ATCO Electric
YUKON

May 11, 2016

Yukon Utilities Board
Box 31728
Whitehorse, YT Y1A 6L3

Attention: Mr. Robert Laking
Vice Chairman

RE: ATCO Electric Yukon
2016-2017 General Rate Application – Phase I

ATCO Electric Yukon (AEY) has attached its Phase I General Rate Application for the 2016-2017 test period.

This Application includes:

- Determination of the 2016-2017 revenue requirement in Sections 1 to 12;
- Interim Refundable Rate Rider in Section 13; and
- Business Cases for 2016-2017 Capital Additions.

In accordance with the *Public Utilities Act* and *Order-In-Council 1995/90*, ATCO Electric Yukon respectfully requests that the Board commence the public notification process in anticipation of a possible public hearing later this year.

The increase in rates requested by ATCO Electric Yukon in each test year is as follows:

	2016	2017
	($000s)	
ATCO Electric Yukon Retail Revenues	53,890	56,173
Cumulative Increase over Existing Rates	2,436	4,076
Cumulative Rate Increase %	4.4%	7.5%
Year Over Year Rate Increase %	4.4%	3.1%
Net Cumulative Rate Increases % (including fuel reduction)	**2.0%**	**5.1%**

Interim Refundable Rate Rider

In Section 13 of this Application, ATCO Electric Yukon has requested approval of an 11.62% Interim Refundable Rate Rider (Rider R) for electrical consumption on or after July 1 2016. By implementing the rate on July 1, 2016, Rider R will recover approximately 50% of

ATCO Electric Yukon's forecast shortfall in 2016. This proposal to collect 50% of ATCO Electric Yukon's forecast shortfall is consistent with the approach filed for and approved by the Board for ATCO Electric Yukon's 2013 Interim Refundable Rider in Board Order 2013-05. For this reason, ATCO Electric Yukon respectfully requests approval of Rider R by June 24, 2016 in order to implement the Rider on July 1, 2016.

Proposed Schedule

To assist the Yukon Utilities Board in scheduling, ATCO Electric Yukon proposes the following schedule for consideration. It should be noted that this proposed schedule culminates in a Hearing commencing September 21, 2016.

	Proposed Date
Filing Application	May 11, 2016
Intervener Registration	May 27, 2016
Interim Rate Decision	June 24, 2016
Information Requests to AEY	June 17, 2016
Information Responses from AEY	July 22, 2016
Intervener Evidence	August 5, 2016
Information Requests to Interveners	August 19, 2016
Information Responses from Interveners	September 2, 2016
Rebuttal Evidence	September 9, 2016
Hearing	September 21-23, 2016
Final Argument	October 7, 2016
Reply Argument	October 21, 2016

Should you have any questions on the above request, please contact the undersigned at (780) 733-2489. If you require a paper copy of this application please contact Cynthia Malchow at (867) 633-7002.

Yours truly,

Original Signed by:

James Grattan, CA
Director, Regulatory

2016-2017 General Rate Application

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Section 1 – Introduction

Summary

Included in this section is a discussion of:

- Approvals Requested;
- Background on ATCO Electric Yukon;
- Overview Current General Rate Application;
  - Tariffs Applied For;
  - Interim Refundable Rate Rider;
  - Deferral Accounts;
  - Key Assumptions;
  - Staff Positions; and
  - Witnesses.

Approvals Requested

ATCO Electric Yukon seeks the following approvals from the Board:

(1) Approval of ATCO Electric Yukon's revenue requirement for the two-year test period 2016-2017;

(2) Continuation of the currently approved deferral accounts including (Purchase Power Flow-Through, Fuel Price Flow Through and Defined Benefit Pension Costs) during the test period;

(3) Approval of new deferral accounts to flow-through costs related to Liquefied Natural Gas (LNG) fuel price changes, statutory tax rate change, feasibility studies and costs arising from Board orders or legislative provisions not currently contemplated; and

(4) Approval of an Interim Refundable Rate Rider (Rider R) for implementation on July 1, 2016 as detailed in Section 13.

Background on ATCO Electric Yukon

Yukon Electrical Company Limited, carrying on business as ATCO Electric Yukon, has been providing electrical service to Yukoners for over one hundred and fifteen years. Chartered in 1901, the pioneer company began generating electricity for the residents of Whitehorse using a wood-fired, horizontal piston steam engine. Since then, ATCO Electric Yukon has grown to serve more than 17,000 customers in 19 communities from the Yukon border to north of the Arctic Circle. A private, investor-owned utility, ATCO Electric Yukon is a member of the ATCO Group of Companies. Its head office and service centre are located in Whitehorse.

Today, ATCO Electric Yukon purchases electricity from Yukon Energy for distribution to its customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek as well as a variety of rural areas surrounding Whitehorse. The company maintains back-up generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption.

The company generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River. ATCO Electric Yukon has customer service offices in Whitehorse and Watson Lake and plant operators in ten communities. ATCO Electric Yukon also owns and operates the Fish Lake Hydro plant on the outskirts of Whitehorse. Built in 1950, the Fish Lake plant continues to provide green hydroelectric power.

ATCO Electric Yukon was last before the Yukon Utilities Board ("Board") for the test years 2013-2015. During this period, ATCO Electric Yukon has continued to provide safe, reliable and cost effective service to our customers. As detailed in this Application, however, there are significant cost pressures, variances between actual and approved sales volumes and capital requirements that require ATCO Electric Yukon to come forward to the Board to ensure that it is possible to continue to deliver the same safe and reliable service to customers at just and reasonable rates.

Overview of Current General Rate Application

This Application deals with ATCO Electric Yukon's requested approval of the revenue requirement detailed herein for the test period 2016-2017.

Tariffs Applied For

The tariffs applied for are detailed in Schedule 2.1 and are as follows:

	2016	2017
	($000s)	
ATCO Electric Yukon Retail Revenues	53,890	56,173
Cumulative Increase over Existing Rates	2,436	4,076
Cumulative Rate Increase %	4.4%	7.5%
Year Over Year Rate Increase %	4.4%	3.1%
Net Cumulative Rate Increases % (including Fuel reduction)	**2.0%**	**5.1%**

Interim Refundable Rate Rider

As explained in Section 13, ATCO Electric Yukon is requesting an increase of 4.42% over the current Rider R of 7.20%. The resulting 11.62% interim refundable Rider R would apply to electrical consumption on or after July 1, 2016. This interim rider has been calculated by taking 50.0% of the 2016 shortfall revenue requirement and collecting this over the July 2016 to December 2016. This rider will be applied to all ATCO Electric Yukon and Yukon Energy retail customer bills, excluding Secondary Energy Rate 32, in order to recover the difference between the forecast revenues on existing rates and riders and the forecast 2016 revenue requirement as applied for in this Application. This request is consistent with the approach approved by the Board for ATCO Electric Yukon's 2013-2015 GRA where a 6.50% interim refundable rider was approved in Board Order 2013-05. By implementing the rider on July 1, 2016, ATCO Electric Yukon will recover approximately 50.0% of the forecast total shortfall in 2016.

Deferral Accounts

The deferral accounts for which ATCO Electric Yukon is seeking approval meet the standard criteria for the establishment of a deferral account:

(a) Costs are not under the control of the company and are not reasonably forecastable; or

(b) A variance in forecasting could produce a loss or gain of a substantial magnitude.

ATCO Electric Yukon is seeking approval to use the following deferral accounts during the test period:

Board Orders or Legislative Provisions	Section 1
Purchased Power Flow Through	Section 3
Diesel Fuel Deferral Account	Section 4
LNG Fuel Deferral Account	Section 4
Defined Benefit Pension Plan	Section 8
Statutory Tax Rates	Section 10
Feasibility Studies	Section 12

Board Orders or Legislative Provisions

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 is prudently incurred costs and opportunity to earn a reasonable return (for example – any future tax or levy to address environmental emissions).

Key Assumptions

	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%

For the 2016 test period, in-scope (subject to a collective agreement) and out-of-scope (not subject to a collective agreement) labour has been escalated by 3.25%. This escalation is based on ATCO Electric Yukon's existing collective agreement that expires on December 31, 2016. Consistent with past practice, ATCO Electric Yukon has applied the same inflation increases to both the in-scope and out-of-scope labour costs. 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.

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.

A vacancy rate of 4.0% (approximately 3 FTEs) has been applied to all labour expenses for the 2016-2017 test periods. This is based on a five year historical average which ATCO Electric Yukon believes to be reasonable and is consistent with the methodology approved in Board Order 2009-2 and 2014-06.

Please refer to Section 8 for discussion of the forecast long term debt rates for 2016-2017.

Staff Positions

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. Please refer to Attachment 1.1 for ATCO Electric Yukon's organization chart which details the labor complement by positions.

	FTEs
2015 Approved Ending Complement	**70.39**
2015 Actual Ending Complement	**69.13**
Engineering Technologist (2016)	1.00
Supervisor, Business Support Services (2016)	0.25
2017 Forecast Ending Complement	**70.38**

Descriptions of the new positions are highlighed below:

- **Engineering Technologist (2016)** This position is responsible for the management of the mechanical aspect of projects. This would include design, specification and tender of bid packages for projects. The position would also provide assistance on project monitoring for quality assurance, cost control, technical reporting and final commissioning of projects.

- **Supervisor, Business Support Services (2016)** 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.

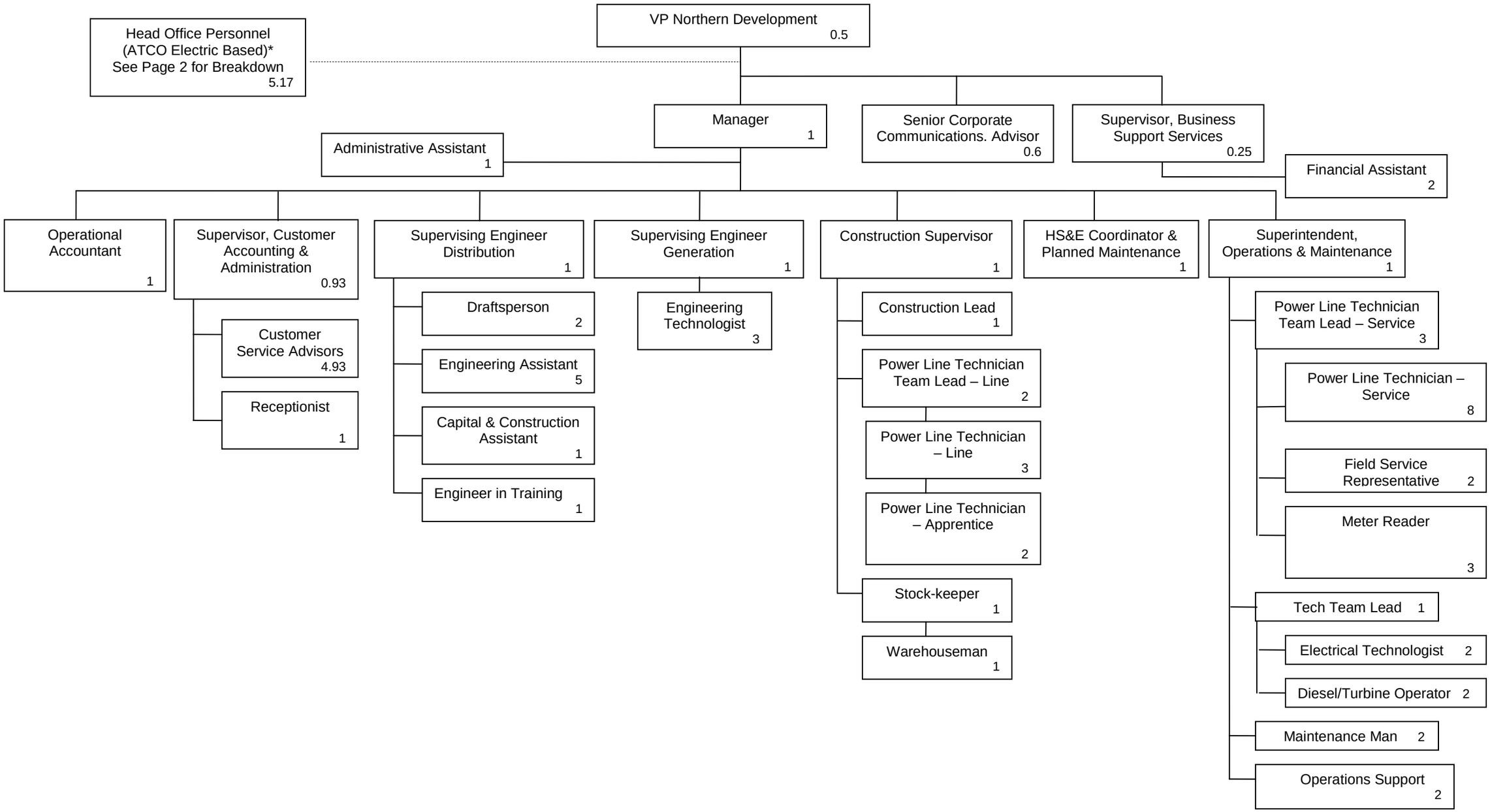
Witnesses

ATCO Electric Yukon has not yet finalized the specific witnesses it will present to speak to various aspects of this Application. This decision will be influenced to some degree by the areas in which the Board and Interveners show the most interest. ATCO Electric Yukon will provide a list of its witnesses to the Board in advance of the hearing.

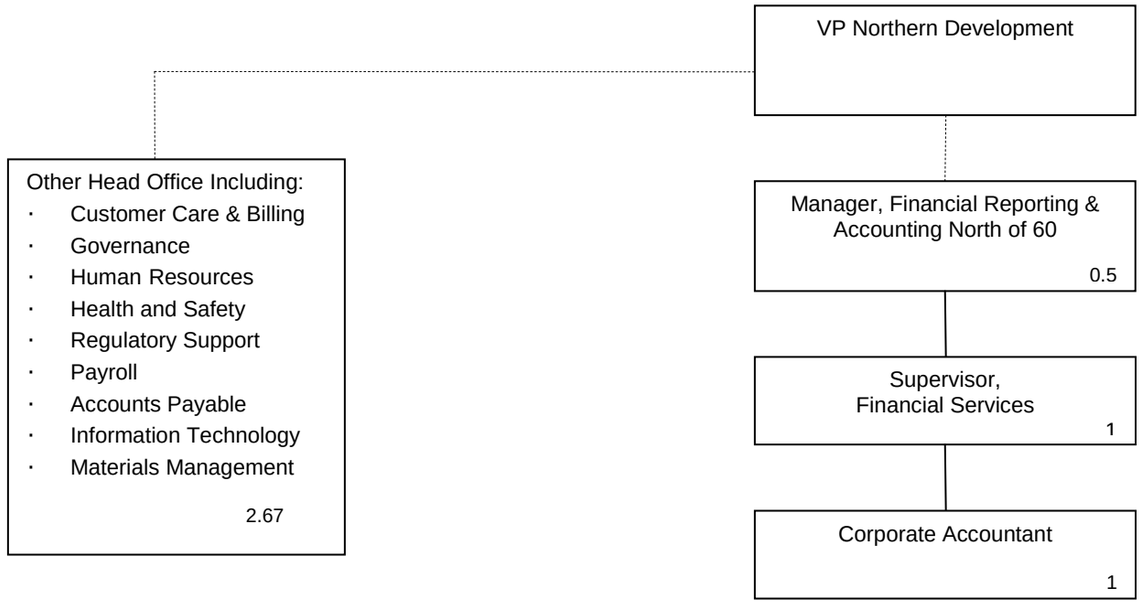
ATCO Electric Yukon
2016 - 2017 General Rate Application
Utility Revenue Requirement
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Revenues**									
2	Retail Revenues	S.2.1 L.54	56,310	49,812	57,687	53,473	57,476	55,183	52,566	54,844
3	Other Revenue	S.2.2 L.6	1,351	1,277	1,315	1,250	1,271	1,275	1,299	1,328
4	**Total Revenues**		57,660	51,089	59,002	54,722	58,747	56,458	53,865	56,172
5										
6	**Costs**									
7	Purchase Power	S.3.1 L.14	31,270	24,858	31,177	26,066	30,373	26,634	24,756	25,250
8	Fuel	S.4.1 L.6	6,708	6,611	6,760	6,701	6,621	6,704	5,225	5,268
9	Operations and Maintenance	S.5.1 L.49	11,718	11,604	11,698	11,882	11,616	11,944	11,993	12,181
10	Property Taxes	Page 6-1	273	257	251	265	256	273	262	267
11	Depreciation	S.7.1 L.4	4,382	4,520	4,895	5,252	5,412	5,778	5,792	6,283
12	Amortization of Contributions	S.8.12 L.8	(1,545)	(1,444)	(1,459)	(1,557)	(1,460)	(1,749)	(1,504)	(1,570)
13	Amortization of Deferred Charges & Credits	S.8.8 L.11	18	18	18	18	17	17	632	832
14	Return on Rate Base	S.8.1 L.5, 10, 15, 20, 25, 30, 35, 40	5,550	5,080	5,782	5,936	5,838	6,545	6,945	7,400
15	Income Taxes	S.10.1 L.30	(714)	(416)	(120)	160	74	313	(235)	261
16	**Total Costs**		57,660	51,089	59,002	54,722	58,747	56,458	53,865	56,172

Organizational Chart
ATCO Electric Yukon
2016 – 2017



Organizational Chart
ATCO Electric Yukon
2016 – 2017



Section 2 – Sales and Revenue

Overview

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 1
ATCO Electric Yukon Sales by Customer Class
(MWh)

	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** [1]	**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**

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

ATCO Electric Yukon forecasts its total primary non-industrial sales in 2016 to decrease 1.5% and increase 1.9% in 2017. The forecast is based on ATCO Electric Yukon's detailed analysis of historical data by community and customer class and takes into account information gathered through ATCO Electric Yukon staff's work in the community as well as consultation with the City of Whitehorse, Yukon Government officials and local developers.

