cost of approximately \$1.0
34 million.
35

36 Each of these updates included updating grid load forecasts, updating estimates of system
37 energy and capacity capability, and assessments of available resource options to address

1 relevant potential load scenario requirements. As reviewed in section 1.6.1.5 of the 2016
2 Resource Plan, the two updates used similar methodologies with the objective of
3 minimizing the present value of all system expenditures while meeting energy and
4 capacity planning criteria.

5
6 The 2016 Resource Plan update included several added features compared with the 2011
7 update, including:

- 8
9 • Established models were specifically applied to the Yukon for assessing load
10 forecast scenarios, with development of more detailed assessments presented in
11 separate appendices.
12
- 13 • A wide range of resource options were separately examined in a number of
14 different consultant reports, presented in separate appendices. In many cases,
15 options for a specific technology were examined for several different sites and also
16 at many different scales of development, using standard methods for assessing
17 levelized costs for energy and capacity.
18
- 19 • An industry-standard capacity expansion optimization model was used for the
20 portfolio analysis of resource options and financial assessments of options which
21 enabled evaluation of a much larger number of potential combinations (portfolios).
22 • A Social Cost of Carbon (SCC) was applied to the economics of resources.
23
- 24 • An environmental, social and economic evaluation was prepared for the full range
25 of resource options and presented in a separate appendix report.
26
- 27 • The 2016 update included a more extensive public engagement process than had
28 occurred with the 2011 update.
29

30 In comparing costs for the two updates it is noted that the 2011 update costs do not reflect
31 the extensive separate and concurrent consultant assessments then carried out for a
32 range of specific resource options (these separate study costs were reviewed during the
33 2012/13 YEC GRA); in contrast, scaled down versions of similar assessments were
34 addressed in the costs directly reported for the 2016 update.

1 (d)

2
3 A detailed comparison of the 2011 and 2016 Resource Plans in terms of planning
4 principles and methodology key input assumptions and conclusions and
5 recommendations is discussed in Section 1.6 of the 2016 Resource Plan. Specifically,
6 Section 1.6.3.1 documents the major findings of the 2016 Resource Plan and contrasts
7 with the 2011 update. In summary, the findings are as follows:
8

- 9 • YEC currently needs new capacity to meet requirements under the N-1 criterion and
10 without remedial measures the capacity shortfall is expected to increase each year.
11 Given the lead time in constructing new resources, the expected electricity demand
12 under all load cases is expected to exceed YECs generating capacity until the year
13 2021. The 2006 and 2011 Resource Plans each identified a need for new future
14 resources, but neither of these resource plans faced the capacity shortfall immanency
15 as that identified in the 2016 Resource Plan.
16
- 17 • The 2016 Load Forecast identified an expected long-term flat-line in peak demand
18 and decline in energy load after about 2030. This trend was not identified in either the
19 2006 or 2011 Plans.
20
- 21 • Both the 2016 and 2011 Resource Plans identified industrial (specifically mining)
22 electricity demand as a key uncertainty facing YEC, and that this potentiality was the
23 primary theme of the load sensitivities/scenarios undertaken. One new mining load
24 could increase YEC electricity demand by 25% or more.
25
- 26 • Both the 2016 and 2011 Resource Plans highlighted the need for flexibility within an
27 uncertain future, particularly due to the continued need to consider potential new mine
28 loads that would not be sustained to the end of the 20-year planning horizon.
29
- 30 • The 2016 Resource Plan recommended both Short and Long Term Action Plans,
31 while the 2011 Resource Plan recommended Near Term and Longer Term resources
32 planning.
33

34 To summarize, these findings were influenced by the added features noted in part (c)
35 above as well as by other factors such as updates to existing unit capabilities and
36 expected retirement dates [which would impact the dependable capacity requirements],
37 load forecast updates and updated information regarding each of the resource options/
38 technologies considered. The following is specifically noted regarding specific features of
39 the 2016 Resource Plan:

- **Load forecasting methodology** - The 2016 Resource Plan load forecast used a more sophisticated econometric approach that integrated demographic, economic, and technological trends. It also considered a broader range and scope of scenarios than the previous YEC Plan.
- **Resource portfolio analysis** - The 2016 Resource Plan portfolio analysis applied sophisticated optimization modeling to select the lowest cost resource solution, while meeting required planning criteria.
- **Engagement methodology** - The 2016 Resource Plan applied a broader, and more sophisticated public consultation approach, specifically enabled through the Electricity Values Survey.
- **Social Cost of Carbon** - The 2016 Resource Plan used the social cost of carbon in evaluation of resource options in the portfolio analysis.
- **Existing unit capabilities** - Updates to existing unit capabilities and expected retirement dates were made in the 2016 Resource Plan to reflect current information.

