

**Utilities Consumers' Group
(UCG)**

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide details of all customer and stakeholder consultations conducted by
10 Yukon Energy Corporation during development of this application prior to
11 submitting it to the YUB.

12
13 b) Please provide specific details on how YEC's customers were informed of
14 proposals being considered for inclusion in the application and how input from
15 customers was used to develop details of the application.

16
17 c) Please provide all documentation related to issues discussed during these
18 consultations and a list of all parties involved in the consultations.

19
20 d) Please confirm how and when the leadership / owners of YEC approved the
21 General Rate Application as provided to the YUB. Please identify the dates on
22 which these approvals were provided.

23
24 **ANSWER:**

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

27
28 YEC did not conduct stakeholder consultations on the context of the GRA prior to the filing.

29
30 **(d)**

31
32 Yukon Energy's Board of Directors was briefed regarding the filing of a GRA in February
33 2017. The GRA documentation was completed following this discussion.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application page 1
4 *YEC states "Pursuant to the Order in Council (OIC) 2014/23 direction,*
5 *the Board must ensure until the end of 2018 that rate adjustments for*
6 *retail customers and major industrial customers apply equally, when*
7 *measured as percentages, to all classes of retail customers and to the*
8 *class of major industrial customers. Consequently, for both 2017 and*
9 *2018, all proposed rate adjustments for retail customers and industrial*
10 *customers apply equally, as percentages".*

11
12 Board Order 2010-13, Appendix A – Reasons for Decision
13 *"29. Therefore, the Board directs the Companies to file a joint COS*
14 *study within six months of the expiry of OIC 2008/149. The Board*
15 *further directs the Companies to incorporate all findings and directions*
16 *of this Decision into the next COS study."*

17
18 **PREAMBLE:**

19
20 **QUESTION:**

- 21
22 a) Please provide details on the progress made to date and the expected schedule
23 for completing and filing the joint COS study as directed by the YUB.

24
25 **ANSWER:**

26
27 **(a)**

28
29 OIC 2014/23 is a specific direction of the Yukon Government and prevents rate
30 rebalancing between rate classes until after December 31, 2018.

31
32 In Order 2013-01 the Board provided a series of directives related to the Cost of Service
33 Study as filed by the Companies noting that it "[did] not accept the COS study as filed by
34 the Companies", "an updated COS study approved by the Board is essential to
35 establishing a future rate restructuring process" and directed the Companies to "file a joint
36 COS study within six months of the expiry of OIC 2008/149" that "incorporate[s] all findings

1 and directions of the decision.” Since Order 2013-01, further directions have been
2 provided by the government that restrict rate rebalancing [OIC 2012/68 and OIC 2014/23].
3
4 Current OIC direction effectively provides that material rate design changes that would
5 result in rebalancing of rates between different customer classes cannot be undertaken
6 until mid-2019 at the earliest.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application page 2
4 YEC states “*Yukon Energy’s last requested rate increase was for the*
5 *2012 and 2013 test years – this was the first requested increase in*
6 *Yukon Energy firm retail rates for non-industrial customers since the*
7 *1998/1999 rate review (which focused on issues arising from the*
8 *closure of the Faro mine).*”
9

10 ATCO Electric Yukon 2016-2017 General Rate Application

- 11 • AEY Response to UCG-AEY-16
- 12 • ATCO Electric Yukon 2016-2017 GRA Compliance Filing (May
- 13 26, 2017)
- 14 • Board Order 2017-03
- 15

16 **PREAMBLE:**

17
18 **QUESTION:**

- 19
20 a) Please confirm that the bills of Yukon ratepayers have continued to change since
21 the 1998/1999 rate review due to the reliance by YEC and YECL/AEY on across-
22 the-board percentage rate riders (e.g., Riders F, J and R) to recover approved rate
23 revenue requirements and changes to fuel costs beyond what was provided by
24 base rates.
25
26 b) Please provide detailed calculations of the total bill (including all riders, rate relief,
27 and taxes) for a YEC residential customer using 800 kWh, 1000 kWh, 1200 kWh
28 and 1400 kWh per month in January 2012, January 2013, January 2014, January
29 2015, January 2016, January 2017 and January 2018 assuming that the 2017 and
30 2018 rate adjustments proposed by YEC are approved. Please provide details of
31 the bill calculations and indicate overall percentage changes in the total bill for each
32 year.
33
34 c) Please provide detailed calculations of the total bill (including all riders, rate relief,
35 and taxes) for an ATCO Electric Yukon (AEY) residential customer in Whitehorse
36 using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2015,
37 January 2016, January 2017 and January 2018 with the approved AEY riders and

1 assuming that the 2017 and 2018 rate adjustments proposed by YEC are
2 approved. Please provide details of the bill calculations and indicate overall
3 percentage changes in the total bill for each year.

4
5 d) Please provide detailed calculations of the total bill (including all riders, rate relief,
6 and taxes) for an ATCO Electric Yukon (AEY) residential customer in Whitehorse
7 using 800 kWh, 1000 kWh, 1200 kWh and 1400 kWh per month in January 2015,
8 January 2016, January 2017 and January 2018 with the approved AEY riders and
9 assuming that only 50% of the 2017 and 2018 rate adjustments proposed by YEC
10 are approved. Please provide details of the bill calculations and indicate overall
11 percentage changes in the total bill for each year.

12
13 **ANSWER:**

14
15 **(a)**

16
17 Confirmed. Adjustments to rates were implemented on a revenue neutral basis, by utility
18 and by class.

19
20 **(b) and (c)**

21
22 Please see Tables 1-1 through 1-4 below (at the end of this response) and
23 UCG-YEC-1-3 Attachment 1 for the requested information. For the Hydro Zone YEC and
24 AEY customers pay the same rate. Therefore, the bill change table is provided for
25 Whitehorse for the range of consumption requested in the question.

26
27 **(d)**

28
29 Please see Tables 2-1 through 2-4 below (at the end of this response) and
30 UCG-YEC-1-3 Attachment 2 for the requested information. Please note that the table uses
31 YEC Rider J assumption of 16.57% for January 1, 2018 column. This is based on the 50%
32 of the proposed Rider J increase effective January 1, 2018 [22.12% proposed compared
33 to 11.01% existing or increase of 11.11%; 50% of the increase of 11.11% is 5.56% which
34 would be 16.57% with the existing Rider J of 11.01%].

Yukon Energy Corporation
2017 – 2018 General Rate Application
UCG -YEC-1-3

Table 1-1 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kWh/month usage [Whitehorse]

Line #	Customer Use per month:		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
	800 kWh		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
2=KWh*Base rate	Customer Charge (per month)	800	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
3=KWh*Base rate	First Block Energy (kWh)	-	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12
4=KWh*Rider F rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00
5=(1+2+3)*Rider J rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$2.82	\$0.001910	\$1.53	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$3.90	-\$0.005600	-\$4.48	-\$0.000110	-\$0.09	-\$0.000110	-\$0.09
6=(1+2+3)*Rider R rate	YEC Rider J (%)				6.40%	\$7.15	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	16.51%	\$18.45	22.12%	\$24.72
7=KWh*Rider E rate	YEC Rider R (%)			\$0.00	3.75%	\$4.19	3.62%	\$4.05		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
8=(1+2+3)*Rider R rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44
9=Sum(1:8)	AEY Rider R (%)						6.50%	\$7.27	7.20%	\$8.05	7.20%	\$8.05	11.62%	\$12.99	8.30%	\$9.28	8.30%	\$9.28
	Total Before Tax Rebate, IER, GST			\$114.59		\$124.64		\$135.39		\$132.12		\$122.79		\$127.14		\$133.97		\$140.24
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$0.84	-0.75%	-\$0.84	-0.60%	-\$0.67	-0.55%	-\$0.61	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29
12=Sum(9:11)	Total After Rebates, before GST			\$92.46		\$102.52		\$113.43		\$110.22		\$100.92		\$105.27		\$112.10		\$118.37
13=12*1.05	Total After GST			\$97.08		\$107.64		\$119.10		\$115.73		\$105.96		\$110.54		\$117.71		\$124.29
	Change from last rate					\$10.56		\$11.46		-\$3.37		-\$9.77		\$4.57		\$7.17		\$6.58
						10.9%		10.6%		-2.8%		-8.4%		4.3%		6.5%		5.6%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-2 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kWh/month usage [Whitehorse]

Line #	Customer Use per month:		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
	1,000 kWh		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
2=KWh*Base rate	Customer Charge (per month)	1,000	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
3=KWh*Base rate	First Block Energy (kWh)	-	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40
4=KWh*Rider F rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00
5=(1+2+3)*Rider J rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$3.52	\$0.001910	\$1.91	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$4.87	-\$0.005600	-\$5.60	-\$0.000110	-\$0.11	-\$0.000110	-\$0.11
6=(1+2+3)*Rider R rate	YEC Rider J (%)				6.40%	\$8.71	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	16.51%	\$22.46	22.12%	\$30.09
7=KWh*Rider E rate	YEC Rider R (%)			\$0.00	3.75%	\$5.10	3.62%	\$4.93		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
8=(1+2+3)*Rider R rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80
9=Sum(1:8)	AEY Rider R (%)						6.50%	\$8.84	7.20%	\$9.80	7.20%	\$9.80	11.62%	\$15.81	8.30%	\$11.29	8.30%	\$11.29
	Total Before Tax Rebate, IER, GST			\$139.57		\$151.77		\$164.80		\$160.82		\$149.15		\$154.44		\$162.89		\$170.53
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.02	-0.75%	-\$1.02	-0.60%	-\$0.82	-0.55%	-\$0.75	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$111.94		\$124.14		\$137.37		\$133.47		\$121.84		\$127.12		\$135.58		\$143.21
13=12*1.05	Total After GST			\$117.54		\$130.35		\$144.24		\$140.14		\$127.93		\$133.48		\$142.36		\$150.37
	Change from last rate					\$12.81		\$13.89		-\$4.10		-\$12.21		\$5.55		\$8.88		\$8.01
						10.9%		10.7%		-2.8%		-8.7%		4.3%		6.7%		5.6%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Yukon Energy Corporation
2017 – 2018 General Rate Application
UCG -YEC-1-3

Table 1-3 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
	1,200 kWh		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
2=KWh*Base rate	Customer Charge (per month)	1,000	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
3=KWh*Base rate	First Block Energy (kWh)		\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68
4=KWh*Rider F rate	Second Block Energy (kWh)	200	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64
5=(1+2+3)*Rider J rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.22	\$0.001910	\$2.29	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$5.84	-\$0.005600	-\$6.72	-\$0.000110	-\$0.13	-\$0.000110	-\$0.13
6=(1+2+3)*Rider R rate	YEC Rider J (%)				6.40%	\$11.90	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	16.51%	\$30.70	22.12%	\$41.14
7=KWh*Rider E rate	YEC Rider R (%)			\$0.00	3.75%	\$6.97	3.62%	\$6.73		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
8=(1+2+3)*Rider R rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16
9=Sum(1:8)	AEY Rider R (%)						6.50%	\$12.09	7.20%	\$13.39	7.20%	\$13.39	11.62%	\$21.61	8.30%	\$15.44	8.30%	\$15.44
	Total Before Tax Rebate, IER, GST			\$190.19		\$207.14		\$225.27		\$219.84		\$205.83		\$213.18		\$223.82		\$234.25
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.39	-0.75%	-\$1.39	-0.60%	-\$1.12	-0.55%	-\$1.02	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$162.19		\$179.13		\$197.54		\$192.20		\$178.25		\$185.60		\$196.24		\$206.67
13=12*1.05	Total After GST			\$170.30		\$188.09		\$207.42		\$201.81		\$187.17		\$194.88		\$206.05		\$217.01
	Change from last rate					\$17.79		\$19.33		-\$5.60		-\$14.65		\$7.71		\$11.17		\$10.96
						10.4%		10.3%		-2.7%		-7.3%		4.1%		5.7%		5.3%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-4 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Proposed Jan-18	
	1,400 kWh		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
2=KWh*Base rate	Customer Charge (per month)	1,000	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
3=KWh*Base rate	First Block Energy (kWh)		\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96
4=KWh*Rider F rate	Second Block Energy (kWh)	400	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28
5=(1+2+3)*Rider J rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.93	\$0.001910	\$2.67	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$6.82	-\$0.005600	-\$7.84	-\$0.000110	-\$0.15	-\$0.000110	-\$0.15
6=(1+2+3)*Rider R rate	YEC Rider J (%)				6.40%	\$15.10	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	16.51%	\$38.95	22.12%	\$52.18
7=KWh*Rider E rate	YEC Rider R (%)			\$0.00	3.75%	\$8.85	3.62%	\$8.54		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
8=(1+2+3)*Rider R rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$9.52	-\$0.006800	-\$9.52	-\$0.006800	-\$9.52	-\$0.006800	-\$9.52
9=Sum(1:8)	AEY Rider R (%)						6.50%	\$15.33	7.20%	\$16.98	7.20%	\$16.98	11.62%	\$27.41	8.30%	\$19.58	8.30%	\$19.58
	Total Before Tax Rebate, IER, GST			\$240.82		\$262.51		\$285.73		\$278.85		\$262.51		\$271.91		\$284.74		\$297.97
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.77	-0.75%	-\$1.77	-0.60%	-\$1.42	-0.55%	-\$1.30	-0.52%	-\$1.23	-0.52%	-\$1.23	-0.52%	-\$1.23	-0.52%	-\$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$212.44		\$234.13		\$257.71		\$250.94		\$234.67		\$244.08		\$256.90		\$270.14
13=12*1.05	Total After GST			\$223.06		\$245.83		\$270.59		\$263.49		\$246.40		\$256.28		\$269.75		\$283.65
	Change from last rate					\$22.77		\$24.76		-\$7.11		-\$17.08		\$9.87		\$13.47		\$13.90
						10.2%		10.1%		-2.6%		-6.5%		4.0%		5.3%		5.2%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Yukon Energy Corporation
2017 – 2018 General Rate Application
UCG -YEC-1-3

Table 2-1 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kWh/month usage [Whitehorse]

Line #	Customer Use per month:	800 kWh																	50% of Proposed	
			Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18			
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill		
Base Rates																				
1	Customer Charge (per month)	800	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65		
2=KWh*Base rate	First Block Energy (kWh)	-	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12		
3=KWh*Base rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00		
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]	-	\$0.003520	\$2.82	\$0.001910	\$1.53	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$3.90	-\$0.005600	-\$4.48	-\$0.000110	-\$0.09	-\$0.000110	-\$0.09	-\$0.000110	-\$0.09
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$7.15	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	16.51%	\$18.45	16.57%	\$18.51		
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$4.19	3.62%	\$4.05		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$7.27	7.20%	\$8.05		\$8.05	11.62%	\$12.99	8.30%	\$9.28	8.30%	\$9.28		
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$114.59		\$124.64		\$135.39		\$132.12		\$122.79		\$127.14		\$133.97		\$134.03		
Less: Rebates																				
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$0.84	-0.75%	-\$0.84	-0.60%	-\$0.67	-0.55%	-\$0.61	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29
12=Sum(9:11)	Total After Rebates, before GST			\$92.46		\$102.52		\$113.43		\$110.22		\$100.92		\$105.27		\$112.10		\$112.16		
13=12*1.05	Total After GST			\$97.08		\$107.64		\$119.10		\$115.73		\$105.96		\$110.54		\$117.71		\$117.77		
	Change from last rate					\$10.56		\$11.46		-\$3.37		-\$9.77		\$4.57		\$7.17		\$0.06		
						10.9%		10.6%		-2.8%		-8.4%		4.3%		6.5%		0.1%		

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Table 2-2 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kWh/month usage [Whitehorse]

Line #	Customer Use per month:	1,000 kWh																	50% of Proposed	
			Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18			
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill		
Base Rates																				
1	Customer Charge (per month)	1,000	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65		
2=KWh*Base rate	First Block Energy (kWh)	-	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40		
3=KWh*Base rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00		
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]	-	\$0.003520	\$3.52	\$0.001910	\$1.91	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$4.87	-\$0.005600	-\$5.60	-\$0.000110	-\$0.11	-\$0.000110	-\$0.11	-\$0.000110	-\$0.11
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$8.71	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	16.51%	\$22.46	16.57%	\$22.54		
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$5.10	3.62%	\$4.93		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00		
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$8.84	7.20%	\$9.80		\$9.80	11.62%	\$15.81	8.30%	\$11.29	8.30%	\$11.29		
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$139.57		\$151.77		\$164.80		\$160.82		\$149.15		\$154.44		\$162.89		\$162.97		
Less: Rebates																				
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.02	-0.75%	-\$1.02	-0.60%	-\$0.82	-0.55%	-\$0.75	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$111.94		\$124.14		\$137.37		\$133.47		\$121.84		\$127.12		\$135.58		\$135.65		
13=12*1.05	Total After GST			\$117.54		\$130.35		\$144.24		\$140.14		\$127.93		\$133.48		\$142.36		\$142.43		
	Change from last rate					\$12.81		\$13.89		-\$4.10		-\$12.21		\$5.55		\$8.88		\$0.08		
						10.9%		10.7%		-2.8%		-8.7%		4.3%		6.7%		0.1%		

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Yukon Energy Corporation
2017 – 2018 General Rate Application
UCG -YEC-1-3

Table 2-3 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kWh/month usage [Whitehorse]

Line #	Customer Use per month:	1,200 kWh	50% of Proposed															
			Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
2=KWh*Base rate	Customer Charge (per month)	1,000	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
3=KWh*Base rate	First Block Energy (kWh)		\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68
4=KWh*Base rate	Second Block Energy (kWh)	200	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64
5=(1+2+3)*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.22	\$0.001910	\$2.29	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$5.84	-\$0.005600	-\$6.72	-\$0.000110	-\$0.13	-\$0.000110	-\$0.13
6=(1+2+3)*Rider R rate	YEC Rider J (%)				6.40%	\$11.90	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	16.51%	\$30.70	16.57%	\$30.81
7=KWh*Rider E rate	YEC Rider R (%)			\$0.00	3.75%	\$6.97	3.62%	\$6.73		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
8=(1+2+3)*Rider R rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16
9=Sum(1:8)	AEY Rider R (%)						6.50%	\$12.09	7.20%	\$13.39	7.20%	\$13.39	11.62%	\$21.61	8.30%	\$15.44	8.30%	\$15.44
	Total Before Tax Rebate, IER, GST			\$190.19		\$207.14		\$225.27		\$219.84		\$205.83		\$213.18		\$223.82		\$223.92
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.39	-0.75%	-\$1.39	-0.60%	-\$1.12	-0.55%	-\$1.02	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$162.19		\$179.13		\$197.54		\$192.20		\$178.25		\$185.60		\$196.24		\$196.34
13=12*1.05	Total After GST			\$170.30		\$188.09		\$207.42		\$201.81		\$187.17		\$194.88		\$206.05		\$206.16
	Change from last rate					\$17.79		\$19.33		-\$5.60		-\$14.65		\$7.71		\$11.17		\$0.11
						10.4%		10.3%		-2.7%		-7.3%		4.1%		5.7%		0.1%

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Table 2-4 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kWh/month usage [Whitehorse]

Line #	Customer Use per month:	1,400 kWh	50% of Proposed															
			Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
2=KWh*Base rate	Customer Charge (per month)	1,000	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
3=KWh*Base rate	First Block Energy (kWh)		\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96
4=KWh*Base rate	Second Block Energy (kWh)	400	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28
5=(1+2+3)*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.93	\$0.001910	\$2.67	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$6.82	-\$0.005600	-\$7.84	-\$0.000110	-\$0.15	-\$0.000110	-\$0.15
6=(1+2+3)*Rider R rate	YEC Rider J (%)				6.40%	\$15.10	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	16.51%	\$38.95	16.57%	\$39.08
7=KWh*Rider E rate	YEC Rider R (%)			\$0.00	3.75%	\$8.85	3.62%	\$8.54		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
8=(1+2+3)*Rider R rate	Rider E (kW.h) [DCF Rider]						6.50%	\$15.33	7.20%	\$16.98	7.20%	\$16.98	11.62%	\$27.41	8.30%	\$19.58	8.30%	\$19.58
9=Sum(1:8)	AEY Rider R (%)			\$240.82		\$262.51		\$285.73		\$278.85		\$262.51		\$271.91		\$284.74		\$284.87
	Total Before Tax Rebate, IER, GST																	
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.77	-0.75%	-\$1.77	-0.60%	-\$1.42	-0.55%	-\$1.30	-0.52%	-\$1.23	-0.52%	-\$1.23	-0.52%	-\$1.23	-0.52%	-\$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$212.44		\$234.13		\$257.71		\$250.94		\$234.67		\$244.08		\$256.90		\$257.03
13=12*1.05	Total After GST			\$223.06		\$245.83		\$270.59		\$263.49		\$246.40		\$256.28		\$269.75		\$269.89
	Change from last rate					\$22.77		\$24.76		-\$7.11		-\$17.08		\$9.87		\$13.47		\$0.14
						10.2%		10.1%		-2.6%		-6.5%		4.0%		5.3%		0.1%

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Table 1-1: Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:																Proposed	
	800 kWh		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																		
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	800	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12
3=KWh*Base rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$2.82	\$0.001910	\$1.53	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$3.90	-\$0.005600	-\$4.48	-\$0.000110	-\$0.09	-\$0.000110	-\$0.09
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$7.15	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	16.51%	\$18.45	22.12%	\$24.72
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$4.19	3.62%	\$4.05		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$7.27	7.20%	\$8.05	7.20%	\$8.05	11.62%	\$12.99	8.30%	\$9.28	8.30%	\$9.28
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$114.59		\$124.64		\$135.39		\$132.12		\$122.79		\$127.14		\$133.97		\$140.24
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$0.84	-0.75%	-\$0.84	-0.60%	-\$0.67	-0.55%	-\$0.61	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29
12=Sum(9:11)	Total After Rebates, before GST			\$92.46		\$102.52		\$113.43		\$110.22		\$100.92		\$105.27		\$112.10		\$118.37
13=12*1.05	Total After GST			\$97.08		\$107.64		\$119.10		\$115.73		\$105.96		\$110.54		\$117.71		\$124.29
Change from last rate						\$10.56		\$11.46		-\$3.37		-\$9.77		\$4.57		\$7.17		\$6.58
						10.9%		10.6%		-2.8%		-8.4%		4.3%		6.5%		5.6%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-2 : Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:		Table 2: Rates and Recent Historical Comparisons - Non-Government Residential at 2000 kWh/month usage (17/06/2018)														Proposed	
		1,000 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																		
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$3.52	\$0.001910	\$1.91	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$4.87	-\$0.005600	-\$5.60	-\$0.000110	-\$0.11	-\$0.000110	-\$0.11
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$8.71	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	16.51%	\$22.46	22.12%	\$30.09
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$5.10	3.62%	\$4.93		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80	-\$0.006800	-\$6.80
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$8.84	7.20%	\$9.80	7.20%	\$9.80	11.62%	\$15.81	8.30%	\$11.29	8.30%	\$11.29
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$139.57		\$151.77		\$164.80		\$160.82		\$149.15		\$154.44		\$162.89		\$170.53
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.02	-0.75%	-\$1.02	-0.60%	-\$0.82	-0.55%	-\$0.75	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71	-0.52%	-\$0.71
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$111.94		\$124.14		\$137.37		\$133.47		\$121.84		\$127.12		\$135.58		\$143.21
13=12*1.05	Total After GST			\$117.54		\$130.35		\$144.24		\$140.14		\$127.93		\$133.48		\$142.36		\$150.37
Change from last rate						\$12.81		\$13.89		-\$4.10		-\$12.21		\$5.55		\$8.88		\$8.01
						10.9%		10.7%		-2.8%		-8.7%		4.3%		6.7%		5.6%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-3: Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kWh/month usage [Whitehorse]

Line #	Customer Use per month:																Proposed	
	1,200 kWh		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																		
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68
3=KWh*Base rate	Second Block Energy (kWh)	200	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.22	\$0.001910	\$2.29	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$5.84	-\$0.005600	-\$6.72	-\$0.000110	-\$0.13	-\$0.000110	-\$0.13
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$11.90	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	16.51%	\$30.70	22.12%	\$41.14
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$6.97	3.62%	\$6.73		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$12.09	7.20%	\$13.39	7.20%	\$13.39	11.62%	\$21.61	8.30%	\$15.44	8.30%	\$15.44
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$190.19		\$207.14		\$225.27		\$219.84		\$205.83		\$213.18		\$223.82		\$234.25
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.39	-0.75%	-\$1.39	-0.60%	-\$1.12	-0.55%	-\$1.02	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$162.19		\$179.13		\$197.54		\$192.20		\$178.25		\$185.60		\$196.24		\$206.67
13=12*1.05	Total After GST			\$170.30		\$188.09		\$207.42		\$201.81		\$187.17		\$194.88		\$206.05		\$217.01
Change from last rate						\$17.79		\$19.33		-\$5.60		-\$14.65		\$7.71		\$11.17		\$10.96
						10.4%		10.3%		-2.7%		-7.3%		4.1%		5.7%		5.3%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 1-4: Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kWh/month usage [Whitehorse]

Line #	Customer Use per month:																Proposed	
	1,400 kWh		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																		
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96
3=KWh*Base rate	Second Block Energy (kWh)	400	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.93	\$0.001910	\$2.67	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$6.82	-\$0.005600	-\$7.84	-\$0.000110	-\$0.15	-\$0.000110	-\$0.15
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$15.10	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	16.51%	\$38.95	22.12%	\$52.18
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$8.85	3.62%	\$8.54		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$9.52	-\$0.006800	-\$9.52	-\$0.006800	-\$9.52	-\$0.006800	-\$9.52
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$15.33	7.20%	\$16.98	7.20%	\$16.98	11.62%	\$27.41	8.30%	\$19.58	8.30%	\$19.58
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$240.82		\$262.51		\$285.73		\$278.85		\$262.51		\$271.91		\$284.74		\$297.97
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.77	-0.75%	-\$1.77	-0.60%	-\$1.42	-0.55%	-\$1.30	-0.52%	-\$1.23	-0.52%	-\$1.23	-0.52%	-\$1.23	-0.52%	-\$1.23
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$212.44		\$234.13		\$257.71		\$250.94		\$234.67		\$244.08		\$256.90		\$270.14
13=12*1.05	Total After GST			\$223.06		\$245.83		\$270.59		\$263.49		\$246.40		\$256.28		\$269.75		\$283.65
Change from last rate						\$22.77		\$24.76		-\$7.11		-\$17.08		\$9.87		\$13.47		\$13.90
						10.2%		10.1%		-2.6%		-6.5%		4.0%		5.3%		5.2%

Note:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.

Table 2-1 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 800 kWh/month usage [Whitehorse]

Line #	Customer Use per month:																50% of Proposed	
	800 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18		
		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	
Base Rates																		
1	Customer Charge (per month)																	
2=KWh*Base rate	First Block Energy (kWh)	800	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	\$97.12	\$0.1214	
3=KWh*Base rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$2.82	\$0.001910	\$1.53	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$3.90	-\$0.005600	-\$4.48	-\$0.000110	-\$0.09	-\$0.000110	
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$7.15	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	11.01%	\$12.31	16.51%	\$18.45	\$18.51	
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$4.19	3.62%	\$4.05		\$0.00		\$0.00		\$0.00		\$0.00	\$0.00	
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	-\$5.44	-\$0.006800	
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$7.27	7.20%	\$8.05	7.20%	\$8.05	11.62%	\$12.99	8.30%	\$9.28	\$9.28	
9=Sum(1:8)	Total Before Tax Rebate, IER, GST		\$114.59		\$124.64		\$135.39		\$132.12		\$122.79		\$127.14		\$133.97		\$134.03	
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$0.84	-0.75%	-\$0.84	-0.60%	-\$0.67	-0.55%	-\$0.61	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	-\$0.58	-0.52%	
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	-\$21.29	-\$0.02661	
12=Sum(9:11)	Total After Rebates, before GST		\$92.46		\$102.52		\$113.43		\$110.22		\$100.92		\$105.27		\$112.10		\$112.16	
13=12*1.05	Total After GST		\$97.08		\$107.64		\$119.10		\$115.73		\$105.96		\$110.54		\$117.71		\$117.77	
	Change from last rate				\$10.56		\$11.46		-\$3.37		-\$9.77		\$4.57		\$7.17		\$0.06	
					10.9%		10.6%		-2.8%		-8.4%		4.3%		6.5%		0.1%	

Notes:

- September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
- January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Table 2-2 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,000 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:																50% of Proposed	
		1,000 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
Base Rates																		
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40	\$0.1214	\$121.40
3=KWh*Base rate	Second Block Energy (kWh)	-	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00	\$0.1282	\$0.00
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$3.52	\$0.001910	\$1.91	\$0.000000	\$0.00	\$0.000000	\$0.00	~~-\$0.004870~~	~~-\$4.87~~	~~-\$0.005600~~	~~-\$5.60~~	~~-\$0.000110~~	~~-\$0.11~~	~~-\$0.000110~~	~~-\$0.11~~
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$8.71	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	11.01%	\$14.98	16.51%	\$22.46	16.57%	\$22.54
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$5.10	3.62%	\$4.93		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										~~-\$0.006800~~	~~-\$6.80~~	~~-\$0.006800~~	~~-\$6.80~~	~~-\$0.006800~~	~~-\$6.80~~	~~-\$0.006800~~	~~-\$6.80~~
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$8.84	7.20%	\$9.80	7.20%	\$9.80	11.62%	\$15.81	8.30%	\$11.29	8.30%	\$11.29
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$139.57		\$151.77		\$164.80		\$160.82		\$149.15		\$154.44		\$162.89		\$162.97
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	~~-\$1.02~~	-0.75%	~~-\$1.02~~	-0.60%	~~-\$0.82~~	-0.55%	~~-\$0.75~~	-0.52%	~~-\$0.71~~	-0.52%	~~-\$0.71~~	-0.52%	~~-\$0.71~~	-0.52%	~~-\$0.71~~
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~
12=Sum(9:11)	Total After Rebates, before GST			\$111.94		\$124.14		\$137.37		\$133.47		\$121.84		\$127.12		\$135.58		\$135.65
13=12*1.05	Total After GST			\$117.54		\$130.35		\$144.24		\$140.14		\$127.93		\$133.48		\$142.36		\$142.43
	Change from last rate					\$12.81		\$13.89		~~-\$4.10~~		~~-\$12.21~~		\$5.55		\$8.88		\$0.08
						10.9%		10.7%		-2.8%		-8.7%		4.3%		6.7%		0.1%

Notes:

1. September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
2. January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Table 2-3 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,200 kW.h/month usage [Whitehorse]

Line #	Customer Use per month:		50% of Proposed															
		1,200 kWh	Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		Jan-18	
Base Rates			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68	\$0.1214	\$145.68
3=KWh*Base rate	Second Block Energy (kWh)	200	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64	\$0.1282	\$25.64
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.22	\$0.001910	\$2.29	\$0.000000	\$0.00	\$0.000000	\$0.00	-\$0.004870	-\$5.84	-\$0.005600	-\$6.72	-\$0.000110	-\$0.13	-\$0.000110	-\$0.13
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$11.90	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	11.01%	\$20.48	16.51%	\$30.70	16.57%	\$30.81
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$6.97	3.62%	\$6.73		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16	-\$0.006800	-\$8.16
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$12.09	7.20%	\$13.39	7.20%	\$13.39	11.62%	\$21.61	8.30%	\$15.44	8.30%	\$15.44
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$190.19		\$207.14		\$225.27		\$219.84		\$205.83		\$213.18		\$223.82		\$223.92
Less: Rebates																		
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	-\$1.39	-0.75%	-\$1.39	-0.60%	-\$1.12	-0.55%	-\$1.02	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97	-0.52%	-\$0.97
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61	-\$0.02661	-\$26.61
12=Sum(9:11)	Total After Rebates, before GST			\$162.19		\$179.13		\$197.54		\$192.20		\$178.25		\$185.60		\$196.24		\$196.34
13=12*1.05	Total After GST			\$170.30		\$188.09		\$207.42		\$201.81		\$187.17		\$194.88		\$206.05		\$206.16
Change from last rate						\$17.79	\$19.33	-\$5.60	-\$14.65		\$7.71	\$11.17		\$0.11		\$0.11		\$0.11
						10.4%	10.3%	-2.7%	-7.3%		4.1%	5.7%						0.1%

Notes:

- September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
- January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

Table 2-4 - Yukon Bills - Recent Historical Comparisons - Non-Government Residential at 1,400 kWh/month usage [Whitehorse]

Line #	Customer Use per month:		Jan-12		Jan-13		Jan-14		Jan-15		Jan-16		Jan-17		Sep-17		50% of Proposed Jan-18	
	1,400 kWh																	
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
1	Base Rates																	
	Customer Charge (per month)		\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65	\$14.65
2=KWh*Base rate	First Block Energy (kWh)	1,000	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96	\$0.1214	\$169.96
3=KWh*Base rate	Second Block Energy (kW)	400	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28	\$0.1282	\$51.28
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]		\$0.003520	\$4.93	\$0.001910	\$2.67	\$0.000000	\$0.00	\$0.000000	\$0.00	~~-\$0.004870~~	~~-\$6.82~~	~~-\$0.005600~~	~~-\$7.84~~	~~-\$0.000110~~	~~-\$0.15~~	~~-\$0.000110~~	~~-\$0.15~~
5=(1+2+3)*Rider J rate	YEC Rider J (%)				6.40%	\$15.10	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	11.01%	\$25.97	16.51%	\$38.95	16.57%	\$39.08
6=(1+2+3)*Rider R rate	YEC Rider R (%)			\$0.00	3.75%	\$8.85	3.62%	\$8.54		\$0.00		\$0.00		\$0.00		\$0.00		\$0.00
7=KWh*Rider E rate	Rider E (kW.h) [DCF Rider]										~~-\$0.006800~~	~~-\$9.52~~	~~-\$0.006800~~	~~-\$9.52~~	~~-\$0.006800~~	~~-\$9.52~~	~~-\$0.006800~~	~~-\$9.52~~
8=(1+2+3)*Rider R rate	AEY Rider R (%)						6.50%	\$15.33	7.20%	\$16.98	7.20%	\$16.98	11.62%	\$27.41	8.30%	\$19.58	8.30%	\$19.58
9=Sum(1:8)	Total Before Tax Rebate, IER, GST			\$240.82		\$262.51		\$285.73		\$278.85		\$262.51		\$271.91		\$284.74		\$284.87
	Less: Rebates																	
10=(1+2+3)*Rebate	Income Tax Rebate		-0.75%	~~-\$1.77~~	-0.75%	~~-\$1.77~~	-0.60%	~~-\$1.42~~	-0.55%	~~-\$1.30~~	-0.52%	~~-\$1.23~~	-0.52%	~~-\$1.23~~	-0.52%	~~-\$1.23~~	-0.52%	~~-\$1.23~~
11=kWh*IER	Interim Electrical Rebate (IER, 1st block)		-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~	-\$0.02661	~~-\$26.61~~
12=Sum(9:11)	Total After Rebates, before GST			\$212.44		\$234.13		\$257.71		\$250.94		\$234.67		\$244.08		\$256.90		\$257.03
13=12*1.05	Total After GST			\$223.06		\$245.83		\$270.59		\$263.49		\$246.40		\$256.28		\$269.75		\$269.89
	Change from last rate					\$22.77		\$24.76		~~-\$7.11~~		~~-\$17.08~~		\$9.87		\$13.47		\$0.14
						10.2%		10.1%		-2.6%		-6.5%		4.0%		5.3%		0.1%

Notes:

- September 1, 2017 YEC Rider J reflects Yukon Utilities Board Order 2017-06 which approved interim refundable Rider J at 16.51% effective September 1, 2017.
- January 1, 2018 YEC Rider J reflects 50% of the proposed increase in the 2017/18 GRA [Proposed Rider J at 22.12% is about 11.11% addition to the existing Rider J at 11.01%; the assumption is based on 50% of 11.11% plus the existing 11.01% to total of 16.57%].

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 2

4 *YEC states: "Measures since the 2012/13 GRA that have helped to*
5 *manage Yukon Energy's ongoing pressures and defer the requirement*
6 *for the Application include debt re-negotiation with Yukon Development*
7 *Corporation (YDC), the Mayo B Promissory Note's flexible debt*
8 *financing provisions, YDC contributions that reduced project costs to*
9 *be recovered from ratepayers, secondary sales revenues, and adjusted*
10 *thermal fuel costs related to Diesel Contingency Fund operation and*
11 *also to the implementation of the Whitehorse Diesel-Natural Gas*
12 *Conversion Project (LNG Project or LNG Plant project)."*

13
14 June 22, 2017 Application, pages 1-3 and 1-4

15 *YEC states that Debt Re-Negotiation with YDC lowered YEC's interest*
16 *costs by about \$1.5 million in 2017 and \$1.4 million in 2018 and that*
17 *revenues from secondary sales are forecast at \$0.642 million per year*
18 *in 2017 and 2018, all of which is used to lower the required level of*
19 *retail rates for firm power.*

20
21 **PREAMBLE:**

22
23 **QUESTION:**

- 24
25 a) Please provide specific details regarding the actual impact that the Mayo B
26 Promissory Note's flexible debt financing provisions, YDC contributions that
27 reduced project costs to be recovered from ratepayers, adjusted thermal fuel costs
28 related to Diesel Contingency Fund operation, and the implementation of the
29 Whitehorse Diesel-Natural Gas Conversion Project has had on YEC's revenue
30 requirements for 2017 and 2018.
31
32 b) Please provide specific details of how YEC has reduced ongoing costs to offset
33 other cost pressures.
34
35 c) Please provide details of YEC's efforts to date to consider a performance-based
36 regulation mechanism including earnings sharing.

1 **ANSWER:**

2
3 **(a)**

4
5 Please see responses to John Maissan-YEC-1-23 (a), YUB-YEC-5(a) and
6 UCG-YEC-1-23(a-e).

7
8 **(b)**

9
10 Please see Tab 1, Section, 1.2 pages 1-2 to 1-4 of the Application which reviews the
11 measures since 2013 to defer the need for a rate increase.