Forecast Accuracy from the 2008-2009 GRA and the 2013-2015 GRA

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. As discussed below, Table 2 demonstrates that ATCO Electric Yukon's forecast sales were more accurate than the Board-approved forecasts.

Table 2
ATCO Electric Yukon Sales Variance
2008-2009 GRA and 2013-2015 GRA Forecasts

Year	Forecast (MWh)	Actual (Normalized) (MWh)	Variance (MWh)	(%)
2008 Filed [1]	269,913	269,799	-114	0.0
2008 Approved [2]	275,224	269,799	-5,425	-2.0
2009 Filed [1]	272,054	275,425	3,371	1.2
2009 Approved [2]	278,133	275,425	-2,708	-1.0
2013 Filed [3]	309,891	313,442	3,550	1.1
2013 Approved [4]	309,894	313,442	3,547	1.1
2014 Filed [3]	315,876	309,961	-5,915	-1.9
2014 Approved [4]	323,823	309,961	-13,863	-4.3
2015 Filed [3]	321,818	314,658	-7,160	-2.2
2015 Approved [4]	330,274	314,658	-15,616	-4.7

Notes:
1) 2008-2009 GRA, Schedule 2.1
2) 2008-2009 Compliance Filing (Board Order 2009-5), Schedule 2.1
3) 2013-2015 GRA Omissions & Updates (excluding Industrial), Attachment 2 - Schedule 2.1
4) 2013-2015 Compliance Filing (Board Order 2014-06), Schedule 2.1

For the 2008-2009 GRA, ATCO Electric Yukon's variance was 0.0% in 2008 and 1.2% in 2009. The Board-approved forecast variance, however, was -2.0% in 2008 and -1.0% in 2009, which indicates that the Board-approved forecast resulted in an over-forecast of sales in both years.

During the 2013-2015 GRA, ATCO Electric Yukon determined that its 2013 residential and commercial sales up to the end of September 2013 were significantly lower than originally applied for in May 2013. This resulted in ATCO Electric Yukon updating its

2013-2015 sales forecast to better reflect what had happened in 2013 year-to-date, and what could have been reasonably expected to occur for 2014 and 2015.

As per Board Order 2014-06, the updated forecast for 2013 was approved; however, the 2014 and 2015 forecasts were not.

As shown in Table 2, the variance between actual sales and ATCO Electric Yukon's updated forecast was 1.1% in 2013, -1.9% in 2014, and -2.2% in 2015. However, the Board-approved forecast resulted in significant variances of 1.1% in 2013, -4.3% in 2014 and -4.7% in 2015. Again, this demonstrates that ATCO Electric Yukon's forecast variances were lower than the variances resulting from the Board-approved forecasts and that the Board-approved forecasts were significantly higher than actual weather-normalized sales for 2014 and 2015.

Background Information

In 2015, ATCO Electric Yukon provided electricity services to approximately 17,600 non-lighting customers in its service area and supplied a total of 308.4 GWh to residential, commercial, and lighting customers. This represents an increase in total primary sales of 0.7% from 2014 levels. This increase follows a 2.0% decrease in 2014 over the previous year, as well as a 0.6% decrease in 2013 over 2012 levels.

After experiencing strong growth from 2004-2012, the pace of economic activity in the Yukon has slowed down significantly. The Yukon economy has declined due to depressed mineral and commodity prices as evidenced by the decreases in real GDP of -1.2% in 2014, and an estimated -6.0% in 2015. Slower population growth has also contributed to minimal customer gains in both residential and commercial sectors for ATCO Electric Yukon. 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.

The overall impact of the economic and population growth slowdown is expected to impact ATCO Electric Yukon's customer growth and sales over the test period.

Forecast Process

The forecast process involves the review of historic sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. The information is obtained through ATCO Electric Yukon's work in the community, as well as consultation with the City of Whitehorse, Yukon Government, and various local agencies and developers. The retail primary sales forecast is prepared by customer class: residential, commercial, street and private lighting. 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.

Table 3
ATCO Electric Yukon Residential and Commercial Customers and Sales by Community

	AEY (2015 Actuals)		Diesel /	Residential				Commercial				
	Community	HDD	Hydro	Customers[1]	Share	Energy	Share	Community	Customers[1]	Share	Energy	Share
					(%)	(MWh)[2]	(%)			(%)	(MWh)[2]	(%)
1	Whitehorse[3]	WH	Hydro	11,256	76.9	122,402	81.8	Whitehorse[3]	2,125	71.1	132,787	85.0
2	Marsh Lake	WH	Hydro	443	3.0	3,836	2.6	Haines Junction	135	4.5	4,040	2.6
3	Haines Junction	WH	Hydro	403	2.8	3,179	2	Carmacks	76	2.5	2,444	1.6
4	Carmacks	WH	Hydro	232	1.6	2,576	1.7	Teslin	75	2.5	1,935	1.2
5	Carcross	WH	Hydro	261	1.8	2,053	1.4	Beaver Creek	45	1.5	1,054	0.7
6	Teslin	WH	Hydro	279	1.9	1,945	1.3	Carcross	70	2.3	1,268	0.8
7	Tagish	WH	Hydro	341	2.3	1,631	1.1	Ross River	43	1.4	1,237	0.8
8	Ross River	WH	Hydro	178	1.2	1,510	1.0	Pelly Crossing	29	1.0	979	0.6
9	Pelly Crossing	WH	Hydro	161	1.1	1,620	1.1	Destruction Bay	47	1.6	854	0.5
10	Old Crow	WH	Diesel	149	1.0	1,148	0.8	Old Crow	42	1.4	901	0.6
11	Destruction Bay	WH	Diesel (S)	98	0.7	687	0.5	Marsh Lake	24	0.8	306	0.2
12	Beaver Creek	WH	Diesel (S)	72	0.5	604	0.4	Stewart Crossing	13	0.4	247	0.2
13	Keno City	WH	Hydro	40	0.3	172	0.1	Tagish	25	0.8	335	0.2
14	Stewart Crossing	WH	Hydro	14	0.1	113	0.1	Keno City	13	0.4	98	0.1
15	Minto Landing	WH	Hydro	-	0.0	-	0.0	Minto Landing	3	0.1	61	0.0
1	Watson Lake	WL	Diesel (L)	589	4.0	5,217	3.5	Watson Lake	181	6.0	7,092	4.5
2	Lower Post BC	WL	Diesel (L)	63	0.4	505	0.3	Upper Liard	15	0.5	226	0.1
3	Upper Liard	WL	Diesel (L)	51	0.3	438	0.3	Lower Post BC	15	0.5	261	0.2
4	Swift River	WL	Diesel (S)	2	0.0	17	0.0	Swift River	13	0.4	169	0.1
	Total AEY			**14,631**	**100.00**	**149,653**	**100.0**		**2,988**	**100.00**	**156,294**	**100.0**

1) Customer numbers are on an annual average basis
2) Billed energy
3) Includes Deep Creek

Update to Forecast Process

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.

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. The process and steps for determining the forecasts for the residential and commercial rate classes are detailed further below.

Residential

The residential sales forecast has two key inputs: (i) the net customer additions; and (ii) the forecast use per customer (UPC). The energy sales forecast is obtained by

multiplying the forecast number of customers (generated based on the net customer adds forecast) by the UPC forecast.

The customer additions forecast includes all known residential property developments and is based on discussion with the aforementioned third parties.

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. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast. Detailed information used for determining the residential sales forecasts by community is provided in Attachments 1-19.

Commercial

The commercial sales forecast also has two key inputs: (i) the net customer additions; and (ii) the forecast use per customer (UPC). The energy sales forecast is obtained by multiplying the forecast number of customers (generated based on the net customer adds forecast) by the UPC forecast.

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. Additionally, three new large commercial customers are anticipated to be added during the test period in Whitehorse. ATCO Electric Yukon has considered these new large customers individually, and has forecast the load each customer will bring to the system each year based on the

start-up time and other pertinent information provided by the customer. The commercial energy sales for Whitehorse are then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.

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. Actual UPC for these communities is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast. Detailed information for determining the commercial sales forecast is provided in Attachments 20-38.

Lighting

The energy forecast for street and private lighting is based on wattage and customer additions.

Wholesale Sales (Sales to Yukon Energy)

Wholesale sales are forecast to remain constant at 2015 levels for the test period.

Secondary Sales

ATCO Electric Yukon uses information from Yukon Energy for the determination of the secondary sales forecast.

Current Forecast

Please refer to Schedule 2.1 for the summary of actual and forecast customers, sales and revenue by customer class compared against the proposed revenue requirement.

Revenue on Existing Rates

The current tariff in effect as of January 1, 2015, is applied to the sales and customer forecast, resulting in the forecast revenue on existing rates provided in Schedule 2.1.

The revenue excludes the Yukon Energy Revenue Shortfall Rider, the Yukon Energy DCF Rider, and the Fuel Adjustment Rider, Rider F.

ATCO Electric Yukon has included a 2016 and 2017 forecast for YEC's Firm Revenue on Schedule 2.1 which accounts for the expected closure of the Minto Mine in the second quarter of 2017.

Other Revenues

ATCO Electric Yukon's other revenues have been included with retail sales revenues as part of the revenue requirement. These amounts are detailed in Schedule 2.2.

Reconnect, Joint Use, and Services to Outside Parties revenues are forecast to increase in each year of the test period due to inflation.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Summary of Customers, Energy Sales and Revenue

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016 Existing	Test Period 2016 Proposed	Test Period 2017 Existing	Test Period 2017 Proposed
1	**Residential**											
2	Customers (average during year)		14,194	14,192	14,409	14,401	14,631	14,647	14,851		15,039	
3	Sales in MWh		148,780	148,010	147,253	154,384	148,605	157,032	147,111		151,617	
4	MWh sales per customer		10.48	10.43	10.22	10.72	10.16	10.72	9.91		10.08	
5	Revenue ($000s)		21,070	20,765	20,629	21,657	20,839	22,029	20,847		21,446	
6	Cents per kWh		14.16	14.03	14.01	14.03	14.02	14.03	14.17		14.15	
7	**Commercial**											
8	Customers (average during year)		2,918	2,922	2,938	2,903	2,988	2,948	2,998		3,039	
9	Sales in MWh		159,322	157,606	154,709	165,106	155,346	168,853	152,187		153,336	
10	MWh sales per customer		54.60	53.94	52.66	56.87	51.99	57.28	50.76		50.46	
11	Revenue ($000s)		26,305	25,753	25,509	27,016	25,534	27,652	24,926		25,044	
12	Cents per kWh		16.51	16.34	16.49	16.36	16.44	16.38	16.38		16.33	
13	**Industrial**											
14	Customers (average during year)		-	-	-	-	-	-	-		-	
15	Sales in MWh		-	-	-	-	-	-	-		-	
16	MWh sales per customer											
17	Revenue ($000s)		-	-	-	-	-	-	-		-	
18	Cents per kWh								-		-	
19	**Street Lights**											
20	Sales in MWh		3,719	3,725	3,765	3,789	3,886	3,854	3,944		4,008	
21	Revenue ($000s)		961	951	962	966	992	981	1,002		1,020	
22	Cents per kWh		25.84	25.54	25.54	25.49	25.52	25.45	25.41		25.46	
23	**Private Lights**											
24	Sales in MWh		551	554	544	544	519	534	493		472	
25	Revenue ($000s)		145	145	142	143	138	141	132		128	
26	Cents per kWh		26.33	26.23	26.05	26.27	26.58	26.31	26.87		27.06	
27	**Total Company - Retail - Primary**											
28	Customers		17,112	17,114	17,347	17,304	17,619	17,595	17,849		18,077	
29	Sales in MWh		312,372	309,894	306,272	323,823	308,356	330,274	303,736		309,433	
30	Revenue ($000s)		48,481	47,614	47,241	49,783	47,503	50,802	46,908		47,638	
31	Cents per kWh		15.52	15.36	15.42	15.37	15.41	15.38	15.44		15.40	
32	**Secondary Sales**											
33	Customers (average during year)		2	-	2	-	3	-	3		3	
34	Sales in MWh		3,959	-	5,415	-	7,030	-	9,429		9,429	
35	MWh sales per customer		1,980	-	2,708	-	2,812	-	3,429		3,143	
36	Revenue ($000s)		336	-	474	-	532	-	519		519	
37	**Cents per kWh**		8.49	-	8.75	-	7.57	-	5.50		5.50	
38	**Wholesale Sales**											
39	Customers (average during year)		2	2	2	2	2	2	2		2	
40	Sales in MWh		361	338	494	338	430	338	427		427	
41	MWh sales per customer		180.71	169.12	246.99	169.12	215.00	169.12	213.63		213.63	
42	Revenue ($000s)		30	28	41	28	36	28	35		35	
43	Cents per kWh		8.30	8.30	8.30	8.30	8.30	8.30	8.30		8.30	
44	**Total Company**											
45	Customers		17,116	17,116	17,351	17,306	17,624	17,597	17,854		18,082	
46	Sales in MWh	S.3.2 L.2	316,692	310,232	312,181	324,162	315,816	330,612	313,592		319,289	
47	Revenue ($000s)		48,847	47,642	47,756	49,811	48,071	50,830	47,462		48,192	
48	Cents per kWh		15.42	15.36	15.30	15.37	15.22	15.37	15.13		15.09	
49	Base Retail Revenues		48,847	47,642	47,756	49,811	48,071	50,830	47,462		48,192	
50	**RIDER R (RATE INCREASE @ CURRENT RATES)**		1,634	1,099	3,672	2,576	4,139	3,267	3,992	2,436	3,905	4,076
51	YEC Revenue Shortfall (Rider J)		5,829		6,259		5,266					
52	**Total Retail Revenue**		56,310	48,741	57,687	52,387	57,476	54,097	51,454	53,890	52,097	56,173
53	Fuel Variance Rider (Rider F)	Note 1		1,071		1,086		1,087		(1,325)		(1,329)
54	**NET REVENUES**	S.1.1 L.2	56,310	49,812	57,687	53,473	57,476	55,183	51,454	52,566	52,097	54,844
55	**% Rate Increase over Existing Rates**											
56	AEY Primary Retail Revenue	L.30		47,614		49,783		50,802	46,908		47,638	
57	YEC Firm Revenue			10,429		12,169		12,304	8,537		6,598	
58	Total YEC/AEY Retail Revenue Primary Rates ($000s)	L.56 + L.57		58,043		61,952		63,106	55,445		54,236	
59	**% Rate Increase Over Existing Rates**	L.50 / L.58		1.9%		4.2%		5.2%		4.4%		7.5%
60	**% Rate Increase - Net Customer Impact**	Note 2		3.7%		5.9%		6.9%		2.0%		5.1%

61 Note 1 - 2016-2017 Rider F calculated based on average 2015 diesel price
62 Note 2 - Net impact of higher revenue requirement and fuel price variance to be flowed through to customers.

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2016 - 2017 General Rate Application
Miscellaneous Revenue
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Reconnect Revenue		195	190	188	194	196	198	200	205
2	Joint Use		711	681	737	694	764	708	781	798
3	Services to Outside Parties		104	109	113	112	68	114	70	71
4	Other		342	297	277	250	243	255	249	254
5										
6	Total	S.1.1 L.3	1,351	1,277	1,315	1,250	1,271	1,275	1,299	1,328

ATCO Electric Yukon
2016 - 2017 General Rate Application

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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2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
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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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

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%**

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%**

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%**

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%**

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
WL-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%**

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
WH-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**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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	5,419.2				
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 =
= (66,906.6 / 66,179.2) ^ (1/2) - 1 = **-2.5%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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		1,081.9	2,238.7	
Feb-16	1,873.7		884.0	1,950.6	
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			17,818.7
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%**

ATCO Electric Yukon
2016 - 2017 General Rate Application

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		1,081.9	1,596.8	
Feb-16	518.1		884.0	550.1	
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			12,876.6
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		1,081.9	4,259.9	
Feb-16	3,758.9		884.0	3,856.3	
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			40,499.4
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		1,081.9	1,663.3	
Feb-16	1,385.5		884.0	1,444.0	
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			13,237.4
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**

Section 3 – Purchase Power

Overview

The volumes of actual and forecast purchase power over the period of 2013-2017 are outlined in Schedule 3.1 and as follows:

	2013 Actual	2014 Actual	2015 Actual	Test Period 2016	Test Period 2017
			$000s		
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized[1]	(402)	-	(72)	(110)	(86)
Total Purchase Power[2]	25,442	24,918	25,107	24,756	25,250

The primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The Primary Purchase Power costs are based on the currently approved Rate Schedule 42 effective July 1, 2011 and the Secondary Purchase Power costs are based on April 1, 2016 Quarterly Rate Schedule 43.