(e)

The Resource Plan Appendices are available on Yukon Energy's website at the link below.
<http://resourceplan.yukonenergy.ca/more>

Links to specific appendices are as follows:

Appendix 3.1 – Electricity Values Survey Report

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 3.1 Electricity Val
ues Survey.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_3.1_Electricity_Val
ues_Survey.pdf)

Appendix 3.2. Communication Methods and Materials

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 3.2 Public Engag
ement Methods and Materials.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_3.2_Public_Engag
ement_Methods_and_Materials.pdf)

Energy and Peak Demand Forecast 2016-2035

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.1 -
Energy and Peak Demand Forecast Data 2016-2035.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.1_-_Energy_and_Peak_Demand_Forecast_Data_2016-2035.pdf)

Appendix 4.2 Yukon Macroeconomic Model 2016-2035

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2 -
Yukon Macroeconomic Model.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.2_-_Yukon_Macroeconomic_Model.pdf)

Appendix 4.3 Long Term Load and Demand Forecast 2016-2035

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3 Long Term L
oad and Demand Forecast 2016-2035.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.3_Long_Term_Load_and_Demand_Forecast_2016-2035.pdf)

Appendix 4.4 Industrial Energy and Peak Demand Forecast 2016-2035

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.4 Industrial Ene
rgy and Peak Demand Forecast 2016-2035.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.4_Industrial_Energy_and_Peak_Demand_Forecast_2016-2035.pdf)

Appendix 4.5 Electric Vehicle Investigation

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.5 Electric Vehic
le Investigation.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.5_Electric_Vehicle_Investigation.pdf)

Appendix 4.6 Home Heating Retrofit Business Case Study

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.6 Home Heatin
g Retrofit Business Case.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.6_Home_Heating_Retrofit_Business_Case.pdf)

Appendix 4.7 Mirrlees Assessment Report

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.7 Mirrlees Asse
ssment Report.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.7_Mirrlees_Assessment_Report.pdf)

Appendix 4.8 Generation Adequacy Evaluation (Karki, 2017)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.8 Generation A
dequacy Evaluation.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_4.8_Generation_Adequacy_Evaluation.pdf)

Appendix 5.1 Greenhouse Gas Emission Life Cycle Assessment of Resource Options (ArcticCan Energy Services 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.1 Greenhouse
Gas Emission Life Cycle Assessment of Resource Options \(ArcticCan Energy Ser
vices 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.1_Greenhouse_Gas_Emission_Life_Cycle_Assessment_of_Resource_Options_(ArcticCan_Energy_Services_2016).pdf)

Appendix 5.2 Environmental, Social and Economic Attribute Evaluation of Resource Options (InterGroup, EDI, Ecofor and CNC 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.2 Environmental Social and Economic Attribute Evaluation of Resource Options \(InterGroup et al. 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.2_Environmental_Social_and_Economic_Attribute_Evaluation_of_Resource_Options_(InterGroup_et_al._2016).pdf)

Appendix 5.3 Southern Lakes Enhanced Storage Concept Studies

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.3 Southern Lakes Concept Project Proposal.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.3_Southern_Lakes_Concept_Project_Proposal.pdf)

Appendix 5.4 Mayo Lake Enhanced Storage Concept Project Proposal

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.4 Mayo Lake Enhanced Storage Project.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.4_Mayo_Lake_Enhanced_Storage_Project.pdf)

Appendix 5.5 Aishihik Turbines Uprate Study (KGS 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.5 Aishihik Turbines Uprate Study \(KGS 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.5_Aishihik_Turbines_Uprate_Study_(KGS_2016).pdf)

**Mayo Hydro (MH0) Future Facility Options Concept Design Report FINAL – REV 0
KGS 16-1404-002 August 2016**

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.6 Mayo Hydro Future Facility Options Report \(KGS 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.6_Mayo_Hydro_Future_Facility_Options_Report_(KGS_2016).pdf)

Appendix 5.7 Small Hydro Screening Assessment (Knight Piesold 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.7 Small Hydro Screening Assessment \(Knight Piesold 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.7_Small_Hydro_Screening_Assessment_(Knight_Piesold_2016).pdf)

Appendix 5.8 Atlin Hydro Expansion Study

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.8 Atlin Hydro Expansion Study \(Morrison Hershfield 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.8_Atlin_Hydro_Expansion_Study_(Morrison_Hershfield_2016).pdf)

Appendix 5.9 Wind Site Inventory (CBER, Envint and V3 Energy 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.9 Wind Site Inventory \(CBER Envint and V3 Energy 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.9_Wind_Site_Inventory_(CBER_Envint_and_V3_Energy_2016).pdf)

