YUB-YECL-1

Reference: YECL 2016-17 General Rate Application (Application), Section 2, Sales and Revenue

Issue/sub-issue: 2015 Actual sales and 2016 to 2017 Forecast sales

Quote:

	Actual			Test Period	
	2013	2014	2015	2016	2017
Residential	148,780	147,253	148,605	147,111	151,617
Commercial	159,322	154,709	155,346	152,187	153,336
Street Lights	3,719	3,765	3,886	3,944	4,008
Private Lights	551	544	519	492	472
Total Retail Primary	**312,372**	**306,272**	**308,356**	**303,735**	**309,433**
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total Company	**316,687**	**312,182**	**315,816**	**313,592**	**319,289**

Source: Application, Table 1, page 2-1

"ATCO Electric Yukon forecasts its total primary non-industrial sales in 2016 to decrease 1.5% and increase 1.9% in 2017."[1]

"Table 3 shows the 2015 annual average customer numbers and the associated energy sales by community and for residential and commercial classes in order of community customer's share."[2]

Request:

(a) Please explain why the Total AEY Energy (MWh), residential (149,653) and commercial (156,294) , shown in Table 3[3] of the application, does not coincide with the totals shown in Schedule 2.1 of YECL's GRA schedules workbook — respectively 148,605 and 155,346 for residential and commercial customers.

(b) Please explain why the total number of YECL customers (residential and commercial) shown in Table 3 does match the number of customers (average during the year) shown in Schedule 2.1; and the 2015 actual residential and commercial shown above do not match those shown in Table 3 of the application.

[1] Application, page 2-1, lines 6 to 7.
[2] Application, page 2-4, lines 9 to 12.
[3] Application, page 2-4.

(c) Please explain the factors contributing to the forecast decrease in sales in 2016 and the subsequent increase in sales for 2017. In the explanation, please provide details as to

a. What is contributing to the decrease in Commercial sales, which make up 68 percent of the decrease in total retail primary sales (4,622 MWh) in 2016.

b. What is contributing to the increase in Residential sales, which make up 79 percent of the increase in total retail primary sales (5,699 MWh) in 2017.

(d) Please explain why YECL's secondary and wholesale sales, respectively 9,429 and 427 MWh, are forecast to remain constant during the test period.

Response:

(a) As noted in footnote 2 of Table 3, the energy shown is based on billed energy, while the energy shown in Schedule 2.1 is based on earned energy. Earned energy is not available at the community level. For this reason, AEY prepares its forecast on a monthly billed basis by community and then it is converted to an earned forecast, which aligns with Schedule 2.1 in this Application. This approach is consistent with past applications.

(b) Table 1 and Schedule 2.1 are based on earned energy, while Table 3 is based on billed energy.

(c)

a. The factors contributing to the forecast decrease in 2016 include warmer than normal weather, a slow-down in economic and population growth, as well as the continuation of Yukon Government energy initiatives, such as the Commercial Energy Incentive Program and Micro-generation. Actual earned commercial sales for the first 6 months of 2016 are down from the same time period in 2015 by 2,359 MW.h.

b. The major factor contributing to the increase in Residential sales in 2017 is that normal weather is assumed in 2017, while three months of actual sales were included in the 2016 Residential sales forecast.

(d) Secondary and Wholesale sales are expected to remain constant during the test period based on the best information available at the time of the forecast.

YUB-YECL-2

Reference: Application, Introduction, pages 1-4 to 1-5.

Issue/sub-issue: Proposed "Board Orders or Legislative Provisions" deferral account

Quote: "ATCO Electric Yukon seeks the ability to flow-through (dollar for dollar) costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that ATCO Electric Yukon operates under, or that bear on the nature and extent of ATCO Electric Yukon's obligations as a regulated utility and which impact its 2016-2017 revenues or revenue requirement.

"ATCO Electric Yukon submits that this deferral account is required in light of the various initiatives currently being considered and implemented throughout the Yukon (for example – IPP Policy for Standard Offer Price). In addition, this deferral account would address any future Board orders or legislative provisions that impact ATCO Electric Yukon's ability to recover [its] prudently incurred costs and opportunity to earn a reasonable return (for example – any future tax or levy to address environmental emissions)."

Request:

(a) Please provide the purpose of and a full description of what the IPP Policy for Standard Offer Price is. Please indicate and give examples of how this policy has and will impact YECL and its rate payers during the test period.

(b) Please describe how the deferral account would work. Specifically address whether YECL, would come before the Board for permission to address certain shortfalls which may arise in future because of Board orders or legislative provisions?

(c) Have Board orders impacted YECL's revenue requirement set for a test year without a new subsequent proceeding? If so, please indicate which order(s) and describe how YECL was impacted.

(d) Have any legislative provisions impacted YECL's revenue requirement set for a test year without a new subsequent proceeding? If so, please indicate which legislative provision(s) and describe how YECL was impacted.

Response:

(a) The Yukon Independent Power Producer Policy is provided in response to YUB-YECL-72.

AEY is working with Yukon Energy, Yukon Development Corporation and Yukon Government to develop the process, rules and Agreements necessary to enable this policy which is targeted for October 2016. The interconnection standards and agreement templates will be filed for approval with the Yukon Utilities Board at an appropriate time.

It is not currently clear who will pay for the costs associated with the development of the policy, any purchase power costs paid to IPPs or any ongoing administrative costs associated with this policy. It is AEY's belief that any third party development costs incurred by AEY to assist in the implementation of this policy as well as any purchase power costs paid to IPPs that exceeds the cost of generation that would have been incurred absent the purchase power agreement should be funded from Yukon Government.

Should the Yukon Government implement this policy without funding these costs, AEY is requesting the proposed deferral account in order to collect these costs from customers in the future as no specific costs for this program have been included in this GRA.

(b) AEY is not requesting that this deferral account provide blanket ability to flow through of costs without seeking Board approval. Any balance(s) as a result of a Board order or legislative changes would be brought forward by AEY for consideration in AEY's next General Rate Application.

(c-d) As discussed in part (a) above, the IPP Policy is one example where there is significant uncertainty with respect to how the final policy will be implemented and what the resultant impacts for AEY will be. Other examples of Board Orders or Legislative changes that have historically impacted AEY include; the Micro Generation Policy and the Commercial Energy Incentive. While in some cases there has been stakeholder input and lead time, there is no guarantee that in the future stakeholder input and the appropriate lead time will be provided. For example, AEY would not expect stakeholder input or a significant lead time if the Government decided to impose a carbon tax or levy.

Programs such as the ones identified above, can impact AEY either through a variance related to sales or costs. AEY generally has no control over these policies or programs, has no way to forecast with certainty the impact related to these programs, and therefore, considers it appropriate to seek a deferral account to ensure the impact is appropriately flowed through to customers.

YUB-YECL-3

Reference: Application, Section 1, Introduction, page 1-6.

Issue/sub-issue: Staff Positions

Quote: "The following table provides the 2015 FTE's approved in the 2013-2015 GRA to the actual FTEs at the end of 2015 as well as the forecast FTEs at the end of the 2017 test period. As shown, ATCO Electric Yukon is forecasting no increase over the approved 2015 FTE's."

Preamble: The Board notes that YECL is proposing a new Engineering Technologist position for 2016.

Request:

(a) Please explain why there is a need for the new Engineering Technologist position for 2016.

(b) Please indicate which of the approved positions were vacant over the previous 2013-15 test period and why.

Response:

(a) The Engineering Technologist position is mechanical discipline based and is within AEY's approved complement. Generation capital projects in the 11 diesel power plants across the Yukon and the two hydro power stations of AEY's are constant and on-going. With the operation of these power plants, and responsibility to ensure diesel is consumed as efficiently as possible, AEY requires a mechanical technologist to ensure mechanical aspects of the power plant are maintained and to identify future improvements to the existing systems. AEY replaced the Environmental Technician position with this Engineering Technologist position.

(b) The chart below indicates the position title, year and reason for the vacancy. Each position was vacant for varying times based on variables of the recruitment process.

Position Title	Year	Vacancy Reason
Maintenance Man	2013	Retired
Draftsperson	2013	Transferred to new position
Engineering Assistant	2013	Transferred to new position
HS&E Coordinator & Planned Maintenance	2013	Deceased
Power Line Technician	2013	Transferred to new position
Power Line Technician	2013	Transferred to new position
Warehouseman	2013	Resigned
Customer Service Advisor	2014	Retired
Electrical Technologist	2014	Transferred to new position
Power Line Technician	2014	Transferred to new position
Power Line Technician	2015	Resigned
Executive Assistant	2015	Transferred to new position
Planning Supervisor	2015	Resigned
Environmental Technician	2015	Transferred to Mechanical Technologist
Construction Assistant	2015	Transferred to Engineer Assistant

YUB-YECL-4

Reference: **Application, Section 2, Sales and Revenue, pages 2-1 to 2-2.**

Issue/sub-issue: **Weather-normalized actuals**

Quote: "Table 1 below summarizes ATCO Electric Yukon's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013, 2014 and 2015 and 2015 updated weather-normalized actuals."

…

"Table 2 below provides ATCO Electric Yukon's total primary energy sales forecasts filed as part of the 2008-2009 GRA and the 2013-2015 GRA, along with the Board approved forecasts and compares them to the total actual weather-normalized sales."

Request:

(a) Table 1 does not provide 2015 updated weather-normalized actuals as suggested in line 5, page 2-1. Please provide the updated weather-normalized actuals.

(b) Please explain the difference between "actual weather-normalized sales" and "updated weather-normalized actuals." Please provide example calculations underpinning the data in Table 1 (updated weather-normalized actuals) and Table 2 (actual weather-normalized sales), for residential customers in 2015. Provide the calculations in an Excel workbook with formula intact.

(c) Please provide an explanation regarding the process that YECL uses to calculate the weather-normalized actual loads for 2015. Please provide accompanying calculations in a spreadsheet with formulae intact that aligns with the explanation.

Response:

(a) Table 1 below has been restated to include weather-normalized actuals for 2015.

Table 1
ATCO Electric Yukon Sales by Customer Class
(MWh)

	Actual			Normalized	Test Period	
	2013	2014	2015	2015	2016	2017
Residential	148,780	147,253	148,605	152,733	147,111	151,617
Commercial	159,322	154,709	155,346	157,521	152,187	153,336
Street Lights	3,719	3,765	3,886	3,886	3,944	4,008
Private Lights	551	544	519	519	492	472
Total Retail Primary	**312,372**	**306,272**	**308,356**	**314,658**	**303,735** [1]	**309,433**
Secondary Sales	3,959	5,415	7,030	7,030	9,429	9,429
Wholesale Sales	356	495	430	430	427	427
Total Company	**316,687**	**312,182**	**315,816**	**322,119**	**313,592**	**319,289**

Note:
1) 2016 Forecast includes 3 months of actuals for January, February & March.

(b) AEY did not intend to differentiate between "updated weather-normalized actuals" and "actual weather-normalized sales"; the two descriptions represent the same results. This is demonstrated by the fact that Table 1 (provided above) and Table 2 both show weather normalized actuals for Residential in the amount of 152,733 MWh.

(c) AEY utilizes a two-step process for determining weather-normalized use per customer (UPC). In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD). In the second step, the coefficient of the HDD from the regression is multiplied by the difference between the actual HDD and the "normal" HDD.

To demonstrate this process, AEY has used the City of Whitehorse as an example. Please refer to YUB-YECL-4(c) Attachment 1.

ATCO Electric Yukon
2016 - 2017 General Rate Application

Section 2
Attachment 1

Whitehorse (Includes Takhini & Deep Creek)

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,539.9		952.0	1,489.6	
Feb-13	1,152.3		665.4	1,264.1	
Mar-13	1,075.4		851.1	1,037.1	
Apr-13	1,092.7		639.9	1,021.6	
May-13	843.2		294.0	815.8	
Jun-13	743.9		112.4	766.3	
Jul-13	667.8		92.5	674.1	
Aug-13	643.5		98.9	671.7	
Sep-13	664.6		264.3	688.9	
Oct-13	762.8		501.4	759.1	
Nov-13	920.2		865.6	876.8	
Dec-13	1,161.1	11,267.6	1,144.7	1,055.0	11,119.9
Jan-14	1,467.1		745.8	1,551.5	
Feb-14	1,067.5		992.4	965.5	
Mar-14	1,217.3		855.1	1,176.4	
Apr-14	949.3		499.8	969.7	
May-14	838.2		269.5	826.9	
Jun-14	718.4		200.5	683.3	
Jul-14	687.6		98.0	690.3	
Aug-14	574.7		144.0	573.5	
Sep-14	738.8		307.1	735.0	
Oct-14	768.1		515.6	755.1	
Nov-14	901.6		772.8	918.9	
Dec-14	1,070.2	10,998.9	854.4	1,153.8	10,999.8
Jan-15	1,414.9		927.0	1,380.8	
Feb-15	1,235.3		851.4	1,225.5	
Mar-15	1,043.4		671.3	1,122.7	
Apr-15	952.6		453.5	1,003.3	
May-15	780.9		192.9	819.6	
Jun-15	647.9		127.2	660.6	
Jul-15	629.0		115.7	620.1	
Aug-15	606.6		183.2	579.7	
Sep-15	743.5		332.7	723.0	
Oct-15	786.2		469.8	803.0	
Nov-15	930.3		759.2	956.4	
Dec-15	1,105.8	10,876.2	947.9	1,128.3	11,023.0
Jan-16	1383.1		827.6	1,414.0	
Feb-16	1061.6		688.0	1,158.6	
Mar-16	1026.0		611.6	1,144.3	
Apr-16	999.0				
May-16	816.0				
Jun-16	657.7				
Jul-16	617.4				
Aug-16	577.2				
Sep-16	719.8				
Oct-16	799.5				
Nov-16	952.2				
Dec-16	1123.4	10,732.9			10,979.1
Jan-17	1407.9				
Feb-17	1153.5				
Mar-17	1139.3				
Apr-17	994.6				
May-17	812.4				
Jun-17	654.9				
Jul-17	614.7				
Aug-17	574.7				
Sep-17	716.7				
Oct-17	796.0				
Nov-17	948.1				
Dec-17	1118.5	10,931.1			10,931.1

Note: January, February and March 2016 have been updated to include actuals.

Step 1

Step 2

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.838195038
R Square	0.702570922
Adjusted R Square	0.693823008
Standard Error	140.2171904
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1579022.018	1579022.018	80.31296588	1.78734E-10
Residual	34	668469.2568	19660.86049		
Total	35	2247491.275			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	579.8341011	44.63470658	12.9906556	9.70538E-15	489.1254638	670.5427385	489.1254638	670.5427385
WH-HDD	0.653667162	0.072939677	8.961750157	1.78734E-10	0.505435904	0.80189842	0.505435904	0.80189842

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (11,023.0 / 11,119.9) ^ (1/2) - 1 = **-0.4%**

YUB-YECL-4 (c)

ATCO Electric Yukon utilizes a two-step approach for determining weather-normalized UPC.

Step 1:
The historical average UPC is regressed on actual monthly Heating Degrees Days (HDD).
(shown in blue)

Step 2:
The coefficient of HDD from the regression output is multiplied by the difference between the actual HDD and the "Normal" HDD.
(shown in green)

Section 2
Attachment 19

Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

YUB-YECL-5

Reference: Application, Section 2, Sales and Revenue, page 2-5, lines 2-11.

Issue/sub-issue: Weather-normalized use per customer (UPC) methodology

Quote: "For the purpose of the 2016-2017 sales forecast, ATCO Electric Yukon reviewed its two-step approach for determining weather-normalized use per customer (UPC). In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in the first step is multiplied by the difference between the actual HDD and the 'Normal' HDD. Upon review of this two-step approach, ATCO Electric Yukon has updated the time frames used in determining weather-normalized UPC as follows:

	Regression data for UPC (step 1)	"Normal" HDD (Step 2)
Prior Methodology	15 years	20 year average
Current Methodology	3 years	3 year average

"In addition to the updated time frames used for determining weather-normalized UPC, ATCO Electric Yukon has also applied the growth rates experienced over the period of 2013 to 2015 to derive the forecast UPC for the 2016 and 2017 test years."

Request:

(a) With respect to weather-normalizing UPC data, please indicate why a shorter time period (three years) is superior to using 15-year regression and 20-year normal HDD data.

(b) For the last 20 years, please provide actual annual average monthly UPC rates for each of the customer classes (residential and commercial) in the various communities of YECL's service territory.

(c) Please explain why different periods were used in steps one and two of the prior methodology; why wasn't historical average monthly UPC regressed on 20 years of actual monthly HDD, or alternatively why in the second step wasn't the coefficient of HDD determined in step one not multiplied by the difference from the actual HDD and the normal HDD for a period of 15 years?

Response:

(a) AEY submits that using the 2013 to 2015 time frame for weather normalizing is more appropriate as it encompasses the most recent year's data immediately proceeding the test period. The 3 year time frame also incorporates recent weather trends. Please refer to AEY's response to YUB-YECL-7.

(b) Please refer to YUB-YECL-5(b) Attachment 1 for Residential UPC.

Please refer to YUB-YECL-5(b) Attachment 2 for Commercial UPC.

(c) In the prior method, Step 1 and Step 2 could have been based on 15 years of data for the regression analysis and 15 years of data for Normal HDD. However, Step 1 and Step 2, performed based on 20 years of data for the regression analysis and 20 years of data for Normal HDD, was not possible due to the lack of monthly billed data, by community, being readily available beyond 15 years.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Whitehorse (Includes Takhini & Deep Creek)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1,478	1,635	1,332	1,382	1,263	1,183	1,221	1,200	1,245	1,276
February	1,581	1,197	1,070	1,163	1,035	937	1,012	994	1,092	1,106
March	1,221	1,063	1,027	1,040	917	986	996	984	923	921
April	1,029	998	901	943	853	867	988	891	948	904
May	877	835	786	811	845	815	797	789	751	733
June	760	747	695	754	730	762	706	748	710	704
July	677	643	627	646	655	656	642	657	667	659
August	643	613	604	610	619	597	647	617	606	621
September	741	679	705	697	733	660	679	709	669	741
October	856	800	780	763	786	753	757	726	761	732
November	1,092	945	922	881	883	903	872	910	897	920
December	1,222	954	970	993	940	1,055	897	1,072	1,014	965
Annual	**12,177**	**11,109**	**10,418**	**10,680**	**10,260**	**10,175**	**10,215**	**10,296**	**10,281**	**10,283**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1,194	1,244	1,296	1,525	1,343	1,434	1,355	1,540	1,467	1,415
February	1,043	1,049	1,184	1,120	1,010	1,127	1,169	1,152	1,067	1,235
March	1,070	1,137	1,009	1,091	938	1,254	1,096	1,075	1,217	1,043
April	932	984	940	943	943	953	929	1,093	949	953
May	800	734	787	771	793	891	833	843	838	781
June	725	718	695	702	717	742	768	744	718	648
July	703	701	679	701	684	676	707	668	688	629
August	634	596	700	626	626	647	676	643	575	607
September	735	688	699	718	719	736	694	665	739	743
October	793	753	731	770	820	830	801	763	768	786
November	937	921	983	951	902	942	1,010	920	902	930
December	1,129	993	1,009	1,010	1,055	1,135	1,261	1,161	1,070	1,106
Annual	**10,695**	**10,519**	**10,712**	**10,928**	**10,550**	**11,367**	**11,299**	**11,268**	**10,999**	**10,876**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Carmacks

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1477	1644	1347	1435	1393	976	1219	1067	1229	1479
February	1333	1182	915	997	908	930	1166	944	943	1034
March	927	874	851	878	833	1078	942	886	928	842
April	798	840	789	933	818	775	853	897	949	955
May	693	849	794	735	808	690	812	751	639	666
June	702	604	547	593	726	698	552	556	552	684
July	577	618	607	714	616	567	580	679	656	550
August	651	670	705	571	625	566	712	595	501	593
September	658	663	668	734	855	744	638	715	788	761
October	797	783	892	849	809	726	896	850	803	775
November	1149	953	848	919	887	999	783	924	861	950
December	956	914	981	944	1095	885	999	1240	950	919
Annual	**10717**	**10595**	**9944**	**10301**	**10373**	**9634**	**10153**	**10103**	**9799**	**10208**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1402	1554	1322	1569	1623	1619	1703	1551	1708	1265
February	980	1055	1749	1236	1029	1315	1191	1104	1211	1129
March	1263	1221	1140	1113	1035	1227	1450	1129	1053	1179
April	805	858	873	996	1023	914	690	1262	921	879
May	689	657	830	612	800	880	804	857	897	772
June	698	728	710	572	566	598	756	569	589	515
July	641	590	522	667	717	678	564	627	550	662
August	515	648	687	598	673	694	759	697	735	563
September	742	655	753	822	738	843	659	614	622	768
October	750	763	825	813	867	836	801	984	944	926
November	1006	1083	1162	1007	964	1103	1382	948	961	1084
December	1108	919	1092	1085	1075	1062	1290	1004	1431	1385
Annual	**10599**	**10731**	**11665**	**11091**	**11111**	**11768**	**12050**	**11345**	**11620**	**11127**

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Carcross

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	957	1044	795	838	558	636	818	744	795	860
February	1084	801	785	728	695	556	636	625	716	760
March	853	696	698	693	577	674	642	609	593	642
April	677	694	607	607	588	532	651	612	590	604
May	660	564	583	609	526	511	568	560	569	506
June	549	554	473	501	488	506	462	482	439	433
July	473	473	428	489	448	412	434	473	486	451
August	444	429	437	412	391	428	446	422	395	398
September	549	454	460	435	500	410	446	460	394	470
October	534	472	499	541	455	448	474	437	488	524
November	659	669	571	527	503	540	567	584	571	558
December	741	627	585	791	631	612	552	662	638	655
Annual	**8180**	**7477**	**6922**	**7170**	**6360**	**6264**	**6695**	**6671**	**6675**	**6862**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	842	831	824	909	951	1038	852	1110	1035	990
February	737	810	961	893	925	874	1020	931	784	874
March	649	792	727	825	741	930	712	771	915	859
April	691	732	687	764	676	796	685	793	796	695
May	518	555	615	696	650	587	622	742	717	680
June	591	529	493	517	530	560	543	553	487	475
July	443	459	457	497	481	457	485	459	517	405
August	462	465	507	441	459	439	511	450	437	479
September	480	451	453	474	454	517	520	450	465	447
October	497	499	496	561	576	532	521	486	548	603
November	612	229	623	617	633	616	704	660	629	593
December	811	680	725	746	692	839	819	755	709	783
Annual	**7334**	**7031**	**7568**	**7941**	**7768**	**8185**	**7994**	**8158**	**8041**	**7884**

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Haines Junction

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1042	1151	984	1022	919	948	966	925	873	866
February	1012	813	757	837	768	741	752	708	767	799
March	786	721	737	759	696	687	737	661	635	620
April	734	721	667	734	654	632	772	649	672	687
May	644	659	641	605	647	668	629	596	551	568
June	606	621	571	616	634	650	600	586	506	531
July	553	571	589	589	589	568	567	545	582	562
August	572	549	505	539	566	570	566	515	490	495
September	605	599	599	589	625	569	600	565	574	646
October	627	598	659	651	645	633	639	547	567	573
November	795	758	689	712	695	719	776	668	650	687
December	881	743	706	771	705	848	625	773	765	705
Annual	**8856**	**8504**	**8105**	**8425**	**8142**	**8233**	**8229**	**7738**	**7632**	**7738**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	877	1088	913	1022	962	1000	928	991	1024	975
February	787	792	847	731	715	754	822	851	734	911
March	738	795	844	789	713	773	730	776	845	632
April	635	713	671	640	610	659	656	729	636	724
May	620	541	564	683	616	666	548	620	627	494
June	565	629	522	548	578	541	599	633	523	513
July	599	479	604	535	518	536	538	553	520	524
August	531	493	527	508	489	467	430	387	494	462
September	581	611	587	532	550	516	560	554	556	585
October	514	554	520	578	572	601	571	551	542	548
November	757	690	669	738	681	682	670	623	602	650
December	659	746	757	701	710	736	905	820	825	869
Annual	**7862**	**8133**	**8023**	**8005**	**7713**	**7928**	**7958**	**8088**	**7928**	**7889**

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Teslin

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	802	1002	815	837	837	638	639	721	832	925
February	844	653	583	604	564	570	720	547	643	615
March	596	556	544	659	492	629	538	531	440	535
April	538	566	579	587	545	537	539	434	575	545
May	501	547	446	458	474	475	584	565	432	480
June	518	462	411	510	514	515	420	427	450	416
July	453	417	499	509	419	453	428	480	511	466
August	538	516	443	411	423	424	486	428	405	430
September	457	418	458	463	547	490	416	464	531	522
October	482	564	540	524	487	473	533	516	503	459
November	686	538	554	512	590	581	529	536	529	553
December	717	609	624	548	566	640	570	623	576	577
Annual	**7131**	**6847**	**6497**	**6621**	**6457**	**6427**	**6401**	**6270**	**6428**	**6524**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	816	822	883	1033	891	858	956	818	800	897
February	600	591	943	916	641	654	676	795	664	698
March	739	737	541	505	608	823	733	617	636	579
April	511	530	546	543	651	555	578	641	539	606
May	502	617	563	603	491	617	511	477	558	460
June	523	522	417	418	460	456	501	540	409	438
July	442	444	425	513	532	511	424	422	394	490
August	419	465	531	427	387	434	390	471	477	415
September	540	500	477	440	526	532	504	435	461	491
October	477	550	601	562	544	532	496	493	561	621
November	546	645	566	570	618	599	744	666	586	611
December	682	589	641	659	785	711	776	733	710	685
Annual	**6797**	**7011**	**7134**	**7188**	**7135**	**7283**	**7290**	**7108**	**6797**	**6990**

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Ross River

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1136	1260	1059	956	963	824	823	845	884	999
February	953	867	803	799	778	680	854	718	769	829
March	777	765	783	707	679	847	657	630	640	633
April	787	695	636	703	788	594	665	550	685	688
May	591	538	528	576	515	580	615	561	499	513
June	546	505	502	505	650	560	448	431	453	435
July	538	507	553	582	467	468	428	457	487	489
August	461	446	451	472	475	431	512	387	415	457
September	600	558	560	471	628	511	415	403	539	584
October	620	639	567	640	600	561	494	473	500	496
November	729	683	592	647	616	735	663	675	568	593
December	891	646	841	724	854	730	622	727	715	736
Annual	**8630**	**8109**	**7875**	**7780**	**8011**	**7520**	**7193**	**6856**	**7154**	**7453**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	961	779	844	1266	1055	1095	1092	1112	1098	1159
February	801	714	1085	802	771	955	980	1052	995	1035
March	697	963	692	806	661	955	973	835	926	893
April	730	682	608	684	750	886	711	806	683	774
May	557	505	652	678	552	652	586	627	717	562
June	533	527	495	570	527	541	641	618	508	454
July	426	422	506	596	564	562	503	460	427	493
August	394	469	527	539	481	499	526	642	586	442
September	522	445	571	432	604	623	507	331	532	518
October	525	563	557	702	586	597	560	580	741	681
November	689	733	809	620	657	643	905	872	788	727
December	892	703	767	851	957	965	985	897	935	750
Annual	**7725**	**7504**	**8115**	**8544**	**8165**	**8973**	**8969**	**8834**	**8936**	**8488**

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Pelly Crossing

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1109	1154	1087	1203	1247	999	1108	871	1004	1184
February	857	856	895	868	839	826	1065	804	823	909
March	756	766	698	786	812	905	774	769	781	731
April	740	786	735	874	900	691	749	728	883	848
May	631	657	713	652	692	684	768	770	643	639
June	581	638	522	572	715	647	532	581	675	703
July	597	517	524	645	585	576	551	644	593	533
August	573	528	585	564	613	502	689	595	559	593
September	689	656	614	671	788	713	661	655	654	749
October	669	697	783	855	749	673	692	784	809	658
November	867	768	716	780	943	927	698	782	861	769
December	908	736	892	833	704	860	868	1062	724	817
Annual	**8977**	**8759**	**8761**	**9302**	**9585**	**9004**	**9155**	**9045**	**9008**	**9135**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1147	1169	1142	1350	973	1251	1316	1185	1580	1147
February	759	872	1287	1030	825	924	898	1017	1192	1016
March	966	1033	958	1006	777	905	1081	907	969	954
April	678	693	576	692	825	760	598	1040	869	883
May	665	722	810	716	681	765	702	877	822	562
June	667	657	608	547	551	545	799	564	627	593
July	559	451	440	606	752	643	444	607	624	635
August	510	729	623	535	520	594	650	657	637	562
September	731	579	568	619	692	714	633	667	748	677
October	681	684	736	841	694	678	724	906	920	830
November	848	929	807	864	774	890	1162	940	911	942
December	915	733	884	924	836	942	1136	944	1264	1288
Annual	**9127**	**9250**	**9441**	**9729**	**8900**	**9611**	**10145**	**10310**	**11162**	**10090**

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Old Crow

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	819	897	875	759	903	720	654	784	792	901
February	584	643	636	605	652	592	716	655	655	687
March	532	641	681	597	772	658	541	621	668	691
April	602	648	495	686	472	607	525	591	591	738
May	449	480	543	459	573	574	537	559	555	537
June	374	477	480	442	604	456	394	457	478	455
July	491	460	211	535	427	434	435	505	485	500
August	398	505	585	449	432	399	508	409	445	481
September	618	587	490	440	467	495	417	464	390	469
October	253	463	563	648	612	429	462	432	546	581
November	567	572	515	582	505	551	635	528	589	555
December	649	633	631	649	673	542	557	639	624	647
Annual	**6336**	**7005**	**6706**	**6850**	**7092**	**6456**	**6380**	**6644**	**6819**	**7241**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	856	755	695	861	816	1044	787	820	986	957
February	731	664	795	643	685	765	731	900	706	790
March	645	763	587	645	634	685	835	726	813	862
April	720	652	572	649	751	877	662	676	708	770
May	589	509	550	594	485	686	567	607	706	538
June	512	547	560	494	442	459	589	630	494	443
July	438	442	400	520	506	549	435	427	622	499
August	422	393	533	408	414	454	587	473	419	437
September	562	530	448	426	472	524	344	494	359	551
October	463	464	409	592	596	508	499	615	608	533
November	469	647	634	637	568	574	646	685	663	616
December	743	627	561	586	638	812	785	728	766	668
Annual	**7152**	**6992**	**6743**	**7057**	**7006**	**7936**	**7467**	**7781**	**7848**	**7663**

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Destruction Bay

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	701	722	659	557	660	460	653	650	554	674
February	641	641	486	538	430	425	544	460	589	513
March	504	281	519	528	460	478	535	510	545	456
April	508	457	426	454	425	417	603	427	525	466
May	408	428	407	372	459	480	465	418	424	439
June	424	397	391	393	440	500	415	457	419	417
July	399	407	391	444	461	431	475	420	388	341
August	482	358	376	361	422	408	428	405	435	421
September	454	475	419	428	418	465	474	498	402	415
October	442	413	435	443	464	468	500	432	383	421
November	487	495	468	487	495	492	570	551	489	488
December	505	490	381	458	597	585	502	642	461	513
Annual	**5954**	**5563**	**5360**	**5463**	**5730**	**5608**	**6162**	**5869**	**5615**	**5565**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	691	836	727	748	832	748	831	869	938	910
February	583	609	562	631	601	732	685	724	728	718
March	587	655	614	592	517	656	693	639	795	593
April	511	618	583	616	616	625	506	675	608	589
May	521	585	524	471	517	486	455	512	551	479
June	403	468	516	430	422	449	551	496	463	416
July	409	512	412	447	440	404	436	505	506	476
August	450	265	437	374	303	400	459	460	327	375
September	445	428	417	453	451	475	446	483	513	539
October	451	465	387	444	494	507	486	528	368	478
November	591	559	557	562	589	523	575	563	571	643
December	646	557	552	566	591	729	799	769	627	768
Annual	**6288**	**6557**	**6288**	**6334**	**6373**	**6735**	**6921**	**7224**	**6995**	**6983**

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Beaver Creek

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1181	1125	1145	927	817	856	922	1052	1057	1000
February	770	782	879	743	789	692	793	754	855	929
March	857	728	511	736	677	637	744	669	803	742
April	678	649	673	668	597	617	840	712	868	691
May	782	576	539	531	619	594	577	594	573	572
June	520	535	498	552	523	552	515	537	535	604
July	577	531	570	546	554	511	529	553	601	528
August	862	615	553	438	504	598	521	559	518	525
September	594	541	489	585	598	652	537	590	622	591
October	471	752	681	604	639	683	655	579	610	637
November	1165	702	795	711	671	743	668	852	715	714
December	924	1019	790	920	734	763	653	838	1006	800
Annual	**9380**	**8555**	**8124**	**7961**	**7722**	**7898**	**7953**	**8290**	**8765**	**8333**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1005	1061	947	946	1096	1133	1100	1137	1076	1167
February	976	841	997	925	876	867	902	1006	1007	774
March	988	1042	718	834	816	866	862	843	662	716
April	708	827	731	741	743	724	668	777	538	743
May	586	615	636	584	694	612	645	656	727	597
June	603	687	607	499	564	533	658	713	567	554
July	488	563	564	610	612	604	560	524	530	534
August	532	582	644	589	630	606	608	602	572	545
September	631	541	532	591	568	595	596	615	588	668
October	616	682	617	692	662	674	716	672	612	519
November	692	755	772	787	678	886	873	893	816	833
December	926	792	1012	846	787	1049	1057	792	839	762
Annual	**8750**	**8987**	**8776**	**8643**	**8726**	**9149**	**9246**	**9230**	**8535**	**8413**

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Tagish

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	549	603	569	537	454	344	420	438	426	532
February	656	382	391	424	337	359	352	353	378	428
March	394	368	360	375	325	303	321	336	340	325
April	345	335	335	373	308	284	315	314	360	316
May	327	306	295	292	299	273	283	282	281	272
June	266	261	270	271	263	241	248	256	250	252
July	293	272	307	306	276	257	272	288	291	286
August	312	292	284	281	300	279	291	270	257	300
September	310	275	300	295	275	262	253	277	317	276
October	365	350	341	288	270	275	299	244	305	312
November	404	324	349	313	291	324	317	263	336	346
December	525	358	378	374	368	439	369	377	375	412
Annual	**4746**	**4127**	**4177**	**4127**	**3765**	**3641**	**3741**	**3698**	**3917**	**4059**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	550	596	529	689	631	731	701	716	607	579
February	436	549	605	557	512	521	507	487	594	537
March	454	455	413	491	425	548	505	502	549	381
April	381	358	341	426	424	393	346	392	375	384
May	327	332	290	292	351	365	352	350	310	303
June	262	297	281	271	281	286	348	335	308	278
July	320	286	269	323	317	324	315	278	295	322
August	277	298	320	281	311	318	344	358	314	288
September	308	297	293	304	336	343	334	259	310	329
October	326	341	317	385	415	362	414	345	340	403
November	425	471	490	451	417	517	513	497	422	460
December	526	510	512	513	537	494	638	593	561	524
Annual	**4591**	**4790**	**4660**	**4982**	**4957**	**5202**	**5318**	**5112**	**4986**	**4789**

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Marsh Lake

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	815	1187	923	907	829	715	806	773	807	869
February	1224	697	720	812	666	674	645	611	657	755
March	694	669	633	661	578	609	628	601	618	605
April	602	662	589	615	569	561	659	602	624	524
May	510	500	494	514	525	554	506	460	482	521
June	418	422	439	473	430	445	445	450	494	452
July	462	494	487	461	452	481	446	466	457	473
August	454	404	467	429	494	438	465	456	461	477
September	497	475	554	511	502	453	463	522	524	513
October	666	653	561	517	581	572	560	492	544	534
November	837	639	656	589	591	643	576	697	635	699
December	992	791	887	824	788	911	745	823	835	774
Annual	**8173**	**7592**	**7409**	**7314**	**7004**	**7054**	**6943**	**6953**	**7138**	**7197**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	849	895	975	1065	987	1273	1122	1031	1034	989
February	796	875	956	919	811	916	981	1020	981	1013
March	758	718	728	852	738	937	814	885	882	702
April	582	589	658	766	708	777	632	823	786	754
May	549	496	526	501	561	606	635	651	505	528
June	462	474	487	494	473	517	527	532	501	452
July	466	480	471	503	525	490	509	489	511	529
August	508	513	556	472	498	558	583	575	486	475
September	527	497	518	559	622	584	558	452	538	655
October	582	644	594	612	671	658	702	717	669	624
November	880	796	845	772	762	874	950	890	762	857
December	885	900	1074	1004	991	1081	1294	1144	1120	1103
Annual	**7843**	**7878**	**8387**	**8517**	**8348**	**9272**	**9309**	**9209**	**8775**	**8682**

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Lower Post

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	985	1036	1059	934	921	975	904	884	847	1013
February	769	754	791	773	844	692	725	664	806	610
March	801	683	740	711	688	683	724	665	709	633
April	696	725	661	678	664	658	759	730	671	619
May	581	566	554	598	638	578	593	648	507	581
June	512	545	504	540	526	536	540	475	562	445
July	550	573	460	479	543	506	468	489	514	494
August	503	495	481	499	520	496	543	497	480	449
September	576	588	570	580	545	537	532	534	510	509
October	538	568	600	577	617	598	576	536	567	621
November	783	736	790	710	681	671	670	684	783	648
December	812	723	788	698	757	732	686	725	802	743
Annual	**8106**	**7991**	**7999**	**7778**	**7944**	**7661**	**7721**	**7530**	**7758**	**7364**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	943	1105	1144	1345	1239	1299	1187	1365	1343	1116
February	910	909	992	1013	900	859	899	761	1005	825
March	827	920	792	960	770	1011	888	1157	1039	816
April	715	950	927	836	905	723	712	982	914	538
May	584	681	649	642	721	681	693	363	752	544
June	617	544	584	535	557	613	487	698	548	431
July	548	589	565	631	515	542	589	432	584	530
August	557	534	618	560	516	590	593	685	486	476
September	563	571	579	676	587	762	363	334	546	611
October	675	691	748	691	653	652	629	647	640	652
November	837	797	827	788	767	689	780	633	631	672
December	906	858	852	955	982	901	937	1121	938	829
Annual	**8682**	**9151**	**9277**	**9631**	**9111**	**9321**	**8755**	**9179**	**9426**	**8039**

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Upper Liard

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	956	985	998	908	873	771	745	814	1029	943
February	771	735	653	683	701	587	715	653	705	625
March	770	600	552	609	555	620	525	619	635	567
April	650	591	564	622	606	487	580	619	613	633
May	547	527	517	502	547	499	554	552	505	481
June	650	485	449	477	475	482	418	477	452	441
July	336	452	459	467	465	434	451	477	487	466
August	458	460	494	480	485	453	463	494	447	517
September	500	498	506	482	534	452	453	512	523	585
October	539	572	555	494	538	507	556	499	570	619
November	748	664	687	740	592	636	655	741	618	693
December	750	597	695	473	674	694	587	735	638	790
Annual	**7675**	**7165**	**7128**	**6936**	**7046**	**6620**	**6701**	**7191**	**7222**	**7359**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	954	954	1026	1149	1037	987	997	1277	1095	1018
February	819	732	874	789	743	727	694	856	766	881
March	786	818	661	857	772	859	721	778	826	745
April	715	704	750	627	646	604	623	763	823	835
May	545	524	447	697	534	695	582	677	597	664
June	515	487	491	553	568	499	517	566	527	476
July	500	495	540	481	496	465	464	518	530	559
August	455	438	524	522	501	527	527	596	521	528
September	480	507	565	530	532	548	531	560	604	661
October	614	539	623	574	654	602	696	652	592	672
November	691	667	626	701	640	656	748	619	679	773
December	853	745	731	866	747	726	921	941	926	733
Annual	**7927**	**7608**	**7857**	**8345**	**7871**	**7896**	**8019**	**8802**	**8487**	**8545**

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Watson Lake

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1147	1191	1054	984	1139	932	967	948	972	1053
February	955	901	768	788	894	813	817	770	807	807
March	794	726	702	744	654	727	725	704	750	746
April	720	706	707	715	703	677	741	774	746	714
May	651	655	564	631	635	652	642	603	588	627
June	562	567	527	547	558	564	544	556	605	584
July	545	545	524	526	547	538	542	563	574	551
August	581	556	538	547	589	555	610	549	565	565
September	616	592	579	625	603	547	558	609	646	690
October	688	672	664	628	664	652	682	649	650	626
November	880	781	748	766	758	793	762	795	779	735
December	946	831	871	797	971	901	828	968	897	895
Annual	**9084**	**8721**	**8248**	**8299**	**8714**	**8349**	**8419**	**8489**	**8581**	**8594**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	918	972	1123	1141	1093	1148	1124	1132	1047	1085
February	911	965	1032	942	861	886	935	913	898	892
March	916	879	835	866	781	972	866	876	947	820
April	726	751	764	811	759	828	779	807	774	729
May	646	690	686	661	648	682	710	737	703	645
June	578	605	567	571	582	614	645	665	598	537
July	587	563	591	601	571	547	589	595	591	553
August	578	577	597	541	529	566	572	587	529	522
September	639	586	592	622	610	642	564	539	572	626
October	664	652	660	665	736	668	690	650	683	681
November	843	843	841	781	745	795	773	763	737	803
December	983	805	931	965	912	925	1002	1019	1019	952
Annual	**8989**	**8890**	**9220**	**9168**	**8827**	**9273**	**9250**	**9282**	**9099**	**8844**

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Keno City

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	437	484	385	360	271	276	220	256	260	246
February	363	371	459	301	237	237	191	204	214	251
March	321	355	240	274	230	288	173	185	193	130
April	253	371	289	329	200	258	200	177	188	115
May	269	277	254	219	257	274	231	139	188	112
June	278	267	244	208	257	188	210	157	168	120
July	290	263	214	289	251	291	236	169	157	142
August	292	278	299	310	295	205	265	168	174	203
September	348	301	300	338	283	243	240	187	222	218
October	369	341	364	370	367	253	250	167	158	156
November	432	285	315	409	283	236	221	200	275	197
December	330	311	245	271	244	263	220	240	191	195
Annual	**3981**	**3904**	**3609**	**3677**	**3175**	**3011**	**2656**	**2248**	**2386**	**2085**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	309	302	261	660	397	588	359	524	489	604
February	214	248	308	295	332	432	406	373	450	291
March	297	313	234	569	417	609	467	472	396	438
April	208	233	304	323	344	342	397	563	419	120
May	166	183	213	247	368	342	382	328	288	352
June	118	160	145	178	128	229	293	279	342	120
July	147	189	173	187	185	336	199	360	304	386
August	188	218	276	180	201	140	221	197	288	264
September	224	252	419	251	427	343	332	280	518	388
October	283	327	398	295	446	447	458	359	541	377
November	327	274	413	360	572	472	566	433	409	400
December	337	223	577	384	575	641	481	406	505	531
Annual	**2816**	**2922**	**3720**	**3928**	**4390**	**4921**	**4561**	**4575**	**4948**	**4271**

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Stewart Crossing

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	696	487	570	1043	881	589	606	1072	1042	1210
February	521	431	418	719	432	469	674	853	683	891
March	496	417	376	511	422	660	482	783	705	716
April	393	423	297	510	474	394	532	761	835	900
May	494	456	388	419	337	536	647	694	641	599
June	445	380	275	373	348	284	483	535	652	711
July	430	346	351	437	335	303	469	701	730	617
August	441	327	348	351	337	310	569	534	598	664
September	492	391	344	460	496	486	504	632	606	732
October	564	375	403	365	462	449	668	726	837	682
November	622	568	455	473	690	749	634	709	850	720
December	720	523	587	493	505	606	842	951	663	830
Annual	**6312**	**5123**	**4811**	**6154**	**5718**	**5837**	**7110**	**8950**	**8842**	**9271**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1086	1227	1086	1134	1036	1153	1281	1108	1056	801
February	948	1030	873	978	667	847	776	899	811	825
March	991	1291	898	672	700	846	850	769	589	787
April	633	693	422	842	663	791	432	810	610	683
May	632	610	548	543	603	880	570	817	535	852
June	831	625	533	491	413	343	626	455	509	66
July	561	541	300	630	493	718	467	514	532	562
August	817	636	641	618	446	524	604	672	445	499
September	941	630	467	642	545	603	443	523	521	528
October	822	626	707	621	312	558	516	645	627	667
November	889	783	624	682	786	671	1003	613	624	679
December	1078	578	724	712	817	807	1002	996	888	966
Annual	**10229**	**9270**	**7824**	**8566**	**7481**	**8741**	**8568**	**8821**	**7747**	**7915**

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Swift River

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1602	2186	1148	975	1438	1345	1300	1562	1503	1431
February	1256	1455	1391	2270	1334	1052	1052	1150	1325	1177
March	1326	1261	1251	1261	1228	1105	1170	1183	660	892
April	1164	803	1104	970	1005	1138	1142	1727	1103	992
May	942	1296	946	1263	1067	995	1029	1079	915	659
June	892	633	861	830	910	853	811	940	965	1585
July	817	837	626	897	840	910	879	713	938	905
August	820	814	1008	817	980	1009	1054	995	936	933
September	920	831	1095	990	858	997	1014	979	971	894
October	989	787	935	1008	1045	1231	1040	1004	1083	1051
November	879	1127	1137	1168	1111	1093	1075	1087	1215	1142
December	2205	963	932	1040	1285	1126	1034	1380	1083	1240
Annual	**13812**	**12992**	**12433**	**13488**	**13100**	**12855**	**12599**	**13800**	**12697**	**12900**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1113	1830	1439	1812	1015	1613	1426	1465	1227	1126
February	1596	1564	1381	1290	860	1036	1154	865	1873	787
March	1870	1426	1053	1636	810	1044	1031	852	1230	725
April	1352	1210	1539	1408	780	1854	1014	907	1108	577
May	1413	1262	667	1376	464	751	435	1412	797	636
June	979	1116	711	1203	310	565	435	791	741	554
July	871	1492	798	1128	123	531	744	809	568	545
August	912	640	712	1108	525	655	774	816	841	531
September	1007	879	792	1143	567	641	804	670	438	657
October	1077	979	852	820	452	833	672	718	612	587
November	1236	1180	1002	820	1050	1138	1031	1216	712	748
December	1498	1136	1205	833	1557	1126	893	1680	963	871
Annual	**14923**	**14714**	**12150**	**14578**	**8511**	**11784**	**10410**	**12198**	**11107**	**8342**

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Whitehorse (Includes Takhini & Deep Creek)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	6774	7165	6506	6310	6270	6239	6625	6118	6328	6542
February	6462	5940	5634	5781	5618	5373	5647	5470	5885	5832
March	6062	5576	5694	5635	5373	5575	5652	5558	5719	5576
April	5546	5688	5163	5329	5136	5255	5820	5635	5676	5447
May	4953	4806	4586	4618	4909	4873	4987	4796	4919	5222
June	4888	4895	4653	4950	5034	5066	4977	5193	5256	4916
July	4792	4859	5010	4691	5237	4856	4831	4872	5382	5069
August	4754	4649	4582	4812	4598	4688	5114	4827	5193	5038
September	4820	4727	4955	4775	4689	4700	4691	4978	4967	5105
October	5085	5013	4829	4766	5075	4776	4776	4909	4899	5019
November	5831	5401	5339	5699	5163	5161	5342	5710	5548	5822
December	6002	5303	5396	5409	5333	6068	5249	6031	5925	5693
Annual	**65970**	**64022**	**62347**	**62775**	**62435**	**62628**	**63711**	**64097**	**65697**	**65280**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	6640	6812	6894	7566	6869	7313	7284	7404	6892	7066
February	5770	6293	6596	5988	5789	5883	6083	5904	5789	5952
March	6392	6661	5836	6293	5691	6634	5987	6003	6027	5707
April	5955	6027	6119	5845	5849	5635	5943	6196	5572	5419
May	4757	5031	4992	5027	5063	5375	5347	4952	4907	4730
June	5281	5125	5006	4869	5070	5021	5059	5025	4699	4398
July	5282	5513	4786	5332	4881	4931	4952	5024	4873	4704
August	5004	4946	5496	5040	4922	4863	4804	5111	4366	4255
September	5003	5034	4956	4763	4998	5016	4622	4619	4901	4777
October	5292	4986	4954	4917	5084	5220	5238	5004	4560	4616
November	5713	5808	6090	5669	5769	5620	5609	5388	5617	5305
December	6170	5860	5795	5607	5898	6053	6391	5956	5643	5574
Annual	**67259**	**68097**	**67519**	**66915**	**65884**	**67563**	**67320**	**66586**	**63846**	**62503**

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Carmacks

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	3232	3335	3407	3818	2576	2317	2778	2656	2815	3055
February	3037	2502	2603	2790	1962	2170	2970	2428	2378	2284
March	2484	2189	2540	2278	2114	2304	2407	2333	2373	2177
April	2145	2312	2255	2284	1919	1909	2316	2281	2535	2473
May	1820	2044	2273	1873	2228	2235	2402	2074	1803	1947
June	2115	1965	1816	1859	1965	2188	1788	1712	1831	2139
July	1854	1983	2206	2249	1674	2070	1941	2134	2141	1763
August	1804	2104	2399	1932	1846	1828	2351	1779	1684	2439
September	1887	2001	2081	2041	1999	2237	1918	2062	2113	1810
October	1921	2245	2420	1892	1940	1994	2398	2294	2349	2205
November	2567	2816	2300	3404	2117	2718	2078	2281	2088	1771
December	2140	2806	2499	1228	2708	2127	2534	2843	2717	2240
Annual	**27006**	**28304**	**28800**	**27648**	**25047**	**26096**	**27882**	**26876**	**26828**	**26303**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2840	3095	3458	3021	3849	3538	3195	3098	3849	3134
February	2589	5505	3262	2726	2602	2867	2725	2705	2848	2469
March	2996	3876	2727	1863	2513	3065	3298	2896	2696	2822
April	1785	2434	2375	1911	2260	2154	2591	3144	2504	2867
May	2053	1855	2329	2694	2164	2893	2287	2753	2604	2250
June	2082	2549	2198	2617	3008	1972	2503	1823	2348	2315
July	1797	1926	1670	2135	2134	2332	2135	2222	2033	2840
August	1763	2285	2138	2002	1082	2202	2474	2270	2373	2106
September	2131	2065	2067	2072	1472	2686	2079	2044	2314	2720
October	2230	2116	2493	2286	3870	2472	2649	2627	2732	2812
November	2589	2869	2511	2230	2831	2984	2820	2770	2403	2940
December	2971	2409	2595	2262	2637	2762	2629	2576	3276	3157
Annual	**27826**	**32984**	**29824**	**27819**	**30423**	**31927**	**31385**	**30930**	**31979**	**32431**

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Carcross

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2512	2389	1930	2035	1847	2095	2345	1634	1907	1878
February	2558	2135	2007	2051	1830	1898	2024	1508	1809	1710
March	2209	1922	1853	1901	1752	2175	1893	1589	1612	1797
April	1912	1893	1605	1650	1615	1585	1785	1432	1899	1433
May	1853	1461	1630	1465	1429	1376	1516	1273	1526	1264
June	1979	2082	1652	1656	1750	1855	1703	1697	1475	1503
July	1874	1962	1701	1659	1631	1489	1659	1743	1938	1718
August	1731	1859	1718	1552	1499	1578	1751	1679	1582	1325
September	2082	1819	1663	1590	1694	1508	1582	1751	1515	1636
October	1746	1614	1572	1491	1432	1477	1455	1377	1608	1455
November	1925	2259	1795	1556	1539	1712	1300	1616	1489	1523
December	1880	1681	1769	1863	1772	2094	1368	1776	1561	1516
Annual	**24261**	**23075**	**20898**	**20467**	**19793**	**20841**	**20381**	**19075**	**19920**	**18756**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1774	1913	1972	2156	1952	2676	1634	2055	1975	1883
February	1577	2140	2178	2119	2022	1873	2191	1954	1602	1683
March	1517	2088	1737	1862	1739	2630	1753	1526	1852	1733
April	1611	2033	1681	1830	1662	1775	1482	1641	1574	1346
May	1294	1332	1550	2093	1342	1484	1456	1772	1465	1529
June	1821	1589	1522	1422	1444	1659	1410	1796	1459	1314
July	1587	1851	1573	1671	1503	1388	1434	1413	1504	1343
August	1663	1763	1731	1485	1426	1406	1330	1476	1527	1524
September	1820	1794	1505	1555	1761	1584	1223	1306	1276	1391
October	1797	1437	1284	1715	1452	1351	1229	1247	1614	1566
November	1381	1558	1460	1324	1827	1457	1424	1345	1320	1311
December	1923	1827	1837	1708	1984	2071	1601	1414	1379	1647
Annual	**19764**	**21325**	**20030**	**20939**	**20114**	**21355**	**18167**	**18944**	**18546**	**18269**

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Haines Junction

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2862	3157	3007	2664	2786	2827	2928	2981	2722	2477
February	2895	2720	2433	2497	2525	2654	2521	2572	2478	2387
March	2615	2585	2562	2441	2555	2329	2418	2471	2201	1899
April	2645	2243	2207	2420	2308	2154	2358	2235	2373	2293
May	2250	2212	1916	1978	2137	2207	2208	1981	1851	1844
June	2103	2136	1978	2181	2408	2365	2129	2215	1856	1924
July	2267	2340	2202	2058	2321	2258	2311	2417	2508	2126
August	2276	2122	2035	2182	2274	2216	2336	2320	2109	1950
September	1838	2013	2109	2245	2174	1963	2005	2206	2131	2161
October	1812	2044	2096	2124	2234	2146	2341	2082	1973	1910
November	2479	2802	2450	2568	2375	2424	2598	2303	2105	2246
December	2429	2445	2236	2585	2430	2565	2298	2343	2340	2240
Annual	**28472**	**28820**	**27230**	**27943**	**28527**	**28107**	**28451**	**28125**	**26647**	**25456**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2486	2625	2686	2849	2784	3045	2709	3192	3196	3111
February	2365	2319	2431	2219	2108	2506	2990	2742	2654	3051
March	2375	2287	2400	2745	2359	2764	2634	2611	3070	2359
April	2028	2342	2180	2095	2230	2355	2764	2527	2393	2821
May	1961	1767	1732	2045	2099	2134	1771	2124	2261	2046
June	2060	2292	2141	1977	2141	1996	2627	2506	2158	2121
July	2271	1880	1932	2156	1956	2065	2436	2332	2258	2371
August	1886	1916	2013	2045	1856	1923	1886	1818	2183	2222
September	2104	2271	1909	1831	1982	2054	2426	2386	2302	2374
October	1837	1718	1813	1959	1912	2280	1888	2083	2082	2129
November	2058	2149	2145	2437	2448	2428	2476	2144	2067	2328
December	2262	2334	2587	2242	2282	2812	2738	2972	3084	2982
Annual	**25692**	**25901**	**25969**	**26599**	**26158**	**28363**	**29344**	**29438**	**29708**	**29914**

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Teslin

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2030	2356	2598	2545	2490	1941	1954	2592	2535	2529
February	1902	1968	1961	2176	2115	2108	2472	2227	2055	1878
March	1641	1690	1770	2094	1741	2230	1963	2089	2114	1861
April	1557	1648	1681	1765	2033	1626	1780	1829	1960	1718
May	1258	1592	1405	1364	1274	1426	1740	1716	1444	1569
June	1596	1436	1399	1552	1726	1785	1516	1571	1646	1676
July	1446	1400	1705	1621	1346	1493	1665	1683	1938	1857
August	1729	1588	1451	1394	1419	1502	1786	1412	1585	1616
September	1320	1322	1322	1386	1537	1501	1438	1733	1696	1975
October	1152	1711	1642	1480	1369	1418	1487	1337	1550	1594
November	1756	1538	1752	1781	1858	1988	1933	1769	1905	2105
December	1810	1683	2012	1836	1970	1920	2087	2276	1852	2038
Annual	**19199**	**19933**	**20697**	**20994**	**20881**	**20938**	**21821**	**22234**	**22281**	**22415**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2804	3211	3336	3427	3377	3234	3171	2936	3041	3083
February	2284	3049	3330	3388	3158	2530	2498	3121	2563	2490
March	2590	3285	2238	2858	2908	3011	2836	2460	2530	2522
April	1942	2446	1881	2591	2790	2176	2333	2295	2098	2005
May	1720	1637	2172	2054	1718	2127	1695	1700	2127	1879
June	2048	2051	1552	1594	1725	1635	1959	2023	1657	1680
July	1719	1629	1685	1917	1762	2015	1718	1598	1672	1895
August	1790	1452	1923	1724	1562	1662	1593	1832	1923	1641
September	1999	1857	1604	1777	2153	1950	1947	1632	1642	1852
October	1876	1732	1775	2271	1695	1844	1825	1594	2159	2130
November	2462	3035	2697	2665	2184	2364	2939	2758	2408	2256
December	2641	2369	2807	2701	3048	2499	2984	2797	2729	2690
Annual	**25874**	**27755**	**27002**	**28967**	**28079**	**27045**	**27497**	**26746**	**26550**	**26122**

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Ross River

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2538	2945	3069	2576	2522	2602	2619	2836	2864	3019
February	2373	2195	2375	2458	2566	2448	3017	2712	2463	2519
March	2097	2227	2564	2377	2167	2862	2539	2495	2343	2225
April	2055	2234	2107	2207	2458	2130	2473	2145	2571	2507
May	1667	1655	1561	1830	1568	2252	2292	2250	1914	1845
June	1522	1470	1514	1478	2215	2016	1875	1900	1819	1658
July	1568	1408	1656	1713	1534	1711	1742	1862	2060	1952
August	1429	1351	1407	1348	1509	1637	1986	1714	1767	1712
September	1898	1728	1747	1811	1934	1879	1670	1663	1741	1930
October	1724	1759	1916	1301	1934	1953	1969	1741	1881	1596
November	2090	2253	1913	1872	2005	2590	2557	2540	1976	1898
December	2253	2062	2636	2276	2663	2517	2260	2348	2566	2445
Annual	**23215**	**23287**	**24466**	**23249**	**25076**	**26596**	**26999**	**26206**	**25965**	**25305**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2708	2301	2483	3053	2993	2974	3734	2516	3380	3214
February	2171	2206	3194	2048	2409	2538	2701	3270	2160	2846
March	2524	2840	2438	2592	2502	2331	2976	2455	2962	2570
April	2415	2334	2115	2201	2507	2422	2161	2640	2720	2938
May	1947	1809	2316	1957	1770	1780	2015	2290	2362	2531
June	1886	1947	1757	1678	1893	1674	2067	2319	2019	1761
July	1555	1619	1548	1631	1925	1836	1770	1924	1901	1489
August	1438	2210	1824	1935	1861	1723	1953	2301	2364	1847
September	1892	1086	1844	1097	1796	1779	1722	1599	1574	1959
October	1934	1928	2042	2178	1946	1743	2062	1854	2267	2465
November	2027	2353	2101	1916	2103	1901	2602	2684	2842	2265
December	2742	2158	2725	2619	2682	1993	2545	2245	2629	2766
Annual	**25239**	**24791**	**26388**	**24904**	**26387**	**24695**	**28309**	**28097**	**29179**	**28651**

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Pelly Crossing

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2922	2356	2544	2861	1871	2838	2830	2564	2676	3521
February	2328	2007	2318	2388	2245	2532	3264	2473	2888	2902
March	1987	1830	2001	1940	1931	2963	2496	2705	2654	2480
April	1838	1768	2114	1889	2081	1971	2345	2639	2703	2773
May	1470	1400	2032	1626	1497	1989	2329	2336	2070	1994
June	1338	1339	1305	1466	1616	2161	1822	1800	2300	2299
July	1462	1227	1553	1616	1510	1457	1335	2121	2167	1765
August	163	889	1415	729	1585	1441	1907	2174	1816	1816
September	1631	1481	1601	1921	2177	1952	1617	2128	2462	2200
October	1596	1623	1962	1320	2099	1898	2054	2383	2509	2020
November	2015	2055	1727	1586	2858	2663	2093	2288	2491	2527
December	2083	2075	2028	2388	2094	2137	2462	2936	2762	2697
Annual	**20832**	**20048**	**22599**	**21732**	**23564**	**26001**	**26553**	**28548**	**29498**	**28994**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2533	3776	3131	2949	3641	4468	4226	3754	4283	3237
February	3058	2743	3729	2262	2837	3478	3159	3099	3335	3137
March	3186	3240	2821	3840	2807	3674	3632	3472	3029	2860
April	2286	2481	2044	2940	2912	3201	2854	3530	2753	3287
May	2164	2244	2502	4370	2397	3487	2587	3228	2665	2546
June	2351	2305	2021	2278	2344	2316	2875	2232	2326	2349
July	1905	1643	1497	2391	2439	2685	2142	2382	2328	2811
August	1537	2246	2016	1898	2193	2341	2423	2620	2104	2235
September	2287	2279	2176	2503	2522	2833	2357	2289	2435	2672
October	2246	2005	2990	2531	3115	2516	2737	3367	3153	2956
November	2691	2910	2723	2924	4462	3328	4274	2891	2926	2782
December	2673	2063	2463	2663	2097	2942	3143	2376	3934	3262
Annual	**28917**	**29935**	**30113**	**33549**	**33766**	**37270**	**36410**	**35238**	**35270**	**34135**

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Old Crow

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2651	2576	1512	1651	2031	1899	1901	2198	2048	2392
February	2214	1749	1683	1582	1619	1835	2240	1998	1868	1983
March	1858	1644	2012	1824	1769	2126	1871	1998	2062	2152
April	2124	1975	1388	2076	1819	1878	1644	1887	1868	2261
May	1803	1338	1474	1430	1641	1669	1843	1880	1980	1750
June	1168	1291	1098	1352	1661	1840	1352	1556	1655	1588
July	1311	1167	245	1473	1248	1278	1311	1485	1455	1481
August	1085	1199	1202	993	1317	1170	1516	1285	1246	1302
September	2021	1280	921	1185	1302	1594	1551	1339	1230	1200
October	930	1285	1211	1621	1776	1363	1511	1460	1918	1819
November	2006	1622	1441	1400	1563	1738	2004	1827	1769	1901
December	2211	2244	1799	1538	2120	1796	1780	1885	1797	2096
Annual	**21383**	**19370**	**15985**	**18125**	**19863**	**20186**	**20523**	**20797**	**20897**	**21924**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2609	1939	1863	2457	2357	2186	2046	2212	2444	2553
February	2111	1860	2292	1824	1855	1997	1844	2682	1886	1857
March	1971	2235	1867	2146	1862	1828	2411	1743	2353	2045
April	2177	1911	1695	2057	2299	1837	2014	1927	1980	2003
May	1747	1703	1789	1873	1536	1817	1628	1789	2080	1573
June	1758	1804	1715	1461	1553	1552	1808	1923	1461	1418
July	1281	1531	1188	1835	1360	1540	1276	1523	2128	1734
August	1250	1330	1664	1305	1188	1379	1738	1476	1128	1307
September	1717	1490	1338	1276	1184	1535	1259	1783	1278	1863
October	1496	1513	1290	1911	1490	1481	1622	1501	1715	1331
November	1552	2031	2155	1740	1651	1721	1591	1804	1814	1731
December	2104	1839	1969	1973	1700	2068	2717	2056	1688	2196
Annual	**21774**	**21187**	**20823**	**21858**	**20034**	**20940**	**21954**	**22418**	**21954**	**21610**

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Destruction Bay

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1534	1738	1621	1824	2075	1691	1762	1667	1592	1506
February	1359	1297	1470	1734	1401	1473	1482	1430	1564	1255
March	1296	1297	1594	1775	1488	1422	1484	1560	1468	1263
April	1353	1293	1296	1480	1364	1239	2263	1985	1544	1912
May	1052	1144	1077	1392	1433	1411	1948	2051	1070	1323
June	1277	1143	1435	1499	1416	1519	1761	2106	1458	1181
July	1132	1436	1320	1809	1625	1339	2116	1878	1692	1251
August	1407	1239	1581	1441	1526	1298	2019	1713	1829	1580
September	1330	1567	1471	1467	1563	1606	2366	1529	2083	1310
October	1163	1230	1281	1325	1394	1721	2413	1355	2062	1223
November	1280	1404	1573	1492	1500	1413	2288	1551	1434	1359
December	1339	1199	1394	1706	1499	1480	1361	1619	1555	1557
Annual	**15520**	**15988**	**17112**	**18943**	**18285**	**17612**	**23262**	**20443**	**19352**	**16720**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1749	1892	2017	2135	1964	1919	2395	2272	1896	2007
February	1430	1670	1766	1995	1501	1601	1743	1947	1608	1900
March	1568	1782	1749	1437	1409	1675	1803	1559	1649	1473
April	1382	1713	1659	1828	1659	1712	1513	1760	1443	1718
May	1495	1108	1431	1092	1179	1551	1237	1302	1425	1287
June	1146	1469	1692	1318	1292	1307	1312	1462	1196	1212
July	1329	1294	1344	1321	1347	1162	1196	1407	1309	1423
August	1544	1358	1637	1251	1246	1208	1429	1334	1379	1097
September	2439	1464	1501	1357	1455	1431	1569	1428	1477	1659
October	265	1399	1250	1127	1234	1270	1406	1102	1181	1054
November	1834	1582	1715	1353	1332	1424	1500	1470	1513	1594
December	1981	1665	1666	1446	1498	1638	1701	1691	1665	1866
Annual	**18161**	**18394**	**19427**	**17660**	**17116**	**17897**	**18806**	**18733**	**17743**	**18291**

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Beaver Creek

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	2446	2505	2339	2658	1502	2157	2259	2783	2684	2746
February	1852	1900	2098	1837	2145	1857	2202	2254	2309	2524
March	1707	1643	1672	2090	1908	1905	2033	1997	2217	1344
April	1260	1716	1787	1658	857	1573	2144	1867	2064	1742
May	2002	2320	1488	1424	1955	1976	1808	1880	1617	1582
June	2436	1997	2474	2676	2302	2330	2207	2228	2297	2361
July	2579	2514	2207	2823	2625	2563	2505	2702	2538	2407
August	3072	2372	2113	1843	2422	2563	2470	2464	2474	2518
September	2645	2313	2530	2288	2601	2064	1826	2053	2326	2449
October	1592	1639	1610	1521	1751	1464	1561	1537	1845	1626
November	2294	1620	2094	1839	1829	1841	1932	2167	2196	2179
December	2371	2045	2030	3008	2031	2161	1620	2326	2600	2235
Annual	**26257**	**24585**	**24443**	**25665**	**23928**	**24454**	**24567**	**26258**	**27168**	**25715**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2485	2613	2031	2448	2554	2702	2310	2415	2960	2624
February	2315	2225	3031	2099	2127	1952	1957	2188	2208	1745
March	3194	2630	864	2017	2009	2243	2018	1908	1882	2396
April	1114	1750	1538	1783	1743	1653	1459	1494	1807	1797
May	1577	1569	2240	1510	1797	2328	1573	1913	1554	1784
June	2225	2504	1506	1825	2117	1892	2350	1802	1837	1564
July	2211	2453	2241	2530	2416	2223	2063	2976	1738	1991
August	2416	2483	2602	2098	2367	2360	2314	2522	1717	1764
September	2174	1446	1805	2029	1749	2110	1725	2157	2433	2158
October	1560	1895	1432	2240	1814	1809	1566	1902	2189	1673
November	1840	1965	1979	946	1818	1790	1933	1704	2204	2013
December	2493	2025	2024	1883	1839	2109	2044	1733	2085	1985
Annual	**25604**	**25557**	**23293**	**23409**	**24349**	**25171**	**23313**	**24715**	**24615**	**23495**

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Tagish

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1382	1509	939	1133	1387	1299	1144	1402	830	1466
February	890	1171	1213	810	1086	1352	1723	1082	1020	809
March	881	1188	1001	1284	1456	1208	1344	1072	1335	1131
April	759	1105	809	926	706	990	1334	1090	1117	994
May	727	981	788	684	677	519	711	513	316	426
June	739	797	753	831	809	960	698	663	800	614
July	774	826	810	954	820	876	677	515	589	645
August	735	910	551	765	856	919	694	903	594	622
September	731	808	1009	576	763	733	344	369	652	706
October	720	705	792	931	569	713	870	943	563	684
November	729	656	776	1017	601	1000	859	903	345	982
December	1157	809	916	1047	1447	1203	1043	1229	647	1055
Annual	**10224**	**11465**	**10356**	**10959**	**11178**	**11772**	**11442**	**10684**	**8807**	**10134**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1354	1493	1148	1116	1312	1306	1400	1248	1768	2339
February	1094	994	1658	1269	877	1067	722	1047	1171	1559
March	946	1121	1116	1003	1192	1058	1107	1001	1149	545
April	676	1245	1057	1050	1088	1242	874	930	1085	1214
May	1487	890	920	810	930	1286	694	618	1711	931
June	588	341	593	695	757	693	661	756	874	649
July	644	636	621	775	683	591	787	716	808	674
August	505	643	731	732	635	587	669	768	786	563
September	578	680	578	721	621	556	578	608	777	798
October	531	594	831	724	830	638	659	653	713	1244
November	759	1063	1034	891	903	698	948	904	952	1360
December	1107	1344	1078	1050	1041	1090	936	964	1029	1385
Annual	**10269**	**11042**	**11363**	**10837**	**10869**	**10813**	**10036**	**10213**	**12823**	**13261**

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Marsh Lake

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1429	2651	1458	1518	1162	1120	1098	1186	975	824
February	2203	2162	1348	929	1436	997	840	874	991	811
March	1933	2137	1083	698	1464	973	887	1077	1011	857
April	1984	2455	417	776	1161	722	928	851	992	633
May	1500	1488	371	417	791	629	495	556	628	632
June	1556	1386	350	400	763	557	447	626	891	668
July	1348	1613	439	368	915	610	506	681	701	631
August	2234	1408	388	398	913	535	598	708	677	599
September	1550	1225	441	519	823	529	539	758	677	659
October	1757	1294	521	838	714	486	496	580	584	554
November	2392	1703	506	1185	698	625	575	915	714	844
December	2716	1929	1559	1774	930	924	1052	1225	850	1035
Annual	**22601**	**21451**	**8880**	**9820**	**11768**	**8708**	**8461**	**10036**	**9694**	**8746**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1043	1029	1244	1393	1132	1737	1503	1285	1566	1323
February	1098	1496	1263	1156	912	1255	1578	1825	1375	1198
March	1029	890	1151	1623	989	1633	1325	1311	1386	1134
April	789	795	1098	486	915	1620	1195	1357	1506	1243
May	606	752	784	736	846	1026	1301	1218	1125	968
June	767	678	827	700	659	981	920	1017	910	813
July	635	697	757	804	931	812	854	820	969	827
August	852	803	910	757	906	846	976	886	896	767
September	787	788	719	856	602	946	877	876	1079	1175
October	531	757	803	811	1665	921	1015	1106	1080	964
November	881	1174	1184	925	1300	1204	1416	1144	1343	1092
December	870	1166	1430	1215	1431	1582	1570	1417	1706	1375
Annual	**9887**	**11026**	**12171**	**11461**	**12287**	**14562**	**14531**	**14261**	**14940**	**12877**

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Lower Post

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1821	1952	2571	2380	2351	2757	2931	2702	2783	2197
February	1669	1388	2149	2362	2343	2324	2462	2573	2545	1650
March	1668	1934	1845	2059	1744	2216	2454	2407	2110	1809
April	1703	1366	1167	1365	1526	1851	2128	2255	1818	2013
May	1157	798	973	1093	1189	1246	1544	1326	1145	1383
June	996	671	840	1146	959	1052	1113	996	1089	981
July	869	794	592	724	707	855	892	1086	873	1023
August	917	705	1084	616	821	1046	735	902	832	994
September	1071	396	527	907	959	823	903	1027	1100	1157
October	494	804	1145	1173	1293	1058	988	1128	1016	1176
November	1430	1609	1661	1747	2086	1888	1500	1657	1461	1777
December	1589	1666	2347	2075	2214	2409	2027	2759	1516	1738
Annual	**15384**	**14083**	**16901**	**17645**	**18192**	**19527**	**19678**	**20819**	**18288**	**17897**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	2105	1807	1722	1877	2142	1948	2413	2641	2146	2434
February	4406	1656	1703	1614	1759	1556	2073	1772	1729	2011
March	2739	1602	1586	1549	1686	1936	1898	1762	1930	1781
April	1859	1670	1617	1385	1477	1336	1650	1883	1482	1837
May	1312	1373	1395	1063	981	1067	1412	1269	1344	1509
June	1244	1070	894	942	909	1185	1313	1257	1135	978
July	1055	1182	701	971	805	822	1180	1342	1169	1050
August	1026	975	665	844	701	976	1147	1380	1018	810
September	1079	1051	714	1041	761	1107	1119	878	994	1285
October	1145	1243	965	1105	956	1376	1478	1378	1146	864
November	1528	1373	1264	1362	2208	1773	1623	1375	1160	1658
December	1401	1495	1542	1771	1919	1927	2189	1787	2014	1889
Annual	**20897**	**16494**	**14767**	**15524**	**16304**	**17009**	**19495**	**18724**	**17267**	**18104**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Upper Liard

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1663	1388	1405	1591	1781	1374	1219	1617	1101	1533
February	1300	1172	1190	1082	1334	1033	1142	1022	985	1206
March	1369	996	923	1136	1217	1316	1088	1055	812	903
April	1126	790	742	1174	1192	856	949	963	896	1244
May	884	800	975	1129	949	813	697	754	772	906
June	1274	1156	1243	1407	1262	1416	1108	1045	990	1067
July	1315	1291	1454	1515	1551	1523	1316	1190	1466	1395
August	1334	1289	1536	1785	1574	1646	1513	2072	1276	1490
September	1255	1321	1330	1489	1616	1565	1168	294	1393	1650
October	1053	1366	1346	1310	1395	1366	1171	1246	1427	1563
November	1049	1389	1497	1644	1342	1509	1382	1352	1157	1531
December	1043	970	1253	1431	1316	1425	1386	1101	1017	1204
Annual	**14665**	**13928**	**14893**	**16694**	**16530**	**15844**	**14140**	**13712**	**13291**	**15693**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1784	1633	2017	2331	1973	1723	2074	2580	1908	1242
February	1406	1295	2120	1921	1653	1348	1524	1868	1041	1043
March	1522	1392	1443	1957	1650	1579	1464	1806	1347	879
April	1434	1348	1599	1767	1669	1110	1412	1878	1531	1043
May	850	832	936	791	914	1025	1029	1385	1260	1227
June	1101	1143	954	1182	1124	985	1174	1123	967	1090
July	1084	1345	1209	1133	1091	1087	1284	1324	1167	1411
August	981	1128	1189	1444	1189	1305	1208	1260	1012	1477
September	1113	1223	1298	1134	261	1017	1144	1045	1062	1455
October	1338	1041	1081	1380	2329	1153	1205	1052	1021	1323
November	1323	1395	1334	1953	1460	1595	1334	1256	1324	1199
December	1670	1507	1452	1714	1494	1623	2300	2312	1396	916
Annual	**15606**	**15283**	**16633**	**18708**	**16807**	**15549**	**17153**	**18889**	**15035**	**14305**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Watson Lake

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	3699	3488	3555	3403	4040	3785	3549	4163	3691	3929
February	3389	3231	3072	2905	3598	3290	3427	2446	3651	3398
March	3245	2799	2923	2635	2946	3324	3161	3209	3350	3262
April	2679	2726	2738	2891	3048	3634	3156	2973	3288	3013
May	2367	2371	2356	2610	2891	1831	2764	2678	2473	2618
June	2679	2643	2597	2734	3001	3001	2917	2737	2967	2700
July	2706	2647	2515	2894	3105	2791	3892	2856	3113	3226
August	2460	2863	2495	2894	3002	2796	2024	2564	2884	2689
September	2568	2271	2453	2682	2936	2557	2654	2893	2892	3248
October	2460	2612	2550	2477	2863	2912	3145	2834	3024	2979
November	3026	2846	2960	2763	3115	3164	3372	3389	3311	3296
December	3130	2836	2833	2940	3253	3464	3407	3659	3511	3442
Annual	**34409**	**33333**	**33047**	**33828**	**37797**	**36549**	**37469**	**36401**	**38154**	**37800**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	4411	3759	3448	3715	3893	3831	4100	4155	4238	4362
February	2831	3605	3580	3260	3665	3149	3359	3610	3597	3655
March	3183	3537	3297	3182	3349	3520	3554	3777	3855	3474
April	2987	3328	3024	3068	3235	2987	3162	3507	3428	3298
May	2640	2751	2807	2767	2478	2658	2952	3010	3394	3179
June	2828	3026	2578	2534	2373	2448	2789	2795	2668	2518
July	2875	2820	2785	2795	2634	2387	2421	2586	3015	2967
August	2644	2724	2886	2654	2474	1931	2689	2720	2812	2802
September	2803	2354	2328	2493	2559	2475	3054	2415	2721	2907
October	2916	2608	2584	2994	3119	2655	1832	2679	2920	2903
November	3443	3308	3268	3874	3013	3100	3536	3091	3198	3591
December	3396	3270	3211	2691	3302	3373	3811	3627	3987	3736
Annual	**36957**	**37092**	**35798**	**36027**	**36094**	**34514**	**37258**	**37972**	**39833**	**39393**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Keno City

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1244	2120	1214	2140	2146	2024	1462	1322	1975	1862
February	1114	1820	1943	1147	1666	1473	1178	1796	1715	664
March	1291	1790	1606	1670	1424	1369	599	1808	1632	2699
April	1232	1927	1829	1751	1484	1322	737	1850	1944	1749
May	892	779	471	313	885	1115	667	1296	1341	970
June	531	547	420	474	501	294	506	358	538	322
July	691	647	475	555	511	628	692	500	418	324
August	667	685	520	594	562	165	429	474	464	367
September	709	640	527	575	498	472	384	589	592	647
October	689	857	614	484	604	309	315	693	829	504
November	1242	805	1283	873	545	499	712	1019	1035	981
December	1650	750	1569	686	620	1392	668	1452	983	1353
Annual	**11951**	**13367**	**12472**	**11263**	**11445**	**11061**	**8348**	**13158**	**13467**	**12442**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1909	2267	1752	1217	813	1080	2039	1447	802	758
February	1521	1705	1740	903	623	836	1093	1029	892	867
March	1708	1873	1350	926	1755	870	1290	1315	787	722
April	1668	1765	884	1145	1125	1203	1082	1260	747	627
May	1421	1522	535	914	350	1229	682	618	528	650
June	389	414	442	652	521	1098	844	509	566	203
July	401	374	493	315	501	676	120	731	620	493
August	371	469	522	580	482	1572	430	596	387	554
September	390	365	490	524	616	466	480	631	746	509
October	797	709	414	552	539	1625	445	68	476	548
November	646	1071	654	682	717	954	669	623	675	1001
December	2208	1351	677	641	772	691	600	670	758	711
Annual	**13428**	**13887**	**9954**	**9050**	**8814**	**12300**	**9773**	**9496**	**7985**	**7641**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Stewart Crossing

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	3,204	2,030	1,932	2,241	3,073	2,402	2,601	2,217	2,078	2,700
February	3,137	1,789	1,756	1,671	1,773	1,845	2,769	1,901	2,730	1,782
March	2,857	1,503	1,429	1,548	2,012	2,155	2,597	1,722	2,027	1,992
April	1,737	1,382	1,469	1,509	2,188	1,081	2,272	1,939	1,682	1,904
May	2,741	1,169	2,579	1,610	1,073	1,311	2,162	1,511	1,596	1,289
June	1,565	3,962	852	1,066	478	1,720	1,580	1,280	1,933	1,352
July	1,273	1,036	1,092	1,500	1,330	1,283	1,251	1,511	959	1,177
August	1,529	955	773	1,140	1,323	1,142	1,634	1,222	1,310	1,227
September	1,553	1,008	1,200	1,575	1,545	1,600	1,199	1,453	1,929	1,513
October	1,587	960	1,272	998	1,362	1,483	1,621	1,807	1,095	1,225
November	2,081	1,374	1,431	1,397	1,986	2,616	1,459	1,966	1,903	1,729
December	1,757	1,310	1,229	1,909	1,755	2,243	1,858	2,878	2,112	2,071
Annual	**25,021**	**18,479**	**17,015**	**18,164**	**19,897**	**20,881**	**23,003**	**21,406**	**21,355**	**19,961**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	3,847	2,638	2,416	3,346	2,536	2,320	2,434	2,107	3,117	2,015
February	2,681	1,917	3,207	2,575	2,055	2,010	1,880	2,070	1,938	2,493
March	2,752	2,942	2,056	1,998	1,772	2,202	3,110	2,884	1,862	2,050
April	1,727	1,673	1,189	1,669	1,732	1,575	696	1,929	1,584	1,641
May	845	1,491	1,789	1,329	1,570	1,541	1,641	1,761	1,523	1,652
June	1,436	1,441	1,427	1,203	1,079	1,148	1,699	1,496	1,098	856
July	1,344	1,351	936	1,444	1,241	1,125	1,277	1,264	1,367	1,343
August	1,079	1,456	1,396	1,265	1,286	1,147	1,153	1,622	794	849
September	1,641	1,710	1,042	1,161	1,411	1,305	1,053	1,200	1,102	1,262
October	1,450	998	1,462	1,270	2,427	1,149	1,370	1,588	1,630	1,339
November	2,212	2,051	1,828	1,370	1,736	1,537	2,359	1,494	1,808	1,531
December	2,409	1,422	2,054	1,642	2,079	2,022	1,838	1,641	2,140	1,728
Annual	**23,423**	**21,089**	**20,802**	**20,273**	**20,924**	**19,080**	**20,510**	**21,056**	**19,962**	**18,759**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Historical UPC (KWh)

Swift River

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
January	1,679	1,745	1,942	1,357	1,658	1,818	2,013	2,180	1,942	1,989
February	1,638	1,309	1,461	1,779	1,443	1,479	1,652	1,850	1,570	1,540
March	1,271	1,291	1,278	1,528	1,681	1,598	1,809	1,877	1,773	1,426
April	1,266	949	1,111	957	1,131	1,493	1,573	1,735	1,405	1,518
May	1,147	1,597	1,052	1,349	1,269	1,355	1,687	1,205	876	1,003
June	1,084	800	907	828	811	1,033	977	1,022	878	843
July	1,111	819	627	972	847	1,001	1,068	810	888	832
August	1,076	742	952	828	987	973	994	1,107	913	880
September	1,378	904	1,049	910	995	961	1,020	1,093	979	884
October	1,115	995	1,043	1,102	1,204	1,309	1,174	1,071	1,226	1,193
November	1,296	1,273	1,347	1,518	1,421	1,682	1,533	1,580	1,584	1,479
December	1,372	1,301	1,090	1,325	1,543	1,743	1,670	1,742	1,889	1,636
Annual	**15,431**	**13,724**	**13,860**	**14,454**	**14,989**	**16,444**	**17,170**	**17,271**	**15,922**	**15,224**

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	1,705	1,874	2,024	1,957	1,695	1,629	1,678	1,442	1,507	1,555
February	1,765	1,668	1,688	1,659	1,335	1,259	1,260	1,139	1,359	1,543
March	1,744	1,446	1,446	1,863	1,129	1,495	1,216	1,204	1,276	1,160
April	1,284	1,517	1,543	1,342	995	1,140	1,170	1,110	1,277	1,159
May	1,131	1,312	1,216	1,088	985	774	915	877	873	1,037
June	874	806	980	893	396	668	913	798	905	707
July	926	1,053	992	1,038	428	624	741	765	821	694
August	902	1,052	1,057	960	593	770	926	780	1,021	654
September	863	696	960	942	859	699	719	849	830	847
October	1,021	1,318	1,013	863	821	1,025	1,058	966	1,042	900
November	1,372	1,625	1,628	1,399	1,400	1,186	1,237	1,223	1,312	1,341
December	1,711	1,651	1,610	1,283	1,321	1,248	1,317	1,575	1,438	1,416
Annual	**15,296**	**16,019**	**16,157**	**15,286**	**11,957**	**12,517**	**13,150**	**12,727**	**13,659**	**13,012**

YUB-YECL-6

Reference: Application, Section 2, Sales and Revenue, page 2-3, lines 23 - 27; page 2-5, lines 12 - 19.

Issue/sub-issue: Effects of initiatives on electricity sales

Quote: "Additionally, ATCO Electric Yukon's Demand Side Management (DSM) program, as well as Yukon Government energy initiatives, such as the Commercial Energy Incentive Program and Micro-generation were introduced in the Yukon over the last few years and have all contributed to lower electricity sales in 2013, 2014, and 2015."

…

"It is ATCO Electric Yukon's view that using the 2013 to 2015 time frame for weather normalizing and forecasting UPC is more appropriate as it encompasses recent trends occurring in the Yukon over the last few years. For example, over the past few years, in addition to changes in electric heating, there has been an increase in energy efficiency programs in the Yukon such as Demand Side Management and the Commercial Energy Incentive program. These trends, combined with a decline in economic activity and increasing effects of global warming have contributed to an overall downward trend in UPC over the 2013-2015 time period."

Preamble: The Board requires further information.

Request:

(a) Please provide a description of the following Yukon government energy initiatives:

a. Commercial Energy Incentive program – please provide an in-depth description of this program and an analysis regarding how it has affected electricity usage in the past and the effects on YECL's test period sales forecast.

b. Micro generation – please provide an in-depth description of this program and examples of micro generation that have arisen as a result of the program and its effects on YECL sales. Additionally, please provide analysis which illustrates how micro generation is expected to impact YECL over the test period, i.e. the quantum of new micro generation and the resultant loss of sales?

(b) Describe the changes in electric heating over the past decade that are affecting YECL's forecast load for the test period. Are the changes in electric heating affecting new developments only?

(c) Please provide an explanation and analysis as to how the demand side management (DSM) in the Yukon has influenced YECL's load since its last GRA and clarify YEC's projections regarding the 2016 to 2017 test period.

(d) YECL states that load increases are driven by load densification and the move towards electric heat in new buildings.[4] With the expectation of increased load due to electric heating, is there any potential for load decreases due to programs/initiatives to offset by the increased heating loads in the test period? Please explain.

(e) Please provide an analysis of how the effects of global warming have contributed to an overall downward trend in UPC (use per customer) throughout the Yukon over the 2013 to 2015 time period and whether the effects are expected to continue during the test period.

(f) Please provide UPCs for residential and commercial UPC for YECL communities throughout the Yukon for the period from 1995 to 2015 (20 years).

Response:

(a) The Yukon Government energy incentive programs are designed to reduce energy consumption through a conservation program or through small scale self-generation. AEY is unable to quantify the precise impact to the sales forecast or uptake of the programs as these are government run programs and implementation is completely at the discretion of customers.

a. The Commercial Energy Incentive Program (CEIP) promotes energy efficiency upgrades for businesses and multi-family dwellings. The program runs for 2 years and ends March 31, 2017. The program includes LED lighting upgrades and thermal enclosure upgrades. Please refer to YUB-YECL-6(a) Attachment 1 for the program update issued by the Yukon Government.

b. Micro-generation refers to small-scale generation of renewable electric power (less than 50 kW) that allows Yukoners to offset their electrical consumption by connecting energy technologies to their homes or businesses while remaining connected to Yukon's electrical grid. At the

[4] Appendix #9, page 1.

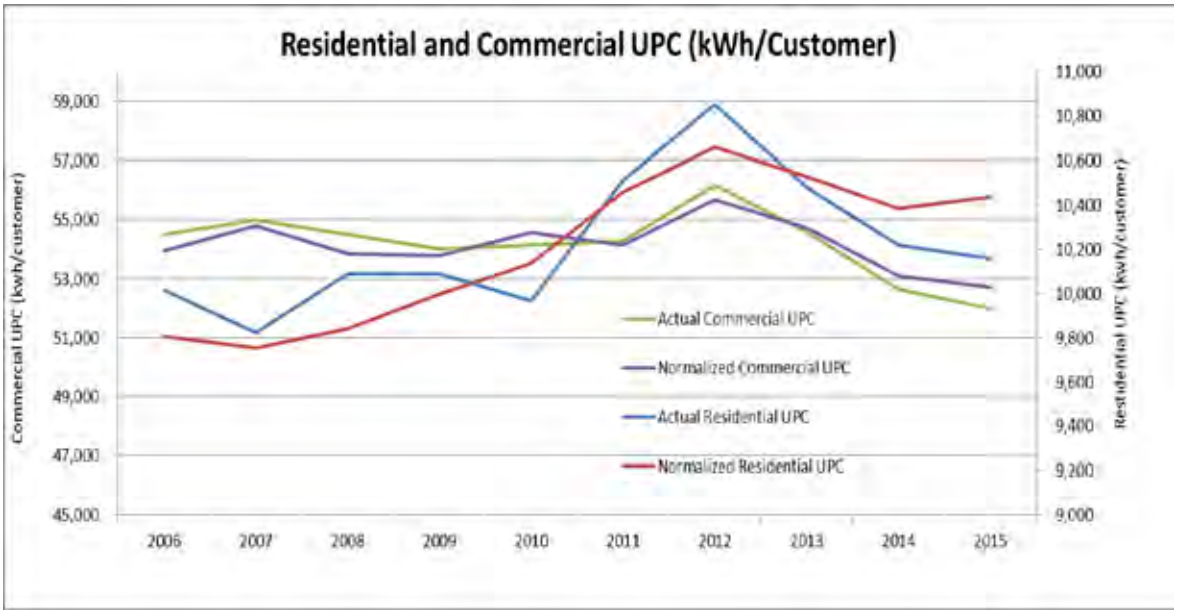
end of 2015, AEY had connected 19 qualified micro-generation customers with a total capacity of 73 kW. The total electricity export that was reported to the Yukon government for 2015 was 20,000 kWh. AEY only measures data related to the export of electricity after the customer has reduced their own consumption. AEY has estimated the amount of electricity reduced to be approximately 11,833 kWh on the customer-side of the meter for 2015 as shown in response to JM-AEY-5(c-d) Attachment 1.

(b) Over the past decade there has been an increase in electric heating that has resulted in an increase in AEY's UPC over time. The adoption of electric heating is predominately affecting new developments. However, with the recent slowdown in the economy and fewer new developments, the adoption of electric heat has lessened.

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

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

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



(d) The Yukon Government energy initiatives are designed to reduce energy consumption. This reduction in load could be offset by increases in the use of electric heating and load densification due to new customer additions. Alternatively, the load could also be further reduced if the anticipated customers and load growth does not materialize, as is the case with the Downtown Whitehorse Capacity Improvement Project (Appendix 9 of the Application).

(e) AEY has not specifically incorporated climate change in the sales forecast because there isn't any specific information available that would allow AEY to model the effect on UPC. To address the impacts of warmer weather on the sales forecast, AEY has reduced the regression of UPC on Heating Degree Days (HDD) from 15 years to 3 years and has reduced the calculation of "Normal" HDD from a 20 year average to a 3 year average. AEY made these changes to better reflect the warming trend of the past few years into the sales forecast.

(f) Please refer to YUB-YECL-6(f) Attachment 1.

Yukon
Energy, Mines and Resources
Energy Branch

Program Update

In May 2015, the Energy Branch introduced the Commercial Energy Incentive Program (CEIP). CEIP has two components – an LED upgrade for commercial buildings and a thermal enclosure incentive for multi-family buildings. The former component targets the lighting efficiency of commercial buildings by encouraging owners to upgrade to energy-efficient and long-lasting LED lighting systems. Yukon businesses can qualify for incentives of 20% of LED lamp and fixture costs up to $10,000. Interest in this incentive has been very strong with 8 business completing lighting retrofits to date and 10 additional businesses in the process of, or preparing for, lighting system upgrades. Thirty-four thousand dollars have been paid in 8 LED upgrades for commercial buildings to date. Annual energy savings to date are estimated at 1,189,000 kWh with $143,000 in annual client cost savings. A total of 24 LED lighting upgrades are projected to be completed by March 31, 2016 (fiscal year end). Annual estimated energy savings for the fiscal year are projected to range from 1,305,000 to 1,900,000 kWh in annual energy savings.[1]

Highlights

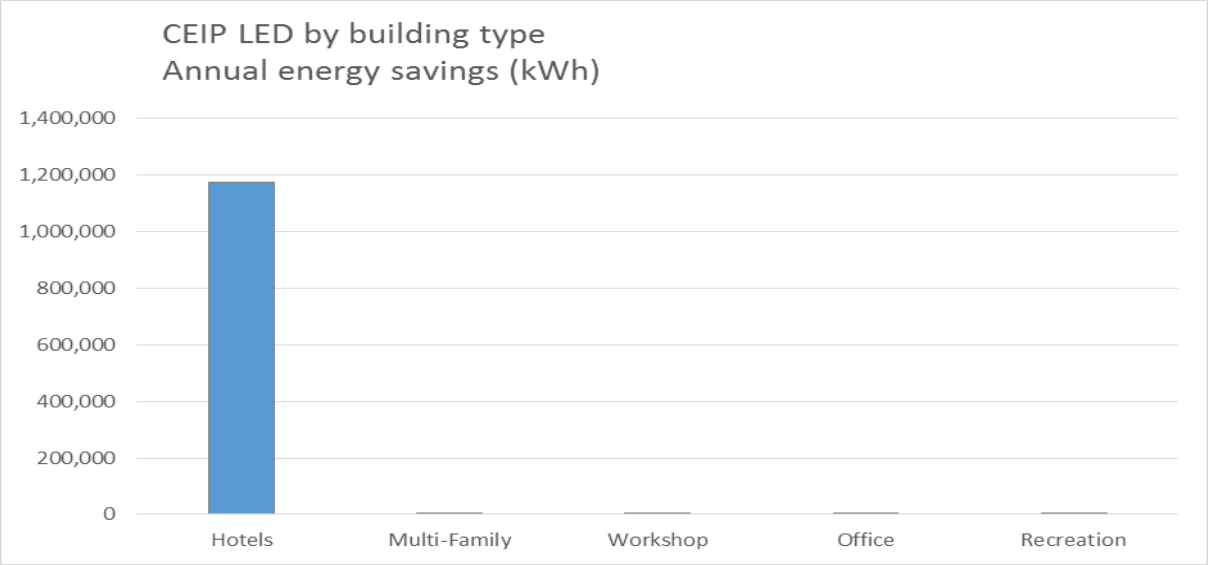
- Four hotels account for bulk of annual energy savings of 8 completed projects (1,174,000 kWh)
- Upgrade of hundreds of incandescent to LED bulbs in hotels leads to substantial energy savings in the case of the hotel upgrades
- Annual energy savings for smaller projects range from 700 to 4,600 kWh
- Average annual energy savings from pending medium-sized projects is 14,000 kWh[2]

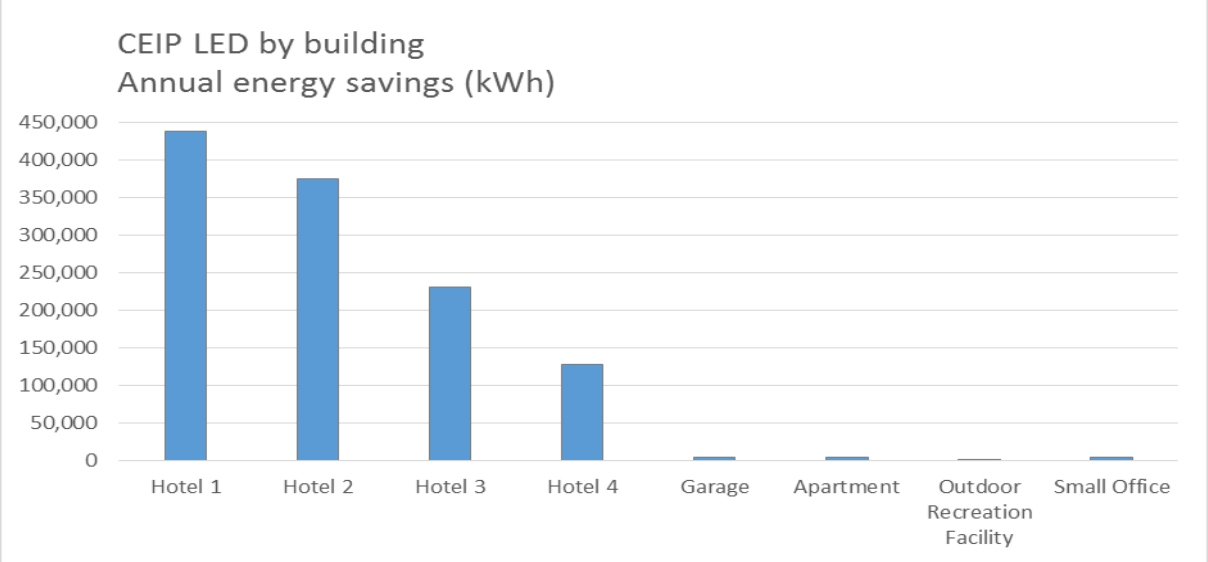
LED Lighting Upgrade Summary by Building

Building	Total Incentive	Count LED Fixture Upgrade	Annual Energy Savings (kWh)	Annual Client Cost Savings
Hotel 1	$10,000	1,905	438,106	$52,573
Hotel 2	$10,000	1,532	375,508	$45,061
Hotel 3	$5,678	773	231,487	$27,778
Hotel 4	$4,197	648	128,533	$15,424
Garage	$776	8	4,370	$524
Apartment	$878	31	4,661	$559
Ski Club	$740	10	728	$87
Small Office	$2,151	58	3,888	$467
Grand Total	**$34,420**	**4,965**	**1,187,279**	**$142,474**

[1] An initial estimate of 3,567,000 kWh energy savings was projected by fiscal year end. This estimate has been revised to account for the lower energy savings expected from pending and potential small business lighting upgrades. The previous estimate projected lighting upgrade projects in similar scale to the hotel projects. The lower end of the range reflects small and medium business-scale projects and the high end reflects the inclusion of two large scale lighting upgrade project.