12
13 **(c)**

14
15 In UCG-YEC-1-19(c) from the 2008/09 GRA, Yukon Energy addressed this UCG concept
16 as follows:

17
18 As noted in response UCG-YEC-1-32 provided during the 2005 Required
19 Revenues and Related Matters proceeding, a multi-year performance
20 based regulatory framework is not currently in place in Yukon.
21 Implementing this form of regulation would likely require significant
22 changes to the regulatory framework in the Yukon that have not yet been
23 assessed. Yukon Energy has not assessed measures that the Yukon
24 Government might adopt to bring in legislation or policy related to
25 performance-based regulation.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 4
4 *YEC states that it is requesting approval of a forecast revenue*
5 *requirement of \$48.544 million for 2017 and \$49.864 million for 2018.*
6

7 **PREAMBLE:**

8
9 **QUESTION:**

- 10
11 a) Please confirm that the YUB-approved revenue requirements for 2012 and 2013
12 were \$38.850 million and \$42.263 million respectively.
13
14 b) Please provide a table similar to Table 3.1 showing YUB-approved revenue
15 requirement components and actuals for 2012, 2013, 2014, 2015 and 2016.
16 Please identify percentage changes from column to column and include footnotes
17 identifying the YUB orders that approved the revenue requirements.
18
19 c) Please provide a table similar to Table 3.2 showing YUB-approved fuel and
20 purchased power costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please
21 identify percentage changes from column to column.
22
23 d) Please provide a table similar to Table 3.3 showing YUB-approved non-fuel O&M
24 expenses and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
25 percentage changes from column to column.
26
27 e) Please provide a table similar to Table 3.4 showing YUB-approved employee
28 complement and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
29 percentage changes from column to column.
30
31 f) Please provide a table similar to Table 3.5 showing YUB-approved production
32 costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
33 percentage changes from column to column.
34
35 g) Please provide a table similar to Table 3.6 showing YUB-approved transmission
36 costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
37 percentage changes from column to column.

- 1 h) Please provide a table similar to Table 3.6.1 showing YUB-approved brushing
2 costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
3 percentage changes from column to column.
4
- 5 i) Please provide a table similar to Table 3.7 showing YUB-approved distribution
6 costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
7 percentage changes from column to column.
8
- 9 j) Please provide a table similar to Table 3.8 showing YUB-approved general O&M
10 costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
11 percentage changes from column to column.
12
- 13 k) Please provide a table similar to Table 3.9 showing YUB-approved administration
14 costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
15 percentage changes from column to column.
16
- 17 l) Please provide a table similar to Table 3.10 showing YUB-approved insurance and
18 reserve for injuries and damages costs and actuals for 2012, 2013, 2014, 2015
19 and 2016. Please identify percentage changes from column to column.
20
- 21 m) Please provide a table similar to Table 3.12 showing YUB-approved property
22 taxes costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
23 percentage changes from column to column.
24
- 25 n) Please provide a table similar to Table 3.13 showing YUB-approved rate base
26 components and actuals for 2012, 2013, 2014, 2015 and 2016. Please identify
27 percentage changes from column to column.
28
- 29 o) Please provide a table similar to Table 3.14 showing YUB-approved depreciation
30 and amortization costs and actuals for 2012, 2013, 2014, 2015 and 2016. Please
31 identify percentage changes from column to column.
32
- 33 p) Please provide a table similar to Table 3.15 showing YUB-approved cost of capital
34 and actuals for 2012, 2013, 2014, 2015 and 2016.

1 **ANSWER:**

2

3 **(a)**

4

5 Confirmed.

6

7 **(b)** through **(p)**

8

9 Please see below copies of the tables as requested from Tab 3 of the Application for the
10 years 2012 to 2016.

Table 3.1
Yukon Energy Revenue Requirement
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fuel and Purchased Power	\$ 2,316	\$ 3,743	62%	\$ 3,200	\$ 3,878	21%	\$ 1,569	-60%	\$ 2,756	76%	\$ 2,159	-22%
Non-Fuel Operating and Maintenance	17,210	17,769	3%	18,111	19,381	7%	19,957	3%	19,580	-2%	20,470	5%
Depreciation and Amortization	7,927	8,225	4%	8,604	9,500	10%	7,783	-18%	8,690	12%	7,816	-10%
Return on Rate Base	11,396	7,346	-36%	12,348	11,139	-10%	11,938	7%	10,829	-9%	12,242	13%
Revenue Requirement/Revenue	\$ 38,850	\$ 37,083	-5%	\$ 42,263	\$ 43,897	4%	\$ 41,247	-6%	\$ 41,855	1%	\$ 42,686	2%

1

Table 3.2
Fuel and Purchased Power
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fuel	\$ 2,276	\$ 3,715	63%	\$ 3,160	\$ 3,848	22%	\$ 1,528	-60%	\$ 2,720	78%	\$ 2,114	-22%
Purchased Power	40	28	-30%	40	30	-26%	41	38%	36	-12%	45	26%
Total Fuel and Purchased Power	\$ 2,316	\$ 3,743	62%	\$ 3,200	\$ 3,878	21%	\$ 1,569	-60%	\$ 2,756	76%	\$ 2,159	-22%

Note:

2 1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance and run-up requirements, and forecast fuel prices.

Table 3.3
Non-Fuel Operating and Maintenance Expenses
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	\$ 9,155	\$ 9,635	5%	\$ 9,348	\$ 10,604	13%	\$ 11,172	5%	\$ 11,068	-1%	\$ 11,739	6%
Production	1,449	1,552	7%	1,437	1,639	14%	1,795	10%	1,595	-11%	1,906	19%
Transmission	760	785	3%	853	1,266	49%	594	-53%	680	15%	709	4%
Distribution	201	786	292%	226	322	43%	553	72%	541	-2%	284	-47%
General O&M	1,094	901	-18%	1,154	1,224	6%	1,321	8%	1,382	5%	1,156	-16%
Administration	3,179	2,691	-15%	3,646	2,778	-24%	2,947	6%	2,585	-12%	2,726	5%
Insurance and Reserve for Injuries/Damages	1,061	1,097	3%	1,121	1,216	8%	1,243	2%	1,256	1%	1,263	1%
Property Taxes	312	322	3%	326	331	1%	331	0%	473	43%	686	45%
Total OM&A (Tab 7, Schedule 10)	\$ 17,210	\$ 17,769	3%	\$ 18,111	\$ 19,381	7%	\$ 19,957	3%	\$ 19,580	-2%	\$ 20,470	5%

Table 3.4
Employee Complement History

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
President	4.50	4.50	0%	4.50	5.00	11%	5.00	0%	5.46	9%	5.09	-7%
Communications	1.00	1.00	0%	1.00	1.00	0%	1.00	0%	1.00	0%	1.00	0%
Human Resources & Info. Mgmt.	6.25	6.18	-1%	6.25	6.16	-1%	6.12	-1%	6.13	0%	5.20	-15%
Resource Planning and Environment	7.00	7.00	0%	7.00	7.00	0%	6.00	-14%	6.00	0%	6.00	0%
Finance, Cust. Acctg. & Purchasing	17.00	17.06	0%	17.00	16.96	0%	17.63	4%	16.81	-5%	16.87	0%
Operations	41.25	42.10	2%	41.25	42.83	4%	42.15	-2%	42.79	2%	44.15	3%
Engineering Services	13.00	12.00	-8%	13.00	12.00	-8%	13.00	8%	13.00	0%	13.00	0%
Health, Safety & Environment	2.00	2.00	0%	2.00	2.00	0%	2.00	0%	2.00	0%	2.00	0%
Total	92.00	91.84	0%	92.00	92.95	1%	92.90	0%	93.19	0%	93.31	0%

Note:

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

Table 3.5
Production Costs
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	\$ 3,003	\$ 3,262	9%	\$ 3,057	\$ 3,671	20%	\$ 3,792	3%	\$ 3,876	2%	\$ 4,133	7%
Diesel	425	446	5%	439	444	1%	569	28%	430	-24%	548	27%
LNG									61		224	269%
Hydro	938	872	-7%	909	1,024	13%	1,107	8%	1,024	-8%	1,058	3%
Wind	27	34	25%	18	17	-2%	43	146%	3	-93%	14	388%
Operation Supervision	59	199	235%	72	154	115%	77	-50%	78	2%	62	-21%
Total Production	\$ 4,452	\$ 4,813	8%	\$ 4,494	\$ 5,310	18%	\$ 5,588	5%	\$ 5,472	-2%	\$ 6,039	10%

5

Table 3.6
Transmission Costs
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	\$ 431	\$ 508	18%	\$ 440	\$ 577	31%	\$ 507	-12%	\$ 562	11%	\$ 621	10%
Brushing Cost	505	561	11%	639	948	48%	1,161	22%	1,069	-8%	1,034	-3%
Deferred Brushing							(748)	na	(632)	-15%	(550)	-13%
Net Brushing Cost	505	561	11%	639	948	48%	413	-56%	437	6%	484	11%
Other Non-Labour	255	224	-12%	214	318	49%	180	-43%	243	35%	225	-7%
Total Transmission	\$ 1,190	\$ 1,293	9%	\$ 1,293	\$ 1,843	43%	\$ 1,100	-40%	\$ 1,242	13%	\$ 1,330	7%

Note:

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

Table 3.6.1
Brushing Costs
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Transmission Brushing	505	561	11%	639	948	48%	1,161	22%	1,069	-8%	1,034	-3%
Distribution Brushing	93	157	69%	113	113	0%	262	131%	160	-39%	39	-76%
Total Brushing	598	718	20%	752	1,062	41%	1,424	34%	1,229	-14%	1,073	-13%
Transmission Deferred	na	na	na	na	na	na	748	na	632	-15%	550	-13%
Distribution Deferred	na	na	na	na	na	na	169	na	95	-44%	21	-78%
Brushing Deferred	na	na	na	na	na	na	917	na	727	-21%	571	-21%
Net Transmission Brushing	505	561	11%	639	948	48%	413	-56%	437	6%	484	11%
Net Distribution Brushing	93	157	69%	113	113	0%	93	-18%	65	-30%	18	-72%
Net Brushing Expense	\$ 598	\$ 718	20%	\$ 752	\$ 1,062	41%	\$ 507	-52%	\$ 502	-1%	\$ 502	0%

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

Table 3.7
Distribution Costs
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	\$ 579	\$ 758	31%	\$ 592	\$ 794	34%	\$ 912	15%	\$ 746	-18%	\$ 837	12%
Brushing Cost	93	157	69%	113	113	0%	262	131%	160	-39%	39	-76%
Deferred Brushing							(169)	na	(95)	-44%	(21)	-78%
Net Brushing Cost	93	157	69%	113	113	0%	93	-18%	65	-30%	18	-72%
Other Non-Labour	108	630	483%	113	209	84%	460	120%	476	3%	266	-44%
Total Distribution	\$ 780	\$ 1,544	98%	\$ 819	\$ 1,117	36%	\$ 1,465	31%	\$ 1,288	-12%	\$ 1,121	-13%

Note:

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

Table 3.8
General Operating and Maintenance
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	\$ 245	\$ 217	-11%	\$ 250	\$ 261	4%	\$ 414	59%	\$ 368	-11%	\$ 366	-1%
Transportation	427	184	-57%	451	569	26%	550	-3%	505	-8%	459	-9%
Maintenance of Company Owned Properties	581	665	14%	611	565	-8%	552	-2%	673	22%	501	-26%
SCADA Communication	86	53	-39%	93	90	-3%	219	144%	203	-7%	197	-3%
Total General O&M	\$ 1,339	\$ 1,117	-17%	\$ 1,405	\$ 1,485	6%	\$ 1,735	17%	\$ 1,749	1%	\$ 1,522	-13%

Table 3.9
Administration
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Labour	\$ 4,897	\$ 4,891	0%	\$ 5,008	\$ 5,301	6%	\$ 5,547	5%	\$ 5,516	-1%	\$ 5,783	5%
Resource Planning	26	89	242%	26	18	-31%	9	-50%	6	-33%	14	138%
Communications	105	102	-3%	105	155	47%	100	-36%	144	44%	129	-10%
Customer Accounting	190	197	3%	191	232	21%	224	-3%	214	-4%	208	-3%
Environmental Mgmt	338	330	-2%	569	230	-60%	350	52%	273	-22%	166	-39%
General	910	438	-52%	1,099	590	-46%	741	26%	438	-41%	613	40%
Information Systems	569	536	-6%	607	481	-21%	488	1%	557	14%	576	3%
Fish Hatchery	182	154	-16%	187	169	-9%	124	-27%	162	30%	157	-3%
Safety	177	121	-32%	189	164	-13%	150	-8%	165	10%	172	4%
Training	260	146	-44%	260	161	-38%	154	-5%	169	10%	143	-15%
Recruitment	120	260	116%	120	124	3%	280	125%	296	6%	231	-22%
Board of Directors	180	112	-38%	168	150	-10%	255	70%	99	-61%	160	62%
Union	23	49	113%	23	117	407%	0	-100%	0	#DIV/0!	0	#DIV/0!
Regulatory Affairs	34	2	-95%	34	113	232%	0	-100%	39	#DIV/0!	99	152%
Material Management	33	147	344%	35	58	66%	55	-5%	17	-69%	41	138%
Contracting	15	10	-34%	16	12	-25%	8	-35%	5	-44%	14	202%
Professional Development	17	0	-100%	17	4	-77%	9	137%	1	-89%	3	155%
Total Administration	\$ 8,076	\$ 7,583	-6%	\$ 8,654	\$ 8,080	-7%	\$ 8,495	5%	\$ 8,101	-5%	\$ 8,509	5%

Table 3.10
Insurance and Reserve for Injuries & Damages
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Insurance	\$ 835	\$ 871	4%	\$ 895	\$ 990	11%	\$ 1,017	3%	\$ 1,030	1%	\$ 1,037	1%
Reserve Appropriation (RFID)	226	226	0%	226	226	0%	226	0%	226	0%	226	0%
Total	\$ 1,061	\$ 1,097	3%	\$ 1,121	\$ 1,216	8%	\$ 1,243	2%	\$ 1,256	1%	\$ 1,263	1%

Note:

1. The RFID amount for 2012-2016 years reflect annual appropriation of \$0.190 million plus amortization of the balance over five year period [\$0.036 million/year] to total \$0.226 million per YUB Order 2013-01.

Table 3.12
Property Taxes
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Property Taxes	\$ 312	\$ 322	3%	\$ 326	\$ 331	1%	\$ 331	0%	\$ 473	43%	\$ 686	45%

Table 3.13
Mid-Year Net Rate Base
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Year-End:												
Net plant in service ¹	\$ 219,444	\$ 216,964	-1%	\$ 222,393	\$ 217,202	-2%	\$ 216,836	0%	\$ 250,737	16%	\$ 251,405	0%
Mid-Year:												
Net plant in service												
Before contributions	\$ 377,608	\$ 376,408	0%	\$ 386,941	\$ 382,576	-1%	\$ 379,478	-1%	\$ 402,204	6%	\$ 425,340	6%
Less contributions	167,254	167,172	0%	166,023	165,732	0%	162,459	-2%	168,417	4%	174,269	3%
Net plant in service	210,354	209,236	-1%	220,918	216,844	-2%	217,019	0%	233,787	8%	251,071	7%
Mid-year regulatory deferral ²	2,005	2,559	28%	1,486	1,693	14%	1,367	-19%	2,007	47%	2,061	3%
Working capital	4,108	4,021	-2%	4,280	4,521	6%	4,495	-1%	4,791	7%	4,928	3%
Net Rate Base	\$ 216,467	\$ 215,816	0%	\$ 226,684	\$ 223,058	-2%	\$ 222,881	0%	\$ 240,585	8%	\$ 258,060	7%

Notes:

¹ Net plant in service at year end is gross property, plant and equipment plus deferred study and relicensing costs, less work in progress, depreciation, amortization, customer contributions, reserve for future removal and site restoration, deferred fire gain, and disallowed assets.

² This reflects the regulatory deferred costs (see Tab 5, Tables 5.3 to 5.8), excluding DSM and the balance of the hearing reserve account (see Table 3.14.1).

Table 3.14
Depreciation and Amortization
(\$000)

	2012 GRA compliance	Actual 2012	% change	2013 GRA compliance	Actual 2013	% change	Actual 2014	% change	Actual 2015	% change	Actual 2016	% change
Fixed Asset Depreciation	\$ 8,406	\$ 8,503	1%	\$ 8,989	\$ 8,894	-1%	\$ 8,906	0%	\$ 9,828	10%	\$ 10,615	8%
Less: Customer contribution	(3,536)	(3,584)	1%	(3,569)	(3,677)	3%	(3,691)	0%	(3,624)	-2%	(4,102)	13%
Less: Amortization of fire insurance recoveries	(262)	(270)	3%	(262)	(262)	0%	(262)	0%	(262)	0%	(262)	0%
Less: Disallowed Depreciation	(4)	(4)	0%	(16)	(16)	0%	(16)	0%	(16)	0%	(16)	0%
Plus: Amortization of deferred charges	3,324	3,580	8%	3,462	4,561	32%	2,846	-38%	2,764	-3%	1,581	-43%
Total Depreciation & Amortization	\$ 7,927	\$ 8,225	4%	\$ 8,604	\$ 9,500	10%	\$ 7,783	-18%	\$ 8,690	12%	\$ 7,816	-10%

Notes:

1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: \$0.004 million (YUB 1992-1) and \$0.012 million (YUB 2013-01).

Table 3.15
Cost of Capital

	2012 GRA compliance	Actual 2012	Change	2013 GRA compliance	Actual 2013	Change	Actual 2014	Change	Actual 2015	Change	Actual 2016	Change
Average Cost of Debt	3.27%	3.47%	0.20%	3.58%	3.38%	-0.20%	3.22%	-0.16%	2.00%	-1.21%	2.10%	0.10%
Return on Equity	8.25%	3.30%	-4.95%	8.25%	7.42%	-0.83%	8.44%	1.01%	8.10%	-0.34%	8.69%	0.59%
Average Cost of Capital	5.26%	4.78%	-0.48%	5.45%	4.99%	-0.46%	5.36%	0.36%	4.50%	-0.86%	4.74%	0.24%

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 9
4 *YEC states "The 2016 Resource Plan addresses Yukon Energy's*
5 *requirements for the next five years, as well as for the longer term*
6 *planning horizon, and describes the extensive consultation undertaken*
7 *during the preparation of this plan. Yukon Energy is not seeking specific*
8 *approvals for the plan. The 2016 Resource Plan is provided for*
9 *information of the Board and stakeholders and to provide context for*
10 *capital expenditures and ongoing planning costs included in the test*
11 *year forecasts."*
12

13 **PREAMBLE:**

14
15 **QUESTION:**

- 16
17 a) Please explain how the YUB and other stakeholders are to put any faith into YEC's
18 2016 Resource Plan's claim that there is a current and growing need for new
19 capacity to meet requirements under the single contingency (N-1) criterion if YEC
20 is not seeking any type of approval of this plan which can only result in a thorough,
21 stand-alone regulatory review of the Resource Plan.
22
23 b) Please provide the studies that substantiate the 2016 Resource Plan's forecast
24 that the single contingency (N-1) dependable capacity shortfall is 6 MW for 2017
25 and 8 MW for 2018.
26
27 c) Please provide details by year of all costs incurred to develop the updated 2016
28 Resource Plan and how it will impact rates.
29

30 **ANSWER:**

31
32 **(a), (b) and (c)**
33

34 YEC has provided ongoing assessments of capacity requirements (including shortfalls
35 when these occur) under the single contingency (N-1) criterion since the 2006 Resource
36 Plan review by the YUB, including reviews at each GRA and each Part 3 review of specific
37 new resource generation projects (Mayo B and the LNG Plant projects). The most recent

1 studies in the 2016 Resource Plan are documented in that plan and its appendices, which
2 have been provided for public review throughout the development of the 2016 Resource
3 Plan. Specific updates to capacity shortfalls for the 2017 and 2018 test years are provided
4 in YEC's GRA Application. Costs by year for the 2016 Resource Plan are detailed in Tab
5 5 of YEC's Application under section 5.3.1.6 and related Tables 5.6-5.8.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 1-7
4 *YEC states "Forecasts for the Minto mine load in 2017 and 2018 have*
5 *changed significantly since the start of 2017. Through early January*
6 *2017, it was understood that the mine would cease operations in late*
7 *2017. The forecast in this Application now assumes continued Minto*
8 *mine operation through 2018, based on updated information provided*
9 *in April 2017."*

10
11 **PREAMBLE:**

12
13 **QUESTION:**

- 14
15 a) Please provide a copy of the referenced updated information and details regarding
16 its source.
17
18 b) Please provide all other information gathered by YEC to confirm its industrial load
19 forecasts for 2017 and 2018.
20
21 c) Please provide a table showing sales to each industrial customer in 2013, 2014,
22 2015, 2016, 2017 and 2018 and associated revenues.
23
24 d) Please provide a description and details of the actual costs associated with
25 providing service to each of the industrial customers (Minto and Alexco, including
26 negotiations numbers with Eagle) and how these costs are determined.
27
28 e) Please provide an update on anticipated industrial customer load requirements
29 beyond 2018.
30
31 f) Please provide details on any planning that YEC is conducting to implement on-
32 site generation for the transient industrial loads of mines and other large
33 customers.

ANSWER:

(a), (b) and (e)

YEC's GRA Application in section 2.2.2 provides the requested information summarizing what was communicated to YEC by Minto mine management, and by the management of Alexco and Victoria Gold. Please see the response to John Maissan-YEC-1-5 for updates with regard to Victoria Gold. YEC relies on the information it receives in this regard from each mine.

(c)

Please see Table 1 below for the requested information.

Table 1: YEC Industrial Sales and Revenues

	Actual				Forecast	
	2013	2014	2015	2016	2017	2018
Sales in MW.h						
Minto	32,248	36,302	37,186	41,169	38,219	38,219
Alexco	8,265					
Total	40,513	36,302	37,186	41,169	38,219	38,219
Revenues in \$000						
Minto	\$3,546	\$3,958	\$4,159	\$4,478	\$4,198	\$4,198
Alexco	\$1,049					
Total	\$4,595	\$3,958	\$4,159	\$4,478	\$4,198	\$4,198
Rider J	\$229	\$291	\$306	\$330	\$309	\$309
Total incl. Rider J	\$4,825	\$4,249	\$4,465	\$4,808	\$4,507	\$4,507

(d)

YEC has not developed any cost of service analysis for the current GRA – the last such analysis, as developed for the 2009 GRA test year, indicated that major industrial customers are paying rates in excess of allocated costs of service determined in accordance with OIC 1995/090 and normal regulatory principles applicable to similar regulated electricity utilities in Canada.

1 Incremental capital costs associated with specific transmission, substation and other
2 related facilities required to connect the Minto and Alexco mines were recovered directly
3 from each mine in accordance with Power Purchase Agreements (PPA's) reviewed and
4 approved by the YUB for each mine after a public hearing review. The Alexco mine and
5 mill also paid YEC's costs to negotiate that mine's PPA and a Fixed Charge each year
6 that it was in operation, pursuant to the approved PPA. Similar to the Alexco PPA, YEC
7 will negotiate a PPA with Victoria Gold for the Eagle Gold mine, and this PPA will be
8 subject to review and approval by the YUB.

9
10 **(f)**

11
12 YEC is not conducting any planning to implement on-site power generation at mine sites.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 1-7
4 *YEC states "Overall, forecast mid-year net rate base (i.e., after*
5 *contributions) in 2018 is \$64 million higher than the mid-year net rate*
6 *base as approved for 2013 in the last GRA."*
7

8 **PREAMBLE:**

9
10 **QUESTION:**

- 11
12 a) Please confirm that YEC's capital expenditures are not rolled into rate base (i.e.,
13 treated as work in progress) for rate setting purposes until the project is completed
14 and deemed to be used and useful and then approved for inclusion in rate base
15 by the YUB.
16

17 **ANSWER:**

18
19 **(a)**

20
21 Please see response to UCG-YEC-1-13(a).

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 1-8
4 *YEC states “The 2012/13 GRA identified the continuing need to meet*
5 *capacity planning requirements, and Yukon Energy's 2016 Resource*
6 *Plan has highlighted a current and growing need for new capacity to*
7 *meet requirements under the single contingency (N-1) criterion. This*
8 *Application (Tab 2, Section 2.4) forecasts the dependable capacity*
9 *shortfall at 7.6 MW for 2017 and 8.7 MW for 2018, based on forecast*
10 *non-industrial load growth without any new diesel unit retirements.”*

11
12 August 15, 2017, Whitehorse Star, Power for Mines is Plentiful
13 *YEC's president Andrew Hall is quoted in this article saying that*
14 *providing grid power to both the Eagle Gold Project and Alexco*
15 *Resource Corp.'s silver operation in Keno City won't be an issue.*

16
17 **PREAMBLE:**

18
19 **QUESTION:**

- 20
21 a) Please provide details of how power will be provided to these projects.
22
23 b) Is YEC currently negotiating a power purchase agreement with Eagle Gold. When
24 is this mine proposed to take industrial power from the grid? Will this affect any of
25 the proposed revenue requirements and rates in 2017 and 2018?
26
27 c) Please confirm that when YEC proposed the Whitehorse Diesel-Natural
28 Conversion Project, it was based on no load related to Alexco's mining operations.
29
30 d) Has YEC ever negotiated a power purchase agreement with Alexco? Please
31 provide details of this agreement and whether it was followed.
32
33 e) Please provide details of how power will be provided to these projects (Alexco and
34 Eagle) and how costs will be managed and paid for.
35
36 f) Since Alexco discontinued their prior industrial power load within a few years after
37 hooking up to industrial grid power, after considerable expense to the utility and

1 thus other ratepayers, how does YEC propose to protect ratepayers from future
2 risk from this company which has not proven to be stable?

3

4 **ANSWER:**

5

6 **(a), (b) and (e)**

7

8 As noted, each of these projects will be supplied with power from the Yukon grid. Further
9 details please see responses provided to CW-YEC-1-12(d), John Maissan-YEC-1-5, and
10 John Maissan-YEC-1-6(c).

11

12 **(c) and (f)**

13

14 The load scenarios reviewed in the Part 3 Application for the Whitehorse Diesel-Natural
15 Gas Conversion Project did not assume Alexco. Ratepayers were protected from added
16 capital costs related to serving Alexco by the PPA with Alexco (which required Alexco to
17 pay for these costs at the outset).

18

19 **(d)**

20

21 The PPA with Alexco was reviewed and approved by the Board in 2011. Materials filed
22 during this process including the Application and the Power Purchase Agreement are on
23 the Board's website at the link below. The PPA has been followed by the Parties to the
24 agreement.

25

26 <http://yukonutilitiesboard.yk.ca/proceedings/yec-alexco-power-purchase-agreement/>.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 1-10
4 *With respect to its Demand Side Management (DSM) Accounting*
5 *Policy, YEC states "In Order 2013-01 following the 2012/13 GRA, the*
6 *Board deferred its findings and directions regarding YEC's DSM*
7 *accounting policy until YEC and ATCO Electric Yukon (AEY) had jointly*
8 *filed a DSM plan as directed in a prior section. The utilities' joint DSM*
9 *Plan was filed as part of AEY's 2013-15 General Rate Application and*
10 *was subject to review by the Board and intervenors. The Board's*
11 *comments on the DSM Plan were provided in Order 2014-06".*
12

13 **PREAMBLE:**

14
15 **QUESTION:**

- 16
17 a) Please identify where in Board Order 2014-06 YEC was given specific directions
18 with respect to its DSM program.
19
20 b) Please provide details on how the impacts of DSM efforts are reflected in the actual
21 sales and load forecasts of YEC's customer classes including secondary sales
22 customers for the period 2013-2018.
23
24 c) Please confirm that all DSM-related costs will be subject to a prudence review by
25 the Yukon Utilities Board prior to being recovered in rates.
26
27 d) Please provide details of YEC's DSM-related expenditures in 2013, 2014, 2015,
28 2016, 2017 and 2018 and their corresponding percentage of total revenue
29 requirement for those years.
30
31 e) Please identify how and where YEC's application reflects benefits to Yukon
32 ratepayers of DSM-related expenditures.

1 **ANSWER:**

2
3 **(a)**

4
5 Please see YEC GRA Application, Tab 6, pages 6-2 and 6-3 which reviews relevant
6 elements of Order 2014-06.

7
8 **(b)**

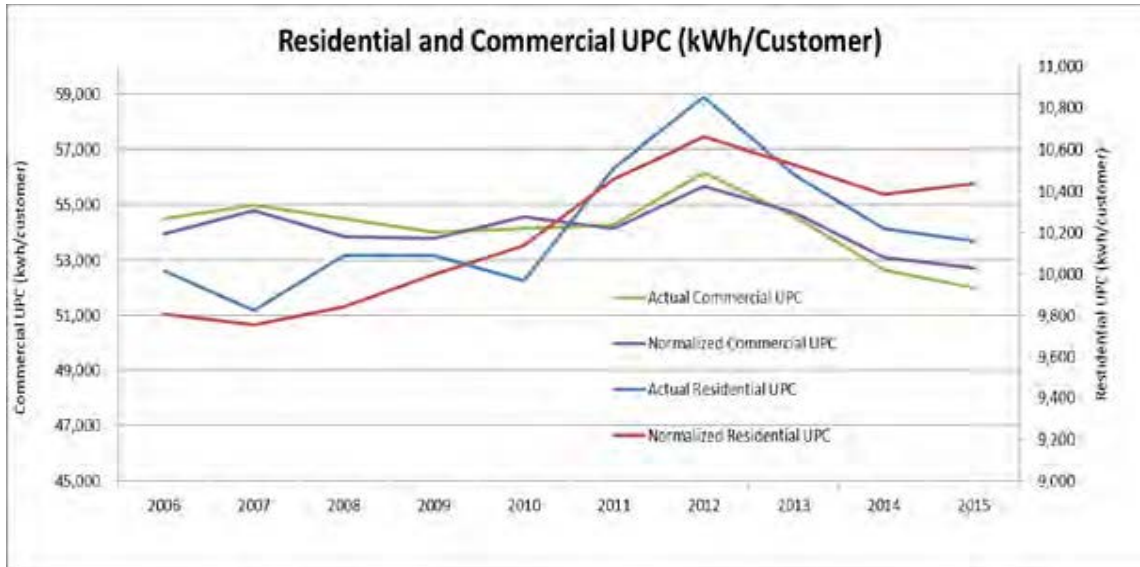
9
10 YEC uses historical sales data to forecast future sales so the savings from delivery of
11 DSM programs is reflected in these recent year actual sales and therefore factored into
12 future year forecasts.

13
14 Please see also response to YECL-YUB-6(c) from the AEY 2016/17 GRA, which notes as
15 follows:

16
17 AEY does not specifically track and measure the actual impact of DSM initiatives
18 for actual sales. The estimated deemed energy savings associated with this
19 program can be found in Table 2 of the inCharge - Interim Evaluation dated July
20 31, 2015 and provided in YUB-YECL-6(c) Attachment 1.

21
22 As shown on Table 2 of this report, the deemed energy savings in year 1 and
23 year 2 of the program resulted in a reduction of 6,454 MWh and 9,015 MWh,
24 respectively. As shown in the graph below, AEY has experienced a reduction in
25 residential and commercial use per customer since 2012. While AEY cannot
26 attribute the reduction in use per customer solely to the DSM initiatives, it does
27 consider the reduction in use per customer attributable to a variety of reasons
28 including Micro Generation, Commercial Energy Initiative Programs and DSM
29 programs.

30
31 AEY has not explicitly adjusted its 2016 and 2017 forecast to reflect future savings
32 as a result of DSM initiatives, but rather, the underlying data and methodology
33 used to derive the forecast incorporates impacts of the DSM initiatives
34 incorporated in the 2014 and 2015 actual consumption.



(c)

Confirmed.

(d)

Please see Table 1 for the requested information.

Table 1: YEC Total Revenues/Revenue Requirements and Net DSM Costs

in \$000	Actual				Forecast	
	2013	2014	2015	2016	2017	2018
Total Revenues/ Revenue Requirement [Table 3.1]	\$43,897	\$41,247	\$41,855	\$42,686	\$48,544	\$49,864
Net DSM Expenditures [Tables 5.3 through 5.8]	\$571	\$383	\$298	\$403	\$210	\$625
DSM Expenditures as % of total Revenues/ Revenue Requirement	1.3%	0.9%	0.7%	0.9%	0.4%	1.3%

(e)

Please see Tab 5, section 5.3.1.5, which reviews the DSM program elements, costs and benefits of implementation. Please see also responses to YUB-YEC-1-80, YCS-YEC-1-14 and John Maissan-YEC-1-3 for further information regarding the DSM program.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 2-10
4 *With respect to Power Generation, YEC states that there is a small*
5 *amount of wind generation available on the system*
6

7 **PREAMBLE:**

8
9 **QUESTION:**

- 10
11 a) Please provide an update on negotiations with Northern Energy Capital on a
12 purchase power agreement related to the proposed wind turbines to be built on
13 Haeckel Hill.
14
15 b) Please provide details of correspondence which indicates YEC's support for the
16 proposed project.
17
18 c) Please provide details of any impact this proposed project will have on YEC's
19 revenue requirements in 2017 and 2018.
20
21 d) Please provide details of how this proposed project impacts YEC's current
22 Resource Plan.
23

24 **ANSWER:**

25
26 **(a)**

27
28 Negotiations on a power purchase agreement with NEC have not commenced, in part
29 because the implementation guidelines for the Standing Offer Program (SOP) of the IPP
30 policy have yet to be developed.
31

32 **(b)**

33
34 YEC has been actively engaged and responsive to NEC in planning activities including
35 site access for wind monitoring activities. YEC has not issued explicit letters of support in
36 this matter.

1 **(c)**

2
3 Based on current information, YEC believes the earliest in-service date for this project is
4 the summer of 2019, assuming that the proponent moves forward with procurement of the
5 turbines by the summer of 2018. On this basis, there is no impact to YEC 2017/18 revenue
6 requirement from this project.

7
8 **(d)**

9
10 The generation of the wind asset that is currently in service was taken into account in the
11 2016 Resource Plan as available existing generation. In addition, the Plan includes
12 assumed generation from IPPs of 10 GWh per year.

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 4-4
4 *YEC states that, despite not including any secondary energy sales in*
5 *its last GRA forecast, “surplus hydro generation (reflecting favourable*
6 *water conditions as well as reductions in firm grid loads) resulted in*
7 *actual secondary sales between 3.9 to 7.0 GW.h per year from 2013 to*
8 *2016”.*
9

10 **PREAMBLE:**

11
12 **QUESTION:**

- 13
14 a) Please provide a table showing actual and projected secondary energy sales and
15 revenues for 2012, 2013, 2014, 2015, 2016, 2017 and 2018.
16
17 b) Please explain how Yukon ratepayers have benefited from secondary energy sales
18 in the 2013-2016 time period when no such sales were included in the last GRA
19 forecast.
20
21 c) Please provide references to when secondary sales and revenues were last
22 reviewed by the YUB.
23
24 d) Please explain why YEC believes that secondary sales should not be reviewed as
25 part of this application.
26

27 **ANSWER:**

28
29 **(a)**

30
31 Please see Table 1 below.
32

33 **Table 1: Actual and Forecast Secondary Energy Sales and Revenues**

Unit	2012	2013	2014	2015	2016	2017F	2018F
Sales (MWh)	1,993	3,959	5,415	7,030	4,835	11,464	11,464
Revenues (\$000)	\$165	\$275	\$410	\$544	\$371	\$642	\$642

1 (b)

2
3 Secondary sales revenues over the period from 2013 through 2016 helped to mitigate the
4 impacts of loss of load and to defer the requirement for another GRA until 2017.

5
6 Please see Tab 1, Section 1.2 which notes as follows at pages 1-3 and 1-4 [excerpted
7 below]:

8
9 **Secondary Sales Revenues to mitigate impacts of loss of load:** No secondary
10 sales were forecast in each test year for the 2012/13 GRA. Due to the fact that
11 diesel was on the margin, secondary sales had been shut off for increasing periods
12 of time, and YEC had proposed in the 2012/13 GRA that any future secondary
13 sales revenues be paid to the account of the reactivated Diesel Contingency Fund
14 rather than to YEC's revenues. The Board did not approve YEC's proposal to
15 reassign secondary sales revenues in the last GRA. Since the 2012/13 test years,
16 industrial load (except for 2016) and firm wholesale load have both declined during
17 a period of higher than average hydro flows, resulting in further opportunities for
18 secondary sales over the period from 2013 to 2015. Since the last GRA, Yukon
19 Energy has actively pursued secondary sales opportunities, including three new
20 SCADA connections, and annual secondary sales from 2013 to 2016 have ranged
21 between 3.9 GW.h and 7.0 GW.h with revenues as follows: \$0.275 million in 2013;
22 \$0.410 million in 2014; \$0.544 million in 2015; \$0.371 million in 2016. Secondary
23 sales are forecast at 11.464 GW.h/year in 2017 and 2018, with revenues forecast
24 (at lower rates now applicable) at \$0.642 million per year. All forecast revenues
25 from secondary power in the test years go to lower the required level of retail rates
26 for firm power. As defined by the rate schedule, the impact of quarterly rate
27 adjustments to market are charged against the Rider F – Diesel Fuel Price
28 Variance Account.

29
30 (c)

31
32 Forecast secondary sales revenues for the 2012 and 2013 test years [included in Yukon
33 Energy's Compliance Filing] were approved by the Board following the 2012/13 GRA in
34 Orders 2013-03 and 2013-04.

1 The secondary sales rate schedule was approved in Order 2005-12 and no changes were
2 sought in the 2009 Phase II rate proceeding. The rate schedule includes an automatic
3 adjustment mechanism that adjusts the rate on a quarterly basis based on the lowest of
4 the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for
5 Whitehorse. The last adjustment to the rate was effective January 1, 2017. The most
6 recent quarterly update provided on August 29, 2017 did not change the rate.

7
8 **(d)**

9
10 Secondary sales revenue forecasts are included for review in this application. Yukon
11 Energy is not seeking any changes to the rate schedule at this time, and is not aware of
12 any specific basis today for seeking any change (given that the rate is automatically
13 adjusted each quarter to reflect current heating oil prices).

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, pages 5-6 and 5-7
4 *YEC states "The Aishihik hydro facility 7 MW third turbine (AH3) came*
5 *into service in December 2011. Yukon Energy has incurred \$2.715*
6 *million of costs after 2012 for wrap up activities related to this project,*
7 *including \$2.574 million of costs from a dispute with a contractor on this*
8 *project.*

9 ...

10 *A decision on the dispute was provided in August 2016 by the Yukon*
11 *Supreme Court, awarding the contractor a net amount of \$1,623,565*
12 *plus interest and costs. The amount awarded by the Court included*
13 *\$1,308,462 that consisted of holdbacks and extra works done where*
14 *the price had been agreed upon, but not yet paid due to YEC's claims*
15 *for set-off rights. The final cost of the claim dispute includes YEC legal*
16 *fees of \$0.962 million. Based on the advice of legal counsel, YEC has*
17 *filed the necessary documentation to appeal the court decision."*

18
19 YEC 2012-2013 GRA, Response to CW-YEC-1-28(c)

20 YEC states that in August 2010, a feasibility review was undertaken
21 that determined that at a revised project cost of \$12.813 million, the
22 Aishihik Third Turbine project was still economically feasible and would
23 have a Net Present Value of \$9.77 million and a payback period of 7.9
24 years.