Appendix 5.10 Geothermal Review and Site Inventory (KGS 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.10 Geothermal Review and Site Inventory \(KGS 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.10_Geothermal_Review_and_Site_Inventory_(KGS_2016).pdf)

Appendix 5.11 Solar Site Inventory (Solvest 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.11 Solar Site Inventory \(Solvest 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.11_Solar_Site_Inventory_(Solvest_2016).pdf)

Appendix 5.12 Final FEED Report Front End Engineering Design (FEED) Study Yukon Bioenergy Demonstration Project in Haines Junction, Yukon

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.12 Biomass Front End Engineering Design Study \(Stantec 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.12_Biomass_Front_End_Engineering_Design_Study_(Stantec_2016).pdf)

Appendix 5.13 Biogas Feasibility Study (WSP 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.13 Biogas Feasibility Study \(WSP 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.13_Biogas_Feasibility_Study_(WSP_2016).pdf)

Appendix 5.14 Waste-to-Energy Design Basis and Business Case Analysis (Morrison Hershfield 2012)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.14 Waste-to-Energy Design Basis and Business Case Analysis \(Morrison Hershfield 2012\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.14_Waste-to-Energy_Design_Basis_and_Business_Case_Analysis_(Morrison_Hershfield_2012).pdf)

Appendix 5.15 Thermal Energy Plan Development Study (Stantec 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.15 Thermal Energy Plan Development Study \(Stantec 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.15_Thermal_Energy_Plan_Development_Study_(Stantec_2016).pdf)

Appendix 5.16 Pumped Storage Assessment (Knight Piesold 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.16 Pumped Storage Assessment \(Knight Piesold 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.16_Pumped_Storage_Assessment_(Knight_Piesold_2016).pdf)

Appendix 5.17 Moon Lake Pumped Storage Conceptual Study Report (Midgard 2015)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.17 Moon Lake Pumped Storage Conceptual Study Report \(Midgard 2015\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.17_Moon_Lake_Pumped_Storage_Conceptual_Study_Report_(Midgard_2015).pdf)

Appendix 5.18 Faro Mine Pumped Storage Conceptual Assessment (EMC2 and Picacho and Associates 2015)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.18 Faro Mine Pumped Storage Conceptual Assessment \(EMC2 and Picacho and Associates 2015\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.18_Faro_Mine_Pumped_Storage_Conceptual_Assessment_(EMC2_and_Picacho_and_Associates_2015).pdf)

Appendix 5.19 Evaluation of Energy Storage Technologies (Transgrid Solutions 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.19 Evaluation of Energy Storage Technologies \(Transgrid Solutions 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.19_Evaluation_of_Energy_Storage_Technologies_(Transgrid_Solutions_2016).pdf)

Appendix 5.20 Updates to Yukon Electricity Conservation and Demand Management Potential Review (ICF 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.20 Updates to Yukon Electricity Conservation and Demand Management Potential Review \(ICF 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.20_Updates_to_Yukon_Electricity_Conservation_and_Demand_Management_Potential_Review_(ICF_2016).pdf)

Appendix 5.21 Transmission Options Evaluation (Midgard 2016)

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.21 Transmission Options Evaluation \(Midgard 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.21_Transmission_Options_Evaluation_(Midgard_2016).pdf)

Appendix 6.1 Liquefied Natural Gas: Potential Supply Options

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 6.1 Fuel Price Forecast.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_6.1_Fuel_Price_Forecast.pdf)

Appendix 6.2 Social Cost of Carbon

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 6.2 Social Cost of Carbon.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_6.2_Social_Cost_of_Carbon.pdf)

Appendix 8.1 Portfolio Analysis Data

[http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 8.1 Portfolio Analysis Data.pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_8.1_Portfolio_Analysis_Data.pdf)

1 **TOPIC:** Marsh Lake Storage, Section 5.3.1.8

2
3 **REFERENCE:** Application, pages 5-46 to 5-47. PDF pages 217 to 218

4
5 **QUOTE:** “The Marsh Lake Storage Project (recently renamed the Southern
6 Lakes Enhanced Storage Project, or SLESP) is a means of enhancing
7 winter energy at the Whitehorse Rapids generating station to displace
8 higher cost thermal generation that would otherwise be required. As
9 reviewed in the 2012/13 GRA ...”

10
11 “In Order 2013-01, the Board found that Marsh Lake Storage was
12 currently a viable project, and as such, all Marsh Lake-related project
13 costs were to be held in WIP, until the project was completed. The
14 Board noted that YEC was to cease work on the project if and when
15 YEC concludes that there is no net economic benefit of the project to
16 ratepayers.