Background

In 2013, ATCO Electric Yukon purchased 92.6% of the required power supply from Yukon Energy as a result of Fish Lake Unit #1 being offline. In 2014, the required supply from Yukon Energy declined by 1.5% as a result of Fish Lake Unit #1 being back online. The remainder of ATCO Electric Yukon's required power supply has been provided by diesel generation and by hydro generation. The percentage of power that ATCO Electric Yukon purchased from Yukon Energy in 2015 was 91.1% and is forecast to be 91.3% in the 2016 and 2017 test years.

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

[1] Consistent with Board Order 2009-2 ATCO Electric Yukon will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds.
[2] Rider J has not been included as these are flow-through amounts to YEC.

average for the new Fish Lake Unit #1 adjusted for planned decrease in generation for capital builds.

Deferral Account

(a) Purchase Power Flow Through

The cost of purchase power in this Application is based on Yukon Energy's rates that are currently in place for primary energy and secondary sales and are outlined on Schedule 3.1, lines 6 and 7. These rates do not include any adjustment to the rates associated with Yukon Energy's Energy Reconciliation Adjustment (ERA). Any increases or decreases to these rates, including any ERA amounts charged by Yukon Energy, are proposed to be flowed through to customers.

ATCO Electric Yukon is of the view that the changes to the wholesale rates including any ERA charges meet the criteria for the establishment of a deferral account, and the variance should be included in the Purchase Power Flow Through Deferral Account. In Order 2014-06 the Board provided the standard criteria for the establishment of a deferral account to include: (a) costs that are not under the control of the company and are not reasonably forecastable, or (b) where a variance in forecasting could produce a loss or gain of a substantial magnitude.

As such, any changes made by YEC to the wholesale rates including any ERA charges are clearly not under the control of ATCO Electric Yukon. ATCO Electric Yukon is of the view that there continues to be uncertainty surrounding these charges, as evidenced by Yukon Energy's pending Leave to Appeal. These charges cannot be reasonably forecast by ATCO Electric Yukon and changes may produce a loss or gain of substantial magnitude. Therefore, consistent with these criteria any changes to the wholesale rates including any ERA charges should be included in ATCO Electric Yukon's existing Purchase Power Flow Through Deferral Account.

Forecast Process

The energy component of the purchase power cost is determined by applying Yukon Energy's currently approved wholesale rate to the total forecast energy purchases. Total forecast purchases are determined by applying a forecast line loss percentage to ATCO Electric Yukon's sales load forecast that was discussed in Section 2. Line losses have been determined to be 6.2% and are calculated using a five-year historical average, consistent with Board Order 2014-06.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Schedule of Purchase Power

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Purchases (MWh)**									
2	Primary Energy		307,927	304,011	295,284	314,125	297,961	320,965	294,664	300,325
3	Secondary Sales	S.2.1 L.34	3,959	-	5,415	-	7,030	-	9,429	9,429
4		S.3.2 L.10	311,886	304,011	300,699	314,125	304,991	320,965	304,093	309,754
5	**Purchase Power Rates**									
6	Primary Energy Charge ($ per kWh)		0.0830	0.0830	0.0830	0.0830	0.0830	0.0830	0.0830	0.0830
7	Secondary Sales ($ per kWh)		0.0738	-	0.077	-	0.065	-	0.044	0.044
8										
9	**Purchase Power Expense ($000s)**									
10	Primary Energy Expense	L.2 x L.6	25,552	25,227	24,503	26,066	24,725	26,634	24,451	24,921
11	Secondary Energy Expense	L.3 x L.7	292	-	415	-	454	-	415	415
12	Shortfall Rider J	S.2.1 L.51	5,829	-	6,259	-	5,266	-	-	-
13	Less: Capitalized		(402)	(369)	-	-	(72)	-	(110)	(86)
14	Total Purchase Power Expense	S.1.1 L.7	31,270	24,858	31,177	26,066	30,373	26,634	24,756	25,250

ATCO Electric Yukon
2016 - 2017 General Rate Application
Schedule of Energy Losses
(MWh)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Sales and Losses**									
2	Total Energy Sales - MWh	S.2.1 L.46	316,692	310,232	312,181	324,162	315,816	330,612	313,592	319,289
3	Losses and Company Used - MWh		20,191	19,234	19,880	20,098	19,019	20,498	19,443	19,796
4	Losses -%		6.4%	6.2%	6.4%	6.2%	6.0%	6.2%	6.2%	6.2%
5	Total Generation and Purchases (MWh)		336,878	329,467	332,063	344,260	334,835	351,110	333,035	339,085
6	**Sources - MWh**									
7	Hydro Generation		3,687	4,329	10,247	8,730	9,180	8,730	8,245	8,536
8	Hydro Grid Standby Diesel Generation	S.4.2 L.15	3	70	67	70	41	70	40	41
9	Diesel Generation	S.4.1 L.1 - L.8	21,302	21,057	21,050	21,335	20,623	21,345	20,657	20,755
10	Purchases	S.3.1 L.4	311,886	304,011	300,699	314,125	304,991	320,965	304,093	309,754
11			336,878	329,467	332,063	344,260	334,835	351,110	333,035	339,085
12	**Sources - %**									
13	Hydro Generation		1.1%	1.3%	3.1%	2.5%	2.7%	2.5%	2.5%	2.5%
14	Diesel Generation		6.3%	6.4%	6.4%	6.2%	6.2%	6.1%	6.2%	6.1%
15	Purchases		92.6%	92.3%	90.6%	91.2%	91.1%	91.4%	91.3%	91.3%
16			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Section 4 – Fuel Costs

Overview

The fuel costs included in this Application are outlined in Schedule 4.1 and are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Fuel Costs	6,708	6,760	6,621	5,225	5,268

The forecast fuel cost decrease in 2016 is mainly due lower fuel prices than previously approved which are currently used as the base fuel prices in Rider F.

Please refer to Schedule 4.1 for the details associated with the calculation of fuel costs for 2013 to 2017.

Background

Fuel is purchased on an ongoing basis for each of the five isolated diesel plants operated by ATCO Electric Yukon. ATCO Electric Yukon conducts a diesel fuel tendering process in which a vendor is selected to be the provider of diesel fuel to ATCO Electric Yukon.

ATCO Electric Yukon also has modest generation and fuel requirements associated with standby units at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing. These units generate power in the event of an interruption of power from the Yukon Interconnected System.

Beginning in 2017, a supply of Liquefied Natural Gas (LNG) for the Watson Lake power plant will be competitively sourced. Please refer to Appendix 3, Watson Lake Bi-Fuel Project, for further information regarding the Watson Lake power plant generating electricity with LNG as well as diesel fuel.

Forecasting Fuel Costs

Fuel costs are recorded as the fuel is consumed by the plant.

Fuel costs are a function of forecast sales, line losses, plant efficiencies, and delivered fuel prices.

Line Losses

As outlined in Section 3 and consistent with the approach approved in Board Order 2014-06, line losses have been calculated based on a five-year average.

Plant Efficiencies

Plant efficiencies are based on the average efficiencies of the previous five years adjusted for any changes due to the replacement of units. This approach is consistent with the approach approved in Board Order 2014-06.

Forecasted Fuel Prices

Price forecasts for each community are based on the 2015 actual prices for diesel fuel. The respective fuel prices for each location are shown in Schedule 4.2.

Fuel Price Flow Through

Diesel Fuel Deferral Account

The variance between actual and forecast fuel prices, as outlined in Schedule 4.2, are refunded to, or recovered from, customers through a fuel price flow through and the associated Rider F.

The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or ‘heat rate’, kWh / Litre) and the plant’s monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.

LNG Fuel Deferral Account

As a result of the conversion of the diesel units in Watson Lake to Bi-Fuel (diesel and LNG) beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. ATCO Electric Yukon requires a deferral account to track and subsequently refund or recover changes in costs due to the differential in actual LNG fuel prices and the price included in rates.

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.

The difference between the actual and GRA-approved price per litre of diesel equivalent is then multiplied by the remaining allowable litres of diesel equivalent to arrive at the LNG fuel deferral amount for the month.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Diesel Generation and Fuel Summary
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Total Diesel Generation (in MWh)	S. 4.2 L.16	21,305	21,127	21,117	21,405	20,664	21,415	20,697	20,795
2	Fuel Heat Rate (kWh per litre)		3.73	3.71	3.69	3.71	3.71	3.71	3.71	3.71
3	Litres of Fuel (000s)	S. 4.2 L.33	5,714	5,692	5,719	5,767	5,573	5,770	5,572	5,601
4	Fuel Costs ($000s)		6,668	6,611	7,116	6,701	5,292	6,704	5,225	5,268
5	Fuel Variance		40	-	(356)	-	1,329	-	-	-
6	Fuel Expense	S.1.1 L.8	6,708	6,611	6,760	6,701	6,621	6,704	5,225	5,268
7	Average Cost (cents per litre)	L.4 / L.3	116.71	116.15	124.43	116.18	94.96	116.18	93.78	94.05

ATCO Electric Yukon
2016 - 2017 General Rate Application
Fuel Information

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Average Cost (in cents per litre)									
2	Watson Lake		100.71	101.76	106.90	101.76	76.18	101.76	76.18	76.18
3	Beaver Creek		115.09	116.53	122.80	116.53	92.40	116.53	92.40	92.40
4	Destruction Bay		114.56	115.41	122.68	115.41	91.90	115.41	91.90	91.90
5	Old Crow		220.71	218.44	230.69	218.44	201.71	218.44	201.71	201.71
6	Swift River		107.28	105.63	114.38	105.63	88.72	105.63	88.72	88.72
7	Standby Units		89.92	89.56	106.78	89.56	97.81	89.56	97.81	97.81
8										
9	Generation (MWh)									
10	Watson Lake		15,120	15,085	14,966	15,261	14,534	15,267	14,721	14,795
11	Beaver Creek		1,893	1,800	1,804	1,832	1,829	1,834	1,769	1,786
12	Destruction Bay		1,886	1,826	1,856	1,860	1,789	1,862	1,778	1,703
13	Old Crow		2,199	2,083	2,205	2,114	2,264	2,114	2,180	2,248
14	Swift River		204	263	219	267	207	268	209	223
15	Standby Units		3	70	67	70	41	70	40	41
16		S.4.1 L.1	21,305	21,127	21,117	21,405	20,664	21,415	20,697	20,795
17										
18	Net Heat Rate (kWh/litre)									
19	Watson Lake		3.88	3.78	3.89	3.78	3.89	3.78	3.85	3.85
20	Beaver Creek		3.36	3.59	3.28	3.59	3.49	3.59	3.43	3.43
21	Destruction Bay		3.67	3.58	3.60	3.58	3.54	3.58	3.61	3.61
22	Old Crow		3.42	3.60	3.30	3.60	3.30	3.60	3.40	3.40
23	Swift River		2.55	2.79	2.72	2.79	2.61	2.79	2.68	2.68
24	Standby Units		0.20	3.02	1.45	3.02	1.13	3.02	2.20	2.20
25										
26	Litres Consumed ($000s)									
27	Watson Lake		3,894	3,988	3,851	4,034	3,740	4,036	3,825	3,844
28	Beaver Creek		563	502	540	511	525	512	516	521
29	Destruction Bay		514	510	525	520	505	520	492	472
30	Old Crow		643	578	667	587	687	587	642	662
31	Swift River		80	94	80	96	79	96	78	83
32	Standby Units		19	20	56	20	36	20	18	18
33		S.4.1 L.3	5,714	5,692	5,719	5,767	5,573	5,770	5,572	5,601

Section 5 – Operations and Maintenance Expenses

Overview

Total operations and maintenance expenses included in this Application, as outlined and explained in detail in Schedules 5.1, 5.2 and 5.3, are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Production	1,706	1,677	1,982	2,096	2,041
Distribution	3,145	2,966	3,098	3,285	3,372
General	179	214	215	248	249
Public Information	142	182	117	138	157
Customer Accounting	2,151	2,254	2,067	2,170	2,229
Administration and General	4,395	4,404	4,137	4,056	4,133
Total Operations and Maintenance	11,718	11,698	11,616	11,993	12,181

Forecast Process

ATCO Electric Yukon's forecast process involves a review of business requirements for the provision of safe and reliable electricity service for the test period and the consideration of the best information available at the time the forecast is developed. A separate forecast is developed for labour and non-labour costs.

The table below shows ATCO Electric Yukon's actual operations and maintenance expenses for 2013, 2014 and 2015 as compared to the amounts filed for in the 2013-2015 GRA and those approved by the Board in Board Order 2014-06.

	2013			2014			2015		
	Actual	Filed	Approved	Actual	Filed	Approved	Actual	Filed	Approved
	($000s)								
Production	1,706	2,046	2,017	1,677	2,263	2,085	1,982	2,512	2,201
Distribution	3,145	3,061	2,977	2,966	3,138	3,071	3,098	3,296	3,148
General	179	159	159	214	162	162	215	165	165
Public Information	142	147	143	182	151	147	117	155	151
Customer Accounting	2,151	2,187	2,085	2,254	2,258	2,186	2,067	2,259	2,255
Administration & General	4,395	3,658	4,223	4,404	3,715	4,232	4,137	3,641	4,024
Total O&M	11,718	11,258	11,604	11,698	11,687	11,882	11,616	12,028	11,944

ATCO Electric Yukon's variances between actual operations and maintenance expenses and the amounts as filed were 4.1% for 2013, 0.1% for 2014 and -3.4% for 2015, with a total variance over the three-year test period of 0.2%. The variances between actual operations and maintenance expenses and the Board-approved amounts were 1.0% for 2013, -1.6% for 2014 and -2.8% for 2015, with a total variance over the three-year test period of -1.1%.

Labour Costs

The total labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. These labour costs are then distributed to operations and maintenance accounts or capital accounts depending on the nature of work being performed by the staff in that job class.

Pension Costs

ATCO Electric Yukon has included the following placeholder amounts for 2016 and 2017 for costs related the defined benefit pension plans.

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Defined Benefit	1,041	902	578	578	578
Defined Contribution	209	242	267	276	286
Total Pension Costs	1,250	1,144	845	854	864

In this Application, ATCO Electric Yukon is seeking Board approval to be tied to the outcome of the upcoming ATCO Utilities 2016 Pension Application which will set the 2016 pension expense levels. ATCO Electric Yukon expects the ATCO Utilities 2016 Pension application will be submitted to the Alberta Utilities Commission over the coming months. ATCO Electric Yukon is also seeking continuation of the deferral account currently in place, to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. ATCO Electric Yukon is of the view that this approach achieves regulatory efficiency considering the issue will be fully vetted and tested by the Alberta Utilities Commission.

ATCO Electric Yukon also has a defined contribution pension plan that applies to employees that were hired after January 1, 1997. The company's contribution to the defined contribution plan is 6.0%.

Non-Labour Costs

Non-labour costs are forecast in two parts: (i) ongoing operational and administrative activities, and (ii) new programs or projects. ATCO Electric Yukon is not forecasting any new programs or projects to be included in non-labour costs in this test period.

Since filing the last General Rate Application, ATCO Electric Yukon has a new IT services provider and has included the costs related to IT services under the non-labour category. These costs were previously included under affiliate costs.

Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period. These costs are shown and explained in detail in Schedule 5.2.

Affiliate Costs

ATCO Electric Yukon outsources certain major administrative functions to affiliate companies, such as ATCO Electric, to take advantage of the economies associated with the scope and scale of services available from a larger utility. The costs of these services are detailed in Schedule 5.3 and are based on a fully allocated cost methodology that does not contain any element of profit or return.