25
26 **PREAMBLE:**

27
28 **QUESTION:**

- 29
30 a) Please confirm that YEC's capital expenditures are not rolled into rate base (i.e.,
31 treated as work in progress) for rate setting purposes until the project is completed
32 and deemed to be used and useful and then approved for inclusion in rate base
33 by the YUB.
34
35 b) Please provide the original costs of this project as of August 2010 by component
36 and the actual costs incurred to date in the same detail with explanations for
37 variances greater than $\pm 5\%$ between August 2010 totals and actual.

1 c) Please provide a copy of any feasibility reviews that have been undertaken related
2 to the costs of the Aishihik Third Turbine project since August 2010.

3
4 d) Please provide a copy of the August 2016 decision by the Yukon Supreme Court.

5
6 e) Please provide supporting documentation for the \$962,000 in legal costs incurred
7 by YEC for the appeal process including timing of when these costs have been
8 incurred.

9
10 f) Please explain what benefit ratepayers receive as a result of the legal costs being
11 incurred by YEC through this ongoing appeal process.

12
13 **ANSWER:**

14
15 **(a)**

16
17 Not confirmed; as has been accepted practice in Yukon, capital expenditures are put into
18 service and thereby rate base at the point when the asset is deemed used and useful.
19 YUB approval is required to place the asset into rates, but the addition to rate base is
20 independent of this process.

21
22 **(b)**

23
24 The question is not relevant; YEC applied for this asset to be included in rates as part of
25 the 2012/13 application. The YUB approved this addition at \$13.8 million in Order 2013-
26 01, P.298.

27
28 **(c)**

29
30 No such studies have been completed.

31
32 **(d)**

33
34 Please see UCG-YEC-1-13 Attachment 1.

1 **(e)**

2
3 The referenced amount is fees paid to legal counsel to assist with settlement negotiations
4 and preparation and defense of the legal claim at trial. The spending by year is as follows:

5

6 2012	\$0.129
7 2013	\$0.031
8 2014	\$0.079
9 2015	\$0.256
10 2016	<u>\$0.467</u>
11	\$0.962

12

13 **(f)**

14
15 The assessment of legal counsel and management is that the expected settlement
16 exceeds the costs to defend the case. This assessment cannot be determined until the
17 legal proceeding has been completed, therefore, YEC is not applying for any of these
18 costs to be recovered at this time.

SUPREME COURT OF YUKON

Citation: *North America Construction (1993) Ltd v
Yukon Energy Corporation*, 2016 YKSC 33

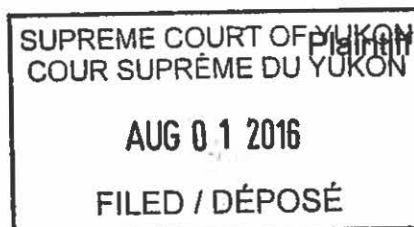
Date: 20160801
S.C. No.: 11-A0114
Registry: Whitehorse

Between:

North America Construction (1993) Ltd.

And

Yukon Energy Corporation



Defendant

Before Mr. Justice G. Hawco

Appearances:

Mr. H. David Edinger / Harpreet Tosanjh

Counsel for the Plaintiff

Morgan Burris / Todd Shikaze

Counsel for the Defendant

REASONS FOR JUDGMENT

[1] North America Construction (1993) Ltd. ("NAC") is a construction company with a fair amount of experience with respect to the construction of dams and generation plants. It had not worked in the Yukon before bidding for this particular job, but it was well aware of the location and the nature of the project.

[2] The man in charge of the project at the time was Mr. Pat Maloney, his first assignment as a project manager, Mr. Scott McPherson, the president of NAC, who had spent some 23 years with the company, knew him well and had no doubt as to his ability to carry out this job.

[3] Yukon Energy Corporation ("YEC") is a Crown corporation, owned by Yukon Development Corporation. YEC owns and operates the Aishihik generating station which is located 120 kms northwest of Whitehorse. The Aishihik facility has been in operation since 1975. It is a unique facility, located approximately 120 meters underground. It was originally built with two turbine-generator units and was designed for the future addition of a third turbine. In April of 2009 YEC's Board of Directors retained AECOM, an engineering firm, to work on preliminary budgeting and design. AECOM was to perform the engineering and detail design, as well as to perform construction management services.

[4] In January of 2010 YEC put the matter out for tender. NAC and two other construction companies attended at the site with YEC representatives and each submitted a tender. YEC cancelled the tender on the basis that all of the bids received exceeded the project budget. Instead of re-tendering, YEC negotiated directly with NAC and the other two contractors.

[5] On or about August 6, 2010, YEC accepted NAC's proposal of \$7,136,885.00 subject to finalization of a number of matters, including what is described as a fan wall design, the size of the camp, the penstock design, which were the pipes to transport the water into the turbine, as well as a schedule.

[6] The contract price was originally based on a substantial completion date of June 11, 2011. The notice to proceed was issued by YEC to NAC in August of 2010, prior to the contract actually being completed. The contract was not executed until December of

2010. By the time it was executed, it was agreed that NAC was to obtain substantial completion by November 30, 2011.

[7] Because the contract price earlier agreed upon was based upon a completion date of June 19, 2011, it was agreed in Schedule D of the contract that:

The Price will be adjusted to reflect the contractor's actual cost caused by the new completion date of November 30, 2011 under Section 3.3. The price at Section 8.1 is based upon the original completion date of June 19, 2011 with a 6 week shutdown commencing May 1, 2011.

[8] The contract also made provisions for changes to the work under Sections 4.5 and 4.6. Section 4.5(d) stated:

If a Change to the Work increases or decreases the cost to the Contractor by more than \$1,000.00, the Parties will agree, in writing, upon a fair adjustment to the Price, on a time and material basis as per Schedule B....

[9] The project was somewhat different and difficult because it appeared to have been a work in progress. As I indicated, when the parties entered into their agreement in early August, 2010, the design was not yet complete and the time frame for completion was yet to be determined.

[10] Notwithstanding the date of the execution of the contract, NAC had mobilized to the site and began its work in late August or early September, 2010.

[11] Because of the ongoing design changes, the parties entered into an agreement which was known as Schedule D. The clause dealing with adjustment to the cost are referred to above.

[12] NAC substantially completed the contract in early December, 2011. The facility has been generating power since December 6 or 7, 2011.

[13] There were ongoing discussions and disputes during the construction of the facility. Much work was done which was claimed by NAC to be extra, without a decision having been made on the cost. Many of the changes made were agreed upon. Some were not, in the sense that NAC has claimed that it was required to carry out certain work which it said was, or should have been, an extra, while YEC takes a position that such work fell under the existing terms and conditions of the contract. YEC claims that the contract provided that such work fell within the existing terms and conditions and therefore it ought not to pay any extra funds for such work.

[14] In addition to these disputes, YEC carried out what it determined to be remedial work which should have, in the normal course of events, been carried out by NAC. Once the project was substantially complete, YEC refused to let NAC back on the site after they had demobilized because they were of the view that NAC was so incompetent that they could not be relied upon to carry out the remedial work properly.

[15] The disputes will be looked at separately, as the Parties have done. I will deal with NAC claims for monies owing for what it says were extra to the contract. I will then look at YEC's claim for remedial work carried out as well as for work which has not yet been carried out. As will be seen, for the most part, NAC has been successful with respect to its claims for extra work required to be carried out.

[16] YEC is also entitled to set off a certain amount for deficient work carried out by NAC.

[17] It is not unusual that friction develops when a project is, in both a literal and figurative meaning, highly charged and under time pressures. That was the case here and, unfortunately, the spirit of cooperation which marked this project in the beginning descended into an atmosphere of confrontation. In such a situation, each party inevitably suffers to some degree.

NAC CLAIMS

[18] YEC has agreed that under the terms of the contract, it owes NAC \$1,308,462.00 which consists of holdbacks and extra work done where the price has been agreed upon, but not yet paid, as well as certain labour and materials. This amount has not been paid by YEC because it has claimed the right to set-off approximately that same amount for work that it says it had to carry out to properly complete the contract, or will have to pay.

[19] There are other monies which NAC claims to be due and owed for various change orders (CRX's). These will be looked at individually. I propose to deal with each of the outstanding CRX's. I will then look to YEC's claims of set-off.

CRX 20

[20] This is one of the most contentious of NAC's claims. It arises because of "Shut Downs" which were agreed upon but with respect to which there was no agreement as to the impact upon the project and the additional cost.

[21] The parties did agree, pursuant to s. 3.3 that:

Prior to the Completion Date, YEC will facilitate two shut-downs of the entire facility (the "Shut Down Windows") in

order to permit the tie of the penstock and substation retrofit work:

- a. The first Shut Down Window will commence on June 20, 2011 and be completed on June 30, 2011.....*
- b. Subject to the status of Mayo outage, the Second Shut Down Window is tentative scheduled to start on October 1, 2011 and be completed by October 31, 2011....*

The price is based upon a completion date of June 19, 2011 with a six week shut down window commencing May 1, 2011. The price is subject to adjustment under Schedule D.

[22] Schedule D of the contract provided that:

The [Contract] Price will be adjusted to reflect the contractor's actual costs caused by the new Completion Date of November 30, 2011, under Section 3.3.

[23] NAC's position is relatively simple. Schedule D is a price adjustment clause. As stated in NAC's brief:

(b) It was intended to entitle NAC for additional payments for its costs resulting from the extension of the construction schedule and time that NAC had to spend on site to complete this work under the contract as a result of the scheduling changes which YEC determined to impose on NAC, with knowledge of NAC's expected additional costs.

[24] The extra time that NAC spent on the project was 102 days. The cost of those extra 102 days was \$633,510.48. That figure was based upon NAC's original estimate and was consistent with Mr. Landry's projected costs for a six week overrun on September 21, 2010. Mr. Landry had determined that figure by simply multiplying 102 days by the sum of \$6,501.89, which was NAC's actual cost per day over the whole project.

[25] YEC's response was that NAC really did not incur any costs as a result of the schedule changes. Rather, the costs claimed were costs incurred because it took NAC longer than it expected to complete the project.

[26] There was a fair amount of evidence from a number of the YEC people on site. Mr. Bob Toms was the first project manager on YEC's behalf. He had no concerns in the beginning of the project with NAC, but did eventually have concerns with respect to what he considered to be their lackadaisical approach to general safety matters on site. He observed delays occurring because of a required design change to what was known as the "Thrust Box" and a delay which he attributed to NAC using an incorrect mix in the concrete used to level the floor in the tunnel. The completion of the floor of that tunnel was along the critical path of the project.

[27] In general, Mr. Toms was concerned about the competency of many of the NAC work crews, as was Mr. Bob Simonson and Mr. Ed Peake. Mr. Toms considered NAC's work to be somewhat sloppy and was generally of the view that NAC had been responsible for any delays to the project.

[28] What I found to be not only unusual, but somewhat incongruous, was that under cross examination, Mr. Toms agreed that NAC had expedited the delivery of the Penstock pipe which was critical to the project on time; that the switch gear building and the installation of equipment with respect to that building was critical and was delivered on time; that the Thrust Box was indeed delivered on time. Mr. Toms went on to admit that YEC continued to have difficulty getting drawings from AECOM throughout the project but that, generally, NAC was keeping up with its schedule.

[29] I also found that Mr. Simonson, a contract administrator with CAP management, an agent of the Defendant, was quite critical of the Plaintiff and was of the view the Plaintiff, because of its inexperience and the laziness of its crew, could have finished the project 4 to 5 weeks earlier than they did.

[30] There is difficulty with some of Mr. Simonson's evidence with respect to the perceived delays which he observed. That is, that no witness for the Plaintiff, neither the project manager nor Mr. Laith Hamad, who was the electrical coordinator and very much on top of things overall with this project, was cross examined in any manner on any of this evidence.

[31] I spoke with counsel during the trial about my concerns about these and other matters that arose in the Defendant's case and had not been touched upon during the Defendant's cross examination of the Plaintiff's witnesses. I explained my concerns within the parameters of *Browne v Dunn* (1893), 6 R.67 (H.L.). I allowed the evidence to go in, but I advised counsel there would or could be a problem as to the amount of weight attached to such evidence.

[32] Having said this, I must say that little of Mr. Simonson's evidence in particular had any adverse impact upon the Plaintiff's claim under CRX 20. The fact is, and was, that the Plaintiff finished this project on time. The items to which Mr. Simonson referred, even if totally accepted, would be, in my mind, rather small. This is, of course, not something which should be simply rejected, but I do so because overall I was not greatly impressed with his evidence. Many of the matters which he considered to be

major appeared to me to be rather minor and with respect to which, hindsight is almost so much better.

[33] In the early stages, there was a lot of interaction between the Plaintiff and the Defendant, even commencing before the contract was executed. Both parties were acting in good faith. Everyone knew that there would be delays, indeed two shutdowns were planned. Discussions were occurring with respect to design changes. Drawings were not complete. The pipe had not yet even been ordered.

[34] It was, in short, organized confusion with much weight being placed upon good faith. Thus, Schedule D.

[35] Relatively early in the project, to be specific, September 27, 2010, Mr. Landry advised Mr. Joudry that they expected NAC costs would be some \$278,000.00 for the additional six weeks spent on the project. The length of delay increased significantly.

[36] Certainly, the Plaintiff's work was often sloppy, to put it crudely. Their work habits often left YEC's management frustrated. They were not as efficient as they might have been. YEC's management may well have been better organized and more efficient. The bottom line, however, is they got the work done within the time agreed upon.

[37] YEC does have legitimate concerns with respect to a number of matters which either were done improperly, or simply poorly. These will be dealt with in this judgment in due course.

[38] I accept NAC's claim for \$633,510.48. I am satisfied that the Plaintiff was required to spend 102 days more on this project than either they or the Defendant had anticipated when the contract was signed.

CRX - Lug Changes

[39] NAC claimed that YEC requested it to increase the number of lugs on various couplings. The original design was varied somewhat by YEC and its engineer, AECOM. Mr. Toms seemed to agree with the fact that it requested a change. He disputed the cost. The CRX is approved. The amount is \$13,381.00.

CRX 39 - Flanges

[40] The issue between the parties here was whether this constituted a change by YEC. Mr. Maloney said that he had submitted the drawings from the pipe manufacturer to YEC, which indicated that the flanges were to be 150 pounds and that YEC had approved them. YEC later said it wanted 300 pound flanges, so the Plaintiff had to change them.

[41] The specifications referred to the court, in Volume 1, Tab 686, does not appear to support this position. I accept YEC's submissions that there was a mistake by NAC or its supplier. The flanges supplied were not in accordance with the contract specifications. That claim is not allowed.

CRX 43 - High Voltage Switch Support

[42] This was a claim for approximately \$18,000.00 with respect to an item which Mr. Maloney appeared to concede may have been missed by NAC's estimator. That claim is not allowed.

CRX 52 - Lifting Equipment

[43] The Plaintiff has claimed approximately \$21,000.00 because it had not allowed for its equipment to lift as much weight as was required. It may be that the original specifications indicated that the Plaintiff would only be required to lift X pounds, but the Defendant had told the Plaintiff before they prepared their tender that the equipment would have to lift Y pounds.

[44] This claim is not allowed.

CRX 71 - Fan Wall Installation

[45] The issue here was whether the Plaintiff should be paid to assemble an Air Handling Unit (AHU) which arrived unassembled. Document 167 would indicate that this was how it was originally supposed to arrive.

[46] That claim is not allowed.

CRX 92 - October Compressed Shutdowns

[47] In their claim, the Plaintiff says that it was required to do a certain amount of work in less time than it had planned. Mr. Hamad said he had 10 men doing 2 extra hours a day for 28 days.

[48] However, it was clear from the evidence that NAC never did, at least during this particular period of time, have 10 men on the job. They only had 5 electricians on the job. In addition, the compressed work was done within 18 days. My math would consist of 5 men working 2 extra hours a day for 18 days at \$58.25 for a total \$10,485.00. The Plaintiff's claim on this CRX is allowed to that extent.

CRX 97 – Generator-Turbine Changes

[49] The Plaintiff claims that the original contract specifications were far less detailed than the actual plans and specifications which arrived. The original details were some 15 to 20 pages (excluding the drawings). On February 28, 2011, the provider supplied the manual and the installation plan, consisting of some 127 pages. The work itself was far more extensive than could have been anticipated in the estimate. NAC's original estimates had been 500 to 600 hours for the work, based upon the contract instructions. The actual man-hours expended were 1200. Mr. Maloney stated that the additional hours were due to the increased instructions.

[50] Indeed, Mr. Maloney had estimated that it could cost the Plaintiff \$155,000.00 more than could reasonably have been anticipated. The Plaintiff was only seeking to recover less than half of that amount, or \$65,868.00.

[51] I accept Mr. Maloney's reasoning and calculations and allow the claim in that amount.

CRX 100 – Cable Changes

[52] NAC claims for a change to the work for its additional labour costs incurred to comply with YEC's requirement that NAC perform extra work to install electrical cables which were not shown on YEC's drawings. The revised amount is \$119,004.00.

[53] This was another contentious issue which arose because of the continuing problem which the Plaintiff faced, of building a generator and turbine some 400 feet underground while the designer/engineer was still working on producing all the

necessary drawings and information. Thousands of feet of cable were required, ranging from centimeters in diameter to inches in diameter.

[54] When NAC bid on the project, the design drawings and the information required to determine just how much cable and how many connections, receptors and receptacles would be required was not known, and, according to the Plaintiff, was not capable of being known. This led to NAC having to “guestimate” a cost for the materials.

[55] In late December of 2010 and early January of 2011, Mr. Hamad was very concerned that the information which he had received thus far from YEC and AECOM was not sufficient for him to even begin to order all of the cable required, as well as the electrical panels and the hundreds of connections.

[56] Mr. Hamad sent a number of requests for information (RFI's) to attempt to have a better understanding of what was needed. That RFI (RFI 44) was followed up by yet another RFI, RFI 44-1.

[57] It soon became obvious to Mr. Hamad that only about one half of the cable required was covered by the drawings and specifications NAC had received initially.

[58] Negotiations began about the cost of these additional materials, which resulted in CRX 24 being agreed upon. This CRX gave NAC an additional \$46,000.00 to acquire the extra cable.

[59] Mr. Hamad was quite confident that CRX-24 only covered the cost of acquiring much of the “new” cable. It did not include any of the costs of connecting any of the cables as no one yet knew exactly where the connections would be located.

[60] Indeed, at the time CRX 24 was agreed upon, AECOM still had not provided the Plaintiff with any of the designs within the various panels or the input/output schematics.

[61] Further drawings and information continued to flow, resulting in yet further changes and the resultant costs. These new drawings and changes continued up to October 3, 2011.

[62] The situation was one described by Mr. Hamad as working and making changes "on the fly" without being assured they would be compensated adequately, but doing the necessary work because they were on the critical path and this work had to get done for the project to become completed on time.

[63] I found Mr. Hamad to be an honest and forthright witness. He was very familiar with the project and familiar with the various emails and other documentation that went back and forth between the parties.

[64] YEC's response to CRX 100 is primarily that NAC had already been compensated for the additional cable (CRX 24) and had been compensated for most of the other work in CRX 79, CRX 80, CRX 85 and CRX 86.

[65] In addition, YEC argued that Mr. Tillebrook and Mr. Peake had seriously undermined the basis of Mr. Hamad's projection of the cost increase after May 2011, as shown in Tab 347.

[66] I did find both Mr. Tillebrook and Mr. Peake to be very good and credible witnesses. However, what was particularly telling in Mr. Peake's evidence was his admission that there were indeed glitches in the design and that the equipment

sometimes arrived in a different conformation than expected and that AECOM's drawings were often unclear.

[67] It was Mr. Peake who was quite critical of the estimate of 4,000 meters of additional cable which NAC had estimated was required. In his opinion, the appropriate figure would have been closer to 400 meters.

[68] As well, the estimate of the crane time, which NAC had estimated was far more than he would have thought necessary.

[69] Unfortunately, we once again come back to the cross examination of Mr. Hamad and Mr. Maloney, or the lack of cross examination of either of these individuals on these very specific points.

[70] I have referred to my concerns about the failure of the Defendant to adhere to the principles annunciated in *Browne v Dunn* and it is particularly telling here.

[71] The Defendant would have known, during the examination-in-chief and cross examination of the Plaintiff's witnesses, that it was going to be proffering a witness (Mr. Peake) who had estimated that the amount of cable and the amount of crane time would be significantly less than either Mr. Hamad or Mr. Maloney had taken into consideration when preparing the estimates with respect to these particular items. It is, quite frankly, simply an issue, as I remarked to counsel, of fair play. If one knows one is about to put forth evidence that calls into question, for example, cost estimates of time and materials, the witnesses putting forth that evidence should be cross examined on the discrepancy that is intended to put forth by the Defendant. That was not done. In my

view, not very much weight may be placed upon the evidence from Mr. Peake with respect to just how much cable was required and the resultant crane time. I do not, as I have said, question Mr. Peake's credibility, what I question is how there can be a legitimate gap in the quantity of cable when nothing was asked of Mr. Hamad with respect to these rather important items. There were questions put to Mr. Hamad about CRX 100, but none that involved the quantity of cable or the crane time.

[72] In the end, I am quite satisfied that as a result of the lack of drawings and detailed connections, due to the evolving design and changes to the previous plans, the Plaintiff was put to a lot of extra time and materials.

[73] I am satisfied that CRX's which were agreed upon, being CRXs 24, 79, 80, 85, and 86 did not included any amount for cable which had yet to be shown to be required.

[74] Both parties were somewhat lax in adhering to a proper extra work charge protocol. It was, as said by Mr. Hamad, a moving target and a reaction to that which had not been envisaged or planned by either party. While both Mr. Hamad and Mr. Peake were good witnesses, and credible witnesses, both cannot be totally right.

[75] I am not able to come up with any firm costs. I will therefore award one half of CRX 100, which would, by my calculations, be \$59,500.00.

[76] My calculation of the amount owing to NAC is, therefore, that which was agreed upon, being \$1,308,462.00 plus those amounts which I have found due and owing pursuant to the various claims, being \$633,510 for CRX 20, \$13,381.00 with respect to the Lug Changes, \$10,485.00 with respect to the October Compressed Shutdown,

\$65,868.00 with respect to the Generator-Turbine Changes and \$59,500.00 with respect to CRX 100 – Cable Changes, for a total of \$2,032,301.00.

YEC's Claims

[77] I now turn to YEC's claim for its costs to what it characterizes as poor workmanship of NAC and additional work it claims had to be carried out because of the actions, or inactions, of NAC.

CRX 104

[78] The first of these would be CRX 104, relating to Bentley-Nevada. This dispute concerned whether Bentley-Nevada was even on site on the dates for which a claim was made covering the 18th, 19th, and 20th of October. There were further claims with respect to two additional days spent after completion of the project, which I have not taken into consideration, because of the date and lack of sufficient evidence.

[79] With respect to the three days, Mr. Hamad was quite clear. He had requested that Bentley-Nevada attend on October 18, 2011. His recollection was that they did not show up on the 18th because YEC had told them to work on another YEC site. He recalls that they did return on October 21st when the Plaintiff was demobilizing and that he therefore had no opportunity of supervising them. As a result, one of YEC's representatives attended with them.

[80] It was Mr. Hamad's recollection that Bentley-Nevada did the work which was required and that NAC paid them directly.

[81] Mr. John Bruineman, a Bentley-Nevada representative, sent Mr. Hamad an e-mail on October 21, 2011 which seems to indicate that Bentley-Nevada was indeed on site on the 18th and 19th, and perhaps 20th. There were other e-mails (see Tab 546) which indicate that Bentley-Nevada was only on the site two days.

[82] While I have already assessed Mr. Hamad's credibility as being quite high, the e-mails back and forth would indicate that Mr. Hamad was mistaken with respect to this issue. One of the other e-mails which I referred to immediately above does indicate that the time spent by Bentley-Nevada was two days, not three. I have simply reduced the claim by YEC by 1/3. They are allowed the claim of \$15,166.00 with respect to the Bentley-Nevada matter.

CRX 106 – Fuel Leak

[83] NAC admits having caused a fuel spill while on site. It only disputes the amount of money required to adequately remedy the situation.

[84] The Defendant's witness was Ms. Shannon Mallory, who was the YEC environmentalist coordinator.

[85] The Plaintiff received a plan prepared by EBA on June 15, 2011. The anticipated costs at that time were \$15,245.00, plus GST (see Tab 575).

[86] YEC did not approve this report and so NAC requested EBA to prepare another estimate. This next estimate, dated March 15, 2012, came in at \$42,070.00. This was also presented to Ms. Mallory who was not satisfied with that report either and proceeded to draw up her own estimate, which was based, primarily, upon the EBA estimate.

[87] Ms. Mallory produced a document showing a budget of \$116,517.00 to totally clean up the site. She arrived at that figure by unilaterally doubling the EBA estimate, and adding another 20%, after having increased the EBA estimate by 20% before doubling it.

[88] Quite frankly, I considered Ms. Mallory to be not particularly helpful at all in this regard. She had no idea of how much soil had been excavated and hauled away and she had no real reason for rejecting the second EBA report.

[89] This claim is allowed, but in the amount of \$42,070.00, being EBA's second estimate.

CRX 111 – Cabinets

[90] YEC's claim with respect to this item is that NAC failed to supply the control and protection panels with open backs.

[91] NAC's response was that it had ordered cabinets with removable backs, but their supplier did not provide these cabinets with either open or removable backs.

[92] YEC approved NAC's drawings without having noted that the drawings required cabinets with open backs.

[93] In any event, the cabinets which were supplied had welded backs. Modifications had to be made to them by making holes in the sides and in the backs so that they could be used. They are still being used, but are not what was requested or required by YEC.

[94] YEC is seeking to replace the cabinets totally at a cost of some \$206,000.00. Mr. Maloney estimated that it would cost \$20,000.00 to \$30,000.00 to cut the panels out. Mr. Peake thought they could be “fixed” for \$100,000.00.

[95] I am satisfied that the cabinets should have been delivered with either removable backs or open backs.

[96] They should be repaired. I accept Mr. Peake’s evidence and allow this claim in the amount of \$100,000.00.

Deficiency Claims

[97] This is perhaps the most contentious claim. YEC says that NAC was sloppy, unprofessional and unsafe with respect to so much of its work that it had totally lost confidence in NAC’s ability to repair or remedy any of the multitude transgressions which it alleges have occurred.

[98] NAC maintains that the list of deficiencies prepared by YEC is quite exaggerated, as is the cost of remedying them.

[99] NAC has always indicated its willingness to attend and rectify any deficiencies. Indeed, numerous discussions were held and at least one walkthrough.

[100] NAC also argues that YEC has a duty to mitigate its damages and that by not allowing NAC back on site, or doing some of the work itself, it has failed to mitigate and that this claim should be dismissed.

[101] As I said earlier in this decision, the spirit of cooperation which permeated this project initially slowly faded. In its place, a sourness began to creep into the relationship.

[102] Minor items such as lack of orderliness and a failure to be careful, or a perceived failure to live up to what YEC considered a minimum standard of quality became more than irritants. Work was viewed as sloppy or careless. Standards began to be imposed without anyone having been given notice that much more was now being expected.

[103] The installation of the cables in the elevator shaft is a good example of how the dynamics changed:

- (i) Notwithstanding that it was YEC itself who determined what "Code" was to be followed, what had been acceptable before was now considered to be not acceptable.
- (ii) How cable was to be fastened to the duct should not be done the way it had been done just years before.
- (iii) The cable trays no longer were sufficient.
- (iv) The clearance was no longer sufficient.
- (v) The electrical code was being followed or not being followed, depending on who was interpreting it at any given time.
- (vi) The cables were now not "tidy".
- (vii) "Sloppy" work became "deficient work".
- (viii) A very slight indentation in a cable coverage became "damage".

[104] It seems to be, and did seem to me during the trial, that the Defendant had formed the view toward the end of the project that the Plaintiff was simply incompetent. It began viewing the work done through coloured glasses, “rose coloured” not being one of the lenses.

[105] Complaints of deficiencies were being directed at the Plaintiff without specifics being given.

[106] It was clear that the Defendant had had enough of the Plaintiff and it was not going to be fixing anything for the Defendant in the future, or doing any more work once they demobilized.

[107] The Plaintiff urges the Court to reject all of the Defendant’s deficiencies list because the project was substantially completed and the deficiencies were not serious ones. That being the case, the Plaintiff argues, there was no fundamental breach of the terms of the contract. That, in turn, required the Defendant to mitigate its damages. The best way to mitigate its damages was to allow the Plaintiff to carry out the necessary remedial work.

[108] I agree with the Plaintiff that that the deficiencies were not so serious as to amount to a fundamental breach of the contract having been committed by the Plaintiff.

[109] I also agree with the Plaintiff that an owner is required to mitigate its damages. However, with the greatest respect to the learned trial judge in *Beta Construction Inc. v Chiu*, 2015 ONSC 5288, at para 86, I do not agree that the owner must allow the contractor an opportunity to repair the deficiencies.

[110] In my respectful view, to compel an owner to allow a contractor with whom it has no confidence simply makes no sense.

[111] But, if such an owner - in this case - YEC, does not want NAC to perform the deficiency work, it cannot simply get the most expensive estimate it can find and ask the Court to award damages in that amount.

[112] I do wish to comment on some of the deficiencies within the elevator shaft before turning to the estimate to which I referred to above.

[113] It struck me time and again during the trial that while some of NAC's work was indeed sloppy, YEC's expectations were perhaps higher than they should have been.

[114] I am aware of the term in the contract that provides that: "The Contractor will perform the Work diligently in a workman like manner and in accordance with the highest industry practice used in Canada."

[115] I am also aware that the majority of this contract was carried out some 140 km north of Whitehorse, much of it in the middle of winter, and at a depth of some 400 feet underground.

[116] Mr. Tillbrook, an electrical engineer on site, considered much of NAC's electrical work to be sloppy. He thought that NAC was "not structured enough". He did not like NAC's overall plan, but admitted that the commissioning of the project did go forward and that the project was up and running within a few days of the substantial completion date. He was of the opinion that the tie wrapping was contrary to the electrical code,

depending on how one might interpret it. But I saw no evidence which satisfied me that the wrapping was improper.

[117] In this connection, it should be noted that the cables which were wrapped, lowered and supported during this project were done much in the same way that the previous cables had been suspended, wrapped and generally looked after.

[118] Mr. Tillbrook was critical of the protection given by NAC to the grips and wrapping, but admitted that nothing was contrary to any approved procedure.

[119] He criticized or commented on “damage” to the covering of one of the cables. The photograph of this particular piece of cable showed a very slight indentation in the wrapping.

[120] Mr. Bob Simonson’s criticisms had more to do with safety issues and lack of organizational skill than to deficiencies in the work carried out. Mr. Peake was also quite critical of NAC’s work within the cable trays. It was primarily sloppy and did not appear to be neat, in his mind. He thought the cable trays themselves were not secure enough and that they had been structurally weakened.

[121] It seemed to me that Mr. Peake’s key concern and complaint was that NAC’s people were not very qualified and that the work they were performing met the “bare minimum” quality level but did not meet what he considered would be the industry standard.

[122] Some of Mr. Peake’s other criticisms were that the wiring was not tidy; that the trays were overstuffed; and that the clearance was not sufficient.

[123] A fair amount of Mr. Peake's evidence concerned the cable trays. Some of his evidence arose as a result of an incident which occurred in October of 2013 when the elevator wires and the cable trays came into contact, resulting in a visit from the Yukon Workers' Compensation Health and Safety Board. In their report, the Board noted that minimum clearance distances between the conveyance and cables and cable trays were not being met. It also referred to the fact that there were deficiencies that were noted in an inspection report dated May 5, 2011 that had not been rectified.

[124] The end result of that incident was that a new design was prepared and the cable trays were ultimately fixed. However, my difficulty is that at the time of the installation, YEC was the electrical code authority and it was admitted that NAC was not advised of the clearance requirements prior to installing the trays or "overstuffing them".

[125] I very much hesitate to consider the cable trays and much of the remedial work done within the elevator shaft as a deficiency as a result of a report made by the Occupational and Safety Board some two years later. Admittedly, the way the wires were "stuffed" into the trays was not particularly tidy or pretty. However, I am not satisfied it constituted a deficiency.

[126] Much of the "Deficiency Claim", indeed, some \$264,000.00, related to the elevator cables (See Exhibit 41). My concerns with respect to the legitimacy of recovering these costs have been voiced.

[127] It was Mr. Peake who quite honestly said that while conducting the walkthrough with Mr. Hamad and others from NAC toward the end of the project, that he and the other YEC people who were attending with him had already determined that they were

not going to have NAC come back to do any of the deficiencies. They did not like NEC's work and refused to allow them to carry any further work out.

[128] YEC was entitled to come to that conclusion and was entitled to make such a decision.

[129] The question then becomes should NAC have to pay anything since the deficiencies did not amount to a fundamental breach of the contract. In my view, they do, because they did not complete the job as they were required to do under the contract.

[130] As I have already said, YEC is entitled to come to that conclusion and make the decision to have someone else perform the work. They are not, however, entitled to have the work carried out in the manner suggested by the Orbus report, prepared by Mr. Amin Kassam. Mr. Kassam had estimated the cost of remedying the deficiencies would be \$970,961.25.

[131] I found Mr. Kassam to be a very interesting witness. He declared himself to be an independent expert and not biased in any manner. However, his bias came through quite clearly.

[132] On a number of occasions, he appeared to suffer from a loss of memory with respect to information which he had received from Mr. Mortimer, a fellow colleague who had prepared an earlier estimate, and was argumentative when, in my view, there was no need to be.

[133] Mr. Mortimer, Mr. Kassam's former colleague, had prepared an estimate as to the cost of remedying the deficiencies. His estimate was \$686,500.00. Mr. Kassam professed to be more aware of the "conditions" and "factors" that should be taken into consideration notwithstanding that Mr. Mortimer was a senior field technology expert and that Mr. Mortimer had spent some 35 years with the company, presumably mostly in the North.

[134] Notwithstanding Mr. Mortimer's apparent expertise in the field, Mr. Kassam determined that Mr. Mortimer had not taken into consideration that:

- 1) the plant would be operating, not shut down;
- 2) the plant was located in a Northern site, and
- 3) the people carrying out the work would not be as skilled as Mr. Mortimer was.

[135] Mr. Craig Miller, an employee of NAC, is an operations analyst and an electrical estimator. He has prepared dozens of estimates on jobs throughout Canada. He was retained to prepare a report and did so. That was introduced as Exhibit 35 in these proceedings.

[136] Mr. Millar had been given a copy of Mr. Kassam's estimate. In fact, he was given both the Orbus reports of 2012 and 2016. He prepared a very detailed estimate of the work that would need to be carried out. He examined the deficiency list prepared by YEC and specifically the list and report of Mr. Kassam. He was very familiar with the site, visited it at least twice. He did not question whether any of the deficiencies were in fact deficiencies. He simply assumed that they were.

[137] Mr. Miller's estimate of the cost to repair was \$251,521.52.

[138] Mr. Kassam was of the view that all of Mr. Miller's estimates of time required were far too low. Where Mr. Miller had estimated some 65 hours to complete "the labelling", Mr. Kassam estimated 482 hours. Where Mr. Miller estimated some 40 hours to prepare as built to drawings, Mr. Kassam estimated some 653 hours. Where Mr. Miller estimated some 4 hours to complete what were described as "code items", Mr. Kassam estimated that this should take some 1,116 hours.

[139] These are rather stunning contrasts, none of which were put to Mr. Miller. Mr. Miller did, however, have access to and read the reports, so would have been aware of them. No cross examination was put to him, however, in that regard.

[140] Mr. Kassam did say that he was aware of a number of matters which he had estimated had been removed from the list as a result of the evidence, primarily, of Mr. Peake. That, in his view, would have reduced his costs by some 10 to 15%. The total hours on site which he had anticipated would be 5,268 hours, would have been reduced by some 37% if the items removed were considered.

[141] Had YEC mitigated their damages, they would have been able to revenue the deficiencies at a cost of, depending on the estimates used, some \$252,000.00 to \$433,000.00 (using Mr. Mortimer's estimate less the 37% with respect to items which had been removed and as conceded by Mr. Kassam).

[142] I was not particularly impressed by Mr. Kassam's evidence. Mr. Mortimer was not called and therefore not questioned with respect to his estimate. Mr. Miller's report was,

in my view, fair and reasonable. I award YEC the sum of \$251,500.00 with respect to the deficiencies as prepared by YEC.

[143] In the end result, from the total of \$2,032,031.00 is payable to NAC pursuant to the terms of the contract, YEC is entitled to deduct the sum of \$408,736.00 for a total judgment owing to NAC of \$1,623,565.00.

[144] The Plaintiff is, of course, entitled to interests and costs. Costs may be spoken to by counsel by means of a conference call.



HAWCO J.

1 **TOPIC:**

2
3 **REFERENCE:** YUB Order 2009-8, Appendix A, page 37

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

- 7 • descriptions of the project
- 8 • economic analysis including preliminary engineering estimates
- 9 • discussion of alternatives and how the chosen option was
- 10 determined
- 11 • discussion of the risks of proceeding with the chosen alternative
- 12 • discussion of risks of not proceeding with the chosen
- 13 alternative; and
- 14 • discussion of assumptions included in the business case
- 15 including escalation factors, loading, financial measures, term
- 16 of project and associated ancillary costs."
- 17

18 **Reference:** YUB Order 2013-01: Reasons for Decision, Appendix A,
19 page 65

20 *"However, in future, the Board directs YEC to provide business cases*
21 *for all projects, including reliability projects, greater than \$1 million.*
22 *These business cases are to include alternatives to the recommended*
23 *projects as well as the economic impact to ratepayers of the*
24 *recommended projects."*

25
26 Reference: June 22, 2017 Application, page 6-6

27 YEC states "Business cases for projects greater than \$1 million (i.e.,
28 "major projects") are provided in Tab 5 of this General Rate
29 Application".