[2] Corporate client upgrading 5 buildings from T12 to LED fixtures.





Assumptions

Annual Energy Savings (kWh) are calculated as follows:

(ExistingFixtureCount x Existing FixtureWattage) – (ReplacementFixtureCount x ReplacementFixtureWattage) x AnnualHourlyUsage / 1,000

Annual Client Cost Savings = Annual Energy Savings x $0.12

Appendix – LED lighting upgrade project details

Date	Status	BuildingName	BuildingType	Installation City	ExistingFixtureCount	ExistingFixtureWattage	ExistingFixtureType	LEDReplacementFixtureCount	LEDReplacementWattage	LEDReplacementFixtureType	AnnualHourlyUsage	AnnualEnergySavingskWh	AnnualClientCostSavings	IncentiveAmount
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	500	100		500	18	LED A21 18w 2700K	4,368	179,088	$21,491	$5,678
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	65	60		65	18	LED A21 30/60/100w 2700K	4,368	11,925	$1,431	
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	96	60		96	10	LED A19 9.5w 2700K	4,368	20,966	$2,516	
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	10	40		10	5	TCP LED5E12F1127K 5 W DIM CANDELABRA Flame Tip	4,368	1,529	$183	
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	24	65		24	10	LED BR30 9.5w 2700K	4,368	5,766	$692	
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	18	90		18	18	LED P38LRP381022700K	4,368	5,661	$679	
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	35	74		35	44	LS4-40L-35K-10V	4,368	4,586	$550	
04/05/2015	Complete	Hotel 3	Hotel	Dawson City	25	54		25	36	UR2-48-45L-35K-S-FD	4,368	1,966	$236	

18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	12	75		12	14	LED A19 13.5w 2700K	4,368	3,197	$384	$4,197
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	168	60		168	10	LED A19 9.5w 2700K	4,368	36,691	$4,403	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	48	65		48	10	LED BR30 9.5w 2700K	4,368	11,532	$1,384	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	6	90		6	18	LED P38LRP38102 2700K	4,368	1,887	$226	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	6	54		5	36	UR2-24-36L-35K-S-FD	4,368	629	$75	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	50	74		50	44	UR2-48-45L-35K-S-FD	4,368	6,552	$786	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	100	74		100	21	LEDT8-48-21L-35K-B1	4,368	23,150	$2,778	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	8	50		8	9	MR16-50W-30K-25D	4,368	1,433	$172	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	205	40		205	5	TCP ED5G25D30KFG25 Dimmable 5W Smooth G2	4,368	31,340	$3,761	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	15	25		15	4	TCP LED4E26F1127KF 4W DIM F11 Flame Tip	4,368	1,376	$165	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	450	100		450	18	LED A21 18w 2700K	4,368	161,179	$19,342	$10,000

18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	408	60		408	10	LED A19 9.5w 2700K	4,368	89,107	$10,693	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	5	60		5	18	LED A21 30/60/100w 2700K	4,368	917	$110	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	84	65		84	10	LED BR30 9.5w 2700K	4,368	20,180	$2,422	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	84	90		84	18	LED P38LRP38102 2700K	4,368	26,418	$3,170	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	25	74		25	44	LS4-40L-35K-10V	4,368	3,276	$393	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	130	74		130	44	UR2-48-45L-35K-S-FD	4,368	17,035	$2,044	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	100	74		100	21	LEDT8-48-21L-35K-B1	4,368	23,150	$2,778	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	145	40		145	5	TCP LED5E12G16 27K 5 W DIM Candelabra G16 Globe	4,368	22,168	$2,660	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	6	40		6	5	TCP ED5G25D30 KFG25 Dimmable 5W Smooth G2	4,368	917	$110	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	40	40		40	5	TCP LED5E12F11 27K 5 W	4,368	6,115	$734	

										DIM CANDELABRA Flame Tip				
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	40	25		40	4	TCP LED4E12F1127K 4W DIM CANDELABRA Flame Tip	4,368	3,669	$440	
18/05/2015	Complete	Hotel 2	Hotel	Whitehorse	15	25		15	4	TCP LED4E26F1127KF 4W DIM F11 Flame Tip	4,368	1,376	$165	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	450	100		450	18	LED A21 18w 2700K	4,368	161,179	$19,342	$10,000
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	12	75		12	14	LED A19 13.5w 2700K	4,368	3,197	$384	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	288	60		288	10	LED A19 9.5w 2700K	4,368	62,899	$7,548	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	48	65		48	10	LED BR30 9.5w 2700K	4,368	11,532	$1,384	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	36	90		36	18	LED P38LRP381022700K	4,368	11,322	$1,359	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	4	54	T12 24" 2 lamp	4	36	UR2-24-36L-35K-S-FD	4,368	314	$38	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	300	74	T12 48" 2 lamp	300	44	UR2-48-45L-35K-S-FD	4,368	39,312	$4,717	

18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	200	74		200	21	LEDT8-48-21L-35K-B1	4,368	46,301	$5,556	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	45	25		45	4	LED4E12G1627K	4,368	4,128	$495	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	10	40		10	5	TCP LED5E12G1627K 5 W DIM Candelabra G16 Globe	4,368	1,529	$183	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	492	50		492	6	GC MR16 GU10 6w	4,368	94,558	$11,347	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	10	25		10	4	TCP LED4E12F1127K 4W DIM CANDELABRA Flame Tip	4,368	917	$110	
18/05/2015	Complete	Hotel 1	Hotel	Whitehorse	10	25		10	4	TCP LED4E26F1127KF 4W DIM F11 Flame Tip	4,368	917	$110	
18/05/2015	Complete	Hotel 4	Hotel	Whitehorse	30	100		30	18	LED A21 18w 2700K	4,368	10,745	$1,289	
10/06/2015	Complete	Garage	Workshop	Whitehorse	8	400	400 W Metal Halide	8	198	IBH18LMVOLT	2,704	4,370	$524	$776
15/06/2015	Complete	Apartm	Multi	Whiteh	4	60		4	16	FMABSL117	4,368	769	$92	$878

		ent	- Family	orse						840F21				
15/06/2015	Complete	Apartment	Multi - Family	Whitehorse	25	74		25	41	LBL4LP840	4,368	3,604	$432	
15/06/2015	Complete	Apartment	Multi - Family	Whitehorse	2	74		2	41	2GTL4LP840	4,368	288	$35	
15/06/2015	Complete	Ski Club	Recreation	Whitehorse	10	250	250 W Metal Halide	10	75	GI-RT-75-CRM	416	728	$87	$740
02/09/2016	Complete	Small Office	Office	Whitehorse	4	32	2x2 T8 32W Fluorescent	4	35	2GTL2LP840	3,640	-44	-$5	$2,151
02/09/2016	Complete	Small Office	Office	Whitehorse	54	59	2x4 T8 32W Fluorescent	54	39	2GTL4LP840	3,640	3,931	$472	
Total									**1,193**			**1,187,279**	**$142,474**	**$34,420**



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 programoffering 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 Costs[1]

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
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		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	Program documentation	5	9	10	9	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
		POP materials issued for all rebate-eligible products and refreshed as needed (Yes/No)		n/a	n/a	Yes	Yes	
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	Estimate based on rebates processed	1,337	2,362	5,484	2,268	Lifetime savings higher than projected in 2014 and on track to reach target in 2015
		MWh of avoided annual electricity consumption		67	118	380		Annual savings higher than projected in 2014. 2015 results will be updated at the end of the year
		kW of avoided coincident electricity demand		16	29	111	63	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 2 newspaper ads designed and placed 22 in 2014 and text edited as needed for community events. 3 newspaper ads were created and placed 21 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	Store managers	-	-	100%	-	To be quantified in next Evaluation
		% of store managers contributed to at least one transaction	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	Participants	-	-	30%	65%	65% of participants had heard of the program from others and 96% of those discussions were positive
		% heard of the program positively from past participants	Non-participants	-	-	10%	-	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
Part A -- Visited Regularly as Part of Tracking and Performance Reporting – Key Performance Indicators (KPIs)								
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	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.
		# of kits distributed		40	220	60	222	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	Program documentation	-	20	2	-	in 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.
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	Participants			30%	65%	See Rebate Program KPIs above (Table 3)
		% heard of the program positively from past participants	Non-participants			10%	-	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

Energy Conservation Measure - Justification of the Incentive Level

ECM61

Inputs - Measure Considerations	
Measure Name:	Standard LEDs (>9 W)
Incentive Amount:	$7.00
Measure/Project Cost:	$7.61
Gross Consumption Savings:	40 kWh/yr
Transport and distribution losses:	8.3%
Gross Cons. Savings w/ T&D Losses:	43 kWh/yr
Gross Demand Savings:	.01 kW
Gross Demand Savings w/ T&D losses:	.010 kW
Participant's Savings on Year 1:	$5.74
Measure Lifetime:	20 yr

Inputs - Program Considerations		
Program Cost (% of Incentive):	192%	
Suggested Program Cost (% of Incentive):	192%	-->not us
Forecasted Freeridership:	10%	
Forecasted Participant Spillover:	0%	
Forecasted Non-participant Spillover:	10%	
Forecasted Rebound Effects:	0%	

Outputs with Program Costs	
PC - Benefit/Cost Ratio	10.64
PC - Net Present Value	$73.39
PC - Levelized Cost	$0.0174/kWh
Simple Payback w/ Incentive (yr)	0.1 yr
RIM - Benefit/Cost Ratio	*1.28*
RIM - Net Present Value	*$26.88*
RIM - Levelized Cost	*$0.1975/kWh*
TRC - Benefit/Cost Ratio	5.76
TRC - Net Present Value	$100.27
TRC - Levelized Cost	$0.0441/kWh
PAC - Benefit/Cost Ratio	*5.93*
PAC - Net Present Value	*$100.88*
PAC - Levelized Cost	*$0.0428/kWh*
RIM-YECL - Benefit/Cost Ratio	*0.65*
RIM-YECL - Net Present Value	*-$24.06*
RIM-YECL - Levelized Cost	*$0.1537/kWh*
RIM-YEC - Benefit/Cost Ratio	*1.93*
RIM-YEC - Net Present Value	*$63.55*
RIM-YEC - Levelized Cost	*$0.1322/kWh*

Reference Data from Other Jurisdictions:

Additional Discussions:

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)

Cumulative Present Value of Cashflows w/ PC Discount Rates	*With Program Costs*	*W/o Program Costs*
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)

Cumulative Present Value of Cashflows w/ RIM Discount Rate	*With Program Costs*	*W/o Program Costs*
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)

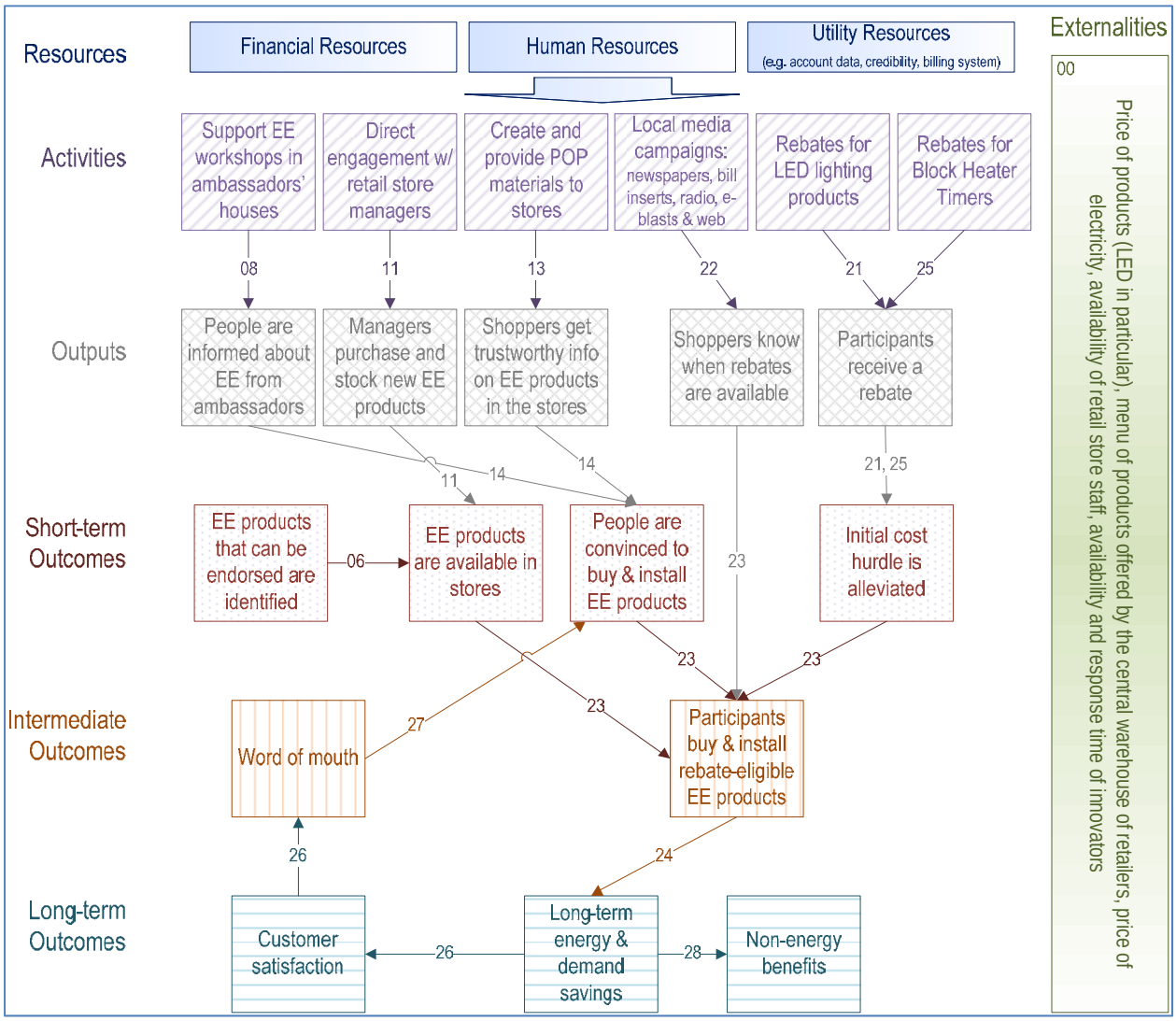
Cumulative Present Value of Cashflows w/ TRC Discount Rate	*With Program Costs*	*W/o Program Costs*
Present Value of Avoided Energy Costs for 20 years	$121.35	$121.35
Present Value of Avoided Capacity Costs for 20 years	$0.00	$0.00
Discounted Cumulative Net Energy Savings for 20 years	478 kWh	478 kWh
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)

Cumulative Present Value of Cashflows w/ PAC Discount Rate	*With Program Costs*	*W/o Program Costs*
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

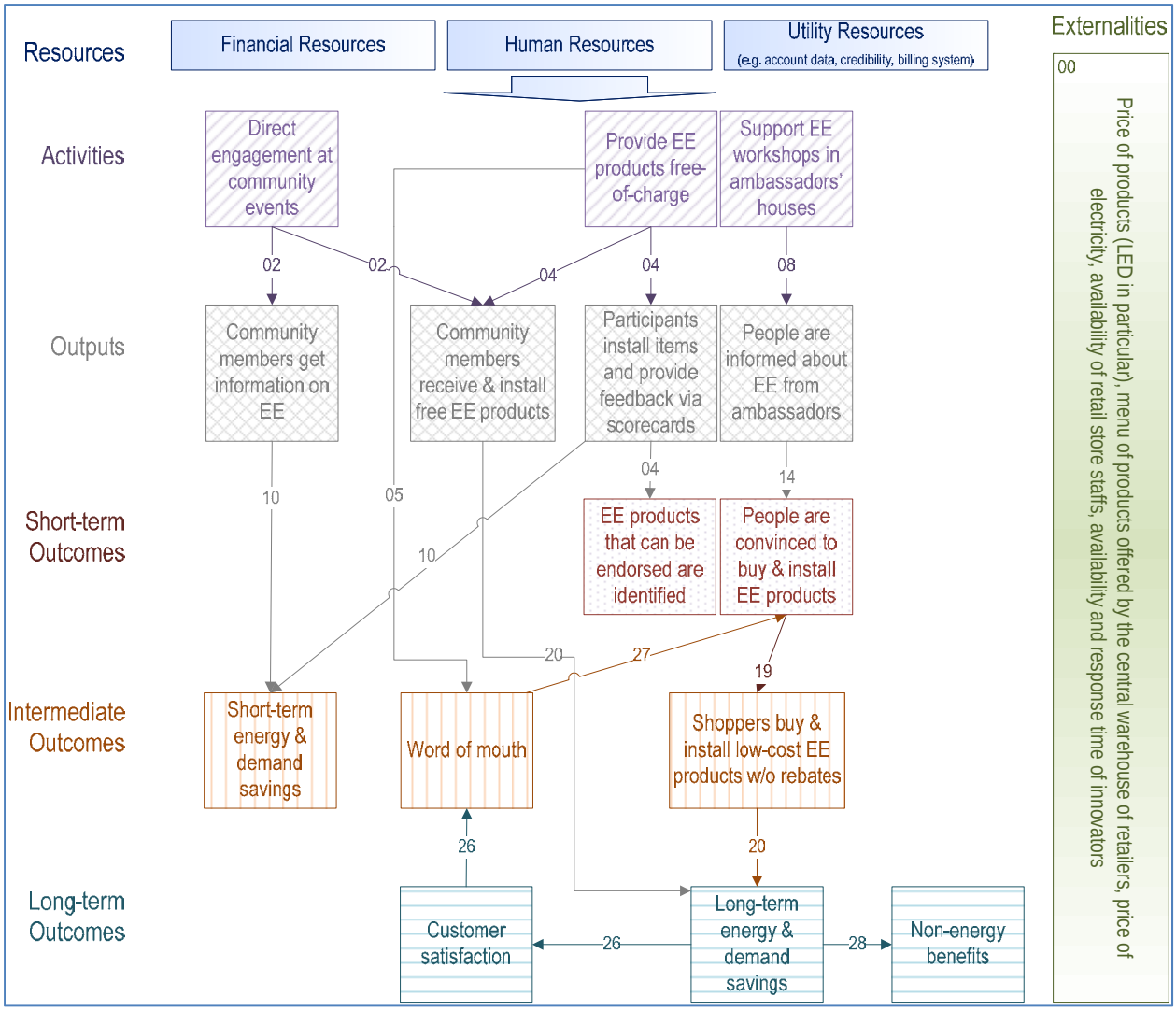
Figure B1: Logic Model for the Residential LED Lights and Automotive Heater Timer Rebate Program



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.

Residential UPC by Community

Year	Whitehorse	Carmacks	Carcross	Haines Junction	Teslin	Ross River	Pelly Crossing	Old Crow	Destruction Bay	Beaver Creek	Tagish	Marsh Lake	Lower Post	Upper Liard	Watson Lake	Keno City	Crossing	Swift River
1995	11,558	9,954	7,336	8,699	6,690	7,786	8,692	6,249	6,036	9,738	4,808	7,538	-	-	8,417	3,836	6,075	13,531
1996	12,177	10,717	8,180	8,856	7,131	8,630	8,977	6,336	5,954	9,380	4,746	8,173	8,106	7,675	9,084	3,981	6,312	13,812
1997	11,109	10,595	7,477	8,504	6,847	8,109	8,759	7,005	5,563	8,555	4,127	7,592	7,991	7,165	8,721	3,904	5,123	12,992
1998	10,418	9,944	6,922	8,105	6,497	7,875	8,761	6,706	5,360	8,124	4,177	7,409	7,999	7,128	8,248	3,609	4,811	12,433
1999	10,680	10,301	7,170	8,425	6,621	7,780	9,302	6,850	5,463	7,961	4,127	7,314	7,778	6,936	8,299	3,677	6,154	13,488
2000	10,260	10,373	6,360	8,142	6,457	8,011	9,585	7,092	5,730	7,722	3,765	7,004	7,944	7,046	8,714	3,175	5,718	13,100
2001	10,175	9,634	6,264	8,233	6,427	7,520	9,004	6,456	5,608	7,898	3,641	7,054	7,661	6,620	8,349	3,011	5,837	12,855
2002	10,215	10,153	6,695	8,229	6,401	7,193	9,155	6,380	6,162	7,953	3,741	6,943	7,721	6,701	8,419	2,656	7,110	12,599
2003	10,296	10,103	6,671	7,738	6,270	6,856	9,045	6,644	5,869	8,290	3,698	6,953	7,530	7,191	8,489	2,248	8,950	13,800
2004	10,281	9,799	6,675	7,632	6,428	7,154	9,008	6,819	5,615	8,765	3,917	7,138	7,758	7,222	8,581	2,386	8,842	12,697
2005	10,283	10,208	6,862	7,738	6,524	7,453	9,135	7,241	5,565	8,333	4,059	7,197	7,364	7,359	8,594	2,085	9,271	12,900
2006	10,695	10,599	7,334	7,862	6,797	7,725	9,127	7,152	6,288	8,750	4,591	7,843	8,682	7,927	8,989	2,816	10,229	14,923
2007	10,519	10,731	7,031	8,133	7,011	7,504	9,250	6,992	6,557	8,987	4,790	7,878	9,151	7,608	8,890	2,922	9,270	14,714
2008	10,712	11,665	7,568	8,023	7,134	8,115	9,441	6,743	6,288	8,776	4,660	8,387	9,277	7,857	9,220	3,720	7,824	12,150
2009	10,928	11,091	7,941	8,005	7,188	8,544	9,729	7,057	6,334	8,643	4,982	8,517	9,631	8,345	9,168	3,928	8,566	14,578
2010	10,550	11,111	7,768	7,713	7,135	8,165	8,900	7,006	6,373	8,726	4,957	8,348	9,111	7,871	8,827	4,390	7,481	8,511
2011	11,367	11,768	8,185	7,928	7,283	8,973	9,611	7,936	6,735	9,149	5,202	9,272	9,321	7,896	9,273	4,921	8,741	11,784
2012	11,299	12,050	7,994	7,958	7,290	8,969	10,145	7,467	6,921	9,246	5,318	9,309	8,755	8,019	9,250	4,561	8,568	10,410
2013	11,268	11,345	8,158	8,088	7,108	8,834	10,310	7,781	7,224	9,230	5,112	9,209	9,179	8,802	9,282	4,575	8,821	12,198
2014	10,999	11,620	8,041	7,928	6,797	8,936	11,162	7,848	6,995	8,535	4,986	8,775	9,426	8,487	9,099	4,948	7,747	11,107
2015	10,876	11,127	7,884	7,889	6,990	8,488	10,090	7,663	6,983	8,413	4,789	8,682	8,039	8,545	8,844	4,271	7,915	8,342

Note: UPC by community is based on billed data.

Commercial UPC by Community

Year	Whitehorse	Carmacks	Carcross	Haines Junction	Teslin	Ross River	Pelly Crossing	Old Crow	Destruction Bay	Beaver Creek	Tagish	Marsh Lake	Lower Post	Upper Liard	Watson Lake	Keno City	Crossing	Swift River
1995	63,958	26,117	22,171	27,739	19,431	20,330	19,526	21,338	15,723	24,807	10,821	15,508	13,932	14,566	33,467	8,575	18,581	15,512
1996	65,970	27,006	24,261	28,472	19,199	23,215	20,832	21,383	15,520	26,257	10,224	22,601	15,384	14,665	34,409	11,951	25,021	15,431
1997	64,022	28,304	23,075	28,820	19,933	23,287	20,048	19,370	15,988	24,585	11,465	21,451	14,083	13,928	33,333	13,367	18,479	13,724
1998	62,347	28,800	20,898	27,230	20,697	24,466	22,599	15,985	17,112	24,443	10,356	8,880	16,901	14,893	33,047	12,472	17,015	13,860
1999	62,775	27,648	20,467	27,943	20,994	23,249	21,732	18,125	18,943	25,665	10,959	9,820	17,645	16,694	33,828	11,263	18,164	14,454
2000	62,435	25,047	19,793	28,527	20,881	25,076	23,564	19,863	18,285	23,928	11,178	11,768	18,192	16,530	37,797	11,445	19,897	14,989
2001	62,628	26,096	20,841	28,107	20,938	26,596	26,001	20,186	17,612	24,454	11,772	8,708	19,527	15,844	36,549	11,061	20,881	16,444
2002	63,711	27,882	20,381	28,451	21,821	26,999	26,553	20,523	23,262	24,567	11,442	8,461	19,678	14,140	37,469	8,348	23,003	17,170
2003	64,097	26,876	19,075	28,125	22,234	26,206	28,548	20,797	20,443	26,258	10,684	10,036	20,819	13,712	36,401	13,158	21,406	17,271
2004	65,697	26,828	19,920	26,647	22,281	25,965	29,498	20,897	19,352	27,168	8,807	9,694	18,288	13,291	38,154	13,467	21,355	15,922
2005	65,280	26,303	18,756	25,456	22,415	25,305	28,994	21,924	16,720	25,715	10,134	8,746	17,897	15,693	37,800	12,442	19,961	15,224
2006	67,259	27,826	19,764	25,692	25,874	25,239	28,917	21,774	18,161	25,604	10,269	9,887	20,897	15,606	36,957	13,428	23,423	15,296
2007	68,097	32,984	21,325	25,901	27,755	24,791	29,935	21,187	18,394	25,557	11,042	11,026	16,494	15,283	37,092	13,887	21,089	16,019
2008	67,519	29,824	20,030	25,969	27,002	26,388	30,113	20,823	19,427	23,293	11,363	12,171	14,767	16,633	35,798	9,954	20,802	16,157
2009	66,915	27,819	20,939	26,599	28,967	24,904	33,549	21,858	17,660	23,409	10,837	11,461	15,524	18,708	36,027	9,050	20,273	15,286
2010	65,884	30,423	20,114	26,158	28,079	26,387	33,766	20,034	17,116	24,349	10,869	12,287	16,304	16,807	36,094	8,814	20,924	11,957
2011	67,563	31,927	21,355	28,363	27,045	24,695	37,270	20,940	17,897	25,171	10,813	14,562	17,009	15,549	34,514	12,300	19,080	12,517
2012	67,320	31,385	18,167	29,344	27,497	28,309	36,410	21,954	18,806	23,313	10,036	14,531	19,495	17,153	37,258	9,773	20,510	13,150
2013	66,586	30,930	18,944	29,438	26,746	28,097	35,238	22,418	18,733	24,715	10,213	14,261	18,724	18,889	37,972	9,496	21,056	12,727
2014	63,846	31,979	18,546	29,708	26,550	29,179	35,270	21,954	17,743	24,615	12,823	14,940	17,267	15,035	39,833	7,985	19,962	13,659
2015	62,503	32,431	18,269	29,914	26,122	28,651	34,135	21,610	18,291	23,495	13,261	12,877	18,104	14,305	39,393	7,641	18,759	13,012

Note: UPC by community is based on billed data.

YUB-YECL-7

Reference: Application, Section 2, Sales and Revenue, page 2-6, lines 5 to 12.

Issue/sub-issue: Residential customer average UPC methodology

Quote: "The residential average UPC for the test period for all communities, with the exception of Keno City, Stewart Crossing and Swift River, is forecast by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC, as discussed above. The UPC for Keno City, Stewart Crossing and Swift River is forecast by using the actual UPC of the previous year as a base and applying the 2013 to 2015 growth in actual UPC. Actual UPC for these 3 communities is used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature."

Preamble: The Board notes the following from YECL's 2013-15 GRA:

"The residential average UPC for the test period for all communities, with the exception of Keno City, Stewart Crossing, Swift River and Whitehorse is forecast by using the most recent three-year average (2010-2012) weather-normalized UPC. The UPC for Keno City, Stewart Crossing and Swift River is forecast by the most recent three-year average actual UPC because there are very few customers in these communities and a poor correlation between their average UPC and temperature."
…
"… in forecasting Whitehorse UPC in 2013, Yukon Electrical used the 2012 weather-normalized UPC, which already reflects the consumption increases due to space heating, as a base and raising it by the most recent three-year average growth in weather-normalized UPC. The increase in UPC relating to electric space heating, however, is not expected to be extended beyond 2013, as it is expected to be offset by a reduction in consumption due to the demand side management program."[5]

Request:

(a) Please clarify which year YECL is referring to as being "the previous year" when stating the UPC "is forecast by using the weather-normalized UPC of the previous year as a base."

[5] YECL 2013- 2015 General Rate Application, Part 1, page 2-5, lines 3 to 16.

(b) With respect to residential customers in the communities of Keno City, Stewart Crossing and Swift River,

a. Please explain why YECL is proposing to use "the actual UPC of the previous year as a base" and applying a three-year (2013 to 2015) UPC growth rate rather than using the three-year average actual UPC as a base that was used in its previous application.

b. For each of the three communities,

i. Please provide calculations underlying the detailed information provided by YECL,[6] in an Excel workbook with all formulas intact.

ii. Please provide a residential UPC calculation using the most recent three-year average actual UPC (2013-2015) in an Excel workbook with all formulas intact.

(c) With respect to residential customers in all communities, with the exception of Keno City, Stewart Crossing, and Swift River,

a. Please explain why YECL is not using a weather-normalized three-year average actual UPC (2013 to 2015) as was done in its last GRA.

b. For each of these communities,

i. Please provide the calculations underlying the detailed information provided by YECL,[7] in an Excel workbook with all formulas intact.

ii. Please provide an alternate residential average UPC calculation using the most recent three-year average (2013 to 2015) weather-normalized UPC as was done in YECL's previous GRA.

Response:

(a) For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year.

(b) a. AEY submits that the methodology used in the previous GRA has resulted in an over forecast of sales, especially in 2014 and 2015. Over the last few years, there have been changes in the use of electric heating as well

[6] Application, Section 2, Attachments 16 to 18.
[7] Application, Section 2, Attachments 1 to 15.

as the introduction of energy efficiency programs across the territory. These trends, combined with a decline in economic activity and warmer weather over the last few years, have impacted UPC over the 2013 to 2015 time period. This is demonstrated in the decline in UPC shown in response to YUB-YECL-6(c). For these reasons, AEY considers that it was necessary to review the existing methodology to ensure it encompasses these recent trends.

b. i) Please refer to YUB-YECL-7(b) – Attachment 1

ii) Please refer to YUB-YECL-7(b) – Attachment 2

(c) a. Please refer to the response per part b) above.

b. i) Please refer to YUB-YECL-7(c) – Attachment 1

ii) Please refer to YUB-YECL-7(c) – Attachment 2

ATCO Electric Yukon
2016 - 2017 General Rate Application

Section 2
Attachment 16

Keno City

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	524.3		952.0	507.7	
Feb-13	373.4		665.4	410.4	
Mar-13	472.0		851.1	459.3	
Apr-13	563.1		639.9	539.6	
May-13	327.9		294.0	318.8	
Jun-13	278.9		112.4	286.3	
Jul-13	359.9		92.5	362.0	
Aug-13	196.7		98.9	206.0	
Sep-13	280.4		264.3	288.4	
Oct-13	359.3		501.4	358.1	
Nov-13	432.8		865.6	418.4	
Dec-13	406.0	4,574.7	1,144.7	370.9	4,525.8
Jan-14	489.4		745.8	517.4	
Feb-14	449.6		992.4	415.8	
Mar-14	396.2		855.1	382.7	
Apr-14	418.8		499.8	425.6	
May-14	288.3		269.5	284.5	
Jun-14	341.8		200.5	330.1	
Jul-14	304.0		98.0	304.9	
Aug-14	288.1		144.0	287.7	
Sep-14	517.9		307.1	516.7	
Oct-14	540.8		515.6	536.5	
Nov-14	408.6		772.8	414.3	
Dec-14	504.5	4,948.0	854.4	532.2	4,948.3
Jan-15	603.7		927.0	592.4	
Feb-15	291.3		851.4	288.0	
Mar-15	437.6		671.3	463.8	
Apr-15	119.7		453.5	136.5	
May-15	351.7		192.9	364.5	
Jun-15	120.1		127.2	124.3	
Jul-15	386.4		115.7	383.5	
Aug-15	263.5		183.2	254.6	
Sep-15	388.2		332.7	381.4	
Oct-15	377.4		469.8	383.0	
Nov-15	400.4		759.2	409.0	
Dec-15	530.9	4,270.9	947.9	538.3	4,319.4
Jan-16	258.8		827.6	269.0	
Feb-16	499.8		688.0	531.9	
Mar-16	294.4		611.6	333.5	
Apr-16	115.7				
May-16	339.8				
Jun-16	116.0				
Jul-16	373.4				
Aug-16	254.6				
Sep-16	375.1				
Oct-16	364.7				
Nov-16	386.8				
Dec-16	513.0	3,892.0			3,973.5
Jan-17	250.1				
Feb-17	482.9				
Mar-17	284.5				
Apr-17	111.7				
May-17	328.3				
Jun-17	112.1				
Jul-17	360.8				
Aug-17	246.0				
Sep-17	362.4				
Oct-17	352.3				
Nov-17	373.8				
Dec-17	495.6	3,760.6			3,760.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.612122162
R Square	0.374693541
Adjusted R Square	0.356302175
Standard Error	92.11545637
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	172873.0226	172873.0226	20.37333889	7.26861E-05
Residual	34	288498.7483	8485.257303		
Total	35	461371.7708			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	270.3915602	29.32269827	9.221237342	8.91768E-11	210.8006677	329.9824527	210.8006677	329.9824527
WH-HDD	0.216284894	0.047917603	4.513683516	7.26861E-05	0.118904609	0.313665179	0.118904609	0.313665179

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (4,270.9 / 4,574.7) ^ (1/2) - 1 = **-3.4%**

ATCO Electric Yukon
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Section 2
Attachment 17
Page 1 of 1

Stewart Crossing

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,108.1		952.0	1,074.3	
Feb-13	898.7		665.4	973.6	
Mar-13	769.3		851.1	743.6	
Apr-13	810.4		639.9	762.7	
May-13	816.5		294.0	798.2	
Jun-13	455.4		112.4	470.4	
Jul-13	513.8		92.5	518.0	
Aug-13	671.9		98.9	690.8	
Sep-13	522.9		264.3	539.2	
Oct-13	644.6		501.4	642.1	
Nov-13	612.7		865.6	583.6	
Dec-13	996.4	8,820.6	1,144.7	925.3	8,721.6
Jan-14	1,055.5		745.8	1,112.1	
Feb-14	811.3		992.4	742.9	
Mar-14	588.8		855.1	561.4	
Apr-14	610.3		499.8	624.0	
May-14	535.0		269.5	527.4	
Jun-14	508.8		200.5	485.2	
Jul-14	531.8		98.0	533.6	
Aug-14	445.0		144.0	444.1	
Sep-14	520.8		307.1	518.3	
Oct-14	627.4		515.6	618.6	
Nov-14	624.1		772.8	635.6	
Dec-14	888.4	7,747.0	854.4	944.4	7,747.6
Jan-15	801.1		927.0	778.3	
Feb-15	825.2		851.4	818.6	
Mar-15	787.0		671.3	840.1	
Apr-15	682.5		453.5	716.5	
May-15	851.8		192.9	877.8	
Jun-15	66.1		127.2	74.7	
Jul-15	562.3		115.7	556.3	
Aug-15	498.7		183.2	480.7	
Sep-15	528.3		332.7	514.5	
Oct-15	667.3		469.8	678.6	
Nov-15	679.1		759.2	696.6	
Dec-15	965.9	7,915.2	947.9	980.9	8,013.6
Jan-16	714.4		827.6	735.1	
Feb-16	673.4		688.0	738.5	
Mar-16	552.0		611.6	631.3	
Apr-16	646.6				
May-16	806.9				
Jun-16	62.6				
Jul-16	532.6				
Aug-16	472.4				
Sep-16	500.4				
Oct-16	632.1				
Nov-16	643.3				
Dec-16	914.9	7,151.7			7,316.8
Jan-17	676.7				
Feb-17	637.9				
Mar-17	522.9				
Apr-17	612.5				
May-17	764.4				
Jun-17	59.3				
Jul-17	504.6				
Aug-17	447.5				
Sep-17	474.0				
Oct-17	598.8				
Nov-17	609.4				
Dec-17	866.7	6,774.7			6,774.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.696788961
R Square	0.485514856
Adjusted R Square	0.47038294
Standard Error	148.7454709
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	709898.2459	709898.2459	32.08548448	2.35096E-06
Residual	34	752257.3135	22125.2151		
Total	35	1462155.559			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	451.5729172	47.34947567	9.537020438	3.87178E-11	355.3472053	547.7986292	355.3472053	547.7986292
WH-HDD	0.438289056	0.077376009	5.664405042	2.35096E-06	0.281042086	0.595536025	0.281042086	0.595536025

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (7,915.2 / 8,820.6) ^ (1/2) - 1 = **-5.3%**

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Swift River

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,464.5		1,129.1	1,412.1	
Feb-13	864.5		765.8	975.4	
Mar-13	852.0		950.7	829.8	
Apr-13	906.5		690.1	851.5	
May-13	1,411.5		304.5	1,399.7	
Jun-13	790.5		96.3	809.2	
Jul-13	809.0		105.1	803.7	
Aug-13	816.0		82.2	838.5	
Sep-13	669.5		239.1	696.6	
Oct-13	718.0		490.2	732.6	
Nov-13	1,216.0		1,021.3	1,177.5	
Dec-13	1,679.5	12,197.5	1,248.8	1,651.2	12,177.7
Jan-14	1,227.0		937.7	1,275.7	
Feb-14	1,872.5		1,204.4	1,751.6	
Mar-14	1,229.5		1,008.9	1,176.5	
Apr-14	1,107.5		570.5	1,115.7	
May-14	797.0		331.1	771.1	
Jun-14	740.5		186.8	711.4	
Jul-14	567.5		87.6	571.4	
Aug-14	841.0		144.8	830.5	
Sep-14	438.0		295.8	435.1	
Oct-14	611.5		539.7	600.0	
Nov-14	712.0		936.4	718.4	
Dec-14	963.0	11,107.0	1,176.7	972.8	10,930.2
Jan-15	1,125.5		1,022.8	1,129.2	
Feb-15	787.0		956.7	797.0	
Mar-15	724.5		766.3	799.7	
Apr-15	576.5		497.4	623.3	
May-15	635.5		210.8	673.2	
Jun-15	553.5		111.8	564.0	
Jul-15	545.0		92.4	546.4	
Aug-15	531.0		147.5	519.0	
Sep-15	657.0		336.1	632.8	
Oct-15	587.0		523.7	583.9	
Nov-15	748.0		887.8	780.1	
Dec-15	871.0	8,341.5	1,160.3	889.5	8,538.1
Jan-16	1,323.5		1,099.3	1,286.8	
Feb-16	1,090.5		930.8	1,114.2	
Mar-16	811.0		724.3	908.4	
Apr-16	476.7				
May-16	525.5				
Jun-16	457.7				
Jul-16	450.7				
Aug-16	439.1				
Sep-16	543.3				
Oct-16	485.4				
Nov-16	618.6				
Dec-16	720.3	7,942.4			8,026.8
Jan-17	1,094.5				
Feb-17	901.8				
Mar-17	670.7				
Apr-17	394.3				
May-17	434.6				
Jun-17	378.5				
Jul-17	372.7				
Aug-17	363.1				
Sep-17	449.3				
Oct-17	401.4				
Nov-17	511.5				
Dec-17	595.7	6,568.1			6,568.1

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.632152079
R Square	0.399616251
Adjusted R Square	0.381957905
Standard Error	262.8228201
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1563217.007	1563217.007	22.63044684	3.53886E-05
Residual	34	2348578.382	69075.83477		
Total	35	3911795.389			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	567.1057634	78.8596892	7.191326381	2.56019E-08	406.843593	727.3679338	406.843593	727.3679338
WL-HDD	0.528301144	0.1110542	4.757146922	3.53886E-05	0.302611857	0.753990432	0.302611857	0.753990432

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (8,341.5 / 12,197.5) ^ (1/2) - 1 = **-17.3%**

Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC				"Normal" HDD
MONTH	**2013**	**2014**	**2015**	**(2013-2015)**
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC				"Normal" HDD
MONTH	**2013**	**2014**	**2015**	**(2013-2015)**
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

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Keno City

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	524.3		952.0	507.7	
Feb-13	373.4		665.4	410.4	
Mar-13	472.0		851.1	459.3	
Apr-13	563.1		639.9	539.6	
May-13	327.9		294.0	318.8	
Jun-13	278.9		112.4	286.3	
Jul-13	359.9		92.5	362.0	
Aug-13	196.7		98.9	206.0	
Sep-13	280.4		264.3	288.4	
Oct-13	359.3		501.4	358.1	
Nov-13	432.8		865.6	418.4	
Dec-13	406.0	4,574.7	1,144.7	370.9	4,525.8
Jan-14	489.4		745.8	517.4	
Feb-14	449.6		992.4	415.8	
Mar-14	396.2		855.1	382.7	
Apr-14	418.8		499.8	425.6	
May-14	288.3		269.5	284.5	
Jun-14	341.8		200.5	330.1	
Jul-14	304.0		98.0	304.9	
Aug-14	288.1		144.0	287.7	
Sep-14	517.9		307.1	516.7	
Oct-14	540.8		515.6	536.5	
Nov-14	408.6		772.8	414.3	
Dec-14	504.5	4,948.0	854.4	532.2	4,948.3
Jan-15	603.7		927.0	592.4	
Feb-15	291.3		851.4	288.0	
Mar-15	437.6		671.3	463.8	
Apr-15	119.7		453.5	136.5	
May-15	351.7		192.9	364.5	
Jun-15	120.1		127.2	124.3	
Jul-15	386.4		115.7	383.5	
Aug-15	263.5		183.2	254.6	
Sep-15	388.2		332.7	381.4	
Oct-15	377.4		469.8	383.0	
Nov-15	400.4		759.2	409.0	
Dec-15	530.9	4,270.9	947.9	538.3	4,319.4
Jan-16	258.8		827.6	269.0	
Feb-16	499.8		688.0	531.9	
Mar-16	294.4		611.6	333.5	
Apr-16	367.2				
May-16	322.6				
Jun-16	246.9				
Jul-16	350.1				
Aug-16	249.4				
Sep-16	395.5				
Oct-16	425.8				
Nov-16	413.9				
Dec-16	480.5	4,305.0			4,386.5
Jan-17	539.1				
Feb-17	371.4				
Mar-17	435.3				
Apr-17	367.2				
May-17	322.6				
Jun-17	246.9				
Jul-17	350.1				
Aug-17	249.4				
Sep-17	395.5				
Oct-17	425.8				
Nov-17	413.9				
Dec-17	480.5	4,597.8			4,597.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.612122162
R Square	0.374693541
Adjusted R Square	0.356302175
Standard Error	92.11545637
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	172873.0226	172873.0226	20.37333889	7.26861E-05
Residual	34	288498.7483	8485.257303		
Total	35	461371.7708			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	270.3915602	29.32269827	9.221237342	8.91768E-11	210.8006677	329.9824527	210.8006677	329.9824527
WH-HDD	0.216284894	0.047917603	4.513683516	7.26861E-05	0.118904609	0.313665179	0.118904609	0.313665179

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Stewart Crossing

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,108.1		952.0	1,074.3	
Feb-13	898.7		665.4	973.6	
Mar-13	769.3		851.1	743.6	
Apr-13	810.4		639.9	762.7	
May-13	816.5		294.0	798.2	
Jun-13	455.4		112.4	470.4	
Jul-13	513.8		92.5	518.0	
Aug-13	671.9		98.9	690.8	
Sep-13	522.9		264.3	539.2	
Oct-13	644.6		501.4	642.1	
Nov-13	612.7		865.6	583.6	
Dec-13	996.4	8,820.6	1,144.7	925.3	8,721.6
Jan-14	1,055.5		745.8	1,112.1	
Feb-14	811.3		992.4	742.9	
Mar-14	588.8		855.1	561.4	
Apr-14	610.3		499.8	624.0	
May-14	535.0		269.5	527.4	
Jun-14	508.8		200.5	485.2	
Jul-14	531.8		98.0	533.6	
Aug-14	445.0		144.0	444.1	
Sep-14	520.8		307.1	518.3	
Oct-14	627.4		515.6	618.6	
Nov-14	624.1		772.8	635.6	
Dec-14	888.4	7,747.0	854.4	944.4	7,747.6
Jan-15	801.1		927.0	778.3	
Feb-15	825.2		851.4	818.6	
Mar-15	787.0		671.3	840.1	
Apr-15	682.5		453.5	716.5	
May-15	851.8		192.9	877.8	
Jun-15	66.1		127.2	74.7	
Jul-15	562.3		115.7	556.3	
Aug-15	498.7		183.2	480.7	
Sep-15	528.3		332.7	514.5	
Oct-15	667.3		469.8	678.6	
Nov-15	679.1		759.2	696.6	
Dec-15	965.9	7,915.2	947.9	980.9	8,013.6
Jan-16	714.4		827.6	735.1	
Feb-16	673.4		688.0	738.5	
Mar-16	552.0		611.6	631.3	
Apr-16	701.1				
May-16	734.4				
Jun-16	343.4				
Jul-16	536.0				
Aug-16	538.5				
Sep-16	524.0				
Oct-16	646.4				
Nov-16	638.6				
Dec-16	950.2	7,552.4			7,717.5
Jan-17	988.2				
Feb-17	845.0				
Mar-17	715.0				
Apr-17	701.1				
May-17	734.4				
Jun-17	343.4				
Jul-17	536.0				
Aug-17	538.5				
Sep-17	524.0				
Oct-17	646.4				
Nov-17	638.6				
Dec-17	950.2	8,161.0			8,161.0

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.696788961
R Square	0.485514856
Adjusted R Square	0.47038294
Standard Error	148.7454709
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	709898.2459	709898.2459	32.08548448	2.35096E-06
Residual	34	752257.3135	22125.2151		
Total	35	1462155.559			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	451.5729172	47.34947567	9.537020438	3.87178E-11	355.3472053	547.7986292	355.3472053	547.7986292
WH-HDD	0.438289056	0.077376009	5.664405042	2.35096E-06	0.281042086	0.595536025	0.281042086	0.595536025

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Swift River

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,464.5		1,129.1	1,412.1	
Feb-13	864.5		765.8	975.4	
Mar-13	852.0		950.7	829.8	
Apr-13	906.5		690.1	851.5	
May-13	1,411.5		304.5	1,399.7	
Jun-13	790.5		96.3	809.2	
Jul-13	809.0		105.1	803.7	
Aug-13	816.0		82.2	838.5	
Sep-13	669.5		239.1	696.6	
Oct-13	718.0		490.2	732.6	
Nov-13	1,216.0		1,021.3	1,177.5	
Dec-13	1,679.5	12,197.5	1,248.8	1,651.2	12,177.7
Jan-14	1,227.0		937.7	1,275.7	
Feb-14	1,872.5		1,204.4	1,751.6	
Mar-14	1,229.5		1,008.9	1,176.5	
Apr-14	1,107.5		570.5	1,115.7	
May-14	797.0		331.1	771.1	
Jun-14	740.5		186.8	711.4	
Jul-14	567.5		87.6	571.4	
Aug-14	841.0		144.8	830.5	
Sep-14	438.0		295.8	435.1	
Oct-14	611.5		539.7	600.0	
Nov-14	712.0		936.4	718.4	
Dec-14	963.0	11,107.0	1,176.7	972.8	10,930.2
Jan-15	1,125.5		1,022.8	1,129.2	
Feb-15	787.0		956.7	797.0	
Mar-15	724.5		766.3	799.7	
Apr-15	576.5		497.4	623.3	
May-15	635.5		210.8	673.2	
Jun-15	553.5		111.8	564.0	
Jul-15	545.0		92.4	546.4	
Aug-15	531.0		147.5	519.0	
Sep-15	657.0		336.1	632.8	
Oct-15	587.0		523.7	583.9	
Nov-15	748.0		887.8	780.1	
Dec-15	871.0	8,341.5	1,160.3	889.5	8,538.1
Jan-16	1,323.5		1,099.3	1,286.8	
Feb-16	1,090.5		930.8	1,114.2	
Mar-16	811.0		724.3	908.4	
Apr-16	863.5				
May-16	948.0				
Jun-16	694.8				
Jul-16	640.5				
Aug-16	729.3				
Sep-16	588.2				
Oct-16	638.8				
Nov-16	892.0				
Dec-16	1,171.2	10,391.3			10,475.7
Jan-17	1,272.3				
Feb-17	1,174.7				
Mar-17	935.3				
Apr-17	863.5				
May-17	948.0				
Jun-17	694.8				
Jul-17	640.5				
Aug-17	729.3				
Sep-17	588.2				
Oct-17	638.8				
Nov-17	892.0				
Dec-17	1,171.2	10,548.7			10,548.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.632152079
R Square	0.399616251
Adjusted R Square	0.381957905
Standard Error	262.8228201
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1563217.007	1563217.007	22.63044684	3.53886E-05
Residual	34	2348578.382	69075.83477		
Total	35	3911795.389			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	567.1057634	78.8596892	7.191326381	2.56019E-08	406.843593	727.3679338	406.843593	727.3679338
WL-HDD	0.528301144	0.1110542	4.757146922	3.53886E-05	0.302611857	0.753990432	0.302611857	0.753990432

Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

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Whitehorse (Includes Takhini & Deep Creek)

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,539.9		952.0	1,489.6	
Feb-13	1,152.3		665.4	1,264.1	
Mar-13	1,075.4		851.1	1,037.1	
Apr-13	1,092.7		639.9	1,021.6	
May-13	843.2		294.0	815.8	
Jun-13	743.9		112.4	766.3	
Jul-13	667.8		92.5	674.1	
Aug-13	643.5		98.9	671.7	
Sep-13	664.6		264.3	688.9	
Oct-13	762.8		501.4	759.1	
Nov-13	920.2		865.6	876.8	
Dec-13	1,161.1	11,267.6	1,144.7	1,055.0	11,119.9
Jan-14	1,467.1		745.8	1,551.5	
Feb-14	1,067.5		992.4	965.5	
Mar-14	1,217.3		855.1	1,176.4	
Apr-14	949.3		499.8	969.7	
May-14	838.2		269.5	826.9	
Jun-14	718.4		200.5	683.3	
Jul-14	687.6		98.0	690.3	
Aug-14	574.7		144.0	573.5	
Sep-14	738.8		307.1	735.0	
Oct-14	768.1		515.6	755.1	
Nov-14	901.6		772.8	918.9	
Dec-14	1,070.2	10,998.9	854.4	1,153.8	10,999.8
Jan-15	1,414.9		927.0	1,380.8	
Feb-15	1,235.3		851.4	1,225.5	
Mar-15	1,043.4		671.3	1,122.7	
Apr-15	952.6		453.5	1,003.3	
May-15	780.9		192.9	819.6	
Jun-15	647.9		127.2	660.6	
Jul-15	629.0		115.7	620.1	
Aug-15	606.6		183.2	579.7	
Sep-15	743.5		332.7	723.0	
Oct-15	786.2		469.8	803.0	
Nov-15	930.3		759.2	956.4	
Dec-15	1,105.8	10,876.2	947.9	1,128.3	11,023.0
Jan-16	1383.1		827.6	1,414.0	
Feb-16	1061.6		688.0	1,158.6	
Mar-16	1026.0		611.6	1,144.3	
Apr-16	999.0				
May-16	816.0				
Jun-16	657.7				
Jul-16	617.4				
Aug-16	577.2				
Sep-16	719.8				
Oct-16	799.5				
Nov-16	952.2				
Dec-16	1123.4	10,732.9			10,979.1
Jan-17	1407.9				
Feb-17	1153.5				
Mar-17	1139.3				
Apr-17	994.6				
May-17	812.4				
Jun-17	654.9				
Jul-17	614.7				
Aug-17	574.7				
Sep-17	716.7				
Oct-17	796.0				
Nov-17	948.1				
Dec-17	1118.5	10,931.1			10,931.1

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.838195038
R Square	0.702570922
Adjusted R Square	0.693823008
Standard Error	140.2171904
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1579022.018	1579022.018	80.31296588	1.78734E-10
Residual	34	668469.2568	19660.86049		
Total	35	2247491.275			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	579.8341011	44.63470658	12.9906556	9.70538E-15	489.1254638	670.5427385	489.1254638	670.5427385
WH-HDD	0.653667162	0.072939677	8.961750157	1.78734E-10	0.505435904	0.80189842	0.505435904	0.80189842

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (11,023.0 / 11,119.9) ^ (1/2) - 1 = **-0.4%**

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Carmacks

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,551.4		952.0	1,492.7	
Feb-13	1,103.7		665.4	1,234.1	
Mar-13	1,129.4		851.1	1,084.8	
Apr-13	1,261.5		639.9	1,178.6	
May-13	857.1		294.0	825.2	
Jun-13	568.8		112.4	595.0	
Jul-13	626.6		92.5	633.9	
Aug-13	696.6		98.9	729.5	
Sep-13	614.4		264.3	642.6	
Oct-13	983.9		501.4	979.5	
Nov-13	947.9		865.6	897.3	
Dec-13	1,003.9	11,345.3	1,144.7	880.2	11,173.1
Jan-14	1,708.4		745.8	1,806.8	
Feb-14	1,210.7		992.4	1,091.8	
Mar-14	1,052.8		855.1	1,005.1	
Apr-14	921.1		499.8	944.9	
May-14	896.7		269.5	883.5	
Jun-14	589.1		200.5	548.1	
Jul-14	549.7		98.0	552.8	
Aug-14	734.6		144.0	733.1	
Sep-14	621.8		307.1	617.4	
Oct-14	943.9		515.6	928.6	
Nov-14	960.6		772.8	980.7	
Dec-14	1,431.2	11,620.4	854.4	1,528.7	11,621.4
Jan-15	1,265.4		927.0	1,225.7	
Feb-15	1,129.5		851.4	1,118.1	
Mar-15	1,179.2		671.3	1,271.5	
Apr-15	878.6		453.5	937.7	
May-15	771.9		192.9	817.1	
Jun-15	515.3		127.2	530.1	
Jul-15	662.1		115.7	651.7	
Aug-15	562.8		183.2	531.5	
Sep-15	767.6		332.7	743.7	
Oct-15	925.5		469.8	945.2	
Nov-15	1,084.0		759.2	1,114.5	
Dec-15	1,384.8	11,126.7	947.9	1,411.0	11,297.8
Jan-16	1073.3		827.6	1,109.4	
Feb-16	1045.3		688.0	1,158.4	
Mar-16	928.6		611.6	1,066.5	
Apr-16	942.9				
May-16	821.6				
Jun-16	533.1				
Jul-16	655.4				
Aug-16	534.4				
Sep-16	747.8				
Oct-16	950.4				
Nov-16	1120.7				
Dec-16	1418.9	10,772.5			11,059.6
Jan-17	1115.6				
Feb-17	1164.9				
Mar-17	1072.4				
Apr-17	948.2				
May-17	826.2				
Jun-17	536.0				
Jul-17	659.0				
Aug-17	537.4				
Sep-17	752.0				
Oct-17	955.7				
Nov-17	1126.9				
Dec-17	1426.8	11,121.1			11,121.1

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.822785364
R Square	0.676975755
Adjusted R Square	0.667475042
Standard Error	173.5723265
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2146732.251	2146732.251	71.25525715	7.39828E-10
Residual	34	1024329.985	30127.35251		
Total	35	3171062.236			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	549.6449397	55.25249677	9.94787515	1.33338E-11	437.3583565	661.9315228	437.3583565	661.9315228
WH-HDD	0.762169412	0.090290708	8.441282909	7.39828E-10	0.578676616	0.945662208	0.578676616	0.945662208

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (11,297.8 / 11,173.1) ^ (1/2) - 1 = **0.6%**

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Carcross

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,109.8		952.0	1,076.3	
Feb-13	930.9		665.4	1,005.1	
Mar-13	770.6		851.1	745.2	
Apr-13	793.2		639.9	745.9	
May-13	742.3		294.0	724.1	
Jun-13	552.9		112.4	567.8	
Jul-13	458.9		92.5	463.1	
Aug-13	449.8		98.9	468.5	
Sep-13	449.9		264.3	466.0	
Oct-13	485.5		501.4	483.0	
Nov-13	659.7		865.6	630.9	
Dec-13	754.9	8,158.4	1,144.7	684.3	8,060.2
Jan-14	1,035.2		745.8	1,091.3	
Feb-14	784.0		992.4	716.2	
Mar-14	915.4		855.1	888.2	
Apr-14	796.3		499.8	809.9	
May-14	716.6		269.5	709.0	
Jun-14	487.0		200.5	463.6	
Jul-14	517.5		98.0	519.3	
Aug-14	437.1		144.0	436.3	
Sep-14	465.3		307.1	462.8	
Oct-14	547.8		515.6	539.1	
Nov-14	629.4		772.8	640.9	
Dec-14	709.3	8,040.9	854.4	764.8	8,041.5
Jan-15	989.5		927.0	966.9	
Feb-15	874.2		851.4	867.7	
Mar-15	858.9		671.3	911.6	
Apr-15	695.3		453.5	729.0	
May-15	679.7		192.9	705.5	
Jun-15	475.4		127.2	483.9	
Jul-15	405.4		115.7	399.5	
Aug-15	479.4		183.2	461.6	
Sep-15	447.4		332.7	433.8	
Oct-15	602.6		469.8	613.8	
Nov-15	593.3		759.2	610.7	
Dec-15	782.7	7,884.0	947.9	797.6	7,981.6
Jan-16	993.3		827.6	1,013.9	
Feb-16	847.5		688.0	911.9	
Mar-16	834.1		611.6	912.6	
Apr-16	725.4				
May-16	702.0				
Jun-16	481.5				
Jul-16	397.6				
Aug-16	459.3				
Sep-16	431.7				
Oct-16	610.8				
Nov-16	607.7				
Dec-16	793.7	7,884.6			8,048.2
Jan-17	1,008.9				
Feb-17	907.5				
Mar-17	908.2				
Apr-17	721.9				
May-17	698.6				
Jun-17	479.2				
Jul-17	395.6				
Aug-17	457.1				
Sep-17	429.6				
Oct-17	607.8				
Nov-17	604.7				
Dec-17	789.9	8,008.8			8,008.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.737710008
R Square	0.544216056
Adjusted R Square	0.530810646
Standard Error	131.0613884
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	697333.8925	697333.8925	40.59674794	2.84723E-07
Residual	34	584020.9758	17177.08752		
Total	35	1281354.868			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	442.5050549	41.72018136	10.60649883	2.52805E-12	357.7194454	527.2906644	357.7194454	527.2906644
WH-HDD	0.434393144	0.068176914	6.371557733	2.84723E-07	0.295840984	0.572945303	0.295840984	0.572945303

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (7,981.6 / 8,060.2) ^ (1/2) - 1 = **-0.5%**

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Haines Junction

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	990.8		952.0	960.1	
Feb-13	851.0		665.4	919.1	
Mar-13	775.5		851.1	752.2	
Apr-13	729.3		639.9	685.9	
May-13	620.4		294.0	603.7	
Jun-13	632.9		112.4	646.6	
Jul-13	553.4		92.5	557.2	
Aug-13	387.2		98.9	404.3	
Sep-13	554.0		264.3	568.8	
Oct-13	550.7		501.4	548.4	
Nov-13	622.8		865.6	596.4	
Dec-13	819.7	8,087.6	1,144.7	755.0	7,997.6
Jan-14	1,024.4		745.8	1,075.9	
Feb-14	733.8		992.4	671.7	
Mar-14	844.8		855.1	819.9	
Apr-14	635.8		499.8	648.2	
May-14	627.0		269.5	620.1	
Jun-14	523.0		200.5	501.6	
Jul-14	519.9		98.0	521.6	
Aug-14	494.3		144.0	493.6	
Sep-14	556.2		307.1	553.9	
Oct-14	541.6		515.6	533.6	
Nov-14	602.3		772.8	612.8	
Dec-14	825.1	7,928.3	854.4	876.1	7,928.9
Jan-15	974.7		927.0	954.0	
Feb-15	910.6		851.4	904.7	
Mar-15	632.5		671.3	680.7	
Apr-15	724.0		453.5	754.9	
May-15	493.9		192.9	517.5	
Jun-15	513.3		127.2	521.1	
Jul-15	524.5		115.7	519.0	
Aug-15	462.5		183.2	446.1	
Sep-15	585.5		332.7	573.0	
Oct-15	548.3		469.8	558.6	
Nov-15	650.2		759.2	666.1	
Dec-15	868.8	7,888.6	947.9	882.5	7,978.1
Jan-16	932.4		827.6	951.2	
Feb-16	777.1		688.0	836.2	
Mar-16	742.0		611.6	814.1	
Apr-16	754.0				
May-16	516.8				
Jun-16	520.4				
Jul-16	518.4				
Aug-16	445.5				
Sep-16	572.3				
Oct-16	557.9				
Nov-16	665.3				
Dec-16	881.4	7,883.6			8,033.6
Jan-17	950.1				
Feb-17	835.2				
Mar-17	813.1				
Apr-17	753.1				
May-17	516.2				
Jun-17	519.8				
Jul-17	517.8				
Aug-17	445.0				
Sep-17	571.6				
Oct-17	557.2				
Nov-17	664.5				
Dec-17	880.3	8,023.8			8,023.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.793409213
R Square	0.629498179
Adjusted R Square	0.618601067
Standard Error	100.7721264
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	586629.4941	586629.4941	57.76743023	7.87227E-09
Residual	34	345270.7299	10155.02147		
Total	35	931900.224			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	456.29257	32.07833705	14.22432121	7.07964E-16	391.1015456	521.4835943	391.1015456	521.4835943
WH-HDD	0.398423111	0.052420722	7.600488815	7.87227E-09	0.291891386	0.504954835	0.291891386	0.504954835

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (7,978.1 / 7,997.6) ^ (1/2) - 1 = **-0.1%**

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Teslin

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	817.9		952.0	791.9	
Feb-13	794.7		665.4	852.4	
Mar-13	617.5		851.1	597.7	
Apr-13	640.8		639.9	604.1	
May-13	477.0		294.0	462.9	
Jun-13	539.6		112.4	551.1	
Jul-13	422.4		92.5	425.7	
Aug-13	471.0		98.9	485.6	
Sep-13	435.3		264.3	447.9	
Oct-13	492.6		501.4	490.7	
Nov-13	665.9		865.6	643.5	
Dec-13	732.7	7,107.6	1,144.7	677.9	7,031.3
Jan-14	800.5		745.8	844.1	
Feb-14	664.0		992.4	611.3	
Mar-14	635.7		855.1	614.6	
Apr-14	539.4		499.8	550.0	
May-14	558.1		269.5	552.2	
Jun-14	409.2		200.5	391.0	
Jul-14	393.7		98.0	395.0	
Aug-14	477.3		144.0	476.6	
Sep-14	461.4		307.1	459.5	
Oct-14	561.2		515.6	554.5	
Nov-14	586.5		772.8	595.4	
Dec-14	709.6	6,796.6	854.4	752.8	6,797.1
Jan-15	896.6		927.0	879.1	
Feb-15	698.5		851.4	693.4	
Mar-15	579.4		671.3	620.4	
Apr-15	605.8		453.5	632.0	
May-15	459.9		192.9	479.9	
Jun-15	437.8		127.2	444.4	
Jul-15	489.7		115.7	485.1	
Aug-15	414.6		183.2	400.7	
Sep-15	490.6		332.7	480.0	
Oct-15	620.9		469.8	629.6	
Nov-15	610.9		759.2	624.4	
Dec-15	685.1	6,989.8	947.9	696.7	7,065.6
Jan-16	915.1		827.6	931.1	
Feb-16	630.8		688.0	680.9	
Mar-16	593.1		611.6	654.2	
Apr-16	633.5				
May-16	481.1				
Jun-16	445.5				
Jul-16	486.3				
Aug-16	401.7				
Sep-16	481.2				
Oct-16	631.1				
Nov-16	625.9				
Dec-16	698.4	7,023.8			7,150.9
Jan-17	933.4				
Feb-17	682.6				
Mar-17	655.8				
Apr-17	635.1				
May-17	482.3				
Jun-17	446.6				
Jul-17	487.4				
Aug-17	402.7				
Sep-17	482.4				
Oct-17	632.7				
Nov-17	627.4				
Dec-17	700.1	7,168.4			7,168.4

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.84543602
R Square	0.714762064
Adjusted R Square	0.706372713
Standard Error	70.31694706
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	421262.8282	421262.8282	85.19873089	8.70474E-11
Residual	34	168112.0835	4944.473043		
Total	35	589374.9117			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	404.362868	22.38367699	18.06507787	5.29865E-19	358.8737633	449.8519726	358.8737633	449.8519726
WH-HDD	0.337628535	0.036578221	9.230315861	8.70474E-11	0.263292646	0.411964424	0.263292646	0.411964424

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (7,065.6 / 7,031.3) ^ (1/2) - 1 = **0.2%**

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Ross River

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,112.2		952.0	1,068.5	
Feb-13	1,051.8		665.4	1,148.7	
Mar-13	835.5		851.1	802.2	
Apr-13	806.5		639.9	744.7	
May-13	626.8		294.0	603.0	
Jun-13	618.2		112.4	637.7	
Jul-13	460.1		92.5	465.5	
Aug-13	642.4		98.9	666.9	
Sep-13	331.5		264.3	352.5	
Oct-13	579.6		501.4	576.3	
Nov-13	872.3		865.6	834.6	
Dec-13	897.2	8,834.1	1,144.7	805.2	8,706.0
Jan-14	1,097.8		745.8	1,171.0	
Feb-14	994.6		992.4	906.2	
Mar-14	926.4		855.1	890.9	
Apr-14	683.3		499.8	701.0	
May-14	717.1		269.5	707.3	
Jun-14	508.4		200.5	477.8	
Jul-14	426.7		98.0	429.0	
Aug-14	586.3		144.0	585.2	
Sep-14	531.9		307.1	528.7	
Oct-14	740.6		515.6	729.3	
Nov-14	788.5		772.8	803.4	
Dec-14	934.7	8,936.3	854.4	1,007.2	8,937.0
Jan-15	1,159.3		927.0	1,129.8	
Feb-15	1,035.1		851.4	1,026.6	
Mar-15	893.2		671.3	962.0	
Apr-15	774.4		453.5	818.4	
May-15	561.6		192.9	595.2	
Jun-15	453.7		127.2	464.7	
Jul-15	493.0		115.7	485.2	
Aug-15	442.1		183.2	418.7	
Sep-15	518.4		332.7	500.6	
Oct-15	680.5		469.8	695.2	
Nov-15	727.1		759.2	749.8	
Dec-15	749.9	8,488.3	947.9	769.4	8,615.6
Jan-16	1,083.6		827.6	1,110.5	
Feb-16	781.4		688.0	865.6	
Mar-16	772.3		611.6	874.9	
Apr-16	814.2				
May-16	592.1				
Jun-16	462.3				
Jul-16	482.7				
Aug-16	416.5				
Sep-16	498.0				
Oct-16	691.5				
Nov-16	745.9				
Dec-16	765.4	8,106.0			8,319.6
Jan-17	1,104.7				
Feb-17	861.0				
Mar-17	870.4				
Apr-17	809.9				
May-17	589.0				
Jun-17	459.9				
Jul-17	480.2				
Aug-17	414.4				
Sep-17	495.4				
Oct-17	687.9				
Nov-17	742.0				
Dec-17	761.4	8,276.3			8,276.3

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.838583702
R Square	0.703222625
Adjusted R Square	0.694493879
Standard Error	121.4563291
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1188450.958	1188450.958	80.56398937	1.72118E-10
Residual	34	501555.7556	14751.63987		
Total	35	1690006.713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	433.7467106	38.6626461	11.21875387	5.66598E-13	355.1747603	512.3186608	355.1747603	512.3186608
WH-HDD	0.567091591	0.063180452	8.975744503	1.72118E-10	0.438693465	0.695489717	0.438693465	0.695489717

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (8,615.6/ 8,706.0) ^ (1/2) - 1 = **-0.5%**

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Pelly Crossing

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,184.6		952.0	1,137.8	
Feb-13	1,016.8		665.4	1,120.7	
Mar-13	907.0		851.1	871.4	
Apr-13	1,039.8		639.9	973.6	
May-13	877.2		294.0	851.7	
Jun-13	564.2		112.4	585.0	
Jul-13	606.9		92.5	612.7	
Aug-13	656.8		98.9	683.0	
Sep-13	667.4		264.3	690.0	
Oct-13	905.7		501.4	902.2	
Nov-13	940.4		865.6	900.0	
Dec-13	943.7	10,310.4	1,144.7	845.0	10,173.2
Jan-14	1,579.6		745.8	1,658.1	
Feb-14	1,191.5		992.4	1,096.7	
Mar-14	969.4		855.1	931.4	
Apr-14	868.5		499.8	887.5	
May-14	822.2		269.5	811.7	
Jun-14	627.2		200.5	594.5	
Jul-14	623.7		98.0	626.2	
Aug-14	636.8		144.0	635.6	
Sep-14	747.6		307.1	744.1	
Oct-14	920.4		515.6	908.2	
Nov-14	911.2		772.8	927.2	
Dec-14	1,263.7	11,162.0	854.4	1,341.4	11,162.8
Jan-15	1,147.2		927.0	1,115.5	
Feb-15	1,015.8		851.4	1,006.6	
Mar-15	953.5		671.3	1,027.2	
Apr-15	883.2		453.5	930.3	
May-15	562.3		192.9	598.3	
Jun-15	593.2		127.2	605.1	
Jul-15	635.5		115.7	627.2	
Aug-15	561.8		183.2	536.8	
Sep-15	677.3		332.7	658.3	
Oct-15	830.3		469.8	846.0	
Nov-15	941.7		759.2	966.0	
Dec-15	1,288.1	10,089.8	947.9	1,309.0	10,226.3
Jan-16	844.5		827.6	873.3	
Feb-16	901.4		688.0	991.6	
Mar-16	756.7		611.6	866.7	
Apr-16	932.8				
May-16	599.9				
Jun-16	606.6				
Jul-16	628.8				
Aug-16	538.2				
Sep-16	660.0				
Oct-16	848.2				
Nov-16	968.5				
Dec-16	1,312.4	9,598.0			9,826.9
Jan-17	875.5				
Feb-17	994.2				
Mar-17	868.9				
Apr-17	935.2				
May-17	601.5				
Jun-17	608.2				
Jul-17	630.5				
Aug-17	539.6				
Sep-17	661.7				
Oct-17	850.4				
Nov-17	971.0				
Dec-17	1,315.8	9,852.5			9,852.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.821475881
R Square	0.674822624
Adjusted R Square	0.665258583
Standard Error	139.0795254
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1364817.646	1364817.646	70.55831954	8.29502E-10
Residual	34	657665.8895	19343.1144		
Total	35	2022483.536			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	559.8897263	44.27255881	12.64642798	2.07697E-14	469.9170617	649.8623908	469.9170617	649.8623908
WH-HDD	0.607714907	0.072347874	8.399899972	8.29502E-10	0.460686337	0.754743477	0.460686337	0.754743477

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (10,226.3 / 10,173.2) ^ (1/2) - 1 = **0.3%**

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Old Crow

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	819.8		952.0	792.9	
Feb-13	900.1		665.4	959.8	
Mar-13	725.9		851.1	705.4	
Apr-13	676.2		639.9	638.2	
May-13	606.9		294.0	592.2	
Jun-13	630.1		112.4	642.1	
Jul-13	427.0		92.5	430.4	
Aug-13	473.0		98.9	488.1	
Sep-13	493.8		264.3	506.8	
Oct-13	615.3		501.4	613.3	
Nov-13	685.1		865.6	661.9	
Dec-13	727.7	7,781.0	1,144.7	671.0	7,702.0
Jan-14	985.8		745.8	1,030.9	
Feb-14	705.6		992.4	651.1	
Mar-14	812.8		855.1	791.0	
Apr-14	707.5		499.8	718.5	
May-14	705.7		269.5	699.6	
Jun-14	494.4		200.5	475.6	
Jul-14	622.2		98.0	623.6	
Aug-14	419.2		144.0	418.5	
Sep-14	358.7		307.1	356.6	
Oct-14	607.7		515.6	600.7	
Nov-14	662.8		772.8	672.0	
Dec-14	765.7	7,848.1	854.4	810.4	7,848.6
Jan-15	956.9		927.0	938.7	
Feb-15	789.9		851.4	784.6	
Mar-15	862.2		671.3	904.6	
Apr-15	770.1		453.5	797.2	
May-15	537.8		192.9	558.5	
Jun-15	443.5		127.2	450.3	
Jul-15	498.8		115.7	494.0	
Aug-15	436.9		183.2	422.5	
Sep-15	550.7		332.7	539.8	
Oct-15	532.7		469.8	541.8	
Nov-15	615.7		759.2	629.7	
Dec-15	667.8	7,662.9	947.9	679.8	7,741.4
Jan-16	849.1		827.6	865.6	
Feb-16	715.3		688.0	767.1	
Mar-16	717.3		611.6	780.5	
Apr-16	799.2				
May-16	559.9				
Jun-16	451.4				
Jul-16	495.3				
Aug-16	423.6				
Sep-16	541.2				
Oct-16	543.1				
Nov-16	631.3				
Dec-16	681.5	7,408.1			7,539.7
Jan-17	867.8				
Feb-17	769.1				
Mar-17	782.5				
Apr-17	801.2				
May-17	561.4				
Jun-17	452.6				
Jul-17	496.6				
Aug-17	424.6				
Sep-17	542.5				
Oct-17	544.5				
Nov-17	632.9				
Dec-17	683.3	7,558.9			7,558.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.723041418
R Square	0.522788892
Adjusted R Square	0.508753271
Standard Error	110.0403782
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	451023.19	451023.19	37.24729373	6.33144E-07
Residual	34	411702.0843	12108.88483		
Total	35	862725.2743			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	464.8619829	35.02865788	13.27090477	5.27645E-15	393.6751853	536.0487806	393.6751853	536.0487806
WH-HDD	0.349351016	0.05724198	6.103056097	6.33144E-07	0.233021316	0.465680716	0.233021316	0.465680716

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (7,741.4 / 7,702.0) ^ (1/2) - 1 = **0.3%**

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Destruction Bay

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	869.1		952.0	840.6	
Feb-13	724.1		665.4	787.4	
Mar-13	638.8		851.1	617.2	
Apr-13	674.9		639.9	634.7	
May-13	511.9		294.0	496.4	
Jun-13	496.3		112.4	509.0	
Jul-13	505.1		92.5	508.7	
Aug-13	460.4		98.9	476.3	
Sep-13	482.9		264.3	496.6	
Oct-13	527.6		501.4	525.4	
Nov-13	563.5		865.6	538.9	
Dec-13	769.4	7,224.0	1,144.7	709.4	7,140.5
Jan-14	937.9		745.8	985.7	
Feb-14	728.2		992.4	670.5	
Mar-14	794.9		855.1	771.7	
Apr-14	608.3		499.8	619.9	
May-14	551.3		269.5	544.9	
Jun-14	463.0		200.5	443.1	
Jul-14	506.2		98.0	507.7	
Aug-14	326.7		144.0	325.9	
Sep-14	513.2		307.1	511.1	
Oct-14	367.5		515.6	360.1	
Nov-14	570.6		772.8	580.4	
Dec-14	627.2	6,995.0	854.4	674.5	6,995.4
Jan-15	909.9		927.0	890.7	
Feb-15	718.0		851.4	712.5	
Mar-15	592.8		671.3	637.6	
Apr-15	588.6		453.5	617.3	
May-15	479.4		192.9	501.4	
Jun-15	415.9		127.2	423.1	
Jul-15	475.7		115.7	470.6	
Aug-15	374.6		183.2	359.4	
Sep-15	539.3		332.7	527.7	
Oct-15	477.6		469.8	487.1	
Nov-15	642.8		759.2	657.6	
Dec-15	768.2	6,982.8	947.9	780.9	7,065.9
Jan-16	762.3		827.6	779.8	
Feb-16	604.9		688.0	659.8	
Mar-16	663.4		611.6	730.3	
Apr-16	614.1				
May-16	498.7				
Jun-16	420.9				
Jul-16	468.2				
Aug-16	357.5				
Sep-16	524.9				
Oct-16	484.5				
Nov-16	654.1				
Dec-16	776.9	6,830.4			6,969.7
Jan-17	775.7				
Feb-17	656.3				
Mar-17	726.5				
Apr-17	610.9				
May-17	496.1				
Jun-17	418.7				
Jul-17	465.7				
Aug-17	355.6				
Sep-17	522.2				
Oct-17	482.0				
Nov-17	650.7				
Dec-17	772.8	6,933.2			6,933.2

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.796569352
R Square	0.634522732
Adjusted R Square	0.623773401
Standard Error	92.54244913
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	505530.9055	505530.9055	59.0290418	6.21878E-09
Residual	34	291179.5663	8564.10489		
Total	35	796710.4718			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	396.109009	29.45862095	13.44628487	3.61955E-15	336.2418884	455.9761297	336.2418884	455.9761297
WH-HDD	0.369859204	0.04813972	7.683035975	6.21878E-09	0.272027521	0.467690886	0.272027521	0.467690886

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (7,065.9 / 7,140.5) ^ (1/2) - 1 = **-0.5%**

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Beaver Creek

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,137.3		952.0	1,105.4	
Feb-13	1,006.1		665.4	1,076.9	
Mar-13	843.4		851.1	819.1	
Apr-13	777.2		639.9	732.2	
May-13	656.2		294.0	638.9	
Jun-13	713.0		112.4	727.2	
Jul-13	524.3		92.5	528.2	
Aug-13	601.9		98.9	619.7	
Sep-13	614.7		264.3	630.0	
Oct-13	671.7		501.4	669.3	
Nov-13	892.8		865.6	865.3	
Dec-13	791.9	9,230.4	1,144.7	724.6	9,136.8
Jan-14	1,075.7		745.8	1,129.2	
Feb-14	1,006.6		992.4	942.0	
Mar-14	662.4		855.1	636.5	
Apr-14	538.5		499.8	551.4	
May-14	727.1		269.5	719.9	
Jun-14	566.8		200.5	544.5	
Jul-14	530.0		98.0	531.7	
Aug-14	571.6		144.0	570.8	
Sep-14	588.1		307.1	585.7	
Oct-14	612.3		515.6	604.0	
Nov-14	816.4		772.8	827.3	
Dec-14	839.3	8,534.8	854.4	892.3	8,535.3
Jan-15	1,167.1		927.0	1,145.6	
Feb-15	773.6		851.4	767.4	
Mar-15	716.1		671.3	766.3	
Apr-15	743.1		453.5	775.2	
May-15	597.0		192.9	621.5	
Jun-15	554.5		127.2	562.5	
Jul-15	533.8		115.7	528.1	
Aug-15	545.1		183.2	528.1	
Sep-15	668.1		332.7	655.1	
Oct-15	519.5		469.8	530.2	
Nov-15	833.3		759.2	849.9	
Dec-15	761.8	8,413.1	947.9	776.1	8,506.0
Jan-16	1,076.4		827.6	1,096.0	
Feb-16	772.0		688.0	833.4	
Mar-16	820.0		611.6	894.9	
Apr-16	748.0				
May-16	599.7				
Jun-16	542.8				
Jul-16	509.6				
Aug-16	509.5				
Sep-16	632.1				
Oct-16	511.5				
Nov-16	820.0				
Dec-16	748.8	8,290.4			8,446.4
Jan-17	1,057.5				
Feb-17	804.1				
Mar-17	863.4				
Apr-17	721.7				
May-17	578.6				
Jun-17	523.7				
Jul-17	491.7				
Aug-17	491.6				
Sep-17	609.9				
Oct-17	493.6				
Nov-17	791.2				
Dec-17	722.5	8,149.6			8,149.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.750424818
R Square	0.563137407
Adjusted R Square	0.550288507
Standard Error	120.2366371
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	633610.0783	633610.0783	43.82767523	1.36344E-07
Residual	34	491532.8625	14456.8489		
Total	35	1125142.941			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	511.292946	38.27438704	13.35861879	4.36807E-15	433.5100331	589.0758589	433.5100331	589.0758589
WH-HDD	0.414069854	0.062545979	6.620247369	1.36344E-07	0.286961131	0.541178577	0.286961131	0.541178577

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (8,506.0 / 9,136.8) ^ (1/2) - 1 = **-3.5%**

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Tagish

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	716.2		952.0	690.7	
Feb-13	487.4		665.4	544.0	
Mar-13	502.0		851.1	482.6	
Apr-13	392.1		639.9	356.1	
May-13	350.2		294.0	336.4	
Jun-13	335.0		112.4	346.3	
Jul-13	278.4		92.5	281.5	
Aug-13	357.9		98.9	372.1	
Sep-13	259.0		264.3	271.2	
Oct-13	344.8		501.4	342.9	
Nov-13	497.0		865.6	475.0	
Dec-13	592.5	5,112.5	1,144.7	538.9	5,037.8
Jan-14	606.7		745.8	649.4	
Feb-14	594.2		992.4	542.7	
Mar-14	548.7		855.1	528.0	
Apr-14	375.4		499.8	385.7	
May-14	310.0		269.5	304.3	
Jun-14	307.9		200.5	290.1	
Jul-14	295.2		98.0	296.5	
Aug-14	314.4		144.0	313.8	
Sep-14	310.3		307.1	308.4	
Oct-14	340.5		515.6	333.9	
Nov-14	421.8		772.8	430.5	
Dec-14	560.6	4,985.6	854.4	602.9	4,986.1
Jan-15	579.2		927.0	562.0	
Feb-15	536.8		851.4	531.8	
Mar-15	381.3		671.3	421.4	
Apr-15	384.5		453.5	410.1	
May-15	302.7		192.9	322.3	
Jun-15	278.4		127.2	284.9	
Jul-15	322.4		115.7	317.9	
Aug-15	287.6		183.2	274.0	
Sep-15	328.7		332.7	318.3	
Oct-15	403.2		469.8	411.7	
Nov-15	460.1		759.2	473.4	
Dec-15	524.3	4,789.3	947.9	535.7	4,863.5
Jan-16	694.1		827.6	709.7	
Feb-16	463.7		688.0	512.8	
Mar-16	415.8		611.6	475.6	
Apr-16	403.0				
May-16	316.7				
Jun-16	279.9				
Jul-16	312.3				
Aug-16	269.2				
Sep-16	312.8				
Oct-16	404.5				
Nov-16	465.1				
Dec-16	526.4	4,863.5			4,988.0
Jan-17	697.3				
Feb-17	503.8				
Mar-17	467.3				
Apr-17	395.9				
May-17	311.2				
Jun-17	275.0				
Jul-17	306.9				
Aug-17	264.5				
Sep-17	307.3				
Oct-17	397.5				
Nov-17	457.0				
Dec-17	517.2	4,900.9			4,900.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.89996326
R Square	0.809933869
Adjusted R Square	0.804343689
Standard Error	52.79318769
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	403812.2738	403812.2738	144.8851062	8.2675E-14
Residual	34	94762.10265	2787.120666		
Total	35	498574.3764			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	241.1973695	16.80541761	14.35235797	5.44582E-16	207.0446518	275.3500872	207.0446518	275.3500872
WH-HDD	0.330561547	0.027462525	12.03682293	8.2675E-14	0.274750982	0.386372112	0.274750982	0.386372112

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (4,863.5 / 5,037.8) ^ (1/2) - 1 = **-1.7%**

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Marsh Lake

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,030.8		952.0	981.5	
Feb-13	1,020.2		665.4	1,129.4	
Mar-13	885.4		851.1	847.9	
Apr-13	823.2		639.9	753.6	
May-13	650.7		294.0	623.9	
Jun-13	531.7		112.4	553.6	
Jul-13	488.7		92.5	494.8	
Aug-13	574.7		98.9	602.2	
Sep-13	452.1		264.3	475.8	
Oct-13	717.3		501.4	713.6	
Nov-13	890.0		865.6	847.6	
Dec-13	1,144.2	9,208.9	1,144.7	1,040.5	9,064.6
Jan-14	1,034.0		745.8	1,116.6	
Feb-14	981.4		992.4	881.7	
Mar-14	881.7		855.1	841.7	
Apr-14	785.7		499.8	805.7	
May-14	504.8		269.5	493.7	
Jun-14	501.4		200.5	467.0	
Jul-14	511.3		98.0	513.9	
Aug-14	486.0		144.0	484.7	
Sep-14	537.9		307.1	534.2	
Oct-14	669.5		515.6	656.7	
Nov-14	761.6		772.8	778.5	
Dec-14	1,119.5	8,774.9	854.4	1,201.3	8,775.7
Jan-15	989.1		927.0	955.8	
Feb-15	1,012.7		851.4	1,003.1	
Mar-15	702.1		671.3	779.5	
Apr-15	754.3		453.5	803.9	
May-15	528.1		192.9	566.0	
Jun-15	451.8		127.2	464.3	
Jul-15	528.7		115.7	520.0	
Aug-15	475.3		183.2	449.0	
Sep-15	655.4		332.7	635.4	
Oct-15	624.3		469.8	640.8	
Nov-15	857.3		759.2	882.8	
Dec-15	1,102.5	8,681.6	947.9	1,124.5	8,825.1
Jan-16	936.7		827.6	966.9	
Feb-16	842.3		688.0	937.1	
Mar-16	830.2		611.6	945.8	
Apr-16	793.2				
May-16	558.5				
Jun-16	458.1				
Jul-16	513.1				
Aug-16	443.0				
Sep-16	626.9				
Oct-16	632.2				
Nov-16	871.1				
Dec-16	1,109.6	8,614.9			8,855.6
Jan-17	954.1				
Feb-17	924.6				
Mar-17	933.3				
Apr-17	782.7				
May-17	551.0				
Jun-17	452.0				
Jul-17	506.3				
Aug-17	437.1				
Sep-17	618.6				
Oct-17	623.8				
Nov-17	859.5				
Dec-17	1,094.8	8,737.8			8,737.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.932748123
R Square	0.870019061
Adjusted R Square	0.866196092
Standard Error	81.44038143
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1509411.356	1509411.356	227.576815	1.25145E-16
Residual	34	225506.2147	6632.535727		
Total	35	1734917.57			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	407.5048998	25.92454975	15.71888051	3.66696E-17	354.8198759	460.1899237	354.8198759	460.1899237
WH-HDD	0.639096415	0.042364528	15.08564931	1.25145E-16	0.553001335	0.725191495	0.553001335	0.725191495

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (8,825.1 / 9,064.6) ^ (1/2) - 1 = **-1.3%**

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Lower Post

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,365.5		1,129.1	1,315.5	
Feb-13	760.6		765.8	866.2	
Mar-13	1,157.2		950.7	1,136.0	
Apr-13	982.1		690.1	929.7	
May-13	363.2		304.5	352.0	
Jun-13	698.5		96.3	716.2	
Jul-13	432.2		105.1	427.2	
Aug-13	685.2		82.2	706.7	
Sep-13	334.0		239.1	359.7	
Oct-13	647.0		490.2	660.9	
Nov-13	632.5		1,021.3	595.9	
Dec-13	1,121.1	9,179.1	1,248.8	1,094.2	9,160.2
Jan-14	1,343.0		937.7	1,389.4	
Feb-14	1,005.4		1,204.4	890.4	
Mar-14	1,038.9		1,008.9	988.5	
Apr-14	914.5		570.5	922.3	
May-14	752.2		331.1	727.6	
Jun-14	547.8		186.8	520.0	
Jul-14	583.8		87.6	587.6	
Aug-14	486.4		144.8	476.3	
Sep-14	545.5		295.8	542.8	
Oct-14	639.8		539.7	628.8	
Nov-14	630.9		936.4	637.0	
Dec-14	937.6	9,425.9	1,176.7	946.9	9,257.6
Jan-15	1,115.7		1,022.8	1,119.3	
Feb-15	824.6		956.7	834.2	
Mar-15	816.2		766.3	887.8	
Apr-15	537.5		497.4	582.1	
May-15	543.9		210.8	579.7	
Jun-15	431.2		111.8	441.2	
Jul-15	529.8		92.4	531.1	
Aug-15	475.6		147.5	464.2	
Sep-15	610.7		336.1	587.6	
Oct-15	652.3		523.7	649.4	
Nov-15	672.4		887.8	702.9	
Dec-15	829.3	8,039.4	1,160.3	846.9	8,226.5
Jan-16	1,197.6		1,099.3	1,162.6	
Feb-16	900.2		930.8	922.8	
Mar-16	848.4		724.3	941.1	
Apr-16	551.6				
May-16	549.4				
Jun-16	418.1				
Jul-16	503.3				
Aug-16	439.9				
Sep-16	556.9				
Oct-16	615.4				
Nov-16	666.1				
Dec-16	802.6	8,049.5			8,129.9
Jan-17	1,101.8				
Feb-17	874.5				
Mar-17	891.8				
Apr-17	522.8				
May-17	520.6				
Jun-17	396.2				
Jul-17	477.0				
Aug-17	416.9				
Sep-17	527.7				
Oct-17	583.2				
Nov-17	631.3				
Dec-17	760.6	7,704.4			7,704.4

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.759683442
R Square	0.577118932
Adjusted R Square	0.564681253
Standard Error	174.7217725
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1416511.318	1416511.318	46.40085631	7.75592E-08
Residual	34	1037941.725	30527.69779		
Total	35	2454453.043			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	443.169536	52.42506975	8.453389534	7.15505E-10	336.6289758	549.7100961	336.6289758	549.7100961
WL-HDD	0.502900353	0.073827633	6.811817401	7.75592E-08	0.352864552	0.652936154	0.352864552	0.652936154

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (8,226.5 / 9,160.2) ^ (1/2) - 1 = **-5.2%**

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Upper Liard

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,277.3		1,129.1	1,243.1	
Feb-13	855.9		765.8	928.3	
Mar-13	777.7		950.7	763.2	
Apr-13	763.2		690.1	727.2	
May-13	676.9		304.5	669.1	
Jun-13	566.5		96.3	578.7	
Jul-13	517.6		105.1	514.1	
Aug-13	596.3		82.2	611.1	
Sep-13	559.6		239.1	577.3	
Oct-13	651.6		490.2	661.2	
Nov-13	618.6		1,021.3	593.5	
Dec-13	940.9	8,802.0	1,248.8	922.4	8,789.1
Jan-14	1,095.2		937.7	1,127.0	
Feb-14	766.4		1,204.4	687.5	
Mar-14	826.4		1,008.9	791.9	
Apr-14	823.1		570.5	828.5	
May-14	596.8		331.1	579.9	
Jun-14	526.8		186.8	507.8	
Jul-14	530.0		87.6	532.6	
Aug-14	521.1		144.8	514.2	
Sep-14	604.0		295.8	602.1	
Oct-14	591.6		539.7	584.0	
Nov-14	679.3		936.4	683.5	
Dec-14	925.9	8,486.6	1,176.7	932.3	8,371.2
Jan-15	1,018.4		1,022.8	1,020.8	
Feb-15	880.8		956.7	887.4	
Mar-15	745.4		766.3	794.5	
Apr-15	835.3		497.4	865.9	
May-15	663.8		210.8	688.4	
Jun-15	475.5		111.8	482.4	
Jul-15	559.2		92.4	560.1	
Aug-15	528.0		147.5	520.2	
Sep-15	661.3		336.1	645.5	
Oct-15	672.2		523.7	670.2	
Nov-15	772.6		887.8	793.5	
Dec-15	732.6	8,545.3	1,160.3	744.7	8,673.7
Jan-16	953.5		1,099.3	929.6	
Feb-16	714.1		930.8	729.5	
Mar-16	668.4		724.3	732.0	
Apr-16	860.2				
May-16	683.9				
Jun-16	479.2				
Jul-16	556.4				
Aug-16	516.8				
Sep-16	641.3				
Oct-16	665.8				
Nov-16	788.3				
Dec-16	739.8	8,267.7			8,322.8
Jan-17	923.4				
Feb-17	724.7				
Mar-17	727.2				
Apr-17	854.5				
May-17	679.4				
Jun-17	476.0				
Jul-17	552.7				
Aug-17	513.4				
Sep-17	637.1				
Oct-17	661.4				
Nov-17	783.1				
Dec-17	734.9	8,267.9			8,267.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.766190237
R Square	0.58704748
Adjusted R Square	0.574901817
Standard Error	117.4322896
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	666541.326	666541.326	48.33392058	5.13861E-08
Residual	34	468871.6497	13790.34264		
Total	35	1135412.976			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	513.9112982	35.23542535	14.58507434	3.39494E-16	442.3042985	585.5182979	442.3042985	585.5182979
WL-HDD	0.344973279	0.049620307	6.952260106	5.13861E-08	0.244132683	0.445813874	0.244132683	0.445813874

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (8,673.7 / 8,789.1) ^ (1/2) - 1 = **-0.7%**

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Watson Lake

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,132.4		1,129.1	1,093.2	
Feb-13	913.2		765.8	996.2	
Mar-13	875.6		950.7	859.0	
Apr-13	807.4		690.1	766.2	
May-13	736.7		304.5	727.9	
Jun-13	665.0		96.3	678.9	
Jul-13	594.5		105.1	590.6	
Aug-13	587.0		82.2	603.8	
Sep-13	538.9		239.1	559.1	
Oct-13	649.6		490.2	660.5	
Nov-13	763.2		1,021.3	734.4	
Dec-13	1,018.9	9,282.4	1,248.8	997.7	9,267.6
Jan-14	1,046.8		937.7	1,083.2	
Feb-14	898.5		1,204.4	808.1	
Mar-14	947.2		1,008.9	907.6	
Apr-14	774.1		570.5	780.3	
May-14	703.0		331.1	683.7	
Jun-14	597.6		186.8	575.8	
Jul-14	591.1		87.6	594.0	
Aug-14	529.2		144.8	521.3	
Sep-14	571.9		295.8	569.8	
Oct-14	683.5		539.7	674.8	
Nov-14	737.2		936.4	742.0	
Dec-14	1,019.1	9,099.1	1,176.7	1,026.4	8,966.8
Jan-15	1,084.7		1,022.8	1,087.5	
Feb-15	892.4		956.7	899.9	
Mar-15	819.6		766.3	875.9	
Apr-15	728.9		497.4	764.0	
May-15	645.2		210.8	673.4	
Jun-15	536.7		111.8	544.5	
Jul-15	552.7		92.4	553.7	
Aug-15	521.9		147.5	512.9	
Sep-15	626.0		336.1	607.9	
Oct-15	680.6		523.7	678.3	
Nov-15	803.0		887.8	827.0	
Dec-15	951.9	8,843.7	1,160.3	965.7	8,990.7
Jan-16	1,081.9		1,099.3	1,054.5	
Feb-16	884.0		930.8	901.7	
Mar-16	839.9		724.3	912.8	
Apr-16	752.5				
May-16	663.2				
Jun-16	536.3				
Jul-16	545.4				
Aug-16	505.2				
Sep-16	598.8				
Oct-16	668.1				
Nov-16	814.6				
Dec-16	951.2	8,841.0			8,904.2
Jan-17	1,038.6				
Feb-17	888.2				
Mar-17	899.0				
Apr-17	741.1				
May-17	653.3				
Jun-17	528.3				
Jul-17	537.2				
Aug-17	497.6				
Sep-17	589.7				
Oct-17	658.1				
Nov-17	802.3				
Dec-17	936.8	8,770.2			8,770.2

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.898925093
R Square	0.808066323
Adjusted R Square	0.802421215
Standard Error	78.16644414
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	874612.0413	874612.0413	143.1445245	9.77309E-14
Residual	34	207739.7616	6109.992989		
Total	35	1082351.803			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	522.9171634	23.45375294	22.29567118	7.14068E-22	475.2534028	570.5809241	475.2534028	570.5809241
WL-HDD	0.395166065	0.03302876	11.96430209	9.77309E-14	0.328043548	0.462288581	0.328043548	0.462288581

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (8,990.7 / 9,267.6) ^ (1/2) - 1 = **-1.5%**

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Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

Whitehorse (Includes Takhini & Deep Creek)

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,539.9		952.0	1,489.6	
Feb-13	1,152.3		665.4	1,264.1	
Mar-13	1,075.4		851.1	1,037.1	
Apr-13	1,092.7		639.9	1,021.6	
May-13	843.2		294.0	815.8	
Jun-13	743.9		112.4	766.3	
Jul-13	667.8		92.5	674.1	
Aug-13	643.5		98.9	671.7	
Sep-13	664.6		264.3	688.9	
Oct-13	762.8		501.4	759.1	
Nov-13	920.2		865.6	876.8	
Dec-13	1,161.1	11,267.6	1,144.7	1,055.0	11,119.9
Jan-14	1,467.1		745.8	1,551.5	
Feb-14	1,067.5		992.4	965.5	
Mar-14	1,217.3		855.1	1,176.4	
Apr-14	949.3		499.8	969.7	
May-14	838.2		269.5	826.9	
Jun-14	718.4		200.5	683.3	
Jul-14	687.6		98.0	690.3	
Aug-14	574.7		144.0	573.5	
Sep-14	738.8		307.1	735.0	
Oct-14	768.1		515.6	755.1	
Nov-14	901.6		772.8	918.9	
Dec-14	1,070.2	10,998.9	854.4	1,153.8	10,999.8
Jan-15	1,414.9		927.0	1,380.8	
Feb-15	1,235.3		851.4	1,225.5	
Mar-15	1,043.4		671.3	1,122.7	
Apr-15	952.6		453.5	1,003.3	
May-15	780.9		192.9	819.6	
Jun-15	647.9		127.2	660.6	
Jul-15	629.0		115.7	620.1	
Aug-15	606.6		183.2	579.7	
Sep-15	743.5		332.7	723.0	
Oct-15	786.2		469.8	803.0	
Nov-15	930.3		759.2	956.4	
Dec-15	1,105.8	10,876.2	947.9	1,128.3	11,023.0
Jan-16	1383.1		827.6	1,414.0	
Feb-16	1061.6		688.0	1,158.6	
Mar-16	1026.0		611.6	1,144.3	
Apr-16	998.2				
May-16	820.7				
Jun-16	703.4				
Jul-16	661.5				
Aug-16	608.3				
Sep-16	715.6				
Oct-16	772.4				
Nov-16	917.4				
Dec-16	1112.4	10,780.6			11,026.7
Jan-17	1474.0				
Feb-17	1151.7				
Mar-17	1112.1				
Apr-17	998.2				
May-17	820.7				
Jun-17	703.4				
Jul-17	661.5				
Aug-17	608.3				
Sep-17	715.6				
Oct-17	772.4				
Nov-17	917.4				
Dec-17	1112.4	11,047.6			11,047.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.838195038
R Square	0.702570922
Adjusted R Square	0.693823008
Standard Error	140.2171904
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1579022.018	1579022.018	80.31296588	1.78734E-10
Residual	34	668469.2568	19660.86049		
Total	35	2247491.275			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	579.8341011	44.63470658	12.9906556	9.70538E-15	489.1254638	670.5427385	489.1254638	670.5427385
WH-HDD	0.653667162	0.072939677	8.961750157	1.78734E-10	0.505435904	0.80189842	0.505435904	0.80189842