Labour support is purchased from ATCO Electric for various services including financial reporting, regulatory support, governance, human resources, health and safety, payroll, IT services, and customer care & billing support.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Operations and Maintenance Expenses
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Production**									
2	62600 - Hydro Generation	S.5.2 L.3	199	310	233	343	261	422	273	265
3	64000 - Supervision and Engineering Diesel		64	60	65	62	66	64	72	74
4	64600 - Diesel Generation	S.5.2 L.11	364	410	413	420	445	431	494	506
5	82600 - Hydro Maintenance		60	48	60	49	62	50	68	85
6	84600 - Diesel Maintenance	S.5.2 L.20	1,020	1,189	907	1,212	1,148	1,235	1,188	1,111
7			1,706	2,017	1,677	2,085	1,982	2,201	2,096	2,041
8	**Distribution**									
9	87000 - Supervision		281	279	305	288	325	297	333	342
10	87100 - Brushing	S.5.2 L.28	420	399	268	408	437	416	414	423
11	87200 - Vehicle Depreciation		(220)	(184)	(206)	(187)	(208)	(191)	(211)	(216)
12	87300 - Maintenance		1,890	1,873	1,989	1,935	1,927	1,984	2,084	2,138
13	87310 - Service to Outside Parties		115	103	108	105	137	107	120	123
14	87400 - Underground Line Maintenance	S.5.2 L.34	156	162	111	167	143	170	150	155
15	87500 - Meter and Meter Testing		189	86	94	89	91	92	94	97
16	87700 - Transformer Repair and Replacement		75	74	47	77	42	79	53	54
17	87800 - Street Light Maintenance	S.5.2 L.40	238	184	252	190	203	194	249	256
18			3,145	2,977	2,966	3,071	3,098	3,148	3,285	3,372
19	**General**									
20	88400 - Communication		19	13	25	13	24	13	25	25
21	88800 - Maintenance Company-Owned Houses		18	17	27	17	46	18	61	59
22	88900 - Maintenance Warehouse and Office	S.5.2 L.46	142	129	162	132	145	134	162	165
23			179	159	214	162	215	165	248	249
24	**Public Information**									
25	70100 - Public Information Administration		21	26	13	27	9	27	15	15
26	70200 - General Public Information	S.5.2 L.54	122	117	169	120	108	124	123	142
27			142	143	182	147	117	151	138	157
28	**Customer Accounting**									
29	71000 - Supervision		48	49	44	51	44	52	46	47
30	71100 - Customer Applications and Service Orders		427	437	432	456	468	467	491	506
31	71200 - Meter Reading		559	526	558	544	599	565	626	645
32	71300 - Customer Billing and Accounting		721	724	774	750	600	775	616	630
33	71400 - Revenue Collections		184	191	197	216	166	222	174	179
34	71500 - Collection of Delinquent Accounts		136	122	130	133	125	137	130	134
35	71800 - Provision for Uncollectible Accounts	S.5.2 L.63	75	36	120	36	65	36	87	89
36			2,151	2,085	2,254	2,186	2,067	2,255	2,170	2,229
37	**Administration and General**									
38	72100 - Administrative	S.5.2 L.73	2,263	2,210	2,282	2,230	1,963	2,078	2,309	2,357
39	72200 - Administrative Corporate		107	135	153	137	131	140	143	146
40	72300 - Insurance		235	262	153	202	90	138	100	102
41	72400 - Injuries & Damages		618	618	618	618	618	618	112	112
42	72500 - Employee Expenses	S.5.2 L.80	273	270	364	276	299	282	337	343
43	72600 - Training and Safety		450	438	469	451	464	464	504	519
44	72700 - Relocation	S.5.2 L.89	241	159	169	162	434	165	366	367
45	72800 - Miscellaneous General		5	0	-	0	-	0	2	2
46	72900 - Audit/Legal Fees & Special Studies		203	132	197	155	139	138	184	187
47			4,395	4,223	4,404	4,231	4,137	4,024	4,056	4,133
48										
49	**Total Operations and Maintenance Expenses**	S.1.1 L.9	11,718	11,604	11,698	11,882	11,616	11,944	11,993	12,181

ATCO Electric Yukon
2016 - 2017 General Rate Application
Operations and Maintenance Expenses
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Actual 2014	Actual 2015	Test Period 2016	Test Period 2017
1	**Production**						
2							
3	62600 - Hydro Generation	S.5.1 L.2	199	233	261	273	265
4							
5	Costs increase from 2013 to 2014 mainly due to higher costs for Fish Lake monitoring						
6	and licence requirements ($31) and inflation ($5).						
7							
8	Costs increase from 2014 to 2015 mainly due to lower vacancy ($24) and inflation ($7).						
9							
10							
11	64600 - Diesel Generation	S.5.1 L.4	364	413	445	494	506
12							
13	Costs increase from 2013 to 2014 mainly due to the full year impact of filling previously vacant						
14	positions ($26) and inflation ($10).						
15							
16	Costs increase from 2015 to 2016 mainly due to the addition of an engineering technologist						
17	position ($40) and inflation ($13).						
18							
19							
20	84600 - Diesel Maintenance	S.5.1 L.6	1,020	907	1,148	1,188	1,111
21							
22	Costs increase in 2014 to 2015 mainly due to more scheduled top end maintenance in 2015						
23	than prior year ($205) and inflation ($23).						
24							
25							
26	**Distribution**						
27							
28	87100 - Brushing	S.5.1 L.10	420	268	437	414	423
29							
30	Costs increase from 2014 to 2015 mainly due to completion of regular brushing program. Prior year						
31	costs were lower due to the availability of resources.						
32							
33							
34	87400 - Underground Line Maintenance	S.5.1 L.14	156	111	143	150	155
35							
36	Costs increase from 2014 to 2015 mainly due to increased maintenance requirements as identified						
37	by regular line patrols, offset by lower overhead costs in 87300.						
38							
39							
40	87800 - Street Light Maintenance	S.5.1 L.17	238	252	203	249	256
41							
42	Cost increase from 2015 to 2016 mainly due to increased streetlight maintenance and						
43	repair activity, based on historical averages as well as inflation.						

ATCO Electric Yukon
2016 - 2017 General Rate Application
Operations and Maintenance Expenses
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Actual 2014	Actual 2015	Test Period 2016	Test Period 2017
44	**General**						
45							
46	88900 - Maintenance Warehouse and Office	S.5.1 L.22	142	162	145	162	165
47							
48	Costs increase from 2013 to 2014 mainly due to additional deficiencies identified at the						
49	warehouse and office facilities that required maintenance.						
50							
51							
52	**Public Information**						
53							
54	70200 - General Public Information	S.5.1 L.26	122	169	108	123	142
55							
56	Costs increase from 2013 to 2014 due to changes required on communication materials and						
57	billing system related to changing "1st Street" to "Front Street" ($28) and for changing the operating						
58	name from "Yukon Electrical Company Ltd." to "ATCO Electric Yukon".						
59							
60							
61	**Customer Accounting**						
62							
63	71800 - Provision for Uncollectible Accounts	S.5.1 L.35	75	120	65	87	89
64							
65	Costs increased from 2013 to 2014 mainly due to the write off of an uncollectible contribution						
66	receivable ($44).						
67							
68	Costs increase from 2015 to 2016 mainly due to the forecast reflecting the historical average cost.						
69							
70							
71	**Administration and General**						
72							
73	72100 - Administrative	S.5.1 L.38	2,263	2,282	1,963	2,309	2,357
74							
75	Costs increase from 2015 to 2016 mainly due to filling previously vacant head office position						
76	($126) and addition of the operational accountant position ($108) as well as inflation ($55)						
77	and additional costs for employee association agreement negotiations ($21).						
78							
79							
80	72500 - Employee Expenses	S.5.1 L.42	273	364	299	337	343
81							
82	Costs increase from 2013 to 2014 mainly due to higher employee service recognition costs and						
83	absence with pay, as well as higher employee benefits.						
84							
85	Costs increase in 2016 mainly due to inflation as well as planned retirement and employee						
86	service recognition costs.						

ATCO Electric Yukon
2016 - 2017 General Rate Application
Operations and Maintenance Expenses
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Actual 2014	Actual 2015	Test Period 2016	Test Period 2017
87	**Administration and General Continued**						
88							
89	72700 - Relocation	S.5.1 L.44	241	169	434	366	367
90							
91	Costs fluctuate year over year from 2013 to 2015 mainly due to relocation requirements to fill						
92	positions that become vacant.						

ATCO Electric Yukon
2016 - 2017 General Rate Application
Affiliate Charges included in Operations and Maintenance Expenses
($000s)

Line No.	O&M Category	Affiliate Company	Services Provided	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Details of Affiliate Costs in Operations and Maintenance											
2	87500 - Meters and Meter Testing	ATCO Electric	Metering Services		33	49	52	50	47	52	48	50
3	87000 - Supervision	ATCO Electric	After Hours - Call Answering		57	62	62	64	58	66	59	61
4	71200 - Meter Reading	ATCO Gas	Meter Services		19	25	23	26	23	27	24	24
5	72100 - Administrative Expenses	ATCO Gas	Office Services		8	8	8	8	6	8	6	6
6	64600 - Diesel Generation	ATCO Gas	LNG Storage and Vapourization Skid		-	-	-	-	-	-	-	-
7	72100 - Administrative Expenses	ATCO I-Tek	Information Technology	Note 1	395	462	246	478	-	494	-	-
8	71300 - Customer Billing and Accounting	ATCO I-Tek (ITBS)	Billing System Services	Note 2	538	546	583	557	-	575	-	-
9	71300 - Customer Billing and Accounting	ATCO Electric	Customer Care & Billing		-	-	-	-	72	-	74	76
10												
11	Details of Head Office Costs											
12	72100 - Administrative Expenses	ATCO Electric	Governance, HR, and Health & Safety		114	137	125	141	142	146	146	150
13	72100 - Administrative Expenses	ATCO Electric	Rates and Terms & Conditions		105	40	12	117	4	42	40	40
14	72100 - Administrative Expenses	ATCO Electric	Financial Reporting and Regulatory Support		588	614	483	636	499	502	561	578
15	72100 - Administrative Expenses	ATCO Electric	Payroll, Use of Systems and IT		45	46	126	47	112	48	115	119
16			Total Head Office Fees		852	837	746	942	756	738	863	887
17												
18	72100 - Administrative Expenses	ATCO Electric	Material Management		2	3	3	3	3	3	3	3
19												
20	Total Affiliate Costs included in Operations and Maintenance				1,905	1,991	1,722	2,127	964	1,963	1,076	1,108

Note 1 - Effective September 1, 2014 ATCO Electric Yukon changed IT service providers.
Note 2 - Effective January 1, 2015 ATCO Electric Yukon changed billing system support providers.

Section 6 – Taxes Other Than Income

Overview

The property taxes included in this Application are:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Property Taxes	273	251	256	262	267

Property Tax

Property taxes are paid to the communities annually for ATCO Electric Yukon's office building, generation facilities, substation properties and power lines. The increases in the forecast over the test period are due to inflation.

Section 7 – Depreciation

Summary

The depreciation expense included in this Application is outlined in Schedules 7.1, 7.2, 7.3, and 7.4 and is:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Depreciation Expense	4,382	4,895	5,412	5,792	6,283

The annual increases in depreciation expense from 2013-2017 are due to growth in property, plant and equipment.

The depreciation rates used to calculate actual 2013 through 2015 and to forecast 2016-2017 depreciation expense were developed using the Board-approved depreciation parameters determined by the Depreciation Study conducted by Gannett Fleming and filed as part for 2013-2015 General Rate Application.

Given the relatively short time period since the last Depreciation Study, ATCO Electric Yukon is proposing to continue with the existing depreciation parameters for this Application's test period. Given there is no update to the depreciation study, ATCO Electric Yukon proposes to continue to fix the annual amount of amortization of accumulated depreciation differences at the level approved in its 2013-2015 General Rate Application.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Schedule of Depreciation Expense
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	General Provision	S. 7.2, 7.3 L.51	4,877	4,997	5,367	5,736	5,915	6,267	6,282	6,775
2	Amortization of Differences	S.7.4 L. 51	(402)	(402)	(402)	(402)	(402)	(402)	(402)	(402)
3	Vehicle Depreciation Capitalized	S.8.6 L. 21	(93)	(75)	(71)	(82)	(101)	(87)	(88)	(90)
4	Total Depreciation Expense	S.1.1 L.11	4,382	4,520	4,895	5,252	5,412	5,778	5,792	6,283

ATCO Electric Yukon
2016 - 2017 General Rate Application
Calculation of Depreciation Expense 2016
($000s)

Line No.	Acct.	Description	Cross Ref.	2016 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2016 Total Depreciation
1		**Production - Hydro**							
2	422 00	Hydro Structures		1,907	2.95%	56	595	9	65
3	423 00	Hydro Resv, Dams & Waterways		2,203	2.42%	53	735	9	62
4	425 00	Hydro Generators		5,153	2.48%	128	1,605	20	148
5	426 00	Hydro Accessory Electrical Equip		-	2.29%	-	-	-	-
6	427 00	Hydro Misc Equip		27	4.28%	1	9	-	1
7		Total Production - Hydro		9,291		238	2,943	38	276
8									
9		**Production - Diesel**							
10	442 00	Structures and Improvements - Other		5,677	2.90%	165	745	11	176
11	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,149	2.96%	93	408	6	99
12	445 00	Generating Equipment & Prime Mover - Other		11,557	3.90%	451	661	13	464
13	446 00	Accessory Electric Equipment - Other		4,367	3.09%	135	531	8	143
14	447 00	Misc. Power Plant Equipment - Other		1,338	2.77%	37	173	2	39
15		Total Production - Diesel		26,089		881	2,518	40	921
16									
17		**Transmission**							
18	457 00	Substation Equipment		1,149	2.04%	23	-	-	23
19		Total Transmission		1,149		23	-	-	23
20									
21		**Distribution Plant**							
22	471 00	Land Rights		1,579	1.50%	24	-	-	24
23	473 00	Poles, Towers & Fixtures		41,563	2.39%	994	2,103	25	1,019
24	474 00	Overhead Conductor		25,676	2.31%	592	1,465	17	609
25	474 10	Services - Overhead		2,758	2.31%	64	194	2	66
26	475 00	Underground Conductor		25,678	2.38%	612	1,596	19	631
27	475 10	Services - Underground		3,277	2.59%	85	202	3	88
28	476 10	Meters		2,739	7.30%	200	103	4	204
29	476 30	AMR - Meters		101	7.06%	7	-	-	7
30	477 10	Substation Equipment		4,904	2.53%	124	306	4	128
31	478 10	Street Lighting		10,452	3.36%	351	575	10	361
32	478 20	Sentinel Lights		286	2.82%	8	-	-	8
33	479 10	Line Transformers		30,815	2.39%	737	253	3	740
34		Total Distribution Plant		149,827		3,798	6,796	87	3,885
35									
36		**General Plant**							
37	482 00	Structures & Improvements		5,063	2.64%	134	94	1	135
38	483 00	Office Furniture & Equipment		237	5.79%	14	11	-	14
39	483 20	Computer Equipment		139	13.58%	19	8	1	20
40	484 00	Transportation & Mobile Equipment		4,344	9.74%	423	93	5	428
41	485 00	Tool & Work Equipment		1,147	6.15%	71	138	4	75
42	486 00	Communication Structures & Equipment		1,207	4.59%	55	117	3	58
43	488 20	Company Housing		361	2.66%	10	-	-	10
44	491 00	Franchise & Consent		1	0.00%	-	-	-	-
45	492 00	Licence - Fish Lake		2,550	4.00%	102	-	-	102
46	493 00	Demand Side Management		389	20.00%	78	534	-	78
47	496 00	Software		2,571	10.00%	257	-	-	257
48		Total General Plant		18,009		1,163	995	14	1,177
49									
50		Plant Studied		204,364		6,103	13,252	179	6,282
51		Plant Not Studied - Land		385					
52		Total Plant	S.8.6 L.10	204,749					

ATCO Electric Yukon
2016 - 2017 General Rate Application
Calculation of Depreciation Expense 2017
($000s)