30
31 Reference: June 22, 2017 Application, page 5-7

32 Aishihik Elevator Shaft Structural Steel Rehabilitation (\$10.116 million).

1 **QUESTION:**

- 2
- 3 a) Please provide a business case analysis for this project which contains details
4 required pursuant to Board Orders 2009-8 and 2013-01.
- 5
- 6 b) Please confirm the total project cost from conception to completion and provide an
7 annual breakdown by project component. Please ensure that all YEC internal costs
8 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.
9
- 10 c) Please provide a chronological history of all the decisions / approvals /
11 consultations related to this project including Board of Director's decisions, all
12 meetings with various First Nation governments / representatives, stakeholder
13 meetings, etc.
14
- 15 d) Please provide a copy of the referenced KGS Group study dated January 2014.
16

17 **ANSWER:**

18

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

20

21 The total project cost as per the Application is \$10.116 million (Page 5-8, I.1).
22 See YUB-YEC-1-62 for analysis of costs.
23

24 YEC is not able to provide the detailed information requested given the considerable time
25 and effort it would take to collect and summarize this information and its limited relevance
26 to the current review process.
27

28 Major capital projects invariably involve a multitude of interactions with a number of
29 individuals or entities internal and external to the organization including consultants and
30 different stakeholder groups. These interactions may occur over extended periods of time
31 as the project moves through the stage gate process. The record of these interactions is
32 commonly across several different platforms (e.g., email, phone conversations, mail,
33 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
34 response to this question will necessitate large amounts of work to compile with low
35 probability that the information gathered will affect the prudence assessment. The request
36 to provide a history of "all meetings with various First Nation governments /
37 representatives, stakeholder meetings, etc." is also overly broad and is not directly

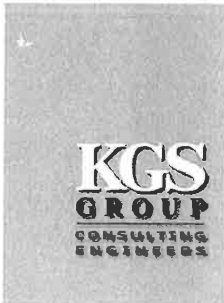
1 relevant to understanding whether costs for this project were reasonable or prudently
2 incurred.

3
4 Relevant information for determining the prudence of costs incurred for this project is
5 available for review on the record of this proceeding as follows:

- 6
7 • Tab 5 section 5.2.1.2 provides the project justification and estimated costs.
8
9 • YUB-YEC-1-62 – detailed initial estimate of budget and explanation of variances
10 as well as project status and alternatives reviewed.
11
12 • John Maissan-YEC-1-24 – estimated useful life of the asset.

13
14 **(d)**

15
16 Please see UCG-YEC-1-14 Attachment 1.



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Kontzamanis Graumann Smith MacMillan Inc.

January 27, 2014

File No.13-1404-005

Yukon Energy Corporation
2 Miles Canyon Road
P.O Box 5920
Whitehorse, Yukon
Y1A 5L6

ATTENTION: Mr. Lawrence Joudry

RE: Yukon Energy Corporation – Aishihik Power Plant Elevator

Dear Mr. Joudry:

KGS Group was retained by Yukon Energy Corporation to prepare a report setting out its opinions in relation to the electrical cables installed in the elevator shaft at Yukon Energy Corporation's Aishihik generating station. Please refer to the letter in Appendix A dated January 17, 2014 for more information.

Pursuant to Orders (I.R. No. 40-20131011-1025 and 40-20131020-0936) issued to Yukon Energy Corporation by the Yukon Workers Compensation Health and Safety Board (YWCHSB), the YWCHSB requires Yukon Energy Corporation to have a qualified independent engineer conduct a comprehensive evaluation of the 2011 installation upgrade in the conveyance shaft of the Aishihik Generating Station and produce documentation showing that the Aishihik conveyance (Elevator YE-1) meets all applicable codes, acts and regulations in regards to the installation and safe operation of the conveyance.

The purpose of the opinions contained within this report is to satisfy the requirements of these Orders and respond to the following questions:

1. **Does the cable suspension system as designed and installed comply with the manufacturer's directives and applicable codes?**
2. **If not, what modifications are required to bring the cable suspension system into compliance?**
3. **If the cable suspension system as designed or installed does not comply with the manufacturer's directives and/or applicable codes, is the cable suspension system as presently installed nevertheless capable of being certified as being safe for operation?**

Mr. Lawrence Joudry
Page 2

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To provide opinions and answer these questions, KGS Group first undertook a review of the relevant drawings of the Aishihik Generating Station. Due to the limited and sometimes contradictory information available, KGS Group travelled to site on three separate occasions to conduct formal site reviews of the present conditions. As KGS Group was unable to ascertain and verify the adequacy of the structure during these site reviews, it was decided to conduct three full load emergency elevator braking tests performed in conjunction with KONE Elevators to assess the structure.

The information on the electrical aspects of the installation obtained from the site reviews and tests was compared to the following codes and standards:

1. National Building Code of Canada - 2010 version.
2. Alberta Electrical Utility Code – 2013 version.
3. Canadian Electrical Code – 2009 and 2012 versions. Specific code sections applicable to this facility are:
 - a) 12-014 Conductors in Hoistways.
 - b) Rule 2-030 Deviation or Postponement.
 - c) 12-2200(4) Method of Installation.
 - d) 12-120(4) Supporting of Conductors.
4. Yukon Electrical Protection Act - 2002 version. The specific section applicable to this facility is:
 - a) Section 4(2) Standards for Installations.
5. Yukon Worker's Compensation Health and Safety Board Regulations. Specific sections applicable to this facility are:
 - a) Section 9.21.
 - b) Table 9.3.

Where applicable, KGS Group has identified deficiencies and outlined appropriate remedial actions to be undertaken by Yukon Energy Corporation to rectify these issues and satisfy these Orders. The report, Aishihik Elevator – AH3 Electrical Cabling Review was originally dated November 29, 2013. Appendix B contains a new revision of this report, which is identical to the November 29, 2013, with the exception that an engineer's seal has been added.

Our engineering opinions to the three questions posted above are as follows:

Question 1: Does the cable suspension system as designed and installed comply with the manufacturer's directives and applicable codes?

KGS Group found that the cable suspension system as designed does not comply with the Canadian Electrical Code requirements for adequate support and mechanical protection of a vertical installation of power cables within an elevator shaft.

During the course of reviewing the cable installation, various cable manufacturers and their representatives were contacted by phone to discuss the cable installation (Aetna, Okonite, and

Mr. Lawrence Joudry
Page 3

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General Cable). The cable manufacturers, and their representatives, typically defer to code requirements for installation and did not have specific written instructions for the installation of the cables. It was noted, however, that the current installation would not sufficiently support the cables to meet code, and that proper cable supports should be installed.

In addition, as a result of concerns with the structural frames in the elevator shaft, KGS Group is unable to determine that the cable suspension system, as installed and in its current condition, complies with the *National Building Code of Canada*.

Question 2: If not, what modifications are required to bring the cable suspension system into compliance?

In KGS Group's opinion, the existing cable suspension system can be brought into compliance with the *Canadian Electrical Code* by replacing the existing cable supports with modern cable clips and by installing a cable tray cover over the medium voltage power cables. KGS Group has recommended that these corrective measures be implemented within the next six months. Yukon Energy Corporation has retained KGS Group to provide engineering assistance for the design and specifications for the installation of the cable clips in compliance with the *Canadian Electrical Code*.

With respect to the shaft structure that supports the cable suspension system, KGS Group has recommended conditions, listed in the response to Question 3 below, on the use of the elevator in the short term and that repairs and upgrades be undertaken within the next 12 months to permanently rehabilitate the structure and enable long-term verification of its load bearing capacity. KGS Group has been retained by Yukon Energy Corporation to develop a concept design for this work. If the work cannot be completed before the end of the 2014, the adequacy of the structure will have to be re-assessed.

Question 3: If the cable suspension system as designed or installed does not comply with the manufacturer's directives and/or applicable codes, is the cable suspension system as presently installed nevertheless capable of being certified as being safe for operation?

To determine the adequacy of the structure, KGS Group conducted a review of the elevator shaft structural frames and support system. These structural frames support the electrical cables installed within the elevator shaft during the 2011 upgrade, as well as the elevator guide rails and various structures and services from the original 1975 installation. As a result of: (a) the limited structural drawings available for review; (b) the significant corrosion observed in some of the structural supports; (c) the vulnerability of the field welded connections to corrosion and cracking; and (d) the lack of load redundancy in the structure's design, KGS Group determined that the load bearing capacity of the "as constructed" structure would have to be verified. However, due to the limited availability of as-built drawings and our finding that many of the structural supports were field fit and field welded, KGS Group was unable to rely on a review and analysis of the drawings to conduct this verification. Another option would have been to conduct a complete physical inspection of each of the structure's support members and anchor points, however, this was not feasible based on the design and construction of the structure, which offers very limited access to the anchor points for inspection or testing.

As a result of these limitations, KGS Group designed a test to determine the adequacy of the structure in the immediate short term. This was achieved by performing a full load elevator braking test at three different points within the elevator shaft. The loads exerted on the shaft

Mr. Lawrence Joudry
Page 4

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structure by the operation of the elevator are normally minimal except in an emergency situation in which the elevator is required to apply its emergency brakes in a free fall condition. This situation represents the highest loading the structure is required to withstand, and was selected to confirm the system load capacity. Accordingly, the elevator was loaded to its rated capacity of 2500 pounds during the braking tests to demonstrate that the shaft structural supports could accommodate the highest loads the structure is likely to ever experience.

Based on the results of our review and the three emergency braking tests performed, KGS Group's opinion is that the structure is adequate for the current loads; however, certain conditions must be imposed to provide a reasonable margin of safety until the structure can be rehabilitated. Accordingly, it is KGS Group's opinion that the risk of a structural failure is as low as reasonably practicable and that the elevator can be safely operated until the corrective measures described above are implemented, if the following restrictions are imposed on its use:

1. The medium voltage power cables that are presently installed within the elevator shaft should be de-energized until the existing cable supports are replaced with modern cable clips and a cable tray cover is installed.
2. The maximum load capacity of the elevator should be de-rated (restricted) from 2500 pounds to 1000 pounds.
3. Although we understand that this is already standard Yukon Energy Corporation practice, no live loads (i.e. staff or non-permanently mounted equipment) should be present on the structure while the elevator is in use.
4. Other than the addition of the recommended modern cable clips and cable tray cover, no additional cables or new loads should be installed onto the shaft structure.
5. Yukon Energy Corporation should perform periodic inspections and monitoring of the shaft structure. KGS Group will forward details of the required inspection and monitoring procedure in the coming weeks.
6. If the recommended repairs and upgrades to the shaft structure are not completed by the end of 2014, the adequacy of the shaft structure should be re-assessed.

By de-energizing the medium voltage power cables (Restriction #1), Yukon Energy Corporation will eliminate the safety risk presented by the non-compliances with the *Canadian Electrical Code*. (A detailed report of KGS Group findings and recommendations in respect of the electrical aspects of its review was provided to Yukon Energy Corporation under a separate report dated November 29, 2013.)

The other interim measures (Restriction #2 - #6) should be implemented until the long term structural concerns of the shaft support structure have been addressed. These measures are meant to provide an adequate safety margin for the continued use of the elevator over a 12-month period. In KGS Group's opinion, there is no structural or electrical reason to limit the frequency of use of the elevator under these conditions.

This report has been prepared for Yukon Energy Corporation to whom this report has been addressed and any use a third party makes of this report, or any reliance on or decisions made based on it, are the responsibility of such third parties. KGS Group accepts no responsibility for

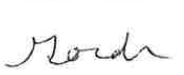
Mr. Lawrence Joudry
Page 5

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damages, if any, suffered by any third party as a result of decisions made or actions undertaken based on this report.

If you have any further questions or need further clarification, please feel free to contact the undersigned.

Prepared by:


Gord McPhail, P.Eng.
Senior Structural Engineer


Approved by:


Dave MacMillan
Principal

Prepared by:


Adam Pawlikewich, P.Eng.
Senior Electrical Engineer


GDM/AP/

Cc: Joel Lambert – KGS Group

1 **TOPIC:** **Aishihik Electrical and Control Upgrades (\$2.511 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-8

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal costs
14 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 c) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 d) Please provide a copy of the referenced KGS Group Study from 2014.

22
23 **ANSWER:**

24
25 **(a), (b) and (c)**

26
27 The business case for this project, including estimated costs, is provided in the Application
28 at Section 5.2.1.3. The project is forecast to be completed in 2018.

29
30 YEC is not able to provide the detailed information requested given the considerable time
31 and effort it would take to collect and summarize this information and its limited relevance
32 to the current review process.

33
34 Major capital projects invariably involve a multitude of interactions with a number of
35 individuals or entities internal and external to the organization, including consultants and
36 different stakeholder groups. These interactions may occur over extended periods of time
37 as the project moves through the stage gate process. The record of these interactions is

1 commonly across several different platforms (e.g. email, phone conversations, mail,
2 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
3 response to this question will necessitate large amounts of work to compile with low
4 probability that the information gathered will affect the prudence assessment. The request
5 to provide a history of “all meetings with various First Nation governments /
6 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
7 relevant to understanding whether costs for this project were reasonable or prudently
8 incurred.

9
10 Relevant information for determining the prudence of costs incurred for this project is
11 available for review on the record of this proceeding as follows:

- 12
- 13 • Tab 5 section 5.2.1.3 provides a review of the project elements, justification, and
14 costs.
 - 15 • Further information is available in the following interrogatory responses for this
16 proceeding:
 - 17 o **YUB-YEC-1-63** – copy of assessment report done by KGS Group, options
18 reviewed, and other related questions.
 - 19 o **CW-YEC-1-36** – review end of life determination.
- 20

21 **(d)**

22
23 Please see Attachment 1 provided as response to YUB-YEC-1-63(a).

1 **TOPIC: Communications Upgrades (\$1.003 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-12

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal costs
14 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 c) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 d) Please provide a copy of the referenced BBA study dated June 2016.

22
23 **ANSWER:**

24
25 **(a), (b) and (c)**

26
27 The business case for this project, including estimated costs for work completed before
28 the end of 2018, is provided in the Application at Section 5.2.1.4.

29
30 YEC is not able to provide the detailed information requested given the considerable time
31 and effort it would take to collect and summarize this information and its limited relevance
32 to the current review process.

33
34 Major capital projects invariably involve a multitude of interactions with a number of
35 individuals or entities internal and external to the organization including consultants and
36 different stakeholder groups. These interactions may occur over extended periods of time
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5 to provide a history of “all meetings with various First Nation governments /
6 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
7 relevant to understanding whether costs for this project were reasonable or prudently
8 incurred.

9
10 Relevant information for determining the prudence of costs incurred for this project is
11 available for review on the record of this proceeding as follows:

- 12
- 13 • Tab 5, section 5.2.1.4 provides a review of the project elements, justification and
14 costs.
 - 15
 - 16 • YUB-YEC-1-67 – review of basis for this work, inclusion of costs in rate base in
17 test years, and any cost changes.
 - 18
 - 19 • CW-YEC-1-37 & YCS-YEC-1-7– review of project benefits.
 - 20

21 **(d)**

22
23 Please see UCG-YEC-1-16 Attachment 1, which provides the Executive Summary and
24 Introduction for this report. The balance of the study has been excluded for IT security
25 purposes.

COMMUNICATIONS NEEDS ASSESSMENT UPDATE

TECHNICAL REPORT

Yukon Energy Corporation

BBA Document No. / Rev.: 5954029-002000-4C-ERA-0001 / R00
2016-06-17



Yukon Energy Corporation
Whitehorse, YT

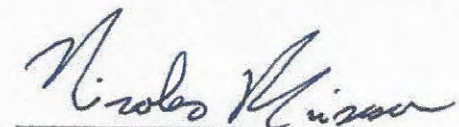
Technical Report
Communication Needs Assessment Update

BBA Document No. / Rev. 5954029-002000-4C-ERA-0001 / R00
June 17, 2016

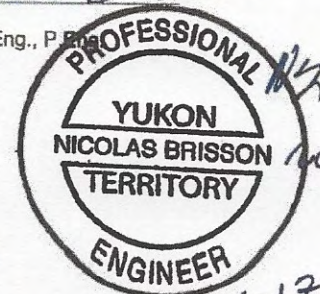
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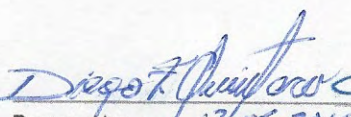
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40-ERA-0002 / R01

REVISION HISTORY

Revision	Document Status – Revision Description	Date
R00	Final	2016-06-17

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While it is believed that the information contained herein is reliable under the conditions and subject to the limitations set forth in the Document, this Document is based on information not within the control of BBA, nor has said information been verified by BBA, and BBA therefore cannot and does not guarantee its sufficiency and accuracy. The comments in the Document reflect BBA's best judgment in light of the information available to it at the time of preparation.

Use of this Document acknowledges acceptance of the foregoing conditions.

EXECUTIVE SUMMARY

To YEC, the generation and distribution of electrical energy is the main source of income, which is why it is important to consolidate an operations network with high efficiency and availability levels. Over time, the technological platform was built to keep the desired service levels. However, the result of this evolution is that both environments (OT & IT) exist to support YEC operations, but they were not implemented in a unified way. Today YEC needs to maintain two different infrastructures, each requiring different technical skills and spare parts, which increases the costs to maintain it operational. Due to the mix of several technologies, The manageability and scalability of the infrastructure will be accomplished with efficiency levels that could be improved with a unified next-generation network.

Over time, new technologies have been released leading to the convergence of industrial and corporate networks. As a result, more efficient and secure networks are supported for a high performance telecommunication network.

Taking into consideration the fact that OT is the core business and that the telecommunications infrastructure is mission critical in supporting operations; the present document is a reference design that will help YEC make its transition into a unified next-generation network. Increasing performance and reducing losses related to problems on the network can be achieved by effective integration of new network technologies and a simplified infrastructure. The unified environment will settle the basis of future implementations and innovations, opening the door to concepts such as Smart Grid.

The adoption of best practices, such as NERC, help improve processes and have a positive impact on operations. The insertion of new technologies and a migration to a unified next-generation network, establishes the basis to adopt NERC practices or ones that better fit YEC's values.

BBA was mandated to conduct an update on the "Communications Needs Assessment" made in 2011. The work includes an analysis of the current communications infrastructure, a description of the available technology, and the optimisation options of the OT and IT infrastructure owned by Yukon Energy Corporation (YEC). The study will include an assessment of the current situation, future trends and recommendations.

To create the Reference Design, a revision of the recommendations and the actual implementation was conducted. As a result, a new view of the status of both networks appear and a strategic plan is developed. This new design is intended to improve critical elements, like SCADA features and performance, reliability, redundancy, and security.

The following are key focuses for the study:

- SCADA and remote data collection;
- Corporate data, voice and video communications;
- Cost effectiveness over life-cycle;

- Reliability and Redundancy;
- Security;
- Safety;
- Accessibility and availability;
- Future needs: new plants, future data collection strategies, bandwidth requirements, protocol migration, backup control center, disaster recovery.

The proposed reference design should be implemented in a transitional way by choosing the most critical assets and then including the less critical ones. In the end, this will cover the whole YEC operations system.

This design will include the V-Connect service from NwTel to deploy the solution. The MPLS service is a private infrastructure that will support the telecommunication needs of the OT network with high security levels and is separated from IT network services. A basic redundant system using the actual satellite infrastructure is proposed.

A Disaster Recovery Site (DRS) is critical for YEC's operations. Currently, the infrastructure based on serial links doesn't allow a truly seamless failover to the new site.

The new topology based on a MPLS network and satellite connections will allow YEC to plan and implement its Disaster Recovery Site, which could be placed anywhere. Furthermore, it will improve the effectiveness to recover and restore the service if a disaster occurs.

The unified next-generation network will be a new challenge to YEC's technological infrastructure custodians. In order to grant efficiency of this new network and benefit from new services, two different roles will appear during the process: OT network lead hand and IT network lead hand. In addition, training should be provided to custodians and leaders to help them better understand and take advantage of the new services of this unified network.

The costs reflected in this report are those required to upgrade telecommunications services in some areas. These seek to meet the needs of both the core and the redundant networks.

Since new services will allow remote administration and management of the OT network, the impact of investments will be reflected in the optimization of operational resources.

With an overall investment of 517K while keeping the same monthly costs, YEC will have a Technological platform of new generation. However, partial upgrades can be done to gradually achieve the final result. The initial investment of 50K corresponds to Whitehorse's upgrade plus the areas chosen to start the project, and the related monthly costs affected.

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APPENDICES

Appendix A: Glossary

Appendix B: Cisco Plantwide Design

Appendix C: VRF Design for MPLS – WAN Overview

Appendix D: VRF Design for MPLS – Satellite Backup

Appendix E: Yukon Territory WAN Architecture

Appendix F: OT Network Architecture Overview

Appendix G: Third Party Connections Diagram

Appendix H: Whitehorse Area LAN Segregation

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Appendix K: Mayo – Stewart Area LAN Segregation

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Appendix M: Mayo – Dawson Area LAN Segregation

Appendix N: Pelly Crossing Area LAN Segregation

Appendix O: Mayo – WAN Lease Costs

Appendix P: Project Costs per Area

Appendix Q: OPEX and CAPEX Costs with Full Redundancy (Satellite Solution)

Appendix R: Mayo – OPEX and CAPEX Costs with Basic Redundancy (Satellite Solution)

Appendix S: Cyber Security for Electrical Utility Operations and Corporate Assets: Presentation

1. INTRODUCTION

1.1 Purpose

The purpose of the Communication Needs Assessment is to provide YEC with a plan of evolution of its OT network that is supported in a robust telecommunications environment.

Based on the situation that YEC has different technologies to control and monitor its operations, including access to the corporate network, the study needs to be focused on the present aspects:

- SCADA system (remote data collection, control, metering, reliability and availability);
- Corporate network services;
- Cost effectiveness over life-cycle;
- Availability, reliability, accessibility and efficiency;
- Redundancy;
- Security;
- Future needs and scalability of the environment.

1.2 About BBA

BBA is an independent Canadian consulting engineering firm operating internationally. Its team is composed of highly-qualified experts in several engineering disciplines including electrical, civil, mechanical, industrial data processing, mining, metallurgical processes, automation, and construction management.

BBA is particularly active in the energy and mining and metals, and oil, gas and biofuels sectors.

Nowadays, the effect of telecommunications networks on a company's productivity has been proven, and industries in the electrical sector are no exception. BBA has proven experience in this sector and takes leadership roles to accompany their clients in the improvement and management of the OT/IT infrastructure. They help them to understand that the mission of the telecommunication infrastructure is to improve the efficiency, availability, management and troubleshooting of the electrical network.

1.3 Scope

The Communications Needs Assessment included the following communication systems:

- SCADA system;
- SCADA network communications support;
- Access to intranet services;
- Wide Area Network (WAN) technologies;
- Unified communications systems (voice, video and data);
- Access control system;
- Intranet services;
- Internet access.

The assessment looked at the following aspects:

- Evaluation of the previous report;
- Projects developed during the last five years;
- Actual status of the OT network;
- Present data network technology and topology;
- Operational and maintenance costs;
- Client needs analysis;
- Problems with the existing systems and critical assets;
- Anticipated needs for future projects.

1.4 Methodology

This report is based on a four-stage approach to the Communication Needs Assessment:

- Revision of the project status proposed in BBA's previous report;
- Audit of the current communication system using documentation obtained from YEC, as well as meetings carried out with YEC IT, maintenance electricians, and SCC personnel;
- Definition of the client's needs based on information provided by the client, the service providers, and the available infrastructure;
- Development of a master plan to bring YEC's existing communication infrastructure in-line with the new communications strategy, and provide guidance for future projects and the predicted future industry trends.

1 **TOPIC: Hydro Unit #WH4 Overhaul (\$4.3 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-15

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal
14 costs (labour, O&M, supplies, etc.) attributable to this project are specifically
15 identified.

16
17 c) Please provide a chronological history of all the decisions / approvals /
18 consultations related to this project including Board of Director's decisions, all
19 meetings with various First Nation governments / representatives, stakeholder
20 meetings, etc.

21
22 d) Please provide details of the tendering process used to award Andritz Hydro the
23 contract to install the new rotor spider and to perform the 10-year overhaul.

24
25 **ANSWER:**

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

28
29 The business case for the project, including estimated costs, is provided in Section 5.2.1.5
30 of the Application. The project is forecast to be completed in 2017.

31
32 Please see response to YUB-YEC-1-68(a) for a current analysis of costs.

33
34 YEC is not able to provide the detailed information requested given the considerable time
35 and effort it would take to collect and summarize this information and its limited relevance
36 to the current review process.

1 Major capital projects invariably involve a multitude of interactions with a number of
2 individuals or entities internal and external to the organization including consultants and
3 different stakeholder groups. These interactions may occur over extended periods of time
4 as the project moves through the stage gate process. The record of these interactions is
5 commonly across several different platforms (e.g. email, phone conversations, mail,
6 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
7 response to this question will necessitate large amounts of work to compile with low
8 probability that the information gathered will affect the prudence assessment. The request
9 to provide a history of “all meetings with various First Nation governments /
10 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
11 relevant to understanding whether costs for this project were reasonable or prudently
12 incurred.

13
14 Relevant information for determining the prudence of costs incurred for this project is
15 available for review on the record of this proceeding as follows:

- 16
17 • Tab 5 section 5.2.1.5 provides a review of the project elements, justification, and
18 costs.
19
20 • YUB-YEC-1-68 – an updated review of costs now that the project is substantially
21 completed, and other related information.
22

23 **(d)**

24
25 Please see response to YUB-YEC-1-68(d).

1 **TOPIC: Hydro Unit #MH2 Overhaul (\$1.657 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-16

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal costs
14 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 c) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 d) Please provide the analysis showing that the "continued operation of the Mayo A
22 facility has been determined to be economic".

23
24 **ANSWER:**

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

27
28 The business case for this project, including estimated costs, is provided in the Application
29 at Section 5.2.1.6. The project is forecast to be completed in 2018.

30
31 YEC is not able to provide the detailed information requested given the considerable time
32 and effort it would take to collect and summarize this information and its limited relevance
33 to the current review process.

34
35 As planning for this project is not complete, significant consultations have not been
36 completed to date.

1 Relevant information for determining the prudence of costs incurred for this project is
2 available for review on the record of this proceeding as follows:

- 3
4 • Tab 5 section 5.2.1.6 provides a review of the project elements, justification, and
5 costs.
6
- 7 • YUB-YEC-1-69 – reviews operation of Mayo A and B, the operation of the two
8 Mayo A units, options reviewed, and other related questions.
9

10 **(d)**

11
12 Please see Appendix 5.6 of the 2016 Resource Plan report by KGS at link below.

13
14 [http://resourceplan.yukonenergy.ca/media/site_documents/Appendix 5.6 Mayo Hydro](http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.6_Mayo_Hydro_Future_Facility_Options_Report_(KGS_2016).pdf)
15 [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)

1 **TOPIC: T&D – Breaker Replacements (\$1.35 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-18

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal costs
14 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 c) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 **ANSWER:**

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

24
25 The business case for this project, including estimated costs for work to be completed by
26 the end of 2018, is provided in the Application at Section 5.2.1.7.

27
28 YEC is not able to provide the detailed information requested given the considerable time
29 and effort it would take to collect and summarize this information and its limited relevance
30 to the current review process.

31
32 Major capital projects invariably involve a multitude of interactions with a number of
33 individuals or entities internal and external to the organization including consultants and
34 different stakeholder groups. These interactions may occur over extended periods of time
35 as the project moves through the stage gate process. The record of these interactions is
36 commonly across several different platforms (e.g., email, phone conversations, mail,
37 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the

1 response to this question will necessitate large amounts of work to compile with low
2 probability that the information gathered will affect the prudence assessment. The request
3 to provide a history of “all meetings with various First Nation governments /
4 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
5 relevant to understanding whether costs for this project were reasonable or prudently
6 incurred.

7
8 Relevant information for determining the prudence of costs incurred for this project is
9 available for review on the record of this proceeding as follows:

- 10
- 11 • Tab 5 section 5.2.1.7 provides a review of the project elements, justification, and
12 costs.
 - 13
 - 14 • CW-YEC-1-39 – review of end of life assessment.

1 **TOPIC: T&D – Line Replacement (\$11.5 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-18

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal costs
14 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 c) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 **ANSWER:**

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

24
25 The business case for this project, including estimated costs for work completed to the
26 end of 2018, is provided in the Application at Section 5.2.1.8.

27
28 YEC is not able to provide the detailed information requested given the considerable time
29 and effort it would take to collect and summarize this information and its limited relevance
30 to the current review process.

31
32 Major capital projects invariably involve a multitude of interactions with a number of
33 individuals or entities internal and external to the organization including consultants and
34 different stakeholder groups. These interactions may occur over extended periods of time
35 as the project moves through the stage gate process. The record of these interactions is
36 commonly across several different platforms (e.g., email, phone conversations, mail,
37 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the

1 response to this question will necessitate large amounts of work to compile with low
2 probability that the information gathered will affect the prudence assessment. The request
3 to provide a history of “all meetings with various First Nation governments /
4 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
5 relevant to understanding whether costs for this project were reasonable or prudently
6 incurred.

7
8 Relevant information for determining the prudence of costs incurred for this project is
9 available for review on the record of this proceeding as follows:

- 10
- 11 • Tab 5 section 5.2.1.8 provides a review of the project elements, justification, and
12 costs.
 - 13
 - 14 • CW-YEC-1-40 – provides a copy of the external assessment, and other related
15 questions.

1 **TOPIC: Wareham Spillway Gate Hoist Replacement (\$2.7 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-21

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal costs
14 (labour, O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 c) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 d) Please provide the referenced International Quest Engineering study dated March
22 2014.

23
24 **ANSWER:**

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

27
28 The business case for this project, including estimated costs, is provided in the Application
29 at Section 5.2.1.9. The project was completed in 2015.

30
31 Project cost information is provided in Table 1 below.

Table 1: Wareham Spillway Gate Hoist Replacement Project Costs

(\$'000s)	2014	2015	Grand Total
Contractors, Materials & Services	1,189	1,376	2,564
YEC - Labour	26	45	71
YEC - Travel	8	11	18
YEC - Materials	2	5	7
YEC - AFUDC	3	36	39
Total Project Cost	1,227	1,473	2,700

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudence assessment. The request to provide a history of “all meetings with various First Nation governments / representatives, stakeholder meetings, etc.” is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding as follows:

- Tab 5, Section 5.2.1.9 provides a review of the project elements, justification and costs.

(d)

Please see UCG-YEC-1-21 Attachment 1.

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**INTERNATIONAL QUEST
ENGINEERING LTD.**

March 31st, 2014

File No. 0849-02-Rev C

YUKON ENERGY CORPORATION
P.O. BOX 5920 - #2 Miles Canyon Way
Whitehorse, Yukon Territory
Canada Y1A 5L6

Attn.: Mr. W.J.S. Haydock, P.Eng. – Supervisor, Mechanical Engineering

Re: WAREHAM LAKE SPILLWAY: GATE HOIST - LIFT SYSTEM OPTIONS

With respect to the '*Wareham Lake Spillway: Gate Hoist - Lift System Options*', INTERNATIONAL QUEST ENGINEERING LTD. is pleased to provide YUKON ENERGY CORPORATION with '**REVISED**' summary of anticipated costs for the options / estimations provided earlier (May 14th, 2012 – Rev B / June 17th, 2009 – Rev C).

Should any questions arise concerning information, figures, or material presented, or if further requirements should arise that may benefit from our involvement, please do not hesitate in calling our office at any time. We look forward to our future potential involvement with YUKON ENERGY CORPORATION on this subject matter, or additional projects & requirements that may benefit from our past experiences.

Thank You.

Regards,

INTERNATIONAL QUEST ENGINEERING LTD.



Gerhard Mikolajczyk P.Eng.
Enclosures

- INTERNATIONAL QUEST ENGINEERING LTD -

YUKON ENERGY CORPORATION
P.O. Box 5920 - #2 Miles Canyon Way
Whitehorse, Yukon Territory Y1A 5L6

IQE File No.: 0849-02 – Rev C
March 30th, 2014
Wareham Gate Hoist - Lift Systems Options



**INTERNATIONAL QUEST
ENGINEERING LTD.**

WAREHAM LAKE SPILLWAY GATE HOIST - LIFT SYSTEM OPTIONS

SUMMARY

March 22nd, 2014 - Revision C
(May 14th, 2012 - Rev B)
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IQE File No.: 0849-02 – Rev C
March 30th, 2014
Wareham Gate Hoist - Lift Systems Options

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1.0 DETAILED SUMMARY:

1.1 INTRODUCTION:

On Tuesday May 25th 2009, Gerhard Mikolajczyk P.Eng. of INTERNATIONAL QUEST ENGINEERING LTD. (IQE) met and discussed with William (Bill) Haydock P.Eng. of the YUKON ENERGY CORPORATION (YEC) various available beneficial upgrade / improvements options - to the existing gate lift system at the Wareham Lake Spillway.

It was discussed that either an 'existing / renovated' or 'alternative / upgraded' *Gate Lift System* would be considered as acceptable options at the existing Wareham Lake Spillway – and improvements were to be considered due to the age and inefficiency of the existing arrangement. Discussion of options for consideration involved: new design configuration similar to the '*Screw Lift Gate System*' used in 'Whitehorse Rapids Development' (replacement of the existing winch/cable configuration) or, suggestions on alternative options. IQE Ltd. had agreed to collect & assemble budget quotes / estimates for a new angle drive '*Screw Lift Gate System*', as well as offer suggestions on alternative options.

1.2 WAREHAM LAKE SPILLWAY (see picture on previous page):

The Wareham Lake spillway was built in the early 1950's. The generation facilities main function is to supply power to Dawson City - to displace the dependency of the previous '*Diesel Power Plants*'.

Replacement options for the existing '*Gate Lift System*' is desired to be investigated due to the age of the existing (60 years old) system, and due to potential / pending issues – Eg.: When opening the gate in cold weather conditions, there is a potential for the gate to 'freeze / seize' in a closed position. If there were a situation whereby the gate was 'stuck' in the closed position, there would be a lack of dam water level control. It is also felt that the existing 'cable/winch' system does not have the capacity to overcome the forces that may be experienced in a harsh ice built-up winter (jam) condition. It has been estimated that if the gate were 'stuck / closed', only a 72 hour window would be available to open the gate before the lake level rises above the dam. Within 72 hours, and in a 'jam' situation, alternate equipment would have to be brought on site in order to 'thaw / free' the gate and force the gate to the opened position.

1.3 WHITEHORSE EXAMPLE (See reference picture on following page):

The 'Whitehorse Rapids Development' was built in mid-1950's - to replace existing Whitehorse facility '*Diesel Power Plants*'. The 'Gates' are presently controlled with an upgraded '*Screw Lift Gate System*' - the system uses two 46'-0" Lg. (ACME) threaded rods which are attached to the top of (and lift up or push down) the existing gates. The threaded rods pass through a hoist unit gear box, which in turn are 'driven' - thus allowing the gates to (positively) travel up or down. The hoist unit / gear boxes are right angle bevel gear units (one per screw) driven by a center drive unit (motor & reducer unit). When the gate is in the up position, the screw is raised above the structure, with a pipe sleeve and support structure required to support / shield the screw. The support structure and pipe sleeve is equal to the length of the screw (46'-0"), and is on top of the gate structure. The center drive unit is housed in a small building to protect against the harsh weather conditions (see following reference pictures).

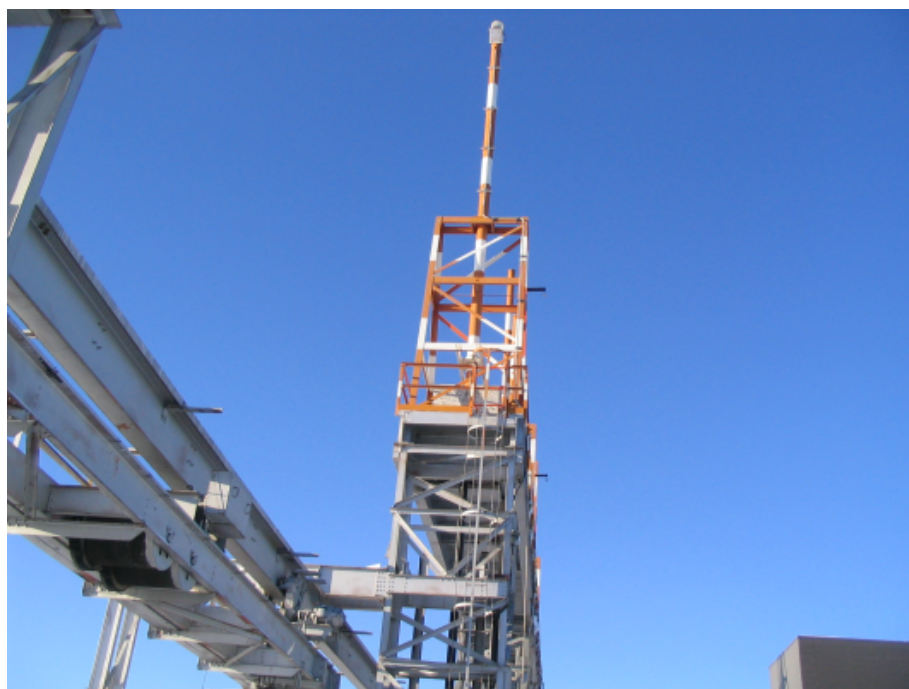
- INTERNATIONAL QUEST ENGINEERING LTD -

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Whitehorse Rapids Development Site



Pipe Sleeve / Drive Guarding and Support Structure

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2.0 ALTERNATIVES:

2.1 OPTION 1: REPLACE WITH A NEW SCREW / ANGLE DRIVE SYSTEM

The initial option for consideration was to replace the existing '*Cable / Winch System*' with a new '*Screw Lift Gate System*'. The advantage of the '*Screw Lift Gate System*' (versus the standard '*Cable / Winch System*') is such that the gate would be 'balanced / powered' (positively) in both the up and down direction. The existing cable system presently depends on gravity to lower the gate – and often (as explained), the existing gate must have additional ballast added in order to increase the weight (for down direction). The screw system would allow for better control of the spillway water level and have available, additional 'drive' capacity as required, to open (or close) the gate in cold weather conditions.

Preliminary quotes were received in a recent inquiry submitted to various experienced suppliers. The preliminary investigation requested the supply of a complete design / supply / install package. Suppliers were to include: new screws, gate connections, pipe sleeves, hoist units, top frame mount components, a housing enclosure for the center drive unit for both gates, & design / engineering of the new system, complete (less final power supply & connection by YEC).

Estimations provided, concluded the following:

OPTION #1 (Area 1): \$ 1.8 M
(2 Gates)

Additionally, it is expected that the existing (lattice / baton) support towers would require remedial upgrade improvements due to the additional component loads and design code upgrade requirements. IQE has suggested (based on preliminary review) that the following be allowed for these anticipated improvements:

OPTION #1 (Area 2): \$ 0.2 M
(2 Gates)

Thus the preliminary revised estimate is as follows:

OPTION #1 GRAND Total Est: \$ 2.0 M
(2 Gates)

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2.0 ALTERNATIVES: Con't

2.2 OPTION 2: UPGRADE / REPLACE EXISTING WINCH & RE-USE CABLE SYSTEM

The second available option for consideration is: replacement / upgrade of the existing '*Cable / Winch System*' - with new / updated winch drives, leaving the existing cable system / operating method intact. The new winch system would be designed to provide more 'capacity' allowance (with built in break motor) - to overcome anticipated cold weather conditions. More importantly, the new components would replace outdated 60 year old existing mechanical items – with more modern and readily available components. (For example: The present Radicon 'BU' winch reducer has since been updated in the '70's to 'AU' units – and today Radicon worm gears are seldom used due to inefficiencies.)