Carmacks

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,551.4		952.0	1,492.7	
Feb-13	1,103.7		665.4	1,234.1	
Mar-13	1,129.4		851.1	1,084.8	
Apr-13	1,261.5		639.9	1,178.6	
May-13	857.1		294.0	825.2	
Jun-13	568.8		112.4	595.0	
Jul-13	626.6		92.5	633.9	
Aug-13	696.6		98.9	729.5	
Sep-13	614.4		264.3	642.6	
Oct-13	983.9		501.4	979.5	
Nov-13	947.9		865.6	897.3	
Dec-13	1,003.9	11,345.3	1,144.7	880.2	11,173.1
Jan-14	1,708.4		745.8	1,806.8	
Feb-14	1,210.7		992.4	1,091.8	
Mar-14	1,052.8		855.1	1,005.1	
Apr-14	921.1		499.8	944.9	
May-14	896.7		269.5	883.5	
Jun-14	589.1		200.5	548.1	
Jul-14	549.7		98.0	552.8	
Aug-14	734.6		144.0	733.1	
Sep-14	621.8		307.1	617.4	
Oct-14	943.9		515.6	928.6	
Nov-14	960.6		772.8	980.7	
Dec-14	1,431.2	11,620.4	854.4	1,528.7	11,621.4
Jan-15	1,265.4		927.0	1,225.7	
Feb-15	1,129.5		851.4	1,118.1	
Mar-15	1,179.2		671.3	1,271.5	
Apr-15	878.6		453.5	937.7	
May-15	771.9		192.9	817.1	
Jun-15	515.3		127.2	530.1	
Jul-15	662.1		115.7	651.7	
Aug-15	562.8		183.2	531.5	
Sep-15	767.6		332.7	743.7	
Oct-15	925.5		469.8	945.2	
Nov-15	1,084.0		759.2	1,114.5	
Dec-15	1,384.8	11,126.7	947.9	1,411.0	11,297.8
Jan-16	1073.3		827.6	1,109.4	
Feb-16	1045.3		688.0	1,158.4	
Mar-16	928.6		611.6	1,066.5	
Apr-16	1020.4				
May-16	841.9				
Jun-16	557.7				
Jul-16	612.8				
Aug-16	664.7				
Sep-16	667.9				
Oct-16	951.1				
Nov-16	997.5				
Dec-16	1273.3	10,634.6			10,921.7
Jan-17	1508.4				
Feb-17	1148.0				
Mar-17	1120.5				
Apr-17	1020.4				
May-17	841.9				
Jun-17	557.7				
Jul-17	612.8				
Aug-17	664.7				
Sep-17	667.9				
Oct-17	951.1				
Nov-17	997.5				
Dec-17	1273.3	11,364.1			11,364.1

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.822785364
R Square	0.676975755
Adjusted R Square	0.667475042
Standard Error	173.5723265
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2146732.251	2146732.251	71.25525715	7.39828E-10
Residual	34	1024329.985	30127.35251		
Total	35	3171062.236			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	549.6449397	55.25249677	9.94787515	1.33338E-11	437.3583565	661.9315228	437.3583565	661.9315228
WH-HDD	0.762169412	0.090290708	8.441282909	7.39828E-10	0.578676616	0.945662208	0.578676616	0.945662208

Carcross

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,109.8		952.0	1,076.3	
Feb-13	930.9		665.4	1,005.1	
Mar-13	770.6		851.1	745.2	
Apr-13	793.2		639.9	745.9	
May-13	742.3		294.0	724.1	
Jun-13	552.9		112.4	567.8	
Jul-13	458.9		92.5	463.1	
Aug-13	449.8		98.9	468.5	
Sep-13	449.9		264.3	466.0	
Oct-13	485.5		501.4	483.0	
Nov-13	659.7		865.6	630.9	
Dec-13	754.9	8,158.4	1,144.7	684.3	8,060.2
Jan-14	1,035.2		745.8	1,091.3	
Feb-14	784.0		992.4	716.2	
Mar-14	915.4		855.1	888.2	
Apr-14	796.3		499.8	809.9	
May-14	716.6		269.5	709.0	
Jun-14	487.0		200.5	463.6	
Jul-14	517.5		98.0	519.3	
Aug-14	437.1		144.0	436.3	
Sep-14	465.3		307.1	462.8	
Oct-14	547.8		515.6	539.1	
Nov-14	629.4		772.8	640.9	
Dec-14	709.3	8,040.9	854.4	764.8	8,041.5
Jan-15	989.5		927.0	966.9	
Feb-15	874.2		851.4	867.7	
Mar-15	858.9		671.3	911.6	
Apr-15	695.3		453.5	729.0	
May-15	679.7		192.9	705.5	
Jun-15	475.4		127.2	483.9	
Jul-15	405.4		115.7	399.5	
Aug-15	479.4		183.2	461.6	
Sep-15	447.4		332.7	433.8	
Oct-15	602.6		469.8	613.8	
Nov-15	593.3		759.2	610.7	
Dec-15	782.7	7,884.0	947.9	797.6	7,981.6
Jan-16	993.3		827.6	1,013.9	
Feb-16	847.5		688.0	911.9	
Mar-16	834.1		611.6	912.6	
Apr-16	761.6				
May-16	712.9				
Jun-16	505.1				
Jul-16	460.6				
Aug-16	455.4				
Sep-16	454.2				
Oct-16	545.3				
Nov-16	627.5				
Dec-16	748.9	7,946.4			8,110.0
Jan-17	1,044.8				
Feb-17	863.0				
Mar-17	848.3				
Apr-17	761.6				
May-17	712.9				
Jun-17	505.1				
Jul-17	460.6				
Aug-17	455.4				
Sep-17	454.2				
Oct-17	545.3				
Nov-17	627.5				
Dec-17	748.9	8,027.8			8,027.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.737710008
R Square	0.544216056
Adjusted R Square	0.530810646
Standard Error	131.0613884
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	697333.8925	697333.8925	40.59674794	2.84723E-07
Residual	34	584020.9758	17177.08752		
Total	35	1281354.868			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	442.5050549	41.72018136	10.60649883	2.52805E-12	357.7194454	527.2906644	357.7194454	527.2906644
WH-HDD	0.434393144	0.068176914	6.371557733	2.84723E-07	0.295840984	0.572945303	0.295840984	0.572945303

Haines Junction

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	990.8		952.0	960.1	
Feb-13	851.0		665.4	919.1	
Mar-13	775.5		851.1	752.2	
Apr-13	729.3		639.9	685.9	
May-13	620.4		294.0	603.7	
Jun-13	632.9		112.4	646.6	
Jul-13	553.4		92.5	557.2	
Aug-13	387.2		98.9	404.3	
Sep-13	554.0		264.3	568.8	
Oct-13	550.7		501.4	548.4	
Nov-13	622.8		865.6	596.4	
Dec-13	819.7	8,087.6	1,144.7	755.0	7,997.6
Jan-14	1,024.4		745.8	1,075.9	
Feb-14	733.8		992.4	671.7	
Mar-14	844.8		855.1	819.9	
Apr-14	635.8		499.8	648.2	
May-14	627.0		269.5	620.1	
Jun-14	523.0		200.5	501.6	
Jul-14	519.9		98.0	521.6	
Aug-14	494.3		144.0	493.6	
Sep-14	556.2		307.1	553.9	
Oct-14	541.6		515.6	533.6	
Nov-14	602.3		772.8	612.8	
Dec-14	825.1	7,928.3	854.4	876.1	7,928.9
Jan-15	974.7		927.0	954.0	
Feb-15	910.6		851.4	904.7	
Mar-15	632.5		671.3	680.7	
Apr-15	724.0		453.5	754.9	
May-15	493.9		192.9	517.5	
Jun-15	513.3		127.2	521.1	
Jul-15	524.5		115.7	519.0	
Aug-15	462.5		183.2	446.1	
Sep-15	585.5		332.7	573.0	
Oct-15	548.3		469.8	558.6	
Nov-15	650.2		759.2	666.1	
Dec-15	868.8	7,888.6	947.9	882.5	7,978.1
Jan-16	932.4		827.6	951.2	
Feb-16	777.1		688.0	836.2	
Mar-16	742.0		611.6	814.1	
Apr-16	696.3				
May-16	580.4				
Jun-16	556.4				
Jul-16	532.6				
Aug-16	448.0				
Sep-16	565.2				
Oct-16	546.9				
Nov-16	625.1				
Dec-16	837.8	7,840.3			7,990.3
Jan-17	996.7				
Feb-17	831.8				
Mar-17	750.9				
Apr-17	696.3				
May-17	580.4				
Jun-17	556.4				
Jul-17	532.6				
Aug-17	448.0				
Sep-17	565.2				
Oct-17	546.9				
Nov-17	625.1				
Dec-17	837.8	7,968.2			7,968.2

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.793409213
R Square	0.629498179
Adjusted R Square	0.618601067
Standard Error	100.7721264
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	586629.4941	586629.4941	57.76743023	7.87227E-09
Residual	34	345270.7299	10155.02147		
Total	35	931900.224			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	456.29257	32.07833705	14.22432121	7.07964E-16	391.1015456	521.4835943	391.1015456	521.4835943
WH-HDD	0.398423111	0.052420722	7.600488815	7.87227E-09	0.291891386	0.504954835	0.291891386	0.504954835

Teslin

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	817.9		952.0	791.9	
Feb-13	794.7		665.4	852.4	
Mar-13	617.5		851.1	597.7	
Apr-13	640.8		639.9	604.1	
May-13	477.0		294.0	462.9	
Jun-13	539.6		112.4	551.1	
Jul-13	422.4		92.5	425.7	
Aug-13	471.0		98.9	485.6	
Sep-13	435.3		264.3	447.9	
Oct-13	492.6		501.4	490.7	
Nov-13	665.9		865.6	643.5	
Dec-13	732.7	7,107.6	1,144.7	677.9	7,031.3
Jan-14	800.5		745.8	844.1	
Feb-14	664.0		992.4	611.3	
Mar-14	635.7		855.1	614.6	
Apr-14	539.4		499.8	550.0	
May-14	558.1		269.5	552.2	
Jun-14	409.2		200.5	391.0	
Jul-14	393.7		98.0	395.0	
Aug-14	477.3		144.0	476.6	
Sep-14	461.4		307.1	459.5	
Oct-14	561.2		515.6	554.5	
Nov-14	586.5		772.8	595.4	
Dec-14	709.6	6,796.6	854.4	752.8	6,797.1
Jan-15	896.6		927.0	879.1	
Feb-15	698.5		851.4	693.4	
Mar-15	579.4		671.3	620.4	
Apr-15	605.8		453.5	632.0	
May-15	459.9		192.9	479.9	
Jun-15	437.8		127.2	444.4	
Jul-15	489.7		115.7	485.1	
Aug-15	414.6		183.2	400.7	
Sep-15	490.6		332.7	480.0	
Oct-15	620.9		469.8	629.6	
Nov-15	610.9		759.2	624.4	
Dec-15	685.1	6,989.8	947.9	696.7	7,065.6
Jan-16	915.1		827.6	931.1	
Feb-16	630.8		688.0	680.9	
Mar-16	593.1		611.6	654.2	
Apr-16	595.4				
May-16	498.3				
Jun-16	462.2				
Jul-16	435.3				
Aug-16	454.3				
Sep-16	462.5				
Oct-16	558.2				
Nov-16	621.1				
Dec-16	709.1	6,935.5			7,062.6
Jan-17	838.3				
Feb-17	719.0				
Mar-17	610.9				
Apr-17	595.4				
May-17	498.3				
Jun-17	462.2				
Jul-17	435.3				
Aug-17	454.3				
Sep-17	462.5				
Oct-17	558.2				
Nov-17	621.1				
Dec-17	709.1	6,964.7			6,964.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.84543602
R Square	0.714762064
Adjusted R Square	0.706372713
Standard Error	70.31694706
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	421262.8282	421262.8282	85.19873089	8.70474E-11
Residual	34	168112.0835	4944.473043		
Total	35	589374.9117			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	404.362868	22.38367699	18.06507787	5.29865E-19	358.8737633	449.8519726	358.8737633	449.8519726
WH-HDD	0.337628535	0.036578221	9.230315861	8.70474E-11	0.263292646	0.411964424	0.263292646	0.411964424

Ross River

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,112.2		952.0	1,068.5	
Feb-13	1,051.8		665.4	1,148.7	
Mar-13	835.5		851.1	802.2	
Apr-13	806.5		639.9	744.7	
May-13	626.8		294.0	603.0	
Jun-13	618.2		112.4	637.7	
Jul-13	460.1		92.5	465.5	
Aug-13	642.4		98.9	666.9	
Sep-13	331.5		264.3	352.5	
Oct-13	579.6		501.4	576.3	
Nov-13	872.3		865.6	834.6	
Dec-13	897.2	8,834.1	1,144.7	805.2	8,706.0
Jan-14	1,097.8		745.8	1,171.0	
Feb-14	994.6		992.4	906.2	
Mar-14	926.4		855.1	890.9	
Apr-14	683.3		499.8	701.0	
May-14	717.1		269.5	707.3	
Jun-14	508.4		200.5	477.8	
Jul-14	426.7		98.0	429.0	
Aug-14	586.3		144.0	585.2	
Sep-14	531.9		307.1	528.7	
Oct-14	740.6		515.6	729.3	
Nov-14	788.5		772.8	803.4	
Dec-14	934.7	8,936.3	854.4	1,007.2	8,937.0
Jan-15	1,159.3		927.0	1,129.8	
Feb-15	1,035.1		851.4	1,026.6	
Mar-15	893.2		671.3	962.0	
Apr-15	774.4		453.5	818.4	
May-15	561.6		192.9	595.2	
Jun-15	453.7		127.2	464.7	
Jul-15	493.0		115.7	485.2	
Aug-15	442.1		183.2	418.7	
Sep-15	518.4		332.7	500.6	
Oct-15	680.5		469.8	695.2	
Nov-15	727.1		759.2	749.8	
Dec-15	749.9	8,488.3	947.9	769.4	8,615.6
Jan-16	1,083.6		827.6	1,110.5	
Feb-16	781.4		688.0	865.6	
Mar-16	772.3		611.6	874.9	
Apr-16	754.7				
May-16	635.2				
Jun-16	526.7				
Jul-16	459.9				
Aug-16	556.9				
Sep-16	460.6				
Oct-16	666.9				
Nov-16	795.9				
Dec-16	860.6	8,354.9			8,568.5
Jan-17	1,123.1				
Feb-17	1,027.2				
Mar-17	885.0				
Apr-17	754.7				
May-17	635.2				
Jun-17	526.7				
Jul-17	459.9				
Aug-17	556.9				
Sep-17	460.6				
Oct-17	666.9				
Nov-17	795.9				
Dec-17	860.6	8,752.9			8,752.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.838583702
R Square	0.703222625
Adjusted R Square	0.694493879
Standard Error	121.4563291
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1188450.958	1188450.958	80.56398937	1.72118E-10
Residual	34	501555.7556	14751.63987		
Total	35	1690006.713			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	433.7467106	38.6626461	11.21875387	5.66598E-13	355.1747603	512.3186608	355.1747603	512.3186608
WH-HDD	0.567091591	0.063180452	8.975744503	1.72118E-10	0.438693465	0.695489717	0.438693465	0.695489717

Pelly Crossing

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,184.6		952.0	1,137.8	
Feb-13	1,016.8		665.4	1,120.7	
Mar-13	907.0		851.1	871.4	
Apr-13	1,039.8		639.9	973.6	
May-13	877.2		294.0	851.7	
Jun-13	564.2		112.4	585.0	
Jul-13	606.9		92.5	612.7	
Aug-13	656.8		98.9	683.0	
Sep-13	667.4		264.3	690.0	
Oct-13	905.7		501.4	902.2	
Nov-13	940.4		865.6	900.0	
Dec-13	943.7	10,310.4	1,144.7	845.0	10,173.2
Jan-14	1,579.6		745.8	1,658.1	
Feb-14	1,191.5		992.4	1,096.7	
Mar-14	969.4		855.1	931.4	
Apr-14	868.5		499.8	887.5	
May-14	822.2		269.5	811.7	
Jun-14	627.2		200.5	594.5	
Jul-14	623.7		98.0	626.2	
Aug-14	636.8		144.0	635.6	
Sep-14	747.6		307.1	744.1	
Oct-14	920.4		515.6	908.2	
Nov-14	911.2		772.8	927.2	
Dec-14	1,263.7	11,162.0	854.4	1,341.4	11,162.8
Jan-15	1,147.2		927.0	1,115.5	
Feb-15	1,015.8		851.4	1,006.6	
Mar-15	953.5		671.3	1,027.2	
Apr-15	883.2		453.5	930.3	
May-15	562.3		192.9	598.3	
Jun-15	593.2		127.2	605.1	
Jul-15	635.5		115.7	627.2	
Aug-15	561.8		183.2	536.8	
Sep-15	677.3		332.7	658.3	
Oct-15	830.3		469.8	846.0	
Nov-15	941.7		759.2	966.0	
Dec-15	1,288.1	10,089.8	947.9	1,309.0	10,226.3
Jan-16	844.5		827.6	873.3	
Feb-16	901.4		688.0	991.6	
Mar-16	756.7		611.6	866.7	
Apr-16	930.5				
May-16	753.9				
Jun-16	594.9				
Jul-16	622.0				
Aug-16	618.5				
Sep-16	697.5				
Oct-16	885.5				
Nov-16	931.1				
Dec-16	1,165.2	9,701.5			9,930.4
Jan-17	1,303.8				
Feb-17	1,074.7				
Mar-17	943.3				
Apr-17	930.5				
May-17	753.9				
Jun-17	594.9				
Jul-17	622.0				
Aug-17	618.5				
Sep-17	697.5				
Oct-17	885.5				
Nov-17	931.1				
Dec-17	1,165.2	10,520.7			10,520.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.821475881
R Square	0.674822624
Adjusted R Square	0.665258583
Standard Error	139.0795254
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1364817.646	1364817.646	70.55831954	8.29502E-10
Residual	34	657665.8895	19343.1144		
Total	35	2022483.536			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	559.8897263	44.27255881	12.64642798	2.07697E-14	469.9170617	649.8623908	469.9170617	649.8623908
WH-HDD	0.607714907	0.072347874	8.399899972	8.29502E-10	0.460686337	0.754743477	0.460686337	0.754743477

Old Crow

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	819.8		952.0	792.9	
Feb-13	900.1		665.4	959.8	
Mar-13	725.9		851.1	705.4	
Apr-13	676.2		639.9	638.2	
May-13	606.9		294.0	592.2	
Jun-13	630.1		112.4	642.1	
Jul-13	427.0		92.5	430.4	
Aug-13	473.0		98.9	488.1	
Sep-13	493.8		264.3	506.8	
Oct-13	615.3		501.4	613.3	
Nov-13	685.1		865.6	661.9	
Dec-13	727.7	7,781.0	1,144.7	671.0	7,702.0
Jan-14	985.8		745.8	1,030.9	
Feb-14	705.6		992.4	651.1	
Mar-14	812.8		855.1	791.0	
Apr-14	707.5		499.8	718.5	
May-14	705.7		269.5	699.6	
Jun-14	494.4		200.5	475.6	
Jul-14	622.2		98.0	623.6	
Aug-14	419.2		144.0	418.5	
Sep-14	358.7		307.1	356.6	
Oct-14	607.7		515.6	600.7	
Nov-14	662.8		772.8	672.0	
Dec-14	765.7	7,848.1	854.4	810.4	7,848.6
Jan-15	956.9		927.0	938.7	
Feb-15	789.9		851.4	784.6	
Mar-15	862.2		671.3	904.6	
Apr-15	770.1		453.5	797.2	
May-15	537.8		192.9	558.5	
Jun-15	443.5		127.2	450.3	
Jul-15	498.8		115.7	494.0	
Aug-15	436.9		183.2	422.5	
Sep-15	550.7		332.7	539.8	
Oct-15	532.7		469.8	541.8	
Nov-15	615.7		759.2	629.7	
Dec-15	667.8	7,662.9	947.9	679.8	7,741.4
Jan-16	849.1		827.6	865.6	
Feb-16	715.3		688.0	767.1	
Mar-16	717.3		611.6	780.5	
Apr-16	717.9				
May-16	616.8				
Jun-16	522.6				
Jul-16	516.0				
Aug-16	443.0				
Sep-16	467.7				
Oct-16	585.3				
Nov-16	654.5				
Dec-16	720.4	7,525.9			7,657.5
Jan-17	920.8				
Feb-17	798.5				
Mar-17	800.3				
Apr-17	717.9				
May-17	616.8				
Jun-17	522.6				
Jul-17	516.0				
Aug-17	443.0				
Sep-17	467.7				
Oct-17	585.3				
Nov-17	654.5				
Dec-17	720.4	7,764.0			7,764.0

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.723041418
R Square	0.522788892
Adjusted R Square	0.508753271
Standard Error	110.0403782
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	451023.19	451023.19	37.24729373	6.33144E-07
Residual	34	411702.0843	12108.88483		
Total	35	862725.2743			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	464.8619829	35.02865788	13.27090477	5.27645E-15	393.6751853	536.0487806	393.6751853	536.0487806
WH-HDD	0.349351016	0.05724198	6.103056097	6.33144E-07	0.233021316	0.465680716	0.233021316	0.465680716

Destruction Bay

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	869.1		952.0	840.6	
Feb-13	724.1		665.4	787.4	
Mar-13	638.8		851.1	617.2	
Apr-13	674.9		639.9	634.7	
May-13	511.9		294.0	496.4	
Jun-13	496.3		112.4	509.0	
Jul-13	505.1		92.5	508.7	
Aug-13	460.4		98.9	476.3	
Sep-13	482.9		264.3	496.6	
Oct-13	527.6		501.4	525.4	
Nov-13	563.5		865.6	538.9	
Dec-13	769.4	7,224.0	1,144.7	709.4	7,140.5
Jan-14	937.9		745.8	985.7	
Feb-14	728.2		992.4	670.5	
Mar-14	794.9		855.1	771.7	
Apr-14	608.3		499.8	619.9	
May-14	551.3		269.5	544.9	
Jun-14	463.0		200.5	443.1	
Jul-14	506.2		98.0	507.7	
Aug-14	326.7		144.0	325.9	
Sep-14	513.2		307.1	511.1	
Oct-14	367.5		515.6	360.1	
Nov-14	570.6		772.8	580.4	
Dec-14	627.2	6,995.0	854.4	674.5	6,995.4
Jan-15	909.9		927.0	890.7	
Feb-15	718.0		851.4	712.5	
Mar-15	592.8		671.3	637.6	
Apr-15	588.6		453.5	617.3	
May-15	479.4		192.9	501.4	
Jun-15	415.9		127.2	423.1	
Jul-15	475.7		115.7	470.6	
Aug-15	374.6		183.2	359.4	
Sep-15	539.3		332.7	527.7	
Oct-15	477.6		469.8	487.1	
Nov-15	642.8		759.2	657.6	
Dec-15	768.2	6,982.8	947.9	780.9	7,065.9
Jan-16	762.3		827.6	779.8	
Feb-16	604.9		688.0	659.8	
Mar-16	663.4		611.6	730.3	
Apr-16	623.9				
May-16	514.2				
Jun-16	458.4				
Jul-16	495.7				
Aug-16	387.2				
Sep-16	511.8				
Oct-16	457.5				
Nov-16	592.3				
Dec-16	721.6	6,793.2			6,932.5
Jan-17	905.6				
Feb-17	723.4				
Mar-17	675.5				
Apr-17	623.9				
May-17	514.2				
Jun-17	458.4				
Jul-17	495.7				
Aug-17	387.2				
Sep-17	511.8				
Oct-17	457.5				
Nov-17	592.3				
Dec-17	721.6	7,067.3			7,067.3

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.796569352
R Square	0.634522732
Adjusted R Square	0.623773401
Standard Error	92.54244913
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	505530.9055	505530.9055	59.0290418	6.21878E-09
Residual	34	291179.5663	8564.10489		
Total	35	796710.4718			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	396.109009	29.45862095	13.44628487	3.61955E-15	336.2418884	455.9761297	336.2418884	455.9761297
WH-HDD	0.369859204	0.04813972	7.683035975	6.21878E-09	0.272027521	0.467690886	0.272027521	0.467690886

Beaver Creek

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,137.3		952.0	1,105.4	
Feb-13	1,006.1		665.4	1,076.9	
Mar-13	843.4		851.1	819.1	
Apr-13	777.2		639.9	732.2	
May-13	656.2		294.0	638.9	
Jun-13	713.0		112.4	727.2	
Jul-13	524.3		92.5	528.2	
Aug-13	601.9		98.9	619.7	
Sep-13	614.7		264.3	630.0	
Oct-13	671.7		501.4	669.3	
Nov-13	892.8		865.6	865.3	
Dec-13	791.9	9,230.4	1,144.7	724.6	9,136.8
Jan-14	1,075.7		745.8	1,129.2	
Feb-14	1,006.6		992.4	942.0	
Mar-14	662.4		855.1	636.5	
Apr-14	538.5		499.8	551.4	
May-14	727.1		269.5	719.9	
Jun-14	566.8		200.5	544.5	
Jul-14	530.0		98.0	531.7	
Aug-14	571.6		144.0	570.8	
Sep-14	588.1		307.1	585.7	
Oct-14	612.3		515.6	604.0	
Nov-14	816.4		772.8	827.3	
Dec-14	839.3	8,534.8	854.4	892.3	8,535.3
Jan-15	1,167.1		927.0	1,145.6	
Feb-15	773.6		851.4	767.4	
Mar-15	716.1		671.3	766.3	
Apr-15	743.1		453.5	775.2	
May-15	597.0		192.9	621.5	
Jun-15	554.5		127.2	562.5	
Jul-15	533.8		115.7	528.1	
Aug-15	545.1		183.2	528.1	
Sep-15	668.1		332.7	655.1	
Oct-15	519.5		469.8	530.2	
Nov-15	833.3		759.2	849.9	
Dec-15	761.8	8,413.1	947.9	776.1	8,506.0
Jan-16	1,076.4		827.6	1,096.0	
Feb-16	772.0		688.0	833.4	
Mar-16	820.0		611.6	894.9	
Apr-16	686.3				
May-16	660.1				
Jun-16	611.4				
Jul-16	529.4				
Aug-16	572.9				
Sep-16	623.6				
Oct-16	601.2				
Nov-16	847.5				
Dec-16	797.7	8,598.4			8,754.3
Jan-17	1,126.7				
Feb-17	928.8				
Mar-17	740.6				
Apr-17	686.3				
May-17	660.1				
Jun-17	611.4				
Jul-17	529.4				
Aug-17	572.9				
Sep-17	623.6				
Oct-17	601.2				
Nov-17	847.5				
Dec-17	797.7	8,726.1			8,726.1

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.750424818
R Square	0.563137407
Adjusted R Square	0.550288507
Standard Error	120.2366371
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	633610.0783	633610.0783	43.82767523	1.36344E-07
Residual	34	491532.8625	14456.8489		
Total	35	1125142.941			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	511.292946	38.27438704	13.35861879	4.36807E-15	433.5100331	589.0758589	433.5100331	589.0758589
WH-HDD	0.414069854	0.062545979	6.620247369	1.36344E-07	0.286961131	0.541178577	0.286961131	0.541178577

Tagish

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	716.2		952.0	690.7	
Feb-13	487.4		665.4	544.0	
Mar-13	502.0		851.1	482.6	
Apr-13	392.1		639.9	356.1	
May-13	350.2		294.0	336.4	
Jun-13	335.0		112.4	346.3	
Jul-13	278.4		92.5	281.5	
Aug-13	357.9		98.9	372.1	
Sep-13	259.0		264.3	271.2	
Oct-13	344.8		501.4	342.9	
Nov-13	497.0		865.6	475.0	
Dec-13	592.5	5,112.5	1,144.7	538.9	5,037.8
Jan-14	606.7		745.8	649.4	
Feb-14	594.2		992.4	542.7	
Mar-14	548.7		855.1	528.0	
Apr-14	375.4		499.8	385.7	
May-14	310.0		269.5	304.3	
Jun-14	307.9		200.5	290.1	
Jul-14	295.2		98.0	296.5	
Aug-14	314.4		144.0	313.8	
Sep-14	310.3		307.1	308.4	
Oct-14	340.5		515.6	333.9	
Nov-14	421.8		772.8	430.5	
Dec-14	560.6	4,985.6	854.4	602.9	4,986.1
Jan-15	579.2		927.0	562.0	
Feb-15	536.8		851.4	531.8	
Mar-15	381.3		671.3	421.4	
Apr-15	384.5		453.5	410.1	
May-15	302.7		192.9	322.3	
Jun-15	278.4		127.2	284.9	
Jul-15	322.4		115.7	317.9	
Aug-15	287.6		183.2	274.0	
Sep-15	328.7		332.7	318.3	
Oct-15	403.2		469.8	411.7	
Nov-15	460.1		759.2	473.4	
Dec-15	524.3	4,789.3	947.9	535.7	4,863.5
Jan-16	694.1		827.6	709.7	
Feb-16	463.7		688.0	512.8	
Mar-16	415.8		611.6	475.6	
Apr-16	384.0				
May-16	321.0				
Jun-16	307.1				
Jul-16	298.6				
Aug-16	320.0				
Sep-16	299.3				
Oct-16	362.8				
Nov-16	459.6				
Dec-16	559.2	4,885.2			5,009.7
Jan-17	634.0				
Feb-17	539.5				
Mar-17	477.3				
Apr-17	384.0				
May-17	321.0				
Jun-17	307.1				
Jul-17	298.6				
Aug-17	320.0				
Sep-17	299.3				
Oct-17	362.8				
Nov-17	459.6				
Dec-17	559.2	4,962.5			4,962.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.89996326
R Square	0.809933869
Adjusted R Square	0.804343689
Standard Error	52.79318769
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	403812.2738	403812.2738	144.8851062	8.2675E-14
Residual	34	94762.10265	2787.120666		
Total	35	498574.3764			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	241.1973695	16.80541761	14.35235797	5.44582E-16	207.0446518	275.3500872	207.0446518	275.3500872
WH-HDD	0.330561547	0.027462525	12.03682293	8.2675E-14	0.274750982	0.386372112	0.274750982	0.386372112

Marsh Lake

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,030.8		952.0	981.5	
Feb-13	1,020.2		665.4	1,129.4	
Mar-13	885.4		851.1	847.9	
Apr-13	823.2		639.9	753.6	
May-13	650.7		294.0	623.9	
Jun-13	531.7		112.4	553.6	
Jul-13	488.7		92.5	494.8	
Aug-13	574.7		98.9	602.2	
Sep-13	452.1		264.3	475.8	
Oct-13	717.3		501.4	713.6	
Nov-13	890.0		865.6	847.6	
Dec-13	1,144.2	9,208.9	1,144.7	1,040.5	9,064.6
Jan-14	1,034.0		745.8	1,116.6	
Feb-14	981.4		992.4	881.7	
Mar-14	881.7		855.1	841.7	
Apr-14	785.7		499.8	805.7	
May-14	504.8		269.5	493.7	
Jun-14	501.4		200.5	467.0	
Jul-14	511.3		98.0	513.9	
Aug-14	486.0		144.0	484.7	
Sep-14	537.9		307.1	534.2	
Oct-14	669.5		515.6	656.7	
Nov-14	761.6		772.8	778.5	
Dec-14	1,119.5	8,774.9	854.4	1,201.3	8,775.7
Jan-15	989.1		927.0	955.8	
Feb-15	1,012.7		851.4	1,003.1	
Mar-15	702.1		671.3	779.5	
Apr-15	754.3		453.5	803.9	
May-15	528.1		192.9	566.0	
Jun-15	451.8		127.2	464.3	
Jul-15	528.7		115.7	520.0	
Aug-15	475.3		183.2	449.0	
Sep-15	655.4		332.7	635.4	
Oct-15	624.3		469.8	640.8	
Nov-15	857.3		759.2	882.8	
Dec-15	1,102.5	8,681.6	947.9	1,124.5	8,825.1
Jan-16	936.7		827.6	966.9	
Feb-16	842.3		688.0	937.1	
Mar-16	830.2		611.6	945.8	
Apr-16	787.7				
May-16	561.2				
Jun-16	495.0				
Jul-16	509.6				
Aug-16	512.0				
Sep-16	548.5				
Oct-16	670.3				
Nov-16	836.3				
Dec-16	1,122.1	8,651.9			8,892.6
Jan-17	1,018.0				
Feb-17	1,004.7				
Mar-17	823.0				
Apr-17	787.7				
May-17	561.2				
Jun-17	495.0				
Jul-17	509.6				
Aug-17	512.0				
Sep-17	548.5				
Oct-17	670.3				
Nov-17	836.3				
Dec-17	1,122.1	8,888.5			8,888.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.932748123
R Square	0.870019061
Adjusted R Square	0.866196092
Standard Error	81.44038143
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1509411.356	1509411.356	227.576815	1.25145E-16
Residual	34	225506.2147	6632.535727		
Total	35	1734917.57			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	407.5048998	25.92454975	15.71888051	3.66696E-17	354.8198759	460.1899237	354.8198759	460.1899237
WH-HDD	0.639096415	0.042364528	15.08564931	1.25145E-16	0.553001335	0.725191495	0.553001335	0.725191495

Lower Post

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,365.5		1,129.1	1,315.5	
Feb-13	760.6		765.8	866.2	
Mar-13	1,157.2		950.7	1,136.0	
Apr-13	982.1		690.1	929.7	
May-13	363.2		304.5	352.0	
Jun-13	698.5		96.3	716.2	
Jul-13	432.2		105.1	427.2	
Aug-13	685.2		82.2	706.7	
Sep-13	334.0		239.1	359.7	
Oct-13	647.0		490.2	660.9	
Nov-13	632.5		1,021.3	595.9	
Dec-13	1,121.1	9,179.1	1,248.8	1,094.2	9,160.2
Jan-14	1,343.0		937.7	1,389.4	
Feb-14	1,005.4		1,204.4	890.4	
Mar-14	1,038.9		1,008.9	988.5	
Apr-14	914.5		570.5	922.3	
May-14	752.2		331.1	727.6	
Jun-14	547.8		186.8	520.0	
Jul-14	583.8		87.6	587.6	
Aug-14	486.4		144.8	476.3	
Sep-14	545.5		295.8	542.8	
Oct-14	639.8		539.7	628.8	
Nov-14	630.9		936.4	637.0	
Dec-14	937.6	9,425.9	1,176.7	946.9	9,257.6
Jan-15	1,115.7		1,022.8	1,119.3	
Feb-15	824.6		956.7	834.2	
Mar-15	816.2		766.3	887.8	
Apr-15	537.5		497.4	582.1	
May-15	543.9		210.8	579.7	
Jun-15	431.2		111.8	441.2	
Jul-15	529.8		92.4	531.1	
Aug-15	475.6		147.5	464.2	
Sep-15	610.7		336.1	587.6	
Oct-15	652.3		523.7	649.4	
Nov-15	672.4		887.8	702.9	
Dec-15	829.3	8,039.4	1,160.3	846.9	8,226.5
Jan-16	1,197.6		1,099.3	1,162.6	
Feb-16	900.2		930.8	922.8	
Mar-16	848.4		724.3	941.1	
Apr-16	811.4				
May-16	553.1				
Jun-16	559.2				
Jul-16	515.3				
Aug-16	549.1				
Sep-16	496.7				
Oct-16	646.4				
Nov-16	645.3				
Dec-16	962.7	8,685.2			8,765.5
Jan-17	1,274.7				
Feb-17	863.6				
Mar-17	1,004.1				
Apr-17	811.4				
May-17	553.1				
Jun-17	559.2				
Jul-17	515.3				
Aug-17	549.1				
Sep-17	496.7				
Oct-17	646.4				
Nov-17	645.3				
Dec-17	962.7	8,881.4			8,881.4

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.759683442
R Square	0.577118932
Adjusted R Square	0.564681253
Standard Error	174.7217725
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1416511.318	1416511.318	46.40085631	7.75592E-08
Residual	34	1037941.725	30527.69779		
Total	35	2454453.043			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	443.169536	52.42506975	8.453389534	7.15505E-10	336.6289758	549.7100961	336.6289758	549.7100961
WL-HDD	0.502900353	0.073827633	6.811817401	7.75592E-08	0.352864552	0.652936154	0.352864552	0.652936154

Upper Liard

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,277.3		1,129.1	1,243.1	
Feb-13	855.9		765.8	928.3	
Mar-13	777.7		950.7	763.2	
Apr-13	763.2		690.1	727.2	
May-13	676.9		304.5	669.1	
Jun-13	566.5		96.3	578.7	
Jul-13	517.6		105.1	514.1	
Aug-13	596.3		82.2	611.1	
Sep-13	559.6		239.1	577.3	
Oct-13	651.6		490.2	661.2	
Nov-13	618.6		1,021.3	593.5	
Dec-13	940.9	8,802.0	1,248.8	922.4	8,789.1
Jan-14	1,095.2		937.7	1,127.0	
Feb-14	766.4		1,204.4	687.5	
Mar-14	826.4		1,008.9	791.9	
Apr-14	823.1		570.5	828.5	
May-14	596.8		331.1	579.9	
Jun-14	526.8		186.8	507.8	
Jul-14	530.0		87.6	532.6	
Aug-14	521.1		144.8	514.2	
Sep-14	604.0		295.8	602.1	
Oct-14	591.6		539.7	584.0	
Nov-14	679.3		936.4	683.5	
Dec-14	925.9	8,486.6	1,176.7	932.3	8,371.2
Jan-15	1,018.4		1,022.8	1,020.8	
Feb-15	880.8		956.7	887.4	
Mar-15	745.4		766.3	794.5	
Apr-15	835.3		497.4	865.9	
May-15	663.8		210.8	688.4	
Jun-15	475.5		111.8	482.4	
Jul-15	559.2		92.4	560.1	
Aug-15	528.0		147.5	520.2	
Sep-15	661.3		336.1	645.5	
Oct-15	672.2		523.7	670.2	
Nov-15	772.6		887.8	793.5	
Dec-15	732.6	8,545.3	1,160.3	744.7	8,673.7
Jan-16	953.5		1,099.3	929.6	
Feb-16	714.1		930.8	729.5	
Mar-16	668.4		724.3	732.0	
Apr-16	807.2				
May-16	645.8				
Jun-16	522.9				
Jul-16	535.6				
Aug-16	548.5				
Sep-16	608.3				
Oct-16	638.5				
Nov-16	690.2				
Dec-16	866.5	8,199.5			8,254.6
Jan-17	1,130.3				
Feb-17	834.4				
Mar-17	783.2				
Apr-17	807.2				
May-17	645.8				
Jun-17	522.9				
Jul-17	535.6				
Aug-17	548.5				
Sep-17	608.3				
Oct-17	638.5				
Nov-17	690.2				
Dec-17	866.5	8,611.3			8,611.3

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.766190237
R Square	0.58704748
Adjusted R Square	0.574901817
Standard Error	117.4322896
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	666541.326	666541.326	48.33392058	5.13861E-08
Residual	34	468871.6497	13790.34264		
Total	35	1135412.976			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	513.9112982	35.23542535	14.58507434	3.39494E-16	442.3042985	585.5182979	442.3042985	585.5182979
WL-HDD	0.344973279	0.049620307	6.952260106	5.13861E-08	0.244132683	0.445813874	0.244132683	0.445813874

Watson Lake

Residential Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,132.4		1,129.1	1,093.2	
Feb-13	913.2		765.8	996.2	
Mar-13	875.6		950.7	859.0	
Apr-13	807.4		690.1	766.2	
May-13	736.7		304.5	727.9	
Jun-13	665.0		96.3	678.9	
Jul-13	594.5		105.1	590.6	
Aug-13	587.0		82.2	603.8	
Sep-13	538.9		239.1	559.1	
Oct-13	649.6		490.2	660.5	
Nov-13	763.2		1,021.3	734.4	
Dec-13	1,018.9	9,282.4	1,248.8	997.7	9,267.6
Jan-14	1,046.8		937.7	1,083.2	
Feb-14	898.5		1,204.4	808.1	
Mar-14	947.2		1,008.9	907.6	
Apr-14	774.1		570.5	780.3	
May-14	703.0		331.1	683.7	
Jun-14	597.6		186.8	575.8	
Jul-14	591.1		87.6	594.0	
Aug-14	529.2		144.8	521.3	
Sep-14	571.9		295.8	569.8	
Oct-14	683.5		539.7	674.8	
Nov-14	737.2		936.4	742.0	
Dec-14	1,019.1	9,099.1	1,176.7	1,026.4	8,966.8
Jan-15	1,084.7		1,022.8	1,087.5	
Feb-15	892.4		956.7	899.9	
Mar-15	819.6		766.3	875.9	
Apr-15	728.9		497.4	764.0	
May-15	645.2		210.8	673.4	
Jun-15	536.7		111.8	544.5	
Jul-15	552.7		92.4	553.7	
Aug-15	521.9		147.5	512.9	
Sep-15	626.0		336.1	607.9	
Oct-15	680.6		523.7	678.3	
Nov-15	803.0		887.8	827.0	
Dec-15	951.9	8,843.7	1,160.3	965.7	8,990.7
Jan-16	1,081.9		1,099.3	1,054.5	
Feb-16	884.0		930.8	901.7	
Mar-16	839.9		724.3	912.8	
Apr-16	770.2				
May-16	695.0				
Jun-16	599.8				
Jul-16	579.5				
Aug-16	546.0				
Sep-16	578.9				
Oct-16	671.2				
Nov-16	767.8				
Dec-16	996.6	9,010.7			9,073.9
Jan-17	1,087.9				
Feb-17	901.4				
Mar-17	880.8				
Apr-17	770.2				
May-17	695.0				
Jun-17	599.8				
Jul-17	579.5				
Aug-17	546.0				
Sep-17	578.9				
Oct-17	671.2				
Nov-17	767.8				
Dec-17	996.6	9,075.0			9,075.0

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.898925093
R Square	0.808066323
Adjusted R Square	0.802421215
Standard Error	78.16644414
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	874612.0413	874612.0413	143.1445245	9.77309E-14
Residual	34	207739.7616	6109.992989		
Total	35	1082351.803			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	522.9171634	23.45375294	22.29567118	7.14068E-22	475.2534028	570.5809241	475.2534028	570.5809241
WL-HDD	0.395166065	0.03302876	11.96430209	9.77309E-14	0.328043548	0.462288581	0.328043548	0.462288581

Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

YUB-YECL-8

Reference: Application, Section 2, Sales and Revenue, pages 2-6 to 2-7

Issue/sub-issue: Commercial customer average UPC methodology

Quote: "The commercial UPC for the test period for Whitehorse is forecast by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC."

…

The commercial UPC forecast for the remaining communities (outside of Whitehorse), is determined by using the actual UPC of the previous year as a base and applying the 2013 to 2015 growth in actual UPC."

Request:

(a) Please explain why YECL is not using a weather-normalized three-year average actual UPC (2013 to 2015) to determine the commercial UPC forecast for all communities as was done in its last GRA application.

(b) For each of the communities,

i. Please provide the calculations underlying, detailed information provided by YECL,[8] in an Excel workbook with all formulas intact.

ii. Please provide alternate calculations using a weather-normalized three-year average actual UPC (2013 to 2015).

Response:

(a) AEY submits that the methodology used in the previous GRA has resulted in an over forecast of sales, especially in 2014 and 2015. Over the last few years, there have been changes in the use of electric heating as well as the introduction of energy efficiency programs across the territory. These trends, combined with a decline in economic activity and warmer weather over the last few years, have impacted UPC over the 2013 to 2015 time period. For these reasons, AEY considers that it was necessary to review the existing methodology to ensure it encompasses these recent trends.

[8] Application, Section 2, Attachments 20 to 37.

(b) i) Please refer to YUB-YECL-8(b) – Attachment 1.

ii) Please refer to YUB-YECL-8(b) – Attachment 2.

Whitehorse (Includes Takhini & Deep Creek)

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	7,403.5		952.0	7,264.9	
Feb-13	5,904.4		665.4	6,212.1	
Mar-13	6,002.6		851.1	5,897.2	
Apr-13	6,195.8		639.9	6,000.0	
May-13	4,951.5		294.0	4,876.2	
Jun-13	5,024.9		112.4	5,086.6	
Jul-13	5,023.9		92.5	5,041.1	
Aug-13	5,111.1		98.9	5,188.7	
Sep-13	4,619.4		264.3	4,686.1	
Oct-13	5,004.4		501.4	4,994.0	
Nov-13	5,387.9		865.6	5,268.4	
Dec-13	5,956.0	66,585.6	1,144.7	5,663.9	66,179.2
Jan-14	6,892.4		745.8	7,124.8	
Feb-14	5,789.4		992.4	5,508.8	
Mar-14	6,026.9		855.1	5,914.3	
Apr-14	5,572.0		499.8	5,628.2	
May-14	4,906.6		269.5	4,875.4	
Jun-14	4,698.8		200.5	4,602.0	
Jul-14	4,872.9		98.0	4,880.2	
Aug-14	4,366.0		144.0	4,362.4	
Sep-14	4,901.2		307.1	4,890.9	
Oct-14	4,560.2		515.6	4,524.2	
Nov-14	5,617.3		772.8	5,664.8	
Dec-14	5,642.8	63,846.5	854.4	5,872.9	63,848.9
Jan-15	7,066.4		927.0	6,972.8	
Feb-15	5,952.5		851.4	5,925.5	
Mar-15	5,706.8		671.3	5,924.8	
Apr-15	5,418.8		453.5	5,558.4	
May-15	4,730.1		192.9	4,836.7	
Jun-15	4,398.0		127.2	4,433.1	
Jul-15	4,703.8		115.7	4,679.2	
Aug-15	4,254.6		183.2	4,180.5	
Sep-15	4,776.7		332.7	4,720.3	
Oct-15	4,616.3		469.8	4,662.7	
Nov-15	5,305.0		759.2	5,377.0	
Dec-15	5,573.6	62,502.6	947.9	5,635.6	62,906.6
Jan-16	6,588.3		827.6	6,673.5	
Feb-16	6,605.9		688.0	5,872.9	
Mar-16	5,511.4		611.6	5,836.9	
Apr-16	5,419.2				
May-16	4,715.6				
Jun-16	4,322.1				
Jul-16	4,562.1				
Aug-16	4,075.8				
Sep-16	4,602.1				
Oct-16	4,546.0				
Nov-16	5,242.4				
Dec-16	5,494.5	60,685.4			61,363.0
Jan-17	6,506.4				
Feb-17	5,725.9				
Mar-17	5,690.8				
Apr-17	5,283.5				
May-17	4,597.5				
Jun-17	4,213.9				
Jul-17	4,447.8				
Aug-17	3,973.8				
Sep-17	4,486.9				
Oct-17	4,432.2				
Nov-17	5,111.1				
Dec-17	5,356.9	59,826.6			59,826.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.768459027
R Square	0.590529276
Adjusted R Square	0.57848602
Standard Error	493.9511555
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	11963699.76	11963699.76	49.03401934	4.43771E-08
Residual	34	8295583.298	243987.7441		
Total	35	20259283.06			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	4421.229047	157.2372462	28.11820452	3.98418E-25	4101.684516	4740.773577	4101.684516	4740.773577
WH-HDD	1.799265811	0.256948792	7.002429531	4.43771E-08	1.277083038	2.321448583	1.277083038	2.321448583

2 year Compound Annual Growth Rate =

= (2015 Normalized UPC / 2013 Normalized UPC) ^ (1/(2015 - 2013)) -1 =

= (62,906.6 / 66,179.2) ^ (1/2) - 1 = **-2.5%**

Carmacks

Commercial Monthly	Actual UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	3,098.4		952.0	3,035.8	
Feb-13	2,705.0		665.4	2,844.1	
Mar-13	2,895.5		851.1	2,847.9	
Apr-13	3,143.9		639.9	3,055.4	
May-13	2,753.4		294.0	2,719.4	
Jun-13	1,823.0		112.4	1,850.9	
Jul-13	2,222.3		92.5	2,230.1	
Aug-13	2,270.0		98.9	2,305.1	
Sep-13	2,044.0		264.3	2,074.1	
Oct-13	2,627.4		501.4	2,622.7	
Nov-13	2,770.4		865.6	2,716.4	
Dec-13	2,576.3	30,929.7	1,144.7	2,444.3	30,746.0
Jan-14	3,848.6		745.8	3,953.6	
Feb-14	2,847.7		992.4	2,720.9	
Mar-14	2,695.9		855.1	2,645.0	
Apr-14	2,504.1		499.8	2,529.5	
May-14	2,603.8		269.5	2,589.6	
Jun-14	2,347.7		200.5	2,304.0	
Jul-14	2,033.0		98.0	2,036.3	
Aug-14	2,373.3		144.0	2,371.7	
Sep-14	2,313.6		307.1	2,308.9	
Oct-14	2,732.0		515.6	2,715.7	
Nov-14	2,403.1		772.8	2,424.6	
Dec-14	3,276.0	31,978.7	854.4	3,380.0	31,979.8
Jan-15	3,133.6		927.0	3,091.3	
Feb-15	2,469.0		851.4	2,456.8	
Mar-15	2,822.0		671.3	2,920.6	
Apr-15	2,866.7		453.5	2,929.8	
May-15	2,250.2		192.9	2,298.3	
Jun-15	2,314.8		127.2	2,330.7	
Jul-15	2,840.1		115.7	2,829.1	
Aug-15	2,106.0		183.2	2,072.5	
Sep-15	2,720.1		332.7	2,694.6	
Oct-15	2,812.1		469.8	2,833.0	
Nov-15	2,939.7		759.2	2,972.2	
Dec-15	3,156.8	32,431.1	947.9	3,184.8	32,613.7
Jan-16	3,254.3		827.6	3,292.8	
Feb-16	3,049.8		688.0	3,170.5	
Mar-16	3,026.9		611.6	3,174.0	
Apr-16	2,935.5				
May-16	2,304.1				
Jun-16	2,370.3				
Jul-16	2,908.3				
Aug-16	2,156.5				
Sep-16	2,785.3				
Oct-16	2,879.5				
Nov-16	3,010.2				
Dec-16	3,232.5	33,913.3			34,219.6
Jan-17	3,332.4				
Feb-17	3,122.9				
Mar-17	3,099.5				
Apr-17	3,005.9				
May-17	2,359.4				
Jun-17	2,427.2				
Jul-17	2,978.0				
Aug-17	2,208.2				
Sep-17	2,852.1				
Oct-17	2,948.6				
Nov-17	3,082.4				
Dec-17	3,310.0	34,726.7			34,726.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.645763695
R Square	0.417010749
Adjusted R Square	0.399864007
Standard Error	316.9841283
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2443659.291	2443659.291	24.32011474	2.10678E-05
Residual	34	3416283.878	100478.9376		
Total	35	5859943.169			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2224.364291	100.9041296	22.04433357	1.02473E-21	2019.302428	2429.426155	2019.302428	2429.426155
WH-HDD	0.81317291	0.164892192	4.931542836	2.10678E-05	0.478071657	1.148274162	0.478071657	1.148274162

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (32,431.1 / 30,929.7) ^ (1/2) - 1 = **2.4%**

Carcross

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,054.7		952.0	2,038.0	
Feb-13	1,953.8		665.4	1,990.8	
Mar-13	1,525.9		851.1	1,513.2	
Apr-13	1,641.3		639.9	1,617.7	
May-13	1,772.1		294.0	1,763.0	
Jun-13	1,795.6		112.4	1,803.0	
Jul-13	1,413.0		92.5	1,415.0	
Aug-13	1,476.0		98.9	1,485.3	
Sep-13	1,305.8		264.3	1,313.9	
Oct-13	1,246.6		501.4	1,245.3	
Nov-13	1,345.3		865.6	1,330.9	
Dec-13	1,413.8	18,943.7	1,144.7	1,378.6	18,894.8
Jan-14	1,975.2		745.8	2,003.2	
Feb-14	1,602.1		992.4	1,568.3	
Mar-14	1,851.8		855.1	1,838.2	
Apr-14	1,574.1		499.8	1,580.9	
May-14	1,465.0		269.5	1,461.3	
Jun-14	1,458.5		200.5	1,446.9	
Jul-14	1,504.1		98.0	1,505.0	
Aug-14	1,527.1		144.0	1,526.7	
Sep-14	1,276.3		307.1	1,275.0	
Oct-14	1,613.5		515.6	1,609.2	
Nov-14	1,319.6		772.8	1,325.4	
Dec-14	1,378.9	18,546.3	854.4	1,406.6	18,546.6
Jan-15	1,882.9		927.0	1,871.6	
Feb-15	1,682.9		851.4	1,679.7	
Mar-15	1,732.9		671.3	1,759.1	
Apr-15	1,345.6		453.5	1,362.4	
May-15	1,529.1		192.9	1,542.0	
Jun-15	1,314.3		127.2	1,318.5	
Jul-15	1,342.5		115.7	1,339.5	
Aug-15	1,523.5		183.2	1,514.6	
Sep-15	1,391.4		332.7	1,384.6	
Oct-15	1,566.0		469.8	1,571.5	
Nov-15	1,311.4		759.2	1,320.0	
Dec-15	1,646.8	18,269.3	947.9	1,654.3	18,317.9
Jan-16	2,021.0		827.6	2,031.3	
Feb-16	1,760.9		688.0	1,793.0	
Mar-16	2,014.5		611.6	2,053.6	
Apr-16	1,321.5				
May-16	1,501.7				
Jun-16	1,290.7				
Jul-16	1,318.4				
Aug-16	1,496.2				
Sep-16	1,366.4				
Oct-16	1,537.8				
Nov-16	1,287.8				
Dec-16	1,617.2	18,534.0			18,615.6
Jan-17	1,984.7				
Feb-17	1,729.3				
Mar-17	1,978.3				
Apr-17	1,297.7				
May-17	1,474.7				
Jun-17	1,267.5				
Jul-17	1,294.7				
Aug-17	1,469.3				
Sep-17	1,341.8				
Oct-17	1,510.2				
Nov-17	1,264.7				
Dec-17	1,588.2	18,201.1			18,201.1

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.326712903
R Square	0.106741321
Adjusted R Square	0.080469007
Standard Error	206.460393
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	173183.9919	173183.9919	4.06288235	0.051794312
Residual	34	1449280.392	42625.8939		
Total	35	1622464.384			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1436.00788	65.72160685	21.84985956	1.35851E-21	1302.445505	1569.570255	1302.445505	1569.570255
WH-HDD	0.216479336	0.107398774	2.015659284	0.051794312	-0.001781233	0.434739906	-0.001781233	0.434739906

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (18,269.3 / 18,943.7) ^ (1/2) - 1 = **-1.8%**

Haines Junction

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	3,192.1		952.0	3,129.4	
Feb-13	2,742.1		665.4	2,881.2	
Mar-13	2,610.9		851.1	2,563.2	
Apr-13	2,527.0		639.9	2,438.4	
May-13	2,124.3		294.0	2,090.3	
Jun-13	2,505.9		112.4	2,533.8	
Jul-13	2,332.0		92.5	2,339.8	
Aug-13	1,818.5		98.9	1,853.6	
Sep-13	2,386.4		264.3	2,416.5	
Oct-13	2,082.8		501.4	2,078.0	
Nov-13	2,143.9		865.6	2,089.9	
Dec-13	2,971.7	29,437.5	1,144.7	2,839.6	29,253.7
Jan-14	3,196.3		745.8	3,301.4	
Feb-14	2,653.6		992.4	2,526.6	
Mar-14	3,069.5		855.1	3,018.6	
Apr-14	2,393.2		499.8	2,418.6	
May-14	2,261.2		269.5	2,247.1	
Jun-14	2,157.7		200.5	2,113.9	
Jul-14	2,258.3		98.0	2,261.6	
Aug-14	2,183.3		144.0	2,181.7	
Sep-14	2,302.1		307.1	2,297.5	
Oct-14	2,082.4		515.6	2,066.1	
Nov-14	2,066.6		772.8	2,088.1	
Dec-14	3,084.0	29,708.1	854.4	3,188.1	29,709.2
Jan-15	3,111.4		927.0	3,069.0	
Feb-15	3,051.3		851.4	3,039.1	
Mar-15	2,358.6		671.3	2,457.2	
Apr-15	2,821.3		453.5	2,884.4	
May-15	2,045.7		192.9	2,093.9	
Jun-15	2,121.3		127.2	2,137.2	
Jul-15	2,370.6		115.7	2,359.5	
Aug-15	2,221.6		183.2	2,188.1	
Sep-15	2,374.2		332.7	2,348.7	
Oct-15	2,129.0		469.8	2,150.0	
Nov-15	2,327.8		759.2	2,360.4	
Dec-15	2,981.6	29,914.2	947.9	3,009.6	30,096.9
Jan-16	3,042.0		827.6	3,080.6	
Feb-16	2,877.6		688.0	2,998.4	
Mar-16	2,637.7		611.6	2,784.9	
Apr-16	2,844.0				
May-16	2,062.2				
Jun-16	2,138.4				
Jul-16	2,389.7				
Aug-16	2,239.5				
Sep-16	2,393.4				
Oct-16	2,146.1				
Nov-16	2,346.6				
Dec-16	3,005.6	30,122.8			30,429.3
Jan-17	3,066.6				
Feb-17	2,900.8				
Mar-17	2,659.0				
Apr-17	2,867.0				
May-17	2,078.8				
Jun-17	2,155.6				
Jul-17	2,408.9				
Aug-17	2,257.6				
Sep-17	2,412.7				
Oct-17	2,163.4				
Nov-17	2,365.5				
Dec-17	3,029.8	30,365.7			30,365.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.681050854
R Square	0.463830266
Adjusted R Square	0.448060568
Standard Error	288.4419534
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2447104.763	2447104.763	29.41275506	4.84113E-06
Residual	34	2828757.856	83198.76046		
Total	35	5275862.619			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2049.630232	91.81842764	22.32264573	6.87061E-22	1863.032737	2236.227728	1863.032737	2236.227728
WH-HDD	0.81374598	0.150044819	5.423352751	4.84113E-06	0.508818221	1.118673739	0.508818221	1.118673739

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (29,914.2/ 29,437.5) ^ (1/2) - 1 = **0.8%**

Teslin

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,935.6		952.0	2,838.9	
Feb-13	3,120.6		665.4	3,335.3	
Mar-13	2,459.6		851.1	2,386.0	
Apr-13	2,295.5		639.9	2,158.9	
May-13	1,700.1		294.0	1,647.6	
Jun-13	2,023.1		112.4	2,066.1	
Jul-13	1,598.2		92.5	1,610.2	
Aug-13	1,832.3		98.9	1,886.4	
Sep-13	1,632.3		264.3	1,678.8	
Oct-13	1,594.1		501.4	1,586.8	
Nov-13	2,757.6		865.6	2,674.2	
Dec-13	2,796.5	26,745.5	1,144.7	2,592.7	26,462.0
Jan-14	3,041.4		745.8	3,203.5	
Feb-14	2,563.2		992.4	2,367.4	
Mar-14	2,530.3		855.1	2,451.8	
Apr-14	2,098.3		499.8	2,137.5	
May-14	2,126.6		269.5	2,104.8	
Jun-14	1,657.1		200.5	1,589.5	
Jul-14	1,672.3		98.0	1,677.4	
Aug-14	1,922.9		144.0	1,920.4	
Sep-14	1,642.3		307.1	1,635.1	
Oct-14	2,158.8		515.6	2,133.7	
Nov-14	2,408.0		772.8	2,441.1	
Dec-14	2,728.6	26,549.7	854.4	2,889.1	26,551.4
Jan-15	3,082.8		927.0	3,017.4	
Feb-15	2,490.2		851.4	2,471.4	
Mar-15	2,521.6		671.3	2,673.8	
Apr-15	2,004.9		453.5	2,102.2	
May-15	1,879.4		192.9	1,953.7	
Jun-15	1,680.0		127.2	1,704.5	
Jul-15	1,895.3		115.7	1,878.2	
Aug-15	1,640.7		183.2	1,589.0	
Sep-15	1,851.7		332.7	1,812.4	
Oct-15	2,130.2		469.8	2,162.5	
Nov-15	2,255.8		759.2	2,306.0	
Dec-15	2,689.6	26,122.2	947.9	2,732.9	26,404.0
Jan-16	3,141.3		827.6	3,200.7	
Feb-16	2,588.1		688.0	2,774.4	
Mar-16	2,152.1		611.6	2,379.1	
Apr-16	1,981.4				
May-16	1,857.3				
Jun-16	1,660.3				
Jul-16	1,873.1				
Aug-16	1,621.4				
Sep-16	1,830.0				
Oct-16	2,105.2				
Nov-16	2,229.3				
Dec-16	2,658.1	25,697.7			26,170.5
Jan-17	3,104.5				
Feb-17	2,557.8				
Mar-17	2,126.9				
Apr-17	1,958.2				
May-17	1,835.6				
Jun-17	1,640.9				
Jul-17	1,851.1				
Aug-17	1,602.4				
Sep-17	1,808.5				
Oct-17	2,080.5				
Nov-17	2,203.2				
Dec-17	2,626.9	25,396.5			25,396.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.852982586
R Square	0.727579292
Adjusted R Square	0.719566918
Standard Error	253.2054623
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5821907.077	5821907.077	90.80695832	3.95128E-11
Residual	34	2179842.209	64113.00615		
Total	35	8001749.287			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1551.652853	80.60175418	19.25085711	7.35786E-20	1387.85038	1715.455325	1387.85038	1715.455325
WH-HDD	1.255148784	0.131715124	9.529268509	3.95128E-11	0.987471446	1.522826122	0.987471446	1.522826122

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (26,122.2 / 26,745.5) ^ (1/2) - 1 = **-1.2%**

Ross River

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,515.6		952.0	2,449.1	
Feb-13	3,270.1		665.4	3,417.7	
Mar-13	2,454.6		851.1	2,404.0	
Apr-13	2,640.4		639.9	2,546.4	
May-13	2,290.4		294.0	2,254.3	
Jun-13	2,319.5		112.4	2,349.1	
Jul-13	1,923.8		92.5	1,932.0	
Aug-13	2,300.6		98.9	2,337.8	
Sep-13	1,599.0		264.3	1,630.9	
Oct-13	1,854.0		501.4	1,849.0	
Nov-13	2,684.1		865.6	2,626.8	
Dec-13	2,244.9	28,096.9	1,144.7	2,104.8	27,902.0
Jan-14	3,380.5		745.8	3,491.9	
Feb-14	2,160.3		992.4	2,025.6	
Mar-14	2,961.8		855.1	2,907.8	
Apr-14	2,719.7		499.8	2,746.7	
May-14	2,361.6		269.5	2,346.6	
Jun-14	2,018.5		200.5	1,972.1	
Jul-14	1,901.3		98.0	1,904.8	
Aug-14	2,363.5		144.0	2,361.9	
Sep-14	1,574.4		307.1	1,569.4	
Oct-14	2,266.6		515.6	2,249.3	
Nov-14	2,842.4		772.8	2,865.1	
Dec-14	2,628.7	29,179.3	854.4	2,739.1	29,180.4
Jan-15	3,214.4		927.0	3,169.4	
Feb-15	2,846.2		851.4	2,833.3	
Mar-15	2,570.3		671.3	2,674.9	
Apr-15	2,938.5		453.5	3,005.4	
May-15	2,530.8		192.9	2,581.9	
Jun-15	1,760.8		127.2	1,777.6	
Jul-15	1,488.7		115.7	1,476.9	
Aug-15	1,847.4		183.2	1,811.9	
Sep-15	1,958.7		332.7	1,931.7	
Oct-15	2,464.5		469.8	2,486.8	
Nov-15	2,265.0		759.2	2,299.6	
Dec-15	2,765.8	28,651.1	947.9	2,795.5	28,844.9
Jan-16	3,375.8		827.6	3,416.7	
Feb-16	2,777.7		688.0	2,905.8	
Mar-16	2,697.0		611.6	2,853.1	
Apr-16	2,967.3				
May-16	2,555.6				
Jun-16	1,778.1				
Jul-16	1,503.3				
Aug-16	1,865.5				
Sep-16	1,978.0				
Oct-16	2,488.7				
Nov-16	2,287.3				
Dec-16	2,792.9	29,067.2			29,392.2
Jan-17	3,408.9				
Feb-17	2,805.0				
Mar-17	2,723.4				
Apr-17	2,996.4				
May-17	2,580.7				
Jun-17	1,795.5				
Jul-17	1,518.1				
Aug-17	1,883.8				
Sep-17	1,997.4				
Oct-17	2,513.1				
Nov-17	2,309.7				
Dec-17	2,820.3	29,352.4			29,352.4

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.586600487
R Square	0.344100131
Adjusted R Square	0.324808959
Standard Error	392.8357671
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2752632.652	2752632.652	17.83718069	0.000169923
Residual	34	5246877.958	154319.9399		
Total	35	7999510.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1936.908687	125.0496401	15.48911844	5.69935E-17	1682.777242	2191.040131	1682.777242	2191.040131
WH-HDD	0.863051484	0.204349509	4.223408658	0.000169923	0.447763317	1.278339651	0.447763317	1.278339651

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (28,651.1 / 28,096.9) ^ (1/2) - 1 = **1.0%**

Pelly Crossing

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	3,754.3		952.0	3,675.9	
Feb-13	3,099.0		665.4	3,272.9	
Mar-13	3,471.9		851.1	3,412.3	
Apr-13	3,529.6		639.9	3,419.0	
May-13	3,227.7		294.0	3,185.1	
Jun-13	2,231.5		112.4	2,266.4	
Jul-13	2,381.5		92.5	2,391.2	
Aug-13	2,619.9		98.9	2,663.8	
Sep-13	2,288.9		264.3	2,326.6	
Oct-13	3,366.7		501.4	3,360.8	
Nov-13	2,890.6		865.6	2,823.1	
Dec-13	2,376.0	35,237.6	1,144.7	2,210.9	35,007.9
Jan-14	4,282.9		745.8	4,414.2	
Feb-14	3,335.3		992.4	3,176.6	
Mar-14	3,028.9		855.1	2,965.3	
Apr-14	2,752.8		499.8	2,784.6	
May-14	2,665.4		269.5	2,647.8	
Jun-14	2,325.8		200.5	2,271.0	
Jul-14	2,327.6		98.0	2,331.8	
Aug-14	2,103.8		144.0	2,101.8	
Sep-14	2,434.6		307.1	2,428.8	
Oct-14	3,153.4		515.6	3,133.1	
Nov-14	2,926.3		772.8	2,953.1	
Dec-14	3,933.6	35,270.4	854.4	4,063.7	35,271.8
Jan-15	3,237.5		927.0	3,184.5	
Feb-15	3,137.1		851.4	3,121.9	
Mar-15	2,860.1		671.3	2,983.4	
Apr-15	3,287.5		453.5	3,366.3	
May-15	2,545.6		192.9	2,605.8	
Jun-15	2,348.6		127.2	2,368.4	
Jul-15	2,811.1		115.7	2,797.2	
Aug-15	2,235.2		183.2	2,193.4	
Sep-15	2,671.8		332.7	2,639.9	
Oct-15	2,956.5		469.8	2,982.7	
Nov-15	2,782.0		759.2	2,822.7	
Dec-15	3,262.4	34,135.5	947.9	3,297.5	34,363.8
Jan-16	3,213.3		827.6	3,261.4	
Feb-16	2,808.9		688.0	2,959.9	
Mar-16	2,794.6		611.6	2,978.6	
Apr-16	3,235.6				
May-16	2,505.5				
Jun-16	2,311.6				
Jul-16	2,766.8				
Aug-16	2,200.0				
Sep-16	2,629.7				
Oct-16	2,909.9				
Nov-16	2,738.2				
Dec-16	3,211.0	33,325.1			33,708.1
Jan-17	3,162.6				
Feb-17	2,764.7				
Mar-17	2,750.6				
Apr-17	3,184.6				
May-17	2,466.0				
Jun-17	2,275.2				
Jul-17	2,723.2				
Aug-17	2,165.3				
Sep-17	2,588.2				
Oct-17	2,864.0				
Nov-17	2,695.0				
Dec-17	3,160.4	32,799.8			32,799.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.634386498
R Square	0.402446228
Adjusted R Square	0.384871118
Standard Error	408.5428129
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3821949.432	3821949.432	22.89864514	3.25558E-05
Residual	34	5674845.82	166907.23		
Total	35	9496795.252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2376.557715	130.0495932	18.27424182	3.71206E-19	2112.265144	2640.850287	2112.265144	2640.850287
WH-HDD	1.016962744	0.212520168	4.785252882	3.25558E-05	0.585069801	1.448855688	0.585069801	1.448855688

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (34,135.5 / 35,237.6) ^ (1/2) - 1 = **-1.6%**

Old Crow

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,211.6		952.0	2,165.6	
Feb-13	2,681.5		665.4	2,783.6	
Mar-13	1,742.7		851.1	1,707.7	
Apr-13	1,927.2		639.9	1,862.2	
May-13	1,789.1		294.0	1,764.1	
Jun-13	1,923.2		112.4	1,943.6	
Jul-13	1,523.1		92.5	1,528.8	
Aug-13	1,476.1		98.9	1,501.9	
Sep-13	1,782.8		264.3	1,804.9	
Oct-13	1,501.1		501.4	1,497.6	
Nov-13	1,804.0		865.6	1,764.3	
Dec-13	2,055.6	22,417.9	1,144.7	1,958.6	22,283.1
Jan-14	2,443.9		745.8	2,521.0	
Feb-14	1,885.9		992.4	1,792.8	
Mar-14	2,352.5		855.1	2,315.1	
Apr-14	1,980.1		499.8	1,998.7	
May-14	2,079.8		269.5	2,069.4	
Jun-14	1,461.1		200.5	1,428.9	
Jul-14	2,128.2		98.0	2,130.6	
Aug-14	1,127.9		144.0	1,126.7	
Sep-14	1,277.9		307.1	1,274.5	
Oct-14	1,715.1		515.6	1,703.1	
Nov-14	1,813.6		772.8	1,829.4	
Dec-14	1,687.8	21,953.8	854.4	1,764.2	21,954.6
Jan-15	2,552.7		927.0	2,521.6	
Feb-15	1,857.0		851.4	1,848.1	
Mar-15	2,044.5		671.3	2,116.9	
Apr-15	2,002.7		453.5	2,049.0	
May-15	1,573.3		192.9	1,608.7	
Jun-15	1,417.5		127.2	1,429.2	
Jul-15	1,733.8		115.7	1,725.7	
Aug-15	1,307.3		183.2	1,282.8	
Sep-15	1,863.3		332.7	1,844.6	
Oct-15	1,331.0		469.8	1,346.4	
Nov-15	1,730.8		759.2	1,754.6	
Dec-15	2,196.0	21,609.9	947.9	2,216.5	21,743.9
Jan-16	2,531.5		827.6	2,559.7	
Feb-16	2,136.8		688.0	2,225.4	
Mar-16	2,258.0		611.6	2,366.1	
Apr-16	1,966.2				
May-16	1,544.7				
Jun-16	1,391.7				
Jul-16	1,702.3				
Aug-16	1,283.6				
Sep-16	1,829.5				
Oct-16	1,306.7				
Nov-16	1,699.3				
Dec-16	2,156.0	21,806.3			22,031.2
Jan-17	2,485.4				
Feb-17	2,097.9				
Mar-17	2,217.0				
Apr-17	1,930.5				
May-17	1,516.6				
Jun-17	1,366.4				
Jul-17	1,671.3				
Aug-17	1,260.2				
Sep-17	1,796.2				
Oct-17	1,283.0				
Nov-17	1,668.4				
Dec-17	2,116.8	21,409.7			21,409.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.536022599
R Square	0.287320227
Adjusted R Square	0.266359057
Standard Error	310.0130474
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1317378.674	1317378.674	13.70726107	0.000753157
Residual	34	3267675.044	96108.08953		
Total	35	4585053.718			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1521.537861	98.68505682	15.4181181	6.538E-17	1320.985696	1722.090026	1320.985696	1722.090026
WH-HDD	0.59705988	0.161265901	3.702331842	0.000753157	0.269328138	0.924791622	0.269328138	0.924791622

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (21,609.9 / 22,417.9) ^ (1/2) - 1 = **-1.8%**

Destruction Bay

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,272.4		952.0	2,228.8	
Feb-13	1,946.7		665.4	2,043.5	
Mar-13	1,558.8		851.1	1,525.6	
Apr-13	1,759.7		639.9	1,698.0	
May-13	1,301.9		294.0	1,278.2	
Jun-13	1,462.2		112.4	1,481.6	
Jul-13	1,406.6		92.5	1,412.0	
Aug-13	1,333.9		98.9	1,358.4	
Sep-13	1,427.5		264.3	1,448.5	
Oct-13	1,102.3		501.4	1,099.0	
Nov-13	1,470.4		865.6	1,432.8	
Dec-13	1,690.9	18,733.4	1,144.7	1,599.0	18,605.5
Jan-14	1,895.9		745.8	1,969.0	
Feb-14	1,608.1		992.4	1,519.8	
Mar-14	1,649.2		855.1	1,613.8	
Apr-14	1,443.2		499.8	1,460.9	
May-14	1,425.4		269.5	1,415.5	
Jun-14	1,196.2		200.5	1,165.8	
Jul-14	1,309.0		98.0	1,311.3	
Aug-14	1,378.9		144.0	1,377.7	
Sep-14	1,477.3		307.1	1,474.1	
Oct-14	1,181.2		515.6	1,169.8	
Nov-14	1,513.4		772.8	1,528.3	
Dec-14	1,665.0	17,742.7	854.4	1,737.5	17,743.4
Jan-15	2,007.4		927.0	1,977.9	
Feb-15	1,900.1		851.4	1,891.6	
Mar-15	1,472.7		671.3	1,541.4	
Apr-15	1,717.7		453.5	1,761.7	
May-15	1,287.4		192.9	1,321.0	
Jun-15	1,212.2		127.2	1,223.3	
Jul-15	1,423.0		115.7	1,415.3	
Aug-15	1,097.4		183.2	1,074.0	
Sep-15	1,659.5		332.7	1,641.7	
Oct-15	1,053.9		469.8	1,068.5	
Nov-15	1,594.0		759.2	1,616.6	
Dec-15	1,865.9	18,291.3	947.9	1,885.4	18,418.4
Jan-16	1,878.0		827.6	1,904.8	
Feb-16	1,604.5		688.0	1,688.6	
Mar-16	1,636.7		611.6	1,739.2	
Apr-16	1,697.3				
May-16	1,272.1				
Jun-16	1,197.8				
Jul-16	1,406.2				
Aug-16	1,084.3				
Sep-16	1,639.8				
Oct-16	1,041.4				
Nov-16	1,575.0				
Dec-16	1,843.8	17,877.1			18,090.4
Jan-17	1,855.8				
Feb-17	1,585.5				
Mar-17	1,617.3				
Apr-17	1,677.2				
May-17	1,257.0				
Jun-17	1,183.6				
Jul-17	1,389.5				
Aug-17	1,071.5				
Sep-17	1,620.3				
Oct-17	1,029.1				
Nov-17	1,556.3				
Dec-17	1,821.9	17,664.9			17,664.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.658944264
R Square	0.434207543
Adjusted R Square	0.417566588
Standard Error	213.1345621
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1185296.192	1185296.192	26.09270636	1.24385E-05
Residual	34	1544495.614	45426.34157		
Total	35	2729791.805			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1226.048323	67.84616503	18.07100404	5.24525E-19	1088.168326	1363.928319	1088.168326	1363.928319
WH-HDD	0.566338413	0.110870615	5.108102031	1.24385E-05	0.341022215	0.791654611	0.341022215	0.791654611

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (18,291.3 / 18,733.4) ^ (1/2) - 1 = **-1.2%**

Beaver Creek

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,415.2		952.0	2,405.4	
Feb-13	2,187.7		665.4	2,209.4	
Mar-13	1,908.5		851.1	1,901.0	
Apr-13	1,493.9		639.9	1,480.0	
May-13	1,913.3		294.0	1,908.0	
Jun-13	1,802.1		112.4	1,806.5	
Jul-13	2,976.0		92.5	2,977.2	
Aug-13	2,522.1		98.9	2,527.6	
Sep-13	2,157.4		264.3	2,162.1	
Oct-13	1,901.6		501.4	1,900.9	
Nov-13	1,704.2		865.6	1,695.8	
Dec-13	1,733.1	24,715.0	1,144.7	1,712.5	24,686.3
Jan-14	2,960.5		745.8	2,976.9	
Feb-14	2,208.3		992.4	2,188.5	
Mar-14	1,882.3		855.1	1,874.3	
Apr-14	1,807.2		499.8	1,811.2	
May-14	1,554.4		269.5	1,552.2	
Jun-14	1,836.9		200.5	1,830.1	
Jul-14	1,738.1		98.0	1,738.6	
Aug-14	1,717.1		144.0	1,716.8	
Sep-14	2,433.1		307.1	2,432.3	
Oct-14	2,188.7		515.6	2,186.2	
Nov-14	2,203.9		772.8	2,207.3	
Dec-14	2,084.7	24,615.1	854.4	2,100.9	24,615.3
Jan-15	2,624.4		927.0	2,617.8	
Feb-15	1,744.7		851.4	1,742.8	
Mar-15	2,396.2		671.3	2,411.6	
Apr-15	1,797.2		453.5	1,807.0	
May-15	1,783.6		192.9	1,791.1	
Jun-15	1,564.2		127.2	1,566.7	
Jul-15	1,991.0		115.7	1,989.2	
Aug-15	1,764.2		183.2	1,759.0	
Sep-15	2,158.4		332.7	2,154.4	
Oct-15	1,672.8		469.8	1,676.1	
Nov-15	2,012.7		759.2	2,017.8	
Dec-15	1,985.5	23,494.7	947.9	1,989.8	23,523.2
Jan-16	2,713.2		827.6	2,719.2	
Feb-16	1,684.4		688.0	1,703.3	
Mar-16	2,077.3		611.6	2,100.3	
Apr-16	1,752.2				
May-16	1,739.0				
Jun-16	1,525.1				
Jul-16	1,941.2				
Aug-16	1,720.1				
Sep-16	2,104.4				
Oct-16	1,631.0				
Nov-16	1,962.4				
Dec-16	1,935.8	22,786.2			22,834.0
Jan-17	2,645.4				
Feb-17	1,642.3				
Mar-17	2,025.4				
Apr-17	1,708.4				
May-17	1,695.5				
Jun-17	1,487.0				
Jul-17	1,892.7				
Aug-17	1,677.1				
Sep-17	2,051.8				
Oct-17	1,590.2				
Nov-17	1,913.4				
Dec-17	1,887.4	22,216.6			22,216.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.11304581
R Square	0.012779355
Adjusted R Square	-0.016256546
Standard Error	367.803698
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	59539.58657	59539.58657	0.440122562	0.511536754
Residual	34	4599505.048	135279.5602		
Total	35	4659044.634			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1956.736633	117.0812943	16.71263241	5.75472E-18	1718.798816	2194.674451	1718.798816	2194.674451
WH-HDD	0.126930351	0.191328059	0.663417336	0.511536754	-0.261895047	0.515755749	-0.261895047	0.515755749

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (23,494.7 / 24,715.0) ^ (1/2) - 1 = **-2.5%**

Tagish

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,248.3		952.0	1,200.4	
Feb-13	1,046.9		665.4	1,153.2	
Mar-13	1,001.3		851.1	964.8	
Apr-13	929.8		639.9	862.1	
May-13	617.5		294.0	591.5	
Jun-13	755.7		112.4	777.0	
Jul-13	715.6		92.5	721.5	
Aug-13	768.1		98.9	794.9	
Sep-13	608.2		264.3	631.2	
Oct-13	653.0		501.4	649.4	
Nov-13	904.0		865.6	862.8	
Dec-13	964.3	10,212.6	1,144.7	863.4	10,072.2
Jan-14	1,768.1		745.8	1,848.4	
Feb-14	1,171.3		992.4	1,074.3	
Mar-14	1,148.8		855.1	1,109.8	
Apr-14	1,085.0		499.8	1,104.5	
May-14	1,710.8		269.5	1,700.0	
Jun-14	874.4		200.5	840.9	
Jul-14	807.7		98.0	810.2	
Aug-14	786.4		144.0	785.1	
Sep-14	776.8		307.1	773.3	
Oct-14	713.3		515.6	700.9	
Nov-14	951.7		772.8	968.1	
Dec-14	1,028.6	12,822.9	854.4	1,108.1	12,823.7
Jan-15	2,339.1		927.0	2,306.7	
Feb-15	1,559.1		851.4	1,549.8	
Mar-15	544.7		671.3	620.0	
Apr-15	1,214.5		453.5	1,262.7	
May-15	931.4		192.9	968.2	
Jun-15	649.2		127.2	661.4	
Jul-15	673.8		115.7	665.3	
Aug-15	562.6		183.2	537.0	
Sep-15	798.1		332.7	778.7	
Oct-15	1,243.5		469.8	1,259.5	
Nov-15	1,360.4		759.2	1,385.2	
Dec-15	1,384.5	13,260.9	947.9	1,405.9	13,400.5
Jan-16	1,636.8		827.6	1,666.3	
Feb-16	1,615.8		688.0	1,708.1	
Mar-16	1,348.8		611.6	1,461.2	
Apr-16	1,383.9				
May-16	1,061.3				
Jun-16	739.8				
Jul-16	767.8				
Aug-16	641.1				
Sep-16	909.5				
Oct-16	1,417.0				
Nov-16	1,550.2				
Dec-16	1,577.7	14,649.7			14,883.8
Jan-17	1,865.2				
Feb-17	1,841.3				
Mar-17	1,536.9				
Apr-17	1,577.0				
May-17	1,209.4				
Jun-17	843.0				
Jul-17	874.9				
Aug-17	730.6				
Sep-17	1,036.4				
Oct-17	1,614.7				
Nov-17	1,766.4				
Dec-17	1,797.8	16,693.5			16,693.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.521963398
R Square	0.272445789
Adjusted R Square	0.251047136
Standard Error	334.8972558
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1427962.612	1427962.612	12.73191289	0.001094401
Residual	34	3813309.847	112156.172		
Total	35	5241272.459			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	684.1489632	106.6063348	6.417526355	2.48416E-07	467.4988247	900.7991018	467.4988247	900.7991018
WH-HDD	0.621614295	0.174210434	3.568180614	0.001094401	0.267576096	0.975652494	0.267576096	0.975652494

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (13,260.9 / 10,212.6) ^ (1/2) - 1 = **14.0%**

Marsh Lake

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,284.8		952.0	1,239.8	
Feb-13	1,825.2		665.4	1,924.9	
Mar-13	1,310.8		851.1	1,276.7	
Apr-13	1,356.7		639.9	1,293.3	
May-13	1,217.8		294.0	1,193.4	
Jun-13	1,017.0		112.4	1,037.0	
Jul-13	819.7		92.5	825.2	
Aug-13	885.5		98.9	910.7	
Sep-13	876.1		264.3	897.7	
Oct-13	1,106.4		501.4	1,103.0	
Nov-13	1,143.6		865.6	1,104.9	
Dec-13	1,417.3	14,260.9	1,144.7	1,322.6	14,129.3
Jan-14	1,566.0		745.8	1,641.3	
Feb-14	1,375.1		992.4	1,284.2	
Mar-14	1,386.1		855.1	1,349.6	
Apr-14	1,505.5		499.8	1,523.7	
May-14	1,125.0		269.5	1,114.8	
Jun-14	909.5		200.5	878.1	
Jul-14	968.7		98.0	971.1	
Aug-14	896.3		144.0	895.2	
Sep-14	1,079.0		307.1	1,075.6	
Oct-14	1,080.1		515.6	1,068.4	
Nov-14	1,342.8		772.8	1,358.1	
Dec-14	1,706.0	14,939.9	854.4	1,780.5	14,940.7
Jan-15	1,322.9		927.0	1,292.5	
Feb-15	1,197.6		851.4	1,188.8	
Mar-15	1,134.0		671.3	1,204.6	
Apr-15	1,243.1		453.5	1,288.3	
May-15	967.7		192.9	1,002.2	
Jun-15	812.6		127.2	824.0	
Jul-15	827.5		115.7	819.5	
Aug-15	767.1		183.2	743.1	
Sep-15	1,174.6		332.7	1,156.4	
Oct-15	963.7		469.8	978.7	
Nov-15	1,091.8		759.2	1,115.1	
Dec-15	1,374.6	12,877.0	947.9	1,394.6	13,007.9
Jan-16	1,331.0		827.6	1,358.6	
Feb-16	1,130.8		688.0	1,217.3	
Mar-16	1,258.1		611.6	1,363.5	
Apr-16	1,181.3				
May-16	919.5				
Jun-16	772.2				
Jul-16	786.3				
Aug-16	729.0				
Sep-16	1,116.2				
Oct-16	915.7				
Nov-16	1,037.4				
Dec-16	1,306.2	12,483.6			12,703.1
Jan-17	1,264.8				
Feb-17	1,074.6				
Mar-17	1,195.5				
Apr-17	1,122.5				
May-17	873.7				
Jun-17	733.8				
Jul-17	747.2				
Aug-17	692.7				
Sep-17	1,060.6				
Oct-17	870.2				
Nov-17	985.8				
Dec-17	1,241.2	11,862.5			11,862.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.734719964
R Square	0.539813426
Adjusted R Square	0.526278526
Standard Error	177.4051342
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1255223.389	1255223.389	39.88307675	3.36509E-07
Residual	34	1070067.776	31472.58163		
Total	35	2325291.164			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	864.9778165	56.47257719	15.31677603	7.95983E-17	750.2117316	979.7439014	750.2117316	979.7439014
WH-HDD	0.582804755	0.092284499	6.315304961	3.36509E-07	0.395260088	0.770349421	0.395260088	0.770349421

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (12,877.0 / 14,260.9) ^ (1/2) - 1 = **-5.0%**

Lower Post

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,640.5		1,129.1	2,557.2	
Feb-13	1,772.1		765.8	1,948.3	
Mar-13	1,762.4		950.7	1,727.0	
Apr-13	1,883.1		690.1	1,795.8	
May-13	1,268.9		304.5	1,250.1	
Jun-13	1,256.9		96.3	1,286.5	
Jul-13	1,342.2		105.1	1,333.8	
Aug-13	1,380.3		82.2	1,416.1	
Sep-13	877.8		239.1	920.8	
Oct-13	1,377.9		490.2	1,401.1	
Nov-13	1,375.0		1,021.3	1,313.9	
Dec-13	1,786.6	18,723.6	1,248.8	1,741.7	18,692.2
Jan-14	2,146.3		937.7	2,223.6	
Feb-14	1,728.9		1,204.4	1,536.9	
Mar-14	1,930.2		1,008.9	1,846.1	
Apr-14	1,482.2		570.5	1,495.2	
May-14	1,343.6		331.1	1,302.5	
Jun-14	1,134.6		186.8	1,088.3	
Jul-14	1,168.9		87.6	1,175.2	
Aug-14	1,018.4		144.8	1,001.7	
Sep-14	993.6		295.8	989.0	
Oct-14	1,146.1		539.7	1,127.7	
Nov-14	1,159.9		936.4	1,170.1	
Dec-14	2,014.4	17,267.1	1,176.7	2,029.9	16,986.2
Jan-15	2,433.7		1,022.8	2,439.6	
Feb-15	2,010.6		956.7	2,026.5	
Mar-15	1,780.9		766.3	1,900.3	
Apr-15	1,837.2		497.4	1,911.6	
May-15	1,508.6		210.8	1,568.4	
Jun-15	978.0		111.8	994.6	
Jul-15	1,049.7		92.4	1,051.9	
Aug-15	809.9		147.5	790.9	
Sep-15	1,284.5		336.1	1,246.1	
Oct-15	864.1		523.7	859.2	
Nov-15	1,657.5		887.8	1,708.5	
Dec-15	1,889.3	18,104.2	1,160.3	1,918.7	18,416.5
Jan-16	2,282.4		1,099.3	2,224.1	
Feb-16	1,873.7		930.8	1,911.4	
Mar-16	1,793.8		724.3	1,948.5	
Apr-16	1,806.6				
May-16	1,483.4				
Jun-16	961.7				
Jul-16	1,032.2				
Aug-16	796.4				
Sep-16	1,263.1				
Oct-16	849.7				
Nov-16	1,629.9				
Dec-16	1,857.8	17,630.8			17,764.8
Jan-17	2,244.3				
Feb-17	1,842.5				
Mar-17	1,763.9				
Apr-17	1,776.4				
May-17	1,458.7				
Jun-17	945.6				
Jul-17	1,015.0				
Aug-17	783.1				
Sep-17	1,242.0				
Oct-17	835.5				
Nov-17	1,602.7				
Dec-17	1,826.8	17,336.7			17,336.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.747433024
R Square	0.558656126
Adjusted R Square	0.545675424
Standard Error	302.7821018
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3945542.978	3945542.978	43.037435	1.62766E-07
Residual	34	3117018.039	91677.00115		
Total	35	7062561.017			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1007.041068	90.84942635	11.08472676	7.82857E-13	822.4128198	1191.669316	822.4128198	1191.669316
WL-HDD	0.839315619	0.127938753	6.560292295	1.62766E-07	0.57931279	1.099318448	0.57931279	1.099318448

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (18,104.2 / 18,723.6) ^ (1/2) - 1 = **-1.7%**

Upper Liard

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,580.4		1,129.1	2,545.7	
Feb-13	1,867.5		765.8	1,940.7	
Mar-13	1,806.4		950.7	1,791.7	
Apr-13	1,877.5		690.1	1,841.2	
May-13	1,384.7		304.5	1,376.9	
Jun-13	1,122.6		96.3	1,135.0	
Jul-13	1,324.2		105.1	1,320.6	
Aug-13	1,260.5		82.2	1,275.3	
Sep-13	1,045.0		239.1	1,062.9	
Oct-13	1,052.5		490.2	1,062.1	
Nov-13	1,256.1		1,021.3	1,230.7	
Dec-13	2,312.2	18,889.5	1,248.8	2,293.5	18,876.4
Jan-14	1,907.7		937.7	1,939.8	
Feb-14	1,040.7		1,204.4	960.9	
Mar-14	1,346.8		1,008.9	1,311.9	
Apr-14	1,530.5		570.5	1,535.9	
May-14	1,260.2		331.1	1,243.1	
Jun-14	967.4		186.8	948.1	
Jul-14	1,167.2		87.6	1,169.7	
Aug-14	1,011.7		144.8	1,004.7	
Sep-14	1,062.0		295.8	1,060.1	
Oct-14	1,020.7		539.7	1,013.1	
Nov-14	1,324.1		936.4	1,328.3	
Dec-14	1,396.0	15,035.0	1,176.7	1,402.5	14,918.2
Jan-15	1,242.5		1,022.8	1,244.9	
Feb-15	1,042.5		956.7	1,049.2	
Mar-15	878.7		766.3	928.4	
Apr-15	1,043.4		497.4	1,074.3	
May-15	1,227.2		210.8	1,252.1	
Jun-15	1,089.6		111.8	1,096.5	
Jul-15	1,410.8		92.4	1,411.7	
Aug-15	1,476.9		147.5	1,469.0	
Sep-15	1,455.5		336.1	1,439.5	
Oct-15	1,322.9		523.7	1,320.9	
Nov-15	1,198.9		887.8	1,220.1	
Dec-15	916.0	14,304.9	1,160.3	928.2	14,434.7
Jan-16	1,615.0		1,099.3	1,590.8	
Feb-16	518.1		930.8	533.8	
Mar-16	970.0		724.3	1,034.3	
Apr-16	908.0				
May-16	1,068.0				
Jun-16	948.2				
Jul-16	1,227.7				
Aug-16	1,285.2				
Sep-16	1,266.6				
Oct-16	1,151.2				
Nov-16	1,043.3				
Dec-16	797.1	12,798.5			12,854.2
Jan-17	1,405.4				
Feb-17	450.9				
Mar-17	844.1				
Apr-17	790.2				
May-17	929.4				
Jun-17	825.2				
Jul-17	1,068.4				
Aug-17	1,118.4				
Sep-17	1,102.2				
Oct-17	1,001.8				
Nov-17	907.9				
Dec-17	693.7	11,137.6			11,137.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.364656649
R Square	0.132974472
Adjusted R Square	0.107473721
Standard Error	361.5389333
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	681593.5154	681593.5154	5.214531622	0.028768898
Residual	34	4444153.609	130710.4003		
Total	35	5125747.124			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1133.719366	108.479347	10.45101577	3.72445E-12	913.2628091	1354.175924	913.2628091	1354.175924
WL-HDD	0.348846717	0.152766099	2.283534896	0.028768898	0.038388652	0.659304783	0.038388652	0.659304783

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (14,304.9 / 18,889.5) ^ (1/2) - 1 = **-13.0%**

Watson Lake

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	4,155.1		1,129.1	4,049.6	
Feb-13	3,609.9		765.8	3,833.0	
Mar-13	3,776.8		950.7	3,732.1	
Apr-13	3,507.1		690.1	3,396.4	
May-13	3,010.4		304.5	2,986.6	
Jun-13	2,795.4		96.3	2,833.0	
Jul-13	2,585.7		105.1	2,575.0	
Aug-13	2,720.1		82.2	2,765.4	
Sep-13	2,414.7		239.1	2,469.2	
Oct-13	2,678.8		490.2	2,708.3	
Nov-13	3,090.9		1,021.3	3,013.5	
Dec-13	3,627.4	37,972.3	1,248.8	3,570.4	37,932.5
Jan-14	4,237.6		937.7	4,335.5	
Feb-14	3,596.9		1,204.4	3,353.7	
Mar-14	3,855.1		1,008.9	3,748.5	
Apr-14	3,427.9		570.5	3,444.3	
May-14	3,394.0		331.1	3,342.0	
Jun-14	2,668.3		186.8	2,609.6	
Jul-14	3,015.0		87.6	3,022.9	
Aug-14	2,811.6		144.8	2,790.4	
Sep-14	2,721.4		295.8	2,715.6	
Oct-14	2,919.7		539.7	2,896.5	
Nov-14	3,198.0		936.4	3,210.9	
Dec-14	3,987.2	39,832.6	1,176.7	4,006.9	39,476.8
Jan-15	4,362.2		1,022.8	4,369.7	
Feb-15	3,655.2		956.7	3,675.3	
Mar-15	3,474.4		766.3	3,625.7	
Apr-15	3,297.9		497.4	3,392.1	
May-15	3,178.7		210.8	3,254.6	
Jun-15	2,518.2		111.8	2,539.3	
Jul-15	2,966.9		92.4	2,969.7	
Aug-15	2,801.6		147.5	2,777.5	
Sep-15	2,907.1		336.1	2,858.5	
Oct-15	2,902.6		523.7	2,896.4	
Nov-15	3,591.4		887.8	3,655.9	
Dec-15	3,736.5	39,392.7	1,160.3	3,773.7	39,788.4
Jan-16	4,315.3		1,099.3	4,241.4	
Feb-16	3,758.9		930.8	3,806.5	
Mar-16	3,769.2		724.3	3,965.2	
Apr-16	3,359.0				
May-16	3,237.6				
Jun-16	2,564.9				
Jul-16	3,021.9				
Aug-16	2,853.6				
Sep-16	2,961.0				
Oct-16	2,956.4				
Nov-16	3,657.9				
Dec-16	3,805.7	40,261.3			40,431.2
Jan-17	4,395.2				
Feb-17	3,828.5				
Mar-17	3,839.0				
Apr-17	3,421.3				
May-17	3,297.6				
Jun-17	2,612.4				
Jul-17	3,077.9				
Aug-17	2,906.4				
Sep-17	3,015.9				
Oct-17	3,011.2				
Nov-17	3,725.7				
Dec-17	3,876.2	41,007.4			41,007.4

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.82201356
R Square	0.675706292
Adjusted R Square	0.666168242
Standard Error	298.9609848
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	6331802.927	6331802.927	70.84323072	7.91525E-10
Residual	34	3038840.794	89377.67042		
Total	35	9370643.721			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2627.664659	89.70290454	29.29297187	1.04535E-25	2445.366424	2809.962894	2445.366424	2809.962894
WL-HDD	1.063250536	0.126324164	8.416842087	7.91525E-10	0.806528948	1.319972124	0.806528948	1.319972124

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (39,392.7 / 37,972.3) ^ (1/2) - 1 = **1.9%**