Line No.	Acct.	Description	Cross Ref.	2017 Opening PPE	Depreciation Rate	Depreciation on Opening Balance	Net Capital Additions	Depreciation on Capital Additions	2017 Total Deprecation
1		**Production - Hydro**							
2	422 00	Hydro Structures		2,501	2.95%	74	204	3	77
3	423 00	Hydro Resv, Dams & Waterways		2,938	2.42%	71	246	3	74
4	425 00	Hydro Generators		6,758	2.48%	168	603	7	175
5	426 00	Hydro Accessory Electrical Equip		-	2.29%	-	-	-	-
6	427 00	Hydro Misc Equip		36	4.28%	2	3	-	2
7		Total Production - Hydro		12,234		315	1,056	13	328
8									
9		**Production - Diesel**							
10	442 00	Structures and Improvements - Other		6,422	2.90%	186	896	13	199
11	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		3,558	2.96%	105	492	7	112
12	445 00	Generating Equipment & Prime Mover - Other		12,218	3.90%	477	1,523	30	507
13	446 00	Accessory Electric Equipment - Other		4,898	3.09%	151	647	10	161
14	447 00	Misc. Power Plant Equipment - Other		1,510	2.77%	42	208	3	45
15		Total Production - Diesel		28,606		961	3,767	63	1,024
16									
17		**Transmission**							
18	457 00	Substation Equipment		1,149	2.04%	23	-	-	23
19		Total Transmission		1,149		23	-	-	23
20									
21		**Distribution Plant**							
22	471 00	Land Rights		1,579	1.50%	24	-	-	24
23	473 00	Poles, Towers & Fixtures		43,666	2.39%	1,045	2,940	35	1,080
24	474 00	Overhead Conductor		27,141	2.31%	626	1,726	20	646
25	474 10	Services - Overhead		2,952	2.31%	68	209	2	70
26	475 00	Underground Conductor		27,274	2.38%	650	1,857	22	672
27	475 10	Services - Underground		3,479	2.59%	90	235	3	93
28	476 10	Meters		2,841	7.30%	208	107	4	212
29	476 30	AMR - Meters		101	7.06%	7	-	-	7
30	477 10	Substation Equipment		5,210	2.53%	132	356	5	137
31	478 10	Street Lighting		11,027	3.36%	370	1,122	19	389
32	478 20	Sentinel Lights		286	2.82%	8	-	-	8
33	479 10	Line Transformers		31,068	2.39%	743	(23)	-	743
34		Total Distribution Plant		156,623		3,971	8,528	110	4,081
35									
36		**General Plant**							
37	482 00	Structures & Improvements		5,157	2.64%	136	301	4	140
38	483 00	Office Furniture & Equipment		248	5.79%	14	11	-	14
39	483.20	Computer Equipment		146	13.58%	20	41	3	23
40	484 00	Transportation & Mobile Equipment		4,438	9.74%	432	145	7	439
41	485 00	Tool & Work Equipment		1,285	6.15%	79	155	5	84
42	486 00	Communication Structures & Equipment		1,324	4.59%	61	161	4	65
43	488 20	Company Housing		361	2.66%	10	-	-	10
44	491 00	Franchise & Consent		1	0.00%	-	-	-	-
45	492 00	Licence - Fish Lake		2,550	4.00%	102	-	-	102
46	493 00	Demand Side Management		923	20.00%	185	-	-	185
47	496 00	Software		2,571	10.00%	257	-	-	257
48		Total General Plant		19,004		1,296	815	23	1,319
49									
50		Plant Studied		217,616		6,566	14,166	209	6,775
51		Plant Not Studied -Land		385					
52		Total Plant	S.8.6 L.10	218,000					

ATCO Electric Yukon
2016 - 2017 General Rate Application
Schedule of Amortization of Differences
($000s)

Line No.	Acct.	Description	Cross Ref.	YFR/ Curve	Life	Net Salvage	Depn. Rates	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1		**Production - Hydro**													
2	422 00	Hydro Structures		R2	72	-10%	3.36%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
3	423 00	Hydro Resv, Dams & Waterways		R3	103	-10%	3.36%	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
4	425 00	Hydro Generators		R3	85	-10%	3.36%	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
5	426 00	Hydro Accessory Electrical Equip		R3	45	-10%	3.36%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
6	427 00	Hydro Misc Equip		R2	30	-10%	3.36%	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
7		Total Production - Hydro						(17)	(17)	(17)	(17)	(17)	(17)	(17)	(17)
8															
9		**Production - Diesel**													
10	442 00	Structures and Improvements - Other		R2.5	40	-10%	2.74%	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)
11	444 00	Fuel Holders, Producers, & Acc. Equipment - Other		R4	35	-20%	3.00%	(8)	(8)	(8)	(8)	(8)	(8)	(8)	(8)
12	445 00	Generating Equipment & Prime Mover - Other		R2.5	26	-10%	3.69%	16	16	16	16	16	16	16	16
13	446 00	Accessory Electric Equipment - Other		R3	35	0%	3.00%	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
14	447 00	Misc. Power Plant Equipment - Other		R3	40	0%	3.15%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
15		Total Production - Diesel						(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
16															
17		**Transmission**													
18	457 00	Substation Equipment		R4	50	-10%	2.55%	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
19		Total Transmission						(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
20															
21		**Distribution Plant**													
22	471 00	Land Rights		R3	75	0%	1.52%	0	0	0	0	0	0	0	0
23	473 00	Poles, Towers & Fixtures		R3	45	-75%	2.67%	(75)	(75)	(75)	(75)	(75)	(75)	(75)	(75)
24	474 00	Overhead Conductor		R4	45	-80%	2.69%	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
25	474 10	Services - Overhead		R3	45	-10%	2.62%	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
26	475 00	Underground Conductor		R3	45	-50%	2.11%	14	14	14	14	14	14	14	14
27	475 10	Services - Underground		R4	40	-10%	2.63%	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
28	476 10	Meters		L0	15	0%	4.06%	60	60	60	60	60	60	60	60
29	476 30	AMR - Meters		R2.5	15	0%	4.54%	1	1	1	1	1	1	1	1
30	477 10	Substation Equipment		R4	40	-10%	2.92%	(16)	(16)	(16)	(16)	(16)	(16)	(16)	(16)
31	478 10	Street Lighting		R3	30	-10%	4.13%	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
32	478 20	Sentinel Lights		R2	23	0%	3.37%	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
33	479 10	Line Transformers		R3	45	-10%	3.04%	(84)	(84)	(84)	(84)	(84)	(84)	(84)	(84)
34		Total Distribution Plant						(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)
35															
36		**General Plant**													
37	482 00	Structures & Improvements		L3	40	0%	3.19%	(15)	(15)	(15)	(15)	(15)	(15)	(15)	(15)
38	483 00	Office Furniture & Equipment		SQ	15	0%	4.49%	8	8	8	8	8	8	8	8
39	483.20	Computer Hardware/Software		SQ	5	0%	20.00%	6	6	6	6	6	6	6	6
40	484 00	Transportation & Mobile Equipment		L0	12	25%	10.82%	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
41	485 00	Tool & Work Equipment		SQ	15	0%	6.54%	4	4	4	4	4	4	4	4
42	486 00	Communication Structures & Equipment		SQ	15	0%	5.79%	4	4	4	4	4	4	4	4
43	488 20	Company Housing		R3	40	10%	2.47%	(72)	(72)	(72)	(72)	(72)	(72)	(72)	(72)
44	491 00	Franchise & Consent					0.00%	-	-	-	-	-	-	-	-
45	492 00	Licence - Fish Lake					10.00%	-	-	-	-			-	-
46	493 00	Demand Side Management						-	-	-				-	-
47	496 00	Software		S3	10	0%	10.00%	-	-	-	-	-	-	-	-
48		Total General Plant						(138)	(138)	(138)	(138)	(138)	(138)	(138)	(138)
49															
50		Total Amortization of Differences	S. 7.1 L. 2					(402)	(402)	(402)	(402)	(402)	(402)	(402)	(402)

Section 8 - Return on Rate Base

Overview

The return on rate base included in this Application is outlined in Schedule 8.1 and is as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Return on Rate Base	5,550	5,782	5,838	6,945	7,400

The increases from 2015 approved to the 2017 forecast is primarily due to growth in rate base as a result of capital additions discussed in Section 9 as well as an increase in the return on equity as discussed below.

The components of the return on rate base are as follows and are discussed below:

- Cost of Capital
  - Capital Structure and Cost of Capital
  - Forecast Long Term Debt Rates
  - No Cost Capital
- Rate Base
  - Capital Additions
  - Contributions
  - Deferred Charges and Credits
  - Working Capital

Cost of Capital

Background

In its 2013-2015 GRA, ATCO Electric Yukon requested its Return on Equity (ROE) be linked to the British Columbia Utility Commission (BCUC) benchmark rate plus a risk premium consistent to that approved in Board Order 2009-02.

In Board Order 2014-06 with respect to the 2013-2015 GRA, the Board reiterated that the precedent and practice is to use a benchmark from another jurisdiction (chiefly British Columbia) and that benchmark is only used to determine the return on equity. The Board also stated in Order 2014-06 that ATCO Electric Yukon had not established a prima facie case to quantify the risk premium over the BCUC benchmark utility and directed ATCO Electric Yukon to provide justification for a risk premium relative to the BCUC Generic Cost of Capital (GCOC) standard as part of its next GRA.

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.

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.

The stand-alone principle is a well-accepted fundamental concept of utility regulation that has been applied by federal and provincial regulatory agencies across Canada. Section 3 of OIC 1995/90 requires the Board to set rates in accordance with the principles established in Canada for utilities, including by regulatory authorities of the

Government of Canada and by provinces regulating hydro and non-hydro electric utilities. Therefore, it is appropriate for the Board to take into account the stand-alone principle and the business risk of ATCO Electric Yukon in the determination of the appropriate ROE premium.

Business Risk Analysis

ATCO Electric Yukon has engaged Concentric Energy Advisors, Inc ("Concentric") to satisfy the Board's direction and determine whether a risk premium relative to the BCUC GCOC would be appropriate, and if so, what that risk premium would be. Consistent with the evidence of Concentric included in Attachment 8.1, ATCO Electric Yukon submits that its ongoing business risks encompass market demand and operational risks. Further, ATCO Electric Yukon's small size and economic and geographic environments expose it to a greater degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.

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.

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.

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.

Based on the above and supported by the expert evidence of Concentric, ATCO Electric Yukon faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore a risk premium is appropriate. As such, Concentric has determined an appropriate risk premium to be 60 basis points.

Requested ROE

In accordance with prior Board direction, ATCO Electric Yukon is requesting to link its ROE for the 2016-2017 test periods to the soon to be determined BCUC GCOC benchmark rate plus a risk premium of 0.6%.

The requested risk premium of 0.6% over the BCUC GCOC benchmark return on equity is supported through the expert evidence of Concentric Energy Advisors.

Common Equity Ratio

ATCO Electric Yukon is seeking continuation of its currently approved common equity ratio of 40% for each 2016 and 2017.

Forecast Long Term Date Rates

ATCO Electric Yukon is forecasting to issue long term debt in the test period. The forecasted debenture rates detailed in the following table are based on the best information available at the time the forecast was prepared. 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.

	2016	2017
Long Canada Bond Rate	1.90% - 2.70%	2.30% - 3.30%
Credit Spread	1.80% - 2.20%	1.80% - 2.20%
Debenture Rate	3.70% - 4.90%	4.10% - 5.50%
Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-In Rate	4.35%	4.85%

The cost of debt includes the weighted average cost of all long term advances from ATCO Electric Yukon's parent company. The cost of issuing the debt is included in the overall embedded costs.

No Cost Capital

The no cost capital included in this Application relates to the balances for deferred pensions including Other Post Employment Benefit ("OPEB") plans as well as the Reserve for Injuries and Damages (RID).

OPEB's are administered on a combined basis with CU Limited, and affiliate corporations to cover such things as drug, health and dental costs for retirees. For these benefits, ATCO Electric Yukon is assessed a percentage of its payroll at a rate calculated for the plan as a whole. Consistent with its last GRA, both the pension plan and OPEB have been accounted for on the cash basis in the test period.

The reserve for injuries and damages is used for uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve mitigates rate fluctuations by smoothing out the charges to O&M with respect to these types of losses. The establishment of the reserve provides financial advantages over paying significantly higher insurance premiums in order to reduce deductibles or to insure items which carry prohibitively high premiums.

Please refer to Attachments 8.2 and 8.3 for a description of the two incidents that have been included in the reserve for injuries and damages over the 2013-2015 period.

ATCO Electric Yukon has included forecast annual charges of $100,000 in the reserve for injuries and damages for the 2016-2017 test periods. ATCO Electric Yukon is proposing to amortize the balance of $23,000 at the end of 2015 as well as the forecast annual charges for the test period over the two test years to bring the overall reserve for injuries and damages to $0 as of December 31, 2017.

The continuity schedule for no cost capital is outlined in Schedule 8.4 and the balances are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
No Cost Capital	165	(24)	446	658	661

Rate Base

Capital Additions

Total capital additions included in Schedule 8.6 and outlined in detail in Section 9 are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Expenditures	15,358	16,837	10,694	15,048	15,318
Capital Additions	14,321	18,849	10,252	14,234	14,907

These additions are primarily driven by a requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their life cycle as well as meet system needs due to load growth.

Please refer to Section 9 for further discussion of capital expenditures.

Contributions

Contributions in aid of construction are received from customers in accordance with the company's investment policy that was approved in Board Order 2010-13. The contributions outlined in Schedule 8.12 are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Contributions in Aid of Construction (per year)	2,153	1,544	1,169	1,804	3,160

ATCO Electric Yukon's forecast process involves a review of projects included in the capital additions outlined in Section 9 to identify those which will require a customer contribution.

Deferred Charges and Credits

The mid-year deferred charges and credit amounts included in rate base are outlined in Schedule 8.8 and are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Mid Year Balance	(322)	149	466	601	366

The deferred charges and credit amounts include the following:

(a) Rate Case Reserve - ATCO Electric Yukon is using a deferral account to flow through to customers the costs associated with filing its GRAs. Please refer to Schedule 8.9 for a breakdown of the costs forecast for 2016-2017 GRA.

(b) Watson Lake Study Costs - ATCO Electric Yukon has incurred $493,000 of study and development costs with respect to the Watson Lake Bi-Fuel project.

ATCO Electric Yukon has included these study costs in its deferred charges accounts for recovery over the test period.

(c) Renewables Feasibility Studies - ATCO Electric Yukon is proposing to include $300,000 in 2016 and another $200,000 in 2017 in its deferred charges account for work it has planned regarding renewable energy feasibility studies over the test period. Please refer to Section 12 of the Application for additional details.

(d) Approved DSM Costs - 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.

(e) Smart Grid Study - ATCO Electric Yukon is seeking approval of costs related to a joint Smart Grid study with Yukon Energy expected to be undertaken in 2017 for $100,000.

(f) Defined Benefit Pension Deferral – ATCO Electric Yukon has included in the deferred charge account the refund over the two year test period related to the over-collection of $154,000 related to the 2014 and 2015 defined benefit pension amounts.

<u>Working Capital</u>

Overview

Working capital is a component of the company's total rate base as generally the payment of expense occurs in advance of the receipt of revenues.

The components of working capital are:

- Purchased Power;
- Operations and Maintenance;
- Income Tax;
- Goods and Services Tax;
- Depreciation Expense;
- Interest Expense;
- Common Equity (retained earnings component);
- Common Equity (dividend component); and
- Material and Supplies Inventory (based on the estimated inventory balance).

To determine the working capital for the 2016-2017 test periods, ATCO Electric Yukon completed a review of the components of each of the items in necessary working capital to ensure that the nature of the revenue/expenses included in each category had not changed materially since the previous lead/lag study. Based on this review, payment dates were updated, which reflect a reduction in lag days from the lag days reported in the previous lead lag study.

The working capital included in rate base in this Application is outlined on Schedule 8.5 with the details on the components incorporating working capital disclosed on Schedule 8.10 and is as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Working Capital	3,322	3,405	3,375	2,964	3,013

The decrease in the forecast working capital requirements over the 2013-2015 actuals is mainly a result of lower operating expenses and a reduction to the O&M lag days.