A quote was again requested and subsequently provided (for budgeting purposes) – the scope, to supply a complete winch package, including: new / modern integral winch break motor / reducer, drive, and necessary equipment bases. The new bases are anticipated to be installed in the existing 'winch houses', coordinated with the location and components of the existing cable lift system. International Quest Engineering Ltd (IQE) would be most willing to potentially assist in coordination of modifications to the existing system as well as assist with potential modifications to the existing structure (to suit the new winch drive arrangement) – with budget allowance considered for this requirement.

The quote for the New Screw Hoist System is broken down as follows:

- 15 HP Hoist Rated Motor / Parallel Shaft Gear Reducer (no open gearing)
- Hoist Duty Motor Brake / Couplings /
- Grooved Hoist Drum / Drum Bearings
- Fabricated Base
- Limit Switches / Encoder
- Assembled and Shop Tested

The total budget for '**Option 2: Replace with New Winch / Drive System**' would be:

OPTION #2 Budget Estimate: \$ 600 K
(2 Gates)

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2.0 ALTERNATIVES: Con't

2.3 OPTION 3: NO CHANGE

A final option remains to simply leave the gate system as is - continue using and maintaining the existing antiquated winch drive and cable system. This would be the least expensive option, with only on-going testing / maintenance required – as exists today. This option would not improve the ‘dependability’ of water level control at the spillway and would not improve the ability to open the gate in cold weather conditions – nor would provide improvements to an antiquated system. Note: There is only an anticipated 72 hour window to open the gate before the water level rises above the dam; in this time, the gate would have to be thawed and raised by means of ‘other’ equipment brought on site, most likely from Whitehorse (5 hrs away).

OPTION #3 Budget Estimate: \$ 0

3.0 REFERENCE

The following YUKON ENERGY CORPORATION drawings were provided for reference purposes:

2045-4DWG8	Western Bridge & Steel Fabricators Ltd / Montreal Engineering Co. Lift Operating Mechanism Gates - Gears (April 4, 1952)
2045-E4	Western Bridge & Steel Fabricators Ltd / Montreal Engineering Co. Lift Operating Mechanism Gates – Preliminary Layout (Jan 9, 1952)

The following INTERNATIONAL QUEST ENGINEERING LTD. drawings were also utilized for reference purposes:

0849-02-901-01D	WAREHAM GATE HOIST – NEW SCREW DRIVE – G.A.
0849-02-901-02B	WAREHAM GATE HOIST – NEW SCREW DRIVE – ELEV & SECTION
0849-02-901-03B	WAREHAM GATE HOIST – NEW SCREW DRIVE – ELEV & SECTION

1 **TOPIC: Whistle Bend Supply/Takhini Upgrade (\$11.383 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-22

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal
14 costs (labour, O&M, supplies, etc.) attributable to this project are specifically
15 identified.

16
17 c) Please provide a chronological history of all the decisions / approvals /
18 consultations related to this project including Board of Director's decisions, all
19 meetings with various First Nation governments / representatives, stakeholder
20 meetings, etc.

21
22 **ANSWER:**

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

25
26 The business case for this project, including estimated costs, is provided in the Application
27 at Section 5.2.1.10. The project was completed in 2015.

28
29 Project cost information is provided in Table 1 and Table 2 below. Please note that the
30 cost information included in Tab 5 of the Application in Section 5.2.1.10 did not include
31 2012 spending of \$0.153 as provided in Table 1 below. Actual total project costs are
32 \$11.537 as noted in table 1 below as not \$11.383 as noted in Tab 5.

Table 1: Whistle Bend Supply/Takhini Upgrade Project Costs

Whistle Bend Supply / Takhini Upgrade	
	(\$'000s)
Building Modifications	116
Electrical (Panels & Wiring)	910
Civil Work	3,110
138kV Transformer	1,775
138kV Ring Bus	1,455
34.5kV Substation	1,151
SCADA	402
Diesel Costs	6
Construction Field Cost	8,925
Preliminary Engineering & Design	106
Detailed Engineering	1,011
Construction Management	395
YEC Owner Costs	661
Construction Financing Costs	438
Indirect Costs	2,611
Total Project Cost	\$ 11,537

Table 2: Whistle Bend Supply/Takhini Upgrade Costs by Year

Spending by Year (\$'000s)				
2012	2013	2014	2015	Total
\$ 153	\$ 5,134	\$ 6,072	\$ 178	\$ 11,537

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g. email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudence assessment. The request to provide a history of “all meetings with various First Nation governments / representatives, stakeholder meetings, etc.” is also overly broad and is not directly

1 relevant to understanding whether costs for this project were reasonable or prudently
2 incurred.

3

4 Relevant information for determining the prudence of costs incurred for this project is
5 available for review on the record of this proceeding as follows:

6

- 7 • Tab 5, Section 5.2.1.10 provides a review of project elements, justification and
8 costs.

1 **TOPIC: LNG Plant (\$41.933 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-22

4
5 *Yukon Energy Blog - Why Energy Conservation April 8, 2015*
6 *Stated: "The natural gas plant is being built purely as back-up, to be*
7 *used during emergencies or during cold periods when we don't have*
8 *enough renewable power to meet demand."*
9

10 **PREAMBLE:**

11
12 **QUESTION:**

- 13
14 a) Please confirm the total project cost from conception to completion and provide an
15 annual breakdown including the costs of feasibility studies, engineering, internal
16 and external labour costs. Please include details of all tenders awarded related to
17 this project. Please ensure that all YEC internal costs (labour, O&M, supplies, etc.)
18 attributable to this project are specifically identified.
19
20 b) Please provide a table showing forecast and actual costs of this project by
21 component as cost estimates have been adjusted (i.e., project cost approved by
22 YEC Board of Directors, Part 3 application cost estimate, project cost updates
23 provided in IR responses, costs approved by YUB, etc.).
24
25 c) Please provide a table showing how this project has reduced costs charged to
26 ratepayers and describe where these savings are reflected in the applied for
27 revenue requirements for 2017 and 2018. Included in this analysis, please show
28 savings in fuel costs to date and through the test years.
29
30 d) Please provide a table showing longer terms costs and benefits of this project
31 under various load and generation / water level scenarios.
32
33 e) Please provide a chronological history of all the decisions / approvals /
34 consultations related to this project including Board of Director's decisions, all
35 meetings with various First Nation governments / representatives, stakeholder
36 meetings, etc.

1 f) Please explain when and how the LNG generation has been used in light of YEC's
2 previous arguments that it would only be used as backup to other generation.

3
4 g) Please confirm that the LNG back-up plant will not be used to supply electricity to
5 industrial (mine) loads that will be added in the short or long-term.

6
7 **ANSWER:**

8
9 **(a) through (e)**

10
11 The total project cost of \$41.93 million (prior to the \$18.3 million YDC contribution) is
12 reviewed in section 5.2.1.11 of the GRA Application, including the following summary of
13 factors accounting for the \$5.45 million cost increase since the 2014 Part 3 LNG
14 proceeding (please see the Application for added detail under each item):

- 15
16 1. Construction contracts (\$31.59 million): \$4.09 million increase over the Part 3
17 hearing estimate of \$27.5 million.
18
19 2. Engineering and Management (\$5.02 million): \$1.54 million increase over the Part
20 3 hearing estimate of \$3.48 million.
21
22 3. Owner's Costs (\$3.03 million): \$0.6 million increase over the Part 3 hearing
23 estimate of \$2.43 million.
24
25 4. Planning & Permitting (\$2.69 million): \$0.18 million increase over the Part 3
26 hearing estimate of \$2.51 million
27
28 5. Demolition (no cost included): The Part 3 hearing cost estimate of \$0.55 million
29 has been redefined as a post project construction activity not required to operate
30 the new facility.
31
32 6. Other Activities (no cost included): Costs for work on LNG transportation (\$0.33
33 million) have been moved to feasibility studies. Costs for First Nation benefits
34 (\$0.09 million) are to be paid by YEC with offset funding by YDC.
35

36 Please see response to John Maissan-YEC-1-27 for a review of the LNG Plant costs and
37 related estimates provided during the Part 3 LNG Application review and the updated

1 costs and related estimates in the current GRA. The response updates Figure 3-1 from
2 the 2013 filing to show how this project has reduced annual YEC costs (including fuel
3 costs) relative to the new diesel alternative since 2015 and the forecast ratepayer cost
4 reductions for 2017 and 2018 test years.

5
6 YEC's annual fuel costs are based on LTA hydro and thermal generation for actual grid
7 loads, and therefore are not affected by varying water level/ availability scenarios for
8 specific years. Please see Attachment 3.4.2 of the GRA Application for a review of
9 potential LTA thermal generation variability for a range of grid load scenarios. Ratepayer
10 cost savings from the LNG Project are tied to savings from displaced diesel generation,
11 which in turn are tied to overall grid loads (i.e., LNG Project cost savings increase with
12 higher loads) and the extent to which other resource option development occurs (i.e., LNG
13 Project cost savings decrease with other resource development that reduces LTA thermal
14 generation at any given load).

15
16 Major capital projects invariably involve a multitude of interactions with a number of
17 individuals or entities internal and external to the organization including consultants and
18 different stakeholder groups. These interactions may occur over extended periods of time
19 as the project moves through the stage gate process. The record of these interactions is
20 commonly across several different platforms (e.g. email, phone conversations, mail,
21 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
22 response to this question will necessitate large amounts of work to compile with low
23 probability that the information gathered will affect the prudence assessment. The request
24 to provide a history of "all meetings with various First Nation governments /
25 representatives, stakeholder meetings, etc." is also overly broad and is not directly
26 relevant to understanding whether costs for this project were reasonable or prudently
27 incurred.

28
29 **(f)**

30
31 LNG generation has been used whenever feasible to displace higher fuel cost diesel
32 generation that was otherwise required to meet grid loads (including for capital projects
33 and RFID related requirements), as well as for maintenance of these thermal generation
34 units.

1 **(g)**

2
3 LNG will be used in future when feasible to displace higher fuel cost diesel generation that
4 would otherwise be required to meet grid loads (including industrial/ mine loads). A
5 material share of any new loads at this time will be supplied by existing LTA hydro
6 generation resources (see Table 3.4-1 in the GRA Application, which indicates the share
7 of new load [in 5 GW.h increments] to be supplied by LTA thermal generation with existing
8 hydro resources as loads increase from current GRA forecasts [about 420 GW.h/year] up
9 to 485 GW.h/year). The 2016 Resource Plan identifies various resource projects that are
10 being examined to enhance hydro and other renewable generation availability within the
11 next decade.

1 **TOPIC: LNG Third Engine (\$6.2 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-26

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for this project which contains details
10 required pursuant to Board Orders 2009-8 and 2013-01.

11
12 b) Please confirm the total project cost from conception to completion and provide an
13 annual breakdown by project component. Please ensure that all YEC internal
14 costs (labour, O&M, supplies, etc.) attributable to this project are specifically
15 identified.

16
17 c) Please provide a chronological history of all the decisions / approvals /
18 consultations related to this project including Board of Director's decisions, all
19 meetings with various First Nation governments / representatives, stakeholder
20 meetings, etc.

21
22 d) Please identify all regulatory approvals that have been received specifically for the
23 LNG Third Engine project.

24
25 **ANSWER:**

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

28
29 The business case for this project, including estimated costs, is provided in the Application
30 at Section 5.2.1.12. The project is forecast to be completed in 2019.

31
32 YEC is not able to provide the detailed information requested given the considerable time
33 and effort it would take to collect and summarize this information and its limited relevance
34 to the current review process.

35
36 Major capital projects invariably involve a multitude of interactions with a number of
37 individuals or entities internal and external to the organization including consultants and

1 different stakeholder groups. These interactions may occur over extended periods of time
2 as the project moves through the stage gate process. The record of these interactions is
3 commonly across several different platforms (e.g. email, phone conversations, mail,
4 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
5 response to this question will necessitate large amounts of work to compile with low
6 probability that the information gathered will affect the prudence assessment. The request
7 to provide a history of “all meetings with various First Nation governments /
8 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
9 relevant to understanding whether costs for this project were reasonable or prudently
10 incurred.

11
12 Relevant information for determining the prudence of costs incurred for this project is
13 available for review on the record of this proceeding as follows:

- 14
- 15 • Tab 5 section 5.2.1.12 provides a review of the project elements, justification, and
16 costs.
 - 17 • YUB-YEC-1-71 – Updated costs for the project.
 - 18 • CW-YEC-1-41 – The 2016 Resource Plan justification for the project, review of
19 options, and related information.
 - 20 • John Maissan-YEC-1-28 – The basis for looking at options, and dependable
21 energy and capacity of the project.
- 22

23 **(d)**

24
25 The YESAB and *Public Utilities Act* Part 3 regulatory reviews were completed for this
26 project. Permit amendments will be required under the *Environment Act* (air emissions
27 permit) and the *Yukon Oil and Gas Act* (LNG facility licence).

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-28
4 YEC states “Growth in net rate base reflects ongoing need to refurbish
5 old assets and improve grid reliability. Significant re-investment in
6 existing infrastructure has been undertaken since 2013 to ensure that
7 the Yukon integrated grid can continue to meet the unprecedented level
8 of growth on the system in a safe and reliable manner”.

9
10 June 22, 2017 Application, Table 2.1, page 2-17
11 Total kWh sales are forecast to increase from 388,363 MWh in 2013 to
12 398,582 MWh in 2018 which equates to a less than 1.3% total growth
13 over 5 years.

14
15 **PREAMBLE:**

16
17 **QUESTION:**

- 18
19 a) Please explain how 1.3% in total growth in sales over 5 years can be considered
20 to be “unprecedented”.
21
22 b) Please provide a table of capital projects that have been undertaken since 2013
23 that have been required to meet system growth. This table should include a
24 description of the project, justification for the project due to system growth, total
25 actual / estimated costs and date of completion.

26
27 **ANSWER:**

28
29 **(a)**

30
31 Please see response to YUB-YEC-1-72(a). The sentence should be amended as follows
32 for the current GRA: “Ongoing re-investment in existing infrastructure ensures that the
33 Yukon integrated grid can continue to meet loads on the system in a safe and reliable
34 manner.”

1 **(b)**

2

3 The Application classifies in Tab 5 the major projects (as well as projects in cost range of
4 \$0.1 to \$1.0 million) undertaken since 2013 required to meet capacity shortfalls, primarily
5 due to retirement of existing thermal units (rather than due to system growth).

1 **TOPIC:**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-28
4 *YEC states "This Application includes approximately \$6.3 million of*
5 *earlier deferred overhaul costs being brought into the property, PP&E*
6 *capital works rate base as of January 1, 2017. No spending on*
7 *overhauls is included for the test years".*
8

9 **PREAMBLE:**

10
11 **QUESTION:**

- 12
13 a) Please explain why deferred overhaul costs must be added to rate base starting in
14 2017.
15

16 **ANSWER:**

17
18 **(a)**

19
20 Deferred overhaul costs are being added to rate base starting in 2017 because the Board
21 directed in the last GRA that these costs be held in WIP until the next GRA, and the
22 planned work has been completed.

1 **TOPIC: WAF Transmission Upgrades**

2
3 **REFERENCE:** June 22, 2017 Application, Appendix 5.3, page 5.3-7

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis of the \$3.1 million in projects under this
10 category between 2013 and 2016.

11
12 b) Please provide details of the projects to be undertaken pursuant to the \$850,000
13 annual budget for these projects in 2017 and 2018.

14
15 **ANSWER:**

16
17 **(a) and (b)**

18
19 The amount for WAF Transmission Upgrades is not a single project, but reflects ongoing
20 capital work to replace end-of-life components. A consultant conducted an assessment of
21 pole condition and made recommendation for replacement of end-of-life components on
22 a priority basis. The work referenced addresses the issues raise in that report. No other
23 specific project business case is available.

24
25 The forecast spending of \$0.850 million for 2017 and 2018 is prepared based on the most
26 recent actual year spending which were at \$0.892 million in 2015 and \$0.881 million in
27 2016. This includes upgrades and replacement of components of the transmission line.

1 **TOPIC:** **Customer Extensions**

2
3 **REFERENCE:** June 22, 2017 Application, Appendix 5.3, page 5.3-8

4
5 June 22, 2017 Application, Table 2.1, page 2-17
6 Total customers increased from 2029 in 2013 to 2098 in 2016 which
7 equates to 69 additional customers over 5 years. Forecasts include an
8 additional 16 customers being added in 2017 and another 12
9 customers in 2018.

10
11 **PREAMBLE:**

12
13 **QUESTION:**

- 14
15 a) Please provide details of the \$2.44 million in customer extensions costs over the
16 2013-2016 period as it is related to the additional 69 customers.
17
18 b) Please provide details of the projects to be undertaken pursuant to the \$475,000
19 annual budget for these projects in 2017 and 2018 to accommodate the additional
20 28 customers.
21

22 **ANSWER:**

23
24 **(a)**

25
26 Details of the \$2.44 million in customer extensions are below. Note that customer
27 extension costs include projects for both new and existing customers and are offset by
28 customer contributions of \$1.91 million.

Table 1: Customer Extension Costs

(\$000's)	2013	2014	2015	2016	Total
Projects greater than \$100,000					
Dawson Airport Underground Phase 2	-	-	354	31	385
Dawson Airport Upgrade Phase 1	3	278	-	-	281
YTG Ice Melt	-	4	156	-	160
Mayo C6 Subdivision Phase 2	-	142	-	-	142
Dawson C4 Subdivision Phase 2	-	-	1	134	135
	3	423	511	165	1,102
Projects less than \$100,000	300	326	299	413	1,339
Total Customer Extensions	303	750	810	578	2,441

(b)

The forecast of \$475,000 in customer extensions in each of 2017 and 2018 is a placeholder forecast because it is not feasible to forecast the volume, size or complexity of requested customer connections in 2017 and 2018. Note that the Application further assumes that \$400,000 of this capital work will be offset by customer contributions. This forecast is consistent with the forecast in the 2012/2013 YEC GRA

1 **TOPIC: Building Condition Report Response**

2
3 **REFERENCE:** June 22, 2017 Application, Appendix 5.3, page 5.3-9

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a copy of the referenced 2016 consultant report and details of the
10 total cost of this report.

11
12 b) Please details of the projects included in the \$299,000 budget for 2018 and related
13 references within the consultant's report.

14
15 c) Please provide justification for undertaking all of these projects in 2018.

16
17 **ANSWER:**

18
19 **(a)**

20
21 Please refer to John Maissan-YEC-1-37. The cost of the report was \$104,405.

22
23 **(b)**

24
25 Please see Table 1 below.

1

Table 1: Projects & references to Building Condition Report

Location	System	Report Reference	Cost
Aishihik Staff House	Study - Freeze Ups	Aishihik pg 13 A02.6b	\$ 11,000.00
833 - 6th Ave	Study - Structural	Dawson pg 54 Imm.4C	\$ 3,000.00
1136 - 5th Ave	Study - Structural	Dawson pg 54 Imm.5D	\$ 5,000.00
Faro Office FD1	Fire Alarm Panel / Detectors Replacement	Faro pg 82 E06.1a & E06.2a	\$ 13,800.00
Faro Plant FD7	Fire Alarm Panel / Detectors Replacement	Faro pg 82 E06.1b & E06.2b	\$ 14,500.00
Mayo Office	Fire Alarm Panel / Detectors Replacement	Mayo pg 102 E05.1A & 103 E03.1A	\$ 10,500.00
Lot 8 Airport Drive	Study - Water Leaks	Mayo pg 27 Imm.1E & A06.1E	\$ 7,000.00
Mayo Office	Study - Roofing	Mayo pg 35 Imm.2A	\$ 5,000.00
Mayo Office	Heattracing Roof/Gutters	Mayo pg 37 Imm.3A & pg 35 R01.1A	\$ 18,500.00
Lot 1088 Airport Drive	Building Envelope	Mayo pg 38 Imm.5D	\$ 5,150.00
Mayo Office	Study - Structural	Mayo Pg 54 Imm.6A	\$ 5,000.00
Mayo Office	Structural	Mayo pg 54 S01.1A & pg 55 S02.1A	\$ 20,000.00
Lot 8 Airport Drive	Study - Freeze Ups	Mayo pg 70 Imm.11E & M01.2E	\$ 5,500.00
Mayo Office	Study - HVAC	Mayo pg 76 M03.1A	\$ 5,000.00
Block 8 Airport Drive	Fire Alarm Panel / Detectors Replacement	Mayo pg 80 Imm12.B & pg 103 Imm21.B	\$ 1,550.00
Whitehorse Fish Ladder	Study - Roofing	WH Fish pg 24 Imm.5B	\$ 2,500.00
Whitehorse Fish Ladder	Waterproof exterior load bearing walls	WH Fish pg 40 S06.2B	\$ 50,000.00
Whitehorse Fish Ladder	Study - Structural	WH Fish pg 41 Imm.7B	\$ 3,000.00
Whitehorse Fish Ladder	Fire Alarm Panel / Detectors Replacement	WH Fish pg 66 Imm.11B	\$ 1,550.00
Kulan Warehouse	Heattracing Roof/Gutters	WH Kulan pg 19 R01.2a	\$ 4,400.00
Whitehorse Office	Fire Alarm Panel / Detectors Replacement	WH Office pg 95-96 E05.1A & E05.3A	\$ 46,350.00
Whitehorse IT Trailer	Fire Alarm Panel / Detectors Replacement	WH Office pg 95-96 E05.1B & E05.3B	\$ 8,350.00
Whitehorse Electrician Office	Fire Alarm Panel / Detectors Replacement	WH Office pg 95-96 E05.1C & E05.3C	\$ 9,400.00
Whitehorse Drafting Trailer	Fire Alarm Panel / Detectors Replacement	WH Office pg 96 E05.1D & E05.3D	\$ 6,300.00
Whitehorse - Diesel Plant / P126	Replace Front Gate	WH Plants pg 11 A01.10a	\$ 17,200.00
Whitehorse - WH4 / P127	Study - Water Leaks	WH Plants pg 18 RAI.1b & A06.5b	\$ 5,000.00
Whitehorse - Diesel Plant / P126	Downspouts	WH Plants pg 22 R01.3a	\$ 5,500.00
Whitehorse - Diesel Plant / P126	Study - Structural	WH Plants pg 35 RAI.3a & S05.1a	\$ 5,000.00
Whitehorse - Diesel Plant / P126	Study - Ventilation	WH Plants pg 48 RAI.7a & M.04.2a	\$ 4,000.00
			<u>\$ 299,050.00</u>

2

3

4 (c)

5

6 Justification is included in the report provided in John Maissan-YEC-1-37 Attachment 1.

7 Please see also the references provided in (b).

1 **TOPIC: Dawson Derrick Digger**

2
3 **REFERENCE:** June 22, 2017 Application, Appendix 5.3, page 5.3-9

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a business case analysis for the replacement of this truck and
10 digger including avoided maintenance costs.

11
12 b) Please provide details of the impact of delaying this replacement until 2019 or
13 2020.

14
15 **ANSWER:**

16
17 **(a) and (b)**

18
19 The average annual repair and maintenance cost for this unit from 2014-2016 is \$18,500.
20 A major overhaul of a number of components would be required to maintain the unit at an
21 acceptable level of reliability, resulting in a significant increase in annual repair costs. It is
22 not feasible to continue using the unit in its current state of repair as the risk of a
23 mechanical breakdown during an emergency or outage in Dawson is too high.

1 **TOPIC: Mayo Transient Trailer Unit**

2
3 **REFERENCE:** June 22, 2017 Application, Appendix 5.3, page 5.3-10

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide details on the impacts to Yukon accommodation, food and other
10 service providers by replacing their services with the proposed trailer.

11
12 **ANSWER:**

13
14 **(a)**

15
16 YEC has not performed an analysis on the impacts to Yukon service providers of locating
17 a transient staff trailer in Mayo. Please see also responses provided to CW-YEC-1-34(e),
18 and YUB-YEC-1-87(f).

1 **TOPIC: Aishihik Relicensing (\$2.899 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-31 and Table 5.3, page 5-56

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please confirm that the Work in Progress (WIP) treatment of these costs means
10 that there will be no impact on rates paid by Yukon ratepayers in 2017 and 2018.

11
12 b) Please explain the difference between the \$2.899 million cost identified at page 5-
13 31 and the \$8.9 million cost identified on Table 5.3 at page 5-56.

14
15 c) Please provide a detail breakdown by year of the \$8.9 million costs shown on Table
16 5.3.

17
18 d) Please confirm that costs related to the Aishihik Relicensing will not be recovered
19 in rates until approved by the YUB in a subsequent general rates application
20 process.

21
22 e) If Aishihik Relicensing is being treated as WIP, why does Table 5.3 at page 5-56
23 indicate that there is accumulated amortization related to this project?

24
25 **ANSWER:**

26
27 **(a) through (e)**

28
29 As indicated on page 5-31, Aishihik Relicensing project is planned for completion in 2019
30 and the expected cost is approximately \$2.899 million. For the 2017 and 2018 test years
31 the project is expected to be in WIP with no impact to rate base or rates.

32
33 The expenditure of \$8.9 million, amortization and accumulated amortization expenses for
34 "Aishihik Relicensing" in Tables 5.3 through 5.8 relate to the previous relicensing
35 processes to the end of 2009. These costs have been previously reviewed and approved
36 by the Board for inclusion in rate base.

1 **TOPIC: Stewart - Keno City Transmission Line Project**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-32

4
5 **PREAMBLE:**

6
7 **QUESTION:**

- 8
9 a) Please provide a detailed chronological list of costs incurred and decision points
10 related to this project including a breakdown of the costs of incurred for feasibility
11 studies, engineering, internal and external labour costs and tenders awarded
12 related to this project. Please ensure that all YEC internal costs (labour, O&M,
13 supplies, etc.) attributable to this project are specifically identified.
14
15 b) Please identify the source of all capital contributions to this project and provide
16 related correspondence.
17
18 c) Please confirm that none of the costs incurred related to this project will be paid by
19 Yukon ratepayers.
20

21 **ANSWER:**

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

24
25 The costs incurred to date relate to work required to get the project to a shovel ready state
26 as described in Section 5.3.1.1 of Tab 5. These costs are fully covered by a government
27 contribution. For further information please see response to YUB-YEC-1-76 and
28 YCS-YEC-1-17.

1 **TOPIC: Gladstone Hydro Enhancement Project (\$4.521 million – project**
2 **not proceeding)**

3
4 **REFERENCE:** June 22, 2017 Application, page 5-45

5
6 **PREAMBLE:**

7
8 **QUESTION:**

9
10 a) Please provide a detailed chronological list of costs incurred and go / no go
11 decision points related to this project including a breakdown of the costs incurred
12 for feasibility studies, engineering, internal and external labour costs and tenders
13 awarded related to this project. Please ensure that all YEC internal costs (labour,
14 O&M, supplies, etc.) attributable to this project are specifically identified.

15
16 b) Please provide a chronological history of all the decisions / approvals /
17 consultations related to this project including Board of Director's decisions, all
18 meetings with various First Nation governments / representatives, stakeholder
19 meetings, etc.

20
21 c) Please provide meeting notes and correspondence related to discussions with
22 Champagne and Aishihik First Nations and Kluane First Nation.

23
24 **ANSWER:**

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

27
28 The costs incurred on this project are as follows:

Table 1: Gladstone Hydro Enhancement Project Costs

Labour	75,760
Consultants	3,326,138
Travel	17,121
Materials	147,820
AFUDC	762,346
Office Expense	890
Other	191,189
Total	\$4,521,265

YEC is not able to provide the detailed information requested given the considerable time and effort it would take to collect and summarize this information and its limited relevance to the current review process.

Major capital projects invariably involve a multitude of interactions with a number of individuals or entities internal and external to the organization including consultants and different stakeholder groups. These interactions may occur over extended periods of time as the project moves through the stage gate process. The record of these interactions is commonly across several different platforms (e.g., email, phone conversations, mail, regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the response to this question will necessitate large amounts of work to compile with low probability that the information gathered will affect the prudence assessment. The request to provide a history of “all meetings with various First Nation governments / representatives, stakeholder meetings, etc.” is also overly broad and is not directly relevant to understanding whether costs for this project were reasonable or prudently incurred.

Relevant information for determining the prudence of costs incurred for this project is available for review on the record of this proceeding, or other public proceedings, as follows:

- **2017/18 GRA:** Application, Tab 5 section 5.3.1.7 provides an update regarding project costs incurred since the 2012/13 GRA, the decision making process, and factors underlying the decision not to proceed with the project. Further information is available in the following interrogatory responses for this proceeding:
 - o YCS-YEC-1-12 – discusses the identification of permitting issues for the project.

- 1 • **2012/13 GRA:** This project was extensively reviewed in the 2012/13 GRA review
2 process and commented on by the Board in Order 2013-01. Section 5.3.1.2 of the
3 2012/13 GRA Application reviews the project concept, risks, costs and benefits,
4 and review work undertaken to that point. Further information is available in the
5 following interrogatory responses for this proceeding:
- 6 o YECL-YEC-1-18 – 20-year Resource Plan: 2011-2030 recommendations
7 regarding the project.
 - 8 o YUB-YEC-1-43 – various details relating to the project status and current
9 stage of development. Provides a breakdown of costs for Gladstone
10 Diversion to the end of 2011 (by task and by consultant).
 - 11 o YUB-YEC-1-40 – notes plan to reach a final determination regarding
12 whether the project is feasible to pursue within the next 6 to 12 months
13 based on discussions with local First Nations and regulators.
 - 14 o YUB-YEC-2-8 – discusses YEC's interactions with DFO and CAFN and
15 decision making process for the project.
 - 16 o YUB-YEC-2-19 – provides a corrected full utilization LCOE is
17 5.7 cents/kW.h with estimated project cost at \$40 million (2010\$).
 - 18 o LE-YEC-1-25 and UCG-YEC-1-60.

1 **TOPIC: Marsh Lake Storage Project (\$8.156 million)**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-46

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a detailed chronological list of costs incurred and decision points
10 related to this project including a breakdown of the costs of incurred for feasibility
11 studies, engineering, internal and external labour costs and tenders awarded
12 related to this project. Please ensure that all YEC internal costs (labour, O&M,
13 supplies, etc.) attributable to this project are specifically identified.

14
15 b) Please provide a chronological history of all the decisions / approvals /
16 consultations related to this project including Board of Director's decisions, all
17 meetings with various First Nation governments / representatives, stakeholder
18 meetings, etc.

19
20 **ANSWER:**

21
22 **(a) and (b)**

23
24 YEC is not able to provide the detailed information requested given the considerable time
25 and effort it would take to collect and summarize this information and its limited relevance
26 to the current review process. This project remains in WIP through the 2018 test year and
27 has no impact on test year rates or rate base.

28
29 Major capital projects invariably involve a multitude of interactions with a number of
30 individuals or entities internal and external to the organization including consultants and
31 different stakeholder groups. These interactions may occur over extended periods of time
32 as the project moves through the stage gate process. The record of these interactions is
33 commonly across several different platforms (e.g., email, phone conversations, mail,
34 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
35 response to this question will necessitate large amounts of work to compile with low
36 probability that the information gathered will affect the prudence assessment. The request
37 to provide a history of "all meetings with various First Nation governments /

1 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
2 relevant to understanding whether costs for this project were reasonable or prudently
3 incurred.

4
5 Relevant information for determining the prudence of costs incurred for this project is
6 available for review on the record of this proceeding, or other public proceedings, as
7 follows:

- 8
9 • **2017/18 GRA:** Application, Tab 5 section 5.3.1.8 provides an update regarding
10 project costs incurred since the 2012/13 GRA. Further information is available in
11 the following interrogatory responses for this proceeding:
 - 12 ○ YUB-YEC-1-84
 - 13 ○ YCS-YEC-1-10
 - 14
- 15 • **2012/13 GRA:** This project was extensively reviewed in the 2012/13 GRA review
16 process and commented on by the Board in Order 2013-01. Section 5.3.1.1 of the
17 2012/13 GRA Application reviews the project concept, risks, costs and benefits,
18 and review work undertaken to that point. Further information is available in the
19 following interrogatory responses for this proceeding:
 - 20 ○ YUB-YEC-1-42 - various details relating to the project status and current
21 stage of development.
 - 22 ○ YECL-YEC-1-38 - additional details regarding capital cost expected and
23 any additional generation upgrades needed.
 - 24 ○ YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030
25 recommends completion of the required environmental, engineering and
26 remediation studies related to the project in order to make a determination
27 whether it is feasible and cost-effective to proceed.
 - 28 ○ YUB-YEC-2-7 and YUB-YEC-2-16.

1 **TOPIC: Mayo Lake Enhanced Storage Project**

2
3 **REFERENCE:** June 22, 2017 Application, page 5-47

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a detailed chronological list of costs incurred and decision points
10 related to this project including a breakdown of the costs of incurred for feasibility
11 studies, engineering, internal and external labour costs and tenders awarded
12 related to this project. Please ensure that all YEC internal costs (labour, O&M,
13 supplies, etc.) attributable to this project are specifically identified.

14
15 b) Please provide a chronological history of all the decisions / approvals /
16 consultations related to this project including Board of Director's decisions, all
17 meetings with various First Nation governments / representatives, stakeholder
18 meetings, etc.

19
20 **ANSWER:**

21
22 **(a) and (b)**

23
24 YEC is not able to provide the detailed information requested given the considerable time
25 and effort it would take to collect and summarize this information and its limited relevance
26 to the current review process. This project remains in WIP through the 2018 test year and
27 has no impact on test year rates or rate base.

28
29 Major capital projects invariably involve a multitude of interactions with a number of
30 individuals or entities internal and external to the organization including consultants and
31 different stakeholder groups. These interactions may occur over extended periods of time
32 as the project moves through the stage gate process. The record of these interactions is
33 commonly across several different platforms (e.g. email, phone conversations, mail,
34 regulatory proceedings, etc.). In the absence of a more targeted line of inquiry, the
35 response to this question will necessitate large amounts of work to compile with low
36 probability that the information gathered will affect the prudence assessment. The request
37 to provide a history of "all meetings with various First Nation governments /

1 representatives, stakeholder meetings, etc.” is also overly broad and is not directly
2 relevant to understanding whether costs for this project were reasonable or prudently
3 incurred.

4
5 Relevant information for determining the prudence of costs incurred for this project is
6 available for review on the record of this proceeding, or other public proceedings, as
7 follows:

- 8
9 • **2017/18 GRA:** Application, Tab 5 section 5.3.1.9 provides an update regarding
10 project costs incurred since the 2012/13 GRA. Further information is available in
11 the following interrogatory responses for this proceeding:
12 ○ YUB-YEC-1-85
13 ○ YCS-YEC-1-11
14
15 • **2012/13 GRA:** This project was extensively reviewed in the 2012/13 GRA review
16 process and commented on by the Board in Order 2013-01. Section 5.3.1.4 of the
17 2012/13 GRA Application reviews the project concept, risks, costs and benefits,
18 and review work undertaken to that point. Further information is available in the
19 following interrogatory responses for this proceeding:
20 ○ YUB-YEC-1-45 - various details relating to the project LCOE and costs.
21 ○ YECL-YEC-1-18 - the Overview of the 20-year Resource Plan: 2011-2030
22 notes, in updated grid load scenarios Appendix A (page A-4), that more
23 recent information suggests that this project's earliest in-service date is
24 now winter 2014/15.
25 ○ YECL-YEC-1-39
26 ○ YUB-YEC-2-18

1 **TOPIC: Expenditures on Property, Plant and Equipment**

2
3 **REFERENCE:** June 22, 2017 Application, Tables 5.2, 5.3, 5.4 and 5.5

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a table showing all projects and studies listed on Tables 5.2 - 5.5
10 with an indication whether the project is designed to meet peak demand or energy
11 needs.

12
13 b) On the table provided in response to part (a), for the projects being added to rate
14 base in 2013-2018, please provide evidence that YEC's Board of Directors
15 performed a prudence review on the expenditures for each project to ensure that
16 all costs incurred were prudent for that project.

17
18 **ANSWER:**

19
20 **(a)**

21
22 YEC generation projects typically address the supply of electricity for energy or capacity
23 (or both) purposes. The remainder of projects are not directly related to energy or capacity;
24 however, they are still critical for supporting the delivery of electricity to ratepayers.

25
26 The Application identifies major capital and deferred cost projects by the following groups,
27 highlighting major projects designed specifically to meet capacity planning requirements
28 (see Tab 5, Sections 5.2.1 and 5.3.1).

- 29
30
 - Completion of Legacy Infrastructure Projects.
 - Spending on Sustaining Capital.
 - Spending to address Capacity Planning Requirements.
 - Spending on planning to meet other potential Future Generation and Transmission Requirements.
34

1 **(b)**

2

3 The response to YUB-YEC-1-78(f) outlines YEC's Stagegate Project Development
4 Framework, and notes that major projects are reviewed by the Board of Directors at each
5 decision point referred to as "Stagegate". The GRA application fully explains, for review
6 by the Yukon Utilities Board, the justification for significant projects being added to rate
7 base.

1 **TOPIC: YEC's distribution and transmission vegetation management policy**

2
3 **REFERENCE:** June 22, 2017 Application, page 6-4 and Appendix 3.1 of Tab 3

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) YEC's policy states that the goal of the brushing program is to reduce reliability
10 incidents caused by vegetation to an acceptable level at the lowest possible cost.

11 i. Please describe YEC's understanding of an acceptable and sustainable
12 level of reliability.

13 ii. Please provide statistics showing reliability numbers since 2012 that have
14 been impacted by YEC's vegetation management policy.

15 iii. Has YEC identified high impact rights-of-way in which YEC's strategy will
16 be to focus on performing vegetation management on an optimum cycle to
17 better mitigate large outages, improve asset condition and realize the cost
18 benefits?

19 iv. Has YEC established a tactical maintenance program on lower impact
20 rights-of-way in which YEC will manage vegetation using a flexible, risk-
21 based approach that targets vegetation management on the worst
22 performing and oldest assets in the inventory?

23
24 b) Please describe the "industry best practices" on which YEC operates its vegetation
25 management program on a pre-determined cycle.

26
27 **ANSWER:**

28
29 **(a)**

30
31 **(i)**

32
33 YEC has a goal of achieving 10 or fewer controllable outages annually (under which
34 vegetation caused outages are classified) and aims to sustain this on an ongoing basis.