17
18 “Work completed since the 2012/2013 GRA includes technical studies
19 and assessments, engagement and consultation with various
20 stakeholders, and extensive meetings with property owners that will be
21 directly impacted by the project... The next major milestone is obtaining
22 First Nations support for the project in order to progress to the YESAB
23 assessment stage. Without such support the project will be cancelled
24 ... It is expected that a decision to proceed to the YESAB assessment
25 phase will be made at a Stagegate 3 project review planned for the 4th
26 quarter of 2017.

27
28 “The deferred cost forecasts in the Application assume that the project
29 continues, with spending in WIP increasing from \$6.517 million at the
30 end of 2015 to \$8.156 million by the end of 2018. Potential in-service
31 for this project in 2022 is provided in the 2016 Resource Plan.”

1 **QUESTION:**

2
3 a) Please provide a detailed breakdown and explanation of the actual costs to date
4 and forecast costs for the Marsh Lake Storage project (renamed Southern Lakes
5 Enhanced Storage Project). Please provide variance explanations for costs that
6 have diverged from forecast.

7
8 b) With respect to (a), please indicate at what stage of the project are First Nations'
9 approvals sought? Please provide a detailed explanation.

10
11 c) From an economics perspective, does YEC have a stop point for this project?
12 Please explain.

13
14 **ANSWER:**

15
16 **(a)**

17
18 Table 1 below shows a summary of Southern Lakes Enhanced Storage Project (SLESP)
19 costs to date and currently forecast costs to complete the project.

20
21 Costs to date for the project have included expenditures on baseline environmental and
22 socio-economic studies necessary to support an effects assessment and the development
23 of mitigation for identified significant adverse project effects. Early planning and
24 engagement identified valued environmental and socio-economic components in a very
25 large project study area. Prior to undertaking planning of the Project, very little
26 comprehensive data regarding the identified valued components of the physical and
27 human environment along the roughly 1,000 km of study area shoreline had been
28 collected and compiled.

29
30 The fact that the Southern Lakes and the Yukon River are relatively densely developed
31 required intensive studies of the shore and subsurface along the perimeter of these
32 watercourses. Complementary public and property owner engagement was also
33 conducted in a highly intensive and repetitive fashion throughout the planning to date. It
34 is the latter aspect of planning that has demanded much of the further technical
35 investigation and examination of the potential effects of the project following the initial
36 years of study. The level of effort and time necessary to undertake engagement and
37 consultation expected by stakeholders and governments as part of the planning was not

anticipated. Resource expenditures related to both technical and non-technical engagement and consultation exceed \$1M and are mostly related to the human resources necessary to reach the large number of organizations and individuals involved and to respond to their concerns. While project planning outcomes are expected to be better for it, overall it is the extra time and resource use related to stakeholder engagement that have driven up the planning portion of the project costs from early planning cycle estimates.

Regarding the forecasts costs to implement the project, early predictions of the extent of sensitive shorelines that would require protection has increased. In addition, engineering concepts have been influenced by public and regulatory engagement activities. Finally, costs estimates made when the project planning first began have increased due to inflation over the 8-year planning period.

**Table 1: Summary of Southern Lakes Enhanced
Storage Project Planning and Implementation Costs**

Cost Centre	Costs to Date	Forecast Remaining Costs	Total Forecast Costs	2012 GRA Forecast	Variance
Effects Assessment (Baseline Studies, Analysis, Engineering, Engagement & Consultation)	\$6,799,235	\$1,151,000	\$7,950,235	\$4,950,000	\$3,000,235
YESAA Assessment & Permitting	\$0	\$300,000	\$300,000	\$300,000	\$0
Mitigation Implementation	\$0	\$7,126,830	\$7,126,830	\$5,250,000	\$1,876,830
Total	\$6,799,235	\$8,577,830	\$15,377,065	\$10,500,000	\$4,877,065

1 **(b) and (c)**

2
3 As noted in Tab 5, Section 5.3.1.8, the next major milestone for this project is obtaining
4 First Nations support; and this milestone is to be achieved in order for the project to
5 progress to the YESAB assessment stage. It is expected that a decision to proceed to the
6 YESAB assessment phase will be made at a Stagegate 3 project review planned for the
7 4th quarter of 2017. As noted in Tab 5, if this is not achieved the project would be
8 cancelled.

9
10 Once the above milestone is achieved, all project authorizations would be formally sought
11 following the conclusion of a project assessment pursuant to the Yukon Environmental &
12 Socio-economic Assessment Act and the subsequent issuance of Decision Documents
13 from the assessment Decision Bodies.

14
15 The Kwanlin Dun First Nation (KDFN) and Carcross/Tagish First Nations (C/TFN) both
16 have low-lying settlement lands along the Southern Lakes that currently experience
17 inundation during both the regulated and unregulated periods of the year. Inundation of
18 settlement land during the regulated period is allowed under the current water use licence
19 and recognized as an encumbering right duly considered during the development and
20 settling of the comprehensive land claim and self-government agreements with both the
21 KDFN and C/TFN.