Keno City

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,447.1		952.0	1,411.9	
Feb-13	1,028.6		665.4	1,106.7	
Mar-13	1,314.5		851.1	1,287.8	
Apr-13	1,260.5		639.9	1,210.7	
May-13	618.2		294.0	599.1	
Jun-13	509.5		112.4	525.1	
Jul-13	730.7		92.5	735.1	
Aug-13	595.7		98.9	615.4	
Sep-13	630.6		264.3	647.6	
Oct-13	67.8		501.4	65.2	
Nov-13	623.0		865.6	592.7	
Dec-13	670.3	9,496.5	1,144.7	596.1	9,393.3
Jan-14	801.8		745.8	860.8	
Feb-14	891.8		992.4	820.6	
Mar-14	787.3		855.1	758.6	
Apr-14	747.2		499.8	761.5	
May-14	528.1		269.5	520.1	
Jun-14	566.4		200.5	541.8	
Jul-14	620.0		98.0	621.9	
Aug-14	386.5		144.0	385.6	
Sep-14	746.2		307.1	743.5	
Oct-14	475.6		515.6	466.4	
Nov-14	675.4		772.8	687.4	
Dec-14	758.5	7,984.6	854.4	816.9	7,985.2
Jan-15	758.4		927.0	734.6	
Feb-15	866.9		851.4	860.1	
Mar-15	722.2		671.3	777.5	
Apr-15	627.4		453.5	662.9	
May-15	649.5		192.9	676.6	
Jun-15	202.6		127.2	211.6	
Jul-15	492.5		115.7	486.3	
Aug-15	553.7		183.2	534.9	
Sep-15	508.5		332.7	494.2	
Oct-15	548.4		469.8	560.2	
Nov-15	1,000.7		759.2	1,018.9	
Dec-15	710.6	7,641.5	947.9	726.3	7,744.1
Jan-16	398.8		827.6	420.5	
Feb-16	940.4		688.0	1,008.2	
Mar-16	174.2		611.6	256.9	
Apr-16	562.8				
May-16	582.6				
Jun-16	181.8				
Jul-16	441.8				
Aug-16	496.7				
Sep-16	456.1				
Oct-16	491.9				
Nov-16	897.6				
Dec-16	637.4	6,262.4			6,434.4
Jan-17	357.8				
Feb-17	843.6				
Mar-17	156.3				
Apr-17	504.9				
May-17	522.6				
Jun-17	163.1				
Jul-17	396.3				
Aug-17	445.6				
Sep-17	409.2				
Oct-17	441.3				
Nov-17	805.2				
Dec-17	571.8	5,617.5			5,617.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.545686993
R Square	0.297774295
Adjusted R Square	0.277120597
Standard Error	231.3276172
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	771514.9882	771514.9882	14.41748136	0.000576992
Residual	34	1819423.86	53512.46648		
Total	35	2590938.849			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	459.6312729	73.6374783	6.24181169	4.18728E-07	309.9819119	609.2806339	309.9819119	609.2806339
WH-HDD	0.456914309	0.120334473	3.797035865	0.000576992	0.212365237	0.70146338	0.212365237	0.70146338

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (7,641.5 / 9,496.5) ^ (1/2) - 1 = **-10.3%**

Stewart Crossing

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,107.2		952.0	2,028.6	
Feb-13	2,070.4		665.4	2,244.8	
Mar-13	2,883.5		851.1	2,823.8	
Apr-13	1,928.8		639.9	1,817.8	
May-13	1,760.9		294.0	1,718.2	
Jun-13	1,495.6		112.4	1,530.5	
Jul-13	1,264.5		92.5	1,274.2	
Aug-13	1,622.2		98.9	1,666.2	
Sep-13	1,199.5		264.3	1,237.3	
Oct-13	1,587.8		501.4	1,581.9	
Nov-13	1,494.1		865.6	1,426.4	
Dec-13	1,641.0	21,055.6	1,144.7	1,475.4	20,825.2
Jan-14	3,117.1		745.8	3,248.8	
Feb-14	1,937.6		992.4	1,778.6	
Mar-14	1,861.8		855.1	1,798.0	
Apr-14	1,584.3		499.8	1,616.2	
May-14	1,522.7		269.5	1,505.0	
Jun-14	1,097.5		200.5	1,042.6	
Jul-14	1,367.0		98.0	1,371.1	
Aug-14	793.7		144.0	791.7	
Sep-14	1,102.4		307.1	1,096.6	
Oct-14	1,629.8		515.6	1,609.4	
Nov-14	1,808.2		772.8	1,835.1	
Dec-14	2,139.9	19,962.1	854.4	2,270.3	19,963.4
Jan-15	2,014.6		927.0	1,961.5	
Feb-15	2,493.4		851.4	2,478.1	
Mar-15	2,049.6		671.3	2,173.2	
Apr-15	1,641.2		453.5	1,720.3	
May-15	1,651.8		192.9	1,712.2	
Jun-15	856.1		127.2	876.0	
Jul-15	1,343.0		115.7	1,329.1	
Aug-15	849.3		183.2	807.3	
Sep-15	1,262.1		332.7	1,230.2	
Oct-15	1,339.1		469.8	1,365.4	
Nov-15	1,530.9		759.2	1,571.7	
Dec-15	1,728.2	18,759.4	947.9	1,763.3	18,988.3
Jan-16	2,523.0		827.6	2,571.3	
Feb-16	1,741.6		688.0	1,892.9	
Mar-16	1,551.3		611.6	1,735.7	
Apr-16	1,549.1				
May-16	1,559.2				
Jun-16	808.0				
Jul-16	1,267.7				
Aug-16	801.6				
Sep-16	1,191.3				
Oct-16	1,263.9				
Nov-16	1,445.0				
Dec-16	1,631.2	17,333.1			17,717.1
Jan-17	2,381.5				
Feb-17	1,643.9				
Mar-17	1,464.2				
Apr-17	1,462.2				
May-17	1,471.7				
Jun-17	762.7				
Jul-17	1,196.5				
Aug-17	756.7				
Sep-17	1,124.5				
Oct-17	1,193.0				
Nov-17	1,364.0				
Dec-17	1,539.7	16,360.7			16,360.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.652691217
R Square	0.426005825
Adjusted R Square	0.409123643
Standard Error	390.2181447
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3842393.94	3842393.94	25.23405058	1.60216E-05
Residual	34	5177186.815	152270.2005		
Total	35	9019580.756			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1128.852203	124.2163841	9.087788307	1.27371E-10	876.4141387	1381.290268	876.4141387	1381.290268
WL-HDD	1.019679103	0.202987846	5.023350534	1.60216E-05	0.607158168	1.432200038	0.607158168	1.432200038

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (18,759.4 / 21,055.6) ^ (1/2) - 1 = **-5.6%**

Swift River

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,442.2		1,129.1	1,378.8	
Feb-13	1,138.9		765.8	1,273.0	
Mar-13	1,204.2		950.7	1,177.4	
Apr-13	1,109.5		690.1	1,043.0	
May-13	876.7		304.5	862.4	
Jun-13	797.9		96.3	820.4	
Jul-13	764.5		105.1	758.1	
Aug-13	780.0		82.2	807.2	
Sep-13	849.5		239.1	882.2	
Oct-13	966.5		490.2	984.1	
Nov-13	1,222.6		1,021.3	1,176.1	
Dec-13	1,574.9	12,727.4	1,248.8	1,540.7	12,703.5
Jan-14	1,506.7		937.7	1,565.6	
Feb-14	1,359.1		1,204.4	1,212.9	
Mar-14	1,275.6		1,008.9	1,211.6	
Apr-14	1,276.7		570.5	1,286.6	
May-14	872.5		331.1	841.3	
Jun-14	905.1		186.8	869.8	
Jul-14	820.9		87.6	825.7	
Aug-14	1,020.9		144.8	1,008.2	
Sep-14	829.6		295.8	826.1	
Oct-14	1,041.8		539.7	1,027.9	
Nov-14	1,312.1		936.4	1,319.8	
Dec-14	1,437.6	13,658.7	1,176.7	1,449.5	13,444.9
Jan-15	1,555.4		1,022.8	1,559.9	
Feb-15	1,542.7		956.7	1,554.8	
Mar-15	1,159.8		766.3	1,250.7	
Apr-15	1,159.4		497.4	1,216.0	
May-15	1,036.8		210.8	1,082.3	
Jun-15	706.8		111.8	719.5	
Jul-15	694.1		92.4	695.8	
Aug-15	653.8		147.5	639.3	
Sep-15	846.5		336.1	817.3	
Oct-15	900.5		523.7	896.7	
Nov-15	1,340.5		887.8	1,379.3	
Dec-15	1,415.5	13,011.8	1,160.3	1,437.9	13,249.5
Jan-16	1,696.5		1,099.3	1,652.2	
Feb-16	1,385.5		930.8	1,414.1	
Mar-16	1,161.2		724.3	1,279.0	
Apr-16	1,172.3				
May-16	1,048.3				
Jun-16	714.7				
Jul-16	701.8				
Aug-16	661.0				
Sep-16	855.9				
Oct-16	910.5				
Nov-16	1,355.4				
Dec-16	1,431.3	13,094.4			13,196.4
Jan-17	1,715.4				
Feb-17	1,400.9				
Mar-17	1,174.1				
Apr-17	1,185.3				
May-17	1,059.9				
Jun-17	722.6				
Jul-17	709.6				
Aug-17	668.4				
Sep-17	865.5				
Oct-17	920.6				
Nov-17	1,370.5				
Dec-17	1,447.2	13,239.9			13,239.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.919338794
R Square	0.845183818
Adjusted R Square	0.840630401
Standard Error	110.9615733
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2285382.773	2285382.773	185.6152856	2.47871E-15
Residual	34	418624.0052	12312.47074		
Total	35	2704006.778			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	717.2010491	33.29389425	21.5415188	2.13391E-21	649.5397153	784.8623829	649.5397153	784.8623829
WH-HDD	0.638780118	0.046886144	13.62407008	2.47871E-15	0.543496009	0.734064228	0.543496009	0.734064228

2 year Compound Annual Growth Rate =

= (2015 Actual UPC / 2013 Actual UPC) ^ (1/(2015 - 2013)) -1 =

= (13,011.8 / 12,727.4) ^ (1/2) - 1 = **1.1%**

Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

Whitehorse (Includes Takhini & Deep Creek)

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	7,403.5		952.0	7,264.9	
Feb-13	5,904.4		665.4	6,212.1	
Mar-13	6,002.6		851.1	5,897.2	
Apr-13	6,195.8		639.9	6,000.0	
May-13	4,951.5		294.0	4,876.2	
Jun-13	5,024.9		112.4	5,086.6	
Jul-13	5,023.9		92.5	5,041.1	
Aug-13	5,111.1		98.9	5,188.7	
Sep-13	4,619.4		264.3	4,686.1	
Oct-13	5,004.4		501.4	4,994.0	
Nov-13	5,387.9		865.6	5,268.4	
Dec-13	5,956.0	66,585.6	1,144.7	5,663.9	66,179.2
Jan-14	6,892.4		745.8	7,124.8	
Feb-14	5,789.4		992.4	5,508.8	
Mar-14	6,026.9		855.1	5,914.3	
Apr-14	5,572.0		499.8	5,628.2	
May-14	4,906.6		269.5	4,875.4	
Jun-14	4,698.8		200.5	4,602.0	
Jul-14	4,872.9		98.0	4,880.2	
Aug-14	4,366.0		144.0	4,362.4	
Sep-14	4,901.2		307.1	4,890.9	
Oct-14	4,560.2		515.6	4,524.2	
Nov-14	5,617.3		772.8	5,664.8	
Dec-14	5,642.8	63,846.5	854.4	5,872.9	63,848.9
Jan-15	7,066.4		927.0	6,972.8	
Feb-15	5,952.5		851.4	5,925.5	
Mar-15	5,706.8		671.3	5,924.8	
Apr-15	5,418.8		453.5	5,558.4	
May-15	4,730.1		192.9	4,836.7	
Jun-15	4,398.0		127.2	4,433.1	
Jul-15	4,703.8		115.7	4,679.2	
Aug-15	4,254.6		183.2	4,180.5	
Sep-15	4,776.7		332.7	4,720.3	
Oct-15	4,616.3		469.8	4,662.7	
Nov-15	5,305.0		759.2	5,377.0	
Dec-15	5,573.6	62,502.6	947.9	5,635.6	62,906.6
Jan-16	6,588.3		827.6	6,673.5	
Feb-16	5,605.9		688.0	5,872.9	
Mar-16	5,511.4		611.6	5,836.9	
Apr-16	5,728.9				
May-16	4,862.7				
Jun-16	4,707.2				
Jul-16	4,866.8				
Aug-16	4,577.2				
Sep-16	4,765.8				
Oct-16	4,727.0				
Nov-16	5,436.7				
Dec-16	5,724.2	63,102.2			63,779.9
Jan-17	7,120.8				
Feb-17	5,882.1				
Mar-17	5,912.1				
Apr-17	5,728.9				
May-17	4,862.7				
Jun-17	4,707.2				
Jul-17	4,866.8				
Aug-17	4,577.2				
Sep-17	4,765.8				
Oct-17	4,727.0				
Nov-17	5,436.7				
Dec-17	5,724.2	64,311.6			64,311.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.768459027
R Square	0.590529276
Adjusted R Square	0.57848602
Standard Error	493.9511555
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	11963699.76	11963699.76	49.03401934	4.43771E-08
Residual	34	8295583.298	243987.7441		
Total	35	20259283.06			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	4421.229047	157.2372462	28.11820452	3.98418E-25	4101.684516	4740.773577	4101.684516	4740.773577
WH-HDD	1.799265811	0.256948792	7.002429531	4.43771E-08	1.277083038	2.321448583	1.277083038	2.321448583

Carmacks

Commercial Monthly	Actual UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	3,098.4		952.0	3,035.8	
Feb-13	2,705.0		665.4	2,844.1	
Mar-13	2,895.5		851.1	2,847.9	
Apr-13	3,143.9		639.9	3,055.4	
May-13	2,753.4		294.0	2,719.4	
Jun-13	1,823.0		112.4	1,850.9	
Jul-13	2,222.3		92.5	2,230.1	
Aug-13	2,270.0		98.9	2,305.1	
Sep-13	2,044.0		264.3	2,074.1	
Oct-13	2,627.4		501.4	2,622.7	
Nov-13	2,770.4		865.6	2,716.4	
Dec-13	2,576.3	30,929.7	1,144.7	2,444.3	30,746.0
Jan-14	3,848.6		745.8	3,953.6	
Feb-14	2,847.7		992.4	2,720.9	
Mar-14	2,695.9		855.1	2,645.0	
Apr-14	2,504.1		499.8	2,529.5	
May-14	2,603.8		269.5	2,589.6	
Jun-14	2,347.7		200.5	2,304.0	
Jul-14	2,033.0		98.0	2,036.3	
Aug-14	2,373.3		144.0	2,371.7	
Sep-14	2,313.6		307.1	2,308.9	
Oct-14	2,732.0		515.6	2,715.7	
Nov-14	2,403.1		772.8	2,424.6	
Dec-14	3,276.0	31,978.7	854.4	3,380.0	31,979.8
Jan-15	3,133.6		927.0	3,091.3	
Feb-15	2,469.0		851.4	2,456.8	
Mar-15	2,822.0		671.3	2,920.6	
Apr-15	2,866.7		453.5	2,929.8	
May-15	2,250.2		192.9	2,298.3	
Jun-15	2,314.8		127.2	2,330.7	
Jul-15	2,840.1		115.7	2,829.1	
Aug-15	2,106.0		183.2	2,072.5	
Sep-15	2,720.1		332.7	2,694.6	
Oct-15	2,812.1		469.8	2,833.0	
Nov-15	2,939.7		759.2	2,972.2	
Dec-15	3,156.8	32,431.1	947.9	3,184.8	32,613.7
Jan-16	3,254.3		827.6	3,292.8	
Feb-16	3,049.8		688.0	3,170.5	
Mar-16	3,026.9		611.6	3,174.0	
Apr-16	2,838.2				
May-16	2,535.8				
Jun-16	2,161.8				
Jul-16	2,365.1				
Aug-16	2,249.8				
Sep-16	2,359.2				
Oct-16	2,723.8				
Nov-16	2,704.4				
Dec-16	3,003.0	32,272.3			32,578.6
Jan-17	3,360.2				
Feb-17	2,673.9				
Mar-17	2,804.5				
Apr-17	2,838.2				
May-17	2,535.8				
Jun-17	2,161.8				
Jul-17	2,365.1				
Aug-17	2,249.8				
Sep-17	2,359.2				
Oct-17	2,723.8				
Nov-17	2,704.4				
Dec-17	3,003.0	31,779.9			31,779.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.645763695
R Square	0.417010749
Adjusted R Square	0.399864007
Standard Error	316.9841283
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2443659.291	2443659.291	24.32011474	2.10678E-05
Residual	34	3416283.878	100478.9376		
Total	35	5859943.169			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2224.364291	100.9041296	22.04433357	1.02473E-21	2019.302428	2429.426155	2019.302428	2429.426155
WH-HDD	0.81317291	0.164892192	4.931542836	2.10678E-05	0.478071657	1.148274162	0.478071657	1.148274162

Carcross

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,054.7		952.0	2,038.0	
Feb-13	1,953.8		665.4	1,990.8	
Mar-13	1,525.9		851.1	1,513.2	
Apr-13	1,641.3		639.9	1,617.7	
May-13	1,772.1		294.0	1,763.0	
Jun-13	1,795.6		112.4	1,803.0	
Jul-13	1,413.0		92.5	1,415.0	
Aug-13	1,476.0		98.9	1,485.3	
Sep-13	1,305.8		264.3	1,313.9	
Oct-13	1,246.6		501.4	1,245.3	
Nov-13	1,345.3		865.6	1,330.9	
Dec-13	1,413.8	18,943.7	1,144.7	1,378.6	18,894.8
Jan-14	1,975.2		745.8	2,003.2	
Feb-14	1,602.1		992.4	1,568.3	
Mar-14	1,851.8		855.1	1,838.2	
Apr-14	1,574.1		499.8	1,580.9	
May-14	1,465.0		269.5	1,461.3	
Jun-14	1,458.5		200.5	1,446.9	
Jul-14	1,504.1		98.0	1,505.0	
Aug-14	1,527.1		144.0	1,526.7	
Sep-14	1,276.3		307.1	1,275.0	
Oct-14	1,613.5		515.6	1,609.2	
Nov-14	1,319.6		772.8	1,325.4	
Dec-14	1,378.9	18,546.3	854.4	1,406.6	18,546.6
Jan-15	1,882.9		927.0	1,871.6	
Feb-15	1,682.9		851.4	1,679.7	
Mar-15	1,732.9		671.3	1,759.1	
Apr-15	1,345.6		453.5	1,362.4	
May-15	1,529.1		192.9	1,542.0	
Jun-15	1,314.3		127.2	1,318.5	
Jul-15	1,342.5		115.7	1,339.5	
Aug-15	1,523.5		183.2	1,514.6	
Sep-15	1,391.4		332.7	1,384.6	
Oct-15	1,566.0		469.8	1,571.5	
Nov-15	1,311.4		759.2	1,320.0	
Dec-15	1,646.8	18,269.3	947.9	1,654.3	18,317.9
Jan-16	2,021.0		827.6	2,031.3	
Feb-16	1,760.9		688.0	1,793.0	
Mar-16	2,014.5		611.6	2,053.6	
Apr-16	1,520.4				
May-16	1,588.7				
Jun-16	1,522.8				
Jul-16	1,419.9				
Aug-16	1,508.9				
Sep-16	1,324.5				
Oct-16	1,475.4				
Nov-16	1,325.4				
Dec-16	1,479.8	18,962.2			19,043.7
Jan-17	1,970.9				
Feb-17	1,746.3				
Mar-17	1,703.5				
Apr-17	1,520.4				
May-17	1,588.7				
Jun-17	1,522.8				
Jul-17	1,419.9				
Aug-17	1,508.9				
Sep-17	1,324.5				
Oct-17	1,475.4				
Nov-17	1,325.4				
Dec-17	1,479.8	18,586.5			18,586.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.326712903
R Square	0.106741321
Adjusted R Square	0.080469007
Standard Error	206.460393
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	173183.9919	173183.9919	4.06288235	0.051794312
Residual	34	1449280.392	42625.8939		
Total	35	1622464.384			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1436.00788	65.72160685	21.84985956	1.35851E-21	1302.445505	1569.570255	1302.445505	1569.570255
WH-HDD	0.216479336	0.107398774	2.015659284	0.051794312	-0.001781233	0.434739906	-0.001781233	0.434739906

Haines Junction

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	3,192.1		952.0	3,129.4	
Feb-13	2,742.1		665.4	2,881.2	
Mar-13	2,610.9		851.1	2,563.2	
Apr-13	2,527.0		639.9	2,438.4	
May-13	2,124.3		294.0	2,090.3	
Jun-13	2,505.9		112.4	2,533.8	
Jul-13	2,332.0		92.5	2,339.8	
Aug-13	1,818.5		98.9	1,853.6	
Sep-13	2,386.4		264.3	2,416.5	
Oct-13	2,082.8		501.4	2,078.0	
Nov-13	2,143.9		865.6	2,089.9	
Dec-13	2,971.7	29,437.5	1,144.7	2,839.6	29,253.7
Jan-14	3,196.3		745.8	3,301.4	
Feb-14	2,653.6		992.4	2,526.6	
Mar-14	3,069.5		855.1	3,018.6	
Apr-14	2,393.2		499.8	2,418.6	
May-14	2,261.2		269.5	2,247.1	
Jun-14	2,157.7		200.5	2,113.9	
Jul-14	2,258.3		98.0	2,261.6	
Aug-14	2,183.3		144.0	2,181.7	
Sep-14	2,302.1		307.1	2,297.5	
Oct-14	2,082.4		515.6	2,066.1	
Nov-14	2,066.6		772.8	2,088.1	
Dec-14	3,084.0	29,708.1	854.4	3,188.1	29,709.2
Jan-15	3,111.4		927.0	3,069.0	
Feb-15	3,051.3		851.4	3,039.1	
Mar-15	2,358.6		671.3	2,457.2	
Apr-15	2,821.3		453.5	2,884.4	
May-15	2,045.7		192.9	2,093.9	
Jun-15	2,121.3		127.2	2,137.2	
Jul-15	2,370.6		115.7	2,359.5	
Aug-15	2,221.6		183.2	2,188.1	
Sep-15	2,374.2		332.7	2,348.7	
Oct-15	2,129.0		469.8	2,150.0	
Nov-15	2,327.8		759.2	2,360.4	
Dec-15	2,981.6	29,914.2	947.9	3,009.6	30,096.9
Jan-16	3,042.0		827.6	3,080.6	
Feb-16	2,877.6		688.0	2,998.4	
Mar-16	2,637.7		611.6	2,784.9	
Apr-16	2,580.5				
May-16	2,143.7				
Jun-16	2,261.6				
Jul-16	2,320.3				
Aug-16	2,074.5				
Sep-16	2,354.2				
Oct-16	2,098.0				
Nov-16	2,179.4				
Dec-16	3,012.4	29,582.0			29,888.5
Jan-17	3,166.6				
Feb-17	2,815.7				
Mar-17	2,679.7				
Apr-17	2,580.5				
May-17	2,143.7				
Jun-17	2,261.6				
Jul-17	2,320.3				
Aug-17	2,074.5				
Sep-17	2,354.2				
Oct-17	2,098.0				
Nov-17	2,179.4				
Dec-17	3,012.4	29,686.6			29,686.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.681050854
R Square	0.463830266
Adjusted R Square	0.448060568
Standard Error	288.4419534
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2447104.763	2447104.763	29.41275506	4.84113E-06
Residual	34	2828757.856	83198.76046		
Total	35	5275862.619			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2049.630232	91.81842764	22.32264573	6.87061E-22	1863.032737	2236.227728	1863.032737	2236.227728
WH-HDD	0.81374598	0.150044819	5.423352751	4.84113E-06	0.508818221	1.118673739	0.508818221	1.118673739

Teslin

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,935.6		952.0	2,838.9	
Feb-13	3,120.6		665.4	3,335.3	
Mar-13	2,459.6		851.1	2,386.0	
Apr-13	2,295.5		639.9	2,158.9	
May-13	1,700.1		294.0	1,647.6	
Jun-13	2,023.1		112.4	2,066.1	
Jul-13	1,598.2		92.5	1,610.2	
Aug-13	1,832.3		98.9	1,886.4	
Sep-13	1,632.3		264.3	1,678.8	
Oct-13	1,594.1		501.4	1,586.8	
Nov-13	2,757.6		865.6	2,674.2	
Dec-13	2,796.5	26,745.5	1,144.7	2,592.7	26,462.0
Jan-14	3,041.4		745.8	3,203.5	
Feb-14	2,563.2		992.4	2,367.4	
Mar-14	2,530.3		855.1	2,451.8	
Apr-14	2,098.3		499.8	2,137.5	
May-14	2,126.6		269.5	2,104.8	
Jun-14	1,657.1		200.5	1,589.5	
Jul-14	1,672.3		98.0	1,677.4	
Aug-14	1,922.9		144.0	1,920.4	
Sep-14	1,642.3		307.1	1,635.1	
Oct-14	2,158.8		515.6	2,133.7	
Nov-14	2,408.0		772.8	2,441.1	
Dec-14	2,728.6	26,549.7	854.4	2,889.1	26,551.4
Jan-15	3,082.8		927.0	3,017.4	
Feb-15	2,490.2		851.4	2,471.4	
Mar-15	2,521.6		671.3	2,673.8	
Apr-15	2,004.9		453.5	2,102.2	
May-15	1,879.4		192.9	1,953.7	
Jun-15	1,680.0		127.2	1,704.5	
Jul-15	1,895.3		115.7	1,878.2	
Aug-15	1,640.7		183.2	1,589.0	
Sep-15	1,851.7		332.7	1,812.4	
Oct-15	2,130.2		469.8	2,162.5	
Nov-15	2,255.8		759.2	2,306.0	
Dec-15	2,689.6	26,122.2	947.9	2,732.9	26,404.0
Jan-16	3,141.3		827.6	3,200.7	
Feb-16	2,588.1		688.0	2,774.4	
Mar-16	2,152.1		611.6	2,379.1	
Apr-16	2,132.9				
May-16	1,902.0				
Jun-16	1,786.7				
Jul-16	1,722.0				
Aug-16	1,798.6				
Sep-16	1,708.8				
Oct-16	1,961.0				
Nov-16	2,473.8				
Dec-16	2,738.2	26,105.5			26,578.3
Jan-17	3,020.0				
Feb-17	2,724.7				
Mar-17	2,503.9				
Apr-17	2,132.9				
May-17	1,902.0				
Jun-17	1,786.7				
Jul-17	1,722.0				
Aug-17	1,798.6				
Sep-17	1,708.8				
Oct-17	1,961.0				
Nov-17	2,473.8				
Dec-17	2,738.2	26,472.5			26,472.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.852982586
R Square	0.727579292
Adjusted R Square	0.719566918
Standard Error	253.2054623
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	5821907.077	5821907.077	90.80695832	3.95128E-11
Residual	34	2179842.209	64113.00615		
Total	35	8001749.287			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1551.652853	80.60175418	19.25085711	7.35786E-20	1387.85038	1715.455325	1387.85038	1715.455325
WH-HDD	1.255148784	0.131715124	9.529268509	3.95128E-11	0.987471446	1.522826122	0.987471446	1.522826122

Ross River

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,515.6		952.0	2,449.1	
Feb-13	3,270.1		665.4	3,417.7	
Mar-13	2,454.6		851.1	2,404.0	
Apr-13	2,640.4		639.9	2,546.4	
May-13	2,290.4		294.0	2,254.3	
Jun-13	2,319.5		112.4	2,349.1	
Jul-13	1,923.8		92.5	1,932.0	
Aug-13	2,300.6		98.9	2,337.8	
Sep-13	1,599.0		264.3	1,630.9	
Oct-13	1,854.0		501.4	1,849.0	
Nov-13	2,684.1		865.6	2,626.8	
Dec-13	2,244.9	28,096.9	1,144.7	2,104.8	27,902.0
Jan-14	3,380.5		745.8	3,491.9	
Feb-14	2,160.3		992.4	2,025.6	
Mar-14	2,961.8		855.1	2,907.8	
Apr-14	2,719.7		499.8	2,746.7	
May-14	2,361.6		269.5	2,346.6	
Jun-14	2,018.5		200.5	1,972.1	
Jul-14	1,901.3		98.0	1,904.8	
Aug-14	2,363.5		144.0	2,361.9	
Sep-14	1,574.4		307.1	1,569.4	
Oct-14	2,266.6		515.6	2,249.3	
Nov-14	2,842.4		772.8	2,865.1	
Dec-14	2,628.7	29,179.3	854.4	2,739.1	29,180.4
Jan-15	3,214.4		927.0	3,169.4	
Feb-15	2,846.2		851.4	2,833.3	
Mar-15	2,570.3		671.3	2,674.9	
Apr-15	2,938.5		453.5	3,005.4	
May-15	2,530.8		192.9	2,581.9	
Jun-15	1,760.8		127.2	1,777.6	
Jul-15	1,488.7		115.7	1,476.9	
Aug-15	1,847.4		183.2	1,811.9	
Sep-15	1,958.7		332.7	1,931.7	
Oct-15	2,464.5		469.8	2,486.8	
Nov-15	2,265.0		759.2	2,299.6	
Dec-15	2,765.8	28,651.1	947.9	2,795.5	28,844.9
Jan-16	3,375.8		827.6	3,416.7	
Feb-16	2,777.7		688.0	2,905.8	
Mar-16	2,697.0		611.6	2,853.1	
Apr-16	2,766.2				
May-16	2,394.3				
Jun-16	2,032.9				
Jul-16	1,771.3				
Aug-16	2,170.5				
Sep-16	1,710.7				
Oct-16	2,195.0				
Nov-16	2,597.2				
Dec-16	2,546.5	29,035.0			29,360.1
Jan-17	3,036.8				
Feb-17	2,758.9				
Mar-17	2,662.2				
Apr-17	2,766.2				
May-17	2,394.3				
Jun-17	2,032.9				
Jul-17	1,771.3				
Aug-17	2,170.5				
Sep-17	1,710.7				
Oct-17	2,195.0				
Nov-17	2,597.2				
Dec-17	2,546.5	28,642.4			28,642.4

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.586600487
R Square	0.344100131
Adjusted R Square	0.324808959
Standard Error	392.8357671
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2752632.652	2752632.652	17.83718069	0.000169923
Residual	34	5246877.958	154319.9399		
Total	35	7999510.61			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1936.908687	125.0496401	15.48911844	5.69935E-17	1682.777242	2191.040131	1682.777242	2191.040131
WH-HDD	0.863051484	0.204349509	4.223408658	0.000169923	0.447763317	1.278339651	0.447763317	1.278339651

Pelly Crossing

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	3,754.3		952.0	3,675.9	
Feb-13	3,099.0		665.4	3,272.9	
Mar-13	3,471.9		851.1	3,412.3	
Apr-13	3,529.6		639.9	3,419.0	
May-13	3,227.7		294.0	3,185.1	
Jun-13	2,231.5		112.4	2,266.4	
Jul-13	2,381.5		92.5	2,391.2	
Aug-13	2,619.9		98.9	2,663.8	
Sep-13	2,288.9		264.3	2,326.6	
Oct-13	3,366.7		501.4	3,360.8	
Nov-13	2,890.6		865.6	2,823.1	
Dec-13	2,376.0	35,237.6	1,144.7	2,210.9	35,007.9
Jan-14	4,282.9		745.8	4,414.2	
Feb-14	3,335.3		992.4	3,176.6	
Mar-14	3,028.9		855.1	2,965.3	
Apr-14	2,752.8		499.8	2,784.6	
May-14	2,665.4		269.5	2,647.8	
Jun-14	2,325.8		200.5	2,271.0	
Jul-14	2,327.6		98.0	2,331.8	
Aug-14	2,103.8		144.0	2,101.8	
Sep-14	2,434.6		307.1	2,428.8	
Oct-14	3,153.4		515.6	3,133.1	
Nov-14	2,926.3		772.8	2,953.1	
Dec-14	3,933.6	35,270.4	854.4	4,063.7	35,271.8
Jan-15	3,237.5		927.0	3,184.5	
Feb-15	3,137.1		851.4	3,121.9	
Mar-15	2,860.1		671.3	2,983.4	
Apr-15	3,287.5		453.5	3,366.3	
May-15	2,545.6		192.9	2,605.8	
Jun-15	2,348.6		127.2	2,368.4	
Jul-15	2,811.1		115.7	2,797.2	
Aug-15	2,235.2		183.2	2,193.4	
Sep-15	2,671.8		332.7	2,639.9	
Oct-15	2,956.5		469.8	2,982.7	
Nov-15	2,782.0		759.2	2,822.7	
Dec-15	3,262.4	34,135.5	947.9	3,297.5	34,363.8
Jan-16	3,213.3		827.6	3,261.4	
Feb-16	2,808.9		688.0	2,959.9	
Mar-16	2,794.6		611.6	2,978.6	
Apr-16	3,190.0				
May-16	2,812.9				
Jun-16	2,302.0				
Jul-16	2,506.8				
Aug-16	2,319.6				
Sep-16	2,465.1				
Oct-16	3,158.8				
Nov-16	2,866.3				
Dec-16	3,190.7	33,629.0			34,012.0
Jan-17	3,758.2				
Feb-17	3,190.5				
Mar-17	3,120.3				
Apr-17	3,190.0				
May-17	2,812.9				
Jun-17	2,302.0				
Jul-17	2,506.8				
Aug-17	2,319.6				
Sep-17	2,465.1				
Oct-17	3,158.8				
Nov-17	2,866.3				
Dec-17	3,190.7	34,881.2			34,881.2

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.634386498
R Square	0.402446228
Adjusted R Square	0.384871118
Standard Error	408.5428129
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3821949.432	3821949.432	22.89864514	3.25558E-05
Residual	34	5674845.82	166907.23		
Total	35	9496795.252			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2376.557715	130.0495932	18.27424182	3.71206E-19	2112.265144	2640.850287	2112.265144	2640.850287
WH-HDD	1.016962744	0.212520168	4.785252882	3.25558E-05	0.585069801	1.448855688	0.585069801	1.448855688

Old Crow

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,211.6		952.0	2,165.6	
Feb-13	2,681.5		665.4	2,783.6	
Mar-13	1,742.7		851.1	1,707.7	
Apr-13	1,927.2		639.9	1,862.2	
May-13	1,789.1		294.0	1,764.1	
Jun-13	1,923.2		112.4	1,943.6	
Jul-13	1,523.1		92.5	1,528.8	
Aug-13	1,476.1		98.9	1,501.9	
Sep-13	1,782.8		264.3	1,804.9	
Oct-13	1,501.1		501.4	1,497.6	
Nov-13	1,804.0		865.6	1,764.3	
Dec-13	2,055.6	22,417.9	1,144.7	1,958.6	22,283.1
Jan-14	2,443.9		745.8	2,521.0	
Feb-14	1,885.9		992.4	1,792.8	
Mar-14	2,352.5		855.1	2,315.1	
Apr-14	1,980.1		499.8	1,998.7	
May-14	2,079.8		269.5	2,069.4	
Jun-14	1,461.1		200.5	1,428.9	
Jul-14	2,128.2		98.0	2,130.6	
Aug-14	1,127.9		144.0	1,126.7	
Sep-14	1,277.9		307.1	1,274.5	
Oct-14	1,715.1		515.6	1,703.1	
Nov-14	1,813.6		772.8	1,829.4	
Dec-14	1,687.8	21,953.8	854.4	1,764.2	21,954.6
Jan-15	2,552.7		927.0	2,521.6	
Feb-15	1,857.0		851.4	1,848.1	
Mar-15	2,044.5		671.3	2,116.9	
Apr-15	2,002.7		453.5	2,049.0	
May-15	1,573.3		192.9	1,608.7	
Jun-15	1,417.5		127.2	1,429.2	
Jul-15	1,733.8		115.7	1,725.7	
Aug-15	1,307.3		183.2	1,282.8	
Sep-15	1,863.3		332.7	1,844.6	
Oct-15	1,331.0		469.8	1,346.4	
Nov-15	1,730.8		759.2	1,754.6	
Dec-15	2,196.0	21,609.9	947.9	2,216.5	21,743.9
Jan-16	2,531.5		827.6	2,559.7	
Feb-16	2,136.8		688.0	2,225.4	
Mar-16	2,258.0		611.6	2,366.1	
Apr-16	1,970.0				
May-16	1,814.1				
Jun-16	1,600.6				
Jul-16	1,795.0				
Aug-16	1,303.8				
Sep-16	1,641.3				
Oct-16	1,515.7				
Nov-16	1,782.8				
Dec-16	1,979.8	22,329.4			22,554.2
Jan-17	2,402.8				
Feb-17	2,141.5				
Mar-17	2,046.6				
Apr-17	1,970.0				
May-17	1,814.1				
Jun-17	1,600.6				
Jul-17	1,795.0				
Aug-17	1,303.8				
Sep-17	1,641.3				
Oct-17	1,515.7				
Nov-17	1,782.8				
Dec-17	1,979.8	21,993.9			21,993.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.536022599
R Square	0.287320227
Adjusted R Square	0.266359057
Standard Error	310.0130474
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1317378.674	1317378.674	13.70726107	0.000753157
Residual	34	3267675.044	96108.08953		
Total	35	4585053.718			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1521.537861	98.68505682	15.4181181	6.538E-17	1320.985696	1722.090026	1320.985696	1722.090026
WH-HDD	0.59705988	0.161265901	3.702331842	0.000753157	0.269328138	0.924791622	0.269328138	0.924791622

Destruction Bay

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,272.4		952.0	2,228.8	
Feb-13	1,946.7		665.4	2,043.5	
Mar-13	1,558.8		851.1	1,525.6	
Apr-13	1,759.7		639.9	1,698.0	
May-13	1,301.9		294.0	1,278.2	
Jun-13	1,462.2		112.4	1,481.6	
Jul-13	1,406.6		92.5	1,412.0	
Aug-13	1,333.9		98.9	1,358.4	
Sep-13	1,427.5		264.3	1,448.5	
Oct-13	1,102.3		501.4	1,099.0	
Nov-13	1,470.4		865.6	1,432.8	
Dec-13	1,690.9	18,733.4	1,144.7	1,599.0	18,605.5
Jan-14	1,895.9		745.8	1,969.0	
Feb-14	1,608.1		992.4	1,519.8	
Mar-14	1,649.2		855.1	1,613.8	
Apr-14	1,443.2		499.8	1,460.9	
May-14	1,425.4		269.5	1,415.5	
Jun-14	1,196.2		200.5	1,165.8	
Jul-14	1,309.0		98.0	1,311.3	
Aug-14	1,378.9		144.0	1,377.7	
Sep-14	1,477.3		307.1	1,474.1	
Oct-14	1,181.2		515.6	1,169.8	
Nov-14	1,513.4		772.8	1,528.3	
Dec-14	1,665.0	17,742.7	854.4	1,737.5	17,743.4
Jan-15	2,007.4		927.0	1,977.9	
Feb-15	1,900.1		851.4	1,891.6	
Mar-15	1,472.7		671.3	1,541.4	
Apr-15	1,717.7		453.5	1,761.7	
May-15	1,287.4		192.9	1,321.0	
Jun-15	1,212.2		127.2	1,223.3	
Jul-15	1,423.0		115.7	1,415.3	
Aug-15	1,097.4		183.2	1,074.0	
Sep-15	1,659.5		332.7	1,641.7	
Oct-15	1,053.9		469.8	1,068.5	
Nov-15	1,594.0		759.2	1,616.6	
Dec-15	1,865.9	18,291.3	947.9	1,885.4	18,418.4
Jan-16	1,878.0		827.6	1,904.8	
Feb-16	1,604.5		688.0	1,688.6	
Mar-16	1,636.7		611.6	1,739.2	
Apr-16	1,640.2				
May-16	1,338.2				
Jun-16	1,290.2				
Jul-16	1,379.5				
Aug-16	1,270.0				
Sep-16	1,521.5				
Oct-16	1,112.5				
Nov-16	1,525.9				
Dec-16	1,740.6	17,937.9			18,151.2
Jan-17	2,058.6				
Feb-17	1,818.3				
Mar-17	1,560.3				
Apr-17	1,640.2				
May-17	1,338.2				
Jun-17	1,290.2				
Jul-17	1,379.5				
Aug-17	1,270.0				
Sep-17	1,521.5				
Oct-17	1,112.5				
Nov-17	1,525.9				
Dec-17	1,740.6	18,255.8			18,255.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.658944264
R Square	0.434207543
Adjusted R Square	0.417566588
Standard Error	213.1345621
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1185296.192	1185296.192	26.09270636	1.24385E-05
Residual	34	1544495.614	45426.34157		
Total	35	2729791.805			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1226.048323	67.84616503	18.07100404	5.24525E-19	1088.168326	1363.928319	1088.168326	1363.928319
WH-HDD	0.566338413	0.110870615	5.108102031	1.24385E-05	0.341022215	0.791654611	0.341022215	0.791654611

Beaver Creek

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,415.2		952.0	2,405.4	
Feb-13	2,187.7		665.4	2,209.4	
Mar-13	1,908.5		851.1	1,901.0	
Apr-13	1,493.9		639.9	1,480.0	
May-13	1,913.3		294.0	1,908.0	
Jun-13	1,802.1		112.4	1,806.5	
Jul-13	2,976.0		92.5	2,977.2	
Aug-13	2,522.1		98.9	2,527.6	
Sep-13	2,157.4		264.3	2,162.1	
Oct-13	1,901.6		501.4	1,900.9	
Nov-13	1,704.2		865.6	1,695.8	
Dec-13	1,733.1	24,715.0	1,144.7	1,712.5	24,686.3
Jan-14	2,960.5		745.8	2,976.9	
Feb-14	2,208.3		992.4	2,188.5	
Mar-14	1,882.3		855.1	1,874.3	
Apr-14	1,807.2		499.8	1,811.2	
May-14	1,554.4		269.5	1,552.2	
Jun-14	1,836.9		200.5	1,830.1	
Jul-14	1,738.1		98.0	1,738.6	
Aug-14	1,717.1		144.0	1,716.8	
Sep-14	2,433.1		307.1	2,432.3	
Oct-14	2,188.7		515.6	2,186.2	
Nov-14	2,203.9		772.8	2,207.3	
Dec-14	2,084.7	24,615.1	854.4	2,100.9	24,615.3
Jan-15	2,624.4		927.0	2,617.8	
Feb-15	1,744.7		851.4	1,742.8	
Mar-15	2,396.2		671.3	2,411.6	
Apr-15	1,797.2		453.5	1,807.0	
May-15	1,783.6		192.9	1,791.1	
Jun-15	1,564.2		127.2	1,566.7	
Jul-15	1,991.0		115.7	1,989.2	
Aug-15	1,764.2		183.2	1,759.0	
Sep-15	2,158.4		332.7	2,154.4	
Oct-15	1,672.8		469.8	1,676.1	
Nov-15	2,012.7		759.2	2,017.8	
Dec-15	1,985.5	23,494.7	947.9	1,989.8	23,523.2
Jan-16	2,713.2		827.6	2,719.2	
Feb-16	1,684.4		688.0	1,703.3	
Mar-16	2,077.3		611.6	2,100.3	
Apr-16	1,699.4				
May-16	1,750.4				
Jun-16	1,734.4				
Jul-16	2,235.0				
Aug-16	2,001.1				
Sep-16	2,249.6				
Oct-16	1,921.0				
Nov-16	1,973.6				
Dec-16	1,934.4	23,974.0			24,021.8
Jan-17	2,666.7				
Feb-17	2,046.9				
Mar-17	2,062.3				
Apr-17	1,699.4				
May-17	1,750.4				
Jun-17	1,734.4				
Jul-17	2,235.0				
Aug-17	2,001.1				
Sep-17	2,249.6				
Oct-17	1,921.0				
Nov-17	1,973.6				
Dec-17	1,934.4	24,275.0			24,275.0

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.11304581
R Square	0.012779355
Adjusted R Square	-0.016256546
Standard Error	367.803698
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	59539.58657	59539.58657	0.440122562	0.511536754
Residual	34	4599505.048	135279.5602		
Total	35	4659044.634			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1956.736633	117.0812943	16.71263241	5.75472E-18	1718.798816	2194.674451	1718.798816	2194.674451
WH-HDD	0.126930351	0.191328059	0.663417336	0.511536754	-0.261895047	0.515755749	-0.261895047	0.515755749

Tagish

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,248.3		952.0	1,200.4	
Feb-13	1,046.9		665.4	1,153.2	
Mar-13	1,001.3		851.1	964.8	
Apr-13	929.8		639.9	862.1	
May-13	617.5		294.0	591.5	
Jun-13	755.7		112.4	777.0	
Jul-13	715.6		92.5	721.5	
Aug-13	768.1		98.9	794.9	
Sep-13	608.2		264.3	631.2	
Oct-13	653.0		501.4	649.4	
Nov-13	904.0		865.6	862.8	
Dec-13	964.3	10,212.6	1,144.7	863.4	10,072.2
Jan-14	1,768.1		745.8	1,848.4	
Feb-14	1,171.3		992.4	1,074.3	
Mar-14	1,148.8		855.1	1,109.8	
Apr-14	1,085.0		499.8	1,104.5	
May-14	1,710.8		269.5	1,700.0	
Jun-14	874.4		200.5	840.9	
Jul-14	807.7		98.0	810.2	
Aug-14	786.4		144.0	785.1	
Sep-14	776.8		307.1	773.3	
Oct-14	713.3		515.6	700.9	
Nov-14	951.7		772.8	968.1	
Dec-14	1,028.6	12,822.9	854.4	1,108.1	12,823.7
Jan-15	2,339.1		927.0	2,306.7	
Feb-15	1,559.1		851.4	1,549.8	
Mar-15	544.7		671.3	620.0	
Apr-15	1,214.5		453.5	1,262.7	
May-15	931.4		192.9	968.2	
Jun-15	649.2		127.2	661.4	
Jul-15	673.8		115.7	665.3	
Aug-15	562.6		183.2	537.0	
Sep-15	798.1		332.7	778.7	
Oct-15	1,243.5		469.8	1,259.5	
Nov-15	1,360.4		759.2	1,385.2	
Dec-15	1,384.5	13,260.9	947.9	1,405.9	13,400.5
Jan-16	1,636.8		827.6	1,666.3	
Feb-16	1,615.8		688.0	1,708.1	
Mar-16	1,348.8		611.6	1,461.2	
Apr-16	1,076.4				
May-16	1,086.6				
Jun-16	759.8				
Jul-16	732.4				
Aug-16	705.7				
Sep-16	727.7				
Oct-16	869.9				
Nov-16	1,072.0				
Dec-16	1,125.8	12,757.8			12,991.9
Jan-17	1,785.2				
Feb-17	1,259.1				
Mar-17	898.2				
Apr-17	1,076.4				
May-17	1,086.6				
Jun-17	759.8				
Jul-17	732.4				
Aug-17	705.7				
Sep-17	727.7				
Oct-17	869.9				
Nov-17	1,072.0				
Dec-17	1,125.8	12,098.8			12,098.8

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.521963398
R Square	0.272445789
Adjusted R Square	0.251047136
Standard Error	334.8972558
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1427962.612	1427962.612	12.73191289	0.001094401
Residual	34	3813309.847	112156.172		
Total	35	5241272.459			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	684.1489632	106.6063348	6.417526355	2.48416E-07	467.4988247	900.7991018	467.4988247	900.7991018
WH-HDD	0.621614295	0.174210434	3.568180614	0.001094401	0.267576096	0.975652494	0.267576096	0.975652494

Marsh Lake

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,284.8		952.0	1,239.8	
Feb-13	1,825.2		665.4	1,924.9	
Mar-13	1,310.8		851.1	1,276.7	
Apr-13	1,356.7		639.9	1,293.3	
May-13	1,217.8		294.0	1,193.4	
Jun-13	1,017.0		112.4	1,037.0	
Jul-13	819.7		92.5	825.2	
Aug-13	885.5		98.9	910.7	
Sep-13	876.1		264.3	897.7	
Oct-13	1,106.4		501.4	1,103.0	
Nov-13	1,143.6		865.6	1,104.9	
Dec-13	1,417.3	14,260.9	1,144.7	1,322.6	14,129.3
Jan-14	1,566.0		745.8	1,641.3	
Feb-14	1,375.1		992.4	1,284.2	
Mar-14	1,386.1		855.1	1,349.6	
Apr-14	1,505.5		499.8	1,523.7	
May-14	1,125.0		269.5	1,114.8	
Jun-14	909.5		200.5	878.1	
Jul-14	968.7		98.0	971.1	
Aug-14	896.3		144.0	895.2	
Sep-14	1,079.0		307.1	1,075.6	
Oct-14	1,080.1		515.6	1,068.4	
Nov-14	1,342.8		772.8	1,358.1	
Dec-14	1,706.0	14,939.9	854.4	1,780.5	14,940.7
Jan-15	1,322.9		927.0	1,292.5	
Feb-15	1,197.6		851.4	1,188.8	
Mar-15	1,134.0		671.3	1,204.6	
Apr-15	1,243.1		453.5	1,288.3	
May-15	967.7		192.9	1,002.2	
Jun-15	812.6		127.2	824.0	
Jul-15	827.5		115.7	819.5	
Aug-15	767.1		183.2	743.1	
Sep-15	1,174.6		332.7	1,156.4	
Oct-15	963.7		469.8	978.7	
Nov-15	1,091.8		759.2	1,115.1	
Dec-15	1,374.6	12,877.0	947.9	1,394.6	13,007.9
Jan-16	1,331.0		827.6	1,358.6	
Feb-16	1,130.8		688.0	1,217.3	
Mar-16	1,258.1		611.6	1,363.5	
Apr-16	1,368.5				
May-16	1,103.5				
Jun-16	913.1				
Jul-16	871.9				
Aug-16	849.7				
Sep-16	1,043.2				
Oct-16	1,050.0				
Nov-16	1,192.7				
Dec-16	1,499.3	13,611.7			13,831.2
Jan-17	1,391.2				
Feb-17	1,466.0				
Mar-17	1,277.0				
Apr-17	1,368.5				
May-17	1,103.5				
Jun-17	913.1				
Jul-17	871.9				
Aug-17	849.7				
Sep-17	1,043.2				
Oct-17	1,050.0				
Nov-17	1,192.7				
Dec-17	1,499.3	14,026.0			14,026.0

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.734719964
R Square	0.539813426
Adjusted R Square	0.526278526
Standard Error	177.4051342
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1255223.389	1255223.389	39.88307675	3.36509E-07
Residual	34	1070067.776	31472.58163		
Total	35	2325291.164			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	864.9778165	56.47257719	15.31677603	7.95983E-17	750.2117316	979.7439014	750.2117316	979.7439014
WH-HDD	0.582804755	0.092284499	6.315304961	3.36509E-07	0.395260088	0.770349421	0.395260088	0.770349421

Lower Post

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,640.5		1,129.1	2,557.2	
Feb-13	1,772.1		765.8	1,948.3	
Mar-13	1,762.4		950.7	1,727.0	
Apr-13	1,883.1		690.1	1,795.8	
May-13	1,268.9		304.5	1,250.1	
Jun-13	1,256.9		96.3	1,286.5	
Jul-13	1,342.2		105.1	1,333.8	
Aug-13	1,380.3		82.2	1,416.1	
Sep-13	877.8		239.1	920.8	
Oct-13	1,377.9		490.2	1,401.1	
Nov-13	1,375.0		1,021.3	1,313.9	
Dec-13	1,786.6	18,723.6	1,248.8	1,741.7	18,692.2
Jan-14	2,146.3		937.7	2,223.6	
Feb-14	1,728.9		1,204.4	1,536.9	
Mar-14	1,930.2		1,008.9	1,846.1	
Apr-14	1,482.2		570.5	1,495.2	
May-14	1,343.6		331.1	1,302.5	
Jun-14	1,134.6		186.8	1,088.3	
Jul-14	1,168.9		87.6	1,175.2	
Aug-14	1,018.4		144.8	1,001.7	
Sep-14	993.6		295.8	989.0	
Oct-14	1,146.1		539.7	1,127.7	
Nov-14	1,159.9		936.4	1,170.1	
Dec-14	2,014.4	17,267.1	1,176.7	2,029.9	16,986.2
Jan-15	2,433.7		1,022.8	2,439.6	
Feb-15	2,010.6		956.7	2,026.5	
Mar-15	1,780.9		766.3	1,900.3	
Apr-15	1,837.2		497.4	1,911.6	
May-15	1,508.6		210.8	1,568.4	
Jun-15	978.0		111.8	994.6	
Jul-15	1,049.7		92.4	1,051.9	
Aug-15	809.9		147.5	790.9	
Sep-15	1,284.5		336.1	1,246.1	
Oct-15	864.1		523.7	859.2	
Nov-15	1,657.5		887.8	1,708.5	
Dec-15	1,889.3	18,104.2	1,160.3	1,918.7	18,416.5
Jan-16	2,282.4		1,099.3	2,224.1	
Feb-16	1,873.7		930.8	1,911.4	
Mar-16	1,793.8		724.3	1,948.5	
Apr-16	1,734.2				
May-16	1,373.7				
Jun-16	1,123.2				
Jul-16	1,187.0				
Aug-16	1,069.5				
Sep-16	1,052.0				
Oct-16	1,129.4				
Nov-16	1,397.5				
Dec-16	1,896.8	17,913.0			18,047.1
Jan-17	2,406.8				
Feb-17	1,837.2				
Mar-17	1,824.5				
Apr-17	1,734.2				
May-17	1,373.7				
Jun-17	1,123.2				
Jul-17	1,187.0				
Aug-17	1,069.5				
Sep-17	1,052.0				
Oct-17	1,129.4				
Nov-17	1,397.5				
Dec-17	1,896.8	18,031.7			18,031.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.747433024
R Square	0.558656126
Adjusted R Square	0.545675424
Standard Error	302.7821018
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3945542.978	3945542.978	43.037435	1.62766E-07
Residual	34	3117018.039	91677.00115		
Total	35	7062561.017			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1007.041068	90.84942635	11.08472676	7.82857E-13	822.4128198	1191.669316	822.4128198	1191.669316
WL-HDD	0.839315619	0.127938753	6.560292295	1.62766E-07	0.57931279	1.099318448	0.57931279	1.099318448

Upper Liard

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,580.4		1,129.1	2,545.7	
Feb-13	1,867.5		765.8	1,940.7	
Mar-13	1,806.4		950.7	1,791.7	
Apr-13	1,877.5		690.1	1,841.2	
May-13	1,384.7		304.5	1,376.9	
Jun-13	1,122.6		96.3	1,135.0	
Jul-13	1,324.2		105.1	1,320.6	
Aug-13	1,260.5		82.2	1,275.3	
Sep-13	1,045.0		239.1	1,062.9	
Oct-13	1,052.5		490.2	1,062.1	
Nov-13	1,256.1		1,021.3	1,230.7	
Dec-13	2,312.2	18,889.5	1,248.8	2,293.5	18,876.4
Jan-14	1,907.7		937.7	1,939.8	
Feb-14	1,040.7		1,204.4	960.9	
Mar-14	1,346.8		1,008.9	1,311.9	
Apr-14	1,530.5		570.5	1,535.9	
May-14	1,260.2		331.1	1,243.1	
Jun-14	967.4		186.8	948.1	
Jul-14	1,167.2		87.6	1,169.7	
Aug-14	1,011.7		144.8	1,004.7	
Sep-14	1,062.0		295.8	1,060.1	
Oct-14	1,020.7		539.7	1,013.1	
Nov-14	1,324.1		936.4	1,328.3	
Dec-14	1,396.0	15,035.0	1,176.7	1,402.5	14,918.2
Jan-15	1,242.5		1,022.8	1,244.9	
Feb-15	1,042.5		956.7	1,049.2	
Mar-15	878.7		766.3	928.4	
Apr-15	1,043.4		497.4	1,074.3	
May-15	1,227.2		210.8	1,252.1	
Jun-15	1,089.6		111.8	1,096.5	
Jul-15	1,410.8		92.4	1,411.7	
Aug-15	1,476.9		147.5	1,469.0	
Sep-15	1,455.5		336.1	1,439.5	
Oct-15	1,322.9		523.7	1,320.9	
Nov-15	1,198.9		887.8	1,220.1	
Dec-15	916.0	14,304.9	1,160.3	928.2	14,434.7
Jan-16	1,615.0		1,099.3	1,590.8	
Feb-16	518.1		930.8	533.8	
Mar-16	970.0		724.3	1,034.3	
Apr-16	1,483.8				
May-16	1,290.7				
Jun-16	1,059.9				
Jul-16	1,300.7				
Aug-16	1,249.7				
Sep-16	1,187.5				
Oct-16	1,132.0				
Nov-16	1,259.7				
Dec-16	1,541.4	14,608.6			14,664.3
Jan-17	1,910.2				
Feb-17	1,316.9				
Mar-17	1,344.0				
Apr-17	1,483.8				
May-17	1,290.7				
Jun-17	1,059.9				
Jul-17	1,300.7				
Aug-17	1,249.7				
Sep-17	1,187.5				
Oct-17	1,132.0				
Nov-17	1,259.7				
Dec-17	1,541.4	16,076.5			16,076.5

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.364656649
R Square	0.132974472
Adjusted R Square	0.107473721
Standard Error	361.5389333
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	681593.5154	681593.5154	5.214531622	0.028768898
Residual	34	4444153.609	130710.4003		
Total	35	5125747.124			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1133.719366	108.479347	10.45101577	3.72445E-12	913.2628091	1354.175924	913.2628091	1354.175924
WL-HDD	0.348846717	0.152766099	2.283534896	0.028768898	0.038388652	0.659304783	0.038388652	0.659304783

Watson Lake

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	4,155.1		1,129.1	4,049.6	
Feb-13	3,609.9		765.8	3,833.0	
Mar-13	3,776.8		950.7	3,732.1	
Apr-13	3,507.1		690.1	3,396.4	
May-13	3,010.4		304.5	2,986.6	
Jun-13	2,795.4		96.3	2,833.0	
Jul-13	2,585.7		105.1	2,575.0	
Aug-13	2,720.1		82.2	2,765.4	
Sep-13	2,414.7		239.1	2,469.2	
Oct-13	2,678.8		490.2	2,708.3	
Nov-13	3,090.9		1,021.3	3,013.5	
Dec-13	3,627.4	37,972.3	1,248.8	3,570.4	37,932.5
Jan-14	4,237.6		937.7	4,335.5	
Feb-14	3,596.9		1,204.4	3,353.7	
Mar-14	3,855.1		1,008.9	3,748.5	
Apr-14	3,427.9		570.5	3,444.3	
May-14	3,394.0		331.1	3,342.0	
Jun-14	2,668.3		186.8	2,609.6	
Jul-14	3,015.0		87.6	3,022.9	
Aug-14	2,811.6		144.8	2,790.4	
Sep-14	2,721.4		295.8	2,715.6	
Oct-14	2,919.7		539.7	2,896.5	
Nov-14	3,198.0		936.4	3,210.9	
Dec-14	3,987.2	39,832.6	1,176.7	4,006.9	39,476.8
Jan-15	4,362.2		1,022.8	4,369.7	
Feb-15	3,655.2		956.7	3,675.3	
Mar-15	3,474.4		766.3	3,625.7	
Apr-15	3,297.9		497.4	3,392.1	
May-15	3,178.7		210.8	3,254.6	
Jun-15	2,518.2		111.8	2,539.3	
Jul-15	2,966.9		92.4	2,969.7	
Aug-15	2,801.6		147.5	2,777.5	
Sep-15	2,907.1		336.1	2,858.5	
Oct-15	2,902.6		523.7	2,896.4	
Nov-15	3,591.4		887.8	3,655.9	
Dec-15	3,736.5	39,392.7	1,160.3	3,773.7	39,788.4
Jan-16	4,315.3		1,099.3	4,241.4	
Feb-16	3,758.9		930.8	3,806.5	
Mar-16	3,769.2		724.3	3,965.2	
Apr-16	3,411.0				
May-16	3,194.4				
Jun-16	2,660.6				
Jul-16	2,855.8				
Aug-16	2,777.8				
Sep-16	2,681.1				
Oct-16	2,833.7				
Nov-16	3,293.4				
Dec-16	3,783.7	39,334.8			39,504.7
Jan-17	4,251.6				
Feb-17	3,620.6				
Mar-17	3,702.1				
Apr-17	3,411.0				
May-17	3,194.4				
Jun-17	2,660.6				
Jul-17	2,855.8				
Aug-17	2,777.8				
Sep-17	2,681.1				
Oct-17	2,833.7				
Nov-17	3,293.4				
Dec-17	3,783.7	39,065.9			39,065.9

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.82201356
R Square	0.675706292
Adjusted R Square	0.666168242
Standard Error	298.9609848
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	6331802.927	6331802.927	70.84323072	7.91525E-10
Residual	34	3038840.794	89377.67042		
Total	35	9370643.721			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2627.664659	89.70290454	29.29297187	1.04535E-25	2445.366424	2809.962894	2445.366424	2809.962894
WL-HDD	1.063250536	0.126324164	8.416842087	7.91525E-10	0.806528948	1.319972124	0.806528948	1.319972124

Keno City

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,447.1		952.0	1,411.9	
Feb-13	1,028.6		665.4	1,106.7	
Mar-13	1,314.5		851.1	1,287.8	
Apr-13	1,260.5		639.9	1,210.7	
May-13	618.2		294.0	599.1	
Jun-13	509.5		112.4	525.1	
Jul-13	730.7		92.5	735.1	
Aug-13	595.7		98.9	615.4	
Sep-13	630.6		264.3	647.6	
Oct-13	67.8		501.4	65.2	
Nov-13	623.0		865.6	592.7	
Dec-13	670.3	9,496.5	1,144.7	596.1	9,393.3
Jan-14	801.8		745.8	860.8	
Feb-14	891.8		992.4	820.6	
Mar-14	787.3		855.1	758.6	
Apr-14	747.2		499.8	761.5	
May-14	528.1		269.5	520.1	
Jun-14	566.4		200.5	541.8	
Jul-14	620.0		98.0	621.9	
Aug-14	386.5		144.0	385.6	
Sep-14	746.2		307.1	743.5	
Oct-14	475.6		515.6	466.4	
Nov-14	675.4		772.8	687.4	
Dec-14	758.5	7,984.6	854.4	816.9	7,985.2
Jan-15	758.4		927.0	734.6	
Feb-15	866.9		851.4	860.1	
Mar-15	722.2		671.3	777.5	
Apr-15	627.4		453.5	662.9	
May-15	649.5		192.9	676.6	
Jun-15	202.6		127.2	211.6	
Jul-15	492.5		115.7	486.3	
Aug-15	553.7		183.2	534.9	
Sep-15	508.5		332.7	494.2	
Oct-15	548.4		469.8	560.2	
Nov-15	1,000.7		759.2	1,018.9	
Dec-15	710.6	7,641.5	947.9	726.3	7,744.1
Jan-16	398.8		827.6	420.5	
Feb-16	940.4		688.0	1,008.2	
Mar-16	174.2		611.6	256.9	
Apr-16	878.4				
May-16	598.6				
Jun-16	426.2				
Jul-16	614.4				
Aug-16	512.0				
Sep-16	628.4				
Oct-16	363.9				
Nov-16	766.4				
Dec-16	713.1	7,014.8			7,186.9
Jan-17	1,002.4				
Feb-17	929.1				
Mar-17	941.3				
Apr-17	878.4				
May-17	598.6				
Jun-17	426.2				
Jul-17	614.4				
Aug-17	512.0				
Sep-17	628.4				
Oct-17	363.9				
Nov-17	766.4				
Dec-17	713.1	8,374.2			8,374.2

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.545686993
R Square	0.297774295
Adjusted R Square	0.277120597
Standard Error	231.3276172
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	771514.9882	771514.9882	14.41748136	0.000576992
Residual	34	1819423.86	53512.46648		
Total	35	2590938.849			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	459.6312729	73.6374783	6.24181169	4.18728E-07	309.9819119	609.2806339	309.9819119	609.2806339
WH-HDD	0.456914309	0.120334473	3.797035865	0.000576992	0.212365237	0.70146338	0.212365237	0.70146338

Stewart Crossing

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Whitehorse) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	2,107.2		952.0	2,028.6	
Feb-13	2,070.4		665.4	2,244.8	
Mar-13	2,883.5		851.1	2,823.8	
Apr-13	1,928.8		639.9	1,817.8	
May-13	1,760.9		294.0	1,718.2	
Jun-13	1,495.6		112.4	1,530.5	
Jul-13	1,264.5		92.5	1,274.2	
Aug-13	1,622.2		98.9	1,666.2	
Sep-13	1,199.5		264.3	1,237.3	
Oct-13	1,587.8		501.4	1,581.9	
Nov-13	1,494.1		865.6	1,426.4	
Dec-13	1,641.0	21,055.6	1,144.7	1,475.4	20,825.2
Jan-14	3,117.1		745.8	3,248.8	
Feb-14	1,937.6		992.4	1,778.6	
Mar-14	1,861.8		855.1	1,798.0	
Apr-14	1,584.3		499.8	1,616.2	
May-14	1,522.7		269.5	1,505.0	
Jun-14	1,097.5		200.5	1,042.6	
Jul-14	1,367.0		98.0	1,371.1	
Aug-14	793.7		144.0	791.7	
Sep-14	1,102.4		307.1	1,096.6	
Oct-14	1,629.8		515.6	1,609.4	
Nov-14	1,808.2		772.8	1,835.1	
Dec-14	2,139.9	19,962.1	854.4	2,270.3	19,963.4
Jan-15	2,014.6		927.0	1,961.5	
Feb-15	2,493.4		851.4	2,478.1	
Mar-15	2,049.6		671.3	2,173.2	
Apr-15	1,641.2		453.5	1,720.3	
May-15	1,651.8		192.9	1,712.2	
Jun-15	856.1		127.2	876.0	
Jul-15	1,343.0		115.7	1,329.1	
Aug-15	849.3		183.2	807.3	
Sep-15	1,262.1		332.7	1,230.2	
Oct-15	1,339.1		469.8	1,365.4	
Nov-15	1,530.9		759.2	1,571.7	
Dec-15	1,728.2	18,759.4	947.9	1,763.3	18,988.3
Jan-16	2,523.0		827.6	2,571.3	
Feb-16	1,741.6		688.0	1,892.9	
Mar-16	1,551.3		611.6	1,735.7	
Apr-16	1,718.1				
May-16	1,645.1				
Jun-16	1,149.7				
Jul-16	1,324.8				
Aug-16	1,088.4				
Sep-16	1,188.0				
Oct-16	1,518.9				
Nov-16	1,611.1				
Dec-16	1,836.4	18,896.4			19,280.5
Jan-17	2,413.0				
Feb-17	2,167.2				
Mar-17	2,265.0				
Apr-17	1,718.1				
May-17	1,645.1				
Jun-17	1,149.7				
Jul-17	1,324.8				
Aug-17	1,088.4				
Sep-17	1,188.0				
Oct-17	1,518.9				
Nov-17	1,611.1				
Dec-17	1,836.4	19,925.7			19,925.7

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.652691217
R Square	0.426005825
Adjusted R Square	0.409123643
Standard Error	390.2181447
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3842393.94	3842393.94	25.23405058	1.60216E-05
Residual	34	5177186.815	152270.2005		
Total	35	9019580.756			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1128.852203	124.2163841	9.087788307	1.27371E-10	876.4141387	1381.290268	876.4141387	1381.290268
WL-HDD	1.019679103	0.202987846	5.023350534	1.60216E-05	0.607158168	1.432200038	0.607158168	1.432200038

Swift River

Commercial Monthly	UPC (kWh)	Annual Actual / Forecast UPC (kWh)	(Watson Lake) MHDD	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
Jan-13	1,442.2		1,129.1	1,378.8	
Feb-13	1,138.9		765.8	1,273.0	
Mar-13	1,204.2		950.7	1,177.4	
Apr-13	1,109.5		690.1	1,043.0	
May-13	876.7		304.5	862.4	
Jun-13	797.9		96.3	820.4	
Jul-13	764.5		105.1	758.1	
Aug-13	780.0		82.2	807.2	
Sep-13	849.5		239.1	882.2	
Oct-13	966.5		490.2	984.1	
Nov-13	1,222.6		1,021.3	1,176.1	
Dec-13	1,574.9	12,727.4	1,248.8	1,540.7	12,703.5
Jan-14	1,506.7		937.7	1,565.6	
Feb-14	1,359.1		1,204.4	1,212.9	
Mar-14	1,275.6		1,008.9	1,211.6	
Apr-14	1,276.7		570.5	1,286.6	
May-14	872.5		331.1	841.3	
Jun-14	905.1		186.8	869.8	
Jul-14	820.9		87.6	825.7	
Aug-14	1,020.9		144.8	1,008.2	
Sep-14	829.6		295.8	826.1	
Oct-14	1,041.8		539.7	1,027.9	
Nov-14	1,312.1		936.4	1,319.8	
Dec-14	1,437.6	13,658.7	1,176.7	1,449.5	13,444.9
Jan-15	1,555.4		1,022.8	1,559.9	
Feb-15	1,542.7		956.7	1,554.8	
Mar-15	1,159.8		766.3	1,250.7	
Apr-15	1,159.4		497.4	1,216.0	
May-15	1,036.8		210.8	1,082.3	
Jun-15	706.8		111.8	719.5	
Jul-15	694.1		92.4	695.8	
Aug-15	653.8		147.5	639.3	
Sep-15	846.5		336.1	817.3	
Oct-15	900.5		523.7	896.7	
Nov-15	1,340.5		887.8	1,379.3	
Dec-15	1,415.5	13,011.8	1,160.3	1,437.9	13,249.5
Jan-16	1,696.5		1,099.3	1,652.2	
Feb-16	1,385.5		930.8	1,414.1	
Mar-16	1,161.2		724.3	1,279.0	
Apr-16	1,181.9				
May-16	928.7				
Jun-16	803.3				
Jul-16	759.8				
Aug-16	818.2				
Sep-16	841.9				
Oct-16	969.6				
Nov-16	1,291.7				
Dec-16	1,476.0	13,314.3			13,416.4
Jan-17	1,501.4				
Feb-17	1,346.9				
Mar-17	1,213.2				
Apr-17	1,181.9				
May-17	928.7				
Jun-17	803.3				
Jul-17	759.8				
Aug-17	818.2				
Sep-17	841.9				
Oct-17	969.6				
Nov-17	1,291.7				
Dec-17	1,476.0	13,132.6			13,132.6

Note: January, February and March 2016 have been updated to include actuals.

Regression Output:

SUMMARY OUTPUT

Regression Statistics

Multiple R	0.919338794
R Square	0.845183818
Adjusted R Square	0.840630401
Standard Error	110.9615733
Observations	36

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2285382.773	2285382.773	185.6152856	2.47871E-15
Residual	34	418624.0052	12312.47074		
Total	35	2704006.778			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	717.2010491	33.29389425	21.5415188	2.13391E-21	649.5397153	784.8623829	649.5397153	784.8623829
WH-HDD	0.638780118	0.046886144	13.62407008	2.47871E-15	0.543496009	0.734064228	0.543496009	0.734064228

Whitehorse

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	952.0	745.8	927.0	**874.9**
FEB	665.4	992.4	851.4	**836.4**
MAR	851.1	855.1	671.3	**792.5**
APR	639.9	499.8	453.5	**531.1**
MAY	294.0	269.5	192.9	**252.1**
JUN	112.4	200.5	127.2	**146.7**
JUL	92.5	98.0	115.7	**102.1**
AUG	98.9	144.0	183.2	**142.0**
SEP	264.3	307.1	332.7	**301.4**
OCT	501.4	515.6	469.8	**495.6**
NOV	865.6	772.8	759.2	**799.2**
DEC	1,144.7	854.4	947.9	**982.3**
TOTAL	**6,482.2**	**6,255.0**	**6,031.8**	**6,256.3**

Watson Lake

Heating Degree Day (HDD) Degree Days Below 18.0 ºC MONTH	2013	2014	2015	"Normal" HDD (2013-2015)
JAN	1,129.1	937.7	1,022.8	**1,029.9**
FEB	765.8	1,204.4	956.7	**975.6**
MAR	950.7	1,008.9	766.3	**908.6**
APR	690.1	570.5	497.4	**586.0**
MAY	304.5	331.1	210.8	**282.1**
JUN	96.3	186.8	111.8	**131.6**
JUL	105.1	87.6	92.4	**95.0**
AUG	82.2	144.8	147.5	**124.8**
SEP	239.1	295.8	336.1	**290.3**
OCT	490.2	539.7	523.7	**517.9**
NOV	1,021.3	936.4	887.8	**948.5**
DEC	1,248.8	1,176.7	1,160.3	**1,195.3**
TOTAL	**7,123.2**	**7,420.4**	**6,713.6**	**7,085.7**

YUB-YECL-9

Reference: Application, Section 3, Purchase Power, pages 3-1 to 3-2.

Issue/sub-issue: Fish Lake hydro generation

Quote: "The forecast Fish Lake hydro generation in the test period outlined in Schedule 3.2 is based on the average output for Fish Lake Unit #2 from 1960-2015 plus the two year average for the new Fish Lake Unit #1 adjusted for planned decrease in generation for capital builds."

Request:

(a) Please describe the capital builds for which generation is decreasing.

(b) If the capital builds do not take place, please provide the Fish Lake generation totals for the test period.

Response:

(a) The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.

(b) If these capital builds do not take place, Fish Lake generation would be estimated at 9,576 MWh for each year.

YUB-YECL-10

Reference: Application, Section 9, Capital Additions, page 9-3, lines 18 to 28.

Issue/sub-issue: Streetlight conversion

Quote: "ATCO Electric Yukon has been in discussions with its customers/municipalities regarding recent developments surrounding converting existing streetlight to Light-Emitting Diode (LED) lamps. Considering there is significant capital outlay associated with the conversion of existing streetlights to LED and in order to understand the rate implications of LED streetlight conversion, ATCO Electric Yukon is seeking Board direction as to the appropriate method of accounting for the capital costs associated with customers requesting conversions of existing streetlights to LED. ATCO Electric Yukon considers there to be two available options:

1) A full customer contribution required for all associated capital costs; or
2) All capital costs associated with requested conversions would be a system cost, not subject to a customer contribution."

Request:

(a) Please provide a history of the discussions that YECL has had with its customer/municipalities with respect to the conversion of existing street lights to LED lamps. Who initiated the discussions and why?

(b) Please provide the total costs of the project and a cost/benefit analysis if the streetlight conversion project were to go ahead.

(c) Please provide the rationale or justification for the project being a system cost.

(d) With respect to the installation of new streetlights, what types of lights does YECL install? Considering the discussions that YECL has had with its customers/municipalities regarding LED lamps, are there any plans for installing LED lamps when installing new street lights? If not, why not?

Response:

(a) Discussions with customers and municipalities are constant and ongoing. Discussions with City of Whitehorse have been occurring for a number of years. LED technology has been evaluated for a number of years to ensure it would meet the requirements of the Road Authority. LED technology for street lights continues to evolve to produce a light spectrum and lighting pattern that is comparable to High Pressure Sodium (HPS) lighting technology. As LED lighting advances, consultation with customers to fit their lighting needs also continues. Customers have shown an interest due to the reduced electrical consumption of LED lights which could lead to reduced costs going forward. AEY sees the benefit of reduced loading on the electrical system and longer life span of equipment which could lead to reduced costs in Operation and Maintenance of the lights.

(b) The per light installation cost and early retirement cost provided in CW-YECL-27(a) was used to estimate the total cost of converting all existing HPS streetlights with LED streetlights in AEY's communities at approximately $2.0M. The project would need to be completed over several years due to resource constraints. The estimated cost to replace existing HPS lights in AEY's thermal communities is approximately $0.27M.

Please refer to YUB-YECL-10(b) Attachment 1 for a cost/benefit analysis of net impact to revenue requirement for converting lights in the thermal communities and hydro communities for two scenarios 1) costs are considered to be system costs and 2) costs are fully contributed by the customer.

(c) The rationale for a system cost would be that the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service of the time. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.

(d) AEY has recently sourced LED lights that can effectively replace HPS lights for the 100 watt and 150 watt HPS street light equivalents. There is also a LED replacement for sentinel lights. As these lights are equivalent replacements AEY is utilizing the LED lights now. The 250 watt HPS equivalent LED street light needs to be evaluated for adequacy in highway applications. AEY is currently working with Yukon Government to provide an acceptable LED lighting option for highway use, as LED lights must meet required lighting specifications and be approved for use by the designated Road Authority. AEY is currently evaluating options for a LED replacement for decorative lights and plans to provide an option by the end of 2016.

ATCO ELECTRIC YUKON 2016-2017 GENERAL RATE APPLICATION
YUB-YECL-10(b) System Costs

Weighted Average Cost of Capital	8.36%
Depreciation (25 years)	4.00%
O&M Escalation	2%
Purchase Power / Fuel Escalation	1.50%
Losses	6.20%

1. Costs	**Installation ($)**	**Conversion factor**	**Cost (/Light/yr)**
LED Installation costs	$503	12.4%	$62

2. O&M Savings	**Cost (/Light/yr)**	**Savings**	**Savings (/Light/yr)**
Savings (First 5 years)	$46	75%	$34
Savings (Beyond 5 years)	$46	25%	$11

3. Energy Savings	**100W Lights (258kWh)**	**150W Lights (272kWh)**	**Savings (/Light/yr)**
Thermal communities ($0.25258/kWh)	99%	1%	$69
Hydro communities ($0.08298/kWh)	85%	15%	$23

					THERMAL COMMUNITIES			**HYDRO COMMUNITIES**		
					NPV:	**($589)**		**NPV:**	**($0)**	
Year	**Rate Base**	**Return**	**Depreciation**	**O&M Savings**	**Fuel Savings**	**Annual Cost / (Savings)**	**Cumulative Present Value**	**Purchase Power Savings**	**Annual Cost / (Savings)**	**Cumulative Present Value**
1	$503	$42	$20	($34)	($69)	($41)	($41)	($23)	$5	$5
2	$483	$40	$20	($35)	($70)	($45)	($83)	($23)	$2	$7
3	$463	$39	$20	($36)	($71)	($48)	($124)	($24)	($1)	$6
4	$443	$37	$20	($37)	($72)	($52)	($165)	($24)	($3)	$4
5	$423	$35	$20	($37)	($73)	($55)	($205)	($24)	($6)	($1)
6	$403	$34	$20	($13)	($75)	($33)	($227)	($25)	$16	$10
7	$383	$32	$20	($13)	($76)	($37)	($250)	($25)	$14	$19
8	$362	$30	$20	($13)	($77)	($40)	($272)	($25)	$12	$26
9	$342	$29	$20	($13)	($78)	($43)	($295)	($26)	$9	$31
10	$322	$27	$20	($14)	($79)	($46)	($317)	($26)	$7	$34
11	$302	$25	$20	($14)	($80)	($49)	($339)	($27)	$5	$36
12	$282	$24	$20	($14)	($82)	($52)	($360)	($27)	$2	$37
13	$262	$22	$20	($15)	($83)	($55)	($381)	($27)	$0	$38
14	$242	$20	$20	($15)	($84)	($59)	($402)	($28)	($2)	$37
15	$221	$19	$20	($15)	($85)	($62)	($422)	($28)	($5)	$35
16	$201	$17	$20	($15)	($87)	($65)	($442)	($29)	($7)	$33
17	$181	$15	$20	($16)	($88)	($68)	($461)	($29)	($10)	$30
18	$161	$13	$20	($16)	($89)	($72)	($479)	($30)	($12)	$27
19	$141	$12	$20	($16)	($91)	($75)	($497)	($30)	($14)	$24
20	$121	$10	$20	($17)	($92)	($78)	($514)	($30)	($17)	$20
21	$101	$8	$20	($17)	($93)	($82)	($530)	($31)	($19)	$16
22	$81	$7	$20	($17)	($95)	($85)	($546)	($31)	($22)	$12
23	$60	$5	$20	($18)	($96)	($89)	($561)	($32)	($24)	$8
24	$40	$3	$20	($18)	($98)	($92)	($575)	($32)	($27)	$4
25	$20	$2	$20	($18)	($99)	($96)	($589)	($33)	($29)	($0)

ATCO ELECTRIC YUKON 2016-2017 GENERAL RATE APPLICATION
YUB-YECL-10(b) Customer Contributed

Weighted Average Cost of Capital	8.36%
Depreciation (25 years)	4.00%
O&M Escalation	2%
Purchase Power / Fuel Escalation	1.50%
Losses	6.20%

1. Costs	**Installation ($)**	**Conversion factor**	**Cost (/Light/yr)**
LED Installation costs	$0	12.4%	$0

2. O&M Savings	**Cost (/Light/yr)**	**Savings**	**Savings (/Light/yr)**
Savings (First 5 years)	$46	75%	$34
Savings (Beyond 5 years)	$46	25%	$11

3. Energy Savings	**100W Lights (258kWh)**	**150W Lights (272kWh)**	**Savings (/Light/yr)**
Thermal communities ($0.25258/kWh)	99%	1%	$69
Hydro communities ($0.08298/kWh)	85%	15%	$23

					THERMAL COMMUNITIES			**HYDRO COMMUNITIES**		
					NPV: ($1,135)			**NPV: ($546)**		
Year	**Rate Base**	**Return**	**Depreciation**	**O&M Savings**	**Fuel Savings**	**Annual Cost / (Savings)**	**Cumulative Present Value**	**Purchase Power Savings**	**Annual Cost / (Savings)**	**Cumulative Present Value**
1	$0	$0	$0	($34)	($69)	($104)	($104)	($23)	($57)	($57)
2	$0	$0	$0	($35)	($70)	($105)	($201)	($23)	($58)	($111)
3	$0	$0	$0	($36)	($71)	($107)	($292)	($24)	($59)	($162)
4	$0	$0	$0	($37)	($72)	($109)	($378)	($24)	($60)	($209)
5	$0	$0	$0	($37)	($73)	($111)	($458)	($24)	($62)	($254)
6	$0	$0	$0	($13)	($75)	($87)	($516)	($25)	($37)	($279)
7	$0	$0	$0	($13)	($76)	($89)	($571)	($25)	($38)	($302)
8	$0	$0	$0	($13)	($77)	($90)	($622)	($25)	($39)	($324)
9	$0	$0	$0	($13)	($78)	($91)	($671)	($26)	($39)	($345)
10	$0	$0	$0	($14)	($79)	($93)	($716)	($26)	($40)	($364)
11	$0	$0	$0	($14)	($80)	($94)	($758)	($27)	($41)	($383)
12	$0	$0	$0	($14)	($82)	($96)	($798)	($27)	($41)	($400)
13	$0	$0	$0	($15)	($83)	($97)	($835)	($27)	($42)	($416)
14	$0	$0	$0	($15)	($84)	($99)	($870)	($28)	($43)	($431)
15	$0	$0	$0	($15)	($85)	($100)	($902)	($28)	($43)	($445)
16	$0	$0	$0	($15)	($87)	($102)	($933)	($29)	($44)	($458)
17	$0	$0	$0	($16)	($88)	($104)	($961)	($29)	($45)	($470)
18	$0	$0	$0	($16)	($89)	($105)	($988)	($30)	($46)	($482)
19	$0	$0	$0	($16)	($91)	($107)	($1,013)	($30)	($46)	($493)
20	$0	$0	$0	($17)	($92)	($109)	($1,037)	($30)	($47)	($503)
21	$0	$0	$0	($17)	($93)	($110)	($1,059)	($31)	($48)	($513)
22	$0	$0	$0	($17)	($95)	($112)	($1,080)	($31)	($49)	($522)
23	$0	$0	$0	($18)	($96)	($114)	($1,099)	($32)	($50)	($530)
24	$0	$0	$0	($18)	($98)	($116)	($1,118)	($32)	($50)	($538)
25	$0	$0	$0	($18)	($99)	($117)	($1,135)	($33)	($51)	($546)

YUB-YECL-11

Reference: Application, Section 9, Capital Additions, Attachment 9.1, page 2

Issue/sub-issue: Project costs

Quote: "DISTRIBUTION NEW EXTENSIONS $2,160,000
(Gross of Customer Contribution)"

Request:

(a) Please explain what is meant when YECL states, in the above quote, that the costs associated with distribution new extensions are "Gross of customer contribution."

(b) For all projects, approved and deemed as capital projects, in the period from 2013 to 2015 (YECL's 2013-2015 Application, pages 9-44 to 9-67), please provide a comparison of forecast and actual costs, accompanied with an explanation for projects with variances of 10 percent and greater than $50,000.

Response:

(a) Distribution New Extensions are completed at the request of customers and the majority of these costs are contributed by the customer. AEY contributes only a portion of the capital costs based on the approved investment levels in the Terms and Conditions of Service. The $2,160,000 is the combined amount of the customer contribution and the company investment.

(b) Please refer to YUB-YECL-11(b) Attachment 1.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity of Capital Expenditures
($000s)

Line No	Project Name	Actual 2013-2015	Approved 2013-2015	Variance $	Variance %	
1	**Generation**					
2	Fish Lake Unit 1 Turbine and Building Replacement	1,850	1,798	(52)	-2.9%	
3	Fish Lake Dyke Upgrade	2,552	1,720	(832)	-48.4%	Please refer to Attachment 11.1 of the Application.
4	Fish Lake Unit 2 Siding Replacement	51	35	(16)	-45.7%	
5	Louise Lake Control Structure	49	-	(49)	-100.0%	
6	Fish Lake Unit 1 Fiber Communication	45	20	(25)	-125.0%	
7	Fish Lake Unit 2 SCADA	44	50	6	12.0%	
8	Fish Lake Unit 2 Penstock Improvements	43	40	(3)	-7.5%	
9	Fish Lake Unit 1 Spillway Diversion Structure	22	120	98	81.7%	2013 costs were for design. Final design identified costs would exceed 2014 forecast. Further work was completed to refine estimate for 2017 work.
10	Fish Lake Unit 2 Building Improvements	20	20	-	0.0%	
11	Fish Lake Unit 2 Vibration Monitoring	19	20	1	5.0%	
12	Fish Lake Ditch 3 Diversion Replacement	134	1,640	1,506	91.8%	Please see Appendix 1 of the Application.
13	Fish Lake Unit 2 Head Pond Low Level Outlet Pipe	-	30	30	100.0%	
14	Fish Lake Unit 1 Needle Detach Failure	21	-	(21)	-100.0%	
15	Fish Lake #2 Head Pond Spillway Replacement	30	30	-	0.0%	
16						
17	Watson Lake Unit 4 Replacement	1,007	1,120	113	10.1%	Actual costs to move and dispose unit were less than forecast.
18	Watson Lake Unit 6 Major Overhaul	243	250	7	2.8%	
19	Watson Lake Bi-Fuel	362	-	(362)	-100.0%	Please see Appendix 3 of the Application.
20	Watson Lake Unit 5 Major Overhaul	239	200	(39)	-19.5%	
21	Watson Lake Replace ABB 5HK Breakers	407	380	(27)	-7.1%	
22	Watson Lake Unit 1 Major Overhaul	278	250	(28)	-11.2%	
23	Watson Lake Unit 2 Replacement	-	1,350	1,350	100.0%	Please see Appendix 4 of the Application.
24						
25	Old Crow Plant Expansion	4,566	1,950	(2,616)	-134.2%	Please see Attachment 11.2 of the Application.
26	Old Crow Unit 4 Addition	612	500	(112)	-22.4%	There was an increase in kW size of unit after a review of community loading. The unit was not delivered in time for winter road and had to be flown in .
27	Old Crow Unit 3 Replacement	213	500	287	57.4%	Please see Appendix 5 of the Application.
28	Old Crow Unit 2 Replacement	161	-	(161)	-100.0%	Please see Attachment 11.7 of the Application.
29	Old Crow Original Plant Rebuild	90	-	(90)	-100.0%	Engineers were on site as work on new power plant proceeded. A concern was identified and AEY needed to assess the mechanical and structural health of the existing power plant.
30						
31	Beaver Creek Programmable Logic Control (PLC) Upgrade	377	180	(197)	-109.4%	Please see Attachment 11.3 of the Application.
32	Beaver Creek Unit 2 Replacement	726	600	(126)	-21.0%	Extra work was needed on the control system to integrate the unit and the time to commission was longer than expected.
33	Beaver Creek Unit 1 Replacement	657	600	(57)	-9.5%	
34	Beaver Creek Fuel Line Upgrade	77	-	(77)	-100.0%	Fuel system performance was not adequate for the power plant and work was required to remedy.
35						
36	Destruction Bay Plant Foundation Refurbishment	131	150	19	12.7%	
37	Destruction Bay Unit 3 Replacement	634	450	(184)	-40.9%	Please see Appendix 11 of the Application.
38	Destruction Bay Programmable Logic Controller Upgrade	109	300	191	63.7%	Design only has occurred to date and resource constraints have deferred project to 2017.
39	Destruction Bay Unit 2 Replacement	136	600	464	77.3%	Please see Appendix 6 of the Application.
40						
41	Ross River Replace ABB 5HK Breakers	-	45	45	100.0%	
42						
43	Stewart Crossing Plant Improvements	-	180	180	100.0%	The project was low priority and was deferred due to work load.
44	Stewart Crossing - Spare Fuel Injector	28	-	(28)	-100.0%	
45						
46	Swift River Unit 2 Replacement	49	30	(19)	-63.3%	
47	500kW Mobile Generator	900	750	(150)	-20.0%	All bids received were more than estimate, the lowest bid was chosen.

48	New 250kW Mobile Generator	211	175	(36)	-20.6%	
49	OSS Control Upgrade	21	-	(21)	-100.0%	
50						
51	Other Projects Less Than $20,000	119	168	49	29.2%	
52	**Generation Total**	**17,233**	**16,251**	**(982)**	**-6.0%**	
53						
54	**New Extensions**					
55	New General Overhead Services - Various Subdivisions	2,336	10,439	8,103	77.6%	Customer additions and new extensions were lower than forecast due to slower economy.
56	New Underground Line Extensions	2,398	2,600	202	7.8%	
57	Annual Land Rights	230	570	340	59.6%	Resource constraints led to less work in securing land tenure on exisiting power lines.
58	General Drafting and Mapping	144	80	(64)	-80.0%	Internal audits required more time to update electronic mapping.
59						
60	Whistle Bend Subdivision Stage 1 & 2	513	-	(513)	-100.0%	Please see Attachment 11.8 of the Application
61	Whistle Bend Underground Residential Service	116	-	(116)	-100.0%	Please see Attachment 11.9 of the Application
62	Whistle Bend Stage 3	-	977	977	100.0%	The project was deferred at request of developer.
63						
64	City of Whitehorse Range Road Widening	188	-	(188)	-100.0%	Please see Attachment 11.10 of the Application.
65	Yukon Government Teslin Sawmill Subdivision	132	75	(57)	-76.0%	Scope increased at the request of the customer.
66	Whitehorse Municipal Services Building	-	420	420	100.0%	The project was deferred at request of developer.
67	Lot 11 Marion Crescent	-	53	53	100.0%	This was a small customer driven project (less than $5000) and actual costs are captured in General OH Services.
68	Lot 1000 Airport Road	-	53	53	100.0%	This was a small customer driven project (less than $5000) and actual costs are captured in General OH Services.
69	Other Projects Less Than $20,000	84	213	129	60.6%	As with all new extensions not under the control of AEY, the number of projects were less than forecast.
70	**New Extensions Total**	**6,141**	**15,480**	**9,339**	**60.3%**	
71						
72	**Distribution Improvements**					
73	Annual Right of Way Widening	1,169	1,168	(1)	-0.1%	
74	General Pole Replacements	354	780	426	54.6%	A portion of pole replacements were inadvertently included in "Other Projects Less than $20,000" in line 132.
75	PCB Identification and Transformer Change Outs	233	375	142	37.9%	This is a multi staged project, compliance with legislation was attained and resources were reallocated.
76	Vault Replacements	41	-	(41)	-100.0%	
77	General Clearance Upgrades/Fixes	124	135	11	8.1%	
78	Test and Treat Pole Program	-	360	360	100.0%	The results of the program indicated that majority of poles were healthy and the program has been put on hold.
79						
80	McIntyre Subdivision Rebuild	1,453	725	(728)	-100.4%	Please see Appendix 8 of the Application.
81	Downtown Whitehorse 25kV Conversion	880	900	20	2.2%	
82	Hillcrest Subdivision Conversion	680	525	(155)	-29.5%	The scope of project was changed to install underground instead of overhead in some areas due to conflicts in road allowance.
83						
84	4L314 Chilkoot Way Upgrade	483	-	(483)	-100.0%	Please see Attachment 11.11 of the Application.
85	Downtown Whitehorse 4L313 Labert Street to Elliot Street	-	424	424	100.0%	AEY was unable to secure land location for underground equipment.
86	Crestview to Mayo Road 5L628 Upgrade to 266 MCM	364	250	(114)	-45.6%	Additional requirements were identified once the project started for brushing and routing changes were needed due to conflicts with original design.
87	Hotsprings Road Main Line Relocation and Upgrade	338	325	(13)	-4.0%	
88	Old Alaska Highway Bypass	212	248	36	14.5%	
89	Tagish 5L600 Rebuild	335	576	241	41.8%	This is a multi staged project and the areas completed in 2013 and 2015 have addressed the reliability concerns in the area. Further stages will continue if power system deficiencies are identified.
90	Jack Hulland School Upgrades	135	100	(35)	-35.0%	
91	Teslin Area Pole Upgrades	93	53	(40)	-75.5%	
92	Firth Breaker Replacement	60	-	(60)	-100.0%	During regular maintenance assessments, this breaker was identified to be changed.
93	McIntyre Substation Change Switches and Busswork	45	-	(45)	-100.0%	
94	600 Amp Feeder from Tamarack to Evergreen	45	-	(45)	-100.0%	
95	97 Lewes Blvd Upgrade	39	-	(39)	-100.0%	
96	Lot 1037 Range Road Line Upgrade	37	34	(3)	-8.8%	
97	Ion Meter Upgrade	29	-	(29)	-100.0%	

98	Ross River Recloser for S7580	29	-	(29)	-100.0%	
99	Shipyards Substation Upgrades	28	-	(28)	-100.0%	
100	Lot 1037 Range Road Trespass	22	-	(22)	-100.0%	
101	Watson Lake Substation Ground Grid Upgrade	22	-	(22)	-100.0%	
102	Downtown Whitehorse 4L316 6th Avenue 266 Reconductor	-	550	550	100.0%	The 4L314 Chilkoot Way Upgrade was completed instead of this project as identified in Attachment 11.11.
103	Carmacks North Main Line Rebuild	-	100	100	100.0%	Project has been deferred due to future possible reconfiguration of supply source for Carmacks from YEC.
104	Whitehorse Asset Management	101	150	49	32.7%	
105	Whitehorse Safety Code Corrections	-	30	30	100.0%	
106						
107	Whitehorse 5L628 and New 34.5kV Build	1,946	1,890	(56)	-3.0%	
108	Takhini/Marwell 4L315 Upgrades	334	600	266	44.3%	The 2nd stage of project has been deferred as the first stage has addressed the business drivers.
109	Deep Creek Subdivision Connection	213	60	(153)	-255.0%	Please see Attachment 11.5 of the Application.
110	Nisutlin Bridge Cable Tray Upgrade	97	-	(97)	-100.0%	AEY upgraded the cable tray in coordination with other work on the bridge that Yukon Government was completing.
111	Marwell Lot 14 Transformer Upgrade	68	-	(68)	-100.0%	Replaced inoperable live front transformer and underground cables.
112	Yukon Wildlife Preserve Powerline Rebuild	54	-	(54)	-100.0%	Line relocated due to close proximity to nearby building.
113	Lewes Lake Substation Conversion	157	146	(11)	-7.5%	
114	Azure Road Extension	151	-	(151)	-100.0%	Please see Attachment 11.12 of the Application.
115	Teslin Sawmill Road Feeder Upgrade	130	38	(92)	-242.1%	The power line route had to be revised due to property conflicts which also increased brushing.
116	2nd Ave Relocation	115	-	(115)	-100.0%	Please see Attachment 11.13 of the Application.
117	MacDonald Road Pole Change	103	250	147	58.8%	A small portion of the project was completed that addressed concerns for the medium term.
118	Watson Lake Underground Subdivision Replacement	78	-	(78)	-100.0%	Installation of a new underground feed to loop existing system.
119	McLintock Substation Upgrade	76	90	14	15.6%	
120	Spirit Lake Substation Upgrade	70	88	18	20.5%	
121	Upper Liard – Replace Liard River Crossing	70	-	(70)	-100.0%	Existing structures and conductors replaced due to deficiencies.
122	Takhini/Marwell Completion of Mountain Air Subdivision	67	300	233	77.7%	The project scope changed which allowed for lower costs to complete the project.
123	Lane Rebuild - 30 Tagish Road	31	-	(31)	-100.0%	
124	Install Interface Metering for 5L655	28	-	(28)	-100.0%	
125	Whitehorse Hotsprings Road 3 Phase Conversion	20	363	343	94.5%	A medium term solution is in place that allows for acceptable system performance. Resources were reallocated to other distribution improvement requirements.
126	Riverdale Line 4L317 Tagish Road	-	250	250	100.0%	A medium term solution is in place (Lane rebuild 30 Tagish Road on line 123) that allows for acceptable system performance.
127	Whitehorse Airport Hanger D Area Rebuild	-	140	140	100.0%	The project is ongoing as AEY continues to plan project with airport authority due to multiple conflicts. Once conflicts are resolved, permits to allow work can be issued.
128	Grey Mountain 4L320 Tie Upgrade	-	65	65	100.0%	AEY was unable to secure an appropriate new line route.
129	Stewart Crossing West Town Conversion	-	60	60	100.0%	Power system performance is acceptable and project is on hold.
130	Upgrade of S2278	-	45	45	100.0%	
131						
132	Other Projects Less Than $20,000	250	160	(90)	-56.3%	Includes pole replacements that should have been included on line 74.
133	**Distribution Improvements Total**	**11,409**	**12,353**	**944**	**7.6%**	
134						
135	**Street and Sentinel Lighting**					
136	General Streetlight Replacements	635	1,110	475	42.8%	A number of the locations identified in section 9 were not completed. Completed areas include Pine, Hickory and Alsek road.
137	New Customer Streetlight Installations	344	483	139	28.8%	These are various projects at the discretion of customers.
138	Whistle Bend Streetlights	142	525	383	73.0%	The project was deferred at request of the developer.
139	Other Projects Less Than $20,000	102	60	(42)	-70.0%	
140	**Street and Sentinel Lighting Total**	**1,223**	**2,178**	**955**	**43.8%**	
141						
142	**Meters**					
143	Replacement of Meters and New Installations	708	1,011	303	30.0%	As new extensions and customer growth were lower, so were the new meters required for these services.
144	**Meters Total**	**708**	**1,011**	**303**	**30.0%**	
145						

146	**Transformers & Regulators**					
147	General Capitalizable Transformers	255	30	(225)	-750.0%	As incremental load growth for electric heat customers grows, distribution transformers need to be upgraded.
148	**Transformers & Regulators Total**	**255**	**30**	**(225)**	**-750.0%**	
149						
150	**GP&E**					
151	Downtown Office Building Envelope Upgrades	589	600	11	1.8%	
152	Whitehorse Service Complex Pole Storage	229	150	(79)	-52.7%	The pole storage bunks material costs were higher than estimated and reconfiguration of storage yard was needed.
153	Downtown Office Interior Renovations	100	100	-	0.0%	
154	Whitehorse Service Complex Parking Lot Improvements	117	100	(17)	-17.0%	
155	Whitehorse Service Complex Office Area Renovations	60	80	20	25.0%	
156	Whitehorse Service Complex - Exterior & Service Bay Upgrades	-	70	70	100.0%	With storage yard reconfiguration in the pole storage project, these upgrades were not needed.
157	Whitehorse Service Complex - Fence Extension	12	20	8	40.0%	
158	Downtown Office Paving & Drain	31	-	(31)	-100.0%	
159	Old Crow Staff Accommodations	274	100	(174)	-174.0%	Please see Attachment 11.6 of the Application.
160	Watson Lake Power Plant Connection to Town Water Supply	-	100	100	100.0%	Testing of existing well and water has proven adequate for the medium term.
161	Whitehorse Various Service Complex Renovations	-	100	100	100.0%	Renovations completed in 2013 were able to address space constraints.
162	Whitehorse Service Complex Yard Extension	-	300	300	100.0%	As pole storage project was completed it opened room in existing yard, the extension was not needed.
163						
164	Communication Equipment	142	23	(119)	-517.4%	Work was needed on communication equipment in conjunction with SCADA upgrades.
165	AEY SCADA Upgrades	57	-	(57)	-100.0%	Unplanned work needed to ensure continued reliable operation of SCADA.
166						
167	Office Furniture & Equipment	23	78	55	70.5%	Offices did not need new furniture.
168						
169	Miscellaneous Tools and Instruments	411	399	(12)	-3.0%	
170						
171	Fish Lake Water License Renewal	841	650	(191)	-29.4%	Actual costs to complete required license renewal were higher due to volume of information requested.
172	Display Change to Yukon Electrical Billing Statements	-	259	259	100.0%	During platform design of the project issues were identified that would increase costs. Benefits of project were not enough to justify costs.
173	Windows 7 Upgrades	49	146	97	66.4%	The project did not require as much work to complete as forecast.
174	E-Post Billing	138	125	(13)	-10.4%	
175	Demand Side Management Costs	75	75	-	0.0%	
176	Field Collection System	58	55	(3)	-5.5%	
177	Field Collection System - Report Development (ITBS)	-	43	43	100.0%	
178	Yukon Electrical Website Improvements	-	35	35	100.0%	
179	New Cashier System	50	25	(25)	-100.0%	
180	Oracle R12 Upgrade	76	-	(76)	-100.0%	This is AEY's share of an ATCO wide upgrade of the Oracle Financials system. AEY was unaware of the costs at the time of the 2013-2015 General Rate Application.
181	Transportation Equipment	1,999	1,819	(180)	-9.9%	
182	Replacement of Unit 989 - 1995 Hot Line Bucket Truck	406	450	44	9.8%	
183						
184	Other Projects Less Than $20,000	183	230	47	20.4%	
185	**GP&E Total**	**5,920**	**6,132**	**212**	**3.5%**	
186	**Grand Total**	**42,889**	**53,435**	**10,546**	**19.7%**	

YUB-YECL-12

Reference: Application, Section 9, Capital Additions

Issue/sub-issue: Reasons for capital additions

Request:

(a) With respect to YECL's proposed Fish Lake Unit 2 (1958 Gilkes hydro turbine) assessment, YECL indicates that the assessment will determine the overall operating condition of the power plant and related infrastructure, and will identify life extension, major refurbishment and/or replacement options.[9]

a. Considering the age of the unit, have previous assessments been performed? If so, please provide the reports. If not, why not? Assuming that YECL performs regular (annual) operation and maintenance assessments, other than age of the unit has anything else led to the need for the assessment in the test years?

b. Is YECL asking to capitalize the assessment, rather than assume under O&M?