1 (ii)

2
3 Tree caused outages by year are as noted in the table below.
4

5 **Table 1: Tree Caused Outages**

Year	Outages
2012	24
2013	22
2014	7
2015	8
2016	3

6
7 (iii)

8
9 Yes.
10

11 (iv)

12
13 Yes.
14

15 (b)

16
17 Please see Appendix 12.2 of YEC's 2012 – 2013 General Rate Application, pages 12.2-
18 22 through 12.2-25. The 2012-13 GRA documents, including Appendix 12.2, are on the
19 YUB website at the following link: [http://yukonutilitiesboard.yk.ca/proceedings/yec-2012-
20 general-rate-application/](http://yukonutilitiesboard.yk.ca/proceedings/yec-2012-general-rate-application/)

1 **TOPIC: Updated Planning Cost Accounting Policy**

2
3 **REFERENCE:** June 22, 2017 Application, page 6.8 and Appendix 5.1

4
5 **PREAMBLE:**

6
7 **QUESTION:**

- 8
9 a) Please provide details of other jurisdictions that have allowed planning costs to be
10 amortized as is proposed by YEC.
11
12 b) Please confirm that the updated planning cost accounting policy would not allow
13 amortization to accumulate while a project was still within Work in Progress.
14
15 c) Under section 2.3(a) of the updated policy, please explain what is meant by the
16 “or” at the end of the sentence “In this way, the Corporation minimizes the risk of
17 spending capital dollars on unsupportable projects; or”.
18
19 d) Please explain the choice of the 5-year and 10-year amortization periods based
20 on project values for projects that are determined uneconomic. Please identify
21 other jurisdictions where this practice is followed.
22

23 **ANSWER:**

24
25 **(a)**

26
27 Historically, in Yukon planning costs for studies that have been closed (or where there has
28 been a decision not to proceed with a project) have been amortized over 5 years. Yukon
29 Energy did not undertake an extensive study of planning cost amortization approaches in
30 other jurisdictions. However, it is understood that treatment of planning study costs varies
31 from jurisdiction to jurisdiction.
32

33 **(b)**

34
35 Amortization of deferred costs only occurs after studies are completed or a decision is
36 made not to continue with the project and it is closed out. Costs are not included in rates
37 until approved by the Board as part of a General Rate Application.

1 (c)

2
3 The “or” at the end of 2.3(a) is a typo and has no specific meaning.
4

5 (d)

6
7 The 5-year and 10-year amortization periods were included in the version of the planning
8 cost accounting policy included as Appendix 5.1 in the 2012/13 GRA Application. Prior to
9 the 2012/13 GRA, costs for deferred projects that were closed out were amortized over 5
10 years pursuant to the planning cost accounting policy that had been in place to that time.
11 In the 2012/13 GRA Application, Yukon Energy sought Board approval of an amended
12 Planning Cost Accounting Policy (see Appendix 5.1 of the 2012/13 GRA) that included
13 specific transition provisions for costs in WIP that were to be closed out and amortized
14 over the 2012 and 2013 test years. The transition measures were intended to mitigate rate
15 impacts from 5-year amortization of existing WIP costs that were above \$1 million.
16

17 While the planning cost policy included in the 2012/13 GRA was not approved by the
18 Board, in Order 2013-1 the Board effectively applied the transition approach for projects
19 over \$1 million that were closed and included in rates at that time (e.g., Atlin and
20 Geothermal). Yukon Energy in the current Application is seeking to apply this approach
21 on an ongoing basis in order to continue to smooth out rate impacts when deferred cost
22 projects over \$1 million are closed out.
23

24 Yukon Energy is not aware of other jurisdictions where this practice is followed.

1 **TOPIC: Updated Demand Side Management (DSM) Accounting Policy**

2
3 **REFERENCE:** June 22, 2017 Application, page 6.8 and Appendix 5.2

4
5 **PREAMBLE:**

6
7 **QUESTION:**

- 8
9 a) Please provide details on the audit processes that have been completed on DSM
10 efforts in 2013 through 2016.
11
12 b) Please provide details of YEC's DSM-related expenditures in 2013, 2014, 2015,
13 2016, 2017 and 2018 and their percentage of revenue requirement.
14
15 c) Please provide evidence of how YEC's DSM programming has "influenced
16 electricity consumption patterns by reducing and/or shifting loads".
17
18 d) Please confirm that no DSM-related costs were recovered from Yukon ratepayers
19 in 2013 through 2017.
20
21 e) Please provide a table showing a detailed breakdown of accumulated costs of
22 DSM programs since 2013 and the related calculation of the amortized costs that
23 will be added to rate base in 2017 (\$2.694 million) and 2018 (\$0.625 million).
24

25 **ANSWER:**

26
27 **(a)**

28
29 The inCharge program has been evaluated by an independent, third party evaluator in
30 2015 and 2016. These evaluation reports are based on the Evaluation, Measurement and
31 Verification Plan filed with the YUB as an attachment to YUB-YECL-26(a) during AEY's
32 2013-2015 General Rate Application. The evaluation reports are provided as
33 UCG-YEC-1-40 Attachment 1 and UCG-YEC-1-40 Attachment 2.

(b)

Annual DSM related expenses are outlined in YUB-YEC-1-80(f).

DSM-related expenditures were held in WIP as directed by the Board for the years 2013 to 2016, therefore, they have no impact on revenue requirement. Amortization of DSM-related expenditures commences in 2017. The percentage of revenue requirement is as follows:

	<u>2017</u>	<u>2018</u>
% of Revenue Requirement	0.5%	0.5%

(c)

The energy savings and coincident peak demand reduction that have resulted from the inCharge program are outlined in Table 2 of the both the 2015 and 2016 Evaluation Reports.

(d)

Not confirmed. While YEC DSM-related costs incurred to date have been held in WIP from 2011 through 2017 and have not been recovered from ratepayers, AEY DSM-related costs have been approved by the Board during that period and included in AEY rate riders.

(e)

For a detailed breakdown of accumulated costs of DSM programs since 2013 see YUB-YEC-1-80(f). Amortization of the DSM costs is shown below.

(\$000's)		2017 Amortization	2018 Amortization
DSM assets added to rate base January 1, 2017	2,484	248	248
DSM assets added to rate base December 31, 2017	210		21
DSM assets added to rate base December 31, 2018	625		
		248	269



August 3, 2015

Yukon Utilities Board
P.O. Box 31728
Whitehorse, Yukon
Y1A 6L3

Attention: Mr. Bruce McLennan, Chair

Re: Interim Evaluation Report - Demand-Side Management (DSM) Program Portfolio for the Yukon

Please find attached the Interim Evaluation Report for the Demand-Side Management (DSM) Program Portfolio as per our filing requirements of Board Order 2014-06. This report has been prepared by the utilities' staff with guidance, review and approval by an independent Evaluation Advisor, Iris Sulyma of Research 4 Results.

As the attached report clearly defines, the DSM Program has benefitted customers not only through financial relief from rebates, but also expanded customer's understanding of their own consumption and of the electricity system in the Yukon. In that respect, the utilities continue to support the concept of demand-side management as a resource in the future. The utilities note, however the specific direction from the Board in order #2014-06:

"Further the Board affirms it does not approve the program for the five year term requested and that the Utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015."

The utilities intend to meet this fall to discuss plans for future programming as part of their respective business planning cycles. It is expected a letter communication defining these plans will be delivered to the Board after these discussions are concluded.



If you have any questions regarding the content within this report please do not hesitate to contact the undersigned.

Yours truly,

Ed Mollard
Chief Financial Officer
Yukon Energy Corporation

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

Jay Massie
Manager
ATCO Electric Yukon

A handwritten signature in blue ink, appearing to read "Jay Massie".



Interim Evaluation Report

Demand Side Management Program Portfolio for the Yukon

31 July, 2015

Submitted to:

Yukon Utilities Board

Submitted by:

Yukon Energy Corporation
ATCO Electric Yukon

Executive Summary

inCharge is an electricity conservation program delivered to residential customers in the Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs: the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and the Engagement, Education and Communication Program. These programs launched in October 2014 and have been well received by Yukoners.

This interim evaluation report will focus on updating the program's projected performance with the actual costs and reported energy savings achieved during the first seven months of the inCharge Program, as well as documenting learnings from the first program offering and participant feedback. The program evaluation was completed by utility staff with guidance and review by an independent evaluation advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner.

The Key Performance Indicator (KPI) results demonstrate that customers were engaged with the program; in particular the LED Lighting Program exceeded expectations. The total number of rebates redeemed by customers in year one was over 2800, surpassing the program target by over 1000 rebates. Additionally, customers reported a 93% satisfaction rate with the LED Rebate Program, 90% satisfaction rate with the Automotive Heater Timer Rebate Program and 95% satisfaction rate with the Low Cost Energy Efficient Products Program. The lifetime electricity savings achieved in 2014 were 9% higher than targeted and costs of the program delivery in 2014 were 9% lower than projected.

As directed by the Yukon Utilities Board, the program achieved an overall Ratepayer Impact Measure (RIM) ratio of 1. This shows that the program is neutral from a utility rate impact perspective. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the program and the utilities, who are the administrators of the program. Most significantly, the program achieved a very high Total Resource Cost (TRC) ratio. This shows that in the context of the comparison with other electricity resource options, the conservation programs performed very well. The tests were conducted assuming a five year program term in order to remain consistent with methodology used in the original program filing.

Overall this evaluation has shown that the inCharge Program was well received by Yukoners, was cost effective and met or exceeded most Key Performance Indicators. The annual and lifetime electricity savings exceeded the forecast savings for the first year of program, was under the projected budget and delivered the results projected by the utilities.

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1 Program Summary

inCharge is an electricity conservation program delivered to residential customers in the Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs; the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and an Engagement, Education and Communication Program. These programs launched in October 2014 and have been extremely well received by Yukoners.

2 Evaluation Context

This interim evaluation report will focus on updating the program's projected performance with the actual costs and reported energy savings achieved during the first seven months of the inCharge Program, as well as documenting learnings from the first program offering and participant feedback. This report will also assess the key performance indicators laid out in the program's Evaluation, Measurement and Verification Plan. The main goals of this evaluation is to ensure that the programs are performing as projected, that participants are happy with the program and to provide recommendations to improve program delivery and cost effectiveness.

This evaluation report will look at the results achieved by the inCharge Program from its launch in October of 2014 to the pause of the rebate program at the end of April 2015. In scoping the evaluation activities, it was recognized that the evaluation was taking place after a relatively short program delivery period. The decision to evaluate the inCharge Program at this time was in order to take advantage of the natural break in program delivery. This will ensure that learnings from the first program offering can be used to optimize the re-launch of the LED and Automotive Heater Timer Rebate Program and Low Cost Energy Efficiency Products Program in the Fall of 2015. It was also important to ensure that an evaluation of the programs was prepared for the Yukon Utilities Board in 2015.

The program evaluation was completed by utility staff with guidance and review by an independent Evaluation Advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner. The evaluation included surveys of participants including cards from customers receiving low cost energy efficient products (n=63), and telephone surveys of customers receiving LED rebates (n=30) and automotive heater timers rebates (n=10).

3 Updated Cost Effectiveness Results and Program Performance

3.1 Cost Effectiveness Results

Table 1 below contains the target energy savings and costs for the inCharge program as presented in the Revised, Evaluation, Measurement and Verification Plan (December 3, 2014) Table 2 contains a summary of the updated energy savings and costs for the inCharge Program. These updated results are based on actual costs and deemed electricity savings for Year 1 and the first quarter of Year 2 and

updated projections based on the programs preliminary results for the second quarter of Year 2 through Year 5. The updates were completed in the excel-based Program Projections Model that has been used throughout the design of the program. A comparison of Tables 1 and 2 show how the programs performed in the first seven months of delivery in comparison to targeted performance. The details of the savings and costs are also discussed below in Tables 3 and 4. The following sections discuss how the actual results were incorporated into Table 2.

Table 1: Targeted Energy Savings and Costs¹

Program Elements	Net Savings with T&D Losses							Utility Expenditure (\$1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	1,337	5,484	5,484	5,484	5,484	23,271	Incentive:	\$12	\$51	\$51	\$51	\$51	\$216	6.2	5.2	20.2	1.2
	Annual MWh:	67	380	692	1,005	1,272	N/A	Non-Incen:	\$82	\$79	\$81	\$84	\$83	\$409				
	Coincident kW:	16	111	206	301	365	N/A	Total:	\$94	\$130	\$132	\$135	\$134	\$625				
Low-cost Energy Efficient Products	Lifetime MWh:	4,605	3,247	3,247	3,247	3,247	17,593	Incentive:	\$78	\$55	\$55	\$55	\$55	\$299	2.4	2.5	5.9	1.0
	Annual MWh:	424	723	1,021	1,225	1,457	N/A	Non-Incen:	\$121	\$172	\$177	\$183	\$188	\$841				
	Coincident kW:	113	192	272	288	323	N/A	Total:	\$199	\$227	\$233	\$238	\$243	\$1,140				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	\$0	\$0	\$0	\$0	\$0	\$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	\$103	\$118	\$121	\$125	\$129	\$596				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	\$103	\$118	\$121	\$125	\$129	\$596				
Total for the Residential Program	Lifetime MWh:	5,942	8,731	8,731	8,731	8,731	40,864	Incentive:	\$90	\$106	\$106	\$106	\$106	\$515	2.7	2.6	9.6	1.0
	Annual MWh:	491	1,102	1,714	2,230	2,730	N/A	Non-Incen:	\$306	\$369	\$380	\$392	\$400	\$1,847				
	Coincident kW:	129	303	478	589	688	N/A	Total:	\$396	\$475	\$486	\$498	\$506	\$2,362				

Table 2: Updated Energy Savings and Costs

Program Elements	Net Savings with T&D Losses							Utility Expenditure (\$1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	2,362	6,129	6,115	6,115	6,115	26,838	Incentive:	\$19	\$51	\$51	\$51	\$51	\$225	6.1	5.8	12.3	1.3
	Annual MWh:	118	463	807	1,152	1,451	N/A	Non-Incen:	\$77	\$82	\$84	\$84	\$84	\$410				
	Coincident kW:	29	131	234	337	409	N/A	Total:	\$96	\$134	\$135	\$135	\$135	\$635				
Low-cost Energy Efficient Products	Lifetime MWh:	4,092	2,885	2,885	2,885	2,885	15,632	Incentive:	\$71	\$50	\$50	\$50	\$50	\$272	2.3	2.4	6.2	1.0
	Annual MWh:	379	646	913	1,085	1,285	N/A	Non-Incen:	\$110	\$171	\$173	\$173	\$173	\$801				
	Coincident kW:	104	178	252	262	290	N/A	Total:	\$181	\$221	\$224	\$224	\$224	\$1,073				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	\$0	\$0	\$0	\$0	\$0	\$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	\$86	\$116	\$121	\$125	\$129	\$577				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	\$86	\$116	\$121	\$125	\$129	\$577				
Total for the Residential Program	Lifetime MWh:	6,454	9,015	9,001	9,001	9,001	42,470	Incentive:	\$90	\$102	\$102	\$102	\$102	\$497	2.8	2.8	8.8	1.0
	Annual MWh:	497	1,109	1,720	2,237	2,736	N/A	Non-Incen:	\$272	\$369	\$379	\$382	\$386	\$1,789				
	Coincident kW:	133	309	485	598	699	N/A	Total:	\$363	\$471	\$480	\$484	\$488	\$2,285				

3.1.1 Actual Costs

Cost estimates are divided by quarter in the Projections Model. The model was updated with actual costs for each quarter from the start of program launch preparation in third quarter of Year 1 (2014) up to the end of first quarter of Year 2 (2015). The projection of costs for the remainder of Year 2 through Year 5 was checked against actuals to ensure the program administrators felt they were still accurate estimates.

3.1.2 Reported Energy Savings

The energy savings attributed to the inCharge program are calculated using a deemed savings approach. An annual and lifetime energy savings is assigned to each type of product that is included in the program and documented in the Technical Reference Manual discussed below. The energy savings projected for the LED and Automotive Heater Timer Rebate Program was based on a target number of rebates issued

¹ See page 14 of Appendix A of 2014 Annual Report – inCharge Demand Side Management (DSM) Program Portfolio for the Yukon, Filed with Yukon Utilities Board January 29, 2015

and also included an assumption of the mix of types of bulbs that customers purchased with their rebates. The energy savings projected for the Low Cost Energy Saving Products Programs was based on the number of each of the products the utilities distributed.

In calculating the reported energy savings for the Rebate Program, the actual number of rebates and types of each bulb were tabulated and the deemed savings as per the TRM were applied. The actual number of rebates and mix of types of products were used to update the projections going forward.

In calculating the reported savings for the Low Cost Energy Efficient Products Program, the number of products purchased and distributed were tabulated and the deemed savings as per the TRM were applied. The variation from projected savings to actual savings was minimal with this program as the purchasing decisions were in the control of the program administrators.

3.1.3 Technical Reference Manual

A Technical Reference Manual (TRM) was created as a part of the Program Projections Model. The TRM is a simple document that summarizes the assumptions and inputs to the Program Projections Model related to costs and energy savings for each individual type of product included in the program. The TRM was updated in late 2014 as part of the work completed to launch the inCharge Program. In particular costs of LED bulbs were updated, as this parameter changes rapidly. The energy savings attributed to each type of product was also reviewed at that time. An example of the TRM entry for standard LEDs can be found in Appendix A.

While the energy savings that can be attributed to a particular product is quite straight forward to estimate, the behavior of customers in purchasing and installing the products is a much more complex and intangible parameter that is considered in the deemed savings. This is captured in the installation ratio and the Net to Gross (NTG) Ratio, discussed in the section below.

3.1.4 Installation Ratio

The installation ratio is an estimate of the percentage of program participants that have installed the product they received as part of an energy saving kit or purchased using a program rebate. As the product must be in use to produce the energy savings estimated, the installation ratio affects the amount of savings that can be claimed for the program. The installation ratio estimated for the program was confirmed through surveys with a sample of program participants.

3.1.5 Stipulated Net-to-Gross Ratio

The stipulated net-to-gross (NTG) ratio includes a mix of the installation ratio, discussed above, as well as the free ridership and spillover of the program. Free ridership accounts for the program participants that would have made the energy saving change without the program, but took advantage of the program anyway. On the other end of the spectrum is spillover. These are people who made the energy saving changes because they were influenced by the inCharge program in some way, such as by point-of-purchase information posters, but did not participate in the program by applying for a rebate. As discussed above, the installation ratio will be confirmed through interviews. The free ridership and spillover rates are a much more intangible and complex parameter to confirm. It is currently assumed

for the rebate program that free ridership and spillover will cancel each other out, as is a common practice. The low cost energy efficient products program includes only a spillover component. The confirmation of these parameters can only be achieved after the program has been running for a few years.

3.2 Key Performance Indicator Results

A set of key performance indicators (KPIs) and targets for each KPI were developed for each program. These KPIs are based on a logic model developed for each program. The logic model is a simple graphic and narrative that maps out the resources, activities and outcomes that are expected from each program and the linkages between those parameters that are expected to ensure the program is successful. The logic model for each program can be found in Appendix B. The KPIs are designed to test the performance of the linkages in the logic model. Tables 3 and 4 below report on how the programs are performing for each indicator and provide a brief commentary on each as appropriate. The first column references the linkage number to allow for reference to the programs logic model. Note that the results for Year 2 represent the progress made in Q1 and Q2 towards meeting the annual (2015) target.

Table 3: LED and Auto Heater Timer Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
<i>Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)</i>								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	-	20	2		In Q4 of 2014, 20 YEC staff acted as community ambassadors in Whitehorse and Dawson distributing kits
		# people attending workshops		-	80	8		in 2014, 80 members of the community were reached by the ambassadors and provided kits
11	Direct engagement with retail store managers	Suggested KPI(s): # of new store managers being engaged for the 1st time	Direct engagement & communication logs	20	30	-	-	In 2014, 30 new store managers throughout the territory were contacted prior to the start of the LED rebate program to encourage participation and to check available qualifying LED products.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		# of store managers contacted with program intel & updates		20	30	20	-	Contacts continued with the 30 new store managers during the first month of the LED rebate program to encourage participation. By November 2014 stores committed to participating had been identified and ongoing communication about the program continued for a total of 296 contacts to the end of 2014. In 2015, no new stores were added for the LED rebate and BHT Rebate was introduced with Home Hardware and Canadian Tire participating. Close contact was maintained with all participating retailers.
13	Utilities issue point of purchase materials for retail managers	Suggested KPI(s): # stores with POP materials POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)	Program documentation	5 n/a	9 n/a	10 Yes	9 Yes	9 Retail stores received POP for a total of 514 pieces. This included rebate pads, collection envelopes, shelf talkers, bin markers, small and large posters, staff info sheets and brochures. In Q1 and Q2 of 2015, an additional 40 items were distributed to complement the existing POP material already in place. This included the addition of several pieces of material related to the new Automotive Heater Timer rebate program
14 & 23	Shoppers buy and install rebate-eligible products[1]	Suggested KPI(s): # of units claimed	Tracking System	1,722	2,831	7,167	2,585	Participation higher than projected in 2014 and on track to reach target in 2015

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings[2]	Suggested KPI(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption kW of avoided coincident electricity demand	Estimate based on rebates processed	1,337 67 16	2,362 118 29	5,484 380 111	2,268 63	Lifetime savings higher than projected in 2014 and on track to reach target in 2015 Annual savings higher than projected in 2014. 2015 results will be updated at the end of the year Demand savings higher than projected in 2014 and on track to reach target in 2015
21 & 25	Participants receive a rebate[3]	Suggested KPI(s): \$ of incentive disbursement for LED lighting and automotive heater timers	Tracking System	\$12K	\$19,817	\$51K	\$18,435	2014 incentive disbursements were higher than projected, however overall project budget was lower than projected. 2015 incentive disbursements are on track to reach target.
22	Shoppers learn about rebates through local media campaigns	Suggested KPI(s): # updates of web content	Tracking System	1	1	4	2	inCharge website created and launched October 1, 2014. Information on the Auto Heater Timer Rebate Program was added in early 2015, website was adjusted when rebates were paused in April 2015 and minor edits in response to customer comments completed.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		# newspaper/radio advertisements		1	4	1	7	2 radio ads created and aired 32 times in 2014. 4 radio ads were created and aired 77 times in Q1 and Q2 of 2015
		# bill insert		1	0	1	0	bill inserts not used in 2014 and 2015
		# email blasts		1	0	1	1	email blasts not used in 2014, 1 e-mail blast in 2015
26	Participating shoppers will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in time to show up on next utility bill (if applications comes in 10 business days before issuance of bill)	Tracking System	70%	99%	80%	99%	99% of the customers received the rebate on either their current bill or on the next month's bill. The remaining .5% of customers received a rebate on a bill which was 2 months from the product purchase. In all cases where the rebate was delayed it was caused by the rebate being processed 1-2 days after the customers' current bill had been processed for mailing. This was anticipated to occur in a small number of cases.
27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	To be commented on in 2015 EM&V Process - see Part B
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	To be commented on in 2015 EM&V Process - see Part B
Part B -- To Be Visited, Checked and Reported On by Evaluators								

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done	
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees	7/10	10/10	8/10		All Ambassador workshop participants surveyed found the information provided helpful
11	Direct engagement with retail store managers	Suggested indicator(s): % store managers who know the program % of store managers contributed to at least one transaction	Store managers	-	-	100%	-	To be quantified in next Evaluation
			Tracking system	-	-	60%	-	To be quantified in next Evaluation
13	Utilities issue point of purchase materials for retail managers	Suggested indicator(s): % of shoppers who noticed POP materials	Shoppers and Participants	-	-	70%	83%	87% LED Rebate participants and 70% Auto Timer Rebate participants for a weighted average of 83%

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		% of shoppers who agree that POP materials contributed to their decision to purchase a rebate-eligible product		-	-	50%	58%	57% LED Rebate participants and 60% Auto Timer Rebate participants for a weighted average of 58%
14 & 23	Shoppers buy and install rebate-eligible products	No evaluation indicator	-	-	-	-	-	
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings	No evaluation indicator	-	-	-	-	-	
21 & 25	Participants receive a rebate	Suggested indicator(s): % of participants who agree that the rebate contributed to them purchasing the energy efficient products rather than the base-case product	Participants	-	-	60%	LED 77% Timer 50%	Participants who rated the program influential or very influential in their decision to purchase the energy efficient product: LED Rebate - 77% Auto Timer Rebate - 50%
22	Shoppers learn about rebates through local	Suggested indicator(s):						

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
	media campaigns	% of shoppers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants	-	-	70%	58%	58% of participants can recall media advertising
26	Participating shoppers will be satisfied by the products that they bought	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the overall rebate program	Participants	-	-	8/10	LED 93% Timer 90%	Percentage of participants who were very satisfied or satisfied with the program: LED Rebate - 93% Auto Timer Rebate - 90%
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants	- -	- -	30% 10%	65% -	65% of participants had heard of the program from others and 96% of those discussions were positive To be quantified in next Evaluation
28	Non-energy benefits	Suggested indicator(s):						

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		1-to-10 scale, level of satisfaction with the lighting/automotive heater timer quality	Participants	-	-	9/10	LED 93% Timer 90%	Percentage of participants who were very satisfied or satisfied with their energy efficient products LED Rebate - 93% Auto Timer Rebate - 90%

Table 4: Low Cost Energy Efficient Products Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
<i>Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)</i>								
00	Externalities	No associated tracked KPIs	-	-	-	-	-	
02	Utilities conduct outreach activities at community events	Suggested KPI(s): # of events w/Program booth # of kits distributed	Program documentation	2 40	7 220	4 60	2 222	YEC conducted outreach at 3 events in their communities and ATCO conducted 1 public event in Whitehorse and three targeted distribution events in 2014. No additional community events were conducted in Q1 and Q2 of 2015 by YEC. In 2015, ATCO staff attended a community meeting in Old Crow and distributed 47 products to 23 customers. ATCO staff also attended a meeting at Yukon Research Center and distributed 90 products to 9 customers. In 2014, 31 kits were distributed at YEC Community events and 929 products were distributed to 189 customers at ATCO Whitehorse Events In Q1 and Q2 of 2015 5 kits were distributed at the YEC Office and 1253 products were distributed to 217 customers at ATCO.
04	Provide EE products free-of-charge	Suggested KPI(s):	Program documentation					

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		# of kits/products distributed		300	356	180	222	In 2014, 31 kits were distributed at YEC Community events, 10 kits were distributed at stakeholder events, 100 kits distributed through ambassadors, 26 kits were distributed by community partners and 929 products were distributed to 189 customers at ATCO Whitehorse Events In Q1 and Q2 of 2015 5 kits were distributed at the YEC Office and 1253 products were distributed to 217 customers by ATCO staff.
04	Scorecard results will be analyzed	Suggested KPI(s): # of scorecards received	Direct engagement & communication logs	30	18	20	45	18 scorecards received by end of 2014. 45 additional scorecards were received in 2015.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops # people attending workshops	Program documentation	- -	20 80	2 8	- -	in 2014, 20 YEC staff acted as community ambassadors in Whitehorse and Dawson distributing kits. in 2014, 80 members of the community were reached by the ambassadors and provided kits.
10	Utilities' community engagement leads to 'behavior-based' electricity and demand savings	No associated tracked KPIs	-	-	-	-	-	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
14 & 19	Shoppers buy and install low-cost EE products	No associated tracked KPIs	-	-	-	-	-	
20	The low-cost EE products will yield long-term electricity and demand savings	Suggested KPI(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	4,605 424 113	4,092 379 104	3,247 723 192	- - -	Savings slightly lower than projected due to lower than estimated installation rate. All savings for kits and products distributed to date are attributed to 2014 to align spending with savings. Savings in 2015 will be calculated for the second offering of kits/ energy efficient products.
26	Participants will be satisfied by the low-cost EE products	Suggested KPI(s): Scorecard feedback1-to-10 scale, level of satisfaction with the products	Tracking System	7/10	-	7/10	9.5/10	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 96%, reflector LEDs - 100%, showerheads - 65%, powerbars 97%, DHW tank wrap - 100%, DHW pipe wrap - 100%, Auto heater timers - 100%, motion detectors - 100% for an average of 95%
05 & 27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-	See Rebate Program KPIs above (Table 3)
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-	See Rebate Program KPIs above (Table 3)

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
Part B -- To Be Visited, Checked and Reported On by Evaluators								
00	Externalities	Done/Not-Done – report on externalities on an annual basis	Program documentation	Done	-	Done	-	
02	Utilities conduct outreach activities at community events	No evaluation indicator	-		-		-	Done
04	Provide EE products free-of-charge	No evaluation indicator	-		-		-	Done
04	Scorecard results will be analyzed	Suggested indicator(s): % of issued score cards that are completed and returned	Program documentation	10%	16%	10%	-	63 cards were returned from the 406 customers that received kits and products.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees	7/10	10/10	8/10		All Ambassador workshop participants surveyed found the information provided helpful
14 & 19	Shoppers buy and install low-cost EE products[2]	No evaluation indicator	-		-		-	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
20	The low-cost EE products will yield long-term electricity and demand savings	No evaluation indicator	-		-		-	
26	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-10 scale, level of satisfaction with their energy efficient products	Participants			8/10	95%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 96%, reflector LEDs - 100%, showerheads - 65%, powerbars 97%, DHW tank wrap - 100%, DHW pipe wrap - 100%, Auto heater timers - 100%, motion detectors - 100% for an average of 95%
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%	65% -	See Rebate Program KPIs above (Table 3) To be quantified in next Evaluation
28	Non-energy benefits	Suggested indicator(s):						

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals to April 30 2015	Progress Commentary
		1-to-10 scale, level of satisfaction with the low cost EE product quality	Participants			8/10	95%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 96%, reflector LEDs - 100%, showerheads - 65%, powerbars 97%, DHW tank wrap - 100%, DHW pipe wrap - 100%, Auto heater timers - 100%, motion detectors - 100%

3.3 General Program Administrator Observations

In addition to the information gathered to assess the KPIs, the staff administering the programs made the following observations and recommendations during the delivery of the first offering of the inCharge program.

3.3.1 LED and Automotive Heater Timer Rebate Program Observations

The choice of Energy Star as a qualifying criterion for LED bulbs in the rebate program caused confusion for some customers. There were a number of customers who submitted rebates for bulbs that were not Energy Star. Some were not aware of the requirement and others were confused with similar branding on the bulbs, such as *Energy Saver*. To help remedy this problem, the Energy Star logo, as opposed to simply text, was added to point of purchase material in January 2015. This was helpful, but there were still some participants that submitted rebates for non-Energy Star bulbs. Energy Star was chosen as a qualifying criterion to ensure that the rebated bulbs were high quality in an effort to make their experience with LEDs positive, resulting in a permanent switch to LEDs. Energy Star should be made much more prominent in future marketing material. Program staff are also looking to Energy Star to see if there is existing Energy Star point of purchase material the program could use.

In the seven months that the LED rebates were offered, it was noted that prices for many of the common LED bulbs continued to decrease, some coming close to the rebate amount. Packages of multiple bulbs at a much lower cost also started to become available. Before reintroducing the rebate program, staff will survey the retailers in the territory to determine if the \$7 rebate level is still appropriate.

At the beginning of the program there was not a high level of flexibility available to retailers in stocking LEDs. Local retailers were very supportive of the program and were proactive in stocking eligible products as they were able. It is our expectation that as LEDs become more popular in general, more retailers will carry a wider range of LEDs. It was also noted that active participation by retailers and sales on the rebated products were a large driver of the rebate program's success.

The Automotive Heater Timer rebate was introduced in January 2015. Due to unseasonably warm temperatures, automotive heaters (e.g. engine block or oil pan heaters) were not required very often and as such the timers were also not required. January and February usually sees many customers calling to enquire on how to lower their higher winter electrical bills, providing an opportunity to discuss automotive heater timers and promote the rebate. This was not the case in early 2015 and as a result participation in the Automotive Heater Timer Rebate Program was quite low. However, a number of participants did re-purpose the timers, using them on lighting and other appliances, which resulted in electrical savings. The rebate will be offered again in the Fall of 2015.

The program was well received Yukoners and participation was higher than projected. A sample of comments on the rebate program overall from participants noted during the evaluation surveys:

- I support the utilities on this program
- Thanks!!

- Very Beneficial, thanks!
- Great Program
- Thanks for the rebate!
- Wonderful

3.3.2 Low Cost Energy Efficient Products Program Observations

The program targeted a very aggressive 100% installment rate for all products distributed. The follow-up surveys showed a lower installation rate, particularly for showerheads, hot water tank wraps and hot water pipe wraps. Many respondents indicated they intend to install the products eventually, but the more involved steps required seemed to be a deterrent. To ensure a higher installation rate going forward, it is suggested that these products be distributed through partners that have staff to complete the installation. These products could also be made available to customers at a specific request, targeting those people who are more likely to install the products. Also, ensure that clear installation instructions and estimate of effort required are provided to the participants as part of program communications. Care should be taken to provide instructions from the manufacturer to minimize program administrator liability.

Participants were very appreciative of the kits and products distributed. A sample of comments on the energy saving products program overall from participants noted during the evaluation surveys:

- Awesome program!
- Unbelievable kit
- Great idea
- Package very helpful
- Loved the program and thanks everyone
- Great idea and thank you
- Great initiative
- Great, free stuff when on a budget

4 Results and Recommendations

Overall this evaluation has shown that the inCharge Program was very well received by Yukoners, was cost effective and met or exceeded most KPIs. The lifetime electricity savings achieved in 2014 were 9% higher than targeted and costs of the program delivery in 2014 were 9% lower than projected.

Table 2 above shows a summary of the inCharge program's updated energy savings and costs as well as the four standard benefit/cost ratios updated with actuals and projected savings over the remainder of the 5 year term. The program achieved an overall Ratepayer Impact Measure (RIM) ratio of 1, with the LED and Auto Heater Timer Rebate Program achieving a RIM ratio of 1.3 and Low Cost Energy Efficient Program achieving a RIM ratio of 1. This shows that the program is neutral from a rate impact perspective. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the

program and the utilities, who are the administrators of the program. Most significantly, the program achieved a very high Total Resource Cost (TRC) ratio. This shows that in the context of the comparison with other energy resource options, the conservation programs performed very well. The tests were conducted assuming a five year program term in order to remain consistent with methodology used in the original program filing.

Table 3 above shows how the LED Rebate and Automotive Heater Timer Rebate Program performed in relation to the targets set out for a number of KPIs. The Program saw higher than projected rebates and electricity savings in 2014 and is on track to meet projected targets in 2015. Customers had a very high satisfaction level with the rebate program as well as the bulbs and timers they purchased using the rebate. The rebate program was effective in influencing customers to switch to the more energy efficient product. The on-bill rebate processing system developed was effective in getting rebates onto customer's bills by the next bill cycle. Store managers were very receptive to the program and many customers noticed and remembered the in-store promotional material. The distribution of promotional material including advertisements in newspapers and radio went well, with a decrease from planned advertising levels in late 2014 when much higher than expected rebates were received. Many participants noticed the promotional material and could remember seeing or hearing the advertisements. Word of mouth was also found to be a very effective way of communicating, as many participants heard positively about the program from family or friends.

Table 4 above shows how the Low Cost Energy Efficient Products Program performed in relation to targets set for a number of KPIs. Distribution of the Low Cost Energy Efficient Products went well with products delivered to participants individually or in Energy Saving Kits. Electricity savings resulting from the Low Cost Energy Efficient Products Program was slightly lower than projected. This was due to a slightly lower than projected installation rates for some products. The program targeted a very aggressive installation rate and program staff took care to work with each participant to ensure they received products that they would use. Adjustments to the installation rate in the cost effectiveness tests showed the program was still cost effective with a lower installation rate projection for a subset of products. Participants were very satisfied with the products they received, with the exception of the ultra-low flow showerhead. The program also gave utility staff the opportunity to talk with customers about how they use electricity and ways to improve efficiency and reduce electricity use.

4.1 LED and Low Cost Energy Efficient Products Program Recommendations

In the next offering of the rebates, it is suggested to work with retailers to increase the amount of point of purchase promotional material displayed. Also work with retailers to plan promotional events that highlight the rebated products and their benefits. To address the customer confusion around the Energy Star criteria for LEDs ensure the Energy Star logo is more prominent on the promotional material. Due to the fast changing LED market and decrease in prices, care should be taken to survey the pricing of LEDs in local stores before the next program offering to ensure the level of the rebate remains appropriate. To ensure the program is as cost effective as possible, program staff should continue to look for transactional process efficiencies to reduce non-incentive program costs, while maintaining customer satisfaction with the program and products.

4.2 Low Cost Energy Efficient Program Recommendations

Distribution of the energy efficient products at community events was very effective and well received. This method, along with having products available for customers who come to the utilities with conservation concerns, should remain the focus of the utilities work. The distribution and installation of products through community partners was also very effective, particularly where those partners had people that were able to help participants complete the installation. The distribution of the showerheads, hot water tank wraps and pipe wraps should focus on these partnerships. To ensure the program is as cost effective as possible, program staff should continue to look for transactional process efficiencies to reduce non-incentive program costs, while maintaining customer satisfaction with the program and products.

4.3 Evaluation Summary and Evaluation Recommendations

Overall this interim evaluation has shown that the inCharge Program was very well received by Yukoners, met or exceeded most KPIs and was cost effective (as shown in Table 2 above). The linkages between activities, outputs, short-term outcomes, intermediate outcomes and long-term outcomes as laid out in the program logic models (Appendix B), are clear, well defined and plausible.

Short-term outcomes were achieved, including:

- Energy efficient products were identified and endorsed;
- Energy efficient products were available in stores;
- Customers were educated about energy efficient products
- Customers were convinced to buy and install energy efficient products; and
- The initial cost hurdle was alleviated.

Intermediate outcomes including effective communication through word of mouth and participant purchase and installation of eligible energy efficient product was achieved.

Long-term outcomes included high customer satisfaction with the programs and the majority of products, and cost effective, long-term energy and demand savings.

Overall, the program rational is sound and the results to date support the plausibility of the claimed cost effectiveness, and the energy and demand savings.

With the launch of the two residential programs and website set-up completed, many of the up-front program launch costs have already been incurred. With these costs included, the programs showed positive cost effectiveness ratios over the modelled five years. As these programs continue to be offered, opportunities to reduce non-incentive costs and increase savings should be pursued whenever possible.