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Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
1	**2013 Actual**						
2	Long-Term Debt	S.8.2 L.23	43,650	59.40%	41,936	5.91%	2,477
3	Common Stock		29,672	40.38%	28,507	10.78%	3,073
4	No Cost Capital	S.8.4 L.8	165	0.22%	159	0.00%	-
5	Total	S.8.5 L.21 S.1.1 L.14	73,487	100.0%	70,602	7.86%	5,550
6	**2013 Approved**						
7	Long-Term Debt	S.8.2 L.47	43,500	59.89%	43,261	5.91%	2,557
8	Common Stock		29,000	39.92%	28,840	8.75%	2,523
9	No Cost Capital	S.8.4 L.8	137	0.19%	136	0.00%	-
10	Total	S.8.5 L.21 S.1.1 L.14	72,637	100.0%	72,237	7.03%	5,080
11	**2014 Actual**						
12	Long-Term Debt	S.8.2 L.71	52,050	59.93%	49,756	5.70%	2,834
13	Common Stock		34,831	40.10%	33,296	8.85%	2,948
14	No Cost Capital	S.8.4 L.8	(24)	-0.03%	(23)	0.00%	-
15	Total	S.8.5 L.21 S.1.1 L.14	86,857	100.0%	83,030	6.96%	5,782
16	**2014 Approved**						
17	Long-Term Debt	S.8.2 L.96	51,000	60.06%	51,084	5.78%	2,955
18	Common Stock		34,000	40.04%	34,056	8.75%	2,981
19	No Cost Capital	S.8.4 L.8	(92)	-0.11%	(92)	0.00%	-
20	Total	S.8.5 L.21 S.1.1 L.14	84,909	100.0%	85,048	6.98%	5,936

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Line No.	Description	Cross Ref.	Mid Year Balance	Ratio	Mid Year Rate Base	Mid Year Cost Rate	Return
21	**2015 Actual**						
22	Long-Term Debt	S.8.2 L.120	56,125	59.69%	55,505	5.58%	3,095
23	Common Stock		37,464	39.84%	37,049	7.40%	2,743
24	No Cost Capital	S.8.4 L.8	446	0.47%	441	0.00%	-
25	Total	S.8.5 L.21 S.1.1 L.14	94,035	100.0%	92,995	6.28%	5,838
26	**2015 Approved**						
27	Long-Term Debt	S.8.2 L.146	56,400	59.73%	56,542	5.74%	3,245
28	Common Stock		37,600	39.82%	37,695	8.75%	3,300
29	No Cost Capital	S.8.4 L.8	422	0.45%	423	0.00%	-
30	Total	S.8.5 L.21 S.1.1 L.14	94,422	100.0%	94,660	6.91%	6,545
31	**2016 Test Period**						
32	Long-Term Debt	S.8.3 L.25	59,240	59.60%	59,241	5.49%	3,251
33	Common Stock		39,494	39.74%	39,495	9.35%	3,695
34	No Cost Capital	S.8.4 L.8	658	0.66%	658	0.00%	-
35	Total	S.8.5 L.21 S.1.1 L.14	99,392	100.0%	99,394	6.99%	6,945
36	**2017 Test Period**						
37	Long-Term Debt	S.8.3 L.52	63,525	59.63%	63,709	5.38%	3,428
38	Common Stock		42,349	39.75%	42,472	9.35%	3,972
39	No Cost Capital	S.8.4 L.8	661	0.62%	663	0.00%	-
40	Total	S.8.5 L.21 S.1.1 L.14	106,535	100.0%	106,844	6.93%	7,400

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Line No.	**2013 Actual**						**Net Capital Employed**					
	Description	**Series**	**Issue Date**	**Coupon Rate**	**Maturity Date**	**Principal Amount Offered**	**Total Amount**	**Per $100 of Principal Amount**	**Effective Cost Rate**	**Principal Outstanding 31-Dec-13**	**Carrying Cost**	**Average Embedded Cost Rate**
5		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
6		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
7		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
8		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
9		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
10		P	2004-11-18	5.11%	2014	500	500	100.00	5.16%	500	26	
11		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
12		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
13		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
14		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
15		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
16		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
17		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
18		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
19		Y	2013-11-01	4.71%	2053	9,400	9,400	100.00	4.76%	9,400	448	
20	Total					48,350				48,350	2,802	5.79%
21	Prior Year									38,950	2,354	6.04%
22	Total									87,300	5,156	
23	Mid Year									43,650	2,578	5.91%
24												
25	**2013 Approved**						**Net Capital Employed**					
	Description	**Series**	**Issue Date**	**Coupon Rate**	**Maturity Date**	**Principal Amount Offered**	**Total Amount**	**Per $100 of Principal Amount**	**Effective Cost Rate**	**Principal Outstanding 31-Dec-13**	**Carrying Cost**	**Average Embedded Cost Rate**
29		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
30		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
31		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
32		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
33		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
34		P	2004-11-18	5.11%	2014	500	500	100.00	5.16%	500	26	
35		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
36		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
37		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
38		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
39		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
40		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
41		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
42		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
43		Y	2013-11-01	4.71%	2053	9,100	9,100	100.00	4.76%	9,100	433	
44	Total					48,050				48,050	2,787	5.80%
45	Prior Year									38,950	2,354	6.04%
46	Total									87,000	5,142	
47	Mid Year									43,500	2,571	5.91%

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Line No.	**2014 Actual**						**Net Capital Employed**					
	Description	**Series**	**Issue Date**	**Coupon Rate**	**Maturity Date**	**Principal Amount Offered**	**Total Amount**	**Per $100 of Principal Amount**	**Effective Cost Rate**	**Principal Outstanding 31-Dec-14**	**Carrying Cost**	**Average Embedded Cost Rate**
52		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
53		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
54		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
55		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
56		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
57		P	2004-11-18	5.11%	2014	500	500	100.00	5.16%	-	26	
58		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
59		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
60		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
61		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
62		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
63		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
64		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
65		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
66		Y	2013-11-01	4.71%	2043	9,400	9,400	100.00	4.76%	9,400	448	
67		Z	2014-11-01	4.07%	2044	7,900	7,900	100.00	4.12%	7,900	325	
68	Total					56,250				55,750	3,127	5.61%
69	Prior Year									48,350	2,802	5.80%
70	Total									104,100	5,929	
71	Mid Year									52,050	2,965	5.70%
72												
73	**2014 Approved**						**Net Capital Employed**					
	Description	**Series**	**Issue Date**	**Coupon Rate**	**Maturity Date**	**Principal Amount Offered**	**Total Amount**	**Per $100 of Principal Amount**	**Effective Cost Rate**	**Principal Outstanding 31-Dec-14**	**Carrying Cost**	**Average Embedded Cost Rate**
77		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
78		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
79		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
80		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
81		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
82		P	2004-11-18	5.11%	2014	500	500	100.00	5.16%	-	26	
83		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
84		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
85		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
86		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
87		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
88		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
89		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
90		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
91		Y	2013-11-01	4.71%	2053	9,100	9,100	100.00	4.76%	9,100	433	
92		Z	2014-11-01	5.03%	2054	6,400	6,400	100.00	5.08%	6,400	325	
93	Total					54,450				53,950	3,113	5.77%
94	Prior Year									48,050	2,787	5.61%
95	Total									102,000	5,900	
96	Mid Year									51,000	2,950	5.78%

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Line No.												
97	**2015 Actual**						**Net Capital Employed**					
98						**Principal**		**Per $100 of**		**Principal**		**Average**
99			**Issue**	**Coupon**	**Maturity**	**Amount**	**Total**	**Principal**	**Effective**	**Outstanding**	**Carrying**	**Embedded**
100	**Description**	**Series**	**Date**	**Rate**	**Date**	**Offered**	**Amount**	**Amount**	**Cost Rate**	**31-Dec-15**	**Cost**	**Cost Rate**
101		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
102		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
103		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
104		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
105		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
106		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
107		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
108		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
109		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
110		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
111		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
112		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
113		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
114		Y	2013-11-01	4.71%	2043	9,400	9,400	100.00	4.76%	9,400	448	
115		Z	2014-11-01	4.07%	2044	7,900	7,900	100.00	4.12%	7,900	325	
116		AA	2015-11-01	3.95%	2045	750	750	100.00	4.00%	750	30	
117	Total					56,500				56,500	3,131	5.54%
118	Prior Year									55,750	3,127	5.77%
119	Total									112,250	6,259	
120	Mid Year									56,125	3,129	5.58%
121												
122	**2015 Approved**						**Net Capital Employed**					
123						**Principal**		**Per $100 of**		**Principal**		**Average**
124			**Issue**	**Coupon**	**Maturity**	**Amount**	**Total**	**Principal**	**Effective**	**Outstanding**	**Carrying**	**Embedded**
125	**Description**	**Series**	**Date**	**Rate**	**Date**	**Offered**	**Amount**	**Amount**	**Cost Rate**	**31-Dec-15**	**Cost**	**Cost Rate**
126		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
127		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
128		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
129		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
130		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
131		P	2004-11-18	5.11%	2014	500	500	100.00	5.16%	-	26	
132		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
133		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
134		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
135		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
136		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
137		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
138		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
139		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
140		Y	2013-11-01	4.71%	2053	9,100	9,100	100.00	4.76%	9,100	433	
141		Z	2014-11-01	5.03%	2054	6,400	6,400	100.00	5.08%	6,400	325	
142		AA	2015-11-01	5.03%	2055	4,900	4,900	100.00	5.080%	4,900	249	
143	Total					59,350				58,850	3,361	5.71%
144	Prior Year									53,950	3,113	5.77%
145	Total									112,800	6,474	
146	Mid Year									56,400	3,237	5.74%

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Line No.	**2016 Test Period**						**Net Capital Employed**					
	Description	**Series**	**Issue Date**	**Coupon Rate**	**Maturity Date**	**Principal Amount Offered**	**Total Amount**	**Per $100 of Principal Amount**	**Effective Cost Rate**	**Principal Outstanding 31-Dec-16**	**Carrying Cost**	**Average Embedded Cost Rate**
5		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
6		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
7		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
8		N	2002-11-22	6.16%	2017	3,900	3,900	100.00	6.21%	3,900	242	
9		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
10		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
11		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
12		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
13		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
14		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
15		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
16		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
17		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
18		Y	2013-11-01	4.71%	2043	9,400	9,400	100.00	4.76%	9,400	448	
19		Z	2014-11-01	4.07%	2044	7,900	7,900	100.00	4.12%	7,900	325	
20		AA	2015-11-01	3.95%	2045	750	750	100.00	4.00%	750	30	
21		AB	2016-11-01	4.30%	2056	5,480	5,480	100.00	4.35%	5,480	238	
22	Total					61,980				61,980	3,370	5.44%
23	Prior Year									56,500	3,131	5.54%
24	Total									118,480	6,501	
25	Mid Year									59,240	3,251	5.49%
26												
27	**2017 Test Period**						**Net Capital Employed**					
	Description	**Series**	**Issue Date**	**Coupon Rate**	**Maturity Date**	**Principal Amount Offered**	**Total Amount**	**Per $100 of Principal Amount**	**Effective Cost Rate**	**Principal Outstanding 31-Dec-17**	**Carrying Cost**	**Average Embedded Cost Rate**
31		D	1990-11-28	11.85%	2020	1,500	1,500	100.00	11.91%	1,500	179	
32		E	1992-05-08	9.46%	2023	2,500	2,500	100.00	9.51%	2,500	238	
33		K	1999-08-13	6.80%	2019	4,500	4,500	100.00	6.85%	4,500	308	
34		N	2002-11-22	6.16%	2017	-	-	100.00	6.21%	-	-	
35		O	2004-01-23	5.42%	2019	1,000	1,000	100.00	5.47%	1,000	55	
36		Q	2005-11-21	5.18%	2035	4,300	4,300	100.00	5.23%	4,300	225	
37		R	2006-11-20	5.02%	2036	3,000	3,000	100.00	5.07%	3,000	152	
38		S	2008-05-26	5.56%	2028	860	860	100.00	5.61%	860	48	
39		T	2008-05-26	5.57%	2038	1,290	1,290	100.00	5.62%	1,290	72	
40		U	2009-03-06	6.23%	2024	2,900	2,900	100.00	6.28%	2,900	182	
41		V	2009-03-06	6.50%	2039	3,700	3,700	100.00	6.55%	3,700	242	
42		W	2011-10-24	4.53%	2041	5,000	5,000	100.00	4.58%	5,000	229	
43		X	2012-11-01	3.84%	2052	4,000	4,000	100.00	3.89%	4,000	156	
44		Y	2013-11-01	4.71%	2043	9,400	9,400	100.00	4.76%	9,400	448	
45		Z	2014-11-01	4.07%	2044	7,900	7,900	100.00	4.12%	7,900	325	
46		AA	2015-11-01	3.95%	2045	750	750	100.00	4.00%	750	30	
47		AB	2016-11-01	4.30%	2056	5,480	5,480	100.00	4.35%	5,480	238	
48		AC	2017-11-01	4.80%	2057	6,990	6,990	100.00	4.85%	6,990	339	
49	Total					65,070				65,070	3,467	5.33%
50	Prior Year									61,980	3,370	5.44%
51	Total									127,050	6,836	
52	Mid Year									63,525	3,418	5.38%

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity Schedule of No Cost Capital
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**No Cost Capital**									
2	**Deferred Pension and Regulatory Asset/Liability**									
3										
4	**Mid-Year Balance Summary**									
5	Other Post Employment Benefits (OPEB)	L.16	537	537	537	537	537	537	537	537
6	Defined Benefit Pension	L.23	152	152	145	148	137	144	138	130
7	Injuries & Damages	L.30	(524)	(552)	(706)	(777)	(228)	(259)	(17)	(6)
8	**Total No Cost Capital Mid-Year Balance**	S.8.1 L.4,9,14,19, 24,29,34,39	165	137	(24)	(92)	446	422	658	661
9										
10										
11	**Other Post Employment Benefits (OPEB)**									
12	Balance at Beginning of Year		537	537	537	537	537	537	537	537
13	Add: Charges		28	37	30	37	34	37	37	37
14	Less: Cash Payments		(28)	(37)	(30)	(37)	(34)	(37)	(37)	(37)
15	Balance at End of Year		537	537	537	537	537	537	537	537
16	Mid-Year Balance	(L.12+L.15) / 2	537	537	537	537	537	537	537	537
17										
18	**Defined Benefit Pension**									
19	Balance at Beginning of Year		154	154	150	150	140	146	142	134
20	Add: Charges		687	687	435	602	465	602	578	578
21	Less: Cash Payments		(691)	(691)	(445)	(606)	(471)	(606)	(586)	(586)
22	Balance at End of Year		150	150	140	146	134	142	134	126
23	Mid-Year Balance	(L.19+L.22) / 2	152	152	145	148	137	144	138	130
24										
25	**Injuries & Damages**									
26	Balance at Beginning of Year		(69)	(69)	(979)	(1,035)	(433)	(518)	(23)	(12)
27	Add: Write-off	S.10.1 L.7	618	618	618	618	618	618	112	112
28	Less: Costs	S.10.1 L.14	(1,528)	(1,584)	(72)	(100)	(208)	(100)	(100)	(100)
29	Balance at End of Year		(979)	(1,035)	(433)	(518)	(23)	(0)	(12)	-
30	Mid-Year Balance	(L.26+L.29) / 2	(524)	(552)	(706)	(777)	(228)	(259)	(17)	(6)

ATCO Electric Yukon
2016 - 2017 General Rate Application
Computation of Rate Base
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Property, Plant and Equipment**									
2	Year End Balance	S.8.6 L.14	182,133	185,500	196,656	204,217	206,310	217,907	220,376	234,953
3	Deduct:									
4	Accumulated Depreciation	S.8.6 L.25	71,231	70,846	73,399	75,156	77,828	80,177	82,504	88,087
5	Construction-in-Progress	S.9.1 L.35	3,131	1,561	1,119	961	1,561	961	2,375	2,786
6	Total Deductions		74,362	72,407	74,518	76,116	79,389	81,137	84,879	90,872
7	**Net Plant in Service**									
8	Current Year End Balance		107,771	113,093	122,138	128,101	126,921	136,770	135,497	144,081
9	Previous Year End Balance		97,696	97,696	107,771	113,093	122,138	128,101	126,921	135,497
10	Total		205,468	210,789	229,909	241,195	249,059	264,872	262,418	279,578
11	Mid-Year Balance		102,734	105,395	114,955	120,597	124,529	132,436	131,209	139,789
12	Mid-Year Deferred Charges/Credits	S.8.8 L.22	(322)	(368)	149	55	466	401	601	366
13	Working Capital	S.8.10 L.29	3,322	3,275	3,405	3,267	3,375	3,601	2,964	3,013
14	**Gross Rate Base**		105,734	108,302	118,509	123,919	128,370	136,438	134,774	143,168
15	Deduct:									
16	**Contributions in Aid of Construction**									
17	Current Year End Balance	S.8.12 L.11	35,436	37,302	35,521	40,440	35,230	43,117	35,529	37,119
18	Previous Year End Balance		34,828	34,828	35,436	37,302	35,521	40,440	35,230	35,529
19	Total		70,264	72,130	70,957	77,742	70,751	83,557	70,759	72,648
20	Mid-Year Balance		35,132	36,065	35,479	38,871	35,375	41,778	35,380	36,325
21	**Net Rate Base**	S.8.1 L.5,10,15,20, 25, 30, 35, 40	70,602	72,237	83,030	85,048	92,995	94,660	99,394	106,844

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity Schedule of Property, Plant and Equipment
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Property, Plant and Equipment**									
2										
3	Balance at Beginning of Year		165,588	165,588	179,002	183,940	195,537	203,257	204,749	218,001
4										
5	Additions	S.9.1 L.33	14,321	19,792	18,849	20,292	10,252	14,484	13,872	14,907
6	Reclassify from Deferred Charges	S. 8.8 L.61	-	-	-	-	-	-	534	-
7	Retirement and Disposals	S.8.7 L.22	(906)	(1,440)	(2,314)	(975)	(1,040)	(794)	(1,154)	(741)
8		S.7.2, 7.3 L.50	13,415	18,352	16,535	19,317	9,212	13,690	13,252	14,166
9										
10	Balance at End of Year	S.7.2, 7.3 L.52	179,002	183,940	195,537	203,257	204,749	216,947	218,001	232,167
11										
12	Construction-in-Progress	S.9.1 L.35	3,131	1,561	1,119	961	1,561	961	2,375	2,786
13										
14	Total Property, Plant and Equipment	S.8.5 L.2	182,133	185,500	196,656	204,217	206,310	217,907	220,376	234,953
15										
16	**Accumulated Depreciation**									
17										
18	Balance at Beginning of Year		67,891	67,891	71,231	70,846	73,399	75,156	77,828	82,504
19	Reclassify from Deferred Charges		-	-	-	-	-	-	-	-
20	Depreciation Expense	S.7.1 L.4	4,382	4,520	4,895	5,252	5,412	5,778	5,792	6,283
21	Depreciation Capitalized	S.7.1 L.3	93	75	71	82	101	87	88	90
22	Dismantling		(230)	(200)	(483)	(50)	(44)	(50)	(50)	(50)
23	Retirements	S.8.7 L.22	(906)	(1,440)	(2,314)	(975)	(1,040)	(794)	(1,154)	(741)
24										
25	Balance at End of Year	S.8.5 L.4	71,231	70,846	73,399	75,156	77,828	80,177	82,504	88,087
26										
27										
28	**Net Property, Plant and Equipment**		**110,902**	**114,654**	**123,257**	**129,062**	**128,482**	**137,731**	**137,872**	**146,867**