22
23 With the SLESP the duration and extent of this inundation would increase and an
24 authorization for this land use is required from the aforementioned First Nations.
25 Applications for those land use authorizations will follow the format as set out by each First
26 Nation at the time.

27
28 Going forward, after the planned Stagegate 3 project review, decision-making at each
29 Stagegate would consider planning costs to date along with those forecast to complete
30 the remaining planning, assessment, permitting, and construction of the Project. Future
31 stagegates would consider whether the results of power benefit and economic analyses
32 predict levelized cost of energy greater than that of the next comparable firm (renewable)
33 energy/capacity project.

1 **TOPIC:** Mayo Lake Storage, Section 5.3.1.9

2
3 **REFERENCE:** Application, pages 5-47 to 5-49. PDF pages 218 to 220

4
5 **QUOTE:** “The Mayo Lake Enhanced Storage Project (MLESPP) will amend the
6 Mayo Generation Station Water Use Licence to provide for up to one
7 metre of additional draw down of Mayo Lake...”

8
9 “... a recent study by external engineers ha[s] shown that sediment in
10 the Mayo Lake outlet channel is constraining water flow through the
11 channel ... and preventing any benefit from being realized by the
12 MLESPP ...”

13
14 “The MLESPP proposal was submitted to the YESAA [Yukon
15 Environmental and Socio-economic Assessment Act] Designated
16 Office in August 2015 (noting that a Mayo Outlet Dredging Project
17 would be pursued separately in the future), with provision for the full
18 one metre of added drawdown after an initial 0.5 metre drawdown and
19 subject to adaptive management provisions that was co-developed,
20 and would be implemented, with the First Nation of Na-Cho Nyak Dun.
21 The YESAA Designated Office suggested that review of the MLESPP be
22 grouped with an unrelated YG project proposed for the lower Mayo
23 River, and also required that the Mayo Lake Outlet Dredging Project be
24 included in the MLESPP review as an accessory project. In order to let
25 the YG proposal move forward in a timely way the Yukon Energy
26 MLESPP proposal was withdrawn, on the understanding that it would be
27 resubmitted at a later time with additional information regarding the
28 Mayo Lake Outlet Dredging Project.

29
30 “Project spending during 2016 includes environmental monitoring and
31 phase 1 of the dredging work, a desktop analysis. Environmental
32 monitoring makes up the majority of the 2017 costs and will continue
33 through 2018. Phase 2 of the dredging work, detailed modelling and
34 design, will take place during 2018. Once phase 2 of the dredging work
35 is complete, YEC will have a much better estimate of the total costs to
36 complete the project.”

1 “The deferred cost forecasts spending in WIP increasing from \$2.406
2 million at the end of 2016 to \$3.356 million by the end of 2018. Potential
3 in-service for this project in 2022 is provided in the 2016 Resource
4 Plan.” [footnote omitted]
5

6 **QUESTION:**
7

- 8 a) Has YEC resubmitted the Mayo Lake storage project (renamed Mayo Lake
9 Enhanced Storage Project), including the Mayo Lake Outlet Dredging Project to
10 YESAA Designated Office?
11
12 b) Please explain what environmental monitoring spending includes and how this
13 might influence project costs.
14
15 c) Please explain what phase 1 and phase 2 of the dredging work include and the
16 related costs.
17
18 d) Has YEC commenced discussions with the First Nation of Na-Cho Nyak Dun with
19 respect to the full one metre of added drawdown? Please explain.
20
21 e) For each of the years 2016 to 2018, please provide a table that includes a
22 breakdown and explanation of the cost totals for each year.
23

24 **ANSWER:**
25

26 **(a)**
27

28 No.
29

30 **(b)**
31

32 The Mayo Lake Enhanced Storage Project (MLESP) proposal includes a detailed
33 monitoring and adaptive management plan (MAMP) co-developed with the First Nation of
34 Na-Cho Nyak Dun. This plan requires the collection of pre-project baseline data regarding
35 specific ecosystem components for the purposes of post-project confirmation of effect
36 predictions, mitigation effectiveness, and potential management response requirements.
37 The required environmental monitoring has been minimized to only those key data

1 necessary to maintain a suitable pre-project baseline for future use under the MAMP
2 should the project proceed. The program currently includes annual juvenile fish surveys
3 designed to assess spawning and overwintering success of Lake Whitefish and Lake
4 Trout, and maintenance of a basic weather station

5
6 **(c)**
7

8 The Mayo Lake Outlet Channel Erosion, Sedimentation, and Dredging Study included a
9 series of initial tasks (Phase I), which were deemed necessary in order to move to a
10 subsequent erosion/sediment transport modeling stage (Phase II) where the key project
11 concerns respecting whether an efficient, effective, and reasonably long-lasting dredging
12 design can be developed and at what cost.