In completing the inCharge program's first evaluation, the following recommendations were made by the Evaluation Advisor and program staff:

- Establish a set schedule and questionnaire for customer surveys of the program to ensure the same type of information is gathered at the same time each year. This will allow for better comparison of trends year over year. Customer surveys of the LED and Auto Heater Rebate Program should happen in November for LEDs and February for Auto Heater Timers and in April for the Low Cost Energy Efficient Products Program. Surveys with non-participants and store managers should happen in February each year.
- Schedule evaluations in June and July of each year. With an impact evaluation scheduled for July 2016. At that point, the program will have been delivered for a sufficient time and participants will have had sufficient experience with the products to provide reliable information to examine current assumptions about installation, spillover and free ridership ratios and the related net-to-gross ratio.
- Data gathered from telephone surveys with participants resulted in much more complete and consistent data in comparison to self-completed hard copy or online surveys. It is recommended that this method be used to gather data.

Appendix A: TRM Example – Standard LEDs > 9W



Yukon Energy Corporation and ATCO Electric Yukon
YEC AEY Residential DSM Program Design - ECM-level Cost-effectiveness test and Incentive Level Substantiation

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations		Outputs with Program Costs	
Measure Name:	Standard LEDs (>9 W)	PC - Benefit/Cost Ratio	10.64
Incentive Amount:	\$7.00	PC - Net Present Value	\$73.39
Measure/Project Cost:	\$7.61	PC - Levelized Cost	\$0.0174/kWh
Gross Consumption Savings:	40 kWh/yr	Simple Payback w/ Incentive (yr)	0.1 yr
Transport and distribution losses:	8.3%	<i>RIM - Benefit/Cost Ratio</i>	1.28
Gross Cons. Savings w/ T&D Losses:	43 kWh/yr	<i>RIM - Net Present Value</i>	\$26.88
Gross Demand Savings:	.01 kW	<i>RIM - Levelized Cost</i>	\$0.1975/kWh
Gross Demand Savings w/ T&D losses:	.010 kW	TRC - Benefit/Cost Ratio	5.76
Participant's Savings on Year 1:	\$5.74	TRC - Net Present Value	\$100.27
Measure Lifetime:	20 yr	TRC - Levelized Cost	\$0.0441/kWh
Inputs - Program Considerations		<i>PAC - Benefit/Cost Ratio</i>	5.93
Program Cost (% of Incentive):	192%	<i>PAC - Net Present Value</i>	\$100.88
Suggested Program Cost (% of Incentive):	192%	<i>PAC - Levelized Cost</i>	\$0.0428/kWh
Forecasted Freeridership:	10%	<i>RIM-YECL - Benefit/Cost Ratio</i>	0.65
Forecasted Participant Spillover:	0%	<i>RIM-YECL - Net Present Value</i>	-\$24.06
Forecasted Non-participant Spillover:	10%	<i>RIM-YECL - Levelized Cost</i>	\$0.1537/kWh
Forecasted Rebound Effects:	0%	<i>RIM-YEC - Benefit/Cost Ratio</i>	1.93
Reference Data from Other Jurisdictions:		<i>RIM-YEC - Net Present Value</i>	\$63.55
		<i>RIM-YEC - Levelized Cost</i>	\$0.1322/kWh

Additional Discussions:



Yukon Energy Corporation and ATCO Electric Yukon
YEC AEY Residential DSM Program Design - ECM-level Cost-effectiveness test and Incentive Level Substantiation

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	\$7.61
Incentive Amount in Year 1	\$7.00
Assumed Program Administration Costs in Year 1	\$13.47
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership + P. Spillover + N-p. Spillover - Rebound

Participant Cost Test (PC)		
<i>Cumulative Present Value of Cashflows w/ PC Discount Rates</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Participant's Avoided Energy Cost for 20 years	\$74.01	\$74.01
Discounted Cumulative Gross Energy Savings for 20 years	439 kWh	439 kWh
PC - Present Value of Benefits	\$81.01	\$81.01
PC - Present Value of Costs	\$7.61	\$7.61
PC - Benefit/Cost Ratio	10.64	10.64
PC - Net Present Value	\$73.39	\$73.39
PC - Levelized Cost	\$0.0174/kWh	\$0.0174/kWh
Simple Payback with Incentive	0.1 yr	0.1 yr

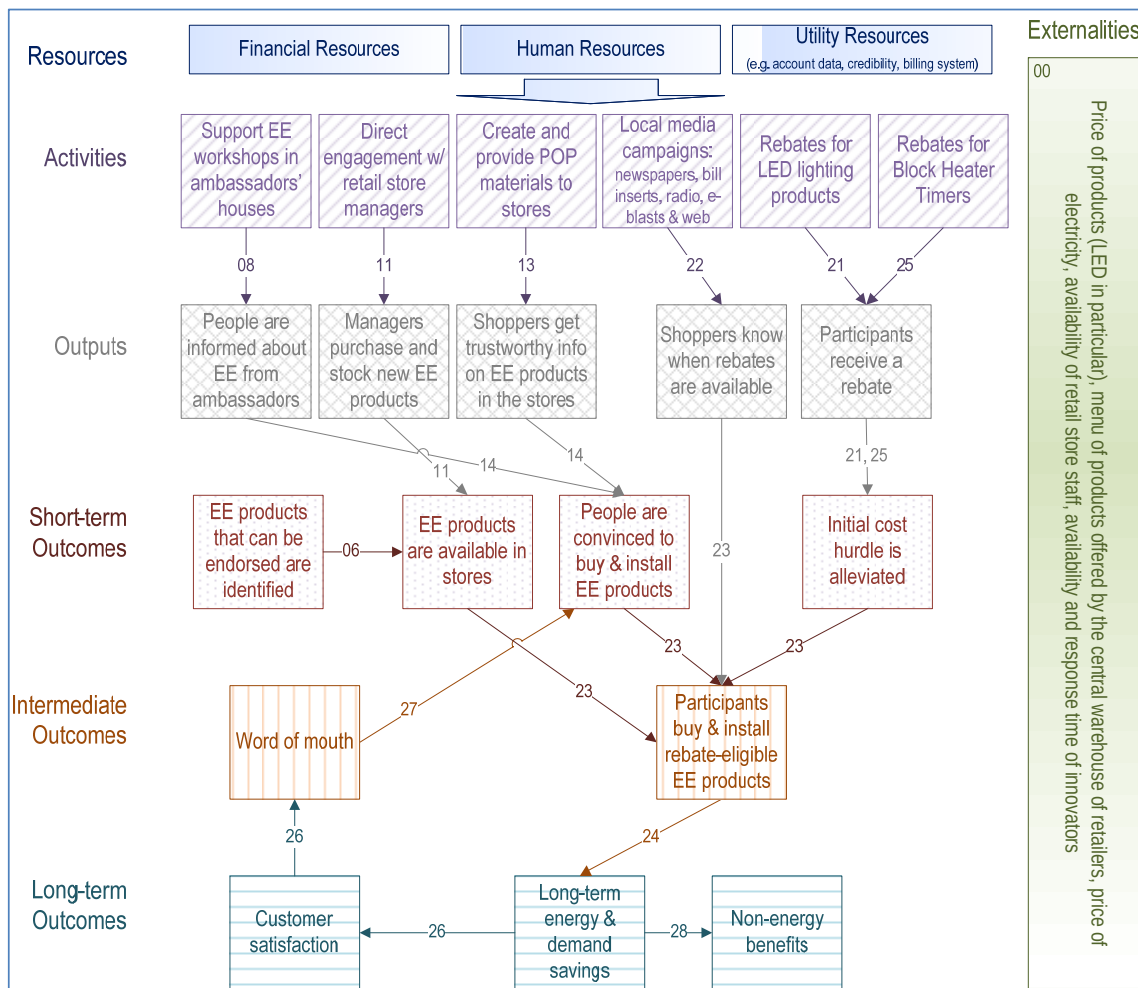
Ratepayer Impact Measure Test (RIM)		
<i>Cumulative Present Value of Cashflows w/ RIM Discount Rate</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Avoided Energy Costs for 20 years	\$121.35	\$121.35
Present Value of Avoided Capacity Costs for 20 years	\$0.00	\$0.00
Present Value of Lost Revenues for 20 years	\$74.01	\$74.01
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
RIM - Present Value of Benefits	\$121.35	\$121.35
RIM - Present Value of Costs	\$94.48	\$81.01
RIM - Benefit/Cost Ratio	1.3	1.5
RIM - Net Present Value	\$26.88	\$40.35
RIM - Levelized Cost	\$0.1975/kWh	\$0.1693/kWh

Total Resource Cost Test (TRC)		
<i>Cumulative Present Value of Cashflows w/ TRC Discount Rate</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Avoided Energy Costs for 20 years	\$121.35	\$121.35
Present Value of Avoided Capacity Costs for 20 years	\$0.00	\$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
TRC - Present Value of Benefits	\$121.35	\$121.35
TRC - Present Value of Costs	\$21.09	\$7.61
TRC - Benefit/Cost Ratio	5.76	15.9
TRC - Net Present Value	\$100.27	\$113.74
TRC - Levelized Cost	\$0.0441/kWh	\$0.0159/kWh

Program Administrator Cost Test (PAC)		
<i>Cumulative Present Value of Cashflows w/ PAC Discount Rate</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Avoided Energy Costs for 20 years	\$121.35	\$121.35
Present Value of Avoided Capacity Costs for 20 years	\$0.00	\$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
PAC - Present Value of Benefits	\$121.35	\$121.35
PAC - Present Value of Costs	\$20.47	\$7.00
PAC - Benefit/Cost Ratio	5.9	17.3
PAC - Net Present Value	\$100.88	\$114.35
PAC - Levelized Cost	\$0.0428/kWh	\$0.0146/kWh

Appendix B: Program Logic Models

Figure B1: Logic Model for the Residential LED Lights and Automotive Heater Timer Rebate Program

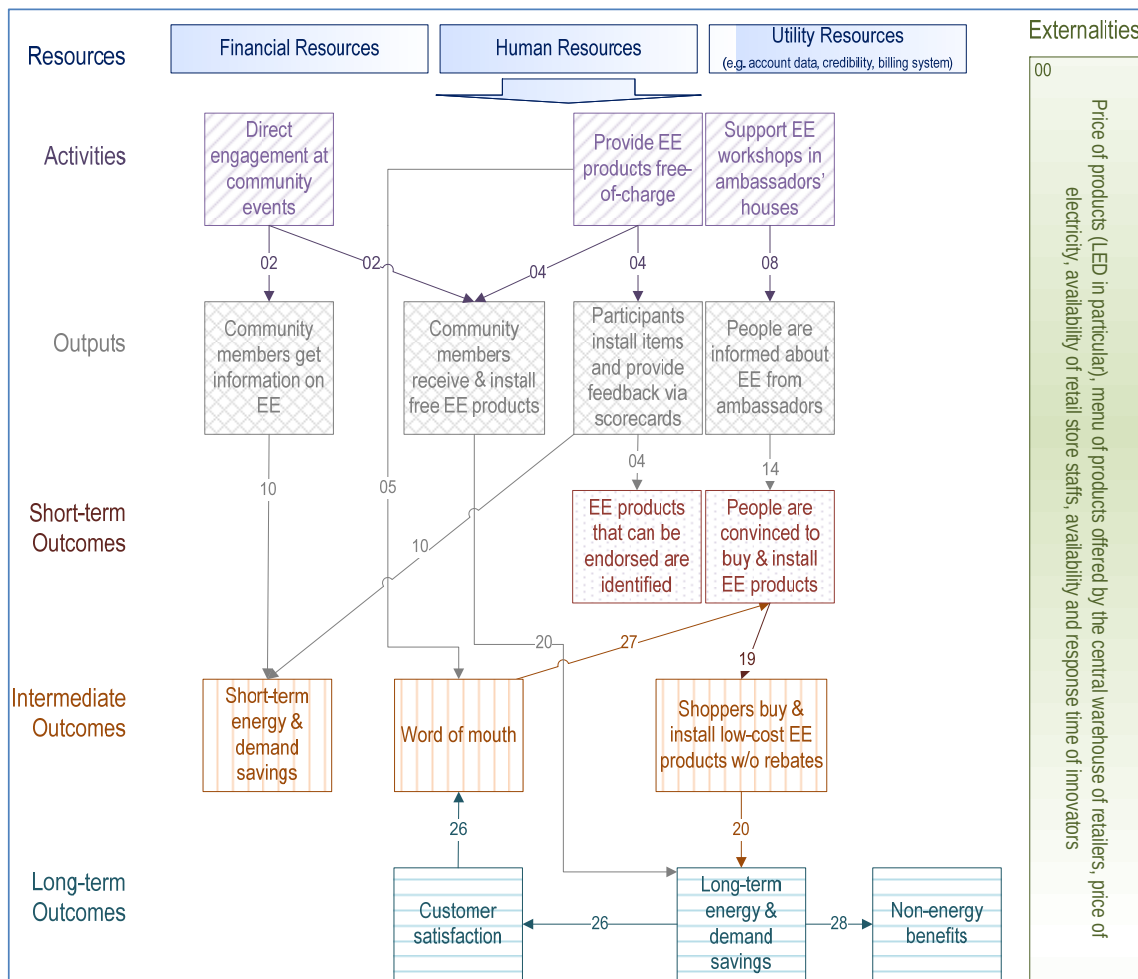


Link # Narrative

- 00 The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff to address any questions. The program administrator should monitor these externalities and adapt the implementation approach based on them.

Link #	Narrative
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
11	The Utilities will establish partnerships with Yukon retail store managers and establish two-way communication. The Utilities will suggest new products to stock; perhaps by providing the results of the low-cost EE product piloting, by revealing in advance what products will be eligible for the LED lighting rebate and automotive heater timer rebate, or by indicating what POP materials will be created and offered to the shops.
13	The Utilities will design and procure educational Point Of Purchase (POP) materials for Yukon retail managers to display in their stores. These materials might include (but not be limited to): brochures, presentation boxes, posters, and displays stands.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
21	The Utilities will provide a flat amount of money per unit to Yukon shoppers after they purchase LED lighting lamps or fixtures selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated which will contribute to the items being purchased and installed.
22	The "rebate" period will be extensively advertised through a media campaign through local radio, local newspapers, co-op advertisement with retailers and in stores, and electricity bill inserts. Consequently, shoppers will know when the rebates are going to be available.
23	Participating Yukon shoppers (i.e. participants) will buy and install LED lighting products or automotive heater timers and receive a rebate because these products will be available in the stores, because they were made aware of the benefits of these products, because they know when the rebate is available, and because the initial cost hurdle was alleviated by the rebate.
24	The LED lighting product installs and automotive heater timer installs will yield long-term electricity and demand savings.
25	The Utilities will provide a flat amount of money per unit to Yukon shoppers for the purchase of automotive heater timers (i.e. outdoor) selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated and/or the rebate will make the purchase of an automotive heater timer much more enticing. This will contribute to the purchase and installation of these items.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	Shoppers will perceive new non-energy benefits and/or the less maintenance related to the energy efficient products when they're compared with the baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

Figure B2: Logic Model for Residential Low Cost Energy Efficient Products Program



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff. The program administrator should monitor these externalities and adapt the implementation approach based on them.
02	The Utilities will carry out outreach activities in community events (eg. sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; and promote the idea of supporting an EE workshop at their home or a at local venue.

Link #	Narrative
04	Low-cost EE products will be used by program participants. Participants will be provided with simple scorecards that will give them the opportunity to provide feedback on the various products. The Utilities will collect all of the scorecards, aggregate and analyze the results, and use the results on consumer satisfaction to improve the products that are distributed by the program in subsequent years.
05	It is expected that the volunteers and EE community network members will like the low-cost EE products and will tell their friends and relatives. This will feed the word of mouth feedback loop.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will also seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
10	The information and tips provided to residents of the Yukon as part of the Utilities direct community engagement activities will influence their behavior and cause them to use less electricity and reduce their peak demand. However, quantifying "behavior-based" electricity and demand savings is challenging and perhaps cost-prohibitive for a small jurisdiction like the Yukon. Moreover, the persistence of "behavior-based" conservation measures is notoriously bad. It is commonly believed to be less than one year by DSM experts. Consequently, the short-term benefits of behavior-based conservation measures will not be quantified. They are considered to be outcomes that are "nice-to-have" yet not necessary to make the program viable.
14	Yukon shoppers will be informed on EE products through the community direct engagement. This will cause them to buy and install these products.
19	Yukon shoppers will buy and install low-cost EE products (even in the absence of rebate) because these products will be available in the stores, and because they were made aware of the benefits of these products. The low-cost EE products may have a certain price increment; however it is assumed that the price increment (if any) is too small to constitute the most important purchase barrier.
20	The free and purchased low-cost EE product installs will yield long-term electricity and demand savings.
26	Shoppers who received low-cost EE products or purchased LED lighting products or automotive heater timers will be satisfied by the products that they bought. As a result, they will tell their friends and relatives about their experience with these products. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products without any support from the Utilities.
28	Program participants will perceive non-energy benefits, including improved comfort and reduced maintenance, as a result of the products they installed. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and are easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have any negative impacts on their vehicles.



2015-2016 Evaluation Report

Demand Side Management Program Portfolio for the Yukon

31 October, 2016

Submitted to:

Yukon Utilities Board

Submitted by:

Yukon Energy Corporation
ATCO Electric Yukon

Executive Summary

inCharge is an electricity conservation program delivered to residential customers in Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs: the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and the Engagement, Education and Communication Program. These programs launched in October 2014 and have been well received by Yukoners.

This evaluation report will focus on the period between April 2015 and July 2016, updating the program's projected performance with the actual costs and reported energy savings achieved from the program launch in October 2014 to the end of July 2016, as well as documenting learnings from program administration and participant feedback. The program evaluation was completed by utility staff with guidance and review by an independent evaluation advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner.

Evaluation data was collected through phone interviews with program participants as well as the rebate program database, which tabulates the number of rebates and types of products rebated. The results demonstrated that customers are very satisfied with the program (96% of participants for the LED rebate and kit products and 100% of participants for the AHT rebate were satisfied). Participation rates were slightly lower than projected in 2015, however in 2016 participation rates are anticipated to be higher than projected. This is a result of increased retail partner participation, program communications and increased customer awareness. Online advertising was added to the communications tactics and was well recognized by participants. The labour cost for the program has decreased in 2016 due to streamlined processes as the utilities gained experience in program delivery and is expected to stay at this level for the remaining years.

This report's recommendations and results demonstrate that the LED and Automotive Heater Timer programs were adopted well by Yukoners. It was also shown that energy efficient products were well received. Results show the KPI's are met or exceeded in most program areas. Programs performed well financially and annual budgets were respected.

As directed by the Yukon Utilities Board, the programs achieved an overall Ratepayer Impact Measure (RIM) ratio of 1.0. This shows that the program is neutral from a utility rate impact perspective. The programs also achieved a very high Participant Cost (PC) ratio and high Program Administrator Cost (PAC) ratio results, showing they are very beneficial to the participants of the program and the utilities, who are the administrators of the programs. Most significantly, the program achieved a high Total Resource Cost (TRC) ratio. This shows that in the context of the comparison with other electricity resource options, the conservation programs performed very well. The tests were conducted assuming a five year program term in order to remain consistent with methodology used in the original program filing. Overall this evaluation has shown that the inCharge Program was well received by Yukoners, was cost effective and met or exceeded most Key Performance Indicators.

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1 Program Summary

inCharge is an electricity conservation program delivered to residential customers in Yukon by the territory's electrical utilities, Yukon Energy Corporation and ATCO Electric Yukon. inCharge consists of three programs; the LED and Automotive Heater Timer Rebate Program, the Low Cost Energy Efficient Products Program and an Engagement, Education and Communication Program. These programs launched in October 2014 and have been extremely well received by Yukoners.

The LED and Auto Heater Timer Rebate Program offers a \$7 rebate on Energy Star LED light bulbs and \$10 rebate on mechanical automotive heater timers that are purchased in the Yukon. Participants can apply for rebates by email, mail, in person at the utilities office or by leaving the rebate form with the cashier at one of the participating retailers. Local retailers can participate in the program by stocking eligible LEDs and timers as well as displaying program advertisements. In addition, stores can also participate by having their cashiers help customers fill out the rebate forms and collect them on behalf of the utilities. Customers will see the rebate appear on their next electrical bill. Retailers have also partnered with inCharge to host events where eligible products are on sale. inCharge will help to advertise the event, to provide staff instore promote the event, to help customers find the right product and fill out the rebate forms properly. The store stocks the sale products and sets up a display area for the event. There are twelve stores in the Yukon displaying program information and collecting rebate forms.

The Low Cost Energy Efficient Products Program distributes kits containing energy saving products and information. These kits contain LED bulbs, an automotive heater timer and a smart power bar. The kits are distributed at community events and utility staff value the opportunity to talk to participants about the products and electricity conservation in general. The program also included a small number of Nest smart learning thermostats that will be distributed to homes that have central electric heat.

The Engagement, Education and Communication Program seeks to raise awareness of electricity conservation and the inCharge program with Yukoners. This includes maintaining the inCharge website, sharing electricity saving tips, answering customer questions regarding electricity conservation and advertisement of the inCharge program.

2 Evaluation Context

This evaluation report will focus on the period between April 2015 and July 2016, updating the program's projected performance with the actual costs and reported energy savings achieved from the program launch in October 2014 to the end of July 2016, as well as documenting learnings from program administration and participant feedback. This report will also assess the key performance indicators laid out in the program's Evaluation, Measurement and Verification Plan. The main goals of this evaluation is to ensure that the programs are performing as projected, that participants are satisfied with the program and to provide recommendations to improve program delivery and cost effectiveness.

The program evaluation was completed by utility staff with guidance and review by an independent evaluation advisor. This method was chosen to keep costs at an appropriate level for the program while still ensuring that the evaluation was completed in an objective manner. The evaluation involved telephone surveys of customers receiving LED rebates (n=31), automotive heater timers rebates (n=11) and energy saving kits (n=30) as well as managers from participating stores (n=7).

3 Updated Cost Effectiveness Results and Program Performance

3.1 Energy Saving and Cost Effectiveness Results

Table 1 below contains the target energy savings and costs for the inCharge program as presented in the Revised Evaluation, Measurement and Verification Plan (December 3, 2014). Table 2 contains a summary of the updated energy savings and costs for the inCharge Program. These updated results are based on actual costs and deemed electricity savings from Year 1 (2014) to end of July of Year 3 (2016). The 2015 interim evaluation reported on the costs and savings for Year 1 (2014) to April of Year 2 (2015), this current evaluation report added the actual costs and deemed savings for the remainder of Year 2 (2015) to July of Year 3 (2016). The updated projections are based on the programs' preliminary results from August of Year 3 (2016) through Year 5 (2018). The updates were completed in the excel-based Program Projections Model that has been used throughout the design and duration of the program. A comparison of Tables 1 and 2 shows how the programs performed in the two years of delivery in comparison to targeted performance. Deemed savings considers the installation rates of each type of product (for more detail see Section 3.1.4). This installation rate is verified through customer surveys and as this model input is refined each year, the deemed savings for past as well as coming years will adjust. The details of the savings and costs are also discussed below in Tables 3 and 4. The following sections discuss how the actual results were incorporated into Table 2. Note that the results in Table 2 from the previous evaluation report may differ as the installation rate for each product is refined through the participant interview process.

Table 1: Targeted Energy Savings and Costs¹

Program Elements	Net Savings with T&D Losses							Utility Expenditure (\$1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	1,337	5,484	5,484	5,484	5,484	23,271	Incentive:	\$12	\$51	\$51	\$51	\$51	\$216	6.2	5.2	20.2	1.2
	Annual MWh:	67	380	692	1,005	1,272	N/A	Non-Incen:	\$82	\$79	\$81	\$84	\$83	\$409				
	Coincident kW:	16	111	206	301	365	N/A	Total:	\$94	\$130	\$132	\$135	\$134	\$625				
Low-cost Energy Efficient Products	Lifetime MWh:	4,605	3,247	3,247	3,247	3,247	17,593	Incentive:	\$78	\$55	\$55	\$55	\$55	\$299	2.4	2.5	5.9	1.0
	Annual MWh:	424	723	1,021	1,225	1,457	N/A	Non-Incen:	\$121	\$172	\$177	\$183	\$188	\$841				
	Coincident kW:	113	192	272	288	323	N/A	Total:	\$199	\$227	\$233	\$238	\$243	\$1,140				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	\$0	\$0	\$0	\$0	\$0	\$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	\$103	\$118	\$121	\$125	\$129	\$596				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	\$103	\$118	\$121	\$125	\$129	\$596				
Total for the Residential Program	Lifetime MWh:	5,942	8,731	8,731	8,731	8,731	40,864	Incentive:	\$90	\$106	\$106	\$106	\$106	\$515	2.7	2.6	9.6	1.0
	Annual MWh:	491	1,102	1,714	2,230	2,730	N/A	Non-Incen:	\$306	\$369	\$380	\$392	\$400	\$1,847				
	Coincident kW:	129	303	478	589	688	N/A	Total:	\$396	\$475	\$486	\$498	\$506	\$2,362				

Table 2: Updated Energy Savings and Costs

Program Elements	Net Savings with T&D Losses							Utility Expenditure (\$1,000s)							Benefit/Cost Ratios for the 5-Year Period			
		Year 1	Year 2	Year 3	Year 4	Year 5	Total		Year 1	Year 2	Year 3	Year 4	Year 5	Total	TRC	PAC	PC	RIM
LED Lighting and Automotive Heater Timer Rebates	Lifetime MWh:	2,418	3,893	7,859	8,128	8,128	30,426	Incentive:	\$19	\$31	\$71	\$69	\$69	\$260	6.4	5.7	13.4	1.3
	Annual MWh:	121	331	747	1,192	1,619	N/A	Non-Incen:	\$77	\$73	\$95	\$98	\$98	\$441				
	Coincident kW:	29	88	200	327	442	N/A	Total:	\$96	\$105	\$166	\$167	\$167	\$700				
Low-cost Energy Efficient Products	Lifetime MWh:	3,208	2,313	2,313	2,313	2,313	12,461	Incentive:	\$71	\$51	\$51	\$51	\$51	\$274	3.0	2.8	6.0	1.0
	Annual MWh:	298	503	708	840	962	N/A	Non-Incen:	\$110	\$154	\$48	\$48	\$48	\$409				
	Coincident kW:	81	169	257	296	329	N/A	Total:	\$181	\$205	\$99	\$99	\$99	\$683				
Engagement, Education and Communication	Lifetime MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Incentive:	\$0	\$0	\$0	\$0	\$0	\$0	N/A	N/A	N/A	N/A
	Annual MWh:	N/A	N/A	N/A	N/A	N/A	N/A	Non-Incen:	\$86	\$108	\$130	\$191	\$191	\$707				
	Coincident kW:	N/A	N/A	N/A	N/A	N/A	N/A	Total:	\$86	\$108	\$130	\$191	\$191	\$707				
Total for the Residential Program	Lifetime MWh:	5,625	6,207	10,173	10,441	10,441	42,887	Incentive:	\$90	\$82	\$121	\$120	\$120	\$533	3.1	2.9	9.2	1.0
	Annual MWh:	419	834	1,456	2,032	2,582	N/A	Non-Incen:	\$272	\$336	\$273	\$337	\$337	\$1,556				
	Coincident kW:	110	257	457	623	771	N/A	Total:	\$363	\$418	\$395	\$457	\$457	\$2,089				

¹ See page 14 of Appendix A of 2014 Annual Report – inCharge Demand Side Management (DSM) Program Portfolio for the Yukon, Filed with Yukon Utilities Board January 29, 2015

3.1.1 Actual Costs

Cost estimates are divided by quarter in the Projections Model. The model was updated with actual costs for each quarter from the start of program launch preparation in third quarter of Year 1 (2014) up to the end of July of Year 3 (2016). The projected costs for the remainder of Year 3 (2016) through Year 5 (2018) were compared to actuals to ensure estimates were still accurate.

The inCharge program administration structure has evolved since its launch in 2014. This is a result of streamlined processes as the utilities gained experience in program delivery. As a result, the labour cost for the program has decreased in 2016 and is expected to stay at this level for the remaining years.

3.1.2 Reported Energy Savings

The energy savings attributed to the inCharge program are calculated using a deemed savings approach. An annual and lifetime energy savings is assigned to each type of product that is included in the program and documented in the Technical Reference Manual (TRM) discussed below. The energy saving projections for the LED and Automotive Heater Timer Rebate Program are based on a target number of rebates issued and included an assumption of the types of bulbs that customers will purchase with their rebates. The energy saving projections for the Low Cost Energy Saving Products Program are based on the number of each of the products the utilities will distribute.

In calculating the reported energy savings for the LED Rebate Program, the actual number of rebated units and types of bulbs purchased were tabulated and the deemed savings as per the TRM were applied. The actual results were used to update the saving projections going forward. In calculating the reported energy savings for the Automotive Heater Timer program, deemed savings as per the TRM were applied.

In calculating the reported savings for the Low Cost Energy Efficient Products Program, the number of products purchased and distributed were tabulated and the deemed savings as per the TRM were applied. The variation from projected savings to actual savings was minimal with this program as the purchasing decisions were in the control of the program administrators.

3.1.3 Technical Reference Manual

A Technical Reference Manual (TRM) was created as a part of the Program Projections Model. The TRM summarizes the assumptions and inputs to the Program Projections Model related to costs and energy savings for each individual type of product included in the programs. The TRM was updated in late 2014 as part of the work completed to launch the inCharge Programs. In particular, costs of LED bulbs were updated as this parameter changes rapidly. The energy savings attributed to each type of product was also reviewed at that time. An example of the TRM entry for standard LEDs can be found in Appendix A.

While the energy savings that can be attributed to a particular product is quite straight forward to estimate. The behavior of customers in purchasing and installing the products is a much more complex and intangible parameter that is considered in the deemed savings calculation. This is captured in the installation ratio and the Net to Gross (NTG) Ratio, discussed in the section below.

3.1.4 Installation Ratio

The installation ratio is an estimate of the percentage of program participants that have installed the product they received as part of an energy saving kit or purchased using a program rebate. As the product must be in use to result in the energy savings estimated, the installation ratio affects the amount of savings that can be claimed for the program. The installation ratio estimated for the program was confirmed through surveys with a sample of program participants.

A new evaluation protocol, the uniform methods project, has been recently developed by the US Department of Energy. This protocol uses a measurement called the in-service rate. For upstream programs like the LED and Automotive Heater Timer Rebate Program, the UMP recommends the following: “In-service rates should be calculated through an in-home audit. Since program bulbs cannot be easily identified, the in-service rate can be calculated as the number of bulbs purchased in a recent 12-month period that are installed divided by the total number of bulbs purchased in the same 12-month period. If the sample size of homes with bulbs purchased in the recent 12-month period is insufficient to provide the necessary levels of confidence and precision, a long term in-service rate can be used using all bulbs regardless of the time of purchase.”² This new method gives the same results as the installation rate. inCharge will continue to monitor the Uniform Methods Project to adjust the evaluation protocol as needed.

3.1.5 Stipulated Net-to-Gross Ratio

The stipulated net-to-gross (NTG) ratio includes effects such as free ridership and spillover. Free ridership accounts for the program participants that would have made the energy saving change without the program, but took advantage of the program anyway. On the other end of the spectrum is spillover. These are people who made the energy saving changes because they were influenced by the inCharge program in some way, such as by point-of-purchase information posters, but did not participate in the program by applying for a rebate. The free ridership and spillover rates are more difficult and complex to confirm. It is currently assumed for the rebate program that free ridership and spillover will cancel each other. According to the survey results, the program seems to have a great influence on the customers’ decision to purchase the energy-efficient products. It can also be assumed that the program will generate some spillover effects because of the general marketing, promotional displays and the fact that not all participants will take time to fill in the rebate form. For the low cost energy efficient products program, the NTG ratio is assumed to be 1 considering the relatively small size of the program, the fact that it is relatively new in the market and that no other jurisdiction has established NTG ratios that would be applicable to the program.

² NREL, Uniform Methods Protocol Chapter 6: Residential Lighting Evaluation Protocol, February 2014, available at < http://www.nrel.gov/extranet/ump/pdfs/20140514_ump_res_lighting_draft.pdf>

3.2 Key Performance Indicator Results

A set of key performance indicators (KPIs) and targets for each KPI were developed for each program. These KPIs are based on a logic model developed for each program. The logic model is a simple graphic and narrative that maps out the resources, activities and outcomes that are expected from each program and the linkages between those parameters that are expected to ensure the program is successful. The logic model for each program can be found in Appendix B. The KPIs are designed to test the performance of the linkages in the logic model. Tables 3 and 4 below report on how the programs are performing for each indicator and provide a brief commentary on each as appropriate. The first column references the linkage number to allow for reference to the programs logic model. Note that the results for Year 3 represent the progress made to the end of July towards meeting the annual (2016) target.

Table 3: LED and Auto Heater Timer Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)										
00	Externalities	No associated tracked KPIs	-	-	-	-	-			
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops	Program documentation	-	20	2	-	-	-	Ambassador workshops not part of 2015 and 2016 program.
		# people attending workshops		-	80	8	-	-		Ambassador workshops not part of 2015 and 2016 program.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
11	Direct engagement with retail store managers	Suggested KPI(s): # of new store managers being engaged for the 1st time	Direct engagement & communication logs	20	30	-	-	-	-	Store managers were contacted at the beginning of the program and efforts continue to engage them as the program continues.
		# of participating stores							12	New KPI added in 2016
		# of store managers contacted with program intel & updates		20	30	20	17	20	17	17 Retail managers were contacted in 2016. Not all participated, but were made aware of the programs and provided with contact information for the future.
13	Utilities issue point of purchase materials for retail managers	Suggested KPI(s): # stores with POP materials	Program documentation	5	9	10	12	10	12	
		POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)		n/a	n/a	Yes	Yes	Yes	Yes	

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
14 & 23	Shoppers buy and install rebate-eligible products[1]	Suggested KPI(s): # of units claimed	Tracking System	1,722	LED: 2,898	7,167	LED: 4,768 Timer: 111 Tot: 4,825	7,000	LED: 7250 Timer: 13 Tot: 7263	Participation higher than projected in 2016 and anticipated to exceed estimates. See Appendix C for rebates by type of LED bulb.
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings[2]	Suggested KPI(s): MWh of avoided lifetime electricity consumption	Estimate based on rebates processed	1,337	2,418	5,484	3,893	5,484	7,859	Lifetime savings were lower than projected in 2015 due to lower than estimated participation, but are on track to exceed targets in 2016.
		MWh of avoided annual electricity consumption		67	121	334	331	692	747	Annual savings were lower than projected in 2015 due to lower than estimated participation, but are on track to exceed targets in 2016.
		kW of avoided coincident electricity demand		16	29	111	88	206	200	Demand savings were lower than projected in 2015 and 2016 due to low uptake in the auto heater timers as a result of warmer than average winters.
21 & 25	Participants receive a rebate[3]	Suggested KPI(s): \$ of incentive disbursement for LED lighting and automotive heater timers	Tracking System	\$12K	\$19,817	\$51K	\$32,512	\$51K	\$35,224	It is expected that program participation will be higher than estimated for 2016 but total program dollars is not expected to be exceeded.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
22	Shoppers learn about rebates through local media campaigns	Suggested KPI(s): # updates of web content	Tracking System	1	1	4	4	4	10	Website updated when substantive changes made to program, events planned and in response to participant comments.
		# newspaper/radio advertisements		1	4	1	9	1	8	Radio and newspaper ads continue to be used to advertise the rebate program with the addition of online ads starting in late 2015.
		# bill insert		1	0	1	0	-	-	Bill inserts not used in 2014 and 2015.
		# online ads				1	1	4	3	Online ads were introduced in October 2015 and continue to be used to announce events and increase brand awareness due to their success.
		# email blasts		1	0	1	1	1	1	1 e-mail blast in 2015 and again in 2016 to notify past participants of planned events.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
26	Participating shoppers will be satisfied by the products that they bought	Suggested KPI(s): % of rebates processed in time to show up on next utility bill (if applications comes in 10 business days before issuance of bill)	Tracking System	70%	99%	80%	99%	80%	99%	Nearly all customers received their rebate on their next utility bill.
27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-			see Part B.
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-			see Part B.
Part B -- To Be Visited, Checked and Reported On by Evaluators										
00	Externalities	Done/Not-Done – report on externalities on a yearly basis	Program documentation	Done	Done	Done	Done			
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-5 scale, level of satisfaction with the workshop on average	Attendees	70% scoring 4-5 out of 5	100%	-	-	-	-	Ambassador workshops not part of 2015 and 2016 program.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
11	Direct engagement with retail store managers	Suggested indicator(s): % store managers who know the program	Store managers	-	-	100%	-	100%		
		% of store managers the program influenced in general.	Tracking system	-	-	60%	-	60%	57%	
		% of store managers the program influenced in quantity of stocked items							71%	New KPI added in 2016
		% of store managers the program influenced in variety of stocked items							29%	New KPI added in 2016
		% of store managers that found the POP material influential							14%	New KPI added in 2016

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
13	Utilities issue point of purchase materials for retail managers	Suggested indicator(s): % of shoppers who noticed POP materials % of shoppers who agree that POP materials contributed to their decision to purchase a rebate-eligible product	Shoppers and Participants	-	-	70%	83%	70%	LED: 73% Timer: 100% Avg: 80%	73% LED Rebate participants and 100% Auto Timer Rebate participants for a weighted average of 80%. 55% LED Rebate participants and 73% Auto Timer Rebate participants for a weighted average of 60%.
14 & 23	Shoppers buy and install rebate-eligible products	% of products installed	Participants	-	-	-	-	-	LED: 99% Timer: 82% Avg: 95%	The vast majority of customers installed the LED bulbs that they purchased (94%) with the rest having installed most of the lights and having purchased a few extras, for an installation rate of 99%.. Despite an unseasonably warm winter, most if the timers were installed (82%).

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
24	The LED lighting and automotive heater timer installations will yield long-term electricity and demand savings	No evaluation indicator	-	-	-	-	-			
21 & 25	Participants receive a rebate	Suggested indicator(s): % of participants who agree the rebate contributed to them purchasing the energy efficient products rather than the base-case product	Participants	-	-	60%	LED 77% Timer 50%	60%	LED 68% Timer 72%	Participants who rated the program influential or very influential in their decision to purchase the energy efficient product: LED Rebate - 68% Auto Timer Rebate - 72%
22	Shoppers learn about rebates through local media campaigns	Suggested indicator(s): % of shoppers who can recall one of the following: bill inserts, web content, or inCharge in the news	Participants & non-participants	-	-	70%	58%	70%	64%	64% of participants can recall media advertising. Non-participants were not surveyed in this evaluation.