(b) Schedule 9.2 indicates an expenditure of $28,000 related to the Watson Lake Unit #4 replacement. Please provide details on whether this related to the $1.1 million expensed in 2013.

(c) Please indicate the section(s) in the *Canadian Environmental Protection Act, 1999*, which informs YECL and underpins the $150,000 and $51,000 expenditures (2016 and 2017, respectively) related to polychlorinated biphenyl (PCB) identification and transformer change outs.[10] YECL proposes to replace Transformer T2 at the Watson Lake Substation. Please provide the rating of the replacement transformer.

Response:

(a)

a. An assessment of this magnitude has not been done to date. Annual inspections are done by AEY staff during routine maintenance, however they do not provide the level of in-depth analysis that this assessment will provide.

[9] Section 9, Attachment 9.1, page 1.
[10] Section 9, Attachment 9.1, page 3.

Multiple key indicators such as increasing maintenance and capital costs, increasing downtime due to maintenance, low generation output, low operating efficiencies, lack of manufacturer support and increasing concerns from annual inspections have led to the need for the assessment.

Please refer to YUB-YECL-12(a) Attachment 1 for previous reports.

b. Yes, AEY is proposing to capitalize the costs of the assessment along with the resulting life extension or replacement required and recovering the costs over the life of the asset.

(b) Correct. Onsite construction and commissioning work for this project carried over to Q1 of 2014.

(c) The legislation pertaining to PCBs in utility equipment are the “PCB Regulations” (SOR/2008-273). The specific sections relating to our equipment are “Cables, pipelines, electrical capacitors and other equipment” – Part 14(1)(d)(i); and “End-of-use dates and extension” – Part 16.

The replacement transformer in Watson Lake will be a 5MVA unit.

YUB-YECL-13

Reference: Application, Appendices – Business Cases, Appendix 3

Issue/sub-issue: Watson Lake bi-fuel project

Preamble: Further information is required.

Request:

(a) When does YECL expect to capitalize the $494,000, shown in Table 1,[11] expensed in the period from 2012-15?

(b) YECL proposes to purchase the LNG vaporization skid and LNG storage tank from ATCO Gas for $1,470,000. Please explain why YECL chose not to competitively tender for the equipment purchased from ATCO Gas.

(c) YECL submits that "the addition of another LNG storage tank will ensure there is sufficient onsite storage of fuel during operations in Phase 2 and an offload pump will be necessary to increase the speed of transfer of the LNG from the shipper to the storage tanks."[12] Are these costs included in Table 1?

(d) YECL has constructed a process heating skid that allows for waste heat from the generating units to be utilized as the heat source in the LNG vaporizer. Are the costs for the process heating skid included in Table 1? Please explain in detail, the complementary uses of the LNG vaporization skid and the process heating skid.

(e) Does the estimated $50,000/year incremental operation and maintenance (O&M) cost include periodic maintenance? Are incremental training costs required for YECL plant personnel? If so, are these costs included in the estimated annual incremental O&M costs.

(f) Please provide a chart/graph which shows the monthly fluctuations in price for LNG and diesel during the period from 2012 to the present.

[11] Appendix #3, page 4.
[12] Appendix #3, Page 2.

Response:

(a) The $494,000 in Table 1 are the costs associated with engineering, licensing and determining the feasibility of such a project. The suggested mechanism to recover these costs is through the amortization of deferred charges similar to the treatment of the Kluane Wind Study and the proposed Renewables Feasibility and Smart Grid Studies, however, AEY is not opposed to capitalization of the costs, should the project be approved, and recovery of costs over the lifetime of the related assets.

Further discussion of these initial feasibility and engineering costs can be found in AEY's response to YUB-YECL-75.

(b) The equipment designed for the Watson Lake Bi-Fuel Project was designed and built specifically for this project for ATCO Gas using a competitive tendering process. Please refer to the YUB-YECL-13(b) Attachment 1 for the information response CW-YECL-8 from YECL's 2013-2015 GRA for further details on ATCO Gas's competitive tendering process.

The cost of the LNG Vaporizer and LNG Storage Tank has been revised to $1,194,000 with further details provided in response to YUB-YECL-24(e). As a result, the estimated Phase 1 cost has decreased from $3,261,000 to $2,985,000. The estimated total project cost has decreased from $4,971,000 to $4,695,000. Consequently, the project economics have improved slightly under all scenarios. AEY has updated Table 1, Table 2 and Table 3 of the business case provided in Appendix 3 of the Application as follows: (changes have been shown in bold).

Revised Table 1: Watson Lake Bi-Fuel Project Phase 1 and 2 Capital Cost

	Phase 1			Phase 2
	2012 - 2015	2016	2017	2018
Study Costs	$222,000			
Engineering, Design, and Permitting	$272,000	$55,000	$152,000	$105,000
LNG Vaporizer and LNG Storage Tank			**$1,194,000**	
Installation (civil, mechanical and electrical) and commissioning			$1,090,000	
Conversion of Remaining Units to Bi-Fuel				$700,000
Tank expansion, piping, cryopump and installation				$905,000
Phase Sub-Total			**$2,985,000**	$1,710,000
Total				**$4,695,000**

Revised Table 2: Comparison of Potential Suppliers and Fuel Price Forecasts

	Supplier	Simple Payback (years)	20 Year NPV ($M)
Sproule Price Forecast	Fortis	**11**	**$0.6**
	AltaGas	**9**	**$2.4**
Both Commodities Escalates at 5%	Fortis	11	**$3.0**
	AltaGas	9	**$5.9**

Revised Table 3: Alternative Fuel Escalation Scenarios

	Supplier	Simple Payback (years)	20 Year NPV ($M)
Scenario 3 Both Commodities Escalated at 2.5%	Fortis	15	**$(0.7)**
	AltaGas	**10**	**$2.0**
Scenario 4 Diesel Commodity Escalation at 5% Natural Gas Escalation at 2.5%	Fortis	11	**$3.7**
	AltaGas	9	**$6.4**
Scenario 5 Diesel Commodity Escalation at 2.5% Natural Gas Escalation at 5%	Fortis	**16**	**$(1.4)**
	AltaGas	11	**$1.5**
Scenario 6 Both Commodity Prices Doubled	Fortis	**6**	**$7.4**
	AltaGas	5	**$10.5**

(c) Confirmed. These costs are included in Table 1 under "Tank expansion, piping, cryopump and installation".

(d) The costs for the process heating skid are included in Table 1 under Engineering, Design and Permitting. The process heating skid collects waste heat that would normally be transferred to the atmosphere in the form of rejected heat in a heat exchanger. A separate and distinct fluid absorbs the rejected heat in the Process Heating Skid heat exchanger and is pumped to the LNG vaporizer

skid through a closed piping loop. Once the process heating skid fluid reaches the LNG vaporizer, it enters another heat exchanger that interfaces with the LNG piping network. As the heat is transferred from the Process Heating Skid loop to the LNG, the LNG is vaporized (change for state from liquid to gas) into natural gas. This process negates the need for additional fuel to be combusted to vaporize the LNG.

(e) The incremental O&M costs are not included in the 2016-2017 forecast costs included in Section 5 of the Application. The project is not planned to be in service until the end of 2017 so AEY is not anticipating any material change to O&M within the test period.

The operations and maintenance contract specific to the LNG equipment will be competitively tendered and will include periodic maintenance and additional safety training for AEY's operations staff.

(f) The graph and table below provide the monthly fluctuations in price for LNG and diesel during the period from 2012 to present. The historical wholesale pricing for diesel in Vancouver was obtained from NRCAN. The historical Vancouver LNG pricing is the summation of FortisBC's Spot Pricing within their Rate Schedules (Rate Schedule 16 for 2012 and Rate Schedule 46 for 2013 to 2016) and monthly historical Sumas natural gas pricing obtained from Sproule.



Date	Vancouver Spot LNG Price	Vancouver Wholesale Diesel Price
month of	$/LDE	$/LDE
Jan-12	0.27	0.85
Feb-12	0.24	0.90
Mar-12	0.23	0.96
Apr-12	0.21	0.96
May-12	0.21	0.90
Jun-12	0.23	0.83
Jul-12	0.23	0.81
Aug-12	0.24	0.87
Sep-12	0.23	0.85
Oct-12	0.25	0.81
Nov-12	0.28	0.77
Dec-12	0.28	0.83
Jan-13	0.29	0.84
Feb-13	0.29	0.91
Mar-13	0.29	0.89
Apr-13	0.30	0.86
May-13	0.30	0.86
Jun-13	0.29	0.84
Jul-13	0.29	0.89
Aug-13	0.28	0.90
Sep-13	0.29	0.90
Oct-13	0.30	0.90
Nov-13	0.31	0.90
Dec-13	0.35	0.91
Jan-14	0.34	0.93
Feb-14	0.45	0.97
Mar-14	0.35	0.94
Apr-14	0.34	0.92
May-14	0.33	0.92
Jun-14	0.33	0.94
Jul-14	0.31	0.91
Aug-14	0.31	0.92
Sep-14	0.31	0.94
Oct-14	0.30	0.86
Nov-14	0.33	0.85
Dec-14	0.30	0.72
Jan-15	0.28	0.63

Date	Vancouver Spot LNG Price	Vancouver Wholesale Diesel Price
Feb-15	0.27	0.74
Mar-15	0.27	0.72
Apr-15	0.26	0.71
May-15	0.27	0.76
Jun-15	0.27	0.75
Jul-15	0.27	0.71
Aug-15	0.28	0.63
Sep-15	0.29	0.65
Oct-15	0.27	0.63
Nov-15	0.27	0.60
Dec-15	0.27	0.51
Jan-16	0.29	0.46
Feb-16	0.25	0.46
Mar-16	0.24	0.49
Apr-16	0.23	0.52
May-16	0.24	0.62
Jun-16	0.26	0.67

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

2013-2015 General Rate Application
The Yukon Public Utilities Board
Information Request No. 1
Dated: July 18, 2013
CW-YECL-8
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CW-YECL-8

Reference: Operating Costs- Lease of LNG, Application, page 5-4 and Business Case 6

In its Application, YECL states:

> In addition, Yukon Electrical purchases information technology and billing system services from ATCO I-Tek and ATCO I-Tek Business Services respectively. Beginning in the fall of 2013, Yukon Electrical will be leasing liquid natural gas (LNG) storage and vaporization equipment from an affiliate company, ATCO Gas, related to the Watson Lake Bi-Fuel Project. Please refer to Business Case #6 for further details on this project.

The City requires information to understand how the decision was made to lease the LNG facility, and how pricing was determined.

Request:

(a) Please provide any financial analysis prepared by YECL comparing the costs of the three alternatives in the Business Case.

(b) Please provide an analysis that demonstrates leasing LNG storage and vaporization equipment is less expensive than owning such equipment.

(c) Please fully describe the process that YECL undertook to determine that an affiliate should provide the equipment. In the response, please discuss whether competitive tendering was used.

(d) Please fully explain, and provide working papers in support of the lease price and its derivation.

Response:

(a) Alternative #1 relates to the status quo of continued operation to generate power using only diesel at no additional cost. A detailed financial analysis was not carried out on Alternative #2 to replace existing units with dual fuel capability as costs would be in excess of $9M. New individual unit costs range from approximately $1M to $1.5M. Each unit would also typically require new radiators, silencers, piping for both cooling and exhaust, and control system integration on top of unit purchase. Technology has changed between these

1990s vintage units and modern engines. As a result, it would not be a straight forward swap to accomplish replacement. The bi-fuel modification kit for an individual existing unit in selected Alternative #3 is approximately $75K. Additionally, a firm supply chain of LNG is not yet established and is to be developed as part of this project.

(b) Leasing equipment may not be less expensive than owning such equipment over the long term life of a project. However, for the purposes of the pilot project, the lease option is prudent as it does not require Yukon Electrical to invest upfront in the equipment, and it allows flexibility for exiting the project if the pilot is not successful. The equipment supply is one component of the lease arrangement. It also includes on-going services for operations and maintenance. If the market develops whereby the equipment and specialized services become more costly going forward, the lease arrangement provides additional cost certainty for the project to achieve fuel cost savings related to diesel. For additional information, please refer to CW-YECL-8(c) below.

This is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable. Yukon Electrical has structured the project to allow flexibility with respect to capital commitments and provision of necessary expertise that allows Yukon Electrical to, if necessary, exit the project after the pilot period without having invested the full capital required. This allows Yukon Electrical to evaluate on a go-forward basis the contractual arrangement for equipment and services. The cost of equipment is only one part of the lease arrangement. Yukon Electrical has taken the lease approach to secure an inclusive expert provider of natural gas rather than a consortium of consultants, equipment providers and specialized service providers. This bundled approach with ATCO Gas includes LNG storage and vaporization services along with their expertise related to systems design, purchasing, installation, commissioning, on-going operations support, maintenance, permitting, licensing for the project, regulator support, Health Safety and Environment policies, procedures and work instructions, regulations and safety. The equipment includes an LNG Facility comprised of on-site storage of LNG, LNG vaporizer and controls, natural gas odorizer, metering and facility safety systems.

(c) Yukon Electrical presently has a provider to supply diesel fuel for use in the Watson Lake Power Plant. Yukon Electrical has the expertise to utilize a new fuel and requires a supply of natural gas at the plant site to implement the bi-fuel project. Yukon Electrical contemplated the approach to consolidate a

consortium of consultants, equipment providers and specialized service providers. Yukon Electrical looked for a solution to minimize the risk to the project and determined that working with an affiliate with the necessary capabilities provided a more secure approach. The equipment being utilized is acquired utilizing ATCO Gas' competitive procurement process that involves engineering, financial and purchasing professionals. Yukon Electrical is involved in each step of the development of this system to ensure appropriate procurement methods are used and that cost expenditures are prudent. A competitive process was also used to secure LNG transportation services.

(d) A competing lease provider was not in the market at the time to meet the needs of the Watson Lake project in 2012. At that time, there were also no regulations, permits or procedures in the Yukon related to this unique project. To derive the lease price, ATCO Gas utilized a competitive procurement process that involved engineering, financial and purchasing professionals to assemble the combination of equipment and services. Yukon Electrical was involved in each step of the pricing process that went into the confidential contractual arrangement. Yukon Electrical has continued to investigate comparative benchmark pricing related to other service providers that may become available.

YUB-YECL-14

Reference: Application, Appendices - Business Cases, Appendix 1 and Appendix 2

Issue/sub-issue: Fish Lake projects

Request:

(a) Please provide the 2014 Dam Safety Report and water licence HY12-065, referred to on page 1 of Appendix #2.

Response:

(a) Please refer to YUB-YECL-14(a) Attachment 1 for the 2014 Dam Safety Report and YUB-YECL-14(a) Attachment 2 for the Water Licence HY12-065.

YUB-YECL-15

Reference: Application, Appendices – Business Cases, Appendix 5

Issue/sub-issue: Old Crow Unit #3 replacement

Quote: "The original budget for this project as per the 2013-2015 GRA was $500,000. The primary drivers for this cost increase are:

- Realization of actual costs based on previous projects in regards to construction and logistics of work completed within the isolated, fly-in only community;
- Understanding of construction and engineering requirements of installations carried out within the new facility; and
- Increase in physical size of unit, and associated costs in respect to transportation and installation as unit has to be disassemble for transport and reassembled on site."

Preamble: The total cost for this project is forecast to be $1,262,000 compared to the $500,000 that was originally forecast in YECL's 2013-2015 GRA. YECL submitted that "The cost differential between a typical 285kW (based on a bids received for the Beaver Creek #2 Replacement) and 600kW unit is approximately $60,000." Further information is required.

Request:

(a) Please provide further clarification and assign the relative cost increases for each of the bulleted items in the quote above.

Response:

(a) Here is further detail with regards to each of the above bullet points:

Bullet 1 – Logistics Experience

AEY has been operating and working in Old Crow for many years and there has been a significant amount of generation projects that have been completed since 2013. The projects have been challenging from the technical and operational aspect and, given that Old Crow is such an isolated community, logistically complex. A significant amount of experience has recently been gained through the construction of the new plant building and the installation of Old Crow Unit

#4. This experience is being leveraged to update estimates for the Old Crow Unit #3 Replacement business case.

The relevant aspects of logistics that are causing an increase in the estimate are;

- Tools and/or materials that are not available when required can significantly affect cost and schedule as the options for local procurement are extremely limited. There is a balance that needs to be managed between bringing enough extra materials to avoid this issue and paying freight charges on unnecessary items.
- There are limited guarantees when it comes to shipping and transportation to Old Crow. Unless an aircraft is chartered, there is no assurance that cargo (tools, material etc.) will make the intended flights. This causes delays in construction and extra crew hours. Extra contingency is required to be able to respond to this uncertainty.
- Unexpected complications can and will happen in large complex projects. The cost of responding to these scenarios is high when working in Old Crow due to logistical constraints. Additionally, Old Crow has some unique risks such as weather delays for shipping and transportation of crews to site that make these unexpected complications more likely. Extra contingency is required to be able to respond to this uncertainty.

Overall the experience of the logistical challenges faced with carrying out construction in the isolated community resulted in an increase of $168,000 to the revised estimate for this project

Bullet 2 – Design & Construction Requirements

There are some requirements for the installation of a unit within the new power plant facility that differ from replacement of a unit in an existing power plant. In respect to design and construction the following items were drivers for the revised cost for this project;

- There are additional seismic restraint requirements since this facility must be designed to operate post disaster.
- Requirement for supply and connection to the newly installed joint waste heat system utilized by both plants.
- Connection costs to a modern control system.

The requirements to integrate into the new facility resulted in an increase of $215,000 to the revised estimate for this project

Bullet 3 – Transportation and Handling of Unit

Installing a larger capacity unit comes with some additional costs as identified below;

- The 600 kW unit needs to be disassembled and reassembled in order to be shipped via aircraft.
- The 600 kW unit requires a large aircraft (even after disassembly) to be shipped.

The requirements of shipping a physically larger unit to site resulted in an increase of $98,000 to the revised estimate for this project.

The remaining cost difference of $280,000 is accounted for in the cost increase for the unit from the original estimate prepared for the 2013-2015 GRA as well as project management and engineering as note in the table below. When the original estimate was made in 2013 the preliminary costs for a 250 kW unit were $200,000. The final cost for the 600 kW unit is $390,000.

Task	Cost Increase ($000)
Bullet 1 - Logistics	168
Bullet 2 - Design & Construction	215
Bullet 3 - Transportation of Unit	98
Unit increase from original estimate	190
Project Management & Engineering	90
Total Variance	761

YUB-YECL-16

Reference: Application, Appendices – Business Cases, Appendix 8

Issue/sub-issue: McIntyre Subdivision replacement project update

Preamble: The Board requires further information.

Request:

(a) Table 1,[13] included in the project post completion summary, indicates that the installation of a main underground feed to the subdivision, at a cost of $379,000, (greater than one-half of the $728,000 total variance) was not included in the original business case scope. In the updated project scope, YECL indicated that the final portion of the main underground feed to the subdivision was installed. Please explain why the main underground feed to the subdivision was not included in the original business case scope.

(b) Please explain how the cost of the temporary overhead shadow electrical system (line, transformers, low voltage pedestals, etc.) is being expensed. Specifically address whether, once the system is not required and has been removed, the costs or a portion thereof are to be credited back to customers? Please provide an estimate of the shadow electric system equipment, other than line, that has been used on the project to date.

(c) Please explain what is meant by low voltage service lines to residences. In the original project description (2013-1015 GRA), YECL submitted that the majority of the low voltage service lines to residences would not be replaced. Is this still the case?

(d) In the original project description, YECL also stated that the electrical infrastructure in the undeveloped areas of the subdivision would not be replaced until an agreement was put in place to replace the infrastructure when the area was developed. Please provide an explanation if anything has changed regarding this assumption per the new business case.

(e) Does the replacement of streetlights to the roadway lighting standard include LED lamps?

[13] Application, Section 11, Attachment 11.4, McIntyre Subdivision Stage 1, page 2.

(f) Do the updated total project costs include the costs to remove the temporary overhead shadow electrical system? If not, please provide a forecast for dismantling the temporary system.

Response:

(a) The McIntyre Subdivision Replacement Project requires a new 25kV feed into the subdivision. The project team identified this need for the McIntyre subdivision. However, as project planning proceeded, it was determined that the original design of the 25 kV feed would not have sufficient capacity for the area's long term system plan. Therefore a higher capacity feed (larger conductor and equipment ratings) on a new and longer alignment was required.

(b) In Appendix 8 – McIntyre Subdivision Replacement Project Update, Table 1 on page 3 provides the 2013 actual costs for the temporary overhead system at $656,000. These costs have been capitalized and included in rate base as part of the first stage of this project. Once the project is completed any portion of the overhead that is dismantled will be salvaged out and retired through ordinary course.

(c) Low voltage lines to residences are the 120/240V underground cables from the low voltage pedestals to the meter base on each residence. The lines being replaced in this project are the high voltage lines (25kV lines replacing 35kV lines) and low voltage feeder lines (large 120/240V cables) between transformers and pedestals that carry the load of several houses. The low voltage lines to the residences will not be replaced as part of this project, consistent with the information provided in the 2013-2015 application.

(d) The electrical infrastructure in the undeveloped areas of McIntyre subdivision will not be replaced as part of this project as stated in the original business case.

(e) Yes, the streetlights to be installed in McIntyre subdivision will be LED.

(f) Yes, the estimates presented in the application include costs to dismantle the temporary overhead shadow electrical system.

YUB-YECL-17

Reference: Application, Appendices – Business Cases, Appendix 9

Issue/sub-issue: Downtown Whitehorse capacity upgrade

Quote: "Load growth in downtown Whitehorse related to increasing population and new construction is causing load restoration during contingency to become inadequate. Without immediate action the system will not be able to serve the needs of existing and future customers, longer power outages are likely to occur as contingency plans become inadequate, key equipment life expectancy will be reduced, and system operation may become hazardous.

"To proactively mitigate these issues, ATCO Electric Yukon is recommending the following work be completed in 2016 & 2017:

- Install a new 34.5kV to 12.5kV Selkirk Substation in Riverdale to increase capacity in downtown Whitehorse and provide contingency options to mitigate the duration of power outages;
- Replace the existing river crossing with larger wire and underground cable; and
- Install new switching points to allow for effective system operation."

…

"Several specific issues have been identified as requiring immediate attention to avoid compromising the safety and reliability of the power system. The work completed in 2014 and 2015 aligns with the updated scope of the project. An overview of the system configuration is also presented below. Further detail is available in the technical appendix."

Preamble: In its 2103-2015 GRA,[14] YECL submitted that since 2010, load growth in the downtown core of Whitehorse had increased significantly. As a result, loading on the 12.5kV system was at or near capacity in a number of areas in the downtown core. YECL also stated that the conversion of the Whitehorse downtown core to 25kV had been identified in YECL's long-term system plan since 1996. As a result, all new transformers installed in the downtown core as well as all electrical equipment in the Shipyard substation were of a dual-voltage configuration (12.5kV/25kV). Moreover, the conversion to 25kV would allow the existing conductors that are near capacity limits to safely handle increased loading.

[14] Business Case #24, Downtown Whitehorse 25kV Conversion business case

Request:

(a) Please indicate where in its last GRA, YECL identified that the first phase of the Downtown Whitehorse 25kV Conversion business case was to install an underground loop to allow easier shifting of load on downtown infrastructure.

(b) Please indicate where in Appendix #9, the technical appendix referred to in the above quote can be found.

(c) Please detail the "…work completed in 2014 and 2015 [that] aligns with the updated scope of the project."[15]

(d) YECL describes three stages of construction in the project scope section on page 4.

a. With respect to the Selkirk Substation installation, will the electrical equipment in this substation be of a dual-voltage configuration to allow for future conversion to 25kV?[16] If not, please explain and provide the additional costs for dual-voltage electrical equipment.

b. With respect to reconductoring the south river crossing, would the conversion to 25kV, alleviate the need for reconductoring? Please explain the reasons underpinning the change out of the conductor. Does the current river crossing have overhead conductor and underground cabling?

(e) With respect to alternatives 2(a) and 2(b) presented on page 6, YECL submits that the alternative 2(b) has been rejected "at this time" as it adds more capacity over what is currently required, and is at a significantly higher cost than other alternatives. When future capacity is required in the area, will the increase in future costs be over and above the differential in costs between the alternatives 2(a) and (b)? Why has future expansion not been considered at this time?

(f) Is it correct that, in addition to the new 25kV substation in Riverdale on Selkirk Street, either of the two alternatives presented on page 6, are to be considered in respect of the 25kV conversion of downtown?

(g) YECL submitted a system performance optimization alternative (page 7). Other than the installation of additional switches, will any other optimization options be considered as part of YECL's preferred option? Please explain.

[15] Application, Appendix #9, page 2.
[16] Application, Appendix #8, McIntyre Subdivision Replacement, page 1; "25kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers due to proper regulation of the electrical system."

Response:

(a) In the YECL 2013-2015 GRA filing, in Business Case #24 Downtown Whitehorse 25kV Conversion under the project description it states:

This project will consist of the following:

- *Change out necessary insulation, switches, transformers and lightning arrestors to 25kV rating*
- *Establish, by specific distribution line, which area will be converted*

During project planning, specifically in establishing which areas were to be converted, it was found that a new underground loop in the south section of the Downtown core would greatly facilitate the ability to transfer load on the distribution system, provide contingency and eventual conversion. The ability of the 12.5kV and 25kV segments to be energized from two directions (loop feed) during conversion will minimize outage times and expedite construction.

(b) Please refer to YUB-YECL-17(b) Attachment 1 - Downtown Capacity Improvement Technical Appendix.

(c) The work completed in 2014 and 2015 was to prepare the loop connection as noted in response YUB-YECL-17(a). This aligns with the updated scope of the project by:

- Providing flexibility for transferring and balancing loads between Shipyards and Selkirk substations.
- Providing the desired loop feeds for an eventual conversion to 25kV.
- Providing another contingency feed in to the Downtown core.

Additionally the process for securing land for the Selkirk substation was initiated under a 2015 project and completed in 2016.

(d)

a. All equipment is of a dual-voltage configuration.

b. Conversion to 25kV would alleviate any immediate need for reconductoring the south river crossing.

The driver for reconductoring the river crossing is capacity during contingency. Several contingency/switching scenarios would require transferring load onto this river crossing. At a system voltage of 12.5kV the

capacity of the river crossing would be exceeded in the following scenarios (under peak load):

- Loss of S1023 in Shipyards Substation
- Loss of regulators R80, R81, R82 in Shipyards Substation
- Loss of transformer T1 in Shipyards Substation
- Loss of switchgear S1034 or S1015 in Shipyards Substation
- Loss of S7191 in Services Substation
- Loss of regulators R15, R20, R21 or R16, R17, R19 in Services Substation
- Loss of transformer T1 or T2 in Services Substation

The river crossing has both overhead conductor and underground cabling. More specifically the river is crossed by 2/0 ACSR overhead conductor which immediately connects to 350 MCM underground cable on the downtown (west) side of the river.

(e) In evaluation of viable alternatives, AEY was focused on alternatives that would address the primary driver of load growth, and corresponding system demands from it, in downtown Whitehorse. Alternative 2 was a full 25 kV conversion of downtown Whitehorse which would require two new 25 kV substations; one at the south end and one at the north end of downtown. Alternatives 2(a) and 2(b) identify two options for a location of a north substation; option (a) top of Two Mile Hill and option (b) bottom of Two Mile Hill. The south 25 kV source (Selkirk substation) has the location already secured. The alternative of a 25 kV conversion was rejected at this time as it provides more capacity than needed at a higher cost than compared to the chosen solution; Alternative #4. Future expansion has been fully considered. When future capacity is required a site option, either 2(a) or 2(b), will be selected for a north substation which will meet the requirements of the system at that time. The 3 stages of the project for the test period; Selkirk substation, River crossing reconductor and installing switching points will all be used and useful for the eventual 25 kV conversion of the downtown core.

(f) Yes. To facilitate the eventual conversion of the Downtown core to 25 kV, there has to be source substations to the North and South of the Downtown core. Installing the Selkirk Substation in Riverdale establishes a substation to the South. Alternatives 2(a) and 2(b) are two potential options for a North substation.

(g) The options discussed under this alternative are still being investigated as they would be able to provide a short term solution as load grows in the future.

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Downtown Whitehorse Capacity Improvement

Technical Appendix

Revision History

Revision	Date	Editor	Comments
R0	January 20, 2016	Tom East	Issued for Review [DRAFT]
R0.1	February 4, 2016	PB, JW, SC	Comments Submitted
R0.2	February 17, 2016	Tom East	Updated Draft

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1. Problem Statement

The downtown Whitehorse area averages about 2-4% peak load growth per year. At present, certain system components in downtown are heavily loaded, significant contingency scenarios cannot be adequately addressed, and restoration after outages is challenging and slow. Furthermore, this issue will continue to become worse as load continues to grow. Steps towards accommodating this load growth need to be taken to ensure continued safe and reliable operation of the power network.

2. Background

Load growth continuously pushes a power system closer to its capacity limits. This leads to electrical equipment being operated past its capacity which compromises the safety and reliability of the network.

To understand the problem statement in more detail we can consider how the downtown Whitehorse system is configured, how the load has grown in the past, how we expect it to grow in the future, and at what point the load is higher than the system's capacity.

2.1 System Configuration

Downtown Whitehorse is supplied power from two separate sources: S17 in the North through Services Substation and S150 in the South through Shipyards Substation. There are many interconnection points between these two sources which allows for a variety of system configurations. In figures 1 & 2 below see the normal operating configuration of the system.

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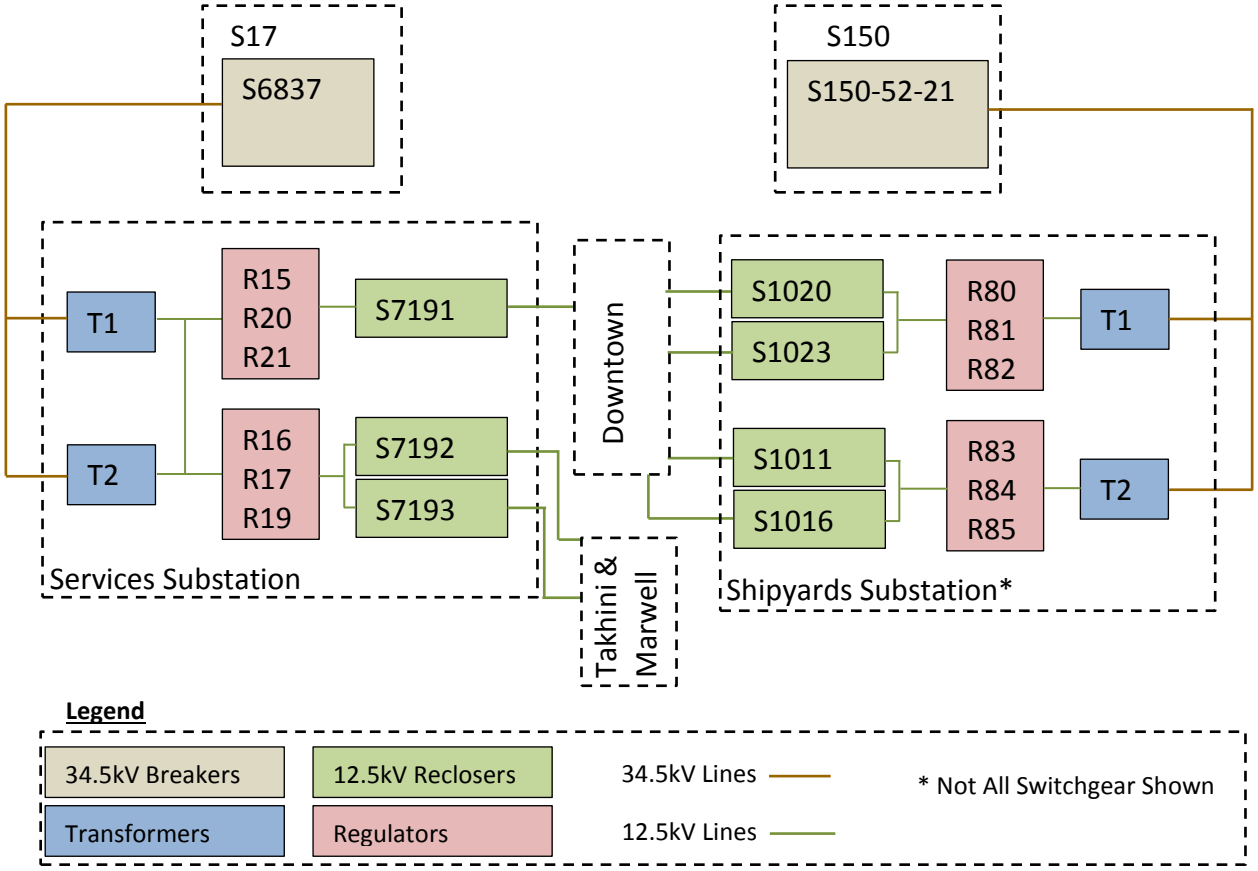

Figure 1 – Downtown Whitehorse Overview

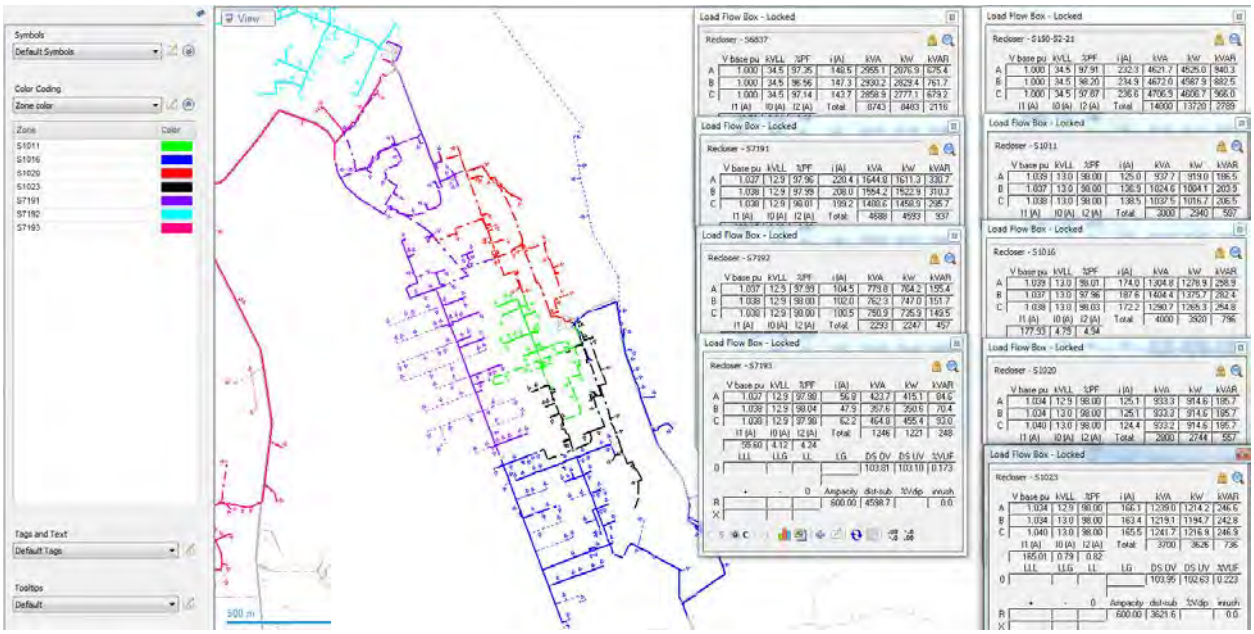

Figure 2 – Downtown Whitehorse Model with 2015 Peak Loads

2.2 Historical Load Growth

Over the last 10 years the Yukon Interconnected System (WAF-MD) has experienced an annual average peak load growth of 3.1%.

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak Load (MVA)	60.7	65.0	63.1	67.5	69.0	72.6	76.3	82.2	82.7	76.5	82.1
Percent Change (%)	-1.27	7.18	-3.03	6.97	2.34	5.14	5.17	7.72	0.54	-7.45	7.23

Figure 3 – Peak Load (Hourly) on the Yukon Interconnected System from 2005-2015

In order to understand the wide variations in peak load it is important to understand that load in the Yukon is highly correlated to temperature. A year with a cold winter have a higher peak than a later year with a warmer winter. In the long term however the base load in the Yukon is increasing.

Looking specifically at the City of Whitehorse (load fed from S150, S17, and S164) there is an annual average peak load growth of 2.4%.

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Peak Load (MVA)	51.5	50.8	51.5	51.5	53.6	52.7	60.1	63.5	59.7	63.9
Percent Change (%)		-1.40	1.36	-0.02	4.03	-1.67	12.19	5.45	-6.47	6.61

Figure 4 – Peak Load (Hourly) on the Whitehorse System from 2006-2015

Disaggregated data for this 10 year period is not available for downtown Whitehorse specifically. To understand the expected load growth in downtown, the load growth drivers are considered.

2.2.1 Overall Trends

Since the combined load on S150, S17, and S164 represents approximately 75% of the WAF-MD load, it is not surprising that the growth in Whitehorse mimics the growth on the overall system. Similarly, downtown comprises approximately 45% of the total load on the Whitehorse system (or 33% of the total WAF-MD load) as seen in figure 5.

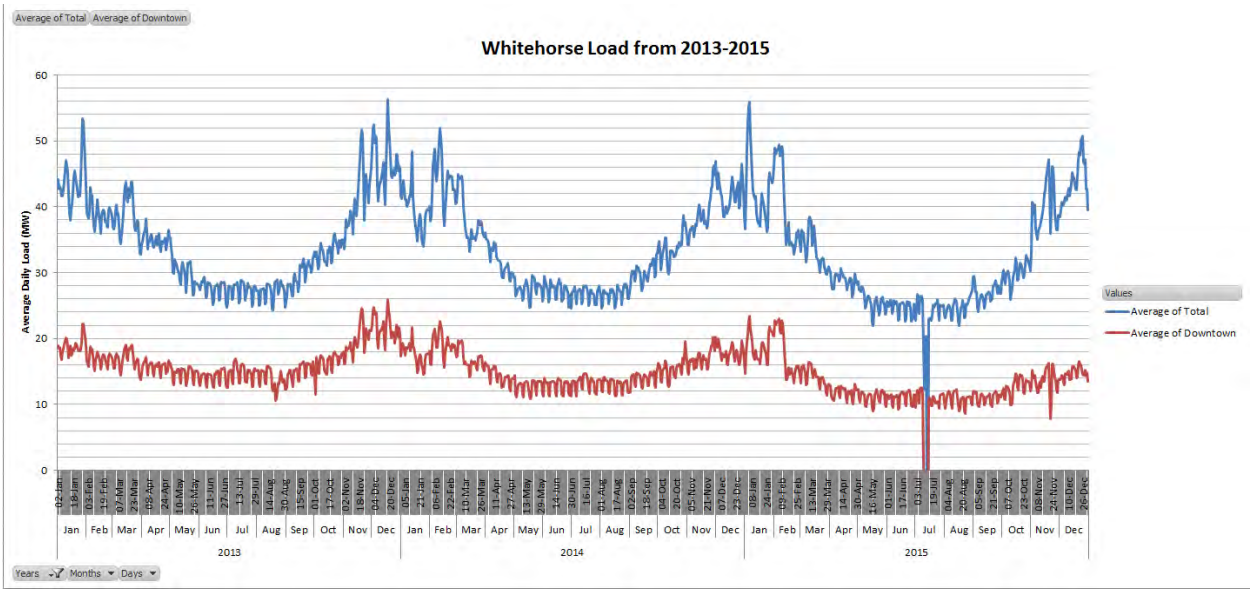

Figure 5 – Average Load (Daily) on Whitehorse and Downtown from 2013-2015

Thus downtown Whitehorse is a significant component of the load in Whitehorse and of the total load in the territory. The overall trends of the in Whitehorse and in the territory should be comparable to those specific to downtown.

2.2.2 Population Growth

The Whitehorse area has experienced an average annual population growth of 2.0% over the last 10 years with a growth of 0.6% in the last 12 months. Since 2011 the most significant growth has occurred in Whitehorse West (e.g. Copper Ridge), however downtown has also seen an average population growth of approximately 0.9% annually in that time period.

Increasing population translates into increasing electrical load. This effect is more pronounced for new households than for increased size of existing households.

2.2.3 New Developments (Residential & Commercial)

There have been many new developments and housing projects constructed within the last few years in Whitehorse which has led to higher-than-average growth recently. Because of the small size of Whitehorse, large developments have significant impact on load growth and they are a large part of the reason that load growth is very volatile from year to year.

There are several large developments planned for the future which implies high growth in the coming years. For example, some of the large expected incremental loads in 2016 include:

- Whitehorse General Hospital (150kW)
- New Sarah Steele Building (230kW)
- Salvation Army Re-development Project (70kW)
- Municipal Services Building (100kW)

2.3 Forecasted Load Growth

From reviewing the historical data and upcoming development it is expected that load in downtown Whitehorse will grow in the range of 2-4% when averaged over the next 10 years. To account for a range of possible scenarios, average load growth rates of 1.0%, 3.0%, and 5.0% are considered.

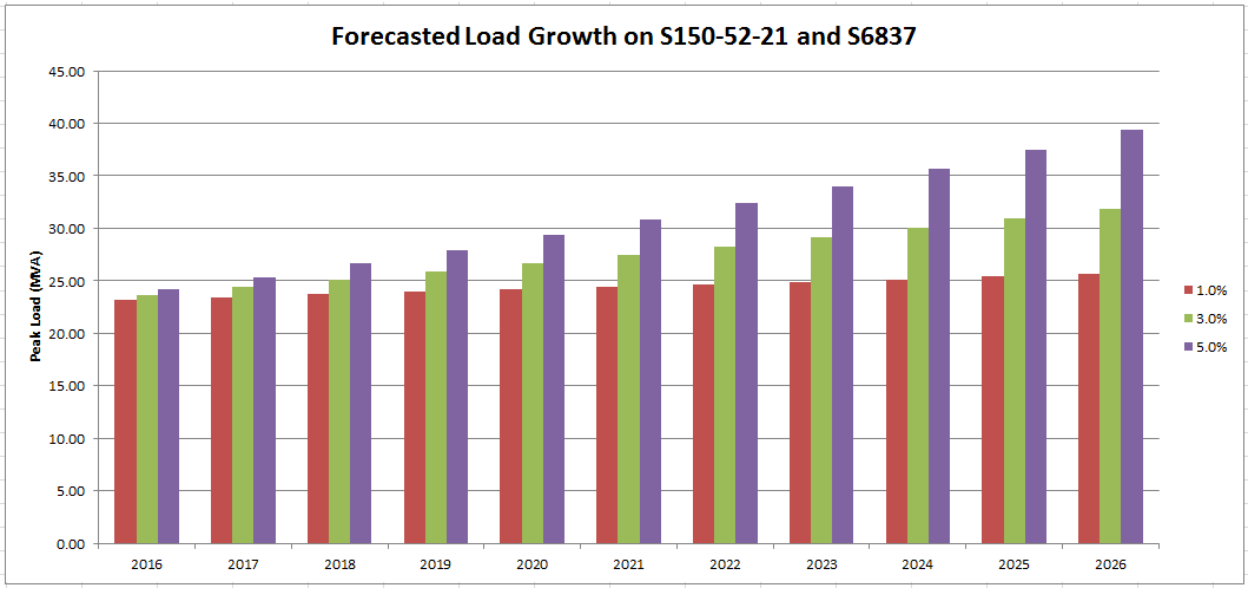

Figure 6 – Forecasted Downtown Peak Loads (10 year)

2.4 System Limitations

For any given load in the downtown Whitehorse system, power flows through the following configuration:

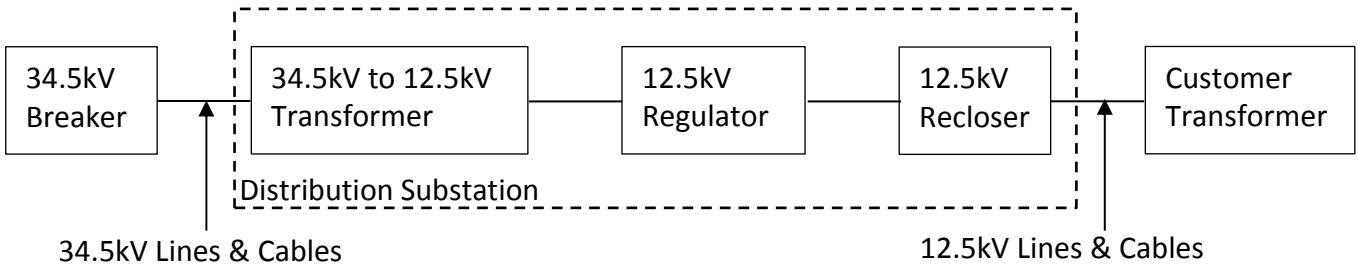

Figure 10 – Basic Structure of Whitehorse Distribution System

Each of these components has a capacity rating which must be separately considered to ensure no ratings will be exceeded. The table below gives an overview of the relevant system ratings for downtown Whitehorse.

Device	34.5kV Breakers	34.5kV Lines & Cables	34.5kV/12.5kV Transformers	12.5kV Regulators	12.5kV Reclosers	12.5kV Lines and Cables
Description	-Interface between YEC and AEY	-266.8/297 ACSR -500 MCM Al	-2x7.5MVA in Services -2x10MVA in Shipyards	-1 set of 3 regulators per transformer	-1-2 per regulator	-266.8/297 ACSR -750 MCM AL -Various smaller feeders
Ampacity	≥600A	266.8 ACSR – 640A 500MCM – 420A	7.5MVA – 347A 10MVA – 463A	400A-438A	600-630A	266.8 ACSR – 640A 750 MCM – 510A

Figure 11 – System Components and Capacities

Note that Shipyards Substation also has 3 pieces of switchgear (S1034, S1015, & S4102) that each have a 600A rating. Although they are not shown in this table, they are considered in this analysis.

Generally speaking, overloading a device will cause it to fail before it reaches its life expectancy. Depending on the degree of overload this could mean something as benign as shortening the lifespan of the device by a few years to something as catastrophic as explosion of oil-filled equipment.

3. Evaluation Criteria

The key measure of success for a utility is whether power is being safely supplied to customers or not. When considering the impact of a change to the system it is important to consider whether it will:

1. Impact our ability to supply power safely
    - Voltage, frequency, and harmonic content within tolerances
    - Electrocution and arc hazards adequately mitigated
    - Infrastructure and equipment operated within capacity limits
    - Infrastructure and equipment in operable condition (e.g. not end-of-life, acceptable risk of failure)
2. Impact our ability to supply power to customers continuously
    - Alternate feeds or quick repair times (i.e. contingency plans) are in place
    - Timely 24/7/365 response to outages

- Appropriately configured protection (reliability, selectivity, speed)
- Power can be restored after an outage (cold load pick-up, block load reserve, switching transients)
- Potential outage causes are mitigated

The downtown Whitehorse system was assessed based on these considerations as well as the constraints and forecasted loads in Section 2 to determine if any issues arising from load growth are expected. The following concerns in particular warranted further examination:

1. Can the system handle peak load during regular operating scenarios?
2. Is there capacity to accommodate load addition?
3. Is it possible to transfer peak load during contingency scenarios?
4. Can power be quickly restored to customers following an outage?

ATCO Electric has established criteria around each of these points that are used to determine if upgrades are required. These criteria help to preemptively address operational constraints that could inhibit safe, reliable operation of the system.

3.1 Regular Operation

No components of the system should have load in excess of their nameplate rating during peak load conditions.

This is to ensure safe operation of equipment and to preserve the lifespan of the electrical infrastructure. The exception to this is for transformers which can handle some amount of overload depending on duration and ambient temperature.

3.2 Load Addition

Substations and main feeders should have sufficient reserve capacity.

This is to handle routine load additions/growth and to provide lead time for system upgrade projects to take place before critical thresholds are exceeded. Sufficient reserve capacity is assessed by looking at the peak load growth that is expected in that area in a 5 year planning window.

3.3 Contingency

The peak load on major equipment (e.g. transformers, regulators, reclosers) in systems that warrant loop connections should be able to be transferred to another power source.

This is to maintain service to customers during equipment failure, faults, or maintenance work. When a portion of the system needs to be removed from service, any downstream load will experience an outage unless that load can be transferred to another source.

In order for this to be a viable tool for maintaining system reliability, the alternate source must be able to handle the load addition in a worst-case scenario. This would be the loss of major equipment such as transformers, regulators, or reclosers during peak load as indicated in the criteria.

Note that for small amounts of load, particularly on overhead systems, loop connections are not warranted. Outage scenarios can be managed through the use of portable generation, temporary feeds, and through quick repair times on overhead system components.

3.4 Power Restoration

Critical loads should be restored within 4 hours (includes residential and commercial customers). All loads should be restored within 24 hours.

It is always our priority as a utility to restore power as soon as it is safe to do so; however, when it comes to proactively preparing for outages it is important to balance cost with needs. ATCO Electric has established a target of restoration within 4 hours for critical loads and we use this target in our planning and design decisions.

This is to help mitigate the potentially serious consequences of losing power. Some crucial loads (e.g. communications, hospitals) have their own back-up systems; however, many customers depend on electrical service for heating, cooking, and other critical functions.

4. Technical Review

Using the evaluation criteria listed above, for downtown Whitehorse we have the following:

4.1 Regular Operation

- *No system components are currently overloaded*
- *Shipyards Substation is expected to be overloaded as early as 2020*

Currently no system components are overloaded. With the exception of transformer/regulator pairs in both substations, the majority of components of the system are lightly loaded as seen below.

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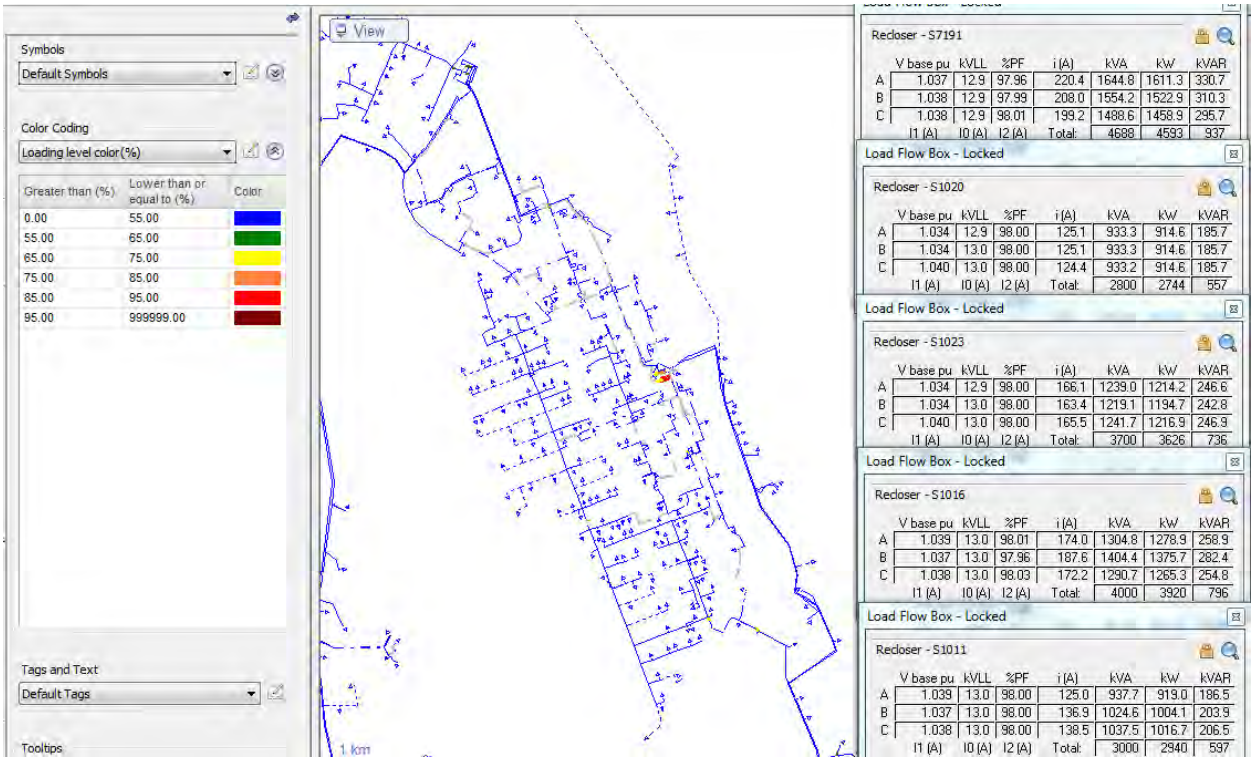

Figure 12 – Downtown System Loading Model

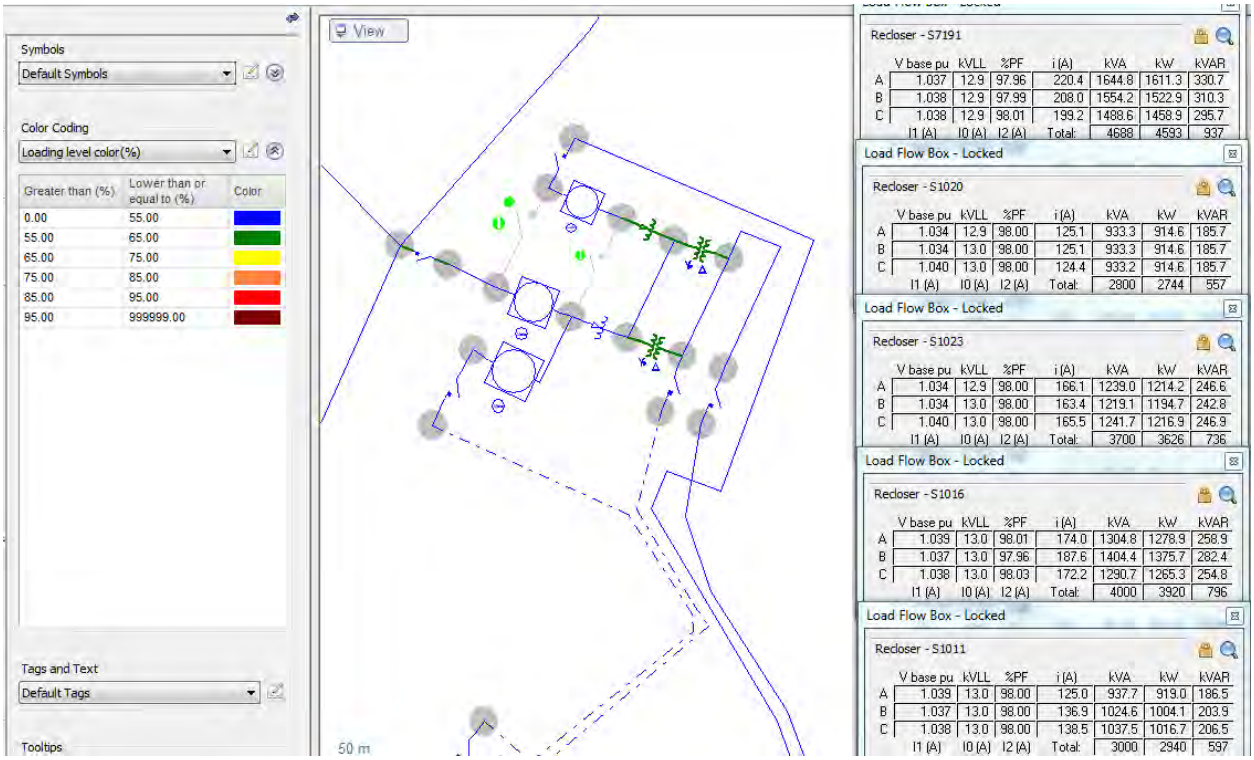

Figure 13 – Services Substation Loading Model

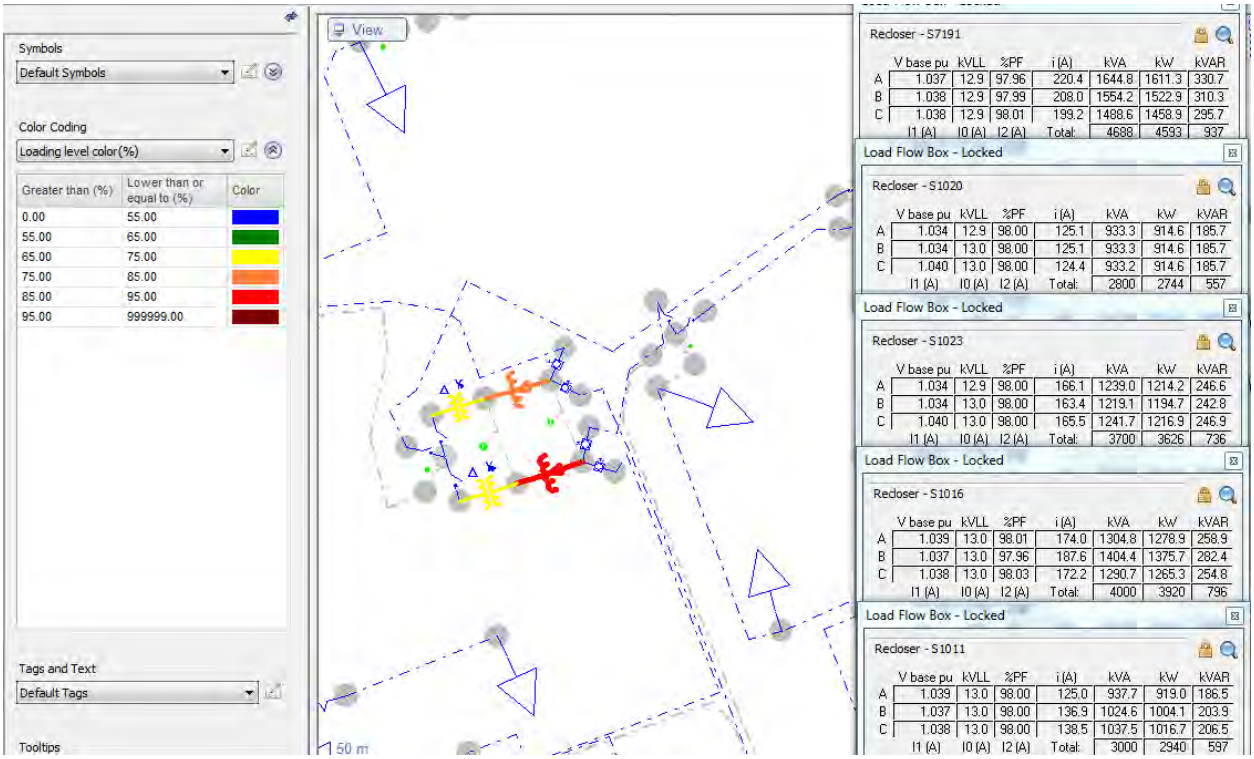

Figure 14 – Shipyards Substation Loading Model

Using the projected load growth numbers of 1.0%, 3.0%, and 5.0% from 2016-2026, the years that overload is expected are:

Device	Ampacity	Forecasted Load Growth		
		1.00%	3.00%	5.00%
S6837	1250A			
34.5kV Lines	420A			
Services T1	347A			
R15, R20, R21	438A			
S7191	630A			
12.5kV Lines	640A			
Services T2	347A			
R16, R17, R19	438A			
S7192	630A			
12.5kV Lines	640A			
S7193	630A			
12.5kV Lines	640A			
S150-52-21	600A			
34.5kV Lines	420A			
Shipyards T1	462A			2024
R80, R81, R82	400A		2025	2021
S1020	600A			
12.5kV Lines	510A			
S1023	600A			
12.5kV Lines	510A			
Shipyards T2	462A			2023
R83, R84, R85	400A		2023	2020
S1011	600A			
12.5kV Lines	510A			
S1016	600A			
12.5kV Lines	510A			

*Blanks indicate load is not expected to exceed ratings before 2026

Figure 15 – Forecasted Overload Years for Downtown Infrastructure

It is clear that there is an upcoming problem with transformer/regulator capacity in Shipyards substation, but the problem is not imminent for regular operation scenarios.

4.2 Load Addition

- *Regulators R83-R85 are loaded to >80% during peak load conditions*
- *All other system components are loaded less than 80%*

As seen in section 4.1, there is a significant capacity margin available on most of the downtown infrastructure with the exception of R83, R84, and R85 in Shipyards Substation. As per the criteria, there should be sufficient system capacity such that no major system components will be overloaded within 5 years to allow for timely responses to load growth.

And so, referring to Figure 15 above, steps should be taken now to address upcoming capacity issues on both sets of regulators in Shipyards Substation. Noting that the transformers in Shipyards are expected to exceed capacity shortly after the regulators, a prudent plan would address the capacity of both sets of equipment.

4.3 Contingency

- *Critical contingency scenarios cannot be adequately handled and require complex switching operations to manage*
    - *The 34.5kV cable feeding into Services and Shipyards Substations will not be able to support contingency load in the near future*
    - *Regulator/Transformer pairs in Services and Shipyards substations do not have enough spare capacity to handle the load from an additional feeder*
    - *Sections of line along 6th Ave and at the south river crossing are unable to support contingency loading*

For the loss of any major piece of equipment or power line in downtown Whitehorse there needs to be a plan in place for how to restore power to as many customers as possible. Put into simplified terms, the peak load of any piece of equipment should be able to be moved to another piece of equipment through a manageable number of switching operations.

The cases to be considered are the loss of:

- Source from S17
    - S6837
    - 34.5kV Lines & Cables
- Source from S150
    - S150-52-21
    - 34.5kV Lines & Cables
- Services Substation Equipment
    - Transformers T1 & T2
    - Regulators R15, R20, R21*
    - Reclosers S7191*
- Shipyards Substation Equipment
    - 34.5kV Switchgear S1034
    - Transformers T1 & T2
    - 12.5kV Switch Cubes S1015 & S4102
    - Regulators R80-R82 & R83-R85
    - 12.5kV Switchgear S1010, & S1012
    - Reclosers S1011, S1016, S1020, & S1023

*Regulators R16, R17, R19 and Reclosers S7192 & S7193 do not feed downtown and are not considered in this study

In order for a contingency configuration to be viable, the system components should not become overloaded. For all of the contingency scenarios presented below it is possible to perform more complex switching operations to mitigate overloading on system components, however doing so increases the duration of the outage and is operationally undesirable as covered in section 4.4.

4.3.1 Loss of S17

In case of loss of supply from S17 (e.g. failure of S6837 or the 34.5kV line feeding Services) the load would be transferred on to S150-52-21 through the loop connection on the 34.5kV system (switch S1028 in Shipyards).

Currently this is a viable contingency plan; however, the following table shows the expected years that the relevant system components will no longer be able to handle this contingency scenario:

Device	Ampacity	Forecasted Load Growth		
		1.00%	3.00%	5.00%
S150-52-21	**600A**			2025
34.5kV Lines				
266.8 ACSR	**640A**			2026
500 MCM Al	**420A**	2024	2018	2017
S1034	**600A**			2025

*Blanks indicate load is not expected to exceed ratings before 2026

Figure 16 – Forecasted Year Overload Occurs – Loss of S17

As seen in the above table, the 150m stretch of 500 MCM Al underground cable (located between the Kwanlin Dün Cultural Center and Shipyards Substation) will no longer be sufficient to handle contingency scenarios in the near future.

4.3.2 Loss of S150

In case of loss of supply from S150 (e.g. failure of S150-52-21 or the 34.5kV line feeding Shipyards) the load would be transferred on to S6837 through the loop connection on the 34.5kV system (switch S1028 in Shipyards). This is the reverse of the contingency discussed in 4.3.1.

Currently this is a viable contingency plan; however, the following table shows the expected years that the relevant system components will no longer be able to handle this contingency scenario:

Device	Ampacity	Forecasted Load Growth		
		1.00%	3.00%	5.00%
S6837	**600A**			2025
34.5kV Lines				
266.8 ACSR	**640A**			2026
500 MCM Al	**420A**	2024	2018	2017

*Blanks indicate load is not expected to exceed ratings before 2026

Figure 17 – Forecasted Year Overload Occurs – Loss of S150

As seen in the above table, the 140m stretch of 500 MCM Al underground cable (located between Walmart Cultural and Services Substation) will no longer be sufficient to handle contingency scenarios in the near future.

4.3.3 Loss of Services Substation Equipment

Although there are many potential points of failure within a substation, for the sake of contingency analysis many failures have exactly the same effect. Consider the Services Substation diagram below:

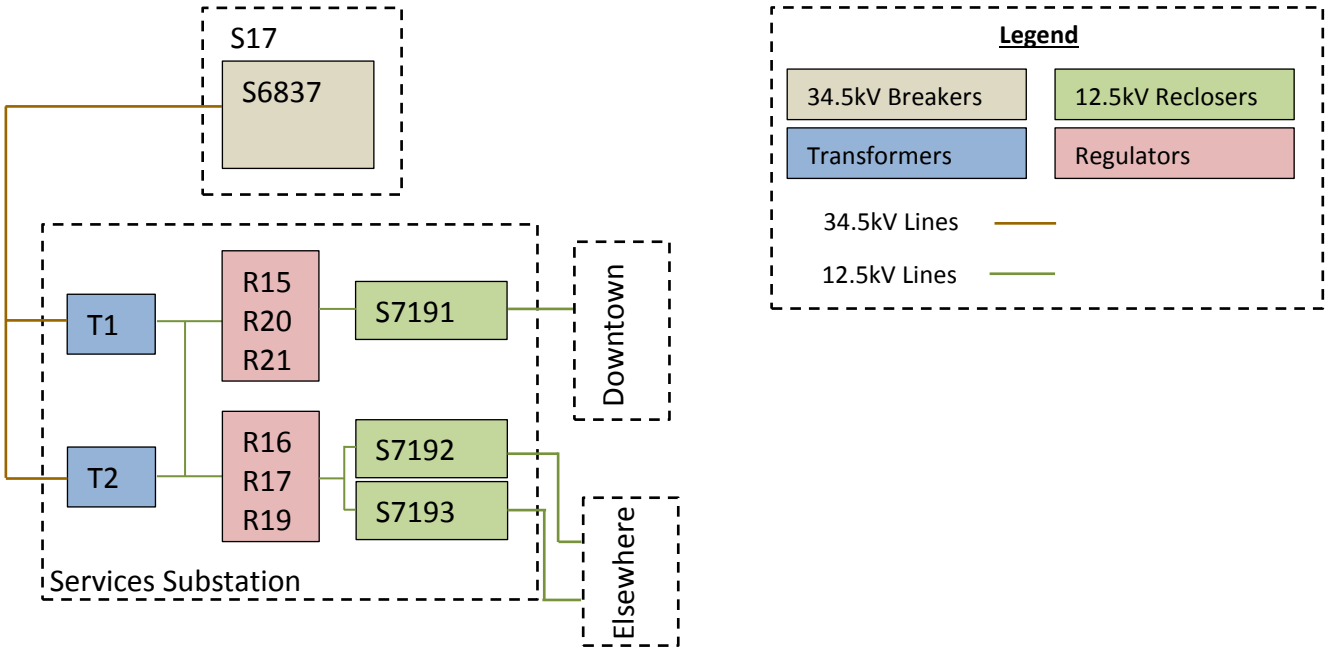

Figure 18 – Services Substation Overview

We can simplify the possible points of failure into the following 2 contingencies:

- Loss of R15, R20, R21
- Loss of R16, R17, R19

Any other failure is either equivalent or less constraining than these. Note that losing either transformer in Services Substation effectively halves the substation capacity since the transformers are paralleled together and the have very similar %Z values. Since regulators R15, R20, and R21 supply more than half of the substation load, the loss of T1 or T2 is less strict than losing these regulators. Because this study focuses on downtown, only the loss of regulators R15, R20, and R21 is considered.

In this contingency scenario the load on S7191 needs to be transferred to another recloser. The following table lists the potential reclosers and concerns with each:

Recloser (N/O Switch)	Notes
S1020 (S9971)	Overloads regulators R80-R82, transformer T1 in Shipyards
S1016 (S7178)	Overloads regulators R83-R85, transformer T2 in Shipyards Overloads 6th Ave and South River Crossing 12.5kV lines
S1011 (S4598)	Overloads regulators R83-R85, transformer T1 in Shipyards
S7193 (S3756)	Overloads regulators R16, R17, R19 in Services

Figure 19 – Contingency Analysis, Loss of R15, R20, & R21

Given current peak loading, there is no simple way to handle the loss of R15, R20, & R21. Further load growth will increase the problem such that the contingency will be unmanageable even in off-peak situations.

4.3.4 Loss of Shipyards Substation Equipment

Similar to section 4.3.3, we can reduce the number of contingency scenarios evaluated for Shipyards Substation. Consider the diagram below:

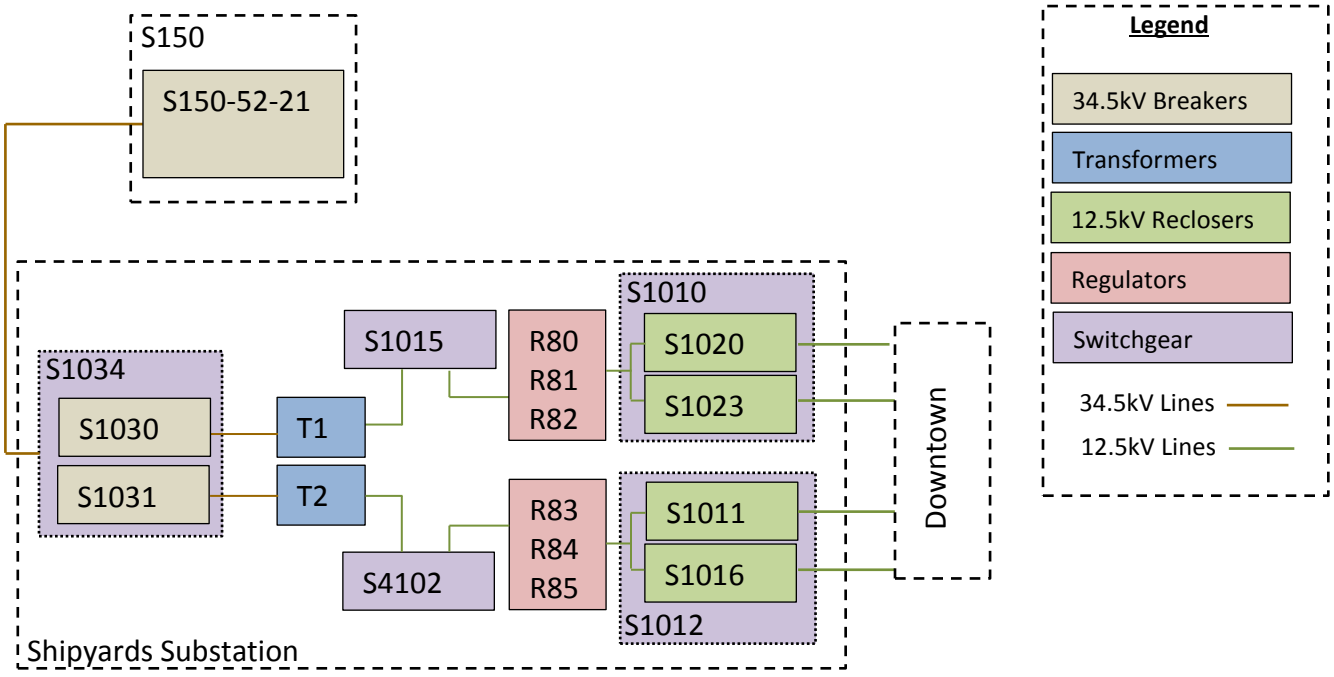

Figure 20 – Shipyards Substation Overview

A contingency scenario that can handle the loss of S1034 would also be capable of handling all other potential scenarios; however, it is also worth considering the loss of individual 12.5kV reclosers because it helps to illustrate the problem experienced when trying to reallocate load for the entire substation.

The following tables show the possible breakers that can be used to pick-up load in the case that any of the Shipyards reclosers fail:

Recloser (N/O Switch)	Notes
S7191 (S4598)	Heavily loads regulators R15, R20, R21 in Services (377A) Heavily loads 6th Avenue (250A on 2/0 ACSR)
S1020 (S8484)	Overloads regulators R80-R82, transformer T1 in Shipyards Overloads fuses S9507 (80A), S9971 (100A)
S1023 (S9945)	Overloads regulators R80-R82, transformer T1 in Shipyards Overloads alley between 2nd Ave and Front St. (Steele to Main)

Figure 21 – Contingency Analysis, Loss of S1011

Recloser (N/O Switch)	Notes
S1023 (S9804)	Overloads regulators R80-R82, transformer T1 in Shipyards Overloads fuse S9805 (80A)
S7191 (S7178)	Overloads regulators R15, R20, R21 Overloads 6th Avenue (300A on 2/0)
S6822 (S7228)	Overloads regulators R10-R12, transformer T1 in Lewes Blvd Sub *No overload if load from Lewes Blvd is transferred to Riverdale Sub (+4 switching operations)

Figure 22 – Contingency Analysis, Loss of S1016

Recloser (N/O Switch)	Notes
S7191 (S9971)	Heavily loads regulators R15, R20, R21 in Services (372A)
S1011 (S8484)	Overloads regulators R83-R85, transformer T2 in Shipyards Overloads fuses S9947 (Solid Barrel), S9507 (80A)

Figure 23 – Contingency Analysis, Loss of S1020

Recloser (N/O Switch)	Notes
S1011 (S9945)	Overloads regulators R83-R85, transformer T2 in Shipyards
S1016 (S9804)	Overloads regulators R83-R85, transformer T2 in Shipyards Overloads fuse S9805 (80A) Overloads South River Crossing

Figure 24 – Contingency Analysis, Loss of S1023

Thus the contingency plans for Shipyards substation in a peak-load scenario are:

Faulty Equipment	Recloser (N/O Switch)	Notes
S1011	S7191 (S4598)	From forecasted load growth rates this will not be a viable solution for long. Years of expected overload or regulators R15, R20, R21 are: 1.0% -> 2021 3.0% -> 2017 5.0% -> 2016
S1016	S6822 (S7228)	Also requires operation of S9499, S6817, S7215, and S3128 to transfer load from Lewes Boulevard Substation to Riverdale Substation. Expected to be a viable solution past 2026.
S1020	S7191 (S9971)	From forecasted load growth rates this will not be a viable solution for long. Years of expected overload or regulators R15, R20, R21 are: 1.0% -> 2022 3.0% -> 2018 5.0% -> 2017
S1023	None	No viable solution that doesn't require breaking the load across multiple breakers. Currently the best available option is to: • Move load from Lewes Blvd. to Riverdale (S9499, S6817, S7215, and S3128) • Spilt load on S1016 by operating S9562 • Split load on S1023 by operating S6639 • Move half the load onto S6822 by operating S7228 • Move the remaining load onto S1011 by operating S9945 This response is too slow/convoluted to be viable
S1010 or R80, R81, R82 or S1015 or T1	None	Same as loss of S1020 + S1023 Can't transfer load off of S1023
S1012 or R83, R84, R85 or S4102 or T2	S7191 (S4598) S6822 (S7228)	Same as loss of S1011 + S1016
S1034	None	Same as loss of S1011, S1016, S1020, and S1023 Can't transfer load from both S1011 and S1020 to S7191 (overload) Can't transfer load off of S1023

Figure 25 – Contingency Analysis Summary, Loss of Shipyards Substation Equipment

In summary, there are a number of contingencies without adequate responses. There may be complex alternatives available, but this is to be avoided because of the increased outage time and risk resulting from additional switching operations.

Even for the contingencies that have adequate responses, forecasted load growth rates indicate that in the near future these contingencies will no longer be easily managed.

4.4 Power Restoration

- *Complexity of required switching operations to restore from an outage is not manageable in an emergency situation*
    - *Cold Load Pick-Up makes restoration after extended outages difficult*
    - *Block Load Reserve Capacity and Distribution System Capacity restricts possible restoration plans*
- *Spares/Temporary bypasses are available for all critical equipment*
- *Loads are fed from more than one source*

Sections 4.1 – 4.3 consider how load growth affects the capacity of the system when the power is on; however, there are some additional factors that come into play when the power is already off. In particular, during restoration cold load pick-up needs to be managed to avoid exceeding distribution system capacity as well as exceeding block load reserve capacity at the generators.

4.4.1 Cold Load Pick-Up (CLPU)

Cold load pick-up is a phenomenon that occurs during restoration from extended outages. It can cause the system to experience 2-5 times the regular load for a period of minutes to hours. Based on experience, typically 200% of regular load for several minutes is assumed.

The basic mechanism of cold load pick-up is that electrical load loses diversity if it is offline for too long. Typically during the day loads will come online and offline intermittently either automatically (e.g. fridges, thermostats), or manually (e.g. stoves, laundry machines). When the power has been offline for an extended period of time and is then restored, many of those cycling loads come on at once and put abnormal strain on the system.

4.4.2 Block Load Reserve Capacity

Generators have a limited ability to handle the instantaneous addition of load, sometimes referred to as block loads. Trying to add block loads beyond the system's reserve capacity will cause stability issues that could result in an outage to the entire system. Because of the relatively small size of the Yukon Interconnected System there is very limited capacity to handle

the addition of block loads, which makes this a pertinent factor when restoring power to downtown Whitehorse.

Real-time discussions between Yukon Energy and ATCO Electric Yukon during restoration determine the maximum amount of load to restore at once. Typical values range between 2-3MVA.

4.4.3 Power Restoration of Downtown Whitehorse

It is difficult to restore power after the loss of any of the 12.5kV reclosers that feed downtown during peak load conditions. In 2015 the peak loads on these reclosers were:

Recloser	Peak Load (MVA)	Capacity (MVA)	Limiting Component
Services			
S7191	4.7	10	Regulators R15, R20, R21
Shipyards			
S1011	3.0	8.6	Regulators R83, R84, R85
S1016	4.0		
S1020	2.8	8.6	Regulators R80, R81, R82
S1023	3.7		

Figure 26 – 2015 Peak Loads on Downtown 12.5kV Reclosers

These loads may need to be restored in stages of 2-3MVA to avoid stability issues with the generators (block load reserve). In many cases this means that the load on any given recloser will need to be restored in stages. Under cold load pick-up scenarios where loads are expected to double it further becomes necessary to split up these loads.

In a quick restoration scenario (no cold load pick-up) during peak load the following switching (or similar) needs to occur:

Recloser	Switch	Stage 1 Peak Load (MVA)	Stage 2 Peak Load (MVA)
Services			
S7191	S7196 (G/S)	2.55	2.15
Shipyards			
S1011	S4597 (S/C)	0.70	2.30
S1016	S9413 (G/S)	2.35	1.65
S1020	S9876 (T)	1.40	1.40
S1023	S9363 (T)	2.50	1.20

Figure 27 – Quick Restoration Plan for Downtown

In a cold load restoration scenario during peak load the following switching (or similar) needs to occur:

Recloser	Switch	Stage 1 Peak Load (MVA)	Stage 2 Peak Load (MVA)	Stage 3 Peak Load (MVA)	Notes
Services					
S7191	S1261 (S/C) S7196 (G/S)	1.60 **(3.2)**	0.95 **(1.9)**	2.15 **(4.3)**†	No switch to split stage 3
Shipyards					
S1011	S4597 (S/C)	0.70 **(1.4)**	2.30 **(4.6)***†		No switch to split stage 2
S1016	S9562 (G/S) S9413 (G/S)	0.90 **(1.8)**	1.45 **(2.9)**	1.65 **(3.3)***†	No switch to split stage 3
S1020	S9876 (T)	1.40 **(2.8)**	1.40 **(2.8)**		
S1023	S6635 (T) S9363 (T)	1.30 **(2.6)**	1.20 **(2.4)**	1.20 **(2.4)**	

Values are reported as "Steady State Load **(Cold Load Pick-Up Load)**"
Values in red denote that some sort of issue is present:
*Distribution System Overload
† Block Load Reserve Capacity Exceeded

Figure 28 – Cold Load Restoration Plan for Downtown

From the above tables it can be seen that it is already very difficult to restore load in some situations and that the problem will become worse with load growth. In particular the lack of switching points and the heavily loaded regulators R83, R84, and R85 make it complex to restore the system through cold load pick-up.

4.4.4 Restoration Time

Within the target restoration time of 4 hours the following must occur:

- Identify that an outage has occurred
- Determine the cause of the outage
- Select an appropriate restoration strategy
- Implement the restoration

Looking more specifically at what influences implementation of restoration strategies, factors that can be controlled are:

- Manpower Limitations (travel to site)
- Number of Switching Operations
- Repair Times

Manpower
Having too few trained staff on-hand to respond to an outage increases its duration. Service staff may need to travel between multiple switching points or complete repairs shorthanded.

Switching Operations
Each additional switching operation increases the duration of an outage. This is mostly because it physically takes more time to perform the additional operations (in the order of 5-30 mins), but also partially because additional steps means that there is additional complexity and risk to be managed.

When dealing with cold lock pick-up, additional time between switching operations is required for load diversity to return (for load to return to steady state values) before bringing the next stage online.

Repairs
Downtown Whitehorse is loop connected with most loads set-up such that they can be fed from more than one source. This avoids the need for quick repair times in many cases; however, for the cases where quick repairs are still required most can be completed within approximately 3 hours if spares are available.

Because of this, for critical equipment and standard equipment there are spares available to accelerate repair times.

To minimize outage durations it is desired to have a system that requires minimal staff to operate, minimal switching operations to restore, and where faulty components can be circumvented to bypass the need for quick repairs.

4.5 Issue Summary

In summary, the root cause for the issues with the downtown power system is load growth. The immediate concerns caused by this load growth are:

Regular Operations

- None

Load Addition

- Regulators in Shipyards Substation will become overloaded within 5-10 years
    - Transformers in Shipyards Substation to become overloaded a few years after the regulators

Contingencies (affected by load growth)

- Marginally sufficient capacity to handle contingencies in S17 or S150
    - 500 MCM Al underground cable to become overloaded within 2-3 years
- Insufficient capacity to handle contingencies out of Services Substation
    - Loss of S7191 in Services Substation cannot be adequately handled
- Insufficient capacity to handle contingencies out of Shipyards Substation
    - Loss of S1016 requires complex switching to handle (6 operations)
    - Loss of S1023 in Shipyards Substation cannot be adequately handled
    - Loss of S1011 or S1020 will be unmanageable after 1-6 years of load growth
    - Loss of S1034 requires quick repair (no switching contingency available)
- Limited load capacity along 6th Ave and at the South River Crossing prevents some switching scenarios

Power Restoration

- Requires extra switching operations due to generation constraints
- Cold load pick-up prevents full restoration of S7191, S1011, & S1016
    - Insufficient regulator capacity and/or switching points

5. Potential Solutions

Many options as to how to address these issues were considered; three options in particular warranted further analysis.

5.1 Solutions Considered

The solutions considered to address the above problems fall into the following framework:

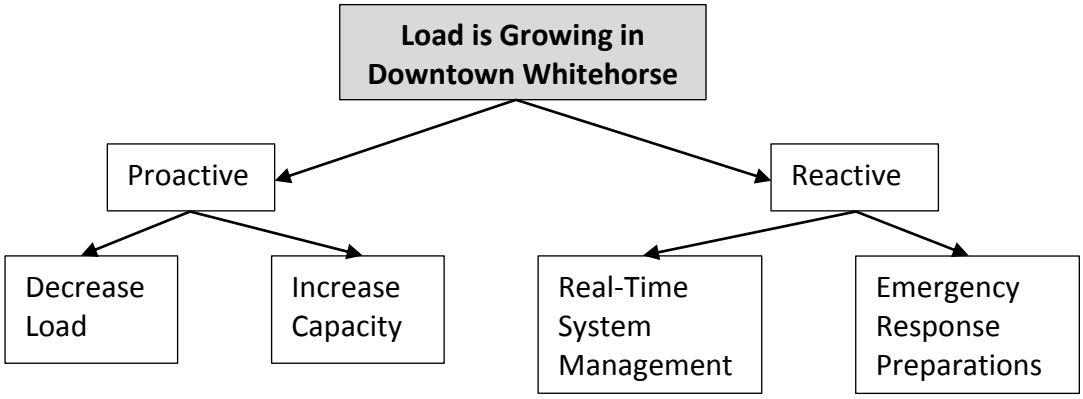

Figure 29 – Downtown Capacity Solution Framework

Decrease Load

Load increase is causing a problem and so decreasing the load should be a solution. Options considered under this category were:

- Voltage Conversion to 25kV – **Further analysis below**
- Voltage Conversion to 34.5kV – Complex, long implementation time, high cost
- Demand Side Management – Slow implementation, unpredictable, unreliable
- Distributed Generation – Complex, cost inefficient, land intensive, high stakeholder impact
- Micro-Generation – Outside of our control, small scale, slow implementation

Increase Capacity

The basic issue caused by load growth is it causes the system to exceed its capacity. One solution would be to add more capacity. Options considered under this category were:

- Upsize constraining equipment – **Part of a viable solution, further analysis below**
- Install additional capacity on existing 12.5kV substations – **Further analysis below**
- Rebuild existing 12.5kV substations – Cost inefficient, logistically complex, insufficient space
- Install new 12.5kV substations – **Further analysis below**
- Install new 34.5kV feeders – Partial solution, cost inefficient

Real-Time System Management
As opposed to increasing capacity, one option to address load growth would be to make better use of the capacity that we already have. This would require us to re-evaluate how we understand our capacity limitations and to improve measurement, control, and protection of our system. Options considered under this category were:

- Install SCADA controlled gang switches and reclosers in critical areas
- Improve measurement, control, and interface at dispatch
- Create dynamic equipment ratings and operating procedures for winter vs. summer conditions – Further analysis below
- Review and optimize protections settings
- Create warning flags for known high risk points

* **All of these are partial solutions. Further analysis below**

Emergency Response Preparations
Choosing not to address issues caused by load growth will lead to more instances of system failure. Even still, peak load is a small percentage of our normal operating condition and it may be viable to fix problems that actually occur rather than anticipate all the possible issues that could happen. Options considered under this category were:

- Procure mobile substation unit
- Create load-shed procedures for downtown
- Perform risk analysis for protection bypasses

Overall this approach was deemed to not adequately address a serious set of problems. It may be prudent to take on some of these measures, but not as a solution to downtown load growth

The set of solutions above was reduced to 3 alternatives for in-depth consideration:

- 25kV Voltage Conversion
- Additional 12.5kV Distribution Capacity
- System Performance Optimization

5.2 Option 1 – 25kV Voltage Conversion

Doubling the distribution voltage from 12.5kV to 25kV allows us to distribute the same amount of power using half as much current. Since the capacity of most system components is based on current, we effectively double the capacity of the 12.5kV equipment by doing this.

It is important to note that this load reduction does not apply to any of the 34.5kV system nor does it apply to the distribution transformers; however, the installation of new substations (which is required to complete the 25kV conversion work) does address capacity concerns on these components.

The advantages of converting Whitehorse from 12.5kV to 25kV have been known for a long time. Because of this and because of the marginal cost difference in 12.5kV vs. 25kV infrastructure, all of the distribution lines & cables, padmount transformers, and any new substation equipment are all rated to operate at both 12.5kV and 25kV with minimal alternations. There still is significant work needs to occur to finish the conversion, but doing so provides long term benefits to the system.

In order to convert the voltage of downtown, 25kV voltage sources to the south and north of downtown are required. There is one dominant option for a south 25kV voltage source, but because of potential cost, land, and operations issues two variations were considered for a north 25kV voltage source:

Install a 25kV substation at the top of Two Mile Hill
Install a 12.5kV/25kV substation at the bottom of Two Mile Hill (Alternate)

5.2.1 Project Scope

Phase 1 – South 25kV Source

- Install a new 25kV substation in Riverdale on Selkirk St.
  - Civil work (brushing, clearing, ground grid, pilings, vaults, gravel, etc.)
  - 10MVA transformer
  - 400A regulator
  - 25kV recloser
  - SCADA metering and control
- Install 300m 34.5kV tie to 19L (S150-52-17)
- Convert 12.5kV circuit right outside the substation to 25kV

Phase 2 – North 25kV Source

- Install a new 25kV substation near the top of Two Mile Hill
  - Civil work (brushing, clearing, ground grid, pilings, vaults, gravel, etc.)
  - 10MVA transformer
  - 400A regulator
  - 25kV recloser
  - SCADA metering and control
- Install short 34.5kV tie to 5L526 (S6837)
- Tie into 12.5kV circuit right outside the substation

Phase 2 (Alternate) – North 25kV Source

- Install a new 12.5kV/25kV substation near the bottom of Two Mile Hill
  - Civil work (brushing, clearing, ground grid, pilings, vaults, gravel, etc.)
  - 12.5kV 10MVA transformer
  - 25kV 10MVA transformer
  - 2x 400A regulator
  - 12.5kV recloser
  - 2x 25kV recloser
  - SCADA metering and control
- Install short 34.5kV tie to 5L526 (S6837)
- Connect into distribution lines
  - 25kV down 4th Ave to feed 6th Ave
  - 25kV down Chilkoot Way to feed Quartz Road
  - 12.5kV up Two Mile Hill to feed Takhini and Marwell

Phase 3 – Voltage Conversion

- Install gang switch to isolate Mountain View Substation
- Transfer load from S7193 to S7192 in Services Substation
- Transfer 12.5kV load from Services Substation to north end substation
- Transfer load from S6822 to S6817 in Lewes Blvd. Substation
- Begin conversion to 25kV
  - Work from new substations towards downtown
  - Replace overhead transformer cans
  - Convert segments of line at a time and cut-over from existing 12.5kV source to new 25kV source

Phase 4 – Finish Conversion and Balance Loads

- Offload S1016 and S7191 onto respective 25kV substations
- Once connection between 25kV substations is established through 6th Ave then begin offloading Shipyards Substation T2 onto 25kV circuits
- Change Shipyards T2 rating to 25kV and reallocate load onto it
- Offload Shipyards Substation T1 onto 25kV circuits
- Change Shipyards T1 rating to 25kV and reallocate load onto it

- Perform switching to balance loads across downtown
- Salvage out unnecessary equipment from Services Substation
- Salvage out Services Substation and reclaim land

5.2.2 Solution Evaluation Matrix

Category	Issue	Solution	Notes
Load Addition	Shipyards Substation regulators and transformers will become overloaded within 5-10 years	• New capacity added in the south will offload Shipyards Substation	Sufficient capacity for >10 years
Contingencies	34.5kV 500 MCM cables to become overloaded within 2-3 years	• Transferring load from S150-52-22 to S150-52-17 will reduce expected load on these cables during a contingency	Moving load onto the new substation alleviates this concern
	Loss of Services – cannot transfer load from S7191	• Load from S7191 is transferred to north end substation	Load still on single breaker. No improvement over current situation Load now split on two breakers. Sufficient contingency capacity in place
	Loss of Shipyards – complex switching for loss of S1016	• Load significantly reduced on S1016. Can be easily transferred to southern substation	Reduced load on S1016 makes additional contingency scenarios viable
	Loss of Shipyards – cannot transfer load from S1023	• Simple connection to southern substation	Reduced load on S1023 makes additional contingency scenarios viable
	Loss of Shipyards – will not be able to transfer load from S1011 or S1020 in 1-6 years	• Balanced loads on Shipyards reduces load on S1020 and S1011 • Load splitting on S1011 may become required in the future, but there	Further work on interconnection points may be required in the future to enable switching

		are options available to do so	
	Loss of Shipyards – cannot transfer load from S1034	• Rely on quick repair times (estimated at 3 hours)	Remains a problematic scenario, but there is an appropriate plan in place considering the probability of the failure
	Limited load capacity along 6th Ave and South River Crossing	• Reduce load currents by converting to 25kV	Capacity effectively doubled on these lines
Power Restoration	Cold Load Pick-Up prevents restoration of S7191, S1011, S1016	• Balance load on all regulators and transformers • Substation addition adds capacity to the system	Capacity margins increased on all transformer/regulator pairs
	Additional switching operations required due to generation constraints	• Reduced/balanced load on reclosers facilitates switching of smaller chunks of load	In high load conditions multi-stage restoration (1-2) may still be required

5.3 Option 2 – 12.5kV Capacity Addition

Installing additional capacity on our system directly counteracts the problems with load growth so long as the capacity addition is located correctly. Successful capacity additions would offload both Shipyards and Services Substations and be integrated with the system in such a way as to support the system in contingency and load restoration scenarios.

There are several potential options for increasing 12.5kV system capacity, but only the two most viable options are considered here.