13
14 Phase I included a review of the existing related studies, as well as a proposed plan on
15 appropriate methodology to address the outstanding project concerns/uncertainties (how,
16 where, how much to dredge). Specific tasks of Phase 1 included:

- 17
18
 - Review of available operational and project research information
 - 19 • Analysis and provision of opinion on sediment sources and sedimentation rates
 - 20 • Identifying potential data gaps
 - 21 • Proposing dredging alternative improvements in Phase II
 - 22 • Developing Scope, Budget and Schedule for Phase II
 - 23 • Phase I Report Preparation

24

25 Phase II has yet to be executed, but would involve the following tasks:

- 26
 - Data Collection, Review, and Interpretation
 - 27 ○ Sub-Aerial Mapping
 - 28 ○ Site Exploration
 - 29 ○ Sub-Aqueous Exploration
 - 30 ○ Sediment Core Dating
 - 31 ○ Additional Channel Surveying
 - 32 • Lake Sediment Transport Modelling
 - 33 • Fluvial Sediment Transport Modelling in Outlet Channel
 - 34 • Dredging Approach and Conceptual Level Design
 - 35 • Regulatory and Contractor Engagement
 - 36 • Phase II Report Preparation

The cost for Phase I was \$92,590 and the estimated cost to complete Phase II is \$670,000.

(d)

Yes. Discussions with the First Nation of Na-Cho Nyak Dun (NND) regarding the Enhanced Storage Project (including the full one metre drawdown) have been ongoing since 2008. A project steering committee and technical working group were established early in the planning process to collaborate on the project planning and design. Numerous engagement activities have also been undertaken with the NND Government personnel and citizens. The Project Proposal that was submitted to YESAB was reviewed by NND prior to it being finalized and the Project Mitigation, Monitoring, and Adaptive Management Plans were developed in cooperation with the NND Government.

(e)

Table 1 below shows the MLESP actual and forecast costs per activities. The costs for 2017 and 2018 are forecast

Table 1. Summary of Annual Costs – Mayo Lake Enhanced Storage Project

Cost Centre	Year		
	2016	Forecast 2017	Forecast 2018
Environmental Baseline Maintenance	\$137,579	\$45,000	\$45,000
Phase I - Erosion, Sedimentation, & Dredging Study	\$92,590	\$0	\$0
Phase II Dredging - Erosion, Sedimentation, & Dredging Study	\$0	\$0	\$670,000
Assessment and Permitting	\$0	\$0	\$50,000
YEC Labour	\$6,414	\$5,000	\$15,000
AFUDC	\$48,459	\$50,000	\$70,000
Total	\$285,042	\$100,000	\$850,000

TOPIC: Projects between \$100,000 and \$1 Million, Section 5.3.2, Appendix 5.4

REFERENCE: Application, Tab 5, page 5-49. PDF page 220

QUOTE: “The projected total 2017 and 2018 spending in deferred cost activities excluding major projects over \$1 million (as described in Section 5.3.1) totals approximately \$2.2 million in 2017 (\$0.7 million in closed projects), as set out in detail in Table 5.7, and a total of approximately \$2.9 million for 2018 (\$1.5 million in closed projects for 2018 spending and \$0.7 million in closed projects from 2017 spending) as set out in detail in Table 5.8. Total increase to rate base from deferred cost activities excluding major projects over \$1 million, but including transfers from WIP spending prior to 2017, is \$4.9 million in 2017 and \$3.3 million in 2018.”

PREAMBLE: The Board requires further information regarding the following projects:

Project	Prior to 2017	Forecast 2017	Forecast 2018
Development of Asset Management Program ¹		\$200,000	\$150,000
Time of Use Rate Structure and Smart Grid ²		\$100,000	
Mt Sumanik Wind Feasibility Study ³	\$540,280	\$50,000	\$250,000
Northern Diesel Plant ⁴			\$100,000
Whitehorse Hydro Uprate ⁵			\$450,000
Small Hydro ⁶			\$625,000