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity Schedule of Capital Retirements by Function
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Generation**									
2	Internal Combustion		(15)	(977)	(846)	(343)	(206)	(369)	(518)	(105)
3	Hydro		(71)	-	(1)	(200)	(49)	-	-	-
4	Other Retirements Less Than $20,000		-	-	-	-	-	-	-	-
5	Total Generation Retirements		(86)	(977)	(846)	(543)	(255)	(369)	(518)	(105)
6										
7										
8	**Distribution**									
9	Poles, Towers & Fixtures		(76)	(80)	(738)	(80)	(160)	(80)	(226)	(226)
10	Line Transformers		(382)	(112)	(385)	(12)	(16)	(12)	(115)	(115)
11	Meters		(51)	(58)	(80)	(127)	(162)	(127)	(97)	(97)
12	Other Retirements Less Than $20,000		(11)	(16)	(20)	(16)	(45)	(16)	(10)	(10)
13	Total Distribution Retirements		(519)	(267)	(1,223)	(235)	(382)	(235)	(448)	(448)
14										
15	**General Plant**									
16	Office Furniture & Equipment		(15)	(32)	-	(32)	(242)	(32)	(9)	(9)
17	Vehicles		(261)	(127)	(245)	(127)	(160)	(120)	(166)	(166)
18	Tool & Work Equipment		(25)	(31)	-	(31)	-	(31)	(11)	(11)
19	Other Retirements Less Than $20,000		(0)	(7)	-	(7)	-	(7)	(1)	(1)
20	Total General Plant Retirements		(301)	(197)	(245)	(197)	(403)	(190)	(187)	(187)
21										
22	**Total Capital Retirements**	S.8.6 L.7	(906)	(1,440)	(2,314)	(975)	(1,040)	(794)	(1,154)	(741)

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity Schedule of Deferred Charges & Credits
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Total Deferred Charges & Credits Summary**									
2										
3	**Write-off Summary**									
4	Rate Case Costs	L. 27	-	-	-	-	-	-	(313)	(313)
5	Watson Lake LNG Study Costs	L. 37	-	-	-	-	-	-	(247)	(247)
6	Pelly Crossing Deferral Account	L. 45	(11)	(11)	(11)	(11)	(11)	(11)	-	-
7	Kluane Wind Study	L. 53	(7)	(7)	(7)	(7)	(6)	(6)	-	-
8	Renewables Feasibility Study	L. 70	-	-	-	-	-	-	(150)	(350)
9	Joint Smart Grid Study	L. 78	-	-	-	-	-	-	-	-
10	Pension Deferral Account	L. 86	-		-	-	-	-	77	77
11	**Total Write-off**	S.1.1 L.13	(18)	(18)	(18)	(18)	(17)	(17)	(632)	(832)
12										
13	**Deferred Credits Mid-Year Balance Summary**									
14	Rate Case Reserve	L. 31	(418)	(402)	(111)	(97)	21	-	176	156
15	Watson Lake LNG Study Costs	L. 40	62	-	123	-	127	-	189	123
16	Pelly Crossing Deferral Account	L. 48	28	28	17	17	6	6	-	-
17	Kluane Wind Study	L. 56	7	7	10	10	3	3	-	-
18	Demand Side Management Program Costs	L. 65	-	-	110	126	309	393	199	-
19	Renewables Feasibility Study	L. 73	-	-	-	-	-	-	75	75
20	Joint Smart Grid Study	L. 81	-	-	-	-	-	-	-	50
21	Pension Deferral Account	L. 89	-	-	-	-	-	-	(39)	(39)
22	**Total Deferred Credits Mid-Year Balance**	S.8.5 L.12	(322)	(368)	149	55	466	401	601	366
23										
24	Rate Case Costs									
25	Balance at Beginning of Year		(611)	(611)	(225)	(193)	4	-	39	313
26	Add: Rate Case Costs	S. 8.9 L.8	386	417	(113)	193	36	-	586	-
27	Less: Rate Case (Write-off) Credit		-	-	-	-	-	-	(313)	(313)
28	Less: Adjustment for Board Order 2014-09		-	-	341	-	-	-	-	-
29	Balance at End of Year		(225)	(193)	4	-	39	-	313	-
30										
31	Mid-Year Balance	(L.25+L.29)/2	(418)	(402)	(111)	(97)	21	-	176	156
32										
33	Watson Lake LNG Study Costs									
34	Balance at Beginning of Year		-	-	123	230	123	246	131	247
35	Add: Costs/AFUDC		123	230	-	16	8	17	-	-
36	Add: Transfers from Plant Additions	S. 9.1 L.35	-	-	-	-	-	-	362	-
37	Less: Write-off		-	-	-	-	-	-	(247)	(247)
38	Balance at End of Year		123	230	123	246	131	263	247	-
39										
40	Mid-Year Balance	(L.34+L.38)/2	62	-	123	-	127	-	189	123
41										
42	Pelly Crossing Deferral Account									
43	Balance at Beginning of Year		33	33	22	22	11	11	-	-
44	Add: Costs		-	-	-	-	-	-	-	-
45	Less: Write-off		(11)	(11)	(11)	(11)	(11)	(11)	-	-
46	Balance at End of Year		22	22	11	11	-	-	-	-
47										
48	Mid-Year Balance	(L.43+L.46)/2	28	28	17	17	6	6	-	-
49										

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity Schedule of Deferred Charges & Credits
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
50	Kluane Wind Study									
51	Balance at Beginning of Year		-	-	13	13	6	6	-	-
52	Add: Costs		20	20	-	-	-	-	-	-
53	Less: Write-off		(7)	(7)	(7)	(7)	(6)	(6)	-	-
54	Balance at End of Year		13	13	6	6	-	-	-	-
55										
56	Mid-Year Balance	(L.51+L.54)/2	7	7	10	10	3	3	-	-
57										
58	Demand Side Management Program Costs									
59	Balance at Beginning of Year		-	-	-	-	220	251	398	-
60	Add: Costs		-	-	220	251	178	283	136	-
61	Less: Transfer to Rate Base								(534)	
62	Less: Write Off								-	-
63	Balance at End of Year		-	-	220	251	398	534	-	-
64										
65	Mid-Year Balance	(L.59+L.63)/2	-	-	110	126	309	393	199	-
66										
67	Renewables Feasibility Study									
68	Balance at Beginning of Year		-	-	-	-	-	-	-	150
69	Add: Costs		-	-	-	-	-	-	300	200
70	Less: Write-off		-	-	-	-	-	-	(150)	(350)
71	Balance at End of Year		-	-	-	-	-	-	150	-
72										
73	Mid-Year Balance	(L.68+L.71)/2	-	-	-	-	-	-	75	75
74										
75	Joint Smart Grid Study									
76	Balance at Beginning of Year		-	-	-	-	-	-	-	-
77	Add: Costs		-	-	-	-	-	-	-	100
78	Less: Write-off		-	-	-	-	-	-	-	-
79	Balance at End of Year		-	-	-	-	-	-	-	100
80										
81	Mid-Year Balance	(L.76+L.79)/2	-	-	-	-	-	-	-	50
82										
83	Pension Deferral									
84	Balance at Beginning of Year		-	-	-	-	-	-	-	(77)
85	Add: Costs		-	-	-	-	-	-	(154)	-
86	Less: Write-off		-		-	-	-	-	77	77
87	Balance at End of Year		-	-	-	-	-	-	(77)	-
88										
89	Mid-Year Balance	(L.84+L.87)/2	-	-	-	-	-	-	(39)	(39)

ATCO Electric Yukon
2016 - 2017 General Rate Application
Rate Case Costs
($000s)

Line No.	Description	Cross Ref.	Test Period 2016	Test Period 2017
1	**Phase I**			
2	Legal Expenses		119	-
3	Cost of Capital Expert		113	-
4	ATCO Electric Disbursements		1	-
5	Yukon Electrical Disbursements		12	-
6	Intervener Costs		108	-
7	Board Costs		233	-
8	**Total Costs**	S. 8.8 L. 26	586	-

ATCO Electric Yukon
2016 - 2017 General Rate Application
Computation of Allowance for Working Capital
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Operations and Maintenance	S.1.1 L.9	11,718	11,604	11,698	11,882	11,616	11,944	11,993	12,181
2	Purchase Power	S.1.1 L.7	31,270	24,858	31,177	26,066	30,373	26,634	24,756	25,250
3	Diesel Fuel	S.1.1 L.8	6,708	6,611	6,760	6,701	6,621	6,704	5,225	5,268
5	Property Taxes	S.1.1 L.10	273	257	251	265	256	273	262	267
6	Net O&M		49,969	43,330	49,885	44,914	48,866	45,554	42,235	42,966
7	O&M Lag Days		7	7	7	7	7	7	4	4
8	Operating Expenses Working Capital		958	831	957	861	937	874	481	490
9	Tax Installments		0	0	0	0	0	160	0	0
10	Income Tax Installment Lag Days		22	22	22	22	22	22	22	22
11	Tax Installments Working Capital		0	0	0	0	0	10	0	0
12	Income Taxes Receivable (Payable)		0	416	0	256	0	103	0	0
13	Tax Receivable Lag Days		204	204	204	204	204	204	204	204
14	Taxes Payable Working Capital		0	233	0	143	0	58	0	0
15	Inventory (Three-Year Average)		2,081	1,938	2,141	1,938	2,147	1,938	2,123	2,123
16	GST Impact on Working Capital	S.8.11 L.36	149	152	162	165	134	144	137	140
17	Return - Long Term Debt		2,477	2,557	2,834	2,955	3,095	3,245	3,251	3,428
18	Combined Long Term Debt Lag Days		(52)	(52)	(52)	(52)	(52)	(52)	(52)	(52)
19	Long Term Debt Working Capital		(353)	(364)	(404)	(421)	(441)	(462)	(463)	(488)
20	Return - 50% of Common Equity		1,537	1,262	1,474	1,491	1,372	1,650	1,847	1,986
21	Dividend Lag Days		(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
22	Common Equity (Dividend) Working Capital		(17)	(14)	(16)	(16)	(15)	(18)	(20)	(22)
23	Return - 50% of Common Equity		1,537	1,262	1,474	1,491	1,372	1,650	1,847	1,986
24	Depreciation Lag Days		42	42	42	42	42	42	42	42
25	Common Equity (Retained Earnings) Working Capital		177	145	170	172	158	190	213	229
26	Net Depreciation		2,837	3,076	3,436	3,695	3,952	4,029	4,287	4,713
27	Depreciation Lag Days		42	42	42	42	42	42	42	42
28	Depreciation Working Capital		326	354	395	425	455	464	493	542
29	Working Capital	S.8.5 L.13	3,322	3,275	3,405	3,267	3,375	3,601	2,964	3,013

ATCO Electric Yukon
2016 - 2017 General Rate Application
Effect of GST on Working Capital
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**REVENUE:**									
2	Total Operating Revenue Subject to GST	S.2.1 L.54	56,310	49,812	57,687	53,473	57,476	55,183	52,566	54,844
3	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
4	GST Billable		2,815	2,491	2,884	2,674	2,874	2,759	2,628	2,742
5										
6	Day Factor - Revenues		41.9	41.9	41.9	41.9	41.9	41.9	41.9	41.9
7	Day Factor - Remittance Lag		56.6	56.6	56.6	56.6	56.6	56.6	56.6	56.6
8			(14.7)	(14.7)	(14.7)	(14.7)	(14.7)	(14.7)	(14.7)	(14.7)
9										
10	GST Impact on Working Capital Increase/(Decrease)	(L.4*L.8)/365	(114)	(101)	(117)	(108)	(116)	(111)	(106)	(111)
11										
12	**EXPENSES:**									
13	Total Utility Expenses	S.1.1 L.16	57,660	51,089	59,002	54,722	58,747	56,458	53,865	56,172
14	Property Taxes	S.1.1 L.10	(273)	(257)	(251)	(265)	(256)	(273)	(262)	(267)
15	Labour and Fringe		(5,994)	(5,929)	(5,947)	(6,208)	(6,209)	(6,412)	(6,333)	(6,460)
16	Depreciation	S.1.1 L.11	(4,382)	(4,520)	(4,895)	(5,252)	(5,412)	(5,778)	(5,792)	(6,283)
17	Amortization of Contributions	S.1.1 L.12	1,545	1,444	1,459	1,557	1,460	1,749	1,504	1,570
18	Income Tax	S.1.1 L.15	(714)	(416)	(120)	160	74	313	(235)	261
19	Injuries & Damages Costs		(1,528)	(1,584)	(72)	(100)	(208)	(100)	(100)	(100)
20	Injuries & Damages Write-off		618	618	618	618	618	618	112	112
21	Rate Case Costs		386	417	(113)	193	36	-	586	-
22	Rate Case Write-off		-	-	-	-	-	-	(313)	(313)
23	Other Deferrals and Studies Costs	S.8.8 L.35,44,52,69,77	143	250	-	16	8	17	300	300
24	Other Deferrals and Studies Write-off	S.8.8 L.37,45,53,70,78	(18)	(18)	(18)	(18)	(17)	(17)	(397)	(597)
25	Capital Expenditures	S.9.1 L.28	15,358	19,259	16,837	19,692	10,694	14,484	15,048	15,318
26	Net Costs Subject to GST		62,801	60,352	66,500	65,116	59,535	61,060	57,984	59,713
27	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
28	GST Refundable		3,140	3,018	3,325	3,256	2,977	3,053	2,899	2,986
29										
30	Day Factor - Expense (Including Capital)		26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
31	Day Factor - Remittance Lag		56.6	56.6	56.6	56.6	56.6	56.6	56.6	56.6
32			30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
33										
34	GST Impact on Working Capital Increase/(Decrease)	(L.28*L.32)/365	263	253	279	273	250	256	243	250
35										
36	Net Impact of GST on Working Capital	S.8.10 L.16	149	152	162	165	134	144	137	140

ATCO Electric Yukon
2016 - 2017 General Rate Application
Continuity Schedule of Contributions in Aid of Construction
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Contributions in Aid of Construction**									
2	Prior Year Gross Contributions		54,075	54,075	56,094	57,851	57,091	62,404	58,177	59,727
3	Additions to Property		2,153	3,918	1,544	4,695	1,169	4,426	1,804	3,160
4	Retirements		(134)	(142)	(547)	(142)	(83)	(142)	(255)	(255)
5	Current Year Gross Contributions		56,094	57,851	57,091	62,404	58,177	66,688	59,727	62,632
6	**Accumulated Amortization**									
7	Prior Year Accumulated Amortization		19,247	19,247	20,658	20,549	21,570	21,964	22,948	24,197
8	Gross Amortization	S.1.1 L.12	1,545	1,444	1,459	1,557	1,460	1,749	1,504	1,570
9	Retirements		(134)	(142)	(547)	(142)	(83)	(142)	(255)	(255)
10	Current Year Accumulated Amortization		20,658	20,549	21,570	21,964	22,948	23,571	24,197	25,513
11	**Net Contributions in Aid of Construction**	S.8.5 L.17	35,436	37,302	35,521	40,440	35,230	43,117	35,529	37,119

PREPARED FOR:
ATCO ELECTRIC YUKON

PRESENTED TO:
YUKON UTILITIES BOARD

MAY 10, 2016

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I. INTRODUCTION

A. Qualifications

My name is James M. Coyne, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Senior Vice President. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752. I am testifying on behalf of ATCO Electric Yukon ("AEY" or the "Company"), a wholly-owned subsidiary of ATCO Electric Ltd.

I am among Concentric's professionals who provide expert testimony before federal, state and Canadian provincial agencies on matters pertaining to economics, finance, and public policy in the energy industry. Concentric provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. I regularly advise utilities, generating companies, public agencies and private equity investors on business issues pertaining to the utilities industry. This work includes calculating the cost of capital for the purpose of ratemaking, and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, capital costs, demand side management, low-income programs, fuels and power markets. I have testified or provided expert evidence in state, provincial and federal jurisdictions in Canada and the U.S. This work has been provided on behalf of utilities, regulatory commissions, and staff.

I am also a frequent speaker and author of articles and white papers on the energy industry. Recently, on behalf of the Canadian Gas Association and the Canadian Electric Association, I prepared a discussion paper for utility executives and provincial regulators that examined the roles that Canada's utilities and regulators can play to promote innovation. In addition, I facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white papers to facilitate further discussion on emerging industry issues. In collaboration with the Canadian Gas and Canadian Electricity Associations, I also publish a newsletter summarizing allowed ROEs and capital structures for gas and electric utilities in Canada and the U.S. I have been an invited speaker for several CAMPUT events, including the recent Energy Regulation Course at Queen's University where I spoke on "Innovations in Utility Business Models and Regulation".