A. Install an additional transformer bay in Shipyards Substation
B. Construct new Selkirk Substation

5.3.1 Project Scope – A. Install an additional transformer bay in Shipyards Substation

- Install new transformer bay in Shipyards Substation
  - Extend substation fence and ground grid
  - 34.5kV switchgear
  - 10MVA transformer

- 12.5kV switch cube
- 400A regulators
- 12.5kV switchgear
- SCADA metering and control

- Balance loads on Shipyards Substation
  - Possible using existing switching options
- Reconductor 34.5kV 500 MCM Al cable with larger cable

5.3.2 Solution Evaluation Matrix – A. Install an additional transformer bay in Shipyards Substation

Category	Issue	Solution	Notes
Load Addition	Shipyards Substation regulators and transformers will become overloaded within 5-10 years	• Transfer load onto new transformer bay	Sufficient capacity for >10 years
Contingencies	34.5kV 500 MCM cables to become overloaded within 2-3 years	• Reconductor with larger 34.5kV underground cable	Affected runs are short (~150m x 2)
	Loss of Services – cannot transfer load from S7191	• Small load can be picked up by any connected feed	In balancing the new transformer bay the load on S7191 is significantly reduced
	Loss of Shipyards – complex switching for loss of S1016	• N/A	Accept consequences of additional switching operations
	Loss of Shipyards – cannot transfer load from S1023	• Small load can be picked up by any connected feed	In balancing the new transformer bay the load on S1023 is significantly reduced
	Loss of Shipyards – will not be able to transfer load from S1011 or S1020 in 1-6 years	• Reduced load on Services allows for load transfer of S1020 • S1011 needs to be split between S1023 and S7191	Can sufficiently handle these contingencies with 2 extra switching operations
	Loss of Shipyards – cannot transfer load from S1034	• New 34.5kV switchgear provides contingency	Can supply 2/3 of Shipyards through each 34.5kV switchgear and remainder from

			Services or Lewes Blvd.
	Limited load capacity along 6th Ave and South River Crossing	• Use of these paths is not required during contingency	No overload expected during regular loading scenarios
Power Restoration	Cold Load Pick-Up prevents restoration of S7191, S1011, S1016	• S7191 easier to restore due to reduced load • S1011 & S1016 have increased capacity because they are on separate transformer bays	Capacity margins increased on all transformer/regulator pairs
	Additional switching operations required due to generation constraints	• N/A	Additional load on S1011 and S1016 further complicates this issue. Accept consequences of additional switching operations.

5.3.3 Project Scope – B. Construct new Selkirk Substation

- Install a new substation in Riverdale on Selkirk St.
  - Civil work (brushing, clearing, ground grid, pilings, vaults, gravel, etc.)
  - 10MVA transformer
  - 400A regulator
  - 12.5kV recloser
  - SCADA metering and control
- Install 300m 34.5kV tie to 19L (S150-52-17)
- Tie into 12.5kV circuit right outside the substation
- Reconductor South River Crossing
- Install new 2 gang switches and replace 1 switch cube to allow for load balancing
  - Gang switches at 6th Ave and Strickland, 3rd Ave and Lowe St.
  - Switch cube S4597 at Strickland St. and 3rd Ave
- Perform switching to balance load across downtown

5.3.4 Solution Evaluation Matrix – B. Construct new Selkirk Substation

Category	Issue	Solution	Notes
Load Addition	Shipyards Substation regulators and transformers will become overloaded within 5-10 years	• Transfer load onto Selkirk Substation	Sufficient capacity for >10 years
Contingencies	34.5kV 500 MCM cables to become overloaded within 2-3 years	• Construct tie between 19L (S150-52-17) and Selkirk Substation	Load fed from Selkirk will be unaffected by 34.5kV 500MCM contingency. This reduces the load on these cables overall in a contingency
	Loss of Services – cannot transfer load from S7191	• Small load can be picked up by any connected feed	In balancing the reclosers the load on S7191 is significantly reduced
	Loss of Shipyards – complex switching for loss of S1016	• Simple connection to Selkirk Substation	Reduced load on S1016 makes additional contingency scenarios viable
	Loss of Shipyards – cannot transfer load from S1023	• Simple connection to Selkirk Substation • Reconductor South River Crossing	Reduced load on S1023 makes additional contingency scenarios viable. South River Crossing reconductor required for transfer of load onto Selkirk Substation
	Loss of Shipyards – will not be able to transfer load from S1011 or S1020 in 1-6 years	• Reduced load on Services allows for load transfer of S1020 and S1011 • Load splitting on S1011 may become required in the future, but there are options available to do so	Can sufficiently handle these contingencies
	Loss of Shipyards –	• Rely on quick repair	Remains a

	cannot transfer load from S1034	times (estimated at 3 hours)	problematic scenario, but there is an appropriate plan in place considering the probability of the failure
	Limited load capacity along 6th Ave and South River Crossing	• Reconductor South River Crossing	Eventual reconductor of 6th Ave may also be warranted
Power Restoration	Cold Load Pick-Up prevents restoration of S7191, S1011, S1016	• Balance load on all regulators and transformers • Addition of Selkirk Substation adds capacity to the system	Capacity margins increased on all transformer/regulator pairs
	Additional switching operations required due to generation constraints	• Reduced/balanced load on reclosers facilitates switching of smaller chunks of load	In high load conditions multi-stage restoration (1-2) may still be required

5.4 Option 3 – System Performance Optimization

With better measurement, control, estimating, and understanding of system limitations it is possible to operate the system closer to its capacity margins. There is a limit to how much additional capacity is available from this solution, but it is a cost effective option for a short term solution.

5.4.1 Project Scope

- Optimize substation transformer tap settings and lock regulators to ±5% buck/boost
  - Increases regulator capacity by 60%
- Improve Dispatch Interface
  - Install temperature measurement
  - Create dynamic transformer rating tool for real-time decision making
  - Cold Load Pick-Up Estimating tool based on temperature, outage time, and last known loads
  - Estimated loads based on temperature & time of day
- Install additional [SCADA controlled] gang switches
  - 6th Ave (North & South)
  - 3rd Ave on S1011
- Install additional metering for the SCADA system at high risk points
  - 34.5kV Cables

- River Crossing
- 6th Ave
- Transformer Temperature

- Reconductor 34.5kV 500 MCM Al cable with larger cable

5.4.2 Solution Evaluation Matrix

Category	Issue	Solution	Notes
Load Addition	Shipyards Substation regulators and transformers will become overloaded within 5-10 years	• Lock regulators to ±5% buck/boost • Dynamic transformer rating based on temperature	Sufficient capacity increase for regular operation scenarios
Contingencies	34.5kV 500 MCM cables to become overloaded within 2-3 years	• Reconductor with larger 34.5kV underground cable	Affected runs are short (~150m x 2)
	Loss of Services – cannot transfer load from S7191	• Increased ratings allow transfer onto S1020 or S1011	This is a medium term solution. Load growth will force load splitting eventually (~5 years)
	Loss of Shipyards – complex switching for loss of S1016	• Additional [SCADA controlled] gang switches create alternate switching options • Improved measurement reduces the likelihood that switching occurs unnecessarily	Additional switching is required when transferring load onto Lewes Blvd would exceed ratings. Splitting load or knowing exact capacity margins could reduce this need
	Loss of Shipyards – cannot transfer load from S1023	• Additional gang switches along 6th Ave (South) provide viable switching options	Allows for transfer of load onto S1016 or S6822. Load growth makes this a medium term solution (~3-5 years). Would require 4+ switching operations to transfer load
	Loss of Shipyards – will not be able to transfer	• Lock regulators to ±5% buck/boost	Sufficient capacity increase to allow for

	load from S1011 or S1020 in 1-6 years	• Dynamic transformer rating based on temperature	these contingencies
	Loss of Shipyards – cannot transfer load from S1034	• Rely on quick repair times (estimated at 3 hours) • Improved dispatch interface will allow for maximal restoration during repairs	Remains a problematic scenario, but there is an appropriate plan in place considering the probability of the failure
	Limited load capacity along 6th Ave and South River Crossing	• Localized metering points and temperature correction will indicate if issues are present to inform decision making	Option to reconductor these locations to improve system performance if problem persists
Power Restoration	Cold Load Pick-Up prevents restoration of S7191, S1011, S1016	• Estimates of cold load pick-up allow for more informed decision making • Additional [SCADA controlled] gang switches improve switching options	Restoration times will be improved; however, load splitting will still be required and extreme cases requiring restoration in many stages may occur
	Additional switching operations required due to generation constraints	• Additional gang switches provide additional switching options to accommodate this need • Improved dispatch interface will allow for better estimation of loads being restored	SCADA controlled switching would speed up this process. A better dispatch interface could help avoid unnecessary operations

6. Recommendation

Delivering power safely and reliably is ATCO Electric Yukon's key mandate; however, load growth in downtown Whitehorse is expected to compromise our ability to provide service within 5 years. To address this, immediate action should be taken. A review of the system, the issues, and the potential solutions has brought forth the construction of Selkirk Substation as the best option.

ATCO Electric Yukon recommends the following solution:

- Install a new 34.5 kV to 12.5 kV Selkirk Substation in Riverdale to increase capacity in downtown Whitehorse and provide additional contingencies to mitigate the number and duration of power outages.
- Replace the existing River Crossing with larger 266.8 ACSR wire and 750MCM underground cable.
- Install new Switching Points to allow for new switching configurations.

By adding Selkirk to the system we are increasing the capacity sufficiently to meet needs for the next 10+ years in the downtown core and we are setting up a scalable solution that is well situated to deal with future load growth.

YUB-YECL-18

Reference: Application, Section 6, Taxes Other Than Income, Schedules, S1.1,

Issue/sub-issue: Taxes other than income tax

Request:

Please provide explanations for the variance between approved and actual taxes other than income tax (property tax) for the years 2013, 2014 and 2015 as illustrated in the following table:

($000)	2013	2014	2015
Approved – property taxes	257	265	273
Actual – property taxes	273	251	256
Actual (under) over approved	(16)	14	17

Source: Exhibit 2016-17 GRA Schedule S1.1, line 10.

Response:

Total property taxes were 15,000 (1.9%) lower than approved for the 2013-2015 test period. The 2013-2015 property taxes were forecast to increase due to planned capital work as well as inflation. Actual property tax increases in the 2013-2015 period were primarily due to inflation, therefore, AEY's 2016-2017 forecast only assumes inflationary increases.

($000)	2013-2015 Test Period
Approved – property taxes	795
Actual – property taxes	780
Actual (under) over approved	(15)
	-1.9%

YUB-YECL-19

Reference: Application, Section 7, Depreciation, page 7-1,

Issue/sub-issue: Depreciation expense

Request:

Please provide explanations for the variance between approved and actual general provision for depreciation expense for the years 2013, 2014 and 2015 as illustrated in the following table:

($000)	2013	2014	2015
Approved – depreciation expense	4,997	5,736	6,267
Actual – depreciation expense	4,877	5,367	5,915
Actual (under) over approved	(120)	(369)	(352)

Source: Exhibit 2016-17 GRA Schedule S7.1, line 1.

Response:

For 2013, 2014 and 2015, actual depreciation is lower due to lower capital additions.

AEY notes that offsetting the variances above are lower amortization of contributions and lower CCA deductions. Please refer to the following table. The net variance is only 3.3% lower than what was approved for the 2013-2015 period.

	Total 2013-2015 ($000)		
	Actual	Approved	Variance
Depreciation	16,160	17,000	(840)
Amortization of Contributions	(4,464)	(4,750)	286
	11,695	12,250	(554)
Tax Implications (CCA)	(4,401)	(4,708)	308
	7,295	7,541	(247)

YUB-YECL-20

Reference: Application, Section 10, Income Tax, Schedules, S1.1

Issue/sub-issue: Income taxes

Request:

Please provide explanations for the variance between approved and actual income taxes for the years 2013, 2014 and 2015 as illustrated in the following table:

($000)	2013	2014	2015
Approved – income taxes	(416)	160	313
Actual – income taxes	(714)	(120)	74
Actual (under) over approved	(1,130)	(280)	(239)

Source: Exhibit 2016-17 GRA Schedule S1.1, line 15.

Response:

In 2013 and 2014, taxable income was lower due to higher taxable deductions mainly from dismantling costs and ES&G resulting in lower income taxes. In 2015, lower earnings before tax, caused by lower sales, resulted in lower income taxes.

YUB-YECL-21

Reference: Application, Section 10, Income Tax, page 10-1

Issue/sub-issue: Income tax rate deferral

Quote: "Beginning in 2016, ATCO Electric Yukon requests an Income Taxes deferral on the enacted Federal and Territorial Statutory Rates of 15% and 15% respectively."

Request:

(a) Has YECL previously requested deferral treatment for income tax rates? If confirmed, please indicate the application(s) in which deferral treatment was requested. If not confirmed, please provide the reasons for not requesting deferral treatment for income tax rates prior to the year 2016.

(b) Please provide the reasons in support of YECL requesting in 2016, the implementation of an income tax deferral on the enacted Federal and Territorial Statutory Rates of 15 per cent and 15 per cent, respectively.

Response:

(a) AEY requested a deferral account for income taxes in its 2008-2009 GRA.

(b) Should changes (increase or decrease) arise in the tax rates during the test period, a deferral account would be appropriate to flow through any difference to customers for the following reasons:

- Changes in statutory tax rates can be material.
- Given that the statutory rates are set by the Provincial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding the accuracy to forecast.
- The statutory rates are determined by the Provincial and Federal Governments, and are therefore beyond the utilities' control.
- The utility is not typically at risk with respect to items that are beyond its control and are material.

Please also refer to AEY's response to YUB-YECL-49.

YUB-YECL-22

Reference: Application, Section 11 – Prior Board Directions

Issue/sub-issue: Board Order 2014-06, Appendix A, Direction No. 12, page 62.

Quote: Direction No. 12, Reference: Page 62

"The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study."

Preamble: YECL advised in its response to prior Board Direction No. 12 that "ATCO Electric Yukon contributed funds ($20,000) towards this initiative in 2013 and received a report titled 'Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update'. ATCO Electric Yukon filed this report in response to Undertaking #17 during the 2013-2015 GRA hearing. Since that time ATCO Electric Yukon has received one further update in early 2014 but ATCO Electric Yukon is no longer engaged in this project and no further contributions have been made to this project, as such, ATCO Electric Yukon is not expecting to receive any further reports arising from this initiative."

Request:

(a) Please file the "one further update" YECL received in 2014.

(b) Please explain why YECL is no longer engaged in this project or pursuing any recommendations that may be contained within the report?

Response:

(a) Please refer to YUB-YECL-22(a) Attachment 1.

(b) AEY is not directly involved in the development of the wind generation component of this project, but rather is involved as the potential purchaser and integrator into the existing grid. The proponent of the project is following the Unsolicited Proposal process allowed for in the Yukon IPP Policy for smaller

isolated communities served by AEY despite the fact that the IPP Policy is not yet fully implemented.

AEY's only involvement in this project as has been to provide and install data meters that allow the proponent to collect 15 minute interval load data from a number of customers as per the customers' explicit agreement.

Update of wind measurement at the Kluane Wind Project site.

By JP Pinard, PhD, PEng. 28 January 2014



Summary

Over one year of wind measurements have now been collected at the Kluane Wind Project site and the data has been analysed and correlated to Burwash Landing's airport to provide an estimate of long term mean wind speed at the site. While the wind speed at 50 m above ground level (AGL) was 6.2 m/s for the October 2012 to November 2013 period the projected long term mean wind speed is estimated to be 6.8 m/s (projected to 2001-2013 period). The Burwash airport wind measurements show that the average wind speed during the 2012-13 period was at 93% of long term average. These recent measurements projected to long term are consistent with previous measurement campaigns and reports. The business plan used a long term mean wind speed of 6.9 m/s at 50 m AGL for calculating wind energy production.

Introduction

In order to confirm past measurement campaigns[1] a met tower (meteorological tower, wind measurement tower or mast) was installed on September 30, 2012 using funding provided by the Cold Climate and Innovation Centre (Yukon Research Centre/Yukon College). The met tower was installed at the location identified in Figure 1, about 4 km north of Destruction Bay along the Alaska Highway. The wind measurements are used to confirm that the proposed wind project using three WindMatic 17s – 95kW wind turbines on 50 m towers will produce enough wind energy to provide an economic return on Kluane First Nation's investment.

The met tower has been measuring wind speeds at 30, 40, 50, and 60 metres (m) above ground. The met mast is also equipped with wind direction sensors at 30, 50, and 60 m, temperature sensors at 2 and 60 m, and a solar pyranometer at 3 m above ground.

The measurement period covered in this update covers from September 30, 2012 to November 4, 2013. The site measurements are compared to the Burwash Landing airport hourly wind speed data which for the purpose of this study cover a 13-year period from 2001 to end of 2013. The met site's wind measurements are correlated to the airport measurements to provide a long term estimate of the wind speed at the project site.

Measurement Results

During this measurement period at the wind project site, the mean wind speeds were about 6.2 m/s at 50 m AGL. The mean wind speeds are shown in Table 1 and Figure 2 below.

The mean wind speed at the Burwash airport was 3.3 m/s (at 10 m AGL) for the 2001-2013 period and 3.1 m/s (at 10 m AGL) for 30 Sept, 2012 to 4 Nov, 2013 period. This indicates that the wind speed at the airport during the 2012-13 measurement campaign are 93% of long term (13 years) mean wind speed. Although this was a low wind year we expect that it will reflect long term average. Other studies made by the author[2] indicate that wind speeds in the Southern Yukon over the past 60 years have been increasing. This is in part due to increased storm activity in the North Pacific Ocean.

A correlation analysis (measure-correlate-predict using linear least squares method and comparing in 8 direction sectors) between the two sites indicates that the long term average wind speed is expected to be 6.8 m/s at 50 m AGL. The business plan for the Kluane Wind Project prepared by Frontier Power Systems[3] used 6.9 m/s to calculate wind energy output.

The long term estimate at 30 m AGL is 6 m/s, which is consistent with previous measurement campaigns[1].

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[1] Report by JP Pinard and John Maissan: Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update, October 2010. Prepared for Yukon Electrical Company Limited.
[2] Peer-reviewed study by JP Pinard: Wind Climate of the Whitehorse Area, 2007. Published in Journal Arctic.
[3] Report by Carl Brothers of Frontier Power Systems: Kluane First Nation Wind-Diesel Project Business Plan, June 2012. Prepared for Kluane First Nation.

The monthly mean long term wind speed at the site is expected to range from roughly 5.2 m/s (all at 50 m AGL) in January to 8.2 m/s in May and also at 8.0 m/s in September. Most of the high winds, 7 m/s and above occur from April to October, see Figure 3.

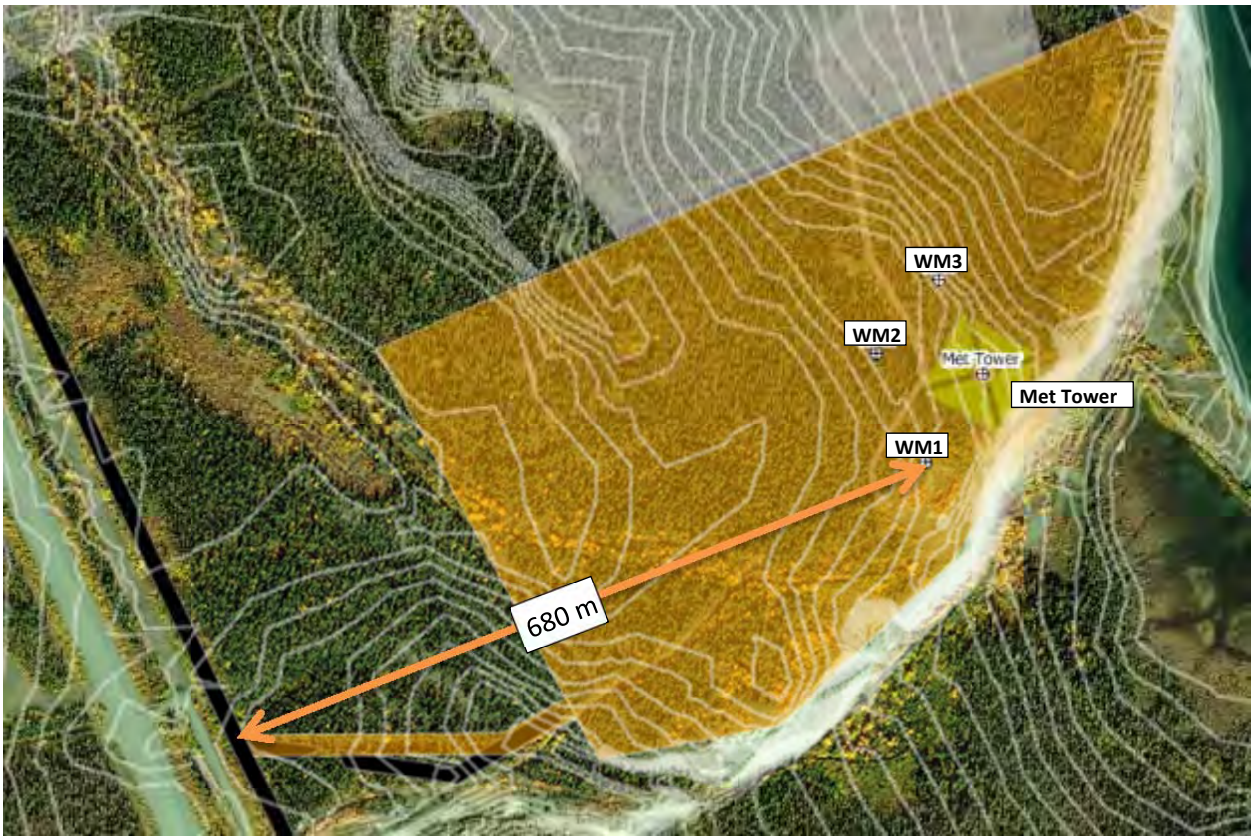


Figure 1 - Aerial map showing location of the met tower (green square with X). Map also shows the land parcel that is reserved for the wind project and the proposed new locations for the three wind turbines (WM1, WM2, WM3).

Table 1 - Mean speeds at various heights in m above ground level (AGL). Time steps indicate the number of 10-minute intervals used to calculate the means.

Wind Speed Sensor	Height (m AGL)	Time Steps	Mean Wind Speed (m/s)
Speed 60 A	60	57,444	6.533
Speed 60 B	60	57,444	6.342
Speed 50 A	50	57,444	6.174
Speed 50 B	50	57,444	6.322
Speed 40 A	40	57,444	5.894
Speed 40 B	40	57,444	5.971
Speed 30	30	57,444	5.509

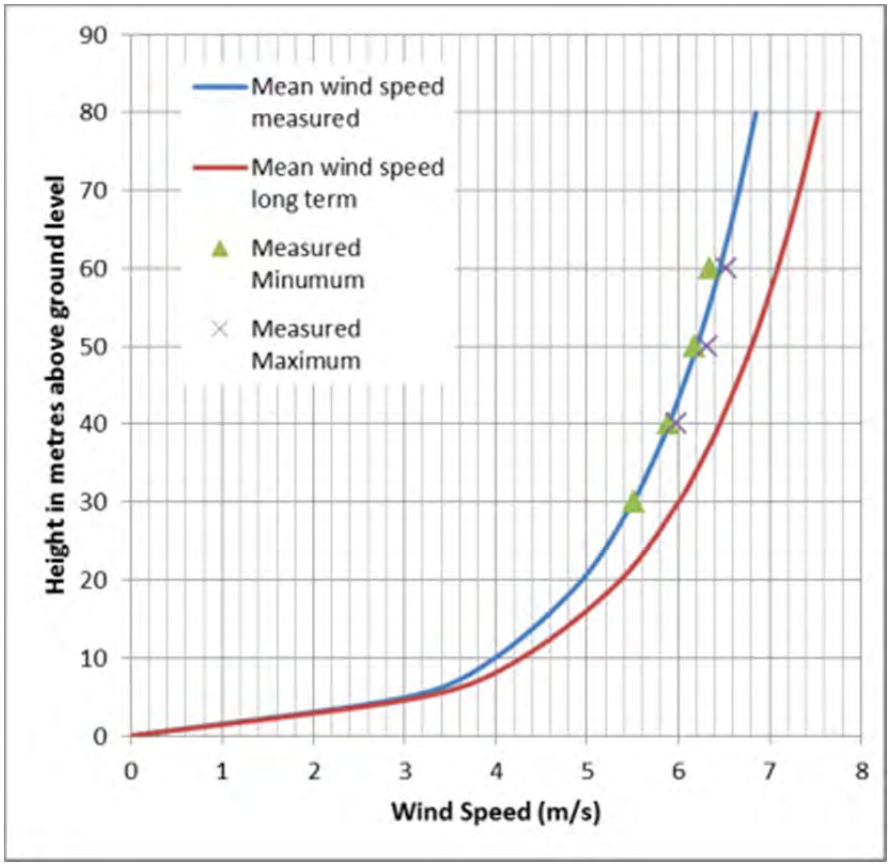


Figure 2 - Vertical profile of horizontal wind speed measured and projected at the wind project site.

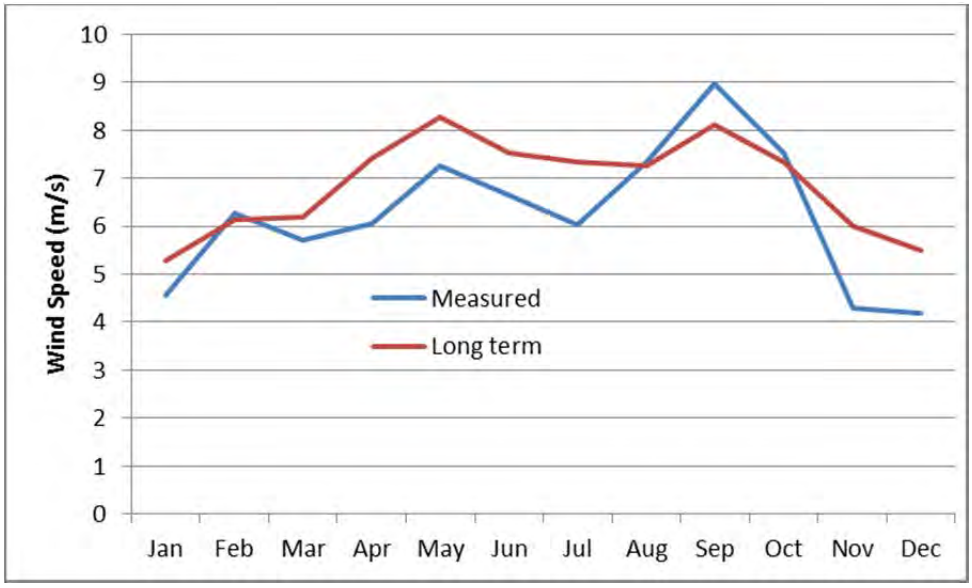


Figure 3 - Monthly mean wind speed measured and projected to long term (2001-2013) at the wind project site.

YUB-YECL-23

Reference: Application, Section 12, Diesel Displacement, pages 12-1 to 12-6,

Issue/sub-issue: Diesel Displacement

Request:

(a) Is YECL's Renewable and Alternative Energy Study expected to include consideration of natural gas or LNG as an alternative energy source? Please explain why or why not.

(b) Is YECL's Renewable and Alternative Energy Study expected to include consideration of wind generation as an alternative energy source? Please explain why or why not.

(c) On what basis, or under what program does YECL expect it would qualify for funding from the federal or Yukon governments?

(d) Will YECL incur any feasibility study costs which would qualify for funding from the federal or Yukon governments?

(e) Does YECL have any completed, in-progress or proposed projects that will qualify for funding from the federal or Yukon governments?

(f) Will the YECL Renewable and Alternative Energy Study to be completed by the end of 2017? If not, please identify the anticipated completion date of the study and any additional costs over and above the $500,000 requested for the 2016-17 test period.

(g) Will YECL ultimately capitalize the study costs, if approved, or expense them?

Response:

(a) AEY's objective is to ensure low cost of electricity for customers. The Renewable and Alternative Energy Study is not expected to include consideration for LNG or natural gas. While LNG is an alternative fuel to diesel, the focus of this study will be on renewable generation sources (eg. Wind and solar PV), energy storage and efficiency upgrades to existing facilities.

(b) AEY's Renewable and Alternative Energy Study is expected to include consideration for wind generation. The impact wind generation will have on

AEY's diesel grids could be significant depending on the penetration level. The existing infrastructure will need to be capable of compensating for fluctuating load and the addition of intermittent generation, such as wind. This may require the introduction of system upgrades, such as energy storage, protection and controls.

(c) The Federal and Territorial governments have indicated a desire to reduce diesel fuel consumption in the North. The governments of Manitoba, Quebec, Newfoundland and Labrador, the Northwest Territories, Yukon and Ontario established a Pan-Canadian Task Force to reduce the use of diesel fuel to generate electricity in isolated communities. The Federal government has earmarked $10.7 million in Budget 2016 to implement renewable energy projects in Indigenous, remote and northern communities that rely on diesel for heat and power. AEY is in early discussions with YTG regarding waste heat recovery and district heating schemes in the communities we serve.

(d) Although it is not certain at this time, any feasibility study costs that qualify for Federal or Territorial funding will be pursued. AEY believes that Federal or Territorial funding may be more likely for the implementation of any project resulting from AEY's Renewable and Alternative Energy studies rather than for the study itself.

(e) AEY has no completed projects, but proposes to identify projects that may be applicable for Territorial or Federal funding through the course of the Renewable and Alternative Energy Study.

(f) Confirmed, AEY expects the study will be completed by the end of 2017. For those projects that appear feasible, additional costs will be incurred to develop them, which if successful and approved by the YUB will be capitalized and if not, expensed, net of any external funding obtained. All of these additional costs will be brought forward in business cases in a stand-alone proceeding for approval by the YUB.

(g) AEY is proposing to amortize the study costs over the test period through deferred charges. This is consistent with the treatment of the Kluane Wind Study costs approved as part of Decision 2014-06.

YUB-YECL-24

Reference: Application, Appendices – Business Cases, Appendix #3

Issue/sub-issue: Watson Lake Bi-Fuel Project

Request:

(a) Will YECL seek any additional funding from the federal and Yukon governments to fund the Watson Lake Bi-Fuel project costs? Please clarify if the additional funding is distinct and separate from the funding identified in the following quote in the Application in Section 12, page 12-2, item 2, lines 13-16, PDF page 225 of 292:

> "2. A portion of ATCO Electric Yukon project execution costs for projects identified in this study to be viable so that the entire financial burden of introducing renewable and alternative energy in the Yukon's diesel communities is not put on Yukon electric ratepayers."

(b) How will replacing reliance on diesel with reliance on LNG meet the governmental objective of introducing renewable energy such that some level of project funding is ensured?

(c) Please explain why YECL no longer proposes that ATCO Gas be involved in the Watson Lake Bi-Fuel project.

(d) Does YECL consider there is any legislative or regulatory impediment(s) to owning "all of the assets required" or providing any of the services stemming from this project?

(e) Of the costs disclosed on Table 1: Watson Lake Bi-Fuel Project Phase 1 and 2 Capital Cost, please identify all costs that will be paid to ATCO Gas.

(f) Of the costs disclosed on Table 1: Watson Lake Bi-Fuel Project Phase 1 and 2 Capital Cost, please provide the amount of Watson Lake bi-fuel project study costs that are held in WIP at the end of each year 2013 through 2017.

(g) Please provide the original historical cost and accumulated depreciation related to the assets being purchased from ATCO Gas.

(h) Why would YECL choose a new unit which requires field modifications to burn both diesel and natural gas versus purchasing a new unit that is factory capable of burning both fuels with name plate performance ratings?

Response:

(a) AEY does not intend to seek additional funding for the Watson Lake Bi-Fuel Project from the Federal and Yukon governments. The analysis presented to the Board indicates the project is cost effective for rate payers under many projected future scenarios. This project is consistent with the Federal and Yukon governments' goal of reducing or eliminating the use of diesel in northern and remote communities by offsetting approximately 50% of the diesel consumed for power generation in Watson Lake.

(b) Please refer to AEY's response to YUB-YECL-24(a).

(c) It is AEY's interpretation of Board Order 2014-06 and 2015-02 that there was a concern over affiliate transactions and a perceived above market return provided to an ATCO Affiliate. To alleviate the Board's concerns, AEY decided to complete this project without any ongoing ATCO affiliate involvement. AEY will purchase the assets specific to this project at book value from ATCO Gas without markup.

(d) AEY does not consider there to be any legislative or regulatory impediments to owning all assets associated with this project and proposes to do so under the revised business case in Appendix #3 of the Application. Specialized services related to the onsite LNG equipment, that AEY does not currently have the expertise to perform, will be contracted with qualified services providers. AEY will own all assets, as ATCO Gas will no longer be providing equipment through a lease or any ongoing services as was originally conceived.

(e) The costs that will be paid to ATCO Gas are composed of $821,000 spent to date, plus a final payment to the equipment supplier once the equipment is delivered of approximately $373,000. The total payment from AEY to ATCO Gas will be approximately $1,194,000. Of these costs, approximately $102,000 will be payable to ATCO Gas for labor plus expenses. The other approximately $1,092,000 has, or will be paid directly to third party, competitively tendered suppliers for services, such as engineering, design and the purchase of LNG equipment.

	Cost
ATCO Gas Labor	$102,000
Competitively Tendered Third Party Costs to Date	$719,000
Competitively Tendered Third Party Costs Future	$373,000
Total to ATCO Gas	**$1,194,000**

(f) Please refer to the following table.

Watson Lake Bi-Fuel - WIP Continuity					
	2013	**2014**	**2015**	**2016**	**2017**
Opening WIP Balance	-	344	426	494	247
Add: Costs	344	82	67		
Less: Amortization of Costs				(247)	(247)
Closing WIP Balance	**344**	**426**	**494**	**247**	**-**

AEY is proposing amortizing the costs through the amortization of deferred charges. Further discussion of the initial engineering and feasibility costs is in the response to YUB-YECL-75.

(g) This equipment has never been put into use and as such, no depreciation has been accumulated. The original historical cost, accumulated depreciation and net book value is shown below:

Gross Asset Value:	$1,194,000
Accumulated Depreciation:	$0
Net Book Value:	$1,194,000

(h) Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.

YUB-YECL-25

Reference: Application, Appendix #10

Issue/sub-issue: Paint Mountain

Quote: "This project will replace cable that is approximately 50 years old serving four customers on Paint Mountain. The cable is at the end of its life, is in poor condition, and is difficult to access. Any sort of failure to this cable would lead to an extended outage for the customers served by this electrical cable."

Request:

(a) Was this line originally installed by YECL? Please explain.

(b) If not originally installed by YECL, when did YECL acquire this line?

(c) For the replacement or upgrade of this line, will there be any contributions from customers? Please explain.

Response:

(a) AEY was not the original owner and did not install this line originally. Survey plan documents show Canadian National (CN) Telecommunications having a right of way for the cable in 1963.

(b) AEY purchased the line from CN Telecommunications in 1977.

(c) AEY is not requesting a contribution for the replacement of this line from the customers served by it. There are no provisions for construction contributions beyond initial installation as per the approved Terms and Conditions of Service. AEY considers this line replacement to be similar to other line rebuilds where no additional contribution is required by customers to maintain service.

YUB-YECL-26

Reference: Application, Attachment 9.2 – Generation Plants

Issue/sub-issue: Destruction Bay PLC, Teslin PLC, Watson Lake Plant Fire Alarm System, Teslin Plant Assessment and Old Crow Plant Rebuild

Preamble: The Board would like more information on each of the listed projects.

Request:

(a) For each of the listed project please provide a further breakdown of the costs, such as design, engineering, materials, and construction.

(b) For each of the listed sites, please provide a summary of previous capital projects undertaken at those sites over the last 10 years.

Response:

(a)

Project	Design & Project Management	Materials	Construction	Total	Notes
Destruction Bay PLC	$16,000	$91,000	$200,000	$307,000	$112,000 spent to date. Majority of the rest to be spent on construction and commissioning.
Teslin PLC	$30,000	$75,000	-	$105,000	Only design and procurement to be completed in the 2016/2017 test period
Watson Lake Plant Fire Alarm System	$102,000	-	-	$102,000	Only design to be completed in the 2016/2017 test period
Teslin Plant Assessment	$102,000	-	-	$102,000	Only assessment to be completed in the 2016/2017 test period
Old Crow Plant Rebuild	$250,000	-	-	$250,000	Only design to be completed in the 2016/2017 test period.

(b) Please refer to YUB-YECL-26(b) Attachment 1.

ATCO Electric Yukon
Destruction Bay, Old Crow, Teslin, and Watson Lake Capital Expenditures
($000s)

Project Name	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Destruction Bay										
Destruction Bay Compton Protection Relay Replacement and Battery Charger Upgrade			65							
Destruction Bay Unit # 1 Replacement					275					
Destruction Bay Fuel System Upgrade							21			
Destruction Bay Plant Foundation Refurbishment								131		
Destruction Bay Unit # 3 Replacement									616	18
Destruction Bay Programmable Logic Controller Upgrade									83	26
Destruction Bay Unit # 2 Replacement										136
	-	**-**	**65**	**-**	**275**	**-**	**21**	**131**	**699**	**180**
Old Crow										
High Voltage Switching Cubicle and Termination for Old Crow Plant						20	90			
Old Crow Plant Expansion								599	2,707	1,260
Old Crow Unit # 4 Addition									504	108
Old Crow Staff Accommodations									233	41
Old Crow Unit # 3 Replacement										213
Old Crow Unit # 2 Replacement										161
Old Crow Original Plant Rebuild										90
	-	**-**	**-**	**-**	**-**	**20**	**90**	**599**	**3,444**	**1,873**
Teslin										
Teslin Fuel System Upgrade	100									
Teslin Replace Unit Breaker		68								
Teslin Plant Combustible Air Intake and Louver Improvements						19				
Teslin Programmable Logic Controller (PLC) Replacement						33	31			
Teslin Fuel System Upgrade							41			
	100	**68**	**-**	**-**	**-**	**52**	**72**	**-**	**-**	**-**
Watson Lake										
Watson Lake Fuel System	84	49								
Watson Lake Replace Protection Relays	37									
Watson Lake Replace Generation Protection		45								
Watson Lake Breaker Refurbish		25								
Watson Lake Generator Upgrades and Fresh Air Intakes			77							
Watson Lake Unit # 5 Replacement					232	32				
Watson Lake Protection Upgrade						48				
Watson Lake Bi-Fuel Project							90	221	82	59
Watson Lake Unit # 3 Major Overhaul							247			
Watson Lake Unit # 4 Replacement							354	979	28	
Watson Lake Unit # 6 Major Overhaul								243		
Watson Lake Unit # 5 Major Overhaul									239	
Watson Lake Replace ABB 5HK Breakers									187	220
Watson Lake Unit # 1 Major Overhaul										278
	121	**120**	**77**	**-**	**232**	**80**	**691**	**1,443**	**536**	**557**

YUB-YECL-27

Reference: Application, page 1-5

Issue/sub-issue: Key assumptions

Quote:

	2016	2017
Labour Inflation	3.25%	3.00%
Other Inflation	2.20%	2.20%
Vacancy Rate	4.00%	4.00%
Long Term Debt Rate	4.35%	4.85%

And

"For the 2017 test period, in-scope and out-of-scope labour has been escalated by 3.0%. This escalation rate is consistent with the inflationary increases being applied for and approved in Alberta for 2017."

Request:

(a) In 2015, did ATCO Electric reduce the number of its FTEs? If so, what impact did this have on YECL? During the period 2014 to 2016, were any wage freezes implemented for out-of-scope employees of ATCO Electric? Please explain and provide any details. If wage freezes were implemented, please explain and provide any details on any impact to YECL.

(b) Please provide the Alberta decision references where inflation rates of 3 percent for out-of-scope positions for 2017 have been approved. Please provide any Alberta examples where inflation rates other than 3 percent have been approved for out-of-scope positions for the years 2016 and 2017.

(c) Please provide the actual (unadjusted) vacancy rates for YECL for the years 2011-2015 inclusive. For each of those years, please provide the approved number of FTEs and the actual number of FTEs.

(d) Please provide the data and calculations used to determine the vacancy rates for 2016 and 2017.

(e) Please provide the data and calculations and provide the actual vacancy rates for 2013 to 2015 inclusive.

Response:

(a) ATCO Electric did reduce their number of FTE's in 2015; this had no impact on AEY. No across the board wage freezes were imposed in the 2014-2016 period. Employees received increases in 2014 and some employees received wage increases in 2015 and 2016.

(b) The AUC has recently approved a 3% labour inflationary increase in 2016 and/or 2017 in the following Decisions.

- Decision 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff)
- Decision 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA)
- Decision 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker)
- Decision 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker)

The AUC has also issued the following Decisions where the approved labour inflationary increases differ from the 3%.

- Decision 3524-D01-2016 (Altalink Management 2015-2016 GTA)
- Decision 20604-D01-2016 (ATCO Gas 2014 True-Up and 2016-2017 Forecast Capital Tracker)

(c) Please refer to the following table:

	FTE				
	Actual	Forecast	+/-	Vacancies	%
2011	54.47	57.08	(2.61)	2.61	4.6%
2012	56.36	60.52	(4.16)	4.16	6.9%
2013	65.23	68.39	(3.16)	3.16	4.6%
2014	68.65	70.39	(1.74)	1.74	2.5%
2015	69.37	70.39	(1.02)	1.02	1.5%
			5 Year Average	2.54	4.00%

(d) Please refer to Response YUB-YECL-27(c); the 5 year average calculation is used to determine the 2016 and 2017 vacancy rates.

(e) Please refer to Response YUB-YECL-27(c).

YUB-YECL-28

Reference: Application, page 1-6

Issue/sub-issue: Staff positions

Preamble: The Board would like further information on the possible FTE reductions undertaken by ATCO Electric and the impact on YECL.

Request:

(a) Please provide the number of positions (FTEs) reduced by the ATCO Electric, to date, from the number of positions (FTEs) ATCO Electric had January 1, 2015. Please explain any impacts on YECL.

(b) If ATCO Electric undertook staff reductions in 2015, and YECL did not, please explain how YECL was able to avoid those reductions.

Response:

(a) ATCO Electric did undertake staff reductions; however AEY is not aware of the number of positions reduced. While AEY was not directly impacted by the FTE reductions, staffing needs were evaluated and AEY eliminated positions that were not required in order to create positions that were needed while remaining within its approved complement.

(b) Despite being a subsidiary of a larger utility, AEY operates on a stand along basis and continues to experience capital growth.

YUB-YECL-29

Reference: Application, Organizational Chart, Attachment 1.1

Issue/sub-issue: Changes in complement

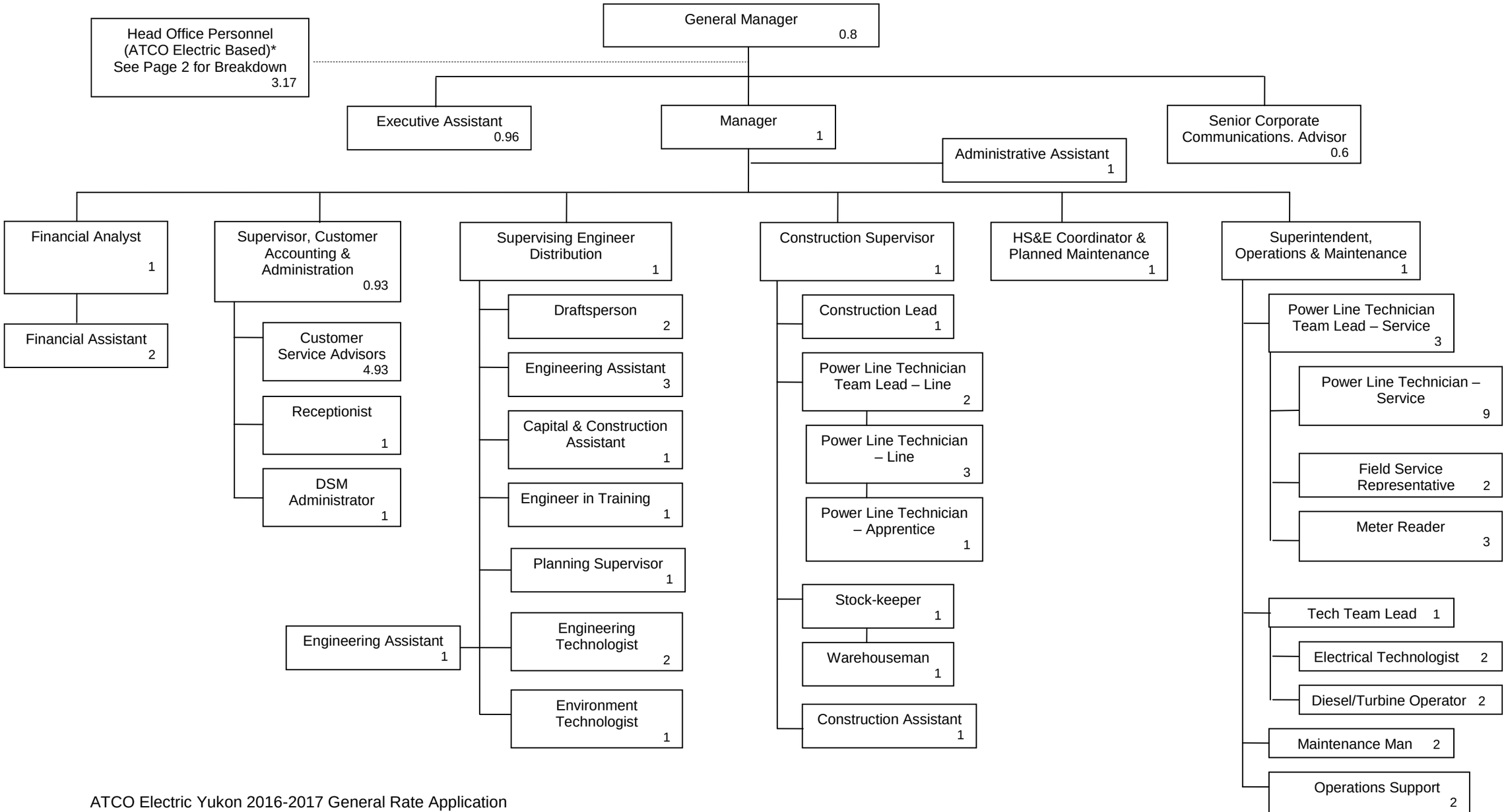
Request:

(a) Please provide an organization chart (to the same detail as Attachment 1.1) of all approved positions for YECL, from the 2015 test year.

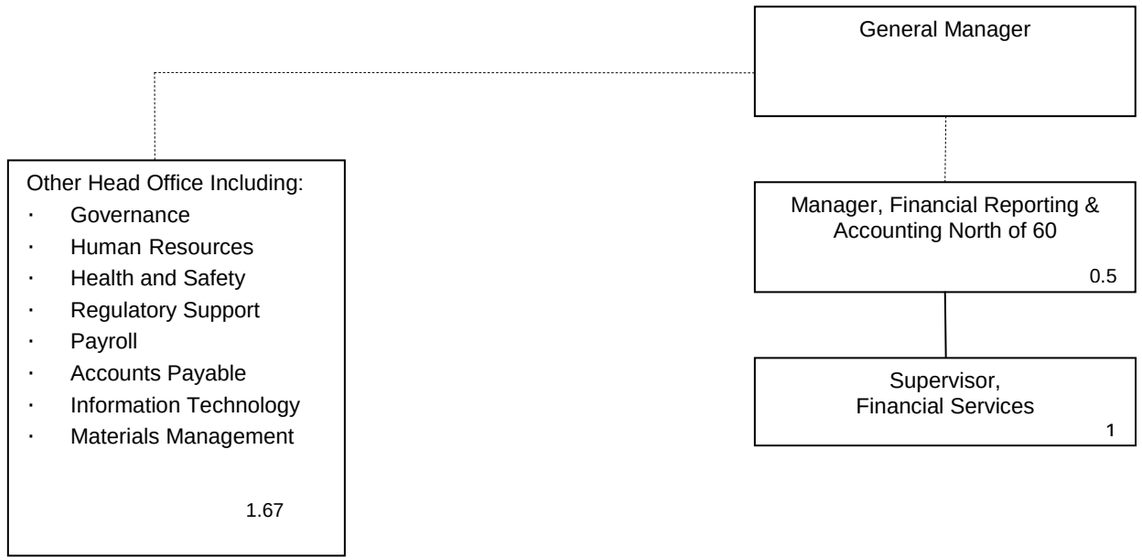
Response:

Please refer to YUB-YECL-29 Attachment 1.

Organizational Chart
ATCO Electric Yukon
2015 Approved



Organizational Chart
ATCO Electric Yukon
2015 Approved



YUB-YECL-30

Reference: Application, page 1-5

Issue/sub-issue: Key Assumptions

Quote: *"For non-labour costs, an inflation rate of 2.2% has been applied for 2016 based on the Yukon Economic Outlook issued by the Yukon Economic Development in October 2015. For 2017, no public forecast of Yukon inflation is available, therefore the 2.2% inflation rates has also been used for 2017."*

Request:

(a) Has Yukon Economic Development provided a more recent Economic Outlook? If so, please provide the updated Economic Outlook.

(b) If there has been a more recent Economic Outlook, please provide what the forecast for Whitehorse CPI is expected to be for 2016 and 2017.

Response:

(a) Please refer to YUB-YECL-30(a) Attachment 1 for the May 2016 Yukon Economic Outlook.

(b) Per the May 2016 Yukon Economic Outlook, Whitehorse CPI is expected to be 2.0% in 2016 and 1.9% in 2017. Discussion of Consumer Price Index can be found on pages 13 and 14 of YUB-YECL-30(a) Attachment 1.

Yukon Economic Outlook

May 2016

Yukon
Economic Development

© 2016 Department of Economic Development
Yukon Government
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ECONOMIC FORECASTING AND RISK

This forecast examines near-term expectations for Yukon's economy, focusing on the anticipated performance of key economic indicators and sectors.

As with all forecasts, the results are dependent on the information available at the time of forecast completion and key assumptions incorporated into the forecast. Assumptions such as the level and timing of mining development activity, estimates of annual mineral production and estimates of construction spending, can all impact the forecast results, particularly for an economy as small as Yukon's. While best efforts are made to develop assumptions that reasonably capture Yukon's potential economic performance in the near-term, there is always a degree of risk and uncertainty associated with these assumptions, and ultimately the forecast results. Key examples of potential risks to the forecast are noted below:

- Global Economic Performance – The performance of Yukon's economy is tied to the performance of other key economies, such as the U.S. and China, and to the global economy as a whole. Demand for Yukon goods and services, including minerals and local tourism activities, can depend very much on what is happening outside of the territory.

- Metal Prices – Metal prices are a key determinant of mining activity (exploration, development and production) and are determined on the global market. Projections from a variety of forecasters were considered in preparing this forecast.

- Energy Prices – Energy prices are also determined on the world market. For Yukon, the price of oil can influence economic activity particularly in how it can impact mining sector activity (fuel for project operations and equipment) as well as impact tourism activities (fuel for travelers' vehicles). The price of fuel also influences the cost of Yukon construction activities and the cost of goods in Yukon as the majority of goods purchased locally are transported from outside the territory.

- Exchange Rates – The value of the Canadian dollar versus other currencies can impact spending decisions by tourists and also investment decisions by resource-based companies. A strengthening or weakening dollar may affect this forecast.

- Interest Rates – Lower interest rates can contribute to increased investment as the cost of borrowing is reduced. Alternatively, increasing interest rates increase the cost of borrowing and can dampen investment spending. The cost of borrowing in Canada has been low for a prolonged period, with the Bank of Canada's daily overnight target for the bank rate not exceeding 1.0 per cent since January 19, 2009. This forecast assumes that interest rates will remain relatively low for the foreseeable future.

Finally, circumstances that impact forecast assumptions can change rapidly, resulting in the forecast becoming dated. Yukon is an example of a small economy that can be rapidly influenced by outside events. Information in this forecast is current to May 12, 2016 which allows for the inclusion of Statistics Canada's preliminary GDP estimates for 2015.

HIGHLIGHTS FOR 2015

- Statistics Canada preliminary estimates for Yukon real Gross Domestic Product (GDP) for 2015, released May 12, 2016, have Yukon's real GDP by Industry at $2.177 billion in 2015, down 3.8 per cent from $2.264 billion in 2014, representing the third consecutive annual contraction.
    - The primary contributor to the contraction was lower mineral production, the result of weak mineral prices and an ongoing slowdown in the global mining industry.
- Yukon's June 2015 population of 37,343 up slightly from the June 2014 figure of 37,251, marking the 12th consecutive year of growth.
- Yukon's labour market was impacted by the weaker economic activity:
    - Total employment averaged 19,400, down 400 from 2014.
    - The labour force averaged 20,700, unchanged from 2014.
    - Average unemployment rate of 6.3 per cent, up from 4.3 per cent in 2014.
- Statistics Canada data for retail sales reports Yukon sales of over $692 million, up 4.7 per cent from 2014.
- Border crossings are reported as falling by 4.1 per cent, to 327,778.
    - Concerns have been raised about the accuracy of the 2015 data as anecdotal information indicates that 2015 was a good year for local tourism operators.
- At $117.7 million, the value of building permits in 2015 was down 9.7 per cent from $130.5 million in 2014.
    - Permit value was down in all areas, with the exception of government/institutional permits. Biggest losses were noted in residential permits.
- A modest decrease in the Consumer Price Index (CPI) was experienced in Whitehorse, down 0.2 per cent in 2015.

FORECAST FOR 2016

- The forecast for real GDP in 2016 is for growth of 2.8 per cent.
    - Growth in 2016 is primarily related to an expected increase in mineral production at the Minto mine with the beginning of stripping of the Minto North pit.
- Modest population growth is expected, with gains of 0.7 per cent in 2016.
- The number of employed and the size of the labour force are both expected to increase slightly to 19,500 and 20,900, respectively. The unemployment rate in 2016 is expected to rise to 6.6 per cent.
- Following reported strong gains in 2015, retail sales are expected to post modest growth in 2016.
- Early indications are that 2016 will be a positive year for Yukon tourism.
- Building permit value is expected to be up slightly from the 2016 level.
- Following deflation in 2015, the Whitehorse CPI is expected to grow by 2.0 per cent in 2016.

PRELIMINARY FORECAST FOR 2017

- Early expectations for 2017 are for Yukon's real GDP to fall by 5.7 per cent.
  - Lower year-over-year mineral production, associated with the expected shutdown of the Minto mine, is the primary contributor to the contraction.
- Population growth of 0.3 per cent.
- Employment and the labour force are expected to post modest gains, with employment increasing to over 19,600 and the labour force increasing to almost 21,000. The unemployment rate in 2017 is expected to fall slightly to 6.3 per cent.
- Retail sales are expected to grow to over $700 million.
- A modest increase in building permit value is expected, growing to about $125 million.
- Growth in the Whitehorse CPI is expected to be just under 2.0 per cent.

GLOBAL, U.S. AND CANADIAN OUTLOOK

The April 2016 *World Economic Outlook* prepared by the International Monetary Fund (IMF) notes that global growth prospects have worsened since their previous forecast release (January 2016).

The current IMF forecast is for global growth of 3.2 per cent for 2016, slightly higher than the 2015 estimate of 3.1 per cent, but below the IMF's January 2016 forecast of 3.4 per cent. Looking to 2017, the IMF is projecting stronger global growth of 3.5 per cent, down from the January 2016 forecast of 3.6 per cent.

The strengthening recovery in 2017 is noted as being driven primarily by emerging market and developing economies, as conditions in stressed economies start to gradually normalize. While growth is expected to pick-up, the IMF notes that uncertainty has increased, and risks of possible weaker growth were becoming more tangible. [1]

Even with the growth rate declining for the fifth consecutive year in 2015, growth in emerging market and developing economies continues to outpace that of growth in advanced economies. The IMF is forecasting that growth in emerging and market and developing economies will continue to account for the lion's share of projected world growth in 2016 and 2017. Following growth of 4.0 per cent in 2015, the IMF is forecasting growth of 4.1 per cent in 2016, to be followed by stronger growth of 4.6 per cent in 2017.

While continuing to grow, prospects across emerging market and developing countries remain uneven and generally weaker than over the past two decades.[2] The IMF's April Outlook noted in particular that a number of large emerging markets, including Brazil and Russia, are still in the midst of recessions. Others, including several oil-exporting countries, were also noted as dealing with weaker terms of trade and tighter external financial conditions.[3] Declining investment growth in emerging market economies was also noted as a contributing factor to recent weaker performance.

China's economy remains in a period of transition, moving to development of services and retail in support of its domestic demand from an economy supported substantially through

manufacturing activities and large scale industrial development. Even with the recent slowdown, China, along with India, will continue to lead the way for emerging market countries. Following estimated growth of 6.9 per cent in 2015, China's economy is expected to grow 6.5 per cent and 6.2 per cent over the next two years. Following growth of 7.3 per cent in 2015, India is forecast to post gains of 7.5 per cent in both 2016 and 2017.[4]

Following estimated growth of 1.9 per cent in 2015, advanced economies are forecast to grow by 1.9 and 2.0 per cent annually over the next two years. U.S. growth is expected to remain the primary driver of growth in advanced economies with U.S. growth rates in both 2016 and 2017 exceeding the overall growth rates of advanced economies.

Stronger housing and labour markets and favourable financial conditions continue to support the U.S. economy. Significant employment gains were noted in 2015, with an average of 221,000 jobs added on a monthly basis.[5] Improving labour income and lower gasoline prices have supported private domestic demand, as reflected in near-record-high vehicle sales, robust residential construction and strong business investment outside the commodity-related sectors.[6] The current IMF forecast has U.S. growth in the near-term approximating recent growth rates. Following estimated growth of 2.4 per cent in 2015, the forecast calls for growth of 2.4 and 2.5 per cent in both 2016 and 2017.

Recently, Canada's economy has underperformed the U.S. economy and expectations are that this will continue in the near-term. Much of the recent weakness is attributed to weaker commodity prices, particularly oil prices, which due to oversupply in the global market has declined significantly in the last 18-20 months, falling below $30 per barrel for a time in early 2016. Prices for many key mineral exports are also down substantially from recent levels which has contributed to mine closures, layoffs, reduction in mineral exports and lower levels of investment in Canada's mining sector. Evidence of the recent poor performance of oil and mineral prices can be seen in estimates of economic performance and expectations for performance in the near-term. The IMF is estimated that Canada's economy only grew by 1.2 per cent in 2015. Expectations for slightly stronger growth is noted by the IMF for 2016 and 2017, with gains of 1.5 per cent and 1.9 per cent, respectively. The April 2016 forecast represents a downgrade from the January 2016 forecast of 1.7 per cent and 2.1 per cent for 2016 and 2017 respectively.

The Bank of Canada is also forecasting relatively weak economic growth for Canada in 2016, to be followed by improved performance in 2017. The April 2016 *Monetary Policy Report* includes real GDP growth forecasts of 1.7 per cent in 2016 and 2.3 per cent in 2017. While the Bank noted that global and domestic developments, including the economy's adjustment to the ongoing weakness in oil prices, would have resulted in a modest downgrade of its outlook for 2016 and 2017, fiscal measures announced in the March Federal budget will have a notable positive impact.[7]

Resource extraction activities continue to be a significant contributor to Canada's economy, and growth prospects for the country are inherently linked to the performance of commodity prices. The weakness in mineral prices that began in 2014 became more prominent in 2015 and has continued into 2016. Prices for key commodities such as gold, silver and copper recently touched lows not seen in five to six years. Concerns about global demand, especially declining demand from China, as well as increases in supply that followed the most recent mining investment boom, continue to contribute to uncertainty about a recovery in mineral prices.

Even more of a downward drag on Canada's economy has been the rapid decline in oil prices. A glut of supply, weaker demand from China and Iranian oil hitting the global market with the lifting of Nuclear related sanctions have all contributed to weakness in oil prices. High crude oil inventories held by the U.S. are also working to keep oil prices low, near record levels at the time of writing. The outlook for oil prices remains poor, with many forecasters expecting prices to remain relatively low throughout 2016, before a minor recovery in 2017. At the time of writing, BMO Capital Markets is calling for oil prices to average US$37 per barrel in 2016, down from US$48.69 in 2015, and US$93.26 just two years ago (2014).[8] At US$37 per barrel, the price of oil would be the lowest since 2003 when it averaged just over US$31 per barrel.

After averaging US$4.39 per MMBTU[9] (Henry Hub) in 2014, the highest annual average since 2010, natural gas prices declined significantly in 2015, averaging about US$2.63 per MMBTU. Natural gas prices are expected to perform better than oil prices in the near-term, but remain well below recent highs. BMO Capital Markets is forecasting Henry Hub Natural Gas prices to fall to US$2.25 per MMBTU in 2016 before increasing to US$3.20 per MMBTU in 2017.

Future growth prospects for Canada are also tied to interest rates. After being pegged at 1.0 per cent since September 2010, the Bank of Canada surprised most analysts in January 2015 when it lowered the overnight rate to 0.75 per cent, and then lowered it further to 0.5 per cent in July 2015. Given the weaker outlook for Canada's economy Canadian interest rates are expected to remain low throughout 2016 and likely into 2017. At its most recent rate announcement on April 13, 2016, the Bank of Canada maintained the overnight rate at 0.5 per cent, opting to continue to keep the cost of borrowing relatively low. The next interest rate announcement for the Bank of Canada is scheduled for May 25, 2016.

Outlook for Global, U.S. and Canadian Economies

The IMF's April 2016 update to the World Economic Outlook includes the following forecasts:

- Global Growth: 3.2 per cent (2016) and 3.5 per cent (2017);
- U.S. Growth: 2.4 per cent (2016) and 2.5 per cent (2017); and
- Canadian Growth: 1.5 per cent (2016) and 1.9 per cent (2017).

RECENT PERFORMANCE AND SHORT-TERM OUTLOOK

PART A: ECONOMIC INDICATORS

GROSS DOMESTIC PRODUCT (GDP)

Preliminary data released by Statistics Canada in May 2016 estimates that Yukon's real GDP by industry in 2015 contracted by 3.8 per cent to $2.177 billion. The decline in 2015 represented a third consecutive year of contraction for the territory.

Among the provinces and territories, Yukon 2015 performance ranked only ahead of Alberta which saw a contraction of 4.0 per cent. Prior to 2013, Yukon's real GDP had posted nine straight years of growth.

Weakness in the mining sector continued to weigh on Yukon's economy in 2015, resulting in a substantial decline in mineral production in 2015. Suspension of production from the Wolverine mine in January 2015 saw mineral production come in well below the 2014 level. A 43 per cent decline in the mining quarrying and oil and gas extraction component of GDP was the primary contributor to the 2015 decline.

While the percentage contribution of mining in 2015 falls well below the high of abour 22 per cent noted in 2012, figure 3[10] shows the current contribution of mining related activities still remains well above estimates of a decade ago. At over 11 per cent of total real GDP the 2015 contribution of mining, quarrying and oil & gas extraction is more than double the contribution noted in 2005.

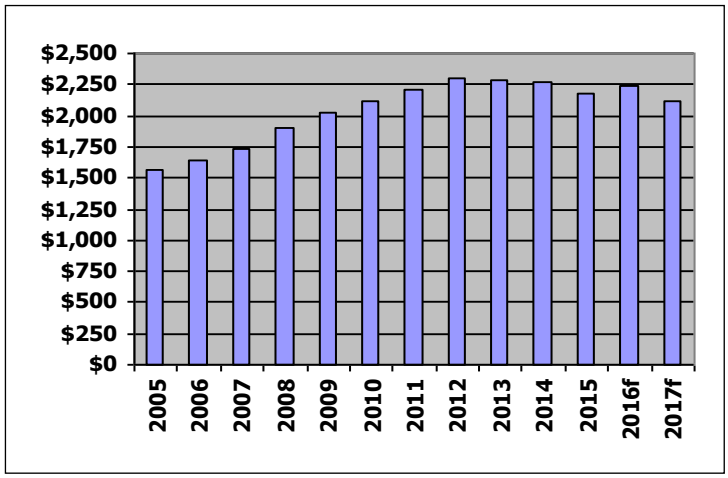


Figure 1 – Real GDP by Industry (2007$ millions)
Source: Department of Economic Development; Statistics Canada

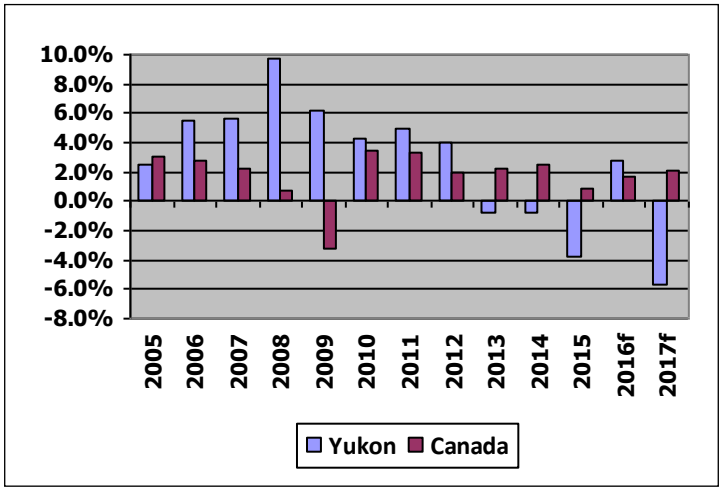


Figure 2 – Real GDP by Industry – Annual Growth Rate
Source: Department of Economic Development; Statistics Canada; International Monetary Fund

Yukon's real GDP is expected to post gains in 2016, with growth primarily related to expectations of increased mineral production as the inclusion of production from its Minto North pit contributes to gains in Minto production. Overall, Yukon's real GDP is forecast to grow 2.8 per cent in 2016.

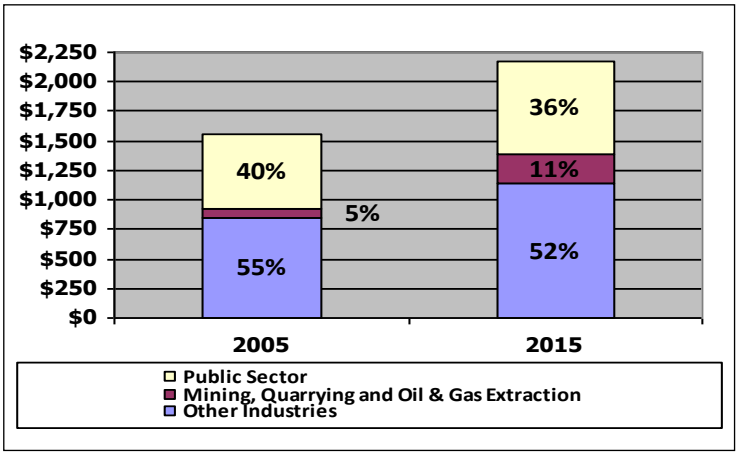


Figure 3 – Real GDP by Industry (2007$ millions)
Source: Department of Economic Development; Statistics Canada

Yukon's economic performance is linked to the performance of the global mineral industry. Expectations are for mineral prices to remain depressed for the medium-term, which will weigh on Yukon growth prospects beyond 2016. With Capstone Mining Corporation already noting that they plan to temporarily shut the Minto mine in the second quarter of 2017, the preliminary forecast for 2017 is for a contraction of 5.7 per cent.

Outlook for GDP

- Preliminary estimates from Statistics Canada note a third straight decline in Yukon's real GDP by industry, with the 2015 estimate of $2.177 representing a 3.8 per cent decline from $2.264 in 2014.
- Anticipated growth in mineral production in 2016 is expected to contribute to real GDP gains, with growth of 2.8 per cent forecasted for 2016.
- The preliminary forecast for 2017 is for a real GDP decline of 5.7 per cent, with the contraction related primarily to lower mineral production.

POPULATION

Population is estimated to have grown for the 12th consecutive year in 2015. Annual population in 2015, as represented by the June 2015 figure, was 37,343, up slightly from 37,251 in June 2014.

Whitehorse[11] – at 28,872 – accounted for over 77 per cent of Yukon's total population in June 2015. Serving as Yukon's primary goods and services hub, population gains in Whitehorse have accounted for the majority of Yukon's recent population growth.

Of the remaining Yukon communities, only two had populations above 1,000 in 2015, Dawson City at 2,067 and Watson Lake at 1,469.

Expectations for the near-term are for modest population gains in the next two years. The current forecast is for population to grow by 0.7 per cent in 2016, followed by growth of 0.3 per cent in 2017. The population forecast represents in part the generally weaker outlook for Yukon's economy. Ongoing weakness in the mining sector and the local economy also presents downside risk to the near-term outlook for population.

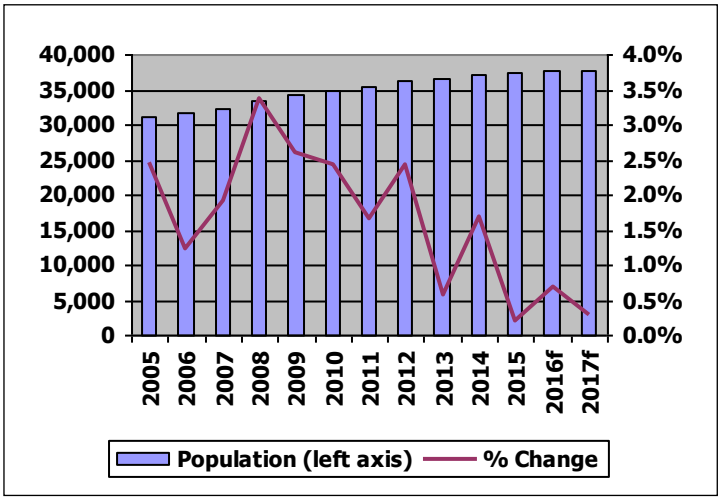


Figure 4 – Yukon Population (June)

Source: Department of Economic Development; Yukon Bureau of Statistics

Outlook for Population

- Following growth of 0.2 per cent in 2015, gains in population in the near-term are expected to remain modest with growth of 0.7 per cent in 2016 and 0.3 per cent in 2017.

LABOUR MARKET

Yukon's labour market has generally performed well in recent years, with Yukon's unemployment rate tracking below the national average for over a decade (see Figure 6). During this time, record levels of employment and labour force have been recorded, with Yukon's unemployment rate amongst the lowest in the country.

Even in light of the struggles for the local economy in 2013 and 2014, Yukon's labour market proved resilient, with notable growth in the labour market and employment, and an unemployment rate that fell to 4.3 per cent.

Signs of weakness in the local labour market were noted in 2015. While Yukon's labour force remained unchanged at 20,700 in 2015, employment fell to 19,400, down 400 from the record level of 19,800 noted in 2014. While down, the number of people employed in Yukon in 2015 was the second highest on record. With no change in the labour force and falling employment, Yukon's unemployment rate increased to 6.3 per cent, up markedly from 4.3 per cent in 2014.

The outlook for Yukon's labour market in 2016 is for marginal growth in both the labour force and employment, with an increase in the unemployment rate for a second consecutive year. With expected GDP growth in 2016 stemming primarily from an increase in mineral production from a mine that is already in production, there is no expectation that this will have a positive impact on local employment. In fact, with Capstone Mining Corporation announcing that it will be ceasing underground mining operations in 2016, local employment losses at the mine are anticipated.

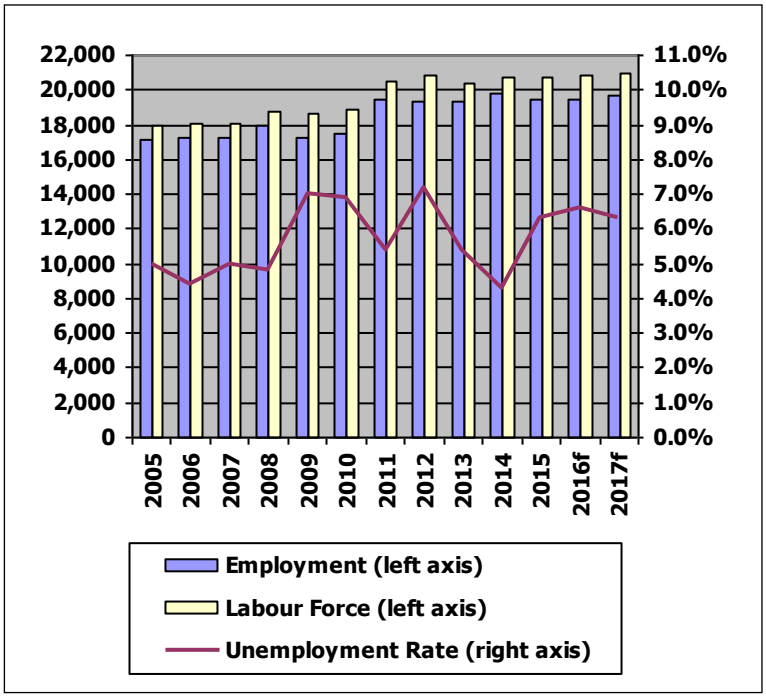


Figure 5 – Key Labour Market Statistics
Source: Department of Economic Development; Statistics Canada

Employment in 2016 is expected to see a modest increase averaging near 19,500. The labour force is also expected to grow, increasing to almost 20,900. A further increase in the unemployment rate is forecasted, increasing to 6.6 per cent in 2016.

Preliminary expectations are for little change in Yukon's labour market in 2017. The number of people employed and the size of the labour force are expected to see minor increases. With the gains in employment to exceed those of the labour force Yukon's unemployment rate is expected to decline slightly to 6.3 per cent.

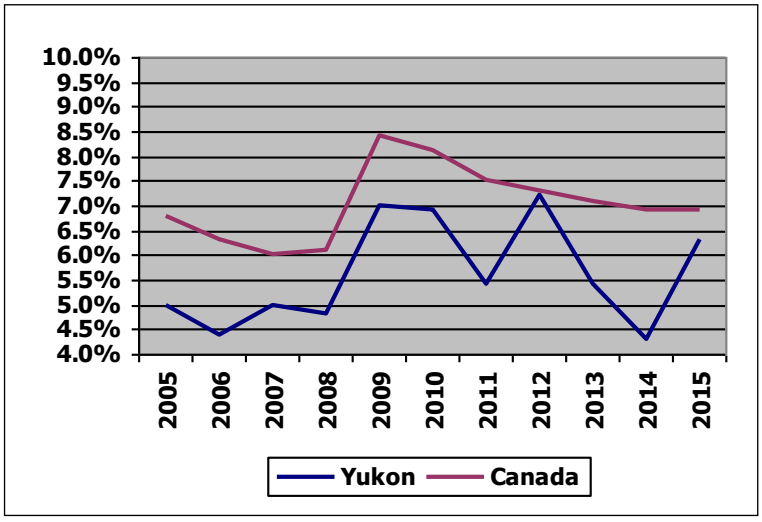


Figure 6 – Unemployment Rate – Yukon vs. Canada
Source: Department of Economic Development; Statistics Canada

Outlook for the Labour Market

- Weaker economic outlook reflected in near-term expectations for the labour market.
  - Average employment is expected to grow slightly in 2016 and 2017.
  - Average labour force expected to increase modestly in 2016 and 2017.
  - Yukon's unemployment rate in 2016 is expected to increase, before a slight decrease in 2017.

CONSUMER PRICE INDEX

Inflation in Whitehorse, as measured by the change in the Whitehorse Consumer Price Index (CPI)[12], has been low in recent years falling below 2.0 per cent over the 2013-2015 period.

The Whitehorse CPI actually declined in 2015, falling 0.2 per cent below the 2014 level. Nationally, CPI posted an increase of 1.1 per cent.

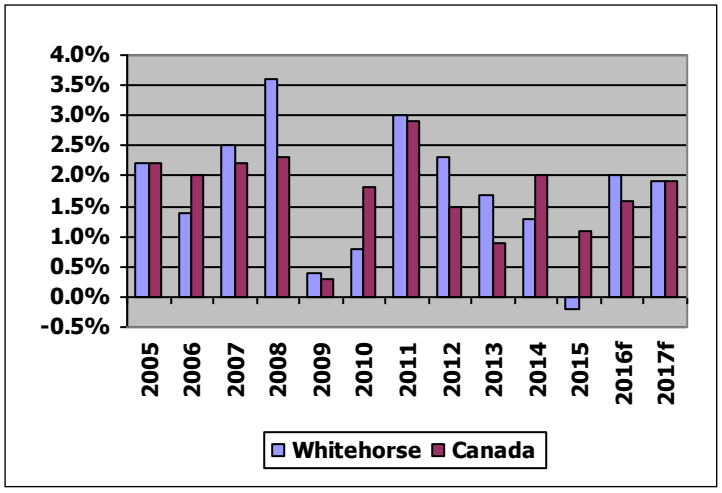


Figure 7 – Change in CPI: Whitehorse vs. Canada
Source: Department of Economic Development; Statistics Canada; BMO Capital Markets

Lower oil prices weighed on gasoline prices in 2015, with average gasoline prices in Whitehorse down about 16 per cent from 2014. Lower gasoline prices were reflected in the Gasoline component of CPI, down 15.7 per cent and the Transportation component, down 3.2 per cent.

The Shelter component of CPI was also down in 2015, 2.4 per cent lower than the average 2014 figure. Lower prices for home heating fuel in Whitehorse, down almost 20 per cent from 2014, helped to contribute to lower shelter costs in 2015.

CPI Components that posted notable price increases in 2015 included Clothing and Footwear (3.0 per cent), Alcoholic Beverages and Tobacco Products (2.4 per cent), Food (2.2 per cent) and Recreation, Education and Reading (2.2 per cent).

Current expectations are for prices to pick up steam in 2016, growing 2.0 per cent. Contributing to this increase is the expectation of higher food prices, partly due to the expectation of the weakness in the Canadian dollar to persist throughout 2016, as well as the expectation that fuel prices might begin to increase later in the year.

Beyond 2016 prices are expected to continue to increase, with a further increase of 1.9 per cent in the Whitehorse CPI growth in 2017.

Outlook for CPI

- Following price deflation of 0.2 per cent in 2015, the Whitehorse CPI is expected to increase by 2.0 per cent in 2016 and 1.9 per cent in 2017.

PART B: ECONOMIC SECTORS

MINING

Weak mineral prices continue to weigh on the global mining sector, contributing to mine closures, layoffs, project delays, and generally lower levels of spending.

Not surprisingly, Yukon's mining sector has also been negatively impacted with two mine closures since the beginning of 2013 and far lower levels of exploration and development spending than what has been experienced in recent history.

While Yukon's world-class geology does position the territory favorably for future growth in the mining sector, the relatively poor outlook for mineral prices has created substantial uncertainty for exploration, development and production activities going forward.

MINERAL EXPLORATION

A weaker environment for mineral prices prevailed throughout 2015 contributing to an inability of many mining companies, particularly junior mining companies, to raise capital to finance exploration activities. A number of operators also took steps to lower costs in response to lower prices.

Yukon, like many jurisdictions, saw less activity related to exploration and lower levels of spending. With much of the exploration work undertaken in the territory completed by junior mining companies, the difficulty of juniors to raise money has seen exploration expenditures fall off substantially. Natural Resources Canada's (NRCAN) latest *Survey of Mineral Exploration, Deposit Appraisal and Mine Complex Development Expenditures*, released in February 2016, estimates exploration spending[13] fell to $73.3 million in 2015, down from $107.1 million, spending in 2015 and well below spending of $331.7 million in 2011 and $233.2 million in 2012.

Following a period where a much greater proportion of exploration-related spending was associated with "exploration"[14] activities, recent years have seen more spending in the areas of deposit appraisal[15]. NRCAN's spending estimate for 2015 includes an estimated $45.3 million related to expenditures on deposit appraisal and the remaining $28.0 million associated with exploration. At $45.3 million, spending on deposit appraisal accounted for almost 62 per cent of the total spending figure, far higher than during the last exploration boom which saw deposit

appraisal spending of $40.7 million (26 per cent), $76.0 million (23 per cent) and $52.9 million (23 per cent) in 2010, 2011 and 2012, respectively.

Estimates from the Department of Energy, Mines & Resources (EMR) have exploration expenditures of about $65 million in 2015, down from EMR's estimate of $80 million in 2014. EMR exploration spending estimates are generally lower than NRCAN estimates as the NRCAN spending numbers include such expenditures as related road development and environmental baseline work. The EMR number is more representative of spending on pure exploration work such as drilling and geochemical. Differences between EMR and NRCAN exploration spending numbers can also occur because the NRCAN numbers are based on a survey completed early in the year while EMR numbers are based on announced company budgets.

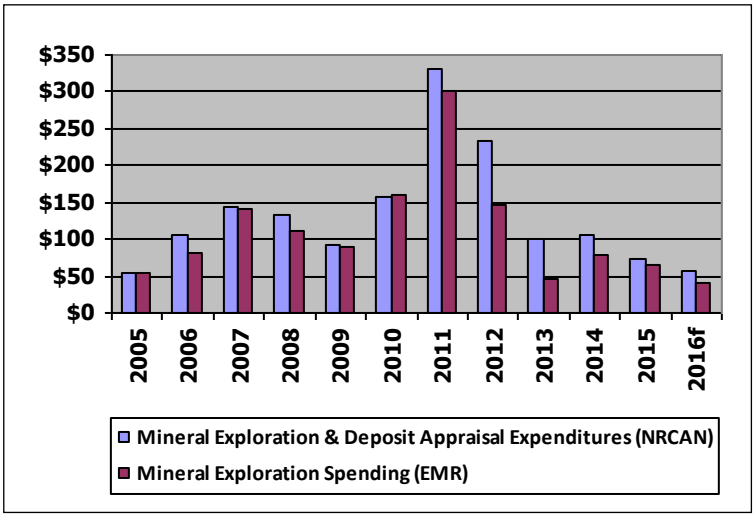


Figure 8 – Mineral Exploration Expenditures ($ millions)
Source: Department of Economic Development; Natural Resources Canada

The near-term outlook for the global mining sector remains poor, as global mining prices are expected to remain well below recent highs. Mining companies are anticipated to continue to take steps to keep costs low with spending on exploration and development activities remaining relatively low. Current estimates from EMR have exploration spending in 2016 falling to approximately $40 million, with spending by BMC Minerals Ltd. at its Kudz Ze Kayah property expected to account for about half of the total spending. Results of NRCAN's latest spending intentions survey have exploration related expenditures in 2016 at $56.4 million, also down from its 2015 spending estimate.

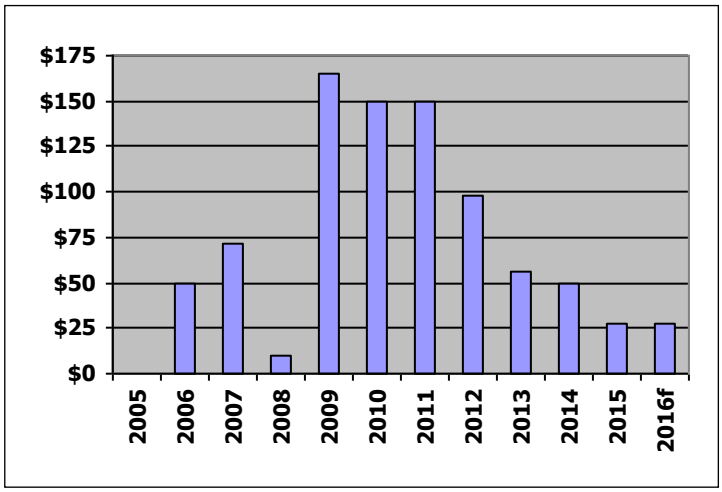


Figure 9 – Mineral Development Expenditures ($ millions)
Source: Department of Economic Development; Department of Energy, Mines & Resources

MINING DEVELOPMENT

With no mines in development, spending over the past three years has fallen well under recent highs.

Development spending in 2015 was estimated at just under $30 million, down from about $50 million in 2014. Almost two-thirds of the 2015 spending estimate is associated with expenditures at the Minto mine related to the continued expansion of underground mining.

EMR's development expenditure forecast for 2016 has spending at slightly below the 2015 estimate.

MINERAL PRODUCTION

After approaching $500 million in 2012, the value of mineral production has fallen in every year since. Closures of the Bellekeno mine in September 2013 and the Wolverine mine in January 2015 account for the majority of the recent declines.

The notable decline in the value of mineral production in 2015 was the result of both lower production and substantially lower year-over-year prices. The closure of the Wolverine mine in January 2015 accounted for the majority of the decline in mineral production. As illustrated in Figure 10, after approaching $500 million in 2012, the value of mineral production in 2015 fell below $250 million.

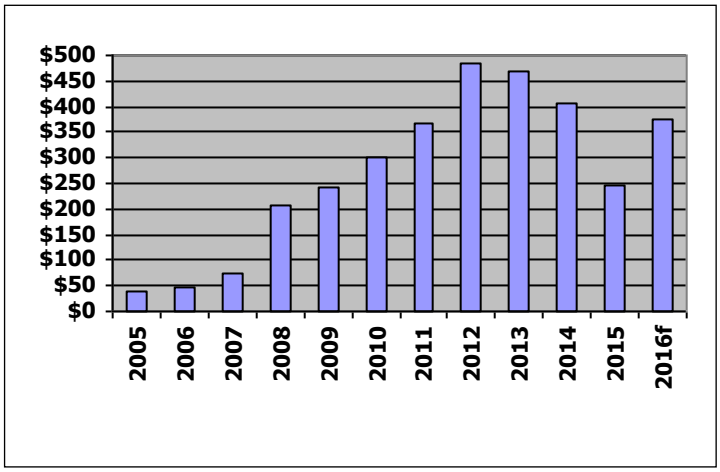


Figure 10 – Value of Mineral Production ($ millions)
Source: Department of Economic Development; Natural Resources Canada

Looking to 2016, expectations are for prices to remain weak and to fall below 2015 levels. Production on the other hand is expected to increase markedly with Capstone Mining Corporation's production guidance[16] for 2016 indicating production well above the 2015 level. The current outlook for the value of mineral production is for growth of over 50 per cent to about $375 million.

Placer mining continues to be a positive story for Yukon's mining sector. Over the past four years, the value of placer production has averaged almost $70 million, making it a significant contributor to Yukon's total value of mining. For the period 2013 to 2015, placer gold production has averaged almost 59,000 crude ounces. Placer gold production in 2016 is expected to be similar to the over 62,000 crude ounces produced in 2015.

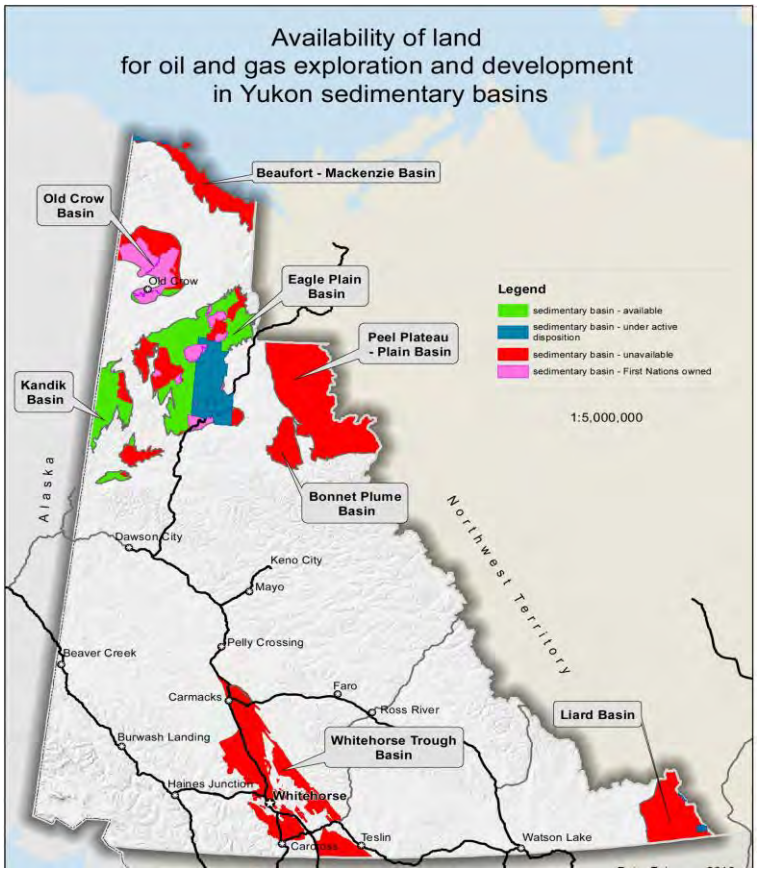
Beyond 2016, further headwinds for Yukon's mining sector are anticipated. The outlook for mineral prices remains poor which is expected to continue to dampen mining-related spending. With the January 2015 announcement by Capstone Mining Corporation that they plan to temporarily cease operations of the Minto mine in early 2017, the value of mineral production will likely fall to the lowest level since 2008 which was the first full year of Minto production.

Outlook for Mining

- Exploration and development spending in 2016 expected to fall below 2015 levels.
- Increased Minto production is expected to contribute to gains in the value of mineral production in 2016, but the planned temporary shutdown of the Minto mine in early 2017 will significantly impact next year's mineral production.

OIL & GAS

Yukon is home to significant hydrocarbon resources, both onshore and offshore. Yukon's onshore sedimentary basins contain an estimated 14.77 trillion cubic feet (Tcf) of conventional natural gas and 663 million barrels (MMbbls) of conventional oil. Offshore conventional resources in the Beaufort Sea include an additional estimated 40 Tcf of natural gas and 4,500 MMbbls of oil. Yukon also has the potential to host significant unconventional oil and gas resources although further assessment work is required.



Since production ceased at the Kotaneelee field in September 2012, there has been no commercial hydrocarbon production in Yukon. EFL Overseas Inc. (EFLO) has a 54 per cent working interest in the Kotaneelee field, and had been interested in workovers of existing wells. At this time EFLO has no plans to start this work in the foreseeable future.

Interest has also been shown in the hydrocarbon potential of the Eagle Plain Basin in Northern Yukon. Supported by investment from China National Offshore Oil Corporation (CNOOC), Northern Cross (Yukon) Limited has spent more than $100 million since their current exploration program began in late 2011.[17] Northern Cross's multi-well exploration program that was submitted to YESAB in 2014, proposes to drill and conduct extended flow tests on up to 20 exploratory oil and gas wells in the area that it completed a 3D seismic program in early 2014. Wells are planned to be drilled and tested from December to mid-April and from May to October, over a period of eight years.[18] These wells would be in addition to the four wells drilled in 2012 and 2013. Citing concerns about the uncertainty of the drilling program's impacts on the Porcupine Caribou Herd, YESAB released an evaluation report that referred the exploration program to the Executive Council for screening.

Future oil and gas development in Yukon is inherently tied to the performance of oil and gas prices. Looking at the performance of the past 10 years, natural gas prices are shown to be quite variable, going as high as US$8.86 MMBTU in 2008 and falling as low as US$2.63 MMBTU in 2015.[19] At US$2.63 MMBTU, the price was down over 40 per cent from US$4.39 MMBTU in 2014. Many forecasters are calling for prices to decline in 2016, before posting growth in 2017.

Like natural gas, oil has seen its price decline substantially in recent history. After averaging over US$90 per barrel in every year from 2011 to 2014, oil prices declined dramatically in 2015,

averaging US$48.69 per barrel, down 48 per cent from 2014 and the lowest annual average since US$41.44 per barrel in 2004.[20] Increased supply and weaker demand have contributed to lower oil prices, and these factors are expected to continue to weigh on oil prices in the near term as oil is expected to average about US$40 per barrel in 2016. Prices are expected to recover somewhat in 2017, averaging almost US$50 per barrel, well below levels seen in the last ten years.

Any development of Yukon's hydrocarbon resources will be shaped in part by decisions related to the production process of hydraulic fracturing. In an effort to engage with Yukoners and generate discussion on what has become a high profile, public topic, the Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing was formed.

The final report of the Select Committee was released on January 19, 2015 and included 21 recommendations. The recommendations focus on the need for continued public dialogue, continued First Nation engagement, detailed assessment of the economic, human health and social impacts, more baseline data and scientific research around water, greenhouse gases, air emissions, wildlife and induced seismicity and assurance that regulatory processes will protect the safety of people and the environment.

The Government of Yukon has stated that it agrees with all 21 recommendations, and has developed an Action Plan on Oil and Gas Development to address many of these areas. Included in this Action Plan is a plan for dialogue on how to responsibly develop oil and gas resources with the public and First Nations; the need to conduct a study of the economics associated with unconventional oil and gas development; requirement for baseline water monitoring work; the need for expanded seismic baseline data; and a discussion of exploring partnerships with affected First Nations and other potential partners.[21]

Outlook for Oil & Gas

- Future development will depend on a number of factors including the performance of oil and natural gas prices and decisions made related to the use of hydraulic fracturing in the territory.
- There is interest in using LNG for power generation in proposed mines in Yukon.
- Production of local resources could offset future hydrocarbon imports.

TOURISM

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

Tourism activities over-lap a number of industries, therefore determining the economic contribution of tourism is not straight-forward. Accommodations & Food Services, Retail Trade and Transportation & Warehousing are three industry classifications where tourism related

activities are reflected strongly. One of the more recent attempts to capture the economic contribution of tourism is noted in the 2015 *Yukon Business Survey* where Yukon businesses are cited as attributing $226.9 million of their gross revenue in 2014 to tourism and based on these revenues the total GDP attributable to tourism was estimated at $95.9 million, representing almost four per cent of Yukon's total GDP in 2014.[22]

Based on reporting from the Canada Border Services Agency (CBSA), the Department of Tourism & Culture notes a decline in total border crossings for 2015, with 327,778 people crossing international borders in Yukon, a decrease of 13,929 or 4.1 per cent from 2014. Excluding Yukon residents, who are not traditionally considered tourists, total border crossings were down 7,151 people, or 2.4 per cent, over 2014. Since posting a 20-year low in 2009, crossings have been well over 300,000 annually, averaging over 330,000 for the period 2010 to 2014. While an imperfect indicator of tourism performance, international border crossings are often used as a performance measure.

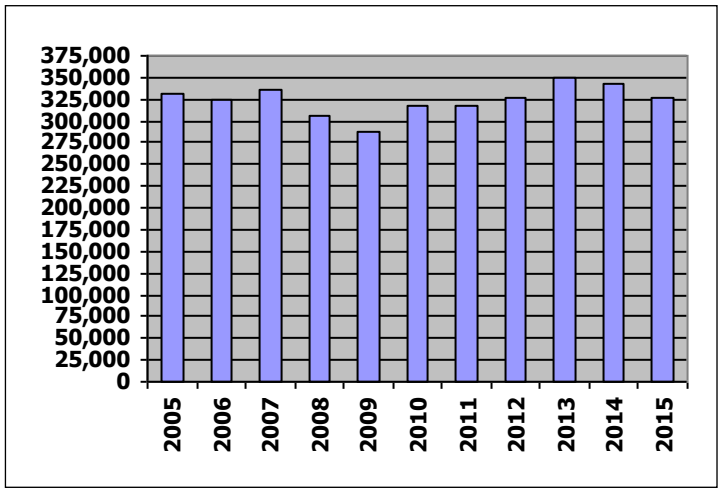


Figure 11 – Border Crossings
(Includes International Air Travel)
Source: Canada Border Services Agency

Anecdotally, Yukon's tourism industry has indicated that 2015 was a good year for tourism and a number of tourism indicators support their perspective. Air arrivals at Erik Neilson Whitehorse International Airport were up 1.7 per cent compared to 2014 with over 156,000 passengers arriving at the airport.[23] Visitation to Yukon Visitor Information Centres was also up 2.4 per cent recording 252,349 visits. Attendance at the Beringia Interpretive Centre was up 6.0 per cent and visitation to Parks Canada's Kluane National Park and Reserve and National Historic Sites were up 8.2 and 5.9 per cent, respectively, compared to the same period last year.[24] The number of non-residents camping at Yukon Government campgrounds was up 13.6 per cent, and the number of non-resident person nights spent at government campgrounds were up 16.6 per cent over 2014.[25]

Further, border crossings provided by U.S. Customs and Border Protection indicate that the number of people entering Alaska from Yukon were up 1.1 per cent to 404,751 people compared to the same period in 2014.[26]

Looking ahead, a weakened Canadian dollar, lower fuel prices, improving consumer confidence, and gains in domestic airline seat capacity are prominent among the factors that will likely impact tourism activities in the near-term.

After a prolonged period where the Canadian dollar performed well against the US dollar, often trading above par, the dollar saw a significant devaluation in 2015 and this has continued into 2016. The Canadian dollar traded at over US$0.90 for the majority of 2014 but began trending downward in the fall of the year. By the end of 2015, the dollar was trading in the low 70s, and in January 2016 dipped below US$0.70 for the first time since 2003. The persistence of a

weaker Canadian dollar may bode well for local tourism operators as visitation becomes more affordable for U.S. and some overseas visitors and may also result in Canadians becoming more inclined to vacation in their own country.

Lower oil prices have translated into lower gasoline prices. Lower fuel prices decrease the cost of travel via personal motor vehicle, and also possibly the costs of travel via motorcoach and airplane, if a portion of the fuel savings are passed along to the customer. Oil prices have fallen dramatically, down over 70 per cent in the last year and a half. Lower oil prices have contributed to lower fuel prices, with the price of regular unleaded gasoline in Whitehorse near $1.00 per litre at the time of writing.

As noted, anecdotal information for 2015 indicates that it was a positive year for the local tourism community. Expectations are that 2016 and 2017 will continue to grow upon the recent positive performance.

Outlook for Tourism

- Expectations are that the near-term will build on what many local operators noted as a good year in 2015.

CONSTRUCTION

Following a 65 per cent increase to $130.5 million in 2014, the value of building permits in 2015 are reported as falling to $117.7 million.

The value of non-residential permits declined in 2015, falling 2.6 per cent to $81.6 million. While down, non-residential permits continued to account for the majority of building permit value in 2015, representing 69 per cent of the annual total. Since the start of 2010, non-residential building permit value accounted for 59 per cent of the total building permit value of over $730 million.