Source: Application, Appendix 5.4. PDF pages 257 to 259

¹ Application, Appendix 5.4 PDF page 257

² Application, Appendix 5.4 PDF page 258

³ Application, Appendix 5.4 PDF page 258

⁴ Application, Appendix 5.4 PDF page 258

⁵ Application, Appendix 5.4 PDF page 259

⁶ Application, Appendix 5.4 PDF page 259

1 **QUESTION:**

- 2
- 3 a) With respect to YEC's proposed asset management program, please explain what
4 does YEC mean when it states that an "asset management methodology or plan
5 ..." will "... systematically assess major asset groups ... and manage the planning
6 of investments to meet overall corporate goals."⁷
- 7 i.) Please explain what YEC is doing presently to manage its assets. Will
8 customers see offsetting operating and management savings? Please
9 provide a detailed explanation.
- 10 ii.) Please explain whether or not the asset management program is a one-
11 time project or if it will be ongoing.
- 12 iii.) If the asset management program is intended to be an ongoing project,
13 please explain why YEC has included it in capital costs instead of as an
14 operating cost.
- 15
- 16 b) Do customers throughout the Yukon have the necessary infrastructure in place
17 (i.e. meters, etc.) to allow for a time of use rate structure? Please explain.
- 18
- 19 c) Please provide the results of the planning studies for potential wind farm sites
20 throughout the Yukon. Please provide the capacity factor(s) of current wind
21 facilities in the Yukon. Please fully explain what the test year expenditures relate
22 to.
- 23
- 24 d) Respecting YEC's northern diesel plant initiative, has YEC investigated any
25 alternatives other than relocation to mitigate issues related to plant noise and flood
26 risk at the current locations? If not, please explain why it has not done so. If yes,
27 please provide the results of the investigations.
- 28
- 29 e) Please provide further details regarding the \$450,000 that is to be spent in 2018
30 related for the Whitehorse Hydro uprate project. Is an outside agency/consultant
31 performing the investigation? For this project, please explain why is it necessary
32 to select an owner's engineer to represent YEC throughout the project. Please
33 explain the financial benefits realized on previous uprate projects.

⁷ Application, Appendix 5.4, page 5.4-2. PDF page 257.

1 f) Relative to the small hydro project, please provide a breakdown of the \$625,000
2 total cost forecast. Please provide a full explanation of what geotechnical
3 investigations are and how they might influence the project. Considering that the
4 small hydro resource option is at a pre-feasibility stage, will a third party consultant
5 be undertaking further studies to confirm site selection and project need? Please
6 explain.

7
8 **ANSWER:**

9
10 **(a)**

11
12 **(i)**

13
14 Current asset management methodology at YEC consists of a combination of internal and
15 external reviews. Internally, all staff are encouraged to take note of equipment issues for
16 follow up to ensure issues are addressed. Externally, YEC has commissioned a number
17 of asset assessment projects over the last several years to build an inventory of asset
18 conditions for key asset classes. The recommendations from these reports are transferred
19 into a checklist of prioritized actions that can then be budgeted and addressed in an orderly
20 manner. This is still an ad hoc system with reliance on manual spreadsheets to track
21 recommendations and limited ability to cross reference these sheets to other relevant data
22 (e.g. maintenance schedules, test results, historical costs). The goal of the AMP is to
23 integrate these different information sources into an asset health index that will allow YEC
24 more complete information for capital planning.

25
26 **(ii) and (iii)**

27
28 The costs referenced in the Application are on-time expenditures related to the
29 development of an asset management program. Once developed the program will provide
30 value over a number of future years and therefore is treated as a capital project.

31
32 **(b)**

33
34 No. Smart meters are critical infrastructure to properly implement time-of-use rate
35 programs.

36
37 Please also see response to John Maissan-YEC-1-34(a).

1 (c)

2
3 Please see the 2016 Resource Plan Appendix 5.9 – Wind Site Inventory publicly available
4 at link below.

5
6 [http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.9 Wind Site In](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.9_Wind_Site_Inventory_(CBER_Envint_and_V3_Energy_2016).pdf)
7 [ventory \(CBER Envint and V3 Energy 2016\).pdf](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.9_Wind_Site_Inventory_(CBER_Envint_and_V3_Energy_2016).pdf)

8
9 Capacity factors for current YEC wind generation are 11% for 2015 and 9% for 2016.

10
11 Test year spending includes continued monitoring in 2017 and the completion of a
12 feasibility study in 2018.

13
14 (d)

15
16 The test year spending does not include physically moving the plants, only studying the
17 various options. The study will investigate alternatives to moving the plants, other
18 mitigation options to address noise and flood risk, and potential uses for the space if the
19 plant(s) are moved.

20
21 (e)

22
23 The 2016 Resource Plan update identified hydro turbine uprates as an economical
24 solution for capacity and energy. The 2018 spending will hire an owner's engineer to
25 conduct preliminary design work and assist YEC with permitting activities. The external
26 engineer is required because uprate studies are a specialized skillset that YEC does not
27 employ internally. YEC has never previously completed a specific hydro uprate project.