Prior to joining Concentric, I was Senior Managing Director in the Corporate Economics Practice for FTI/Lexecon, and Managing Director for Arthur Andersen's Energy & Utilities Corporate Finance Practice. In those positions, I provided expert testimony and advisory services on mergers, acquisitions, divestitures and capital markets for clients in the energy industry. In addition to the foregoing positions, I was also Managing Director for Navigant Consulting, with responsibility for the firm's Financial Services practice, Director in DRI's Electric and Natural Gas practices, and Senior Economist for the Massachusetts Energy Facilities Siting Council, where I analyzed the supply plans and facilities proposals from the state's electric and gas utilities. I also served as State Energy Economist for the Maine Office of Energy Resources. I hold a B.S. in Business Administration from Georgetown University and a M.S. in Resource Economics from the University of New Hampshire. My qualifications are detailed more fully in Attachment 1.

B. Purpose

AEY has retained Concentric to provide an assessment of the risk of AEY in relation to other electric and gas distribution utilities, and to determine whether this assessment indicates that AEY's business and financial risks justify a risk premium, and, if so, to quantify an appropriate risk premium for AEY. As discussed below, the Yukon Utilities Board (the "Board") has previously expressed its preference for using a benchmark utility from another jurisdiction (chiefly British Columbia) in order to determine the return on equity for AEY.[1] Concentric's risk assessment compares:

1) The business and financial risk of AEY to FortisBC Energy, the benchmark utility in British Columbia, as well as other regulated electric and gas distribution utilities in Canada; and

2) The business and financial risk of AEY today to the Company's risk profile at the time of the Company's 2008 GRA filing, when the Board determined that a 46 basis point risk premium was justified.

[1] See, for example, Board Order 2014-06 – Appendix A: Reasons for Decision, issued April 23, 2014, at 50.

C. Background

In previous decisions,[2] the Board has set out three questions that need to be answered in relation to applicable generic cost-of-capital methods and risk premiums:

1) Which generic cost-of-capital model should be used and from which jurisdiction?

2) Should a risk premium be applied?

3) What risk premium should be applied to AEY?

In Board Order 2014-06, the Board found that AEY (formerly known as Yukon Electrical Company Ltd.) had not provided sufficient evidence to justify a risk premium over the British Columbia Utilities Commission's ("BCUC") benchmark utility, FortisBC Energy.[3] For that reason, the Board directed AEY to use an ROE of 8.75 percent, which was the ROE authorized by the BCUC for the benchmark utility. The Board further directed AEY to provide justification for a risk premium relative to the BCUC's Generic Cost of Capital standard in its next General Rate Application ("GRA").[4]

In Board Order 2009-02, the Board made the following findings with regard to the risk premium for AEY:[5]

1) The Board directs that the BCUC generic cost of capital is the most appropriate as it has been the most recently reviewed, and is generally accepted by the parties;

2) The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities; and

---

2 *Ibid.*

3 *Ibid*, at 51.

4 *Ibid*.

5 Appendix A to Board Order 2009-02 – Reasons for Decision, at 29.

3) The Board finds it reasonable to place the risk premium for YECL (now known as AEY) at the midpoint of the risk premiums for Yukon Energy Corporation and FortisBC (the electric utility) – at 46 basis points.

D. Executive Summary

Figure 1 shows the currently allowed ROEs and equity ratios for selected Canadian electric and gas utilities and the average for electric transmission and distribution utilities in the U.S., as well as my assessment of the relative risk of AEY to the group of Canadian comparators.

Figure 1: Allowed ROEs and Equity Ratios

	Allowed ROE	Equity Ratio	Risk Compared to AEY
ATCO Electric Yukon	8.75%	40.0%	N/A
Canadian Electric & Gas Utilities			
FortisBC Energy	8.75%	38.5%	Lower
FortisBC Electric	9.15%	40.0%	Lower
Newfoundland Power	8.80%	45.0%	Lower
Maritime Electric Company Ltd	9.35%	40.9%	Similar
ATCO Electric Distribution	8.30%	38.0%	Lower
Pacific Northern Gas-West	9.50%	46.5%	Higher
2014-2016 U.S. Electric Utilities			
Electric T&D Utilities	9.41%	49.4%	Lower

The 2016 Generic Cost of Capital proceeding is currently underway in British Columbia and a decision is expected by July 2016. The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY. As a gas distributor, FortisBC Energy owns its regulated gas distribution system, whereas AEY owns the electric distribution system and some generation facilities. 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. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity, while AEY currently has the same ROE and a slightly higher equity ratio of 40 percent.

Among the group of distribution utilities in Figure 1, only PNG-West has higher business risk than AEY. PNG-West was awarded a risk premium of 75 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding.[6] PNG-West also has 46.5 percent deemed common equity, as compared to AEY's 40 percent common equity ratio. PNG-West is 16 percent larger than AEY in terms of retail customers served, and PNG-West's rate base is approximately 67 percent greater than AEY's. The BCUC determined in the GCOC Stage 2 proceeding that PNG-West had higher risk with respect to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012).[7] 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.

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. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk.

AEY's generation profile and customer mix is more comparable to Newfoundland Power, which supplies about 7 percent of its load requirements through company-owned regulated generation assets and also serves only residential and commercial customers. Newfoundland Power has 15X more retail electric customers, and its rate base is approximately 12X greater than AEY's. 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.

[6] BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014, at 113.

[7] Ibid, at 102.

Newfoundland Power's currently allowed ROE is 8.80 percent, with a deemed equity ratio of 45 percent, as compared to 40 percent for AEY.

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.

ATCO Electric Distribution is purely a distribution utility that does not own generation. ATCO Electric Distribution is approximately 13X larger than AEY in terms of customers served and 23X larger in terms of 2014 rate base. ATCO Electric Distribution operates under an incentive regulation framework, as opposed to the cost of service regime for AEY. In 2015, the AUC reduced the allowed ROE for all electric and gas utilities in Alberta from 8.75 percent to 8.30 percent. The 2016 Generic Cost of Capital proceeding is currently under way before the Alberta Utilities Commission with a decision expected later this year. 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.

Based on my research and analysis, an ROE risk premium between 40 and 75 basis points is appropriate for AEY as compared to the BCUC benchmark utility. This range is framed by FortisBC Electric on the lower end and by PNG-West on the upper end in relation to the benchmark, FortisBC Energy. From within that range, a ROE risk premium for AEY of 60 basis points is reasonable because it would be consistent with the recent 9.35 percent ROE award for Maritime Electric, a company with similar business risk as AEY and a deemed equity ratio of 40.9 percent.

II. KEY REGULATORY PRECEDENTS FOR THE DETERMINATION OF A FAIR RETURN

A. The Fair Return Standard

The principles surrounding the concept of a "fair return" for a regulated company were first established by the Supreme Court of Canada in Northwestern Utilities v. City of Edmonton (1929) ("Northwestern"), where the Supreme Court found:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[8]

Similar precedent may be found in the United States common law in landmark cases such as *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (262 U.S. 679, 693 (1923)) and *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591, 603 (1944)).

The Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the National Energy Board ("NEB") summarized its interpretation of the "fair return standard" in its RH-2-2004 Phase II Decision and more recently reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> The Board is of the view that the fair return standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

[8] *Northwestern*, at p. 186.

> In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.[9]

As observed by the Ontario Energy Board ("OEB") in its 2009 Generic Cost of Capital Order, all three requirements of the Fair Return Standard must be met, and none ranks in priority to the others.

> The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.[10]
>
> ***
>
> … all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate comparability to the comparable investment test is not sufficient to meet the [Fair Return Standard].[11]

The assessment of whether the Fair Return Standard has been met requires an examination of the required returns by investors in comparable risk enterprises. Investors must consider whether there are alternative investment opportunities that would provide a better return for the same risk. This weighing of alternatives and the highly competitive nature of capital markets causes stocks and bonds to settle on a price that provides investors with a return that is adequate for the risks involved. Thus, for any given level of risk, there is a corresponding return that investors expect in order to take on that risk and not invest their money elsewhere. That return is referred to as the "opportunity cost" of capital or "investor required" return.

---

9 National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, at p. 17.

10 Ontario Energy Board, EB-2009-084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, at i.

11 *Ibid*, at p. 19.

In addition to setting the fair return at the "opportunity cost" of capital, a fair return must also be adequate to maintain the financial integrity of the utility, which requires a return sufficient to maintain credit metrics such that the utility can sustain a favorable credit rating in order to minimize debt costs and provide lenders assurance that the company's earnings are adequate to meet its fixed obligations. Finally, a fair return must be sufficient to attract incremental capital on reasonable terms and conditions, to the benefit of both investors and customers.

B. The Stand-Alone Principle

The stand-alone principle provides that the utility must be regulated as if it were a stand-alone entity. In this way, capital may be efficiently allocated, with each business segment earning a return based on its own unique set of risks and business characteristics regardless of affiliations within the holding company structure. In order to establish a fair return and satisfy the stand-alone principle, the utility must be allowed a return sufficient to meet all three requirements of the Fair Return Standard on the basis of the utility's individual merits.

The stand-alone principle is commonly recognized among Canadian regulators. For example, in the 2014 Generic Cost of Capital (Stage 2) Decision, the BCUC stated:

> In its Stage 1 Decision, the Commission acknowledged the long history and importance of the stand-alone principle in Canadian utility regulation. The Panel found no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility.[12]

The Alberta Utilities Commission ("AUC") also has recognized the stand-alone principle in previous cost of capital decisions. For example, in the 2009 Generic Cost of Capital Decision, the AUC stated: "As a result, some utilities argued, they are not attracting equity capital on their own merit, and this is contrary to the stand-alone principle the Commission has embraced."[13]

AEY is 100 percent owned by ATCO Electric, which in turn is a wholly-owned subsidiary of Canadian Utilities Inc. ("CUI"). CUI raises debt on behalf of AEY and through ATCO Electric provides equity capital to AEY mirrored down from ATCO Electric and CUI. CUI's long-term

[12] BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014, at 6.
[13] AUC D-2009-216, 2009 Generic Cost of Capital, November 12, 2009, at 14.

issuer rating from Standard and Poor's is A, with a negative outlook as of July 7, 2015. Debt raised by CUI is also mirrored down to the individual ATCO Utilities, including AEY, at the cost incurred by CUI. AEY's customers, therefore, receive the benefits of CUI's credit ratings. As a stand-alone entity, AEY would not be able to issue debt in public markets and likely would not be able to obtain investment grade credit ratings given its small size. The estimate of a reasonable ROE risk premium for AEY should take into consideration the benefits and cost savings that AEY customers receive through AEY's ability to access debt and equity capital through CUI instead of on its own.

C. The Relationship Between Capital Structure and ROE

The cost of common equity depends in part on the company's capital structure. The equity ratio and equity rate of return must therefore be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate shareholders for the additional financial risks. Consequently, when a regulator approves a capital structure, that decision impacts the required rate of return on common equity.

The risk to the earnings stream of the company is a function of both its business and financial risk. Business risk refers to the political and regulatory environment that the company operates within and the operational and competitive forces that could potentially exert pressure on earnings. Financial risk refers to the amount of debt in the utility's capital structure and the extent to which fixed debt obligations must be met before utility shareholders receive their returns. Both business and financial risks therefore need to be considered when setting the capital structure.

III. ECONOMIC AND CAPITAL MARKET CONDITIONS

A. Economic Conditions and Outlook in Canada

Weak oil prices and the weaker-than-expected U.S. recovery led to a contraction in the Canadian economy in the first two quarters of 2015 and overall economic growth in 2015 of just 1.2

percent, the weakest since 2009.[14] As of March 2016, economic growth in Canada has resumed albeit at somewhat lower than normal levels, and unemployment rates have declined since the previous recession. The Bank of Canada acknowledges that much of the world, including Canada, continues to be highly dependent on monetary policy that is intended to stimulate the economy through interest rates that are near historic lows. In this environment of accommodative monetary policy, equity indexes are near all-time highs, while volatility in financial markets has increased since August 2015.

The Bank of Canada predicts that monetary policy will begin to normalize in advanced economies, and interest rates are projected to rise. The Bank sees risks to the Canadian economy arising from an abrupt increase in global risk premiums, the slowdown in the Chinese economy, a real estate market correction, slower growth in investment spending, and the impact of prolonged weakness in commodity prices.[15] The Bank predicts that the U.S. economic recovery will continue to strengthen and lead the global recovery; however, stalled growth in China and the Euro area may serve as a drag on the Canadian economy.

The Conference Board of Canada adopts a somewhat similar view. Economic conditions in Canada are expected to weaken in 2016 as plummeting oil prices have a significant negative impact on the Canadian economy. In addition to low oil prices, economic growth will also be affected by a weakening of consumer spending. Meanwhile, the depreciation of the Canadian dollar has not spurred growth in other sectors, such as manufacturing and exports, as was previously anticipated.[16] Though low oil prices provide a benefit to Canadian consumers, the negative impact on the Canadian oil industry more than offsets these gains.

The U.S. continues its economic recovery at a steady, but uneven pace. Overall GDP growth in 2015 was 2.4 percent,[17] and Blue Chip forecasts 2016 growth at 2.1 percent[18]. U.S. consumer

[14] The Conference Board of Canada, Provincial Outlook Executive Summary, Winter 2016, at 1-2.

[15] Bank of Canada, Financial System Review December 2015, at 1-3.

[16] The Conference Board of Canada, Provincial Outlook Executive Summary, Winter 2016, at 1-2.

[17] U.S. Bureau of Economic Analysis, "National Income and Product Accounts - Gross Domestic Product: Fourth Quarter and Annual 2015 (Third Estimate)," news release (March 25, 2016), http://www.bea.gov/newsreleases/national/gdp/2016/gdp4q15_3rd.htm.

[18] Blue Chip Financial Forecast, Volume 35, Issue No. 3, March 1, 2016, at 2.

spending has benefited from a drop in fuel prices, with the price of West Texas Intermediate now in the $40/barrel range, after dropping from over $100/barrel. The U.S. economic recovery is also reflected in an improving job market, with the unemployment rate at 4.9 percent in February 2016, down from 5.5 percent a year earlier.[19] The strong U.S. dollar and a European economic downturn may negatively affect U.S. exports, but the loss from declining exports has thus far been more than offset by the savings on oil imports due to lower oil prices.

B. Economic Conditions and Outlook in Yukon

According to the Department of Economic Development for the Yukon Government, Yukon is a prime example of a small economy that can be rapidly influenced by outside events.[20] In 2015, real GDP was expected to contract for the third consecutive year, decreasing by 6 percent due in large part to a significant decline in mineral production. The weaker economy was expected to negatively impact the performance of Yukon's labor market, contributing to an increase in the unemployment rate to 6.7 percent. Furthermore, retail sales in 2015 were expected to fall, and consumer prices in Whitehorse (the capital and largest town) were projected to decline by 0.6 percent.[21]

The outlook for 2016 is for a return to real GDP growth of 3.5 percent, primarily related to an expected increase in mineral production; population growth of 1.0 percent; a further increase in the unemployment rate to 7.5 percent; an increase in retail sales back to 2014 levels; and an increase in consumer prices of approximately 2.2 percent in Whitehorse.[22] Yukon's economy is highly dependent on mining and tourism, both of which are cyclical industries. The forecast notes that Yukon's economy is linked to the performance of the global mineral industry mineral prices. If mineral prices remain depressed, Yukon's mining sector would be negatively impacted, which would weigh on Yukon's growth prospects for 2016 and beyond.[23]

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19 Bureau of Labor Statistics, The Employment Situation, February 2016, Table A-10.

20 Yukon Economic Outlook, Department of Economic Development – Yukon Government, October 2015, at 2.

21 *Ibid*, at 3.

22 *Ibid*, at 4.

23 *Ibid*, at 8.

Figure 2 compares Yukon to Canada on a number of key macroeconomic indicators from 2013 through 2016.

Figure 2: Key Economic Indicators[24]

Economic Indicator	Yukon 2013	Yukon 2014	Yukon 2015	Yukon 2016
GDP Growth	1.0%[25]	(1.2%)	(6.0%)	3.5%
Population Growth	1.9%	1.7%	0.6%	1.0%
Unemployment Rate	5.4%	4.3%	6.7%	7.5%
Retail Sales	(2.5%)	1.3%	(2.6%)	2.8%
Consumer Prices	1.6%	1.3%	(0.6%)	2.2%
	Canada 2013	**Canada 2014**	**Canada 2015**	**Canada 2016**
GDP Growth	2.0%	2.4%	0.8%	2.5%
Population Growth	1.2%	1.1%	0.9%	1.0%
Unemployment Rate	7.1%	6.9%	6.9%	7.0%
Retail Sales	3.2%	4.6%	2.2%	3.4%
Consumer Prices	0.9%	2.0%	1.1%	2.0%

Recognizing that Yukon is recovering from three years of subpar economic performance, the projected 2016 economic indicators shown in Figure 2 must be taken with a degree of caution.