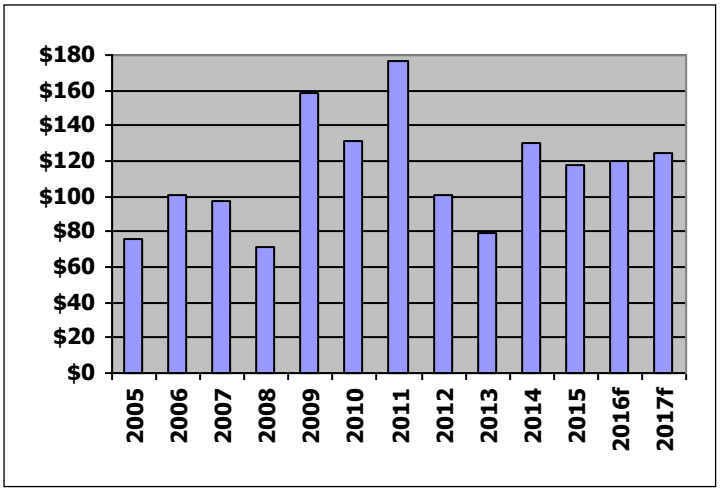


Figure 12 – Value of Yukon Building Permits ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Contributing to the decline in non-residential permits in 2015 was a significant decline in the value of industrial permits which fell from $5.8 million to $769,000. Commercial permit value also fell in 2015, totalling $27.0 million, down about 15 per cent from $31.6 million in 2014. Countering a portion of the decline in non-residential permit value was an increase in government/institutional permit value, up 16 per cent to $53.9 million.

The value of residential permits showed a more significant decline in 2015, falling 22.5 per cent to $36.1 million. After totalling over $71 million in 2011 and almost $66 million in 2012, residential permit value has averaged about $39 million over the last three years. For the period 2010 to 2015, residential building permits accounted for 41 per cent of total building permit value, totalling just over $300 million.

Weaker residential activity in 2015 is also supported by the most recent Northern Housing Report[27] from the Canada Mortgage & Housing Corporation (CMHC), which forecasts a near 13 per cent decline in the number of housing starts, falling from 212 in 2014 to 185 in 2015. The annual decline in 2015 is noted as being similar for both single-detached starts, down 12.8 per cent to 95, and multi-family starts, down 12.6 per cent to 90. At 185, total starts in 2015 are well below the high of 332 in 2011, and the average of the previous five years of over 240 starts.

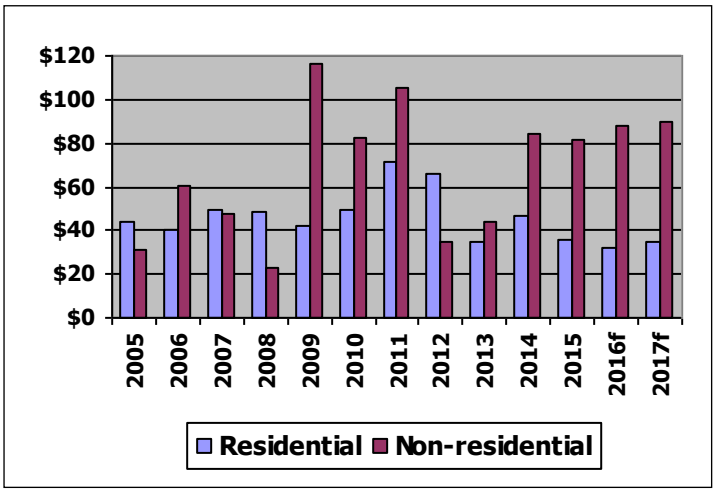


Figure 13 – Value of Yukon Building Permits – Residential vs. Non-residential ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

While falling below the record capital spending of $313 million noted for 2015-16, the 2016-17 territorial budget delivered on April 7, 2016 includes a total capital spending figure of $306.6 million. Key areas of spending identified for 2016-17 include:

- Notable projects associated with health and social services, included continued work on a 150-bed continuing care facility in Whitehorse ($66.9 million), $21.9 million for the ongoing Whitehorse emergency department expansion and MRI at the Whitehorse General Hospital, a further $8.3 million for the new Salavation Army building being constructed in Whitehorse, an additional $7.3 million for replacement of the Sarah Steele alcohol and drug detox centre, and $1.7 million for the 6th Avenue continuing care facility in Whitehorse.
- Notable capital projects associated with supporting and improving community services include $21.7 million under the New Building Canada Fund including spending on a new wastewater treatment plant in Burwash Landing and upgrades to the Mayo water reservoir, $15.0 million associated with planning of phases 3-7 of the Whistle Bend sub-division, $4.4 million for upgrades to the Government of Yukon's main administration building, $3.0 million for a new firehall in Carcross, $2.2 million for a wastewater treatment facility in Ross River and $2.0 million for the sewage system in Carmacks.
- Among the notable projects related to transportation are the $12.0 million identified for spending on rehabiliating sections of the road covered under the Alaska Highway-Shakwak Agreement, $11.4 million for reconstruction and rehabilitation of the Robert Campbell Highway, $3.1 million for Dempster Highway erosion and rehabilitation, $3.9 million for work on the Erik Nielsen Whitehorse International Airport, $2.8 million for Community Airport improvements, and $2.5 million for Whitehorse Corridor passing and turning lanes on the Alaska Highway.

- The majority of education specific spending remains associated with the replacement of the F.H. Collins school in Whitehorse. The 2016-17 budget notes $3.0 million for construction of the F.H. Collins Technical Education Wing and $2.9 million for site development of the old F.H. Collins School.
- Other notable projects identified in the 2016-17 budget include $7.2 million from the CMHC for Investments in Affordable Housing, $5.6 million for the expansion of the Department of Tourism & Culture's Archives Vault Expansion, $4.0 million under the the Rural Land Development Program and $3.0 million for the construction of a 6-unit residential staff housing building in Ross River.

The City of Whitehorse's building consolidation project is another major initiative that will impact the local economy in the near-term. The City of Whitehorse's Capital Budget 2016-2019 notes a total capital cost of over $56 million for this project with almost $50 million of that slated to be spent in 2017.

Because of questions regarding timing of permits, and what future construction activities may require permits, forecasting the value of building permits can be difficult. As well, the performance of mineral prices and the subsequent impact on the local mining sector continue to be key determinants of the nature and level of construction activity in Yukon. Given the current uncertainty in the global mining sector and what it could mean for local mining activities, the risk to the building permit outlook is elevated. In terms of the value of building permits, modest gains in the value of residential and non-residential building permits are anticipated for 2016 and 2017 with growth focused primarily in non-residential permits.

Outlook for Construction

- The value of building permits is expected to grow modestly in the next two years.
    - Construction activities in the realm of health and social services are expected to be a key driver of the value of institutional building permits and overall building permits in the near-term.

RETAIL TRADE

Data from Statistics Canada indicates that Yukon reported a record level of retail sales in 2015, with the value of $692.2 million[28] representing annual growth of 4.7 per cent from $660.9 million. While growth in 2015 was anticipated, the impressive annual growth was unexpected given recent weaker economic performance.

Among categories of retail sales that are not suppressed for Yukon, sales from Food and Beverage Stores represented the largest component in 2015 accounting for over 29 per cent of total sales, increased by 2.7 per cent to $203.4 million. The value of sales related to Gasoline stations, the second largest component of retail sales, were reported as increasing slightly (up 0.3 per cent) to $107.8 million in 2015 as lower gasoline prices dampened sales. Sales from Health and Personal Care Stores were also reported as being up in 2015, with the estimated value of $37.5 million up 17.1 per cent from $32.0 million in 2014.

Sales from Furniture and Home Furnishings Stores were noted as being down in 2015, declining 4.6 per cent to $12.9 million.

Due to issues around confidentiality, retail sales data for other retail classifications are suppressed.[29] Total sales from these suppressed classifications in 2015 totalled $330.7 million, well above the $310 million recorded in 2014.

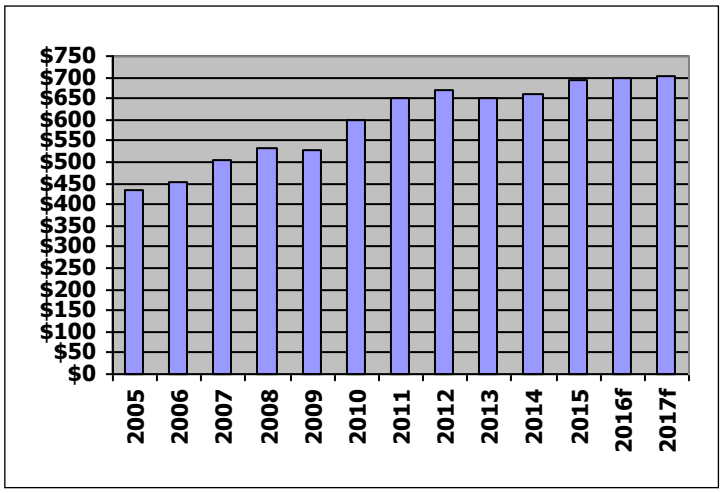


Figure 14 – Value of Retail Sales ($ millions)
Source: Department of Economic Development; Yukon Bureau of Statistics

Growth in the short-term is expected to be modest with the current forecast calling for growth of 0.8 per cent in 2016 and 1.1 per cent in 2017.

Outlook for Retail Trade

- Statistics Canada reports the value of retail sales in 2015 at over $692 million, up 4.7 per cent from $660.9 million in 2014.
- Retail sales are forecast to grow 0.8 per cent in 2016 and a further 1.1 per cent in 2017.
- A weaker economy and continued weakness in the mining sector increases the uncertainty for the near-term performance of retail sales.

KEY ECONOMIC INDICATORS

Indicator	*2014*	*2015*	*2016f*	*2017f*
Population, Prices, Rates				
Population (June)	37,251	37,343	37,600	37,750
Population Growth Rate	1.7%	0.2%	0.7%	0.3%
CPI Growth Rate^	1.3%	-0.2%	2.0%	2.0%
Overnight Rate	1.00%	0.63%	0.50%	0.69%
Canada/U.S. Exchange Rate	$0.906	$0.783	$0.757	$0.777
Employment ƒ				
Labour Force	20,700	20,700	20,900	21,000
Employment	19,800	19,400	19,500	19,650
Unemployed	900	1,300	1,400	1,350
Unemployment Rate	4.3%	6.3%	6.6%	6.3%
Economic Output				
Real GDP By Industry (billions of chained 2007 $)	$2.264 (r)	$2.177 (p)	$2.238	$2.111
Real GDP Growth Rate	-0.8%	-3.8%	2.8%	-5.7%
Commodity Prices~				
Gold ($US/oz)	$1,266	$1,160	$1,170	$1,150
Silver ($US/oz)	$19.08	$15.70	$14.75	$15.00
Zinc ($US/lb)	$0.98	$0.88	$0.80	$0.95
Copper ($US/lb)	$3.11	$2.50	$2.10	$2.20
Oil - WTI ($US/bbl)	$93.26	$48.69	$37.00	$47.00
Natural Gas – Henry Hub ($US/MMBTU)	$4.39	$2.63	$2.25	$3.20
Mining				
Value of Mineral Production	$408.0 million (r)	$246.9 million (p)	$375 million	--
Exploration Expenditures	$107.1 million	$73.3 million	$56.4 million	--
Development Expenditures	$50 million	$28 million	$27 million	--
Construction				
Permitted Building Construction	$130.5 million	$117.7 million	$120 million	$125 million
Trade				
Value of Retail Sales	$660.9 million	$692.2 million	$698 million	$705 million
Tourism				
Non-resident Border Crossings+	341,707	327,778	--	--

f = forecast, e = estimate, p = preliminary, r = revised, -- = not available
^ CPI increase for Whitehorse only
ƒ annual averages – Labour force and employment rounded to nearest 100. Totals may not add due to rounding.
~ annual averages
+ as reported by the Department of Tourism & Culture

DATA SOURCES FOR KEY ECONOMIC INDICATORS TABLE

Indicator	*Source*
Population	Yukon Bureau of Statistics, Yukon Population Estimates, Yukon Department of Economic Development
Inflation (Consumer Price Index)	Statistics Canada, Consumer Price Index, Yukon Department of Economic Development
Overnight Rate	BMO Capital Markets
Canada/U.S. Exchange Rate	BMO Capital Markets
Labour Force Indicators	Statistics Canada, Yukon Labour Force Survey, Yukon Department of Economic Development
Economic Output (Real GDP)	Statistics Canada, Provincial Economic Accounts, Yukon Department of Economic Development
Commodity Prices	BMO Capital Markets
Value of Mineral Production	Natural Resources Canada Minerals and Mining Statistics Division, Yukon Department of Economic Development
Mineral Exploration Expenditures	Natural Resources Canada; Minerals and Mining Statistics Division
Mine Development Expenditures	Yukon Department of Energy, Mines & Resources, Yukon Department of Economic Development
Tourism Visitation	Yukon Department of Tourism & Culture, Yukon Department of Economic Development
Permitted Building Construction	Yukon Bureau of Statistics, Yukon Department of Economic Development
Retail Trade	Statistics Canada, Yukon Department of Economic Development

ENDNOTES

[1] World Economic Outlook - Update. (April 2016). International Monetary Fund. http://www.imf.org/external/pubs/ft/weo/2016/01/pdf/text.pdf
[2] World Economic Outlook - Update. (April 2016). International Monetary Fund. http://www.imf.org/external/pubs/ft/weo/2016/01/pdf/text.pdf
[3] World Economic Outlook - Update. (April 2016). International Monetary Fund. http://www.imf.org/external/pubs/ft/weo/2016/01/pdf/text.pdf
[4] World Economic Outlook - Update. (April 2016). International Monetary Fund. http://www.imf.org/external/pubs/ft/weo/2016/01/pdf/text.pdf
[5] Monetary Policy Report Summary (January, 2016). Bank of Canada. http://www.bankofcanada.ca/wp-content/uploads/2016/01/mpr-2016-01-20.pdf
[6] Monetary Policy Report Summary (January, 2016). Bank of Canada. http://www.bankofcanada.ca/wp-content/uploads/2016/01/mpr-2016-01-20.pdf
[7] Bank of Canada maintains overnight rate target at ½ per cent. Bank of Canada. http://www.bankofcanada.ca/2016/04/fad-press-release-2016-04-13/
[8] Commodity Forecasts (April 20, 2016). BMO Capital Markets. http://www.bmonesbittburns.com/economics/goods/current/
[9] MMBTU refers to a million British thermal unit (Btu)
[10] The "Public Sector" is an aggregation of the industry classifications of Public Administration, Educational Services Health Care & Social Assistance and.
[11] Includes City of Whitehorse and surrounding area as well as the community of Marsh Lake.
[12] Consumer Price Index data is only available in Yukon for Whitehorse.
[13] Exploration and deposit appraisal expenditures include on-mine-site and off-mine-site activities; field work, overhead costs, engineering, economic and pre- or production feasibility studies, environment, and land access costs. Expenditures also include only the search for and appraisal of deposits and do not include work for extensions for known reserves.
[14] The exploration work phase is defined as the search for, discovery, and first delimitation of a previously unknown mineral deposit or the re-evaluation of a sub-marginal or neglected mineral deposit in order to enhance its potential economic interest based on delimited tonnage, grade, and other characteristics. The phase is completed when a deposit has sufficient indicated mineral resources accompanied by a positive scoping study (preliminary economic assessment that justifies additional, more detailed, and costly deposit appraisal work.
[15] The deposit appraisal work phase is defined as the steps undertaken to bring a delimited deposit, by definition drilling, comprehensive tests, and planning, to the stage of detailed knowledge required for a complete feasibility study that will fully justify and support a production decision and the large investment required.
[16] Capstone Mining 2016 Operating and Capital Guidance. http://capstonemining.com/news/news-details/2016/Capstone-Mining-2016-Operating-and-Capital-Guidance/default.aspx
[17] Northern Cross (Yukon) Limited Open House Presentations (June 16-18, 2014). http://www.northerncrossyukon.ca/upload/news_item/11/02/community-open-house-presentations-june-2014.pdf
[18] Eagle Plains Multi-well Exploration Program. Project Proposal Summary YESAB Registry. http://www.yesabregistry.ca/wfm/lamps/yesab/lowspeed/projectsummary.jsp;time=1434126836032
[19] EIA. U.S. Energy Information Administration. http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm
[20] EIA. U.S. Energy Information Administration. http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=rwtc&f=m
[21] Yukon Oil & Gas – Annual Report 2015. http://www.emr.gov.yk.ca/oilandgas/pdf/yukon-oil-and-gas-annual-report-2015.pdf
[22] Yukon Business Survey 2015. Yukon Bureau of Statistics. http://www.eco.gov.yk.ca/stats/pdf/2015_Business_Survey_Report.pdf
[23] Monthly Indicator Report; December 2015. Department of Tourism and Culture. http://www.tc.gov.yk.ca/pdf/12-dec-2015-indicator-report.pdf
[24] Parks Canada, Yukon Field Unit.
[25] Department of Environment, Parks Unit.

[26] Bureau of Transportation Statistics Border Crossing/Entry; January to December 2015. United States Department of Transportation. http://transborder.bts.gov/programs/international/transborder/TBDR_BC/TBDR_BC_Index.html
[27] Northern Housing Report 2015. CMHC. http://www.cmhc-schl.gc.ca/odpub/esub/65446/65446_2015_A01.pdf?fr=1456331518178
[28] Retail sales data is unadjusted for inflation.
[29] Data suppressed but included in the total: Motor Vehicle and Parts Dealers; Electronics & Appliance Stores; Building Material & Garden Equipment; Clothing & Clothing Accessories Stores Sporting Goods, Hobby, Book & Music Stores; General Merchandise Stores; and Miscellaneous Store Retailers, and Supplies Dealers.

YUB-YECL-31

Reference: Application, Organizational Chart, Section 1, Attachment 1.1; YECL 2013-15 GRA, Organizational Chart, Section 1, Attachment 1; Appendix A to Board Order 2014-06, page 23.

Issue/sub-issue: Accounting positions

Quote: From Appendix A to Board Order 2014-06, page 23 the Board stated:

> "Accordingly, the Board orders YECL to reduce its FTE complement in the test years by 3.0 FTEs, one of which must be from accounting and finance, and to provide an explanation in the compliance filing on how it plans to meet this reduction. More specifically, the Board approves a 2015 forecast ending complement of 70.39 (not including the two DSM-related FTEs YECL inadvertently excluded from its Application). The compliance filing should also provide a schedule demonstrating how these reductions will affect labour costs."

Request:

(a) Please confirm that in the YECL's 2013-15 GRA, YECL applied for 7.17 FTEs (page 2 of Attachment 1 – 4.17 positions, and page 1 of Attachment 1 – 3 positions) for accounting and admin-related positions (Accounting and admin related are defined as head office personnel plus the financial analyst and financial assistants). If not confirmed, please provide the correct amount and list each position with its FTE.

(b) Please confirm that the total number of accounting and admin related positions approved by the Board was 6.17.

(c) Please confirm that the total number of accounting and admin positions (Accounting and admin related are defined as head office personnel plus the operational accountant, the financial assistants and the Supervisor, Business Support Services) applied for in the current application is 8.42. If not confirmed, please provide the correct amount and list each position with its FTE.

(d) Please explain the difference in the "Other Head Office" total of 2.67 FTEs in the current application versus 1.67 FTEs in the 2013-15 GRA.

(e) Please explain whether AE has or plans to contract any if the "Other Head Office" functions listed on page 2 of Attachment 1.1 to an outside party.

(f) If part (e) is confirmed, please explain the impact on YECL.

(g) Please confirm that the costs associated with the employment of either the Supervisor, Financial Services or the Corporate Accountant only relate to work for YECL and have not or do not perform any duties for other affiliates, corporate office or the parent ATCO Electric.

(h) Please explain why 50 percent of the time for the VP Northern Development, Manager, Financial Reporting & Accounting North of 60 is charged to YECL? Please explain why YECL receives a larger share of the costs than Northlands (Yellowknife) and Northlands (NWT).

(i) Regarding the issues and regulatory proceeding concerning the Hay River franchise in the NWT, please explain the impact of that process on the time allocations of the VP Northern Development, the Manager, Financial Reporting & Accounting North of 60 and any of the Head Office allocations.

Response:

(a) Confirmed.

(b) Confirmed.

(c) Confirmed.

(d) The additional FTE in head office costs is a reallocation of the Customer Care and Billing processes that were previously included in the services being provided by ITEK Business Solutions and are now being completed by Head Office personnel. Overall, AEY has seen a reduction in Customer Care and Billing costs.

The processes included in head office costs are billing quality assurance, financial activities, monthly balance and control processes as well as ad hoc requests and support. Services not included that were previously provided by ITEK Business Solutions are distribution, enhancement and support of the ATCO CIS system as well as statement and postage charges.

(e) ATCO continues its company-wide initiatives to find efficiencies and reduce costs, and as part of this initiative some of the head office costs may be contracted to outside parties in the future.

(f) AEY is unable to quantify any impact, if any, at this time.

(g) Confirmed.

(h-i) The cost allocation of the Manager, Financial Reporting and Accounting North of 60 is based on various factors including:

- AEY's capital program is twice the size of Northland Utilities
- AEY has more than a 40-percent higher FTE complement than Northland Utilities
- AEY has more than 60-percent higher number of customers than Northland Utilities
- AEY provides service to more than double the communities Northland Utilities provides service to

Due to these factors, the Manager, Financial Reporting and Accounting North of 60 spends approximately half of their time on AEY matters and as such, AEY submits the allocation is reasonable.

The VP, Northern Development position has replaced the General Manager role that was previously allocated 80% to AEY and 20% to Northland Utilities.

Due to the Franchise matters occurring in the NWT, the allocations of the VP, Northern Development were revisited and reduced to 50% to AEY and 50% to Northland Utilities. In addition to the issues in the NWT, this position is also involved in matters within the Yukon such as IPP Policy development and diesel displacement activities that contributes to the 50/50 allocation.

YUB-YECL-32

Reference: Application, page 1-6, Attachment 1.1, page 2.

Issue/sub-issue: Supervisor, Business Support Services

Quote: "This 0.25 FTE position was added to oversee the Financial Assistants as well as perform accounts payable and accounts receivable duties previously done by the Financial Analyst. This position will also perform general business support services."

Request:

(a) The organization chart shows Accounts Payable as a Head Office function. Please explain the need for further supervision of a head office support function.

(b) YECL is seeking approval of 8.42 accounting and admin positions. Of those requested positions, one is for a Manager, Financial Reporting, one is for a Supervisor, Financial Services, and 0.25 is for a Supervisor, Business Support Services. This results in a ratio of 2.25 supervisors to 6.17 non-supervisor FTEs. Please explain the need for 2.25 supervisors for 6.17 employees. Further please explain the need for a 36-percent increase in accounting and admin resources.

Response:

(a) The accounts payable function provided by head office is for system and support and is not a significant portion of the allocated Head Office FTEs.

The Supervisor, Business Support Services oversees the daily accounts payable and invoicing processes as well as the support staff of these functions based in Whitehorse. Additionally, business support tasks that were previously performed by the Executive Assistant role, that no longer exists, are now performed by the Supervisor, Business Support Services.

(b) AEY is seeking approval of 8.42 accounting and admin positions as provided in response YUB-YECL-31 "head office personnel plus the operational accountant, the financial assistants and the Supervisor, Business Support Services". Of these 8.42 positions, 1.75 are supervisory:

a. 0.5 FTE Manager, Financial Reporting & Accounting North of 60
b. 1.0 FTE Supervisor, Financial Services
c. 0.25 FTE Supervisor, Business Support Services

AEY does not believe that there has been a 36-percent increase in accounting and admin resources included in this Application. AEY reduced 1.0 FTE resource with the elimination of the Executive Assistant and has added 2.25 FTE resources for a net addition of 1.25 FTE.

An additional 1.0 FTE in head office is for customer care and billing services that were previously resourced through ITEK Business Solutions. This is not an additional resource but a reallocation of previously approved resources.

An additional 0.25 FTE is only a 3-percent increase in accounting and admin resources. AEY requires sufficient resources in this function to manage increasing regulatory and audit requirements as well as to provide financial, business and administrative support for all current business functions of a regulated utility, as well as, and new initiatives such as Yukon Government's IPP policy and diesel displacement initiatives.

Despite this addition in accounting and admin resources, AEY complement remains at 70.38 to the end of 2017. In Board Order 2014-06 Appendix A: Reasons for Decision, page 20 the Board stated:

> *"The Board is of the view that more discipline must be exercised by YECL in the growth of its employee complement; however, the Board does not know, and will not speculate on, which positions are more important or necessary to the Applicant. In the Board's view, the Applicant knows best how to allocate and optimize its human capital resources."*

AEY has managed to allocate and optimize its human capital resources within the 70.39 complement approved in Board Order 2014-06.

YUB-YECL-33

Reference: Application, Organizational Chart, Attachment 1.1; YECL 2013-15 GRA Application, Organizational Chart, Attachment 1

Issue/sub-issue: Supervisor, Customer Accounting & Administration, Customer Service Advisors

Request:

(a) Please explain how the FTE amounts for the Supervisor, Customer Accounting and Administration (0.93) and the Customer Service Advisors (4.93) were determined.

Response:

(a) The Supervisor, Customer Accounting and Administration and a Customer Service Advisor are the "super users" for the ATCO CIS system which is also utilized by Northland Utilities. Based on historical usage, these two positions spend approximately 2.5 hours per week on Northland related matters which equates to 7% of their costs being charged to Northland Utilities. This allocation is unchanged since YECL's 2013-2015 GRA.

YUB-YECL-34

Reference: Application, Organizational Chart, Attachment 1.1

Issue/sub-issue: Head Office Personnel

Request:

(a) Are each of the Supervisor, Customer Accounting & Administration, Customer Service Advisors, Supervisor, Business Support Services and the VP Northern Development positions located in the YECL offices in Yukon or are they located in Head Office in Alberta?

(b) If any of the above noted positions, or any other position, are not located in the YECL offices in Yukon, please explain why they are not included as part of Head Office personnel.

Response:

(a) The Supervisor, Customer Accounting and Administration and the Customer Service Advisors positions are located in the AEY offices in Whitehorse. The Supervisor, Business Support Services position is located in Yellowknife and the VP Northern Development position is located in Alberta.

(b) The Supervisor, Business Support Services and VP Northern Development positions are not considered Head Office personnel because they are not employees of AEY's parent company ATCO Electric.

YUB-YECL-35

Issue/sub-issue: Trade name of ATCO Electric Yukon

Request:

(a) Please provide the date that YECL started using the trade name ATCO Electric Yukon (AEY).

(b) When YECL made the change to AEY, did it make any corresponding changes to stationery, signage, websites, logos on vehicles, etc.? Please itemize any related changes.

(c) If the answer to part (b) is affirmative, please indicate what the costs were for any trade name related changes, when those costs were incurred, and to what accounts those costs were charged.

Response:

(a) YECL started using the trade name ATCO Electric Yukon (AEY) June 14, 2014.

(b) When AEY changed its trade name it did make changes to stationery, customer's bills, website, logos on vehicles and work wear.

AEY's trade name change coincided with the City of Whitehorse changing the name of 1st Avenue to Front Street. The change of the street name required AEY to change stationery and customer's bills regardless, which is over 65-percent of the related costs.

(c) The incremental costs that AEY incurred for media related charges and to change the signage and logos on vehicles and work wear was $28,400. These costs were incurred and expensed in 2014.

YUB-YECL-36

Reference: Application, pages 5-2 to 5-3

Issue/sub-issue: Pension Costs

Preamble: On page 5-3, YECL shows actual and forecast defined benefit pension costs.

Request:

(a) For each of the actual and forecast years 2013 to 2017 inclusive, please indicate the number of employees to which the defined benefit pension costs relate.

(b) For defined contribution pension costs, please indicate the number of employees the costs are attributed to for the years 2013-17 inclusive.

(c) YECL has asked to be tied to the outcome of the upcoming ATCO Utilities 2016 Pension Application to be heard before the Alberta Utilities Commission. Please describe, in general terms, how final costs from that proceeding will be attributed to YECL. Can YECL separate itself from any unique or special charges that may apply only to other ATCO entities? Please explain.

(d) YECL is seeking continuation of the defined benefit pension cost deferral account. Please describe how YECL expects this deferral account to work. Please provide a continuity table of the current and forecast balance in that deferral account.

(e) Please indicate whether YECL's regulated affiliates in other Canadian jurisdictions have a deferral account for their defined benefit pension plans and how it was established? If yes, please indicate the current status of those deferral accounts. Do any of the ATCO regulated affiliates operate without a DB pension deferral account?

(f) What is the date of the last actuarial review regarding YECL's DB pension plan? What year did it cover? If there has been an update since the filing of this application, please provide that update.

Response:

(a-b) Please refer to the following tables for AEY employees on the defined benefit and defined contribution plans.

	2013	2014	2015	2016	2017
Defined Benefit	13	12	12	12	12
Defined Contribution	48	52	52	52	52

(c) No costs from that proceeding will be attributed to AEY.

(d) AEY has proposed to refund or collect the balances in the pension deferral account through amortization of deferred charges on Schedule 8.8 of the Application. The following table is a continuity of the deferral account. For the test period, AEY has assumed actual approved pension costs are equal to the applied for amounts.

Pension Deferral Continuity ($000's)					
	2013	2014	2015	2016	2017
Opening Balance	-	-	(85)	(154)	(77)
Add: Costs/(Credits)	-	(85)	(69)	-	-
Less: Refund/(Collection)	-	-	-	77	77
Closing Balance	-	(85)	(154)	(77)	-

(e) Since 2013, Northland Utilities (Yellowknife) Limited and Northland Utilities (NWT) Limited have similar deferral accounts approved that cover all increases or decreases to required cash contributions to the defined benefit pension plan as compared to forecast.

With respect to other ATCO regulated affiliates in Alberta, ATCO Electric Distribution and ATCO Gas who operate under a PBR plan in Alberta do not have DB pension deferral account since 2013. However, in the event of a material change in pension obligations (either positively or negatively), a Z factor application would be available to address the change.

(f) Please refer to YUB-YECL-36(f) Attachments 1-4 for the recent actuarial valuations. Defined benefit pension funding requirements have decreased from the 2015 amount of $578,000. 2016 actual defined benefit costs (assuming COLA of 100% CPI) are $505,000.

YUB-YECL-37

Reference: Application, page 5-3

Issue/sub-issue: Non-labour costs - IT

Request:

(a) Please provide a table showing IT costs, and the source of those costs for the years 2013-17 inclusive.

Response:

(a) 2013-17 IT costs by service provider are shown in Table 1 below.

Table 1:
ATCO Electric Yukon
IT Costs by Service Provider
($000s)

IT Service Provider	Actual 2013	Actual 2014	Actual 2015	Test Period 2016	Test Period 2017
ATCO I-Tek	395	246	-	-	-
Wipro Solutions Canada Ltd.	-	108	322	360	372
Total	**395**	**354**	**322**	**360**	**372**

YUB-YECL-38

Reference: Application, page 5-4, Schedule 5.3

Issue/sub-issue: Affiliate Costs

Request:

(a) In table 5.3 under Affiliate Costs, line 7 shows IT costs. Line 15 also refers Use of Systems and IT. Please explain the difference between the two lines.

(b) For any of the line items referred to in Schedule 5.3, are there any corresponding costs that occur within YECL? Please explain.

Response:

(a) Use of Systems refers to computer processing services provided by ATCO Electric and consists of:

- Monthly processing of accounting and payroll information
- Maintaining chart of accounts
- Access to and maintenance of historical information on the Oracle Financial Information System
- Use of the query software which is part of Oracle Financials
- Use of human resources systems

Information Technology services refers to the distribution, administration, and maintenance of AEY's information technology infrastructure. This includes computers, monitors, Xerox machines, phones, servers, etc.

(b) No.

YUB-YECL-39

Reference: Account 72700 – Relocation, Application, Schedules 5.1 and 5.2.

Issue/sub-issue: Relocation

Preamble: The Board requires more information regarding the cost increases in Account 72700 – Relocation

Request:

(a) Please indicate the average cost of relocating an employee to the Yukon or how YECL forecasts how much it will cost to relocate an employee.

(b) Please provide a table showing the number of employees relocated and the related costs for each of the years 2013 to 2017 inclusive.

(c) Please confirm whether relocation costs only apply to employees moving to or within Yukon.

Response:

(a) The average cost to relocate an employee to the Yukon, based on recent actual costs, is $62,000. AEY forecast costs for 2016-2017 based on historic costs and known upcoming vacancies (retirements).

(b)

	2013	2014	2015	2016FC	2017FC
Number of Employees	4	3	6		
Total relocation costs	$241	$169	$434	$366	$367
Average cost per relocation	$60	$56	$72		

(c) Forecast Relocation costs only apply to relocation of AEY employees.

YUB-YECL-40

Reference: Application, page 5-2 and Schedule 5.1

Issue/sub-issue: Production costs

Preamble: Schedule 5.1 shows production costs consistently increasing for 2016 over 2015. The increases are illustrated as follows ($000s):

Production Accounts	2015 Actual	2016 Forecast	% Change
62600 – Hydro Generation	261	273	4.6
64000 – Supervision and Engineering Diesel	66	72	9.0
64600 – Diesel Generation	445	494	11.0
82600 – Hydro Maintenance	62	68	9.7
84600 – Diesel Maintenance	1,148	1,188	3.5

Request:

(a) Please explain why the increases in each of these accounts exceed YECL's inflation assumptions.

Response:

(a) All accounts with labour allocations have slightly higher than inflation due to a placeholder of COLA at 100% CPI as compared to the 50% allowed in 2015. Please refer to the following continuity for the changes in production costs aside from inflation.

Production Costs	
2015 Actuals	1,982
Inflation	54
COLA	13
Engineering Technologist – Production Allocation	42
Other	5
2016 Forecast	**2,096**

YUB-YECL-41

Reference: Application, page 5-2 and Schedules 5.1 and 5.2

Issue/sub-issue: Distribution costs

Preamble: The Table on page 5-2 shows distribution costs increasing for 2016 over 2015 for the listed accounts. The increases are illustrated as follows ($000s):

Distribution Accounts	2015 Actual	2016 Forecast	% Change
87300 – Maintenance	1,927	2,084	8.2
87400 – Underground Line Maintenance	143	150	4.9
87700 – Transformer Repair and Replacement	42	53	26.2
87800 – Street Light Maintenance	203	249	22.7

Request:

(a) Please explain why the increases in each of these accounts exceed YECL's inflation assumptions.

(b) Please explain the historical average used to calculate the increase in street light maintenance (Account 87800).

Response:

(a-b) All accounts with labour allocations have slightly higher than inflation due to a placeholder of COLA at 100% CPI as compared to the 50% allowed in 2015. In addition to this the maintenance activities within these account vary on a year to year basis depending on what needs are identified through line patrols, heat scanning and call ins.

Due to the fluctuating nature of the costs simply applying inflation is not indicative of what the forecast costs may be and AEY uses an inflated 3 year average for items such as materials, vehicle usage and contractor services.

Please refer to the following continuity table for a summary of changes in addition to inflation.

Distribution Costs	
2015 Actuals	2,315
Inflation	69
COLA	18
Engineering Technologist – Distribution Allocation	19
Lower Vacancy	23
3-Year Averaged Costs	89
Other	3
2016 Forecast	**2,536**

YUB-YECL-42

Reference: Application, page 5-2 and Schedule 5.1

Issue/sub-issue: General costs

Preamble: The Table on page 5-2 shows General costs increasing for 2016 over 2015 for the listed accounts. The increases are illustrated as follows ($000s):

General Accounts	2015 Actual	2016 Forecast	% Change
88800 – Maintenance Company-Owned Houses	46	61	32.6
88900 – Maintenance Warehouse and Office	145	162	11.7

Request:

(a) Please explain why the increases in each of these accounts exceed YECL's inflation assumptions.

Response:

(a) All accounts with labour allocations have slightly higher than inflation due to a placeholder of COLA at 100% CPI as compared to the 50% allowed in 2015. In addition to this the maintenance activities within these accounts vary on a year to year basis depending on what needs are identified.

Due to the fluctuating nature of the costs simply applying inflation is not indicative of what the forecast costs may be and AEY uses an inflated 3 year average for items such as materials, vehicle usage and contractor services. Please refer to the following continuity table for the changes in general costs aside from inflation.

General Costs	
2015 Actuals	191
Inflation	4
COLA	1
Housing Differential Loan Carrying Costs	13
3-Year Averaged Costs	14
2016 Forecast	**223**

YUB-YECL-43

Reference: Application, page 5-2 and Schedule 5.1

Issue/sub-issue: Public Information costs

Preamble: The Table on page 5-2 shows Public Information costs increasing for 2016 over 2015 for the listed accounts. The increases are illustrated as follows ($000s):

Public Information Accounts	2015 Actual	2016 Forecast	% Change
70100 – Public Information Administration	9	15	66.7
70200 – General Public Information	108	123	13.9

Request:

(a) Please explain why the increases in each of these accounts exceed YECL's inflation assumptions.

(b) Please list and describe what types of charges are contained in General Public Information.

Response:

(a) All accounts with labour allocations have slightly higher than inflation due to a placeholder of COLA at 100% CPI as compared to the 50% allowed in 2015.

In addition to this costs in these accounts may fluctuate on a year to year basis dependent on what is going on within the communities and what initiatives AEY is taking part in. Because of the varying nature of the costs AEY uses an inflated average for materials and contractor services. AEY would like to note that all costs related to the change in trade name were removed from the base costs used in determining the 2016-2017 forecasts.

Please refer to the following continuity for changes in Public Information costs aside from inflation:

Public Information Costs	
2015 Actuals	117
Inflation	4
COLA	2
3 Year Average Costs	15
2016 Forecast	**138**

(b) The types of charges contained in General Public Information include:

i. External Communications related to public and community relations, safety, outages, electricity conservation and customer billing

ii. Website and media administration

YUB-YECL-44

Reference: Application, page 5-2 and Schedule 5.1

Issue/sub-issue: Customer Accounting costs

Preamble: The Table on page 5-2 shows Customer Accounting costs increasing for 2016 over 2015 for the listed accounts. The increases are illustrated as follows ($000s):

Customer Accounting Accounts	2015 Actual	2016 Forecast	% Change
71000 – Supervision	44	46	4.6
71100 – Customer Applications and Service Orders	468	491	4.9
71400 – Revenue Collections	166	174	4.8
71500 – Collection of Delinquent Accounts	125	130	4.0
71800 – Provision for Uncollectible Accounts	65	87	33.8

Request:

(a) Please explain why the increases in each of these accounts exceed YECL's inflation assumptions.

(b) What is the historical average used to calculate the increase in the Provision for Uncollectible Accounts (Account 71800)? Please explain the forecast increase of 33.8 percent

Response:

(a) All accounts with labour allocations have slightly higher than inflation due to a placeholder of COLA at 100% CPI as compared to the 50% allowed in 2015. Costs are also higher due to a position being vacant for a portion of 2015.

Please refer to the following continuity for the changes in customer accounting costs in addition to inflation.

Customer Accounting Costs	
2015 Actuals	868
Inflation	26
COLA	4
3-Year Averaged Costs	22
Lower Vacancy	8
2016 Forecast	**928**

(b) Due to the varying nature of uncollectible accounts simply applying inflation is not indicative of what the costs may be. AEY uses a three year average to forecast these costs.

2013	2014	2015	Average
$75	$120	$65	$87

YUB-YECL-45

Reference: Application, page 5-2 and Schedules 5.1 and 5.2.

Issue/sub-issue: Administration and General costs

Preamble: The Table on page 5-2 shows Administration and General costs increasing for 2016 over 2015 for the listed accounts. The increases are illustrated as follows ($000s):

Administration and General Accounts	2015 Actual	2016 Forecast	% Change
72100 – Administrative	1,963	2,309	17.6
72200 – Administrative Corporate	131	143	9.2
72300 – Insurance	90	100	11.1
72500 – Employee Expenses	299	337	12.7
72600 – Training and Safety	464	504	8.6
72900 – Audit/Legal Fees & Special Studies	139	184	32.4

Request:

(a) Please explain why the increases in each of these accounts exceed YECL's inflation assumptions.

(b) Please explain the types of charges in Administrative Corporate (Account 72200).

(c) Please explain the types of charges referred to as Special Studies, and give examples, in Account 72900. Please explain the reason for the increase in forecast costs.

(d) Please provide separately the employee retirement and employee recognition costs included in Account 72500 for each of the years 2013 to 2017 inclusive.

(e) For Account 72500, for the cost increases in 2014 over 2013, please provide the amount for the absence with pay and the reason rate payers should cover such costs.

Response:

(a) All accounts with labour allocations have slightly higher than inflation due to a placeholder of COLA at 100% CPI as compared to the 50% allowed in 2015. In addition to this increases in excess of inflation are due to:

72100	Positions were vacant for both AEY based and head office accounting and admin positions for a portion of 2015. Some costs on a year to year basis depending on needs, these costs are forecast using an inflated 3 year average rather than simply applying inflation.
72200	Costs within this account include bank fees which have been increasing at a higher rate than inflation due to more and more people using electronic payment methods and credit cards which AEY has to pay a fee.
72300	Increases in AEY's property insurance are greater than inflation due to capital growth and the increase in insurable properties.
72500	Costs are higher than inflation due to known upcoming employee service recognition and retirements in the test period.
72600	These costs vary on a year to year basis depending on training needs and availability of training programs. The increases from 2015 to 2016 are mainly due to using an inflated 3 year average for training fees and additional labour for new employees who will be participating in orientation and basic training.
72900	Costs increase due to upcoming collective agreement negotiations.

(b) Account 7220 consists of bank service charges and bank fees

(c) The special study charges include external auditor fees, collective agreement negotiations and other non-capitalizable studies.

(d) The employee retirement and employee recognition costs ($000s) are as follows:

	2013	2014	2015	2016	2017
Service Recognition	5	22	7	18	18
Retirements	13	24	4	15	15

(e) The labour costs in 72500 are costs related to either collective bargaining or absence with pay. Absence with pay is sick days, bereavement days and travel days for medical or bereavement related travel. These costs are the cost of having employees which in turn are a cost of providing service. As such AEY submits they are recoverable through rates.

YUB-YECL-46

Reference: Application, page 1-4; Appendix A to Board Order 2014-06, page 103.

Issue/sub-issue: Deferral Accounts

Quote: "The Board notes that legislative and regulatory changes can have an impact on utilities. However, on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented. The Board notes the YECL submission that no costs have been incurred to date that YECL would be seeking to incur in this deferral account. The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any subsequent GRA filing. Therefore, the Board rejects YECL's request for this deferral account." [footnote omitted]

Request:

(a) Please confirm that the Board has previously ruled on the same YECL request for a legislative and regulatory change deferral account.

(b) In an earlier IR, the Board asked YECL to explain its understanding of the IPP Policy for Standard Offer Price. In terms on understanding the lead time related to a legislative or regulatory change, when does YECL expect this policy to be implemented?

Response:

(a) Confirmed.

(b) AEY understands that the Yukon Government's desire is to have the IPP Policy implemented by October, 2016. The utilities are working with this goal in mind however, given the interaction required with government and the pending Territorial election, this implementation date will be challenging.

Additional information on this matter has been addressed in AEY's response to YUB-YECL-2.

YUB-YECL-47

Reference: Application, pages 1-4, 3-2 and 3-3; Appendix A to Board Order 2015-01, page 30.

Issue/sub-issue: Deferral Accounts – Purchase Power Flow Through

Quote:

"The Board is of the view that for sales in excess of the forecast, the risks lie with the regulated utility. That is, the utility assumes the forecast risk for those revenues and related costs in excess of forecast and for those periods where there is no forecast — non-test years.

"However, for the current proceeding, issues regarding the ERA had not been determined. The Board had to consider between divergent proposals regarding purchase power costs — ERA — and the Board is of the view that as these issues were not determined it would have been difficult for YECL to include ERA amounts in its forecasts. The Board considers it would be unfair for YECL to assume this risk of these ERA costs during the intervening period, or include such costs in its last GRA, until the Board made its determinations on the ERA issue. Therefore, the Board will allow YECL to use the PPFTDA for the period 2012-2015, and only if it incurs any ERA charges. Outside of the specified period, YECL will be required to apply for and justify the need for a PPFTDA." [Footnote omitted, underlining added]

Request:

(a) Please explain how a PPFTDA would operate and provide a numerical example.

(b) Please comment on whether, under a PPFTDA, YECL would be guaranteed a fixed margin (the margin would be incremental sales revenues less purchase power costs as set in YEC's last GRA; ERA costs would be part of the PPFTDA) on sales in excess of forecast amounts. Is there any application before the Board in which YEC has requested a change to its wholesale energy rates for 2016? 2017?

(c) Please comment on how an ERA charge should be calculated? If so, please provide an example.

(d) What is the amount of the last approved level of YEC wholesales to YECL?

(e) For 2016, please confirm that YECL has filed a forecast of Wholesale purchases obtained from YEC and indicate the amount.

(f) Are YECL and YEC able provide a consensus forecast of Wholesale quantities for energy for any given period? Please explain.

Response:

(a) The PPFTDA acts to flow through any price changes of AEY's Wholesale purchases from YEC because:

1) Wholesale rate changes (including the ERA) are material and outside AEY's control and ability to forecast; and

2) It is not in ratepayers', the Board's, or the Utilities' interest to speculate on these rate changes in this GRA.

The Purchase Power Flow-Through Deferral Account and associated collection mechanism would operate as follows:

(i) AEY would be notified of a YEC price change from the current Wholesale Price of 8.298¢/kWh by either:

A. A Board-approved interim rate associated with a YEC General Rate Application;

B. A Board-approved final rate determined after a YEC General Rate Application; or

C. A Board-approved ERA charge determined after YEC submits its past year's Retail, Industrial, and Wholesale sales volumes variances compared with its last GRA test year, losses, operations, and YECSIM analyses to the Board.

(ii) Expecting a one-month turnaround from a Wholesale rate change approval, AEY would submit an application to the Board to recover via a Rider:

A. A catch-up component for balances accrued associated with the Wholesale rate change; and

B. A keep-up component for on-going shortfalls associated with the Rate change.

Please refer to YUB-YECL-47(a) Attachment 1 for sample calculations.

(b) Consistent with historical practice, under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate.

AEY is unaware of any application before the Board in which YEC has requested a change to its wholesale energy rates for 2016 or 2017. However, AEY understands that the matter of the DCF and ERA is currently before the Yukon Court of Appeals.

AEY submits that, awareness of a YEC application to change the Wholesale rate would not preclude the requirement for the PPFTDA. For example, a process and hearing would need to be held for a YEC application, and applied-for rates might not be what is finally approved by the Board (as was the case with the DCF and ERA from YEC's last proceeding). AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.

(c) AEY submits the intent of the ERA is for YEC to provide a price signal indicative of the expected change in costs of generation based on hydro/diesel/LNG fuel availability.

The main issue with respect to the ERA is that AEY is unable to accurately and reasonably forecast the expense it would incur. YEC's proposed ERA calculation was based on a complex and unclear simulation model of "diesel costs" based on a number of inputs including YEC's forecasting variances, YEC's Retail and Industrial loads, and YEC's operation of the system. These inputs are outside the control and visibility of AEY.

The ERA is further complicated when considered alongside YEC's Rider E in the postage stamp rate environment. YEC would be refunding surpluses due to YEC's "diesel variances", while ATCO Electric Yukon (via its PPFTDA) would be collecting a shortfall (from the same ratepayers) due to YEC's "diesel variances".

For the above reasons, AEY submits the ERA should not exist as a charge to AEY. If the ERA continues to be required, it should be entirely managed by Yukon Energy in conjunction with its Diesel Contingency Fund and Rider E mechanism.

Nevertheless, if the Board decides there is merit to a Wholesale price signal for changing costs of generation based on hydro/diesel/LNG availability, then an alternative YEC proposal could include a straightforward, stepped wholesale rate design, to help mitigate YEC's risks associated with forecast changing costs of generation. In turn, AEY would reasonably be given the opportunity to forecast

and reflect the significant change in its supply costs in its own rate application. This type of wholesale rate design could potentially increase the frequency of AEY's rate applications.

Considering the ERA is entirely outside the control of AEY, its significant complexity, and the difficulty AEY has in forecasting these potential charges, it is appropriate to include these costs as part of the PPFTDA. AEY submits that the PPFTDA is still required for any pricing design changes (including the ERA or a stepped rate design) until the point where these rate adjustments can reasonably be included in its forecasts. Furthermore, a PPFTDA would still be required for price changes related to incremental revenue requirement adjustments to any existing rate structure.

(d) In Board Order 2014-09, the Board approved Wholesale purchases for AEY's 2015 test year at 320,965MWh (from Schedule 3.1 of AEY's 2013 - 2015 General Rate Application Compliance Filing).

In Board Order 2013-03, the Board approved Wholesale sales for YEC's 2013 test year at 302,078MWh (from Table 1.1-5 of Yukon Energy Corporation's 2012/13 GRA Compliance Filing).

(e) From Schedule 3.1 of the 2016-2017 General Rate Application, AEY's forecast Wholesale purchases from YEC for 2016 are 294,664MWh.

(f) Considering:

1) Phase I GRAs are not scheduled simultaneously for the two companies because the two utilities have different capital plans, business cycles, and stakeholder obligations;

2) A GRA-quality forecast (along with defense throughout a proceeding and at a hearing) requires more detailed analyses and review than a non-GRA forecast; and

3) Forecasting generally requires incorporation of the most current available information,

AEY's forecasting resources cannot be responsible for providing detailed forecasts, analyses and defense to YEC for a Phase I proceeding, and vice versa.

Generally, the Utilities work together where possible and provide high level assistance to each other for their respective Phase I forecasts.

Under the postage stamp rate system, Phase II forecasts will have a common test period and the Utilities will need to agree upon a sales forecast. Generally, in a Phase II rate application, each Utility would be responsible for forecasting its own retail and industrial customer base.

ATCO Electric Yukon - Purchase Power Flow Through Deferral Account

PPFTDA Balance to be (Refunded To)/Collected From Customers

Line	Description		Balance
1	PPFTDA Under/(Over)-Collection Balance as of December 31, 2015		$ -
	A) Changes to Balance Since last update: January 1, 2016 - June 30, 2016		
2	Rider "P" Revenue		$ -
3	Energy Purchases (kWh)	147,639,692	
4	Incremental Purchase Power Price ($/kWh)	$0.0000	
5=3*4	Incremental Purchase Power Expense		$ -
6=1+2+5	PPFTDA Under/(Over)-Collection Balance as of June 30, 2016		$ -
	B) Catch-up Expense: Additional expense incurred July 1, 2016 - July 31, 2016		
7	Forecast Energy Purchases (kWh)	19,383,280	
8	Incremental Purchase Power Rate ($/kWh)	$0.0083	
9=7*8	Forecast Incremental Purchase Power Expense		$ 160,881
10	AEY Forecast Energy Sales (kWh)	20,208,666	
11	YEC Forecast Energy Sales (kWh)	6,480,878	
12=10+11	Total Forecast Energy Sales (kWh)	26,689,544	
13	Current Rider "P" Rate ($/kWh)	$0.0000	
14=-13*12	Forecast Rider "P" Revenue		$ -
15	Energy Reconciliation Adjustment		$ 400,000
16=6+9+14+15	PPFTDA Forecast Under/(Over)-collection Balance as of July 31, 2016		$ 560,881
	C) Keep-up Expense: Additional Expense incurred August 1, 2016 - July 31, 2017		
16	AEY Forecast Purchases (kWh)	311,185,796	
17	Incremental Purchase Power Rate ($/kWh)	$0.0083	
18=16*17	Forecast Incremental Purchase Power Expense		$ 2,582,842
	D) Rider "P" Calculation		
19	AEY Forecast Energy Sales (kWh)	319,238,165	
20	YEC Forecast Energy Sales (kWh)	64,544,872	
21=19+20	Total Sales which Rider "P" applies to (kWh)	383,783,037	
22	Catch-up component (untilJuly 31, 2017 or next Wholesale rate adjustment)		$ 0.0015
23	Keep-up component (On-going or until next Wholesale rate adjustmet)		$ 0.0067
24=22+23	Rider "P" Adjustment effective August 1, 2016 ($/kWh)		$ 0.0082

YUB-YECL-48

Reference: Application, pages 1-4 and 4-3.

Issue/sub-issue: LNG Fuel Deferral Account

Quote: "Similarly to the Diesel Fuel Deferral Account, the LNG Fuel Deferral Account will use the GRA-approved community-based plant efficiencies and the plant's monthly gross generation to determine the volume of litres of diesel equivalent for the monthly fuel deferral calculation. Actual diesel volumes used for the diesel fuel deferral account calculation will be subtracted from this volume, with remaining allowable litres of diesel equivalent for use in the calculation of the LNG fuel deferral."

Request:

(a) How has YECL determined the community-based efficiency for the bi-fuel units. Please provide any calculations.

(b) Can actual efficiency vary from rated efficiency? How will YECL account for this? Can this rating change depending on the fuel mix?

(c) Please provide a numerical example of how the equivalencies will be determined, how the account will work, in Excel format with formulae intact.

Response:

(a) On an energy unit basis (eg. GJ), the Bi-Fuel units will maintain similar efficiency, whether operating in diesel-only mode or Bi-Fuel mode. The same amount of energy will be required to produce each kWh whether operating under Bi-Fuel or diesel-only modes. AEY considers LNG as per Litre of Diesel Equivalent (LDE or DLE). Each LDE of LNG contains the same energy content as a Litre of diesel. From an accounting perspective, the only variance between the two fuel sources will be their price per LDE.

(b) The efficiency of any internal combustion engine can deviate slightly from manufacturers' ratings and can degrade slightly over time. AEY's operations and maintenance regime for generating units ensures that each unit maintains efficient operation throughout their life. AEY measures efficiency in terms of Heat Rate, defined as follows:

Heat Rate = kWh's produced / Litre Diesel Equivalent

The heat rate of each power plant is recorded monthly at all AEY diesel facilities. AEY believes that efficiency will remain the same whether operating as diesel-only versus Bi-Fuel.

(c) Please refer to YUB-YECL-48(c) Attachment 1.

AEY 2016-2017 General Rate Application
Bi-Fuel Price Deferral Sample Calculation
YUB-YECL-48(c)

Line	Description	Units	Amount
1	Approved Diesel Price	$/L	0.7618
	Diesel		
2	Actual Diesel Price[1]	$/L	0.7618
3	Actual Diesel Volume[1]	L	165,000
4	Total Diesel Cost	$	125,697
	LNG		
5	Actual LNG[1]	L	170,000
6	DLE Factor[2]		59.1%
7=5*6	Diesel Litres Equivalent	DLE	100,518
8	Actual Cost[1]	$	60,000
9=8/7	Actual Price	$/DLE	0.5969
	Deferral Calculation		
10	Total Cost of Fuel	$	185,697
11	Total Volume of Fuel	DLE	265,518
12=10/11	Effective Fuel Price	$/DLE	0.6994
13=(1-12)*11	**Total Fuel Price Deferral Refund / (Collection)**	**$**	**16,574**

Table 1 - Lower and Higher Heating Values of Diesel, LNG, and NG

	Diesel		LNG	NG	
	HHV	LHV	HHV	HHV	LHV
Energy Content (MJ/kg)	45.575	42.612	55.206	52.225	47.141
Density (g/gal)	3,206	3,206	1,621		
Density (kg/L)	0.85	0.85	0.43		
Energy Content (MJ/L)	38.6	36.1	23.6		

http://cta.ornl.gov/bedb/appendix_a/Lower_and_Higher_Heating_Values_of_Gas_Liquid_and_Solid_Fuels.pdf

[1] - Assumed actual prices and volumes for purposes of sample calculation

[2] - DLE Factor determined using energy content, densities, and LHV:HHV ratios from Table 1:

YUB-YECL-49

Reference: Application, pages 1-4, 10-1 and Appendix A to Board Order 2009-2, page 42.

Issue/sub-issue: Income Tax Rate Deferral Account

Quote: "The Board is not persuaded by YECL's contention that notices of changes in tax rates are not received in sufficient time to be reasonably included in YECL's forecast. Therefore, the Board does not accept YECL's request for an income tax deferral account and directs that YECL not use such an account in its refiling."

Request:

(a) Please explain what has changed since the above-noted finding?

(b) Is YECL aware of any proposed changes to income tax rates that either have not been enacted or have been announced but have not been enacted?

(c) How has YECL accounted for changes in tax rates (either federally or territorially) during the years 1997 to 2015?

Response:

(a) Recent changes in the federal government and upcoming territorial elections significantly increase the possibility of tax rate changes between general rate applications.

Tax rate changes are not within AEY's control and are not forecastable, as such, AEY submits such costs are eligible for deferral. Please refer to AEY's response to YUB-YECL-21.

(b) No.

(c) AEY has incurred tax expense in accordance with the tax rates imposed by the federal and territorial government.

YUB-YECL-50

Reference: Application, page 8-2

Issue/sub-issue: Return on equity

Quote: "The BCUC currently has before it a GCOC proceeding (Stage 1 proceeding) to determine the appropriate benchmark ROE which is currently set at 8.75%. The hearing has concluded and it is expected that a decision related to the BCUC generic ROE will be released either in the second or third quarter of this year. Therefore, ATCO Electric Yukon is proposing to use this benchmark ROE (once released) for the 2016 and 2017 test years and is also seeking approval of a risk premium of 60 basis points."

Request:

(a) Please provide the BCUC decision that has set the benchmark ROE at 8.75 percent.

(b) IF the BCUC GCOC proceeding does not release its decision before the close of record of this proceeding, what does YECL propose for its ROE?

Response:

(a) BCUC Commission Order G-75-13 dated May 10, 2013 approved the 8.75% benchmark ROE.

(b) Reply submissions on the BCUC 2016 ROE proceeding were filed at the end of April 2016. Therefore, it is expected that a decision will be issued within the next several months which would be prior to the close of the record in this proceeding.

YUB-YECL-51

Reference: Application, page 8-2.

Issue/sub-issue: Return on equity

Quote: "ATCO Electric Yukon submits that the determination of whether a ROE premium is appropriate with respect to ATCO Electric Yukon should address the relative business risks of ATCO Electric Yukon compared to the BCUC benchmark utility and other similar type utilities across Canada, taking into account the stand-alone principle."

Request:

(a) Should YEC be considered as one of the comparable utilities?

(b) In terms of relative comparability, would YEC be the most comparable utility to YECL?

(c) If YEC is the most comparable utility, please provide the last ROE approved for YEC.

Response:

(a) Concentric does not believe that YEC should be considered as a comparable utility because it is a crown corporation rather than being owned by a publicly-traded holding company that raises debt and equity capital in public markets. Further, YEC is primarily a generation and transmission utility that also serves a few commercial customers, whereas AEY is mainly a distribution utility that owns limited generation. Lastly, YEC's ROE is also set by this Board and would not provide an independent source. As discussed in Concentric's report, we believe that smaller publicly-traded electric and gas utilities in Canada are the most appropriate comparators to AEY for purposes of determining whether a risk premium above the benchmark utility is justified.

(b) No. Please refer to part (a).

(c) Not applicable.

YUB-YECL-52

Reference: Application, page 8-3 and Schedule 2.1.; 2013-15 Application – Schedule 2.1

Issue/sub-issue: Return on equity

Quote: "Market demand risks relate to the volatility of sales and their impact on return on equity. Realization of sales forecasts in ATCO Electric Yukon's service territory is subject to many variables including the weather and the economic health of the community. ATCO Electric Yukon's sales are more sensitive to weather than other electric utilities due to the extreme range of temperatures experienced in northern Canada."

Preamble: The following table is derived from Schedules 2.1 from the current Application and YECL's 2013-15 GRA:

Year:	2011A	2012A	2013A	2014A	2015A	2016F	2017F
Company Sales (MW.h)	297,445	316,575	316,692	312,181	315,816	313,592	319,289
YOY Change (%)		6.4	0.0	-1.4	1.2	-0.7	1.8

Request:

(a) Please explain why YECL's sales are more sensitive to weather than other electric utilities.

(b) Please provide examples where other utilities are not affected by extreme weather conditions such as heat, wind, ice, etc.

(c) Please provide an example of any electric utilities which are not impacted by the economic health of the community.

(d) In light of the table above which shows that, other than the high growth in 2012, annual sales are consistently within 2 percent of the previous year's levels, please explain how YECL's annual sales are volatile.

Response:

(a-b) AEY has not completed extensive analysis on a large sample of other utilities, but has reviewed the weather sensitivity of AEY's residential sales compared to its affiliate electric companies. AEY performed a simple regression of UPC and weather which shows that AEY has a significantly higher HDD coefficient than ATCO Electric Distribution, NUY and NWT. These findings are also consistent with the fact that AEY has higher residential average use and a higher proportion of customers using electric heat.

	HDD Coefficient	2015 Actual Annual UPC (kW.h)
AEY (Whitehorse)	0.6537	10,876
AED	0.2984	7,247
NUY	0.2422	7,424
NWT (Hay River)	0.2134	5,818

(c) Please refer to response to YUB-YECL-53.

(d) As shown in Figure 8 of Concentric's report, AEY's residential and commercial use per customer on a weather-normalized basis has fluctuated by up to three percent from year-to-year since 2006. As discussed on page 24 of the report, AEY believes that the increased variability in residential use per customer is due in part to customers responding to changes in prices for alternative fuels. For example, when heating oil and propane prices were high, more customers chose to use electricity for space heating. As heating oil and propane prices have decreased in the past year, more customers are decided to use those alternative fuels for space heating rather than electricity. However, electric space heating has become much more common in new residential housing development in recent years. In 2012, approximately 18.2 percent of Yukon households used electricity as their principal heating fuel compared with less than 10 percent in 2003.

YUB-YECL-53

Reference: Application, page 8-3.

Issue/sub-issue: Business Risk Analysis

Quote: "ATCO Electric Yukon also serves a relatively small market with considerably less economic strength and diversity than the service areas of other utilities. Its residential and commercial sales are primarily affected by the general economic activity within the communities served."

Request:

(a) Would the above statement similarly apply to any other electric utility with a rural base? If not, please explain why not?

Response:

(a) AEY is of the view that economic conditions would have an impact on all utilities including rural based utilities. The impact to a utility from changes in economic conditions would vary based on many items such as the size of the utility, the level of diversification of the economies in the cities and towns served by the utility, and the level of customer diversity.

YUB-YECL-54

Reference: Application, pages 8-3 to 8-4.

Issue/sub-issue: Business Risk Analysis

Quote: "Operational cost risks exist due to the potential to under-estimate various cost items including: capital expenditures, financing costs and operating and maintenance expenses. The remote locations served by ATCO Electric Yukon can result in higher than anticipated repair costs for unplanned maintenance of facilities. Also, due to the severe weather conditions that can occur in northern Canada, repair costs can deviate substantially from those forecast in operating budgets which are based on normal weather conditions. The length of the winter period increases the probability that these severe weather conditions may be experienced."

Request:

(a) Can YECL's experience mitigate some of those operational risks? Please explain.

Response:

(a) AEY continually works to ensure that known operational risks are managed and where possible mitigated. While AEY has extensive experience operating in northern climates; it is not able to reasonably forecast repair costs for unplanned maintenance of facilities due to severe weather conditions and is of the view it is not appropriate to incorporate costs to account for any and every event that may or may not materialize within a test period.

YUB-YECL-55

Reference: Application, Attachment 8.1, Concentric report, Figure 1, report page 4.

Issue/sub-issue: Comparables

Preamble: Figure 1 lists utilities compared to YECL.

Request:

(a) Why should any gas utilities be used in the comparison to YECL? Please explain.

(b) Would other electric utilities be a stronger comparator to YECL? Please explain.

(c) Why was YEC not included in the list of comparators?

(d) For the column "Risk Compared to AEY" how were those ratings made? Were those relative risk assessments determined by Concentric? If those relative risk assessments were not made by Concentric, then please provide the source of those relative risk assessments. Please provide any quantitative evidence used to assess those ratings.

(e) For each of the utilities cited, please provide the year the ROE was determined and the corresponding decision reference from the governing regulatory authority.

Response:

(a) Figure 1 on page 4 of Concentric's report includes two gas distribution companies: FortisBC Energy and Pacific Northern Gas West. Both companies provide gas distribution service in British Columbia, which is the province the Board has previously indicated a preference for using in the determination of a risk premium for AEY. FortisBC Energy is included in Figure 1 because it is the benchmark utility in British Columbia. Pacific Northern Gas West is included in Figure 1 because like AEY it also provides distribution service (gas, not electric) and it serves approximately the same number of customers as AEY. As discussed in the Concentric report, PNG-West has been awarded a risk premium of 75 basis points above the benchmark utility in British Columbia which we believe is a useful point of reference.

(b) The other four companies in Figure 1 are electric utilities. Concentric believes that from a business risk perspective, electric utilities are generally an appropriate comparator for AEY. As discussed on pages 19-21 of the Report, however, AEY is smaller than any of the other investor-owned electric and gas distribution utilities in the comparator group. Due to the extremely small size of AEY, the Company has higher investment risk. In addition, the small size of AEY magnifies the risk associated with other factors such as adverse economic conditions and severe weather conditions. Lastly, the small size of AEY's limits the Company's financial flexibility in terms of raising capital. For all of these reasons, it is appropriate to reflect this additional risk through a risk premium above the benchmark utility.

(c) Please refer to AEY's response to YUB-YECL-51(a).

(d) The relative risk assessment in Figure 1 labeled "Risk Compared to AEY" was made by Concentric based on our qualitative assessment of the business risks that AEY faces as compared with the business risks for the comparator group. On pages 4-6 of Concentric's report, we provide a narrative description of the factors that were considered for each comparator group company in arriving at the relative risk assessment shown in Figure 1.

(e) Please refer to the table for the year the ROE was determined and the decision reference.

	Allowed ROE	Year ROE Determined	Decision
ATCO Electric Yukon	8.75%	2014	Board Order 2014-06
Canadian Electric & Gas Utilities			
FortisBC Energy	8.75%	2013	G-75-13
FortisBC Electric	9.15%	2014	GCOC Stage 2
Newfoundland Power	8.50%[14]	2016	P.U. 18 (2016)
Maritime Electric Company Ltd	9.35%	2016	UE16-04
ATCO Electric Distribution	8.30%	2015	2191-D01-2015
Pacific Northern Gas-West	9.50%	2014	GCOC Stage 2

[14] Concentric has updated the table to reflect the recent decision for Newfoundland Power.

YUB-YECL-56

Reference: Application, Attachment 8.1, Concentric report, pages 4-5.

Issue/sub-issue: Generation risk

Quote: "As discussed in more detail later in the report, investors and credit rating agencies view companies that own generation as higher risk than pure transmission and/or distribution utilities."

Request:

(a) Does the above quote apply to any generation level contained in a utility or significant levels of generation?

(b) Would a utility whose self-supply of load requirements consist of five-percent generation be considered a lower risk than a utility whose self-supply of load requirements consists of 45-percent generation? Please explain.

Response:

(a) As explained on pages 21-22 of Concentric's report, companies that own electric generation facilities are generally considered riskier by credit rating agencies than companies that only own transmission and distribution facilities, or than gas distribution companies and gas transportation pipelines. As stated on page 22 of the report, Concentric believes that AEY's generation risk is equivalent to that of Newfoundland Power in that both companies purchase more than 90 percent of their electricity supply from a crown corporation. As a general premise, Concentric's view is that companies that derive a higher percentage of their electricity supply from company-owned generation have higher generation risk than companies that derive lower percentage of their electricity supply from company-owned generation. Supply risk is also higher for companies such as AEY (and Newfoundland Power) that derive their purchased power from a single source rather than from multiple sources.

(b) All else being equal, Concentric agrees that a utility that derives five percent of its load requirements from company-owned generation would have less generation risk than a utility that derives 45 percent of its load requirements from company-owned generation. That is but one of many factors, however, that determine utility business risk, and financial risk must also be considered.

YUB-YECL-57

Reference: Application, Attachment 8.1, Concentric report, page 5.

Issue/sub-issue: Customer Growth/Declining Volume

Quote: "AEY has not experienced these issues related to customer growth or declining volume to the same magnitude as PNG-West; however, use per customer has been variable over the past decade."

And

"FortisBC Electric was awarded an ROE risk premium of 40 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding."

Request:

(a) Which factor is given more weight when assessing risk, usage per customer or overall sales by the utility? Please explain.

(b) For what year was FortisBC Electric awarded a risk premium of 40 basis points above the benchmark utility?

(c) If part (b) does not relate to the current GCOC proceeding before the BCUC, is the previously awarded risk premium applicable? Please explain.

Response:

(a) It depends on the specific circumstances for the utility in question. In some cases, customer growth can cause the utility to need to make substantial capital investment in order to serve the additional customers in its service territory, especially if the customers are not located in close proximity to existing customers. In other instances, the utility may be experiencing declining use per customer due to economic conditions, energy efficiency and DSM programs, or other factors. The risk assessment must consider if either of these factors is creating business or financial risk for the utility, if that risk has been mitigated in any way through regulatory mechanisms, and how the utility compares to other utilities in the comparator group on these specific risk factors.

(b) FortisBC Electric was awarded a risk premium of 40 basis points above the benchmark utility by the BCUC in Stage 2 of the Generic Cost of Capital proceeding. The decision was issued on March 25, 2014. The effective date of the allowed ROE and equity ratio was January 1, 2013.

(c) This is the most recent BCUC decision regarding the cost of capital for FortisBC Electric. The current GCOC proceeding in British Columbia is for the benchmark utility, FortisBC Energy. A decision has not yet been issued by the BCUC in that proceeding.

YUB-YECL-58

Reference: Application, Attachment 8.1, Concentric report, page 5.

Issue/sub-issue: Usage per Customer

Quote: "The majority of Newfoundland Power's residential customers use electricity for space heating purposes, which increases variability in usage per customer depending on weather conditions."

Request:

(a) When a utility prepares its sales forecast, does it use normalization procedures to adjust its forecast? If yes, does the use of normalization procedures reduce the variability and any related risk in the forecast?

Response:

(a) There is an important distinction between a utility that weather normalizes its sales forecast and a utility that is allowed to recover revenues that were lost due to abnormal weather. In the former case, it depends on the ability of the utility to accurately forecast the effect of weather on sales. In the latter case, the utility is allowed to recover revenues if actual sales are different than forecast sales due to the effect of abnormal weather. Weather normalizing the sales forecast does not protect the utility's earnings and cash flows in the event of abnormal weather.

YUB-YECL-59

Reference: Application, Attachment 8.1, Concentric report, page 6.

Issue/sub-issue: Maritime Electric

Quote: "Maritime Electric is also similar to AEY in that it supplies about 24 percent of its load requirements through company-owned regulated generation and serves primarily residential and commercial customers. Maritime Electric has 4X more retail customers than AEY, and its rate base is also about 4X larger than AEY's. Maritime Electric has a deemed equity ratio of 40.9 percent in 2016, and its allowed ROE in the most recent settlement agreement approved in February 2016 was 9.35 percent, or 60 basis points higher than FortisBC Energy's. Maritime Electric was recently allowed to implement a weather normalization variance account, while AEY has no protection against volumetric risk."

Request:

(a) Please confirm that YECL produces 9 percent of its load requirements? Is the supply of 24 percent of its load requirements through its own generation considered to be a quantum higher than the 9 percent? The ROE for Maritime Electric was determined through a negotiated settlement. Is it probable that the settlement agreement was the result of various trade-offs between the negotiating parties? Does Concentric have any particular knowledge with respect to that settlement agreement?

(b) Regarding volumetric risk, is Concentric aware of any reason that YECL did not ask for a deferral account similar to the one described in the above-quote?

(c) Is there a benefit to YECL in taking the volumetric risk?

Response:

(a) As stated on page 21 of Concentric's report, AEY derives approximately nine percent of its electricity supply from company-owned hydro and diesel generation facilities.

While Maritime Electric derives a higher percentage of its load requirements from company owned generation than AEY does (24% vs. 9%), as indicated on page 6 of the report, Concentric views the companies as having similar

generation risk from an investor perspective. In addition, both Maritime Electric and AEY primarily serve residential and commercial customers.

Yes, it is probable that the negotiated settlement was the result of various trade-offs between the parties. For example, the Island Regulatory and Appeals Commission ("IRAC") approved the settlement agreement, which included approval of Maritime Electric's requested weather normalization mechanism on an interim basis as well as changes to Maritime Electric's depreciation rates.

With respect to the Commission's approval of the 9.35% ROE in the settlement agreement, the IRAC stated:

> The Commission also accepts that a ROE risk premium is appropriate due to the unique risk factors that exist in this Province, as set out by Concentric and Maritime Electric. The Commission recognizes, in particular, that Maritime Electric faces incremental risk relative to other utilities due to the frequency in which the regulatory framework in the Province has been changed over the last twenty years. Such changes may be perceived by investors as increasing the regulatory risk of the Company, resulting in the need for a higher risk premium when compared to similar utilities in other jurisdictions. The Commission recognizes the Company's responsibilities for electricity supply which are unique when compared to other Canadian distribution utilities. The Commission is reluctant to assign a value to the risk premium, and views this as an assessment to be conducted based on the circumstances as they exist at the time of each rate application.[14]

Concentric provided a report in which we recommended the appropriate ROE and equity ratio for Maritime Electric, but we were not involved in the negotiations that led to the settlement agreement.

(b) Concentric has no knowledge of why AEY has not requested a weather normalization variance account.

(c) A weather normalization account is intended to reduce risk due to changes in volume attributable to abnormal weather. To the extent the utility's revenues, earnings, and cash flows are more stable and predictable, the utility has lower investment risk. Concentric does not see a specific benefit for any utility from incurring weather-related volume risk.

[14] Island Regulatory and Appeals Commission, Docket UE 20942, Order UE16-04R, July 11, 2016, at paragraph 75.

YUB-YECL-60

Reference: Application, Attachment 8.1, Concentric report, page 6.

Issue/sub-issue: DSM

Quote: "Alberta does not have DSM/energy efficiency programs, unlike Yukon which approved DSM programs for AEY several years ago. For that reason, AEY has more volumetric risk associated with energy efficiency and conservation programs than does ATCO Electric Distribution."

Request:

(a) What, if any, impediments are faced by YECL in terms of forecasting volumes due to the DSM programs?

(b) Does the DSM program represent a significant level of risk? Please explain.

Response:

(a) The implementation of energy efficiency and DSM programs generally makes it more difficult for the utility to forecast sales volumes because the effectiveness of those programs, both in terms of actual energy savings and customer participation rates, which are not known when the forecast is made and can vary significantly depending on how the DSM program is designed.

(b) Concentric does not believe that the DSM program represents a significant level of risk for AEY at this time. However, AEY does have more volumetric risk due to DSM programs than other utility companies that have protection against lost revenues from DSM programs.

YUB-YECL-61

Reference: Application, Attachment 8.1, Concentric report, page 18.

Issue/sub-issue: Comparison Group Criteria

Preamble: Concentric utilized three criteria when determining its comparators. The Board wishes to understand how the comparison criteria were selected.

Request:

(a) Why were the three criteria listed on page 18 of the report selected?

(b) What other criteria could have been selected? Please explain.

Response:

(a) Due to risk associated with the extremely small size of AEY, Concentric determined that it was appropriate to develop a comparator group that consisted of smaller investor-owned electric and gas utilities in Canada. In order to limit the need to make adjustments for generation ownership, we selected electric utilities that are primarily engaged in transmission and distribution services like AEY, and which own limited generation assets. From a geographic perspective, we focused on British Columbia and Alberta because of their proximity to Yukon, and because the Board has expressed a preference for using a benchmark utility from another jurisdiction (chiefly British Columbia) to set the ROE for AEY. Lastly, as mentioned on page 17 of the report, we selected investor-owned utilities because we believe that investor-owned companies have different risk profiles or may be perceived as having different risk profiles by their regulators than government-owned utilities (i.e., crown corporation, municipal utilities, etc.)

(b) Please see previous response. Given our assignment, Concentric believes these criteria are the most appropriate for purposes of selecting a risk-comparable comparator group for AEY.

YUB-YECL-62

Reference: Application, Attachment 8.1, Concentric report, page 18.

Issue/sub-issue: Business Risk

Quote: "In particular, as discussed in the following section, the risk factor that most distinguishes AEY from FortisBC Energy and other investor-owned electric and gas distribution utilities in Canada is its small size."

Request:

(a) Is it standard when choosing comparators to utilities to use size as the dominant criteria for assessing a risk premium for business risk? Please explain.

Response:

(a) Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).

YUB-YECL-63

Reference: Application, Attachment 8.1, Concentric report, page 20.

Issue/sub-issue: Unpredictable Returns

Quote: "Size is an important consideration for investors in setting their return requirements. According to Morningstar, investors in smaller companies typically require a higher return because returns for smaller companies are more unpredictable."

Request:

(a) Please file any information that shows that the returns (ROE) for small regulated electric utilities are more unpredictable.

(b) Please provide examples showing that YECL's returns (ROE) have been unpredictable. Provide YECL's returns in the last five years.

Response:

(a) Concentric is not aware of any studies that are specific to the utility industry and small size. However, Morningstar does provide data showing that returns for smaller companies have exhibited higher variability. The table below is reproduced from the Table 7-1 of the 2015 Classic Yearbook referenced on page 20 of Concentric's report. It demonstrates that the standard deviation of annual returns increases for smaller companies. Because the returns for smaller companies are more unpredictable, investors in smaller companies typically require a higher return to compensate for that variability. Concentric is also aware, based on its experience in the acquisition and sale of utility companies, that utility investors consider size an important risk factor.

Decile	Geometric Mean	Arithmetic Mean	Standard Deviation
1 – Largest	9.4	11.2	19.1
2	10.7	13.0	21.7
3	11.1	13.7	23.6
4	11.0	14.0	25.8
5	11.7	14.8	26.4
6	11.5	15.0	27.3
7	11.6	15.5	29.2
8	11.7	16.3	33.3
9	11.6	17.1	37.4
10	13.5	20.6	42.8

(b) AEY's earned ROE over the last 5 years are as follows:

2011	2012	2013	2014	2015
10.74%	10.18%	10.78%	8.85%	7.40%

YUB-YECL-64

Reference: Application, Attachment 8.1, Concentric report, page 20.

Issue/sub-issue: Utility Size

Quote: "For example, adverse economic conditions in the territory may result in reduced customer demand for electricity. Under those circumstances, the small size of AEY means that the Company's fixed costs are spread across a very small customer and revenue base, making it more likely that AEY will fail to earn its authorized ROE."

Request:

(a) The above example describes a volumetric risk. Can this risk be compensated by frequent regulatory filings or by special applications such as the YEC/YECL application when the Faro mine closed?

Response:

(a) While more frequent regulatory filings might be useful in terms of adjusting the sales forecast in future years, they do not provide the utility with a better opportunity to earn its authorized ROE in a previous year. If adverse economic conditions occur during a year in which there is no rate case, the utility has no way to go back and recover any lost revenues or earning shortfall after the fact, unless there is an earnings sharing mechanism that allows the utility to increase rates in order to achieve a specified return. In addition, more frequent regulatory filings and special applications also can result in less regulatory efficiency and higher costs for both the customer and the regulatory agency.

YUB-YECL-65

Reference: Application, Attachment 8.1, Concentric report, page 21.

Issue/sub-issue: Generation Risk

Quote: "FortisBC Electric purchases approximately 55 percent of its electricity supply and generates the other 45 percent of its supply requirements through company-owned facilities."

Request:

(a) FortisBC Electric generates 45 percent of its supply requirements. Does Concentric consider this a significant increase in generation relative to YECL?

(b) Please comment on whether FortisBC Electric would be considered to have higher generation risk than YECL?

Response:

(a) On the spectrum of generation risk, FortsBC Electric at 45 percent of its load requirements has higher generation risk than AEY at 9 percent of its load requirements.

(b) On page 5 of Concentric's report, we indicate that FortisBC Electric has relatively more generation risk than AEY.

YUB-YECL-66

Reference: Application, Attachment 8.1, Concentric report, page 22.

Issue/sub-issue: Fuel and Purchased Power Cost Risk

Request:

(a) In terms of overall business risk assessment, does fuel and purchase power cost risk have a lower weighting than size and generation risk? Please explain.

(b) In regards to this risk, is YECL only exposed to purchase power requirements in excess of its forecast amounts? Please explain.

Response:

(a) While fuel and purchased power cost risk are important, most utilities are able to pass through those costs directly to customers and therefore are not at risk for cost recovery if actual costs are higher/lower than forecast. Risk differences occur when the utility is not allowed to pass through 100 percent of these costs, or when the variance accounts expire, as in the case of AEY. As a general premise, Concentric agrees that fuel and purchased power cost risk is not as important as small size and generation risk.

(b) Consistent with historical practice, AEY is proposing continuation of its existing purchase power and fuel deferral accounts where costs related to price variances are flowed through to customers. AEY continues to assume risk for costs related to forecast volumes.

YUB-YECL-67

Reference: Application, Attachment 8.1, Concentric report, pages 23-24.

Issue/sub-issue: Volume/Demand Risk

Quote: "AEY does not have any regulatory protection against changes in volume/demand due to weather conditions or demand side management and energy efficiency programs. By comparison, all but one of the electric and gas distribution companies in the proxy group has some form of revenue protection against volumetric risk. The following companies have weather normalization clauses that help to stabilize their revenues if weather conditions are abnormal: FortisBC Energy; FortisBC Electric; Newfoundland Power; and Maritime Electric."

And

"In Yukon, electric space heating has become much more common in new residential housing developments…"

Request:

(a) Please provide and describe in detail the weather normalization clauses for FortisBC Electric.

(b) Please explain how FortisBC Electric was awarded this clause and any concerns/conditions expressed by the BCUC regarding the awarding of such a clause.

(c) In terms of determining overall business risk, please provide the relative weighting of this risk versus the risks of size, generation fuel and purchased power risk and the other business risks evaluated in the report.

(d) Does increased use of electric space heating increase the average use per customer and therefore support growth in electricity consumption?

Response:

(a) Fortis notes in its annual report that it maintains regulatory deferral mechanisms to "minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence of the above-noted regulatory

deferral mechanisms could have a material adverse effect on the results of operations and financial position of the utilities."[14]

(b) The British Columbia Utilities Commission ("BCUC") approved the implementation of a Purchased Power Expense Variance Account and a Revenue Variance Account in the 2012-2013 Revenue Requirements Application of FortisBC Electric. Both of these accounts are designed to mitigate risk associated with load variances related to variances in customer growth, usage, or weather. On page 33 of the Decision, the BCUC notes that "FortisBC has proposed a deferral account to capture variances in forecast and actual Power Purchase Expense. This is in part in response to a request from stakeholders in the 2011 Negotiated Settlement Agreement." In approving the Power Purchase Expense Variance Account, the BCUC states on page 34 of the Decision: "The Panel understands the complexity of managing a number of variables affecting the power purchase process and is in agreement that any positive or negative variances are most appropriately borne by the customer. The establishment of a Power Purchase Expense Variance Deferral Account is the most effective way to manage this process with variances being handled in customer rates in subsequent periods."

In approving the proposed Purchased Power Expense Variance Account, the Commission Panel did express concern with the level of accuracy of FortisBC's forecasts for power purchases, stating on page 35 of the Decision: "The Commission Panel finds that based on the past five years, FortisBC has been overly conservative with its power purchase expense forecasts."

(c) Concentric has not assigned relative weights to the risk factors that are discussed in the report. Risk assessments are generally more qualitative than quantitative. The most important considerations are whether the utility faces the specific risk, the magnitude of the risk on earnings and cash flows, and whether the utility has some form of regulatory protection that mitigates the effect of the risk.

(d) All else being equal, an increase in electric space heating should lead to increased average use per customer. This would support growth in overall electricity consumption, but greater volatility in earnings and sales if weather is warmer or colder than normal.

[14] Fortis Inc. 2015 Annual Report, p. 54.

YUB-YECL-68

Reference: Application, Attachment 8.1, Concentric report, pages 24-25.

Issue/sub-issue: Residential use per customer

Quote: "The Company believes that the increased variability in residential use per customer is due in part to customers responding to changes in prices for alternative fuels. For example, when heating oil and propane prices were high, more customers chose to use electricity for space heating. As heating oil and propane prices have decreased in the past year, more customers are deciding to use those alternative fuels for space heating rather than electricity."

Request:

(a) Has the company filed any studies to support the statement that customers are responding to changes in prices for alternative fuels. If so, please provide those studies. If not, what is the basis for the statement?

(b) In terms of alternative fuel sources, does this mean that most homes will have duplicate sources for heat such as an oil burning furnace and electric space heating? Please comment.

(c) When heating oil prices were high, the choice of customers was to use electric heating, does this refer to new customers entering the system or existing customers retrofitting their homes? Please explain.

Response:

(a-c) AEY has not filed or completed any formal studies with respect to fuel switching. The statement is based on anecdotal evidence from employees, and individuals throughout the community that confirm "fuel switching" between heating sources is common.

Traditionally, homes in the Yukon have been heated primarily using oil and/or propane as the primary fuel type with many homes also having the ability to utilize secondary heating sources such as wood stoves and or portable electric heaters. Considering the fact that many homes have the ability to "fuel switch", when heating oil prices are high it would impact existing customers.

The Yukon Bureau of Statistics, Yukon Energy Facts 2013 is provided in YUB-YECL-68 Attachment 1. As shown in that attachment, the amount of housing stock using electric heat has grown significantly from 2003 indicating a large proportion of new housing is utilizing electric heat.

YUKON BUREAU OF STATISTICS

Yukon Energy Facts 2013

Highlights:

- Yukon's 2013 electricity generation of 448,212 mega-watt hours (MWh) consisted of 424,720 MWh in hydro (94.8%), 23,215 MWh in thermal (5.2%) and 277 MWh in wind generation (0.1%).
- Of the 397,053 MWh of electricity sold in Yukon in 2013, sales to *non-residential* customers accounted for 59.1% and sales to *residential* customers accounted for 40.9%.

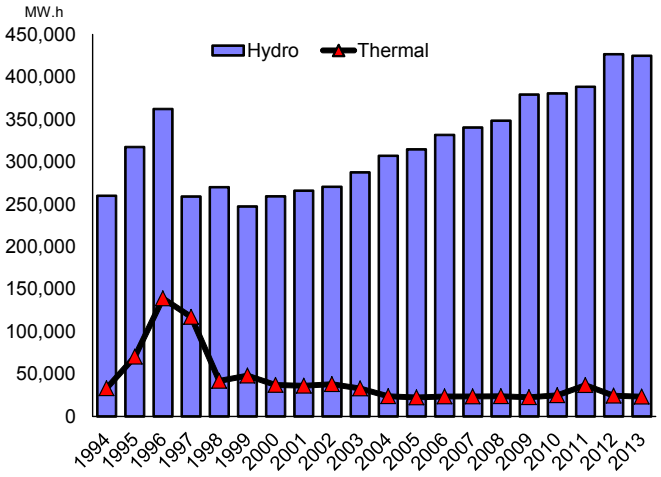
Electricity Generation, Yukon, 2004 to 2013

	ATCO ELECTRIC YUKON		YUKON ENERGY CORPORATION			YUKON TOTAL			GRAND TOTAL
	HYDRO	THERMAL	HYDRO	THERMAL	WIND	HYDRO	THERMAL	WIND	
					(MWh)				
2013	3,417	21,305	421,303	1,910	277	424,720	23,215	277	**448,212**
2012	3,388	21,310	423,206	3,055	445	426,594	24,365	445	**451,404**
2011	3,638	20,933	384,429	15,935*	402	388,067	36,868	402	**425,337**
2010 (r)	3,388	19,839	377,043	5,127	85	380,431	24,966	85	**405,482**
2009 (r)	8,094	19,966	370,962	2,645	238	379,056	22,611	238	**401,905**
2008 (r)	6,551	22,065	341,742	1,662	437	348,293	23,727	437	**372,457**
2007	9,025	22,334	331,226	1,247	362	340,251	23,581	362	**364,194**
2006	6,950	21,804	324,473	1,694	605	331,423	23,498	605	**355,526**
2005	6,858	21,807	307,717	580	890	314,575	22,387	890	**337,852**
2004	5,799	21,988	301,038	1,705	477	306,837	23,693	477	**331,007**

Hydro electricity: Energy produced by utilizng the water flow in a river.
Thermal electricity: Energy produced by generators run on petroleum products (e.g. diesel).
Wind electricity: Wind generator at Haeckel Hill, Whitehorse, went into service in the fall of 1993. A second wind generator was added in October 2000.

** Reflects impact of additional diesel to accomodate capital projects of Mayo B and Aishihik Unit #3.*
Source: ATCO Electric Yukon and Yukon Energy Corporation.

Hydro and Thermal Generation, Yukon, 1994 to 2013

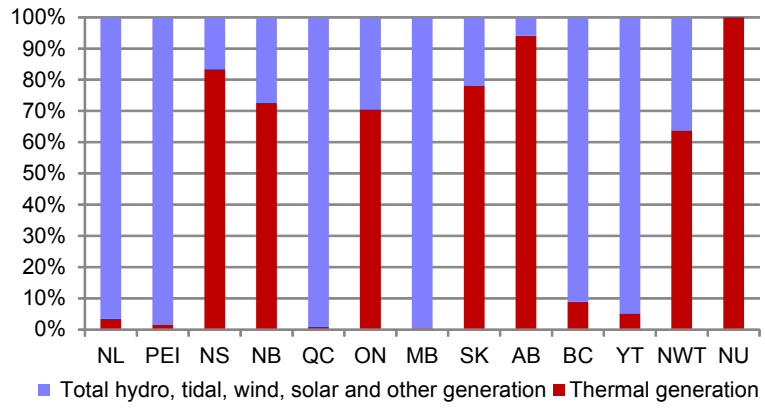


Source: ATCO Electric Yukon and Yukon Energy Corporation.

Type of Generation, 2013	Location	Ownership	Installed Generation Capacity (MW)
Hydroelectric generating facilities	Whitehorse (WAF)	YEC	40.0
	Aishihik	YEC	37.0
	Mayo	YEC	15.1
Hydro plant	Fish Lake	YECL	1.3
Wind turbines	Whitehorse	YEC	0.8
Diesel generating facilities	Whitehorse (WAF)	YEC	23.0
	Faro (WAF)	YEC	8.5
	Dawson	YEC	5.1
	Mayo	YEC	2.5
Off-grid diesel generation facilities	Watson Lake	YECL	5.0
	Carmacks (WAF)	YECL	1.5
	Haines Junction (WAF)	YECL	1.5
	Teslin (WAF)	YECL	1.5
	Pelly Crossing	YECL	1.2
	Ross River (WAF)	YECL	1.0
	Beaver Creek	YECL	0.9
	Destruction Bay	YECL	0.9
	Old Crow	YECL	0.7
	Swift River	YECL	0.3
	Stewart Crossing	YECL	0.1

WAF = Whitehorse Aishihik Faro line YEC = Yukon Energy Corportion
YECL = ATCO Electric Yukon
Source: Yukon Energy Corporation.

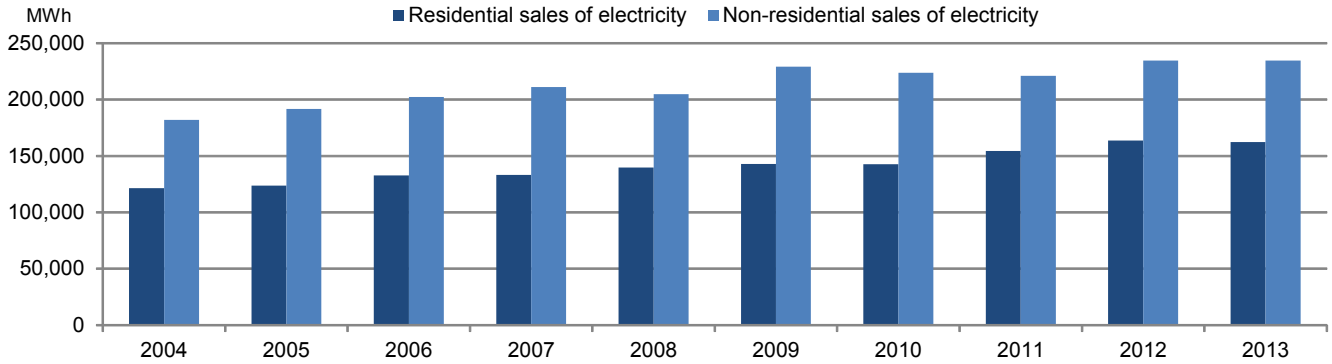
Electricity by Type of Generation, Provinces and Territories, 2013



Source: Statistics Canada, CANSIM 127-0007.

According to Statistics Canada, hydro and wind generation accounted for 94.8% of Yukon's total electricty generation in 2013. The remaining 5.2% was from thermal generation. Yukon ranked the fifth highest in the hydro, tidal, wind, solar and other generation category, and the fifth lowest in thermal generation.

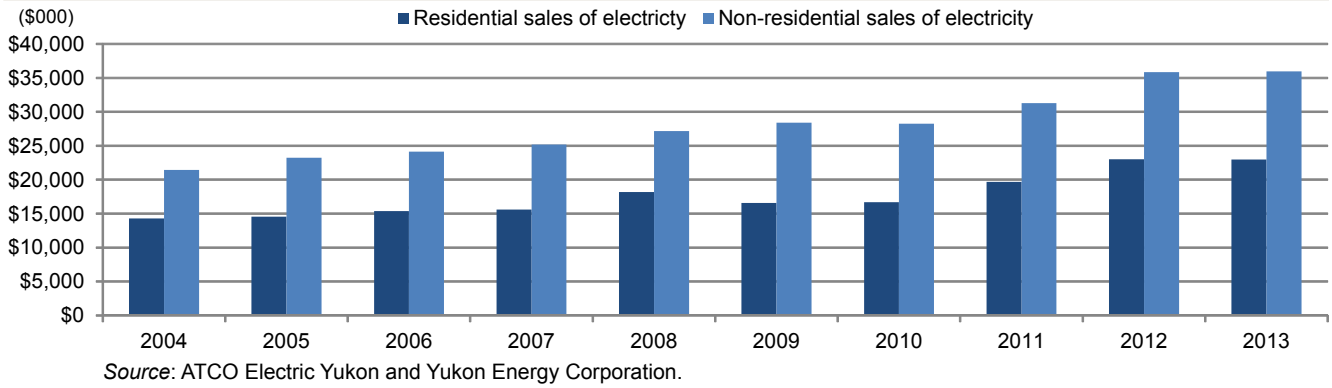
Electricity Distribution (MWh), Yukon, 2004 to 2013



Source: ATCO Electric Yukon and Yukon Energy Corporation.

- Of the 397,053 MWh of electricity sold in Yukon in 2013, sales to *non-residential* customers accounted for 59.1% (234,680 MWh), and sales to *residential* customers accounted for 40.9% (162,373 MWh).
- Compared to 2012, both *non-residential* sales and *residential* sales remained relativley flat with small decreases of -0.01% and -0.8%, respectively.

Electricity Sales ($000), Yukon, 2004 to 2013



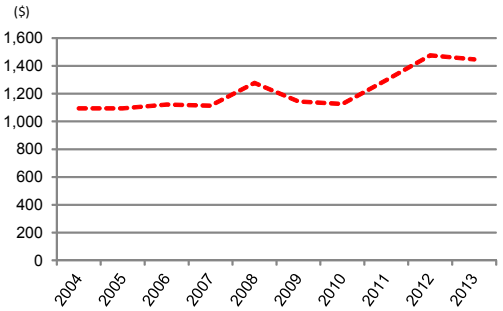
Source: ATCO Electric Yukon and Yukon Energy Corporation.

- Sales of electricity to ultimate customers in 2013 totalled $58.9 million; an increase of $86,000, or 0.1%, compared to 2012.
- Compared to 2012, sales to *non-residential* customers ($36.0 million) in 2013 increased by $98,000, or 0.3%, while sales to *residential* customers ($23.0 million) decreased by $12,000, or 0.1%.

Residential Electricity Cost and Consumption, Yukon

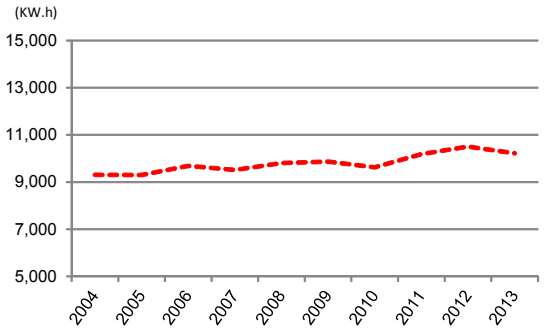
	Residential Customers (#)	Average Residential Annual Bill ($)	Consumption per Residential Customer (KWh)	Residential Consumer Cost per KWh (cents)
2013	15,886	1,446.89	10,221	14.16
2012	15,580	1,476.05	10,503	14.05
2011	15,168	1,298.09	10,188	12.74
2010	14,825	1,125.90	9,624	11.70
2009	14,498	1,143.38	9,865	11.59
2008	14,240	1,277.69	9,808	13.03
2007	14,009	1,113.35	9,511	11.71
2006	13,714	1,121.57	9,685	11.58
2005	13,312	1,094.05	9,301	11.76
2004	13,052	1,094.70	9,308	11.76

Average Residential Electricty Bill, Yukon, 2004 to 2013

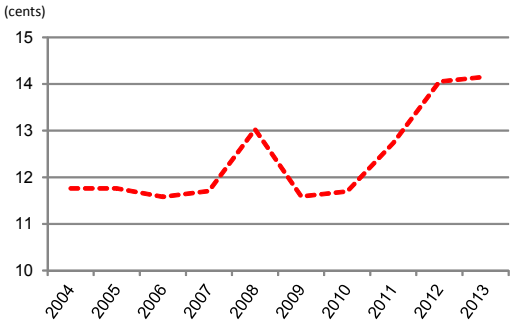


- In 2013 ,the average residential annual electricity bill in Yukon was $1,446.89, a decrease of $29.16, or 2.0%, from 2012, and an increase of $352.19, or 32.2% compared to 2004.
- Over the past ten years, Yukon residential customers consumed an average of 9,801 KWh of electricity annually.
- In 2013 ,the residential electrical consumer cost per KWh in Yukon was $0.14, an increase of $0.10, or 0.7%, from 2012, and an increase of $2.39, or 20.4% compared to 2004.