28
29 (f)

30
31 Table 1 provides a breakdown of the 2018 spending for the small hydro project:

32
33 **Table 1: Small Hydro Project 2018 Forecast Spending**

Stakeholder consultation	\$100,000
Environmental and geotechnical	\$500,000
Water gauging	\$25,000

1 Geotechnical investigations involve analyzing the properties of the soil and rock at a given
2 site to determine such things as location and extent of permafrost, distance to bedrock, or
3 the competency of rock. This information will be used to determine if the project is feasible
4 and will influence the detailed design of the structure.

5
6 The potential need for this project was established by the resource plan process. A third
7 party consultant will undertake the necessary studies to confirm the site selection and
8 project economics in order for YEC to make an informed decision at the appropriate stage
9 gate.

TOPIC:

REFERENCE: Application, Tab 5, Appendix 5.3

PREAMBLE: The Board requires further information in respect to the following projects:

Project	Prior to 2017	Forecast 2017	Forecast 2018
Aishihik Generator Fire Protection ¹			\$125,000
Whitehorse Local HMI/Historian Upgrade ²		\$180,000	
Dawson P158 T1/T2 Transformer ³			\$200,000
Transmission System Protection Upgrades ⁴		\$100,000	
Critical Spares – System Requirement ⁵	\$200,000	\$100,000	\$100,000
Mayo Transient Trailer Unit ⁶			\$250,000
Stewart-Minto Local SCADA ⁷			\$165,000

QUESTION:

- a) Is there a link between the “Aishihik Generator Fire Protection” project and the previous “AHO Deluge System” project?

¹ Application, Appendix 5.3, PDF page 245

² Application, Appendix 5.3, PDF page 247

³ Application, Appendix 5.3, PDF page 249

⁴ Application, Appendix 5.3, PDF page 250

⁵ Application, Appendix 5.3, PDF page 252

⁶ Application, Appendix 5.3, PDF page 253

⁷ Application, Appendix 5.3, PDF page 253

1 b) Please explain the benefits accruing to customers from the “Whitehorse Local
2 HMI/Historian Upgrade” project.

3
4 c) Is the Dawson P158 T1/T2 transformer connected to the Mayo to Dawson project?

5
6 d) Please explain how a tripping scheme for L178 will eliminate grid separation by
7 faults on L178.

8
9 e) Please provide the prioritized list of the components (generation, transmission, and
10 communications equipment) that are to be purchased during the test period.

11
12 f) Are there any carrying costs associated with the “Mayo Transient Trailer Unit”
13 project? Please explain.

14
15 g) With respect to the Stewart-Minto Local SCADA project, please provide the key
16 performance indicator improvements and an explanation of the benefits will accrue
17 to YEC’s customers from this project?

18
19 **ANSWER:**

20
21 **(a)**

22
23 Yes. The AHO Deluge System project was the preliminary design report that assessed
24 different suppression agent options and costs.

25
26 **(b)**

27
28 The current HMI has been deemed end of life and must be replaced. The addition of a
29 local historian to the plant will benefit customers by providing faster outage analysis
30 (resulting in faster restoration), labour cost savings during troubleshooting, and lower
31 asset maintenance costs due to better planning.

32
33 **(c)**

34
35 Yes.

(d)

YEC currently has protection relays at Takhini, Minto Landing, and Faro substations. By using these existing relays to detect a fault on L178 and communicate via powerline carrier, a transfer trip can be issued to the existing circuit switcher at the Carmacks Airport substation. This would result in L178 (east of Carmacks) becoming isolated while maintaining the grid connection north and south of Carmacks.

(e)

Please see Table 1 below.

Table 1: Prioritized List of the Components

<u>Description</u>	<u>Estimate</u>
<u>2017 Spending</u>	
seal repair kit for Mayo B	\$ 22,200.00
slip rings for WH4	\$ 35,000.00
brush holder fo AH1&2	\$ 12,000.00
hydro governor parts for Mayo B, WH3,WH4, AH3	\$ 30,000.00
	<u>\$ 99,200.00</u>
<u>2018 Spending</u>	
lift pumps for hydro bearing lubrication - MH	\$ 15,000.00
lift pumps for hydro bearing lubrication - AH	\$ 15,000.00
lift pumps for hydro bearing lubrication - WH	\$ 15,000.00
sliprings AH1&2	\$ 30,000.00
brush holders for AH3	\$ 5,000.00
various PLC parts - Mayo	\$ 12,500.00
various PLC parts - Whitehorse	\$ 3,000.00
HMI	\$ 5,000.00
	<u>\$ 100,500.00</u>

(f)

Annual carrying costs are estimated between \$6,000 and \$8,000 and include electricity, heat, water delivery, snow removal, and routine maintenance.

1 **(g)**

2

3 YEC customers will benefit from increased reliability due to easier protection setting
4 modifications and faster outage restoration due to enhanced substation control by SCC.
5 Travel time will decrease as diagnostic work will be able to be performed remotely,
6 resulting in increased labour efficiency.