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
26	Participating shoppers will be satisfied by the products that they bought	Suggested indicator(s): 1-to-5 scale, level of satisfaction with the overall rebate program	Participants	-	-	80% scoring 4-5 out of 5	LED 93% Timer 90%	80% scoring 4-5 out of 5	LED 96% Timer 100%	Percentage of participants who were very satisfied or satisfied with the program: LED Rebate - 96% Auto Timer Rebate - 100%
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants	Participants	-	-	30%	65%	30%	46%	46% of participants heard of the program from others and 100% of those discussions were positive.
		% heard of the program positively from past participants	Non-participants	-	-	10%	-	-	-	Non-participants were not surveyed in this evaluation.
28	Non-energy benefits	Suggested indicator(s): 1-to-5 scale, level of satisfaction with the LED lighting or automotive heater timer in general	Participants	-	-	90% scoring 4-5 out of 5	LED 93% Timer 90%	90% scoring 4-5 out of 5	LED 100% Timer 84%	Percentage of participants who were very satisfied or satisfied with their energy efficient products: LED Rebate - 100% Auto Timer Rebate - 84%
		1-to-5 scale, level of satisfaction with the LED light quality							100%	New KPI added in 2016

Link #	Narrative	Performance Indicator	Sources	Year 1		Year 2		Year 3		Progress Commentary
				Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	
		1-to-5 scale, level of satisfaction with the LED bulb lifetime							100%	New KPI added in 2016
		1-to-5 scale, level of satisfaction with the Auto Heater Timer usefulness							89%	New KPI added in 2016

Table 4: Low Cost Energy Efficient Products Program KPI Summary

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
<i>Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)</i>										
00	Externalities	No associated tracked KPIs	-	-	-	-	-			
02	Utilities conduct outreach activities at community events	Suggested KPI(s): # of events w/Program booth	Program documentation	2	7	4	2	4	10	Program staff participated in a number of community events to discuss inCharge and distribute kits. Kits were also given to walk-in customers at utility offices.
		# of kits distributed		40	220	60	223	400	239	Kits were distributed to 223 customers in 2015 and 239 customers to the end of July 2016.
04	Provide EE products free-of-charge	Suggested KPI(s): # of kits/products distributed	Program documentation	300	356	180	223	400	239	

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
06	Scorecard results will be analyzed	Suggested KPI(s): # of scorecards received	Direct engagement & communication logs	30	18	20	45	-	-	Scorecards were not used in the 2016 program documentation and were replaced with phone interviews.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested KPI(s): # workshops # people attending workshops	Program documentation	- -	20 80	2 8	- -	- -	- -	Ambassador workshops not part of 2015 and 2016 program. Ambassador workshops not part of 2015 and 2016 program.
10	Utilities' community engagement leads to 'behavior-based' electricity and demand savings	No associated tracked KPIs	-	-	-	-	-	-	-	
14 & 19	Shoppers buy and install low-cost EE products	No associated tracked KPIs	-	-	-	-	-			

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
20	The low-cost EE products will yield long-term electricity and demand savings	Suggested KPI(s): MWh of avoided lifetime electricity consumption MWh of avoided annual electricity consumption MW of avoided coincident electricity demand	Estimate based on free products provided	4,605 424 113	3208 298 81	2885 646 178	2313 503 169	2885 913 252	2313 708 257	2015 & 2016 kits were redesigned to be simpler than 2014 kits and focused on products that customers were installing at high rates. This resulted in similar savings for lower administrative costs.
26	Participants will be satisfied by the low-cost EE products	Suggested KPI(s): Scorecard feedback 1-to-5 scale, level of satisfaction with the products	Tracking System	70%	-	70% scoring 4-5 out of 5	95%	-	-	Scorecards were not used in the 2016 program documentation and were replaced with phone interviews.
05 & 27	Word-of-mouth	No associated tracked KPIs	-	-	-	-	-			See Rebate Program KPIs above (Table 3).
28	Non-energy benefits	No associated tracked KPIs	-	-	-	-	-			See Rebate Program KPIs above (Table 3).
Part B -- To Be Visited, Checked and Reported On by Evaluators										
00	Externalities	Done/Not-Done – report on externalities on an annual basis	Program documentation	Done	-	Done	-			

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
02	Utilities conduct outreach activities at community events	No evaluation indicator	-		-		-			Done
04	Provide EE products free-of-charge	No evaluation indicator	-		-		-			Done
06	Scorecard results will be analyzed	Suggested indicator(s): % of issued score cards that are completed and returned	Program documentation	10%	16%	10%	-	-	-	Scorecards were not used in the 2015 and 2016 program documentation and were replaced with phone interviews.
08	Utilities support EE workshops hosted by EE ambassadors	Suggested indicator(s): 1-to-10 scale, level of satisfaction with the workshop on average	Attendees	7/10	10/10	8/10	-	-	-	Ambassador workshops were not part of 2015 and 2016 program.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
14 & 19	Shoppers buy and install low-cost EE products	% products installed			-		-		LED: 72% Timer: 46% SPB: 89%	New KPI added in 2016. Note the low installation rate of Auto Heater Timers was attributed to the warmer than average winter in 2016. This low rate will be monitored in 2017 to confirm assumption.
20	The low-cost EE products will yield long-term electricity and demand savings	No evaluation indicator	-		-		-			
26	Participants will be satisfied by the low-cost EE products	Suggested indicator(s): 1-to-5 scale, level of satisfaction with their energy efficient products	Participants			80% scoring 4-5 out of 5	95%	80% scoring 4-5 out of 5	96%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 94%, powerbars - 95%, Auto heater timers - 100%, for an average of 96%.
27	Word-of-mouth	Suggested indicator(s): % heard of the program positively from other past participants % heard of the program positively from past participants	Participants Non-participants			30% 10%	65% -	30% -	46% -	46% of participants had heard of the program from others and 100% of those discussions were positive (from Table 3). Non-participants were not surveyed in this evaluation.

Link #	Narrative	Performance Indicator	Sources	Target 2014	Actuals 2014	Target 2015	Actuals 2015	Target 2016	Progress 2016	Progress Commentary
28	Non-energy benefits	Suggested indicator(s): 1-to-5 scale, level of satisfaction with their energy-efficient product	Participants			80% scoring 4-5 out of 5	95%	80% scoring 4-5 out of 5	96%	Percentage of participants who were very satisfied or satisfied with each product: LEDs - 94%, powerbars - 95%, Auto heater timers - 100%, for an average of 96%.

3.3 General Program Administrator Observations

In addition to the information gathered to assess the KPIs, the staff administering the programs made the following observations and recommendations during the delivery of the inCharge program.

3.3.1 LED and Automotive Heater Timer Rebate Program Observations

The participation in the rebate program is now closely linked to instore events and communications, particularly when the price point of LED bulbs drops. LED bulb prices have dropped significantly since the start of the program and as a result participation levels have increased allowing more customers to take advantage of the rebate program. Participation rates were lower than expected in 2015, but are now higher than projected in 2016 resulting from an increase in communication and the introduction of instore events. Ongoing education with retail staff has resulted in greater in-store support and purchasing assistance for customers. The major retailers have noted the success of the instore events and are actively seeking opportunities for events and sales. National offices of the larger retailers are now aware of the Yukon programs and include the local stores in bulk purchasing opportunities resulting in lower prices and better stock choices. Online communication was also launched in late 2015 and is the most recognized advertising method.

Participants reported being very satisfied with the quality of LEDs. A bias still remains from the negative experience some customers have had with CFLs, but that comment is heard less frequently. More customers are choosing to purchase LEDs and are influenced by the program to buy more or to buy them sooner.

The larger Energy Star logo on the program forms resulted in less participant confusion and rebates being submitted for non-eligible products. Additional retail staff education has also contributed to less confusion at point of purchase.

The winter of 2015/2016 was warmer than average with the El Nino effect and the need for block heaters was minimal. This resulted in very low uptake of the automotive heater timer program. Given the uncertainties of weather for the 2016/2017 winter, a communications push regarding block heater timers will be launched in Q4 2016.

Based on the results of the participant survey, 99% of the LED bulbs purchased through the program and 82% of the block heater timers were installed. This means that only a small number of LED bulbs were left in storage. As for the timers, the explanation given by the participants who did not install it yet was the warm winter. Considering these high installation rates and the fact that it is very likely that the participants, who had to spend a certain amount of money to purchase the products, will install them ultimately, all of the savings associated with the rebates were claimed.

Comments from participants on the LED and Auto Heater Timer Rebate Program received during the phone surveys were very positive and a sample of the comments is below.

- Good and effective program. Savings are real and significant.
- Like the program design, really easy to participate.

- Been bragging to friends about the program. Love it!
- Excellent program, told many friends about it.
- Like the program being done by the utilities.

3.3.2 Low Cost Energy Efficient Products Program Observations

The simplified kit was easy to distribute and gave utility staff more time to engage with the recipient on electricity efficiency. Many of the recipients heard about the inCharge program for the first time when they received a kit. This is an opportunity to promote the inCharge program and increase brand awareness.

Telephone surveys showed that some participants did not recall receiving a kit and that there was some confusion with how to install and use the smart power bar. The telephone surveys also showed that the installation rates for the LED bulbs was slightly lower than 2015 (92% in 2015 as compared with 72% in 2016), higher for the smart power bars (84% in 2015 and 89% in 2016) and much lower for the automotive heater timers (98% in 2015 to 46% in 2016). An average installation rate of 85% was used for these products. This assumption will continue to be tested in follow-up evaluations. The kits were given for free to participants without validating their need for the products. Therefore it is important to apply the installation rates obtained from the participant surveys.

Comments from participants on the Low Cost Energy Efficient Products Program during the phone surveys were very positive and a sample of the comments is below.

- They are excellent products.
- Excellent program, keep it going.
- Good way to raise awareness.
- Keep the information coming. Helps to keep energy efficiency in the forefront.
- Very appreciative inCharge came out to Haines Junction. Not many organizations will travel there.

4 Results and Recommendations

LED and Automotive Heater Timer Rebate Program Recommendations

Recommendations for the rebate program are to continue to increase the communications efforts, particularly enhancement of instore advertising at the point of purchase. The goal is to increase participation, particularly among customers that are not already considering the purchase of LED's.

Also recommend is to provide a higher level of feedback to retail staff and managers on how their store is contributing to the program, which products participants are purchasing and share positive comments from participants to encourage their continued support as well as assist with stocking decisions.

4.1 Low Cost Energy Efficient Products Program Recommendations

To help increase awareness around the program and reach an audience that may not already be interested in electricity conservation, information regarding the inCharge program in general should be added to the kits. As the events where the kits are distributed are an opportunity to discuss the products and electricity conservation in general, care should be taken to ensure these events provide the time and space needed to engage with participants in a meaningful way. This is also intended to increase installation rates and reduce the number of participants that do not recall receiving an energy saving kit.

Installation rates of the automotive heater timers were lower in 2016 as compared to 2015. This trend and the cause of the low installation rates will be monitored closely to see if this was influenced by the warmer than average winter or if it is because of another barrier to installation. The 2017 evaluation could include a follow-up with 2015 participants to check if they had used their timer the following year. A reminder note to the 2015 kit recipients reminding them of the benefits of their automotive heater timers could also be sent. Also, the information included in the kits should be updated with more information on how to use the products, particularly the smart power bars, to ensure all participants are aware of their proper use and benefits.

4.2 Evaluation Summary and Evaluation Recommendations

Overall, this interim evaluation has shown that the inCharge Programs were well received by Yukoners, participation met or exceeded most KPIs (as shown in Tables 3 and 4 above) and were cost effective (as shown in Table 2). The linkages between activities, outputs, short-term outcomes, intermediate outcomes and long-term outcomes as laid out in the program logic models (Appendix B), are clear, well defined and reasonable.

The following short-term outcomes were achieved:

- Energy efficient products identified and endorsed;
- Energy efficient products available in stores;
- Retail staff educated about energy efficient products and provided in-store customer support;
- Customers educated about energy efficient products
- Customers convinced to buy and install energy efficient products; and
- The initial cost hurdle was alleviated.

The intermediate outcomes that were achieved include effective communication through advertising and word of mouth and participant purchase and installation of eligible energy efficient products was achieved.

The long-term outcomes that were achieved include high customer satisfaction with the programs and products, and cost effective, long-term energy and demand savings.

Overall, the program rationale is sound and the results to date support the reasonableness of the claimed cost effectiveness, and the energy and demand savings.

The US Department of Energy, Uniform Methods Project (UMP) has been recently completed and presents updated protocols for DSM program evaluation. The inCharge program will continue to work to ensure that the program evaluation is aligned with the new UMP methods.

In the Program Projections excel workbook that was developed to model the cost effectiveness of the inCharge program, one installation rate is applied to all five years. While this simple approach works for the current program, it would be an improvement if future projections or evaluation models could apply a separate installation rate to each year.

The program administrators should start to look for cost effective ways to measure the free ridership and spillover assumptions. This may be from surveys completed by other utilities with larger programs or through a short survey in the Yukon.

Appendix A: TRM Example – Standard LEDs > 9W



Yukon Energy Corporation and ATCO Electric Yukon
YEC AEY Residential DSM Program Design - ECM-level Cost-effectiveness test and Incentive Level Substantiation

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations		Outputs with Program Costs	
Measure Name:	Standard LEDs (>9 W)	PC - Benefit/Cost Ratio	10.64
Incentive Amount:	\$7.00	PC - Net Present Value	\$73.39
Measure/Project Cost:	\$7.61	PC - Levelized Cost	\$0.0174/kWh
Gross Consumption Savings:	40 kWh/yr	Simple Payback w/ Incentive (yr)	0.1 yr
Transport and distribution losses:	8.3%	<i>RIM - Benefit/Cost Ratio</i>	1.28
Gross Cons. Savings w/ T&D Losses:	43 kWh/yr	<i>RIM - Net Present Value</i>	\$26.88
Gross Demand Savings:	.01 kW	<i>RIM - Levelized Cost</i>	\$0.1975/kWh
Gross Demand Savings w/ T&D losses:	.010 kW	TRC - Benefit/Cost Ratio	5.76
Participant's Savings on Year 1:	\$5.74	TRC - Net Present Value	\$100.27
Measure Lifetime:	20 yr	TRC - Levelized Cost	\$0.0441/kWh
Inputs - Program Considerations		<i>PAC - Benefit/Cost Ratio</i>	5.93
Program Cost (% of Incentive):	192%	<i>PAC - Net Present Value</i>	\$100.88
Suggested Program Cost (% of Incentive):	192%	<i>PAC - Levelized Cost</i>	\$0.0428/kWh
Forecasted Freeridership:	10%	<i>RIM-YECL - Benefit/Cost Ratio</i>	0.65
Forecasted Participant Spillover:	0%	<i>RIM-YECL - Net Present Value</i>	-\$24.06
Forecasted Non-participant Spillover:	10%	<i>RIM-YECL - Levelized Cost</i>	\$0.1537/kWh
Forecasted Rebound Effects:	0%	<i>RIM-YEC - Benefit/Cost Ratio</i>	1.93
Reference Data from Other Jurisdictions:		<i>RIM-YEC - Net Present Value</i>	\$63.55
		<i>RIM-YEC - Levelized Cost</i>	\$0.1322/kWh

Additional Discussions:



Yukon Energy Corporation and ATCO Electric Yukon
YEC AEY Residential DSM Program Design - ECM-level Cost-effectiveness test and Incentive Level Substantiation

Detailed Calculation of the Cost-effectiveness Tests

Values Used in All Cost-effectiveness Tests	
Incremental Cost in Year 1	\$7.61
Incentive Amount in Year 1	\$7.00
Assumed Program Administration Costs in Year 1	\$13.47
Assumed Net-to-gross Ratio	100%

NTG = 1 - Freeridership + P. Spillover + N-p. Spillover - Rebound

Participant Cost Test (PC)		
<i>Cumulative Present Value of Cashflows w/ PC Discount Rates</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Participant's Avoided Energy Cost for 20 years	\$74.01	\$74.01
Discounted Cumulative Gross Energy Savings for 20 years	439 kWh	439 kWh
PC - Present Value of Benefits	\$81.01	\$81.01
PC - Present Value of Costs	\$7.61	\$7.61
PC - Benefit/Cost Ratio	10.64	10.64
PC - Net Present Value	\$73.39	\$73.39
PC - Levelized Cost	\$0.0174/kWh	\$0.0174/kWh
Simple Payback with Incentive	0.1 yr	0.1 yr

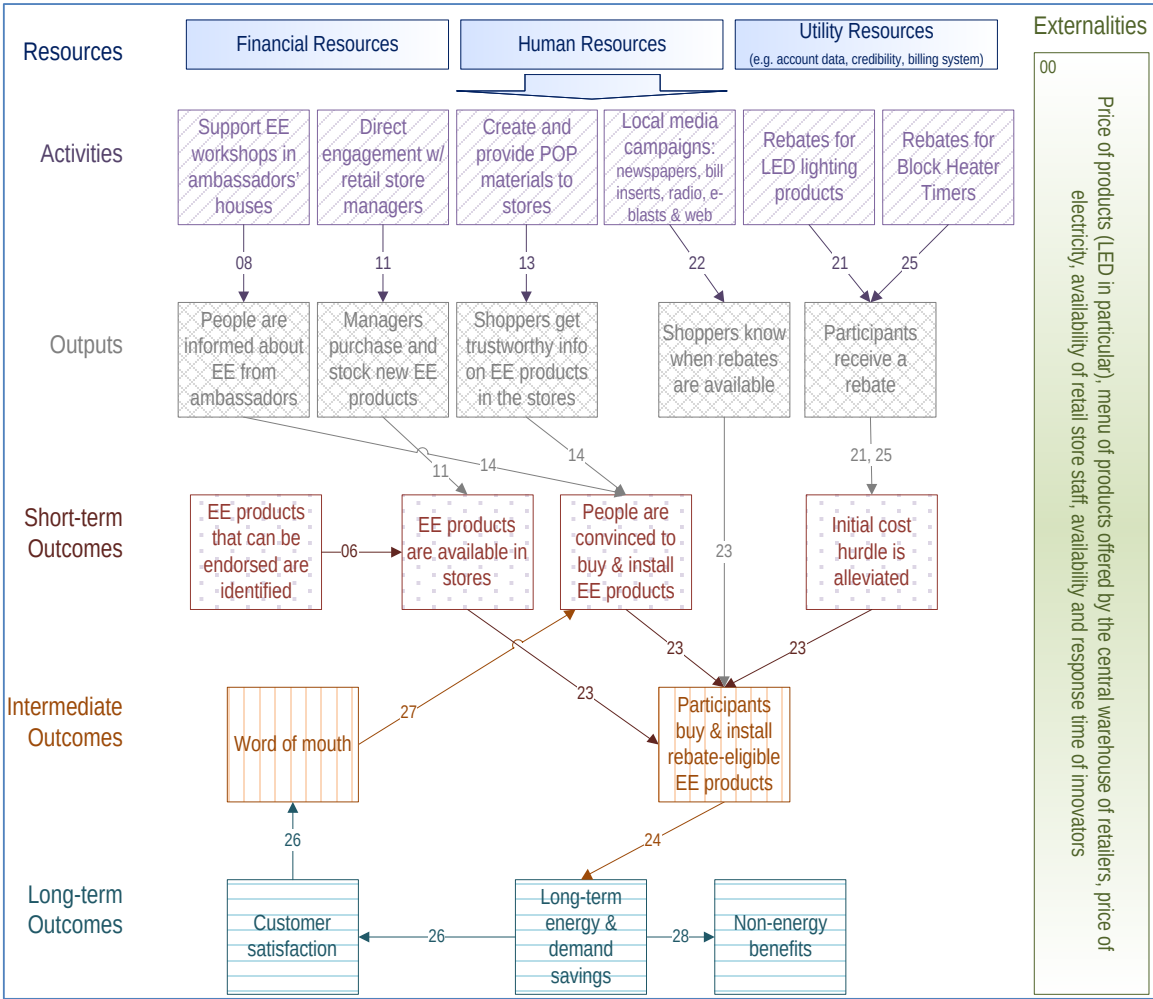
Ratepayer Impact Measure Test (RIM)		
<i>Cumulative Present Value of Cashflows w/ RIM Discount Rate</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Avoided Energy Costs for 20 years	\$121.35	\$121.35
Present Value of Avoided Capacity Costs for 20 years	\$0.00	\$0.00
Present Value of Lost Revenues for 20 years	\$74.01	\$74.01
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
RIM - Present Value of Benefits	\$121.35	\$121.35
RIM - Present Value of Costs	\$94.48	\$81.01
RIM - Benefit/Cost Ratio	1.3	1.5
RIM - Net Present Value	\$26.88	\$40.35
RIM - Levelized Cost	\$0.1975/kWh	\$0.1693/kWh

Total Resource Cost Test (TRC)		
<i>Cumulative Present Value of Cashflows w/ TRC Discount Rate</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Avoided Energy Costs for 20 years	\$121.35	\$121.35
Present Value of Avoided Capacity Costs for 20 years	\$0.00	\$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
TRC - Present Value of Benefits	\$121.35	\$121.35
TRC - Present Value of Costs	\$21.09	\$7.61
TRC - Benefit/Cost Ratio	5.76	15.9
TRC - Net Present Value	\$100.27	\$113.74
TRC - Levelized Cost	\$0.0441/kWh	\$0.0159/kWh

Program Administrator Cost Test (PAC)		
<i>Cumulative Present Value of Cashflows w/ PAC Discount Rate</i>	<i>With Program Costs</i>	<i>W/o Program Costs</i>
Present Value of Avoided Energy Costs for 20 years	\$121.35	\$121.35
Present Value of Avoided Capacity Costs for 20 years	\$0.00	\$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
PAC - Present Value of Benefits	\$121.35	\$121.35
PAC - Present Value of Costs	\$20.47	\$7.00
PAC - Benefit/Cost Ratio	5.9	17.3
PAC - Net Present Value	\$100.88	\$114.35
PAC - Levelized Cost	\$0.0428/kWh	\$0.0146/kWh

Appendix B: Program Logic Models

Figure B1: Logic Model for the Residential LED Lights and Automotive Heater Timer Rebate Program

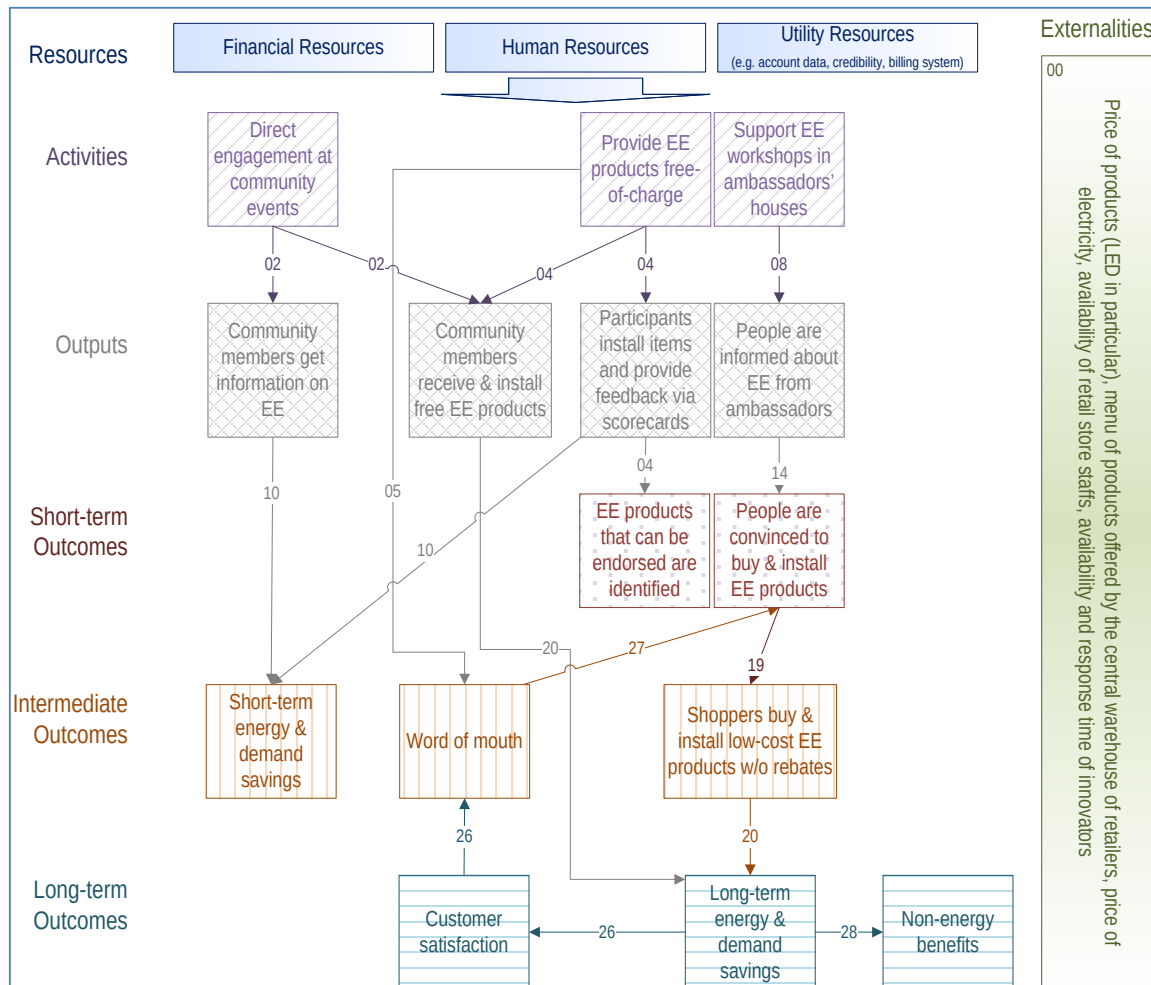


Link # Narrative

- 00 The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff to address any questions. The program administrator should monitor these externalities and adapt the implementation approach based on them.

Link #	Narrative
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products, and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
11	The Utilities will establish partnerships with Yukon retail store managers and establish two-way communication. The Utilities will suggest new products to stock; perhaps by providing the results of the low-cost EE product piloting, by revealing in advance what products will be eligible for the LED lighting rebate and automotive heater timer rebate, or by indicating what POP materials will be created and offered to the shops.
13	The Utilities will design and procure educational Point Of Purchase (POP) materials for Yukon retail managers to display in their stores. These materials might include (but not be limited to): brochures, presentation boxes, posters, and displays stands.
14	Yukon shoppers will be informed on EE products through the community direct engagement, and through the POP materials. This will cause them to buy and install these products.
21	The Utilities will provide a flat amount of money per unit to Yukon shoppers after they purchase LED lighting lamps or fixtures selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated which will contribute to the items being purchased and installed.
22	The "rebate" period will be extensively advertised through a media campaign through local radio, local newspapers, co-op advertisement with retailers and in stores, and electricity bill inserts. Consequently, shoppers will know when the rebates are going to be available.
23	Participating Yukon shoppers (i.e. participants) will buy and install LED lighting products or automotive heater timers and receive a rebate because these products will be available in the stores, because they were made aware of the benefits of these products, because they know when the rebate is available, and because the initial cost hurdle was alleviated by the rebate.
24	The LED lighting product installs and automotive heater timer installs will yield long-term electricity and demand savings.
25	The Utilities will provide a flat amount of money per unit to Yukon shoppers for the purchase of automotive heater timers (i.e. outdoor) selected from a prescriptive list of eligible products. The initial-cost hurdle will be alleviated and/or the rebate will make the purchase of an automotive heater timer much more enticing. This will contribute to the purchase and installation of these items.
26	Shoppers who bought low-cost EE products, LED lighting products or automotive heater timers will be satisfied by the products that they bought. They will tell their friends and relatives. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products.
28	Shoppers will perceive new non-energy benefits and/or the less maintenance related to the energy efficient products when they're compared with the baseline systems. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have negative impact on their car.

Figure B2: Logic Model for Residential Low Cost Energy Efficient Products Program



Link #	Narrative
00	The program effectiveness and impact will be influenced by the following externalities: price of products (LED technologies, in particular), menu of products offered by the central warehouse of retailers, price of electricity, and availability of retail store staff. The program administrator should monitor these externalities and adapt the implementation approach based on them.
02	The Utilities will carry out outreach activities in community events (e.g. sport events, cultural events, town hall meetings, etc.), engage with organization and people who have a natural interest in electricity conservation; hook individuals with a continuous stream of free low-cost EE products or contests; do personalized follow-ups; and promote the idea of supporting an EE workshop at their home or a at local venue.

Link #	Narrative
06	Low-cost EE products will be used by program participants. Participants will be provided with simple scorecards that will give them the opportunity to provide feedback on the various products. The Utilities will collect all of the scorecards, aggregate and analyze the results, and use the results on consumer satisfaction to improve the products that are distributed by the program in subsequent years.
05	It is expected that the volunteers and EE community network members will like the low-cost EE products and will tell their friends and relatives. This will feed the word of mouth feedback loop.
08	The Utilities will support EE workshops in the homes of EE community network members or nearby community venues with approximately ten friends and relatives. The Utilities will send facilitator(s), provide communication materials and low-cost EE products to give away, and perhaps provide food and beverages. The Utilities' skilled facilitator(s) will have a few key messages regarding low-cost EE products, LED lighting products and automotive heater timers. The facilitator will encourage the participants to share tips and information on electricity conservation. The facilitator will also seek to eliminate potential sources of confusion and false beliefs in the communities by presenting hard facts.
10	The information and tips provided to residents of the Yukon as part of the Utilities direct community engagement activities will influence their behavior and cause them to use less electricity and reduce their peak demand. However, quantifying "behavior-based" electricity and demand savings is challenging and perhaps cost-prohibitive for a small jurisdiction like the Yukon. Moreover, the persistence of "behavior-based" conservation measures is notoriously bad. It is commonly believed to be less than one year by DSM experts. Consequently, the short-term benefits of behavior-based conservation measures will not be quantified. They are considered to be outcomes that are "nice-to-have" yet not necessary to make the program viable.
14	Yukon shoppers will be informed on EE products through the community direct engagement. This will cause them to buy and install these products.
19	Yukon shoppers will buy and install low-cost EE products (even in the absence of rebate) because these products will be available in the stores, and because they were made aware of the benefits of these products. The low-cost EE products may have a certain price increment; however it is assumed that the price increment (if any) is too small to constitute the most important purchase barrier.
20	The free and purchased low-cost EE product installs will yield long-term electricity and demand savings.
26	Shoppers who received low-cost EE products or purchased LED lighting products or automotive heater timers will be satisfied by the products that they bought. As a result, they will tell their friends and relatives about their experience with these products. This will generate word-of-mouth advertisement.
27	With time, word-of-mouth will become an important information channel that will cause Yukon residents to buy and install EE products without any support from the Utilities.
28	Program participants will perceive non-energy benefits, including improved comfort and reduced maintenance, as a result of the products they installed. For example, the Utilities will seek to make sure that participants will perceive that their new LED products last longer, are less sensitive to power quality issues, are more reliable, cast better light (color rendering, intensity, and visual acuity), and are easier and less hazardous to dispose of than CFLs. The Utilities will seek to make sure that participants will perceive that automotive heater timers are reliable and that the use of a timer does not have any negative impacts on their vehicles.

Appendix C: LED Rebates by Bulb Type

	2014		2015								2016					
Type	Q4		Q1		Q2		Q3		Q4		Q1		Q2		Q3	
Candelabra LEDs (Up to 6 W)	52	2%	61	3%	7	1%	7	8%	57	3%	29	3%	24	1%	2	0%
Standard LEDs (Up to 9 W)	300	10%	365	20%	220	24%	13	14%	658	33%	302	33%	2689	65%	1843	84%
Standard LEDs (>9 W)	2258	78%	1219	66%	623	67%	64	70%	908	45%	383	41%	1107	27%	259	12%
Reflector LEDs (Up to 9 W)	264	9%	172	9%	59	6%	3	3%	313	16%	196	21%	289	7%	87	4%
Reflector LEDs (>9 W)	24	1%	23	1%	12	1%	2	2%	41	2%	11	1%	11	0%	1	0%
Recessed LED Fixtures	0	0%	2	0%	8	1%	2	2%	40	2%	6	1%	11	0%	0	0%
Total	2898	100%	1842	100%	929	100%	91	100%	2017	100%	927	100%	4131	100%	2192	100%

1 **TOPIC: Reconciliation of Utility Income to Net Earnings**

2
3 **REFERENCE:** June 22, 2017 Application, Schedule 8, page 7-12

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please explain why \$269,351 in cost claims by YEC that were disallowed in Board
10 Order 2013-08 dated September 13, 2013 are not shown at line 6 (Disallowed
11 Costs).

12
13 b) Please provide a breakdown of all costs associated with regulatory proceedings in
14 2012 through 2016 and identify where these costs are included within the current
15 application.

16
17 c) Please provide a breakdown of all costs (actual to date and forecast) associated
18 with regulatory proceedings in 2017 and 2018 and identify where these costs are
19 included within the current application. Please include details related to in-house
20 as well as consultant and outsourced services (labour, O&M, etc.).

21
22 **ANSWER:**

23
24 **(a)**

25
26 The cost claims disallowed in Board Order 2013-08 are included on Line 3 of Schedule 8
27 and disclosed in Note 2 of Schedule 6.

28
29 **(b)**

30
31 2012 costs are not shown in this application. Costs associated with regulatory proceedings
32 for 2013 through 2016 are detailed below and summarized in Table 3.14.1 of the
33 Application.

Table 1: Regulatory Proceeding Costs: 2013-2016

(\$000's)	2013	2014	2015	2016
2012-2013 GRA costs	387			
DSM/inCharge	58	8		
LNG Part 3		423		
DCF/ERA			213	138
	444	432	213	138

In addition, \$105,000 of costs associated with the 2017-2018 GRA were incurred in 2016 and are shown in Table 5.6.

(c)

All costs are external costs/services. Forecast costs are included within the Application in Table 3.14.1, Table 5.7 (Regulatory) and Table 5.8 (Regulatory). Actual 2017 costs to June 30, 2017 are disclosed below.

Table 2: Regulatory Proceeding Costs: 2017

(\$000's)	
2017-2018 GRA	241
DCF/ERA	3
	244

1 **TOPIC: Summary of Customers, Energy Sales and Revenues**

2
3 **REFERENCE:** June 22, 2017 Application, Schedule 9, page 7-13

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please confirm that YEC is predicting a 4% increase in total sales (line 43) from
10 2013 allowed (383,061 MWh) to 2017 forecast (397,859 MWh) and a 15% increase
11 in total revenues (line 51) between 2013 allowed (\$42,263,000) and 2017 forecast
12 (\$48,544,000).

13
14 b) Please confirm that YEC is predicting a 0.2% increase in total sales (line 43) from
15 2017 forecast (397,859 MWh) to 2018 forecast (398,582 MWh) and a 2.7%
16 increase in total revenues (line 51) between 2017 forecast (\$48,544,000) and 2018
17 forecast (\$49,864,000).

18
19 c) Please explain why significant increases to sales volumes in 2017 and 2018 still
20 require a significant increase to riders charged to Yukon ratepayers.

21
22 **ANSWER:**

23
24 **(a)**

25
26 Confirmed.

27
28 **(b)**

29
30 Confirmed.

31
32 **(c)**

33
34 A 4% increase in sales volumes from 2013 approved to 2018 forecast requires a rate
35 increase due to other changes that have occurred between 2013 and 2017/2018. For
36 further details see Application pages 1-1 through 1-7.

1 **TOPIC: Summary of Operating and Maintenance Expenses**

2
3 **REFERENCE:** June 22, 2017 Application, Schedule 10, page 7-14

4
5 **PREAMBLE:**

6
7 **QUESTION:**

- 8
9 a) Please provide an explanation for the increases to the Administration and General
10 expense (line 5) between 2013 approved (\$8,654,000) and the expenses for 2015
11 actual (\$8,101,000), 2016 actual (\$8,509,000), 2017 forecast (\$9,110,000) and
12 2018 forecast (\$8,912,000). Also explain the proposed 7.1% increase between
13 2016 and 2017 and the 2.2% decrease from 2017 to 2018.
14
15 b) Please provide an explanation for the increases to the Reserve for Injuries and
16 Damages expense (line 16) between 2013 approved (\$226,000) and the expenses
17 for 2017 forecast (\$479,000) and 2018 forecast (\$479,000).
18
19 c) Please provide an explanation for the increases to the Property Taxes expense
20 (line 17) between 2013 approved (\$326,000), 2015 actual (\$473,000), 2016 actual
21 (\$686,000), 2017 forecast (\$696,000) and 2018 forecast (\$708,000).
22
23 d) Please provide an explanation for the increases to the Donations expense (line 18)
24 between 2013 approved (\$85,000), 2016 actual (\$95,000), 2017 forecast
25 (\$96,000) and 2018 forecast (\$100,000).
26

27 **ANSWER:**

28
29 **(a)**

30
31 See CW-YEC-1-24 and YUB-YEC-1-11.

32
33 **(b)**

34
35 See Application Section 3.3.6.

1 **(c)**

2

3 See YUB-YEC-1-14 and CW-YEC-1-20.

4

5 **(d)**

6

7 YEC Board of Directors approved an increase of \$10,000 for donations in 2016. Similarly,
8 changes in 2017 and 2018 reflect Board of Directors approved changes to YEC's
9 scholarship policy. Note donations are excluded from revenue requirement determination.

1 **TOPIC: Summary of Cost of Long-Term Debt**

2
3 **REFERENCE:** June 22, 2017 Application, Schedule 11, page 7-15

4
5 **PREAMBLE:**

6
7 **QUESTION:**

8
9 a) Please provide a breakdown of the \$92.5 million YDC debt (line 10), the \$21 million
10 YDC debt (line 11), the \$12 million YDC debt (line 12), the new 2017 \$23.828
11 million debt (line 13) and the new 2018 \$7 million debt (line 14) including terms
12 and payment requirements as well as reasons for the debt.

13
14 b) Please explain why the new long-term debt for 2017 is increasing from \$13.118
15 million to \$23.828 million.

16
17 **ANSWER:**

18
19 **(a)**

20
21 Debt is required is to maintain Yukon Energy's YUB approved capital structure. Terms
22 and payment requirements of the \$92.5 million YDC debt and the \$21 million YDC debt
23 are detailed in Tab 9 of the Application on page 9-26. The \$12.1 million YDC issued debt
24 in 2016 has an interest rate of 2.1%, payable annually, and is due December 31, 2041.
25 The forecast 2017 and 2018 debt are assumed to have an interest rate of 2.15%.

26
27 **(b)**

28
29 Please see the response to YUB-YEC-1-1(b) for an explanation regarding the difference
30 between "Existing" and "Proposed" forecasts. The forecast debt required for 2017 is higher
31 under the "Proposed" forecast than the "Existing" forecast primarily due to a higher rate
32 base resulting from the addition of assets previously held in WIP per Order 2013-01. For
33 further details see the Summary of Requested Orders 1(d)(ii) and (iii), included in the
34 Application at pages 6-7.