Consumption (KWh) per Residential Customer, Yukon, 2004 to 2013

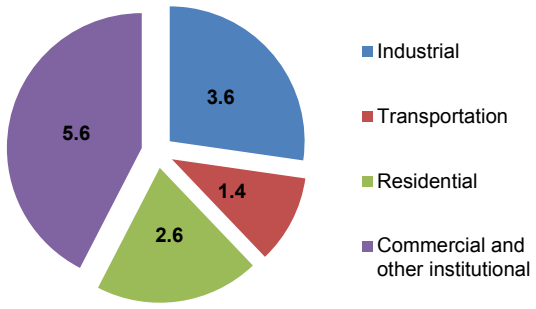


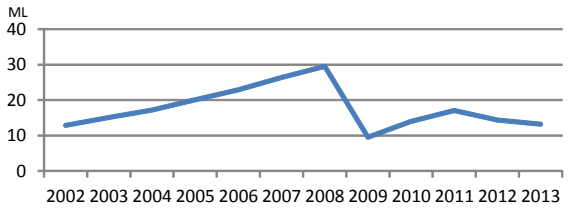
Residential Consumer Cost per KWh, Yukon, 2004 to 2013



Source: ATCO Electric Yukon and Yukon Energy Corporation.

Final Demand for Propane (Megalitres), Yukon, 2013





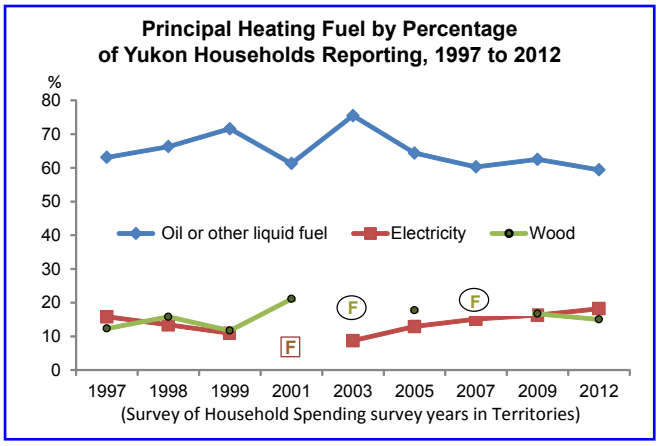
In 2013, 13.2 megalitres of propane were consumed in Yukon. Of the total consumption, 42.4% was in *Commercial and other institutional*; 27.3% in *Industrial*; 19.7% in *Residential*; and 10.6% in *Transportation*.

Source: Statistics Canada, CANSIM 128-0012.

Principal Heating Equipment and Heating Fuel, Territories, 2012

	Yukon	NWT	Nunavut
	---------- % ----------		
Principal Heating Equipment			
Steam or hot water furnaces[1]	F	30.5	52.8
Hot air furnaces[2]	58.0	56.4	39.4
Heating Stoves[3]	15.7	F	F
Electric Heating[4]	17.9	F	F
Other[5]	F	F	F
Age of Prinicipal Heating Equipment			
5 years old and under	23.7	29.6	F
6 to 10 years old	27.7	26.0	21.1
Over 10 years old	48.6	44.4	61.2
Prinicipal Heating Fuel			
Oil or other liquid fuel	59.4	59.7	94.3
Natural gas	F	F	F
Propane	F	16.2	F
Electricity	18.2	F	F
Wood	15.0	F	F
Other	F	F	F

F = too unreliable to publish.
[1] Steam or hot water systems distribute central heating through radiators located throughout the house and connected by pressure pipes.
[2] Hot air furnaces distribute central heating by a motor-driven fan through vents located throughout the dwelling.
[3] Heating stoves are localized heating units with no central distribution system to other parts of the house (e.g., oil space heater, gas space heater, wood stoves).
[4] Electric heating includes permanently installed baseboard electric heating and other types such as floor or ceiling heating wires in all or most rooms.
[5] Other heating includes cookstoves and any other type of heating equipment not listed above.
Source: Statistics Canada, CANSIM 203-0031.

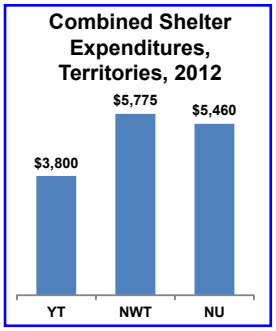


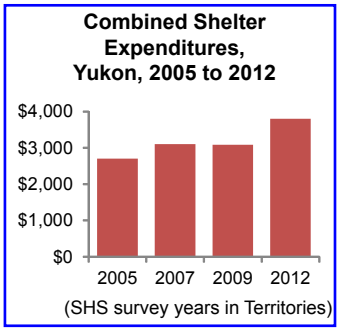
In 2012, 59.4% of Yukon households used oil or other liquid fuel as their principal heating fuel, 18.2% used electricity, while 15.0% used wood as their primary heating source. Hot air furnaces (58.0%) were the most common principal heating equipment in Yukon in 2012, followed by electric heating (17.9%) and heating stoves (15.7%).

Median Expenditure per Household Reporting, Selected Energy Components, Territories, 2012

	YT	NWT	NU
	---------- $ ----------		
Shelter Expenditures[1]			
Electricity	1,400	2,275	960
Other fuels[2]	2,400	3,500	4,500
Transportation Expenditures			
Gas & other fuels (owned/leased vehicles)	2,700	2,760	2,500
Gas & other fuels (rented vehicles)	150	160	F
Gas & other fuels (recreational vehicles)	300	500	1,000

[1] For principal accommodation.
[2] For heating and cooking (example: oil, propane, wood)
F = Too unreliable to be published.
Source: Statistics Canada, CANSIM 203-0003 and 203-0030.





Executive Council Office
Bureau of Statistics

Info sheet no. 59.13
Dec '14

Additional Information:
Government of Yukon
Executive Council Office
Bureau of Statistics (A-8C)
Box 2703, Whitehorse, Yukon Y1A 2C6
Telephone: (867) 667-5640; Fax: (867) 393-6203
Email: ybsinfo@gov.yk.ca
Website: www.eco.gov.yk.ca/stats/

YUB-YECL-69

Reference: Application, Attachment 8.1, Concentric report, page 27.

Issue/sub-issue: Business Risk

Quote: "In summary, AEY's residential customers respond to price signals as the relative cost of heating with electricity changes. However, this risk is difficult to quantify and likely does not have a material effect on the risk profile of AEY. It does, however, make it more difficult for AEY to accurately forecast sales, which in turn increases the variability in AEY's cash flows and earnings."

Request:

(a) If the risk of alternative fuels is not material, why is the risk considered?

Response:

(a) Concentric has considered the principal business risks relevant to a regulated utility from an investor's perspective. As part of our risk assessment, we then determined if the utility has that risk, if the risk is material to the stability and predictability of the earnings and cash flows of the company, and if utility has a way to mitigate the risk through regulatory protections. In the case of competition from alternative fuels, Concentric determined that this risk exists but is not material for AEY at this time.

YUB-YECL-70

Reference: Application, Attachment 8.1, Concentric report, page 25

Issue/sub-issue: Regulatory Environment

Quote: "Traditional cost of service regulation is generally considered to be less risky than incentive regulation by credit rating agencies, although the degree of risk depends on the length of the incentive regulation plan and the ability for the utility to adjust certain costs during the term of the plan."

Request:

(a) Please describe in detail the PBR plan for FortisBC Electric.

Response:

(a) FortisBC Electric ("FBC"), a vertically integrated electric utility, currently operates under a Performance Based Ratemaking plan ("PBR") as prescribed by the British Columbia Utilities Commission ("BCUC"). The BCUC issued its decision on FBC's current multi-year PBR plan in September 2014,[14] setting a five-year term that extends through 2019.

FBC operates under an I-X program with an X factor of 1.03%, a symmetric earnings sharing mechanism ("ESM"), and formulaic capital recovery with adjustment mechanisms.[15]

Prior to the current PBR plan, FBC was under Cost of Service Regulation in 2012 and 2013, PBR from 2007-2011, Cost of Service in 2005 and 2006, and PBR from 1996-2004. Given FBC has consistently been awarded a 40 basis point risk premium above the benchmark utility in British Columbia since 2000, regardless of whether FBC has been regulated under Cost of Service or Performance Based Ratemaking, the form of regulation has not impacted the quantum of risk premium

[14] BCUC Decision, FortisBC Inc. Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018, September 15, 2014.
[15] *Ibid.*

YUB-YECL-71

Reference: Application, Attachment 8.1, Concentric report, pages 29-31

Issue/sub-issue: Changes to Business Risk

Preamble: Concentric lists four items with respect to changes in business risk.

Request:

(a) Are the items with respect to changes in business risk listed in order of priority? Please explain.

(b) The author concludes that business risks have not materially changed since 2009. If the business risks have not materially changed, please explain why the Board should deviate from its 2009 decision and award a risk premium?

Response:

(a) No, the changes in business risk are not listed in order of priority. Among the four risks listed in the Concentric report in relation to changes since 2009, the most important risk is related to power supply costs because the variance accounts for fuel and purchased power have expired. If the requested deferral accounts for fuel and purchased power are not approved, this would have a material impact on AEY's risk profile (increase in risk) as compared to 2009.

(b) According to Board Order 2009-02, in 2009, the Board determined that it was appropriate to award AEY a risk premium of 46 basis points above the benchmark utility in British Columbia. Concentric believes it is appropriate to consider the magnitude of the risk premium in light of the updated evidence presented in its report.

YUB-YECL-72

Reference: Application, Attachment 8.1, Concentric report, page 30

Issue/sub-issue: Micro generation

Quote: "The Yukon provincial government has been pursuing a policy that encourages micro generation. In October 2015, new legislation was passed that requires AEY to provide a Standard Offer Price to independent power producers by October 2016. For AEY, this new requirement has the greatest impact in the community of Watson Lake, which represents approximately 10 percent of AEY's total sales. The move toward micro generation has the potential to increase the risk associated with customers using less electricity from AEY and increasing self-generation through use of solar panels. Since the policy has just been implemented, it is not possible to quantify the risk at this time."

Request:

(a) Please provide a copy of the legislation.

(b) Please explain and provide a definition of the "Standing Offer Price".

(c) Please provide the amount of micro generation that has been supplied to the grid for each of the years 2013-15 and the forecast amounts for 2016 and 2017. Also, for each of the years, how much energy from micro generation has displaced generation form YECL?

(d) Please provide the price that YECL pays for micro-generated power.

(e) For micro generators, are any standby rates in place? Please explain. What should a standby rate be based on?

Response:

(a) Please refer to YUB-YECL-72(a) Attachment 1 for the copy of the IPP policy. For further clarity, there are two separate and distinct policies referenced in the above quote: 1) The IPP policy and 2) The Micro Generation Policy provided in attachment YUB-YECL-72(a) Attachment 2.

(b) The IPP policy statement does not specifically define the Standing Offer Price. Concentric's understanding is the utilities will work with the Yukon government's Energy Branch to establish and publish a rate under the Standing Offer Program for delivered energy based on current avoided costs of new supply. Accordingly, rates will be higher in the winter than in the summer. These rates will be indexed to reflect appropriate annual inflation in electrical generation costs. According to the October 2015 policy statement, the utilities will work with the Yukon government to structure the program such that it will not lead to higher costs for the consumer. Independent power producer rates are to provide potential proponents with pricing and market certainty for their generated power. Details of the program will be completed by the utilities and the Yukon government within one year of the effective date of the policy.

(c) Please refer to AEY's response to YUB-YECL-6(a) sub-part b.

(d) The microgeneration rate is administered by the Yukon Government not AEY, and is currently $0.21/kWh on the Hydro system and $0.30/kWh in communities powered by diesel.

(e) No, there are no standby rates currently in place. AEY has not at this time evaluated what an appropriate standby rate would be.

ENERGY STRATEGY FOR YUKON

Independent Power Production Policy

October 2015

Yukon
Energy, Mines and Resources



IMPLEMENTING THE ENERGY STRATEGY FOR YUKON

BACKGROUND

The Government of Yukon (YG) released the *Energy Strategy for Yukon* in January 2009. The strategy sets out YG's energy priorities, strategies and actions. The Independent Power Production (IPP) policy is part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy." The policy provides a mechanism for the purchase of electricity from independent power producers.

A discussion paper on net metering and IPP was released for public consultation between November 2009 and February 2010. Through that consultation, the public clearly indicated that there should be separate policies for net metering and IPP. Valuable input was received about proposed policy objectives, eligible energy sources, size of electricity projects, connections to the Yukon electrical grid, financial arrangements, policy framework, and roles and responsibilities.

The IPP policy is about providing opportunities for non-utility entities to generate new power that can assist the utilities in meeting the demand for affordable, reliable, flexible and clean electrical energy.

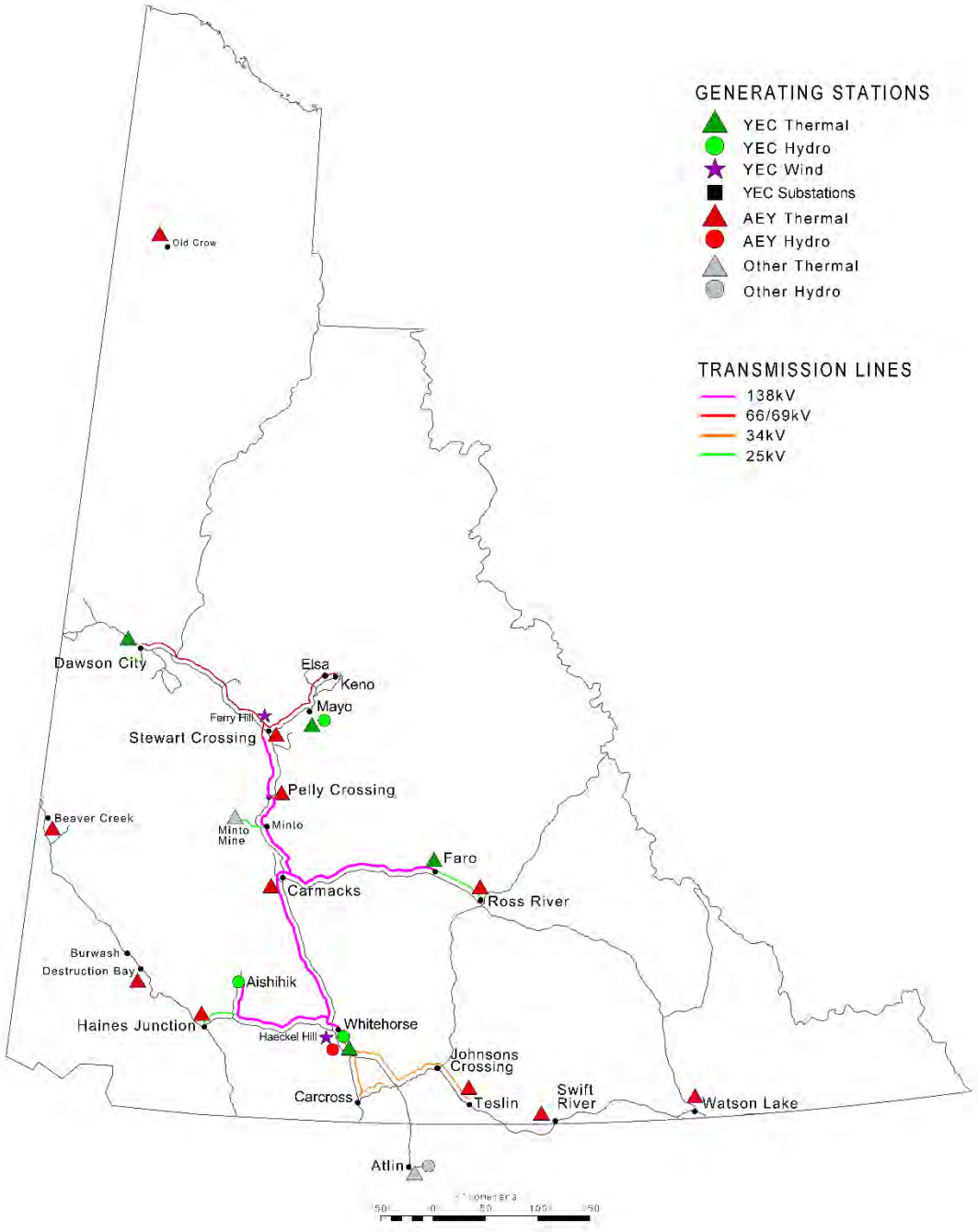
The IPP policy will look different in Yukon than it does in other jurisdictions. Yukon's electrical grids are not connected to the North American grid and are smaller than other jurisdictions' grids. The inability to export excess electricity makes it risky for the utilities and Yukon ratepayers to generate electricity in anticipation of increased demand, as this future demand may not materialize in Yukon's commodity-based economy. At the same time, Yukon is unable to import electricity when required, making growth in local generation capacity crucial to future economic and population growth.

As of 2015, the electrical system in Yukon (shown in map below) is comprised of:

- 1 large hydro-based grid called the Yukon Integrated System (YIS);
- 1 medium-sized diesel-based grid serving Watson Lake; and
- Three smaller isolated communities with diesel generation (Old Crow, Beaver Creek and Destruction Bay/Burwash Landing).

The YIS had a winter peak demand of approximately 84 megawatts, as of 2015. The renewable energy capacity in the winter is 72 megawatts. To avoid the use of thermal-generated electricity, and if the residential, commercial and industrial loads continue to grow as forecast, this (hydro-based) grid will require additional renewable sources of energy.

Electrical Generation and Transmission System for Yukon



SCOPE

Application

This policy applies to independent power producers who want to generate electricity from eligible sources and sell it to a publicly owned utility, Yukon Energy Corporation (YEC) or ATCO Electric Yukon (AEY).

This policy does not apply to producers covered under the Government of Yukon's Micro-generation Policy.

Policy Goal and Objectives

The goal of this policy is to support the participation of independent power producers, including Yukon First Nations and communities, in the development and expansion of environmentally sound and affordable electrical supply options now and into the future, while respecting the integrity of the existing electrical system.

The objectives of the IPP Policy are to:

1. Increase electrical supply to meet future energy needs;
2. Strengthen energy security and affordability of Yukon's electrical system;
3. Develop local electricity resources, which are renewable and/or cleaner than diesel;
4. Encourage new, local economic opportunities;
5. Provide Yukon First Nations with opportunities to participate in the Yukon economy, obtain economic benefits, and develop economic self-reliance; and
6. Facilitate collaboration between public utilities and independent power producers, in the development of new clean energy supply projects, which best serve the long-term interests of Yukon consumers.

IPP Target

In order to meet these objectives, this policy will establish the following aspirational targets for IPP contribution to Yukon's electrical grids.

1. 10% of new electrical demand to be met by Independent Power Production; and
2. At least 50% of IPP projects to have a Yukon First Nation ownership component.

POLICY PARAMETERS

This policy establishes three separate approaches for development of IPP projects. For small, simple projects, a Standing Offer Program will be established. A Call for Power process will be established to allow the territory's energy planners to access IPPs to meet expected large-scale electrical demands. And for large-scale projects that are primarily being developed by communities, an Unsolicited Proposal process would allow an IPP to propose a generation project at any time. Details are as follows.

1. Standing Offer Program

The Standing Offer Program (SOP) encourages the development of new, small and renewable projects. The intention of the program is to streamline the process for selling electricity to YEC on the YIS and to AEY in Watson Lake, and to simplify the contracting process between IPP developers and the utilities. Details of the program will be completed by the utilities and the Yukon government within one year of the effective date of this policy.

Remote Communities and the SOP

Due to the isolated nature of the three smaller communities with diesel generation (Old Crow, Beaver Creek and Destruction Bay/Burwash Landing) and the relatively small size of the generating facilities in these communities, a cautious approach is required to ensure the safety and security of the electrical grid for all residents. For this reason, these sites are not eligible for the SOP. Potential IPPs in these communities are, however, eligible for the Unsolicited Proposal processes described below. As well, smaller systems (up to 50 kW) are eligible for the Micro-generation Production Incentive Program and proponents would be offered an incentive through that program.

In addition, YG is committed through this policy to work with these communities and the local electrical utility (AEY) to provide resources that will facilitate the development of community-owned IPP projects, such that these communities can develop economic and energy self-reliance, while reducing the greenhouse gas emissions from diesel generation.

Connecting the SOP Projects to the Electrical Grids

The utilities and the Yukon government will develop all required interconnection materials (i.e., interconnection standards, interconnection agreement templates and SOP pricing information) within one year of the effective date of this policy and file the interconnection standards and agreement templates with the Yukon Utilities Board (YUB) for approval at an appropriate time.

Eligible SOP Energy Sources

Eligible energy sources for SOP projects are limited to local renewable sources as discussed in the *Energy Strategy for Yukon*, which include:

- wind
- hydro
- geothermal
- biomass
- solar

New technologies will be considered when this policy is reviewed.[1] Electricity-generating technologies and energy sources must be proven to be reliable before they will be accepted for interconnection to Yukon's electrical grid.

[1] This policy will be reviewed two years from its effective date.

SOP Project Size and System-Wide Limits

SOP Projects must be between 30 kW and 1,000 kW in nameplate capacity in order to be considered.

Any renewable energy electrical generation project under 50 kW can be included in the Micro-generation Production Incentive Program if the project offsets a building's energy consumption and electricity is exported to the grid; however, proponents are required to choose between the IPP or Micro-generation policies.

System-wide limits under the SOP are set by the utilities, Yukon Development Corporation (YDC) and YG's Energy Branch to meet the policy objectives (listed above), while also observing the technical limitations of Yukon's electrical system and minimizing financial risks to Yukon's electrical customers. On the YIS, system-wide limits will be phased in over time to reflect expected increases in electrical loads over time. The following table lists the targeted final system wide limits for the SOP for both the YIS and Watson Lake grid.[2] These limits will be evaluated and revised every two years by the two Yukon utilities, YDC and YG's Energy Branch.

Grid	**System-Wide Generation Limits**
Yukon Integrated System	10,000 MWh/year
Watson Lake	2,100 MWh/year

SOP Interconnection Agreement and Agreement to Purchase Power Principles

The following principles will be used in the development of interconnection agreements and internal policy for the SOP:

1. Utilities will work with the Yukon government's Energy Branch to establish and publish a rate under the SOP for delivered energy based on current avoided costs of new supply. Accordingly, rates will be higher in the winter than in the summer. These rates will be indexed to reflect appropriate annual inflation in electrical generation costs.

2. The utilities will work with Yukon government to structure the program, such that it will not lead to higher costs for the consumer.

3. IPP rates are to provide potential proponents with pricing and market certainty for their generated power.

4. The contract term will be of a duration that enables the prospective independent power producer to access independent financial support.

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[2] System-wide limits for the Watson Lake grid are based on approximately 10% of current peak loads. The system-wide limit for the YIS allows several small projects to be added to the hydro system without oversupplying the system.

5. The contract term will be of a duration that fits with the proposed technology's (anticipated) life expectancy, reliability and associated utility risks.

6. Independent power producers will be responsible for interconnection costs and necessary interconnection upgrades, as well as maintenance of their infrastructure.

7. Each utility will retain the right to cancel or suspend the Interconnection Agreement and the Agreement to Purchase Power, if the independent power producer no longer meets the requirements as outlined in the Agreement to Purchase Power and the Interconnection Agreement.

2. Call for Power

A Call for Power (CFP) applies to projects larger than the above system-wide limits on Yukon's Integrated System. The CFP will require government approval. The CFP process will be used by YEC to incorporate large-scale IPP projects into Yukon's electrical system. The CFP process is proposed to meet future electrical needs, and to fulfill the objectives and targets set out in the above sections.

The Agreement to Purchase Power will be negotiated by YEC and the IPP, and will require final approval by the YUB.

Connecting CFP Projects to the Electrical Grid

When YEC and/or YDC determines that there is a need for new electrical generation above and beyond the system-wide limits set in the table above, YEC may release a CFP for IPP electrical generation, consistent with the objectives of this policy. YEC will review and assess proposals, based on criteria to be developed by YEC in consultation with YG's Energy Branch.

Draft agreements to purchase power from potential producers who have submitted successful proposals will be brought forward to the YUB by YEC for approval.

Eligible CFP Energy Sources

Eligible energy sources for CFP projects are limited to clean energy sources as discussed in the *Energy Strategy for Yukon*, which include:

- wind
- hydro
- geothermal
- biomass
- solar
- natural gas

CFP Project Size and Technology Limitations

No limitations on either project size or technology will be set on CFP type projects. These parameters will be established by YEC in consultation with YG and YDC at the time in which the process is developed, based on the current needs of the territorial electrical system and this IPP policy.

CFP Interconnection Agreement and Agreement to Purchase Power Principles

The Agreement to Purchase Power under a CFP will be developed for each individual call. The following principles will be used by YEC in the development of power purchase agreements under a CFP:

1. IPP rates are to provide potential proponents with pricing and market certainty for their generated power.
2. The contract term will be of a duration that enables the prospective independent power producer to access independent financial support.
3. The contract term will be of a duration that fits the proposed technology's anticipated life expectancy, reliability and associated utility risks.
4. In evaluating projects, preference will be given to those projects which include First Nation ownership (see definitions below).
5. The independent power producer will be responsible for interconnection costs and necessary interconnection upgrades, as well as maintenance of its electrical infrastructure.
6. Each utility will retain the right to cancel or suspend the Interconnection Agreement and the Agreement to Purchase Power if the independent power producer no longer meets the requirements as outlined in the Agreement to Purchase Power and the Interconnection Agreement.

3. Unsolicited Proposals

Unsolicited proposals can be submitted to the utilities or YG's Energy Branch at any time for projects larger than the SOP system-wide limits (on the YIS or in Watson Lake), or any systems installed in the three smaller isolated communities (Old Crow, Beaver Creek and Destruction Bay/Burwash Landing). Eligibility of proposals will be assessed based on current energy needs in the territory, as well as the principles established through this policy. The utilities will negotiate power purchase agreements with IPP proponents to enable project development(s), should they be in the best interest of the territory. YG's Energy Branch will offer support to IPPs in navigating the power purchase agreement development process.

Eligible Unsolicited Proposal Energy Sources

Eligible energy sources for unsolicited proposal projects are limited to clean energy sources as discussed in the *Energy Strategy for Yukon*, which include:

- wind
- hydro
- geothermal
- biomass
- solar
- natural gas

ROLES AND RESPONSIBILITIES

An Implementation Plan accompanies this policy.

Joint Responsibilities of the Government of Yukon and the Utilities

1. Implement, maintain and communicate this policy.
2. Evaluate this policy two years from its effective date.
3. Develop the SOP (including the rates to be paid), technical interconnection standards, and interconnection agreement templates for SOP projects.

Government of Yukon

1. Ensure this policy is consistent with the *Energy Strategy for Yukon*, the *Climate Change Action Plan*, the *Water Strategy* and other government priorities and trade agreements.
2. Meet obligations under First Nation Final Agreements and ensure that this policy is consistent with those obligations.
3. Facilitate First Nation economic development through risk sharing on projects with First Nation IPPs.
4. Encourage IPP proponents to partner with Yukon First Nations and/or Yukon First Nation development corporations and Yukon businesses.
5. Provide access to YG's best management practice guidelines.

Utilities (Yukon Energy Corporation/ATCO Electric Yukon)

1. Determine whether SOP applicants meet YUB approved interconnection standards and are therefore eligible to participate in the program.
2. Develop and manage the Request for Proposal process for CFP projects. Develop interconnection standards and Agreements to Purchase Power for CFP projects.
3. Meet utilities' commitments within interconnection agreements.
4. Provide the public with annual, hourly energy demand data that could be used in assessing the viability of and need for proposed IPP projects in the territory.
5. Establish a 'wheeling' policy between ATCO Energy Yukon and YEC establishing rules governing transmission of IPP power over AEY's grid infrastructure for sale to YEC.

Yukon Utilities Board

1. Review CFP and Unsolicited Proposal projects per the *Public Utilities Act*, and if approved, include in electrical rates.

Yukon Development Corporation

1. Assist YG and the utilities in the implementation of this policy, including setting system wide limits for the SOP and parameters for the CFP.

Independent Power Producer

1. Enter into an interconnection agreement and an Agreement to Purchase Power with the appropriate utility prior to connection to the electrical grid.
2. Be responsible for obtaining all permits and paying associated costs.
3. Be responsible for initiating all environmental and/or regulatory obligations related to its project.
4. Make available the electrical generation project for inspection by the utilities or the applicable government agency, as per the interconnection agreement and Agreement to Purchase Power.
5. Develop a business case and conduct project analysis, including review and screening, permitting, licensing and meeting land tenure requirements.
6. Be responsible for costs associated with project feasibility assessments.
7. Be responsible for securing technical, legal and financial advice.

8. Meet requirements of the interconnection agreement.
9. Be responsible for addressing requirements of the First Nation land claim agreements, including appropriate consultation.

DEFINITIONS

Agreement to Purchase Power – An agreement between the prospective independent power producer and a utility for the purchase of power from the independent power producer by the utility.

ATCO Electrical Yukon – A private investor-owned utility, and member of the ATCO Group of Companies.

Biomass (energy) – Energy harnessed through combustion of organic matter, including wood and agricultural waste.

Call for Power – A process to permit independent power producers to generate and contribute power to the grid, meeting expected larger-scale electrical demand.

First Nation Ownership – Part or complete ownership of an IPP project by a Yukon First Nation government, a Yukon First Nation development corporation, or other agencies of a Yukon First Nation that are at least 50% owned and controlled by a Yukon First Nation(s).

Geothermal (energy) – Energy derived from geothermal resources, which are steam, water, or vapour (greater than 80º C) and all substances dissolved in the steam, water or vapour.

Hydro (energy) – Potential or kinetic energy of water.

Independent Power Producer – An agency or individual other than a public utility (as defined by the *Public Utilities Act)* who generates electricity to sell (to the utilities). An independent power producer does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Kilowatt (kW) – A unit of electric power. One kilowatt is equal to 1,000 watts (W):

Kilowatt hour (kWh) – A unit of energy equivalent to one kilowatt (1 kW) of power expended for one hour of time.

Nameplate capacity – The power output of an electrical generation plant under ideal conditions, usually expressed in kilowatts (kW) or megawatts (MW).

Public Utility – As defined by the *Public Utilities Act and Regulations* (i.e., YEC and/or AEY).

Solar energy – Radiant light or heat from the sun. This is used to generate electricity by converting the light or heat using photovoltaics and solar thermal technologies.

Standing Offer Program – A program that enables Yukon public utilities (i.e., YEC, AEY) to purchase electricity from independent power producers.

Thermal generation – Refers to the process of generating electricity from heat. There are four thermal energy fuels: coal, natural gas, diesel, wood waste and geo-thermal. In Yukon this refers to diesel and natural gas exclusively.

Utility – See Public Utility (i.e., YEC and/or AEY)

Wind energy – Kinetic energy of wind. Electricity is produced from a system of airfoils or blades that spin a drive shaft to capture the energy.

Yukon Energy Corporation – A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

(Yukon Government) Energy Branch – A branch of YG's Department of Energy, Mines and Resources. The Energy Branch's mandate is to facilitate the coordinated, effective and collaborative delivery of energy policy, projects and programs to promote a secure Yukon energy sector that is environmentally, economically and socially responsible.

Yukon Integrated System – The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by YEC.

Yukon Utilities Board –The board gets its mandate from the *Public Utilities Act*. It fixes rates, standards, classifications, regulations, practices, measurements or services to be observed, provided or followed by a public utility.

ACRONYMS

AEY – ATCO Electrical Yukon

CFP – Call for Power

IPP – Independent Power Production

SOP – Standing Offer Program

YEC – Yukon Energy Corporation

YG – Government of Yukon

YIS – Yukon Integrated System

YUB – Yukon Utilities Board

YDC – Yukon Development Corporation

ENERGY STRATEGY FOR YUKON

Micro-Generation Policy

October 23, 2013

Yukon
Energy, Mines and Resources



BACKGROUND

The Yukon government released the *Energy Strategy for Yukon* in January 2009. The Energy Strategy sets out the government's energy policies and priorities.

In the Energy Strategy, the government committed to developing policies that will assist individuals to connect renewable energy sources to the grid.

Between November 2009 and February 2010, public consultation was conducted on a discussion paper on micro-generation and independent power production. Through that consultation, the public indicated clearly that there should be separate policies for micro-generation and independent power production. Subsequently, a specific policy for micro-generation was released for public consultation. Valuable input was received on proposed policy objectives, eligible energy sources, size of electricity projects, connecting to the grid, financial arrangements, policy framework, and roles and responsibilities.

This policy is part of the Energy Strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy" by assisting "individuals to connect renewable energy sources to the grid" (p.15).

SCOPE

Application

This policy applies to customers in the residential, general service and industrial classes as defined under the Rate Schedules and the Terms and Conditions of Service, who want to generate electricity from eligible sources for their own consumption. This policy does not apply to Secondary Sales connections. The electrical generation will be interconnected to Yukon Energy Corporation's (YEC) or Yukon Electrical Company Limited's (YECL) distribution systems.

Policy Objectives

Working with our utility partners, the objectives of the micro-generation policy are to:

a. Provide opportunities for Yukoners to produce electricity from renewable technologies for their own consumption.
b. Encourage the development and adoption of new individual renewable energy sources to reduce greenhouse gas emissions.
c. Support ongoing research and technology to diversify renewable energy sources.
d. Promote energy conservation and greater energy efficiency.



POLICY PARAMETERS

Eligible Energy Sources

Eligible energy sources under this policy are limited to renewable technologies, which generally include wind power, micro-hydro, biomass, and solar systems. New renewable technologies will be considered as they emerge.

Size of Electricity Projects

Micro-generation name plate capacity of less than 5 kilowatts for customers on a shared transformer, and less than 25 kilowatts for customers on a single transformer will be assessed through a streamlined utility approval process. Micro-generation name plate capacities larger then these limits up to 50 kilowatts will be considered on a case-by-case basis by the utilities and will be subject to a detailed review of the customer's current infrastructure capacity and local grid reliability factors. Costs related to this review will be the responsibility of the customer.

Customers considering projects larger than 25 kilowatts are cautioned not to incur any expenses until the appropriate utility has approved the micro-generation project for connection to the grid.

Connection to the Electrical Grid

Technical interconnection standards are required to ensure the safety of utility workers, micro-generation customers, and equipment. Yukon-wide interconnection standards and interconnection agreement templates will be developed by the utilities within three months of the effective date of this policy and presented to the Yukon Utilities Board (YUB) for approval to ensure safety and consistency of application. The utilities have the right to limit the number of micro-generation customers in circumstances where infrastructure and/or technical constraints exist.

Financial

The following principles will be used in the development and implementation of the utility interconnection standards, utility policies and the Yukon government "Micro-Generation Production Incentive Program" described in appendix A.

1. The utilities will pay for, own, operate and maintain the metering equipment for the micro-generation customer.
2. The utility will install a single, bi-directional meter that minimizes interconnection costs but allows the utility to measure both imported energy from the grid and exported energy from the micro-generation costumer.
3. The micro-generation customer is responsible for the interconnection costs and any potential transformer upgrade requirements.
4. All Yukon micro-generation customers will be eligible for the Yukon government's "Micro-Generation Production Incentive Program". This program will reimburse customers for the amount of electricity exported to the grid at a rate reflective of



the avoided cost of new generation in the territory. Details of this program can be found in Appendix A.

5. All Yukon micro-generation customers who live outside of municipal boundaries will be eligible for the Yukon government's Rural Electrification and Telecommunications Program. This program offers rural Yukoners an affordable and convenient way to install electrical or phone services at their home or business through land taxation based financing. Details of this program can be found in Appendix B.
6. Exported energy does not include energy produced by a micro-generation system but consumed within the building in which the micro-generation system is installed. For the purpose of this policy "exported" is the instantaneous net of energy consumed and produced within the building at any given time; however, energy produced for consumption within the building will result in reduced electricity imported from the utility and therefore result in reduced electricity bills for the customer.
7. The utility will report to the micro-generation customer and the Yukon government on the total energy exported for a given time period.
8. Yukon government will compensate micro-generation customers through the Micro-Generation Production Incentive Program on an annual basis based on the anniversary date in which the system was approved by the utility through the utility interconnection standards.

ROLES AND RESPONSIBILITIES

Joint Responsibilities of the Government of Yukon and the Utilities

1. Implement, maintain and communicate this policy.
2. Evaluate this policy two years from the effective date to ensure its implementation is meeting the policy objectives.

Government of Yukon

1. Ensure this policy is consistent with the *Energy Strategy for Yukon*, the *Climate Change Action Plan*, and other government priorities.
2. Meet obligations under First Nation Final Agreements, and ensure this policy is consistent with those obligations.
3. Deliver the "Micro-Generation Production Incentive Program" as described in Appendix A of this document.
4. Provide information to customers seeking to become micro-generation customers with respect to forecasting capital/maintenance costs and potential energy savings.



Utilities (YEC/YECL)

1. Develop technical interconnection standards and an interconnection agreement template within three months of the release of this policy.
2. Determine whether micro-generation customers meet the interconnection standards and are therefore eligible for micro-generation.
3. Provide estimates to customers of any upgrades required on the utility side of the meter for interconnection to the grid.
4. Assist the Yukon government in delivering the "Micro-Generation Production Incentive Program" by reporting to the Yukon government and the customer all electricity exported to the grid.

YUB

1. Review and approve the proposed technical interconnection standards and interconnection agreement templates for micro-generation as required.

Micro-Generation Customer

1. Meet the interconnection standards set by the utilities.
2. Notify the utilities of micro-generation plans and make available the electrical generation project for inspection by the utilities, or the applicable government regulator. The installation of all eligible energy sources must conform to relevant municipal by-laws, and to territorial and federal regulations.
3. Enter into an interconnection agreement with the relevant electrical service provider (YEC or YECL).
4. Be responsible for their own cost/benefit analysis.

DEFINITIONS

Name plate capacity – The maximum rated capacity of a generation unit.

Micro-Generation – The small-scale generation of electric power by individuals, small businesses and communities to meet their own needs, as alternatives or supplements to traditional centralized grid-connected power

Secondary sales – Those connections defined under Rate Schedule 32 "Secondary Energy".



Appendix A

Micro-Generation Production Incentive Program

BACKGROUND

The Micro-Generation Production Incentive Program is a Yukon government program designed and delivered to support the Yukon Micro-Generation Policy. The purpose of this program is to offer a production incentive to micro-generation customers that encourages the installation and operation of renewable energy based micro-generation technology in the territory.

SCOPE

Application

This program applies to customers in the residential, general service and industrial classes as defined under the Rate Schedules and the Terms and Conditions of Service, who want to generate electricity from eligible sources for their own consumption. This program does not apply to Secondary Sales connections. The electrical generation will be interconnected to Yukon Energy Corporation's (YEC) or Yukon Electrical Company Limited's (YECL) distribution systems.

Program Objectives

The objectives of this program are to support the objective of the Yukon's Micro-Generation Policy by:

a. Encouraging the development and adoption of new individual renewable energy sources to reduce greenhouse gas emissions.

b. Supporting ongoing research and technology to diversify renewable energy sources.

c. Promoting energy conservation and greater energy efficiency.

ELIGIBILITY CRITERIA

Basic Eligibility Criteria

In order to be considered eligible for this program applicants must meet all utility requirements under the Micro-Generation Policy for Yukon including: system size, eligible energy source, and all interconnection standards.

Eligible Energy Sources

Eligible energy sources under this policy are limited to renewable technologies, which include wind power, micro-hydro, biomass, and solar systems. New renewable technologies will be considered as they emerge.

Electric Inspection

Applicants must provide proof that their micro-generation system has been inspected by both a qualified electrical inspector (territorial or municipal) and the relevant electrical utility for their region.

PRODUCTION INCENTIVE

Micro-Generation Production Incentive

Successful applicants to the Yukon government's Micro-Generation Production Incentive Program will receive an incentive for electricity exported to the grid that is reflective of the current avoided cost of new electrical generation in the territory.

The incentive rate will apply to electricity exported to the grid and be set at $0.21/kWh on the Yukon's Integrated System (YIS) and $0.30/kWh in electrically isolated communities powered by diesel generation. This rate will be reevaluated after two years to ensure its relevance as an appropriate incentive rate. These rates are based on the latest analysis conducted by the utilities on avoided cost of new generation supply and published through the Yukon Electric Company Ltd. 2013 rate application (DSM Plan Appendix F).

Any electricity produced by the customer but used by the customer within their own facility will not receive this incentive. Only electricity exported to the grid will receive a production incentive through the Yukon government's program. Through this process the incentive further encourages energy efficiency within the customer's home or business (the less energy used internally the more production incentive offered).

Export data will be collected by the utilities and reported to both the micro-generation customer and the Yukon government. The Yukon government will reimburse micro-generation customers on an annual bases for all exported electricity accrued through the year.

APPLICATION PROCESS

Before applying for the Yukon government's Micro-Generation Production Incentive Program applicants must apply and be accepted by their local utility as a micro-generation customer. This will require meeting all of the utility's interconnection and safety requirements for a micro-generation customer as set out by the utility.

For more information contact the Yukon Energy Corporation or the Yukon Electrical Company Ltd. (contact information provided below).

Applications to the Micro-Generation Production Incentive Program can be made to the Yukon government's Energy Solutions Centre, 206A Lowe Street, Whitehorse, Yukon Y1A 1W6. Application forms will be available at the Energy Solutions Centre office (206A Lowe Street), the Energy Solutions Centre Website (www.energy.gov.yk.ca), and local utility offices.

Micro-generation customers can choose to opt out of the Micro-Generation Production Incentive Program; however, no credit for electricity exported to the grid will be received from the utility or the Yukon government.

YUKON INTEGRATED SYSTEM COMMUNITIES

The following communities and surrounding areas make up the Yukon Integrated System:

> ***Dawson City, Keno, Elsa, Mayo, Stewart Crossing, Pelly Crossing, Carmacks, Faro, Ross River, Haines Junction, Whitehorse, Marsh Lake, Tagish, Carcross, Teslin***

Isolated Communities that are served by diesel generation include the following:

> ***Beaver Creek, Burwash Landing, Destruction Bay, Old Crow, Upper Liard and Watson Lake***

CONTACT INFORMATION

For information about this program and the Yukon's Micro-Generation Policy contact the Yukon Government's Energy Solutions Centre or visit our website at:

> **Website:** www.energy.gov.yk.ca
> **Phone:** (867) 393-7063 or toll free at 1-800-661-0408, ext. 7063
> **Email:** energy@gov.yk.ca
> **Mail or Storefront:** 206A Lowe St., Whitehorse Yukon, Y1A 1W6

For information about the Yukon's micro-generation interconnection standard contact your electrical service provider (YEC or YECL) at:

Yukon Energy Corporation
Phone: (867) 393-5300 or toll free at 1-866-926-3749
Mail: #2 Miles Canyon Road, Box 5920, Whitehorse Yukon, Y1A 6S7

Yukon Electrical Company Limited
Phone: (867) 633-7000 or toll free at 1-800-661-0513
Mail: 100-1100 1st Avenue, Whitehorse Yukon, Y1A 4T4

RURAL ELECTRIFICATION

POLICY & GUIDELINES

1. Objective and Program Overview

The program objective is to facilitate the extension of electrical services to rural residential, small load commercial and other non-industrial property outside incorporated communities where the Yukon Government is the property taxation authority.

The program will consider support for a range of electrical service installations from single site specific installations to multiple properties in larger geographic areas. It provides planning, design, project management, and project financing at favorable interest rates.

The program is jointly sponsored by the Yukon Development Corporation (YDC) and the Department of Community Services (CS).

2. Definitions

"alternative service" means electrical power generated from sustainable energy sources such as wind, solar, and water and distributed from a permanent standalone installation not connected to the WAF (Whitehorse/Aishihik/Faro electrical transmission) grid that is serving a single property;

"capital costs" means costs relating to the construction of a primary electrical service extension or a secondary service extension;

"interest" is Bank of Canada rate in effect at the time the project approval ballot survey is issued;

"owner" with respect to real property means:

(a) an owner with fee simple title or ownership in which the rights, obligations and liabilities are equivalent to fee simple, specifically Category A and Category B Settlement Land where the Yukon Government is the property taxation authority;

(b) a purchaser by way of agreement for sale with the Government of the Yukon or the Government of Canada;

(c) a lessee from the Government of the Yukon or the Government of Canada, and where the remaining term of the lease for which the property taxes are payable by the lessee is equal to or greater than the amortization period ; or

(d) the Department of Indian Affairs and Northern Development acting on behalf of the Indian Band with respect to land which has been reserved or set aside by notation in the property records of the Department of Indian Affairs and Northern Development.

"primary electrical service" means the main electrical power distribution line for all properties within a project area, including supporting poles or underground conductors, and all necessary high voltage transformers;

"rural property" means real property located outside of the boundaries of a municipality;

"secondary electrical service" means the electrical power distribution line required to deliver electrical power to **a** property from a primary electrical service, including all transmission lines, supporting poles and underground conductors, including the transformer(s) directly required as a part of an individual service connection located on the property;

"project area" means an area of rural property, the boundaries of which have been defined by the Yukon Energy Corporation and Yukon Electrical Company Ltd. where appropriate , with input from affected property owners and the Department of Community Services.

3. Principles and Practices

The Rural Electrification Policy is based on the following general principles and practices. These principles and practices will be used to guide operational decisions that are not covered by explicit policy provisions.

A. Responsiveness to Needs of Rural Yukoners

The provision of rural electrification services will be in response to requests from rural property owners.

B. Public Participation

The rural property owners that may benefit or be directly impacted will have the opportunity to participate in both the planning and decision-making processes for electrification projects.

C. Democratic Project Approval

The approval of rural electrification projects will be determined through a democratic vote of a special majority of the property owners in the project area.

D. Cost-effectiveness, Prudent Planning, and Utility Standards

Services must be planned from an area and community development perspective consistent with applicable standards and impacts for the systems as a whole.

E. Full Cost Recovery

Property owners within a project area must contribute a fair share of the full costs for providing rural electrical services to their properties.

F. Equitable and Proportional Distribution of Costs

Property owners who receive an equitable benefit from a rural electrification service, both at the time the service is provided or at a subsequent time, should pay an equitable and proportional share of the costs of the service.

G. Creating Partnerships

The provision of rural electrical services should be achieved by property owners, service providers and the Yukon Government working in a cooperative, open partnership.

4. Criteria

4.1 Eligibility

Eligible applicants are rural Yukon people, small load commercial and other non-industrial businesses or property owners seeking the extension of electrical services to property outside the boundary of an incorporated community who are owners as defined in Section 2.

To be eligible, an application for stand-alone alternative electrification service to a single property must require funding of at least $1,000.00.

Specific Exclusions

Developers who have undertaken the construction and servicing of a subdivision are not eligible applicants, however where a developer continues to hold a minority number of the total properties in a service area, the developer is included under 5.2 and 5.4.

Major and isolated industrial customers subject to OIC 1995/090 and resource development projects eligible under the Energy Infrastructure Loans for Resource Development Program (OIC 1993/099 as amended) are not eligible applicants.

4.2 Scope of electrical services

Program funding is intended to enable installation of primary and secondary electrical distribution infrastructure and/or permanently installed alternative services to property. Where necessary, provision may be

made for improvements to transmission or substation facilities to allow a rural electrification project to proceed.

Only infrastructure and installations meeting utility standards and specifications or other applicable codes and standards will be supported. Electrical service regulations approved by the Yukon Utilities Board also apply.

4.3 Financing

4.3.1 Program Financing

The level of program funding available for financing electrification projects through the Rural Electrification and Telecommunication Program, is set each year by appropriation. Funding availability shall be subject to the necessary approval of the Yukon Legislative Assembly.

4.3.2 Project Financing Terms and Conditions

Projects costs are determined on an all-inclusive basis including extraordinary planning not normally covered by the service provider, capital costs, and interest on the amortized principal.

Funding for each project, excluding any contribution by the service provider, is limited to a loan maximum of 25% of the total assessed value of land and improvements within the project area. The investment is secured through a local improvement charge to property owners, under the authority of the Assessment and Taxation Act.

4.3.3 Public Utility Contributions

Limited contributions may be available from the Yukon Energy Corporation or The Yukon Electrical Company Ltd. (YECL) in accordance with the electrical service regulations approved by the Yukon Utilities Board.

Subject to justification based on the benefits to other rate payers or the system as a whole, and related regulatory and budgetary approvals that may apply, the Yukon Energy Corporation or Yukon Development Corporation may contribute to upgrading or changes to transmission or substation facilities as part of a rural electrification project.

4.3.4 Equitable Allocation of Costs

All property owners within the area covered by the project will be allocated an equitable portion of the all inclusive project cost from the outset, either as a lump sum or through a local improvement charge, identified on the annual property tax notice, and amortized over a term of up to 15 years depending on the size of the project, and where possible, the preference stated by the affected property owners.

4.3.5 Fair Contribution Toward Existing Systems

Properties outside the original project area who, at a later date, choose to subscribe to an already implemented rural electrification project may apply for the electrical infrastructure specific to their project area, which would be calculated as a separate new project.

Property owners who apply for a service extension which is dependent on an existing electrical system extension that was implemented under this program shall, for a period of 15 years following completion of the initial project, make a fair and proportional contribution toward the costs of the existing electrical system extension. The contribution will be rebated to the owners of property in the original project area, unless they have already been rebated by the utility.

Properties inside the original project area that were not yet approved for legal land tenure when the initial project was completed shall, for a period of 15 years following completion of the initial project, make a fair and proportional contribution toward the costs of the existing electrical system extension. The contribution will be rebated to the owners of property in the original project area, unless they have already been rebated by the utility.

5. Application and Approval Process

5.1 Expression of Interest

Application forms are available from, and must be submitted to, Property Assessment and Taxation, Department of Community Services. Requests are dealt with on a first come, first served basis.

5.1.1. a) Stand-alone Services

For an application requesting stand-alone alternative energy service to one property, the applicant(s) are encouraged to solicit competitive proposals from service providers. If the proposed project is determined, through the technical analysis, to be not cost-effective or not competitive, the applicant(s) will be required to seek competitive proposals

The applicant(s) must provide information for technical review and approval which includes:

- property that would be served by the proposed solution;
- features and benefits of the proposed solution;
- detailed information on equipment including costs.

b) Other Single Property Services

With the support of the applicant(s), a project benefiting a single property can proceed to “Detailed Planning and Costing”.

5.1.2 Multiple Property Application

For an application requesting service to two or more properties, preliminary work on the identification of project area, infrastructure requirements, costing including a reasonable planning deposit, if required and financing alternatives, will be undertaken through the Yukon Energy Corporation in cooperation with the Department of Community Services and The Yukon Electrical Company Limited where appropriate.

With the support of the applicant(s), and any other beneficiaries, small projects, can proceed to “Detailed Planning and Costing”. For other projects, if interest is sustained after the review of preliminary information with project proponent(s), a public information meeting may be organized by the Department of Community Services in cooperation with the appropriate utility and proponents. A project may proceed to the Verification of Support Vote or lapse at this stage.

5.2 Verification of Support Vote

Formal survey of all property owners within the project area proposed for electrification services may be undertaken through a mail ballot survey (Vote #1). The Ballot will provide information about the proposed service, and the amount of the planning deposit required, if any, from property owners in the project area.

Each property owner will have the opportunity to vote on whether the project should proceed to detailed planning and costing. Approval by a special majority of 65% of those who respond to the survey ballot is required..

5.3 Detailed Planning and Costing

If the required support is obtained and the planning deposit, if any, is paid, the sponsoring agencies proceed with detailed planning, costing and financing analysis. A specific service plan and budget estimate will be prepared by the Yukon Energy Corporation or The Yukon Electrical Company Ltd., or the appropriate service provider, along with a forecast by the Department of Community Services of the local improvement charges the property owner(s) would pay.

If there is a significant and material change in the final project plan and cost estimates, the proposal may be subject to further review with affected property owners before it can proceed for project approval voting.

The financing plan will include eligible contributions by YEC or YECL pursuant to the Electrical Service Regulations, and other contributions, if any, justified on the basis of benefits to other rate payers or the system as a whole.

5.4 Project Approval by Property Owners

5.4.1 Single Property Application

After confirming program loan funding, the Department of Community Services will require the property owner to enter into an Agreement authorizing the project and agreeing to repayment terms.

5.4.2 Multiple Property Application

After confirming program loan funding and that the project is feasible, a mail ballot is undertaken (Vote #2). This ballot will include the information necessary for property owners to understand the financial implications and costs to individual properties, of the proposed electrification service, and provide each affected property owner with the opportunity to vote on whether the proposed service should proceed as planned and estimated.

Approval by a special majority of 65% of property owners in the proposed project area, is required for the project to be implemented.

5.5 Installation

If the required support is obtained, YEC and/or YECL, or the service provider in the case of an alternative service installation are responsible for the installation of electrical services based on the specific project contribution that was approved by the property owner(s) in the project area.

5.6 Recovery of Costs

After completion of the installation project and final costs are known, a regulation pursuant to the Assessment and Taxation Act will be prepared, to attach local improvement charges to all properties in the project area, for the recovery of the project costs. Local improvement charges are payable on an annual basis for a defined period (e.g., up to 15 years) or can be paid out as a lump sum.

Should CS become aware that a stand-alone system which was funded through this program is not functional or has been removed, the property owner may be required to pay the LIC in full immediately.

5.7 Deferment

Where a rural electrification system serves two or more properties, a property owner may chose not to hook up to the system and enter into an Agreement to defer payment of the Local Improvement Charge for up to 15 years, subject to legislative amendment, from the completion date of the system.

The property owner will be required to start paying the deferred Local Improvement Charge:

1) if they hook-up to the service;
2) at the expiry of the deferment period.

The property owner must pay the deferred Local Improvement Charge in full if the property is sold.

YUB-YECL-73

Reference: Application, pages 8-4 to 8-5.

Issue/sub-issue: Long-term debt

Quote: "ATCO Electric Yukon used an average Long Canada Bond Rate and applied a spread to determine the forecast debenture rate. The forecast for Long Canada Bonds and credit spreads were based on discussions with ATCO's Treasury Department at the time of the filing."

Request:

(a) Please provide a table showing the forecast issues and spreads (long-term Canada bond rates and spreads) and then the actual issues and spreads for the years 2010 to 2015 inclusive. Include in that table the amounts dates and final rates for the acquired long-term debt.

(b) Please provide the sources for the Long Canada Bond Rate and spreads.

(c) Please provide any updates to the forecast Long Canada Bond Rates and Spreads, and the date of that update.

(d) Please provide details of the amounts of long-term debt YECL intends to issue during each of the years 2016 and 2017.

Response:

(a) Please refer to the following table of actual debt rates for 2011-2012 and forecast and actual debt rates for 2013-2015. AEY did not have new debt issued in 2010, 2011 and 2012, as these were not test years.

	2011	2012	2013	
	Actual	Actual	Approved	Actual
Issue Date	24-Oct-2011	14-Nov-2012	9-Sep-2013	9-Sep-2013
Maturity Date	24-Oct-2041	14-Nov-2052	9-Sep-2043	9-Sep-2043
Long Canada Bond	2.943%	2.357%	3.172%	3.172%
Issue Spread	1.637%	1.533%	1.589%	1.589%
Debenture Rate	4.580%	3.890%	4.761%	4.761%
Debenture Amount	$5,000,000	$4,000,000	$9,100,000	$9,400,000

	2014		2015	
	Approved	**Actual**	**Approved**	**Actual**
Issue Date	1-Nov-2014	2-Sep-2014	1-Nov-2015	27-Jul-2015
Maturity Date	1-Nov-2044	2-Sep-2044	1-Nov-2055	27-Jul-2045
Long Canada Bond	3.500%	2.645%	4.200%	2.234%
Issue Spread	1.550%	1.475%	1.600%	1.767%
Debenture Rate	5.050%	4.120%	5.800%	4.001%
Debenture Amount	$6,400,000	$7,900,000	$4,900,000	$750,000

(b) Please refer to YUB-YECL-73(b) Attachment 1.

(c) As of July 15, 2016 forecast debt rates for 2016 and 2017 are as follows:

	2016	**2017**
Long Canada Bond Rate	1.92%	2.22%
Credit Spread	1.80%	1.80%
Debenture Rate	3.72%	4.02%
Issue Costs	0.05%	0.05%
Recommended All-In Rate	**3.77%**	**4.07%**

(d) Details of the debt included in the Application are as follows:

	2016	**2017**
Issue Date	1-Nov-2016	1-Nov-2017
Maturity Date	1-Nov-2056	1-Nov-2057
Long Canada Bond	2.300%	2.800%
Issue Spread	2.050%	2.050%
Debenture Rate	4.350%	4.850%
Debenture Amount	$5,480,000	$6,990,000

RBC ECONOMICS | RESEARCH

FINANCIAL MARKET FORECASTS

February 11, 2016

Interest rates (%, end of quarter)

	Actual							Forecast					Actual		Forecast	
	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	2014	2015	2016	2017
Canada																
Overnight	0.75	0.75	0.50	0.50	0.50	0.50	0.50	0.50	0.75	1.00	1.25	1.75	1.00	0.50	0.50	1.75
Three-month	0.55	0.58	0.43	0.51	0.40	0.40	0.50	0.60	0.85	1.10	1.35	1.80	0.91	0.51	0.60	1.80
Two-year	0.50	0.48	0.52	0.48	0.40	0.50	0.65	1.00	1.30	1.60	1.95	2.45	1.01	0.48	1.00	2.45
Five-year	0.77	0.82	0.80	0.73	0.60	0.80	1.05	1.35	1.70	2.00	2.35	2.70	1.34	0.73	1.35	2.70
10-year	1.36	1.69	1.43	1.40	1.20	1.50	1.65	2.00	2.35	2.60	2.80	3.05	1.79	1.40	2.00	3.05
30-year	1.98	2.31	2.20	2.15	1.85	2.25	2.40	2.70	2.95	3.05	3.20	3.35	2.34	2.15	2.70	3.35
Yield curve (10s-2s)	86	121	91	92	80	100	100	100	105	100	85	60	78	92	100	60
United States																
Fed funds*	0.25	0.25	0.25	0.50	0.50	0.75	1.00	1.25	1.50	1.75	2.25	2.75	0.25	0.50	1.25	2.75
Three-month	0.04	0.03	0.00	0.17	0.20	0.40	0.45	0.70	1.00	1.30	1.90	2.45	0.04	0.17	0.70	2.45
Two-year	0.56	0.64	0.64	1.05	0.85	1.10	1.25	1.60	1.90	2.20	2.60	2.95	0.67	1.05	1.60	2.95
Five-year	1.37	1.64	1.37	1.76	1.30	1.60	1.75	2.15	2.40	2.65	2.95	3.20	1.65	1.76	2.15	3.20
10-year	1.93	2.35	2.04	2.27	1.85	2.10	2.15	2.55	2.80	3.00	3.25	3.40	2.17	2.27	2.55	3.40
30-year	2.54	3.12	2.86	3.02	2.65	2.90	2.95	3.30	3.45	3.55	3.75	3.85	2.75	3.02	3.30	3.85
Yield curve (10s-2s)	137	171	140	122	100	100	90	95	90	80	65	45	150	122	95	45
Yield spreads																
Three-month T-bills	0.51	0.55	0.43	0.34	0.20	0.00	0.05	-0.10	-0.15	-0.20	-0.55	-0.65	0.87	0.34	-0.10	-0.65
Two-year	-0.06	-0.16	-0.12	-0.57	-0.45	-0.60	-0.60	-0.60	-0.60	-0.60	-0.65	-0.50	0.34	-0.57	-0.60	-0.50
Five-year	-0.60	-0.82	-0.57	-1.03	-0.70	-0.80	-0.70	-0.80	-0.70	-0.65	-0.60	-0.50	-0.31	-1.03	-0.80	-0.50
10-year	-0.57	-0.66	-0.61	-0.87	-0.65	-0.60	-0.50	-0.55	-0.45	-0.40	-0.45	-0.35	-0.38	-0.87	-0.55	-0.35
30-year	-0.56	-0.81	-0.66	-0.87	-0.80	-0.65	-0.55	-0.60	-0.50	-0.50	-0.55	-0.50	-0.41	-0.87	-0.60	-0.50

Exchange rates (end of quarter)

	Actual							Forecast					Actual		Forecast	
	15Q1	15Q2	15Q3	15Q4	16Q1	16Q2	16Q3	16Q4	17Q1	17Q2	17Q3	17Q4	2014	2015	2016	2017
AUD/USD	0.76	0.77	0.70	0.73	0.67	0.65	0.65	0.65	0.66	0.66	0.67	0.68	0.82	0.73	0.65	0.68
USD/CAD	1.27	1.25	1.33	1.38	1.45	1.40	1.36	1.33	1.31	1.29	1.27	1.25	1.16	1.38	1.33	1.25
EUR/USD	1.07	1.11	1.12	1.09	1.03	1.00	1.00	1.02	1.03	1.04	1.05	1.06	1.21	1.09	1.02	1.06
USD/JPY	120.1	122.5	119.9	120.2	124.0	128.0	132.0	128.0	126.0	124.0	122.0	120.0	119.7	120.2	128.0	120.0
NZD/USD	0.75	0.68	0.64	0.68	0.62	0.60	0.62	0.63	0.64	0.64	0.65	0.66	0.78	0.68	0.63	0.66
USD/CHF	0.97	0.94	0.97	1.00	1.08	1.12	1.13	1.12	1.12	1.11	1.10	1.09	0.99	1.00	1.12	1.09
GBP/USD	1.48	1.57	1.51	1.47	1.41	1.41	1.43	1.48	1.51	1.55	1.59	1.63	1.56	1.47	1.48	1.63

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Quarterly Forecasts

	2015		2016				2017			
Canada	Q3	Q4f	Q1f	Q2f	Q3f	Q4f	Q1f	Q2f	Q3f	Q4f
Real GDP (q/q, ann. % change)	2.3	0.0	0.5	1.2	2.3	2.5	2.7	2.7	2.3	2.3
Real GDP (y/y, % change)	1.2	0.4	0.7	1.0	1.0	1.6	2.2	2.5	2.6	2.5
Consumer Prices (y/y, % change)	1.2	1.3	1.6	1.4	1.8	2.0	2.1	2.2	2.2	2.2
Core CPI (y/y % change)	2.2	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.0	2.0
United States										
Real GDP (q/q, ann. % change)	2.0	0.7	2.2	2.6	2.8	2.8	2.9	2.7	2.6	2.5
Real GDP (y/y, % change)	2.1	1.8	2.2	1.9	2.1	2.6	2.8	2.8	2.7	2.7
Consumer Prices (y/y, % change)	0.1	0.2	1.0	1.1	1.4	2.2	2.4	2.2	2.3	2.3
Core CPI (y/y % change)	1.8	2.0	2.1	2.1	2.2	2.2	2.2	2.2	2.3	2.3

Financial Markets

Central Bank Rates

Americas						(%, end of period)				
Bank of Canada	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.75	1.00
U.S. Federal Reserve	0.25	0.50	0.75	1.00	1.25	1.50	1.75	2.00	2.25	2.50
Bank of Mexico	3.00	3.25	3.75	4.00	4.25	4.50	5.00	5.25	5.50	5.50
Central Bank of Brazil	14.25	14.25	14.50	14.50	14.75	14.75	14.75	14.25	14.00	13.75
Bank of the Republic of Colombia	4.75	5.75	6.00	6.00	6.00	6.00	5.75	5.50	5.25	5.00
Central Reserve Bank of Peru	3.50	3.75	4.25	4.50	4.50	4.50	4.25	4.25	4.25	4.25
Central Bank of Chile	3.00	3.50	3.50	3.75	3.75	3.75	3.75	4.00	4.25	4.25
Europe										
European Central Bank	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Bank of England	0.50	0.50	0.50	0.50	0.50	0.75	0.75	1.00	1.00	1.25
Swiss National Bank	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75	-0.75
Asia/Oceania										
Reserve Bank of Australia	2.00	2.00	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75
People's Bank of China	4.60	4.35	4.10	4.10	4.10	4.10	4.10	4.10	4.35	4.35
Reserve Bank of India	6.75	6.75	6.50	6.50	6.50	6.50	6.50	6.50	6.75	6.75
Bank of Korea	1.50	1.50	1.50	1.50	1.50	1.50	1.75	2.00	2.25	2.50
Bank Indonesia	7.50	7.50	7.25	7.25	7.00	7.00	7.00	7.00	7.00	7.00
Bank of Thailand	1.50	1.50	1.25	1.25	1.25	1.25	1.25	1.50	1.75	2.00
Canada										
3-month T-bill	0.44	0.51	0.50	0.50	0.50	0.50	0.50	0.55	0.85	1.10
2-year Canada	0.52	0.48	0.50	0.65	0.75	0.90	1.10	1.25	1.50	1.80
5-year Canada	0.80	0.73	0.80	0.95	1.10	1.30	1.50	1.85	2.00	2.20
10-year Canada	1.43	1.39	1.35	1.40	1.55	1.70	1.90	2.15	2.30	2.50
30-year Canada	2.20	2.15	2.10	2.20	2.30	2.35	2.50	2.60	2.70	2.95
United States										
3-month T-bill	-0.02	0.16	0.25	0.60	1.00	1.40	1.70	2.05	2.30	2.50
2-year Treasury	0.63	1.05	1.05	1.35	1.75	2.05	2.30	2.55	2.80	3.00
5-year Treasury	1.36	1.76	1.70	1.95	2.20	2.35	2.60	2.85	3.00	3.15
10-year Treasury	2.04	2.27	2.10	2.25	2.35	2.50	2.75	3.00	3.15	3.35
30-year Treasury	2.85	3.02	2.85	3.00	3.10	3.20	3.35	3.45	3.55	3.75
Canada-U.S. Spreads										
3-month T-bill	0.46	0.35	0.25	-0.10	-0.50	-0.90	-1.20	-1.50	-1.45	-1.40
2-year	-0.11	-0.57	-0.55	-0.70	-1.00	-1.15	-1.20	-1.30	-1.30	-1.20
5-year	-0.56	-1.03	-0.90	-1.00	-1.10	-1.05	-1.10	-1.00	-1.00	-0.95
10-year	-0.61	-0.88	-0.75	-0.85	-0.80	-0.80	-0.85	-0.85	-0.85	-0.85
30-year	-0.65	-0.87	-0.75	-0.80	-0.80	-0.85	-0.85	-0.85	-0.85	-0.80

Feb 5, 2016

Interest Rate Forecasts
Percent (averages)

	Actual Jan	2016 Feb	Mar	Apr	Q2	Q3	Q4	2017 Q1	Q2	Q3	Q4
Cdn. Yield Curve											
Overnight	0.50	0.50	0.50	0.25	0.25	0.25	0.25	0.25	0.25	0.50	0.75
3 month	0.42	0.45	0.45	0.25	0.25	0.25	0.25	0.25	0.25	0.48	0.72
6 month	0.42	0.44	0.44	0.28	0.28	0.28	0.28	0.28	0.28	0.51	0.75
1 year	0.41	0.43	0.42	0.30	0.30	0.32	0.36	0.41	0.47	0.73	0.97
2 year	0.39	0.41	0.38	0.36	0.37	0.40	0.47	0.57	0.71	0.93	1.16
3 year	0.40	0.41	0.39	0.37	0.37	0.41	0.47	0.58	0.71	0.94	1.16
5 year	0.65	0.63	0.62	0.61	0.62	0.66	0.73	0.83	0.97	1.17	1.38
7 year	0.97	0.96	0.97	0.97	0.99	1.04	1.10	1.20	1.35	1.52	1.70
10 year	1.26	1.19	1.20	1.22	1.24	1.30	1.36	1.46	1.61	1.77	1.92
30 year	2.05	2.00	2.02	2.03	2.04	2.07	2.10	2.17	2.28	2.41	2.54
1m BA	0.85	0.85	0.85	0.60	0.60	0.60	0.60	0.60	0.60	0.83	1.06
3m BA	0.84	0.84	0.84	0.59	0.59	0.59	0.59	0.59	0.59	0.83	1.07
6m BA	0.91	0.90	0.90	0.69	0.69	0.69	0.69	0.69	0.69	0.93	1.17
12m BA	0.96	0.95	0.93	0.77	0.77	0.79	0.82	0.87	0.94	1.21	1.44
Prime Rate	2.70	2.70	2.70	2.55	2.55	2.55	2.55	2.55	2.55	2.80	3.05
U.S. Yield Curve											
Fed funds	0.38	0.38	0.38	0.38	0.46	0.63	0.71	0.96	1.21	1.46	1.71
3 month	0.26	0.29	0.29	0.29	0.37	0.53	0.61	0.85	1.09	1.33	1.57
6 month	0.43	0.44	0.44	0.44	0.52	0.68	0.76	0.99	1.23	1.47	1.70
1 year	0.54	0.54	0.58	0.61	0.69	0.82	0.93	1.15	1.38	1.60	1.83
2 year	0.90	0.74	0.82	0.90	0.98	1.07	1.21	1.42	1.64	1.85	2.06
3 year	1.14	0.95	1.02	1.09	1.17	1.26	1.39	1.59	1.78	1.98	2.18
5 year	1.52	1.30	1.36	1.42	1.48	1.58	1.69	1.86	2.03	2.20	2.37
7 year	1.85	1.64	1.69	1.74	1.79	1.89	1.99	2.12	2.27	2.41	2.56
10 year	2.09	1.91	1.95	2.00	2.04	2.14	2.22	2.33	2.46	2.58	2.71
30 year	2.86	2.74	2.77	2.80	2.84	2.91	2.96	3.04	3.14	3.23	3.33
1m LIBOR	0.43	0.43	0.43	0.43	0.51	0.67	0.75	1.00	1.25	1.49	1.74
3m LIBOR	0.62	0.62	0.62	0.62	0.70	0.87	0.95	1.19	1.44	1.69	1.93
6m LIBOR	0.86	0.89	0.89	0.89	0.97	1.14	1.22	1.47	1.72	1.97	2.22
12m LIBOR	1.15	1.17	1.21	1.25	1.33	1.46	1.58	1.81	2.05	2.29	2.53
Prime Rate	3.50	3.50	3.50	3.50	3.58	3.75	3.83	4.08	4.33	4.58	4.83
Other G7 Yields											
ECB Refi	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
10yr Bund	0.50	0.60	0.55	0.55	0.55	0.55	0.50	0.65	0.80	1.00	1.20
BoE Repo	0.50	0.50	0.50	0.50	0.50	0.65	0.90	1.15	1.40	1.50	1.50
10yr Gilt	1.78	1.75	1.80	1.80	1.85	1.90	2.00	2.10	2.20	2.35	2.50
BoJ O/N	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
10yr JGB	0.23	0.15	0.15	0.20	0.20	0.25	0.30	0.35	0.45	0.50	0.60

INTEREST RATE OUTLOOK

	Spot Rate	2015				2016				2017			
	Jan-28	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADA													
Overnight Target Rate	0.50	0.75	0.75	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
3-mth T-Bill Rate	0.49	0.55	0.58	0.43	0.51	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.60
2-yr Govt. Bond Yield	0.45	0.51	0.49	0.53	0.48	0.50	0.60	0.70	0.75	0.80	0.90	1.00	1.20
5-yr Govt. Bond Yield	0.73	0.77	0.81	0.81	0.73	0.80	0.90	1.05	1.25	1.40	1.55	1.70	1.85
10-yr Govt. Bond Yield	1.29	1.36	1.68	1.45	1.39	1.40	1.55	1.70	1.90	2.05	2.20	2.30	2.50
30-yr Govt. Bond Yield	2.08	1.99	2.31	2.21	2.15	2.15	2.30	2.45	2.55	2.60	2.70	2.80	3.00
10-yr-2-yr Govt Spread	0.84	0.85	1.19	0.92	0.91	0.90	0.95	1.00	1.15	1.25	1.30	1.30	1.30
U.S.													
Fed Funds Target Rate	0.50	0.25	0.25	0.25	0.50	0.75	1.00	1.25	1.25	1.50	1.75	1.75	1.75
3-mth T-Bill Rate	0.31	0.03	0.01	0.00	0.16	0.50	0.75	1.00	1.00	1.25	1.50	1.50	1.50
2-yr Govt. Bond Yield	0.83	0.56	0.64	0.64	1.06	0.95	1.00	1.20	1.40	1.60	1.75	1.90	2.00
5-yr Govt. Bond Yield	1.44	1.37	1.63	1.37	1.76	1.55	1.65	1.85	2.00	2.15	2.25	2.35	2.45
10-yr Govt. Bond Yield	2.02	1.94	2.35	2.06	2.27	2.15	2.25	2.40	2.50	2.55	2.65	2.75	2.80
30-yr Govt. Bond Yield	2.82	2.54	3.11	2.87	3.01	2.90	3.00	3.10	3.20	3.20	3.25	3.30	3.35
10-yr-2-yr Govt Spread	1.19	1.38	1.71	1.42	1.21	1.20	1.25	1.20	1.10	0.95	0.90	0.85	0.80
CANADA - U.S SPREADS													
Can - U.S. T-Bill Spread	0.18	0.52	0.57	0.43	0.35	-0.05	-0.30	-0.55	-0.55	-0.80	-1.05	-1.05	-0.90
Can - U.S. 10-Year Bond Spread	-0.74	-0.58	-0.67	-0.61	-0.88	-0.75	-0.70	-0.70	-0.60	-0.50	-0.45	-0.45	-0.30

F: Forecast by TD Economics, January 2016; Forecasts are end-of-period; Source: Bloomberg, Bank of Canada, Federal Reserve.

GLOBAL STOCK MARKETS

	Price Jan-28	30-Day % Chg.	YTD % Chg.	52-Week High	52-Week Low
S&P 500	1,883	-8.4	-8.5	2,131	1,859
S&P/TSX Composite	12,378	-7.0	-15.4	15,451	11,843
DAX	9,782	-8.2	-0.2	12,375	9,392
FTSE 100	5,994	-4.2	-8.7	7,104	5,674
Nikkei	17,041	-9.7	-2.3	20,868	16,017
MSCI AC World Index*	367	-8.5	-12.0	443	357

*Weighted equity index including both developed and emerging markets
Source: Bloomberg.

COMMODITY PRICE OUTLOOK

	Price	52-Week	52-Week	2015				2016				2017			
	Jan-28	High	Low	Q1	Q2	Q3	Q4	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
Crude Oil (WTI, $US/bbl)	34	61	27	49	58	46	42	30	40	50	55	57	57	60	60
Natural Gas ($US/MMBtu)	2.24	3.27	1.53	2.87	2.78	2.75	2.25	2.25	2.30	2.45	2.60	3.25	3.10	3.40	3.60
Gold ($US/troy oz.)	1114	1284	1051	1218	1191	1124	1105	1085	1100	1150	1200	1200	1175	1150	1125
Silver (US$/troy oz.)	14.2	17.7	13.7	16.74	16.44	14.92	14.75	14.25	14.75	15.75	16.50	16.55	16.25	15.25	15.00
Copper (cents/lb)	209	294	196	264	275	238	225	199	209	215	215	220	220	230	230
Nickel (US$/lb)	3.93	6.95	3.74	6.51	5.94	4.78	4.50	3.92	4.00	4.18	4.45	4.75	5.00	6.00	6.25
Aluminum (Cents/lb)	69	90	65	82	79	72	68	67	69	72	72	74	74	76	76
Wheat ($US/bu)*	5.99	8.11	5.82	7.45	7.34	6.50	6.25	6.50	6.75	6.90	7.00	7.10	7.25	7.35	7.50

F: Forecast by TD Economics, January 2016; Forecasts are period averages; Source: Bloomberg, USDA (Haver). *As at January 26, 2016.

Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.5%		Rates on Survey Date 1.2%	
Unemploy-ment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligat-ions d'État de 10 ans %*	
2016	2017	2016	2017	FY 16-17	FY 17-18	End May'16	End Feb'17	End May'16	End Feb'17
6.9	6.9	-59.0	-42.0	na	na	0.5	1.0	1.6	2.0
7.1	6.9	-77.0	-65.0	-18.0	-15.0	0.5	0.5	1.6	1.9
6.8	6.5	-71.4	-44.4	na	na	0.5	0.8	1.8	2.4
7.1	7.0	-61.5	-43.0	-12.0	-15.0	0.5	0.5	1.3	1.8
7.0	6.8	-59.0	-50.0	na	na	0.5	0.5	na	na
7.0	6.4	-56.0	-47.1	na	na	na	na	na	na
7.1	6.7	-64.6	-54.8	na	na	0.5	0.8	1.4	1.9
7.1	7.0	na	na	na	na	na	na	na	na
7.0	6.9	-55.6	-53.5	-10.0	-10.0	0.3	0.3	1.4	1.4
7.0	6.8	-43.4	-27.2	na	na	0.4	0.6	1.9	2.2
7.2	7.0	-75.0	-57.1	na	na	0.5	0.5	1.5	2.1
7.2	6.9	na	na	na	na	0.5	0.5	1.6	2.1
7.2	7.1	-59.7	-62.7	-23.9	-15.9	0.4	0.7	1.2	1.5
7.2	7.0	-62.0	-50.0	-15.0	-15.0	0.3	0.3	1.4	1.6
7.2	7.1	-55.6	-40.9	-32.5	-22.5	0.5	0.5	1.4	1.9
7.3	7.1	-60.0	-45.0	-17.0	-15.0	0.3	0.3	1.2	1.4
7.3	7.0	-69.0	-61.0	na	na	0.5	0.5	1.5	1.9
7.6	7.8	-85.2	-25.9	na	na	0.4	0.4	1.5	2.0
7.1	6.9	-63.4	-48.1	-18.3	-15.5	0.4	0.5	1.5	1.9
7.0	6.7	-59.1	-48.7	-13.5	-14.3				
6.9		-53.7		-7.3					
7.6	7.8	-43.4	-25.9	-10.0	-10.0	0.5	1.0	1.9	2.4
6.8	6.4	-85.2	-65.0	-32.5	-22.5	0.3	0.3	1.2	1.4
0.2	0.3	10.1	11.2	7.7	3.7	0.1	0.2	0.2	0.3
6.8	6.4								

Worsening GDP Growth Forecasts

After a 0.5% (m-o-m) decline in September and flat growth in October, November saw a +0.3% rebound in output-based GDP. Both services and goods production increased, by +0.2% and 0.4%, respectively. Services were buoyed by a 1.3% turnaround in wholesale and 1.2% surge in retail trade. On the production front, utilities rebounded by 1.0% while mining, quarrying, oil & gas extraction shook off maintenance shutdowns and production cutbacks of the previous few months to post a 0.6% advance. However, the retrenchment in the commodity markets continues to weigh heavily on the economy; the precipitous fall in oil and gas prices has made high-cost extraction of oil cost-ineffective, hence sweeping cutbacks in production, staffing and investment. In value terms, export receipts are also badly hit. 2015 imports rose by 4.4% while exports fell by 0.9%, moving the merchandise trade balance from a C$+4.8bn surplus in 2014 to a C$-23.3bn deficit in 2015. However, in volume terms, real exports actually rose faster than imports. The Bank of Canada has cuts its 2015 GDP forecast from 2% to 1.4%. Despite the bank keeping its key rate unchanged at its January policy meeting, some observers expect a further cut, to 0.25% in order to support activity, especially with monthly headline and core prices declining in November and December.

After a poor start to the first half of 2015, as well as a renewed drop in GDP in September, November's 0.3% (m-o-m) increase could signal that growth has turned a corner. Indeed, manufacturing saw a 0.4% monthly gain, supported by durables output, while manufacturing sales and new orders during the same month rose noticeably. Our panel's 2016 industrial production forecast has fallen into recession, however.

Canada Overnight Lending Rate – Feb. 8, 2016 = 0.50%

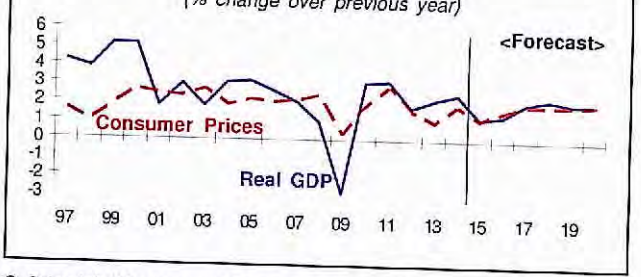
FORECASTS	End Mar. 2016	End June 2016	End Sep. 2016	End Dec. 2016
Consensus Mean Average:	0.50%	0.45%	0.45%	0.46%
Mode (most frequent forecast):	0.50%	0.50%	0.50%	0.50%

Direction of Trade – 2014

Major Export Markets (% of Total)		Major Import Suppliers (% of Total)	
United States	76.8	United States	54.5
China	3.7	China	11.5
United Kingdom	2.9	Mexico	5.6
EU	*7.4*	*Asia (ex. Japan)*	*14.7*
Asia (ex. Japan)	*5.4*	*EU*	*11.3*
Latin America	*2.6*	*Latin America*	*8.9*

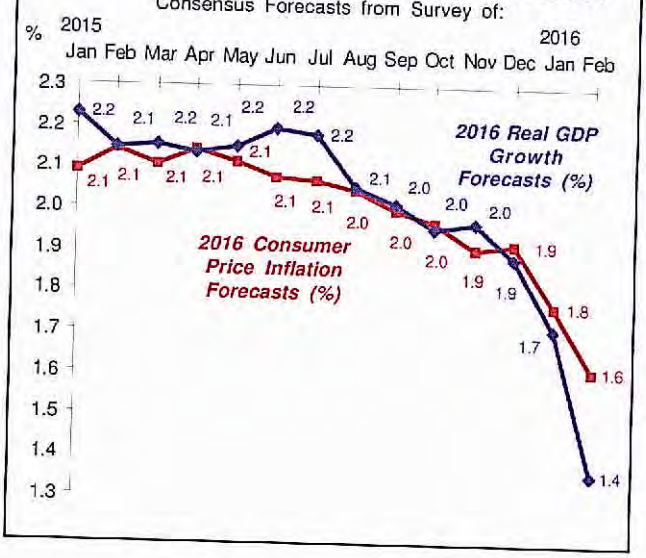
Real Growth and Inflation

(% change over previous year)



2016 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



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continued from page 3

France

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	2.1	0.2	0.7	0.2	1.1	1.5	1.6	1.6	1.6	1.5	1.3
Household Consumption*	0.3	-0.2	0.5	0.6	1.7	1.4	1.6	1.6	1.5	1.4	1.4
Business Investment*	4.0	-0.1	0.8	2.0	0.8	2.3	2.9	2.9	2.6	2.4	1.8
Manufacturing Production*	3.9	-3.2	-1.2	-0.1	1.0	1.9	2.1	2.0	2.0	1.4	1.3
Consumer Prices*	2.1	2.0	0.9	0.5	0.1	1.0	1.4	1.6	1.7	1.8	1.8
Current Account Balance (Euro bn)	-20.4	-24.9	-17.1	-19.7	-8.8	-6.7	-6.9	-10.4	-12.6	-11.7	-18.9
10 Year Treasury Bond Yield, %[2]	3.2	2.0	2.4	0.8	1.0 [3]	1.3 [4]	1.9	2.4	2.7	3.1	3.3

United Kingdom

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	2.0	1.2	2.2	2.9	2.5	2.4	2.3	2.2	2.2	2.3	2.3
Household Consumption*	-0.1	2.0	1.9	2.7	3.0	2.5	2.3	2.2	2.2	2.3	2.3
Gross Fixed Investment*	2.0	1.5	2.6	7.5	4.6	5.1	4.0	3.2	2.7	2.6	2.8
Manufacturing Production*	1.8	-1.3	-0.7	3.2	0.4	1.5	1.7	1.5	1.4	1.3	1.3
Retail Prices (underlying rate)*	5.3	3.2	3.1	2.4	1.1	2.3	2.7	3.1	3.2	3.0	2.9
Consumer Prices*	4.5	2.8	2.5	1.5	0.1	1.4	2.0	2.1	2.1	2.1	2.1
Current Account Balance (£ bn)	-27.4	-54.7	-77.9	-92.9	-88.5	-81.3	-73.2	-80.2	-80.2	-77.9	-80.8
10 Year Treasury Bond Yield, %[2]	2.1	2.0	2.8	1.8	2.0 [3]	2.4 [4]	2.7	3.0	3.3	3.6	3.7

Italy

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	0.6	-2.8	-1.7	-0.4	0.8	1.3	1.3	1.2	1.2	1.3	1.3
Household Consumption*	0.0	-3.9	-2.8	0.4	0.7	1.2	1.2	1.1	1.0	1.2	1.2
Gross Fixed Investment*	-1.9	-9.3	-6.6	-3.5	0.9	2.1	2.4	2.5	2.0	1.6	1.6
Industrial Production*	1.2	-6.3	-3.2	-0.6	1.1	2.1	2.5	2.0	1.4	1.3	1.5
Consumer Prices*	2.8	3.1	1.2	0.2	0.1	0.9	1.4	1.5	1.6	1.9	1.9
Current Account Balance (Euro bn)	-50.4	-6.9	15.0	30.9	33.7	34.2	33.3	38.9	36.6	39.9	35.9
10 Year Treasury Bond Yield, %[2]	7.0	4.5	4.1	1.9	1.9 [3]	2.2 [4]	2.5	3.1	3.6	4.0	4.2

Canada

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	3.0	1.9	2.0	2.4	1.1	2.0	2.2	2.2	2.1	2.1	2.0
Personal Expenditure*	2.2	1.9	2.5	2.7	2.0	2.0	2.1	2.2	2.1	2.1	2.0
Machinery & Eqpt Investment*	8.1	1.9	-1.7	1.0	-5.0	0.2	4.0	4.2	3.2	2.9	2.6
Industrial Production*	4.1	1.4	1.8	4.1	-1.3	1.5	2.4	2.3	2.2	2.1	1.8
Consumer Prices*	2.9	1.5	0.9	1.9	1.2	2.0	2.0	2.0	1.9	2.0	2.0
Current Account Balance (C$ bn)	-47.2	-59.9	-56.3	-41.5	-68.0	-54.8	-45.3	-38.4	-33.6	-31.1	-29.0
10 Year Treasury Bond Yield, %[2]	1.9	1.8	2.8	1.8	1.7 [3]	2.1 [4]	3.0	3.5	3.6	3.9	3.9

Euro zone

* % change over previous year	Historical				Consensus Forecasts						
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-2025[1]
Gross Domestic Product*	1.7	-0.8	-0.2	0.9	1.5	1.7	1.6	1.5	1.5	1.4	1.3
Private Consumption*	0.0	-1.2	-0.6	0.9	1.8	1.7	1.5	1.4	1.3	1.3	1.3
Gross Fixed Investment*	1.8	-3.4	-2.6	1.3	1.9	2.7	2.7	2.5	2.2	1.9	1.6
Industrial Production*	3.5	-2.3	-0.7	0.8	1.6	2.0	1.9	2.1	2.0	1.5	1.4
Consumer Prices*	2.7	2.5	1.3	0.4	0.1	1.1	1.5	1.6	1.7	1.9	1.9
Current Account Balance (Euro bn)	7.2	120	178	207	272	263	294	287	277	334	359

[1]*Signifies average for period* [2]*End period* [3]*End January 2016* [4]*End October 2015*

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YUB-YECL-74

Reference: Application, pages 8-5 to 8-6, Attachments 8.2 and 8.3

Issue/sub-issue: RFID

Preamble: YECL has included to attachments with respect to RFID claims.

Request:

(a) Please explain why the Beaver Creek or Fish Lake events qualify as an RID claim?

(b) Please provide the history of RFID claims for the period 2010 to 2015.

(c) YECL has forecast annual charges for RFID of $100,000. Please explain how that number was derived.

Response:

(a) In determining which events qualify as RFID claims, AEY refers to Accounting Policy E.5 – Reserve for Injuries and Damages. This document was filed as Attachment 1 in Section 8 of YECL's 2013-2015 GRA and has been included as YUB-YECL-74(a) Attachment 1.

The policy states:

> *"The reserve is established for the payment of:*
>
> 1. *The deductible portion of insured losses including any portion of a claim not paid by the insurance company.*
>
> 2. *Uninsured and uninsurable losses resulting from but not limited to design error, failure to supply (blackout, brownout), professional liability and pollution liability.*
>
> *Also, effective with events charging to the reserve after January 1, 1999, only those that are significant and of low probability shall be charged to the reserve.*
>
> *All events will be considered on a case by case basis and will be reviewed and approved by the Manager, Insurance and a representative from the company's insurance adjusters."*

The Beaver Creek House Fuel Spill claim is an uninsured loss resulting from pollution liability, while the Fish Lake Ditch #1 Spillway Failure claim is the deductible portion of insured losses. It is AEY's view that both events were significant and of low probability. Therefore, AEY has included them as RFID claims in its 2016-2017 GRA.

(b) The history of RFID claims for the period 2010 to 2015 is noted in Table 1 below.

Table 1:
ATCO Electric Yukon
Reserve for Injuries and Damages Claims

	($000s)
2015	
Beaver Creek House Fuel Spill	108
Fish Lake Ditch #1 Spillway Failure (deductible)	100
	208
2014	
Fish Lake Unit #1	72
2013	
Fish Lake Unit #1	1,445
Fish Lake Ditch #3	83
	1,528
2012	
Shipyards Transformer Failure (deductible)	100
2011	
Carmacks Diesel Fuel Spill (deductible)	100
2010	
Fish Lake Unit #1 (deductible)	100

(c) The $100,000 forecast RFID charges for the 2016 and 2017 test periods are placeholders that are consistent with what was previously approved in YECL's 2013-2015 GRA.

THE YUKON ELECTRICAL COMPANY LIMITED ACCOUNTING POLICY MANUAL	*Reserve for Injuries and Damages*
	Date: 94-12-08 **Number:** E.5
PREPARED BY: **K. Trunzo**	**APPROVED BY:** David Freedman
	UPDATED: December 15, 2010

INTRODUCTION

The charges made against the Reserve for Injuries and Damages fall into two main categories. The first category is insured losses and the second is uninsured or uninsurable losses.

Insured Losses:

With respect to incurred losses, the item in question must be covered by insurance. Charges against the reserve include the deductible portion of insured losses as well as any portion of the claim not paid by the insurance company.

Uninsured or Uninsurable Losses:

An uninsured loss is one where insurance coverage could have been obtained except that the exposure risk was minimal or the cost of the insurance was prohibitively high.

An uninsurable loss is one where insurance coverage was not available as a result of very high-risk exposure.

PURPOSE OF THE RESERVE

The reserve serves as a protection against uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve will mitigate rate fluctuations by smoothing out the charges to O&M with respect to these types of losses. The establishment of such a reserve provides financial advantages over paying significantly higher insurance premiums in order to reduce deductibles or to insure items which carry prohibitively high premiums.

The reserve is established for the payment of:

1. The deductible portion of insured losses including any portion of a claim not paid by the insurance company.

2. Uninsured and uninsurable losses resulting from but not limited to design error, failure to supply (blackout, brownout), professional liability and pollution liability.

Also, effective with events charging to the reserve after January 1, 1999, only those that are significant and of low probability shall be charged to the reserve.

All events will be considered on a case by case basis and will be reviewed and approved by the Manager, Insurance and by a representative from the company's insurance adjusters.

YUB-YECL-75

Reference: Application, page 8-8; Appendix A to Board Order 2014-06, page 61.

Issue/sub-issue: Deferred Charges and Credits – Watson Lake Bi-Fuel Project

Quote: "ATCO Electric Yukon has included these study costs in its deferred charges accounts for recovery over the test period."

Request:

(a) In Appendix #3, YECL discusses the Watson Lake Bi-Fuel Project. If the project is approved, should the study costs be capitalized along with the project costs? Please explain.

Response:

(a) In the Application AEY proposes that, regardless of the decision on the Watson Lake Bi-Fuel Project, the costs associated with the determination of the feasibility of such a project be collected.

In Decision 2013-01 Appendix A, the Board acknowledged the need to explore alternatives to diesel generation. AEY incurred costs of this nature through 2013-2015 which have remained in WIP as per Board direction in Decision 2014-06 Appendix A. Within that decision the Board stated:

> "Despite the Board having rejected YECL's proposed Watson Lake bi-fuel project in Section 10.8.2 of this decision, the Board finds that this project has potential to be viable in the future."

Because the Board has acknowledged the viability of the project AEY submits that the costs of an exploratory nature are prudent and should be recovered from customers irrespective of the decision regarding the proposed project.

The suggested mechanism is through the amortization of deferred charges similar to the treatment of the Kluane Wind Study and the proposed Renewables Feasibility and Smart Grid Studies, however, AEY is not opposed to capitalization of the costs, should the project be approved, and recovery of costs over the lifetime of the related assets.

YUB-YECL-76

Reference: Application, page 8-8

Issue/sub-issue: Smart Grid Study

Request:

(a) Please explain what the Smart Grid study is to entail and the reasons for such a study.

(b) Please list the benefits of a smart grid on an isolated system and provide the probability of each of those listed benefits being achieved.

(c) Can time of use metering be automated without automated meter reading?

(d) Does a smart grid imply that control of home appliances is surrendered to the utility? Please explain.

Response:

(a) The smart grid study is intended to assess the potential fit and viability of a smart grid in the Yukon. As there is no universal definition of a smart grid, and therefore, the study is intended to review aspects of a smart grid that would be advantageous and beneficial for the Yukon Utilities and ratepayers. The scope of the study is not finalized, but in general the study has the following objectives:

1. Identify opportunities for efficient utilization of energy that could arise from the implementation of smart grid infrastructure. Such opportunities may include, but are not limited to; time-of-use rate structure, utility controlled demand response initiatives, renewable integration, demand side management and increased customer interfacing with energy consumption.

2. Identify opportunities for operational efficiencies such as; increased accuracy of energy billed to customers, identify energy losses on the electrical system, reduction of staff deployment for meter readings, outage diagnostics and associated costs and increased quality of power consumption data for purposes of load forecasting.

3. Identify and define costs associated with smart grid components including meters, communication equipment, data storage equipment, software and billing system integration.

4. Determine whether implementation of smart grid would be Yukon wide or limited to large population centers.

(b) The benefits of a smart grid will wholly depend on the particular initiatives that are implemented. There are numerous options for automated metering infrastructure in a smart grid and each potential component will have to be analyzed in the study to weigh the potential benefits to an isolated grid.

(c) With current revenue meters in place, a time-of-use rate structure cannot be implemented at this time. In order for a time-of-use rate structure to be put in place, all revenue meters need time registry ability. If a time-of-use rate structure is developed set on a specific time table (ie a different rate for the hours of 11pm to 4am), revenue meters have to be able to register that time of day, and the consumption, to standards set by Measurement Canada. If a time-of-use rate structure is developed set on a variable time table (ie a different rate based on available energy supply), revenue meters will have to be communicated with to set the appropriate rate. At this time, AEY is not aware of revenue meters that could store energy use (consumption readings) for specific time blocks until the meter was manually read.

(d) There are smart grids that employ utility control of customer devices such as home appliances and non-critical loads such as air conditioning. Though this option is available for smart grids, with the appropriate infrastructure in place, it is not an option that must be integrated. The proposed smart grid study will evaluate this option to see if it is beneficial for the Yukon.

YUB-YECL-77

Reference: Application, page 8-9

Issue/sub-issue: Working Capital

Request:

(a) Please provide a copy of the updated lead/lag study.

(b) Please state what the updated payment dates are in the new study and what the previous payments dates were.

(c) Please state what the updated O&M lag days are and what the previous O&M lag days were.

Response:

(a) Please refer to YUB-YECL-77(a) Attachment 1.

(b) AEY determined that there were no material changes in the types of revenues and expenses or in payment terms, other than the change in the timing of intercompany settlements. These balances were previously paid through AEY's accounts payable system and are now settled on the 15th of the month via bank transfer.

As a result, AEY did not conduct a full lead/lag study for the purpose of this Application as it was determined to be unnecessary.

(c) The updated O&M lag days are 4 and the previous O&M lag days in YECL's 2013-2015 GRA were 7.

ATCO Electric Yukon
2016-2017 GRA
Lead/Lag Study

	Days
Average lag in revenue collection:	41.87
Less: average lag in payment of operating expense:	37.71
Net O&M lag days	4.16

Lead/Lag on Revenues

Revenue Type	2015 Revenue ($000s)	Lag Days	Weighted Revenue ($000s)
Residential	22,404	42.83	959,669
Commercial	27,121	41.12	1,115,229
Street & Sentinel Lighting	1,242	40.84	50,724
Secondary	890	41.89	37,284
Revenues included in Lead/Lag Study	51,657	41.87	2,162,906

Lead/Lag on Operating Expenses

	2015 Operating Expenses ($000s)	(Lead)/Lag Days	Weighted Revenue ($000s)
Salary and wages	5,710	31.60	180,409
Fuel	6,621	47.94	317,427
Purchased Power	30,373	37.68	1,144,397
Property taxes	256	2.90	743
Other Operating Expenses			
Insurance	90	(135.90)	(12,231)
Intercompany	961	31.86	30,618
IT Services	481	41.40	19,913
Employee travel and expenses	206	36.77	7,574
Other	4,168	36.93	153,918
	5,906	33.83	199,793
Operating Expenses included in the Lead Lag Study	48,866	37.71	1,842,769

YUB-YECL-78

Reference: Application, page 8-8

Issue/sub-issue: Approved DSM Costs

Quote: "ATCO Electric Yukon is proposing to move the costs related to the approved Demand Side Management (DSM) program out of the deferred account into capital and recover these costs over a 5-year term. This treatment is consistent with the findings in Section 12.1 of Board Order 2014-06, which approved the collection of previous DSM costs over the 2014-2018 timeframe."

Request:

(a) Please provide further explanation on how the utilities have demonstrated the benefits of the DSM program.

(b) Please explain how DSM sales reductions can be directly quantified.

Response:

(a) Demand Side Management is a system of options for reducing, shifting, or re-allocating electrical demand. For an overview of the benefits and the impact to load from DSM, please refer to AEY's response to YUB-YECL-6(c).

(b) Please refer to AEY's response to YUB-YECL-6(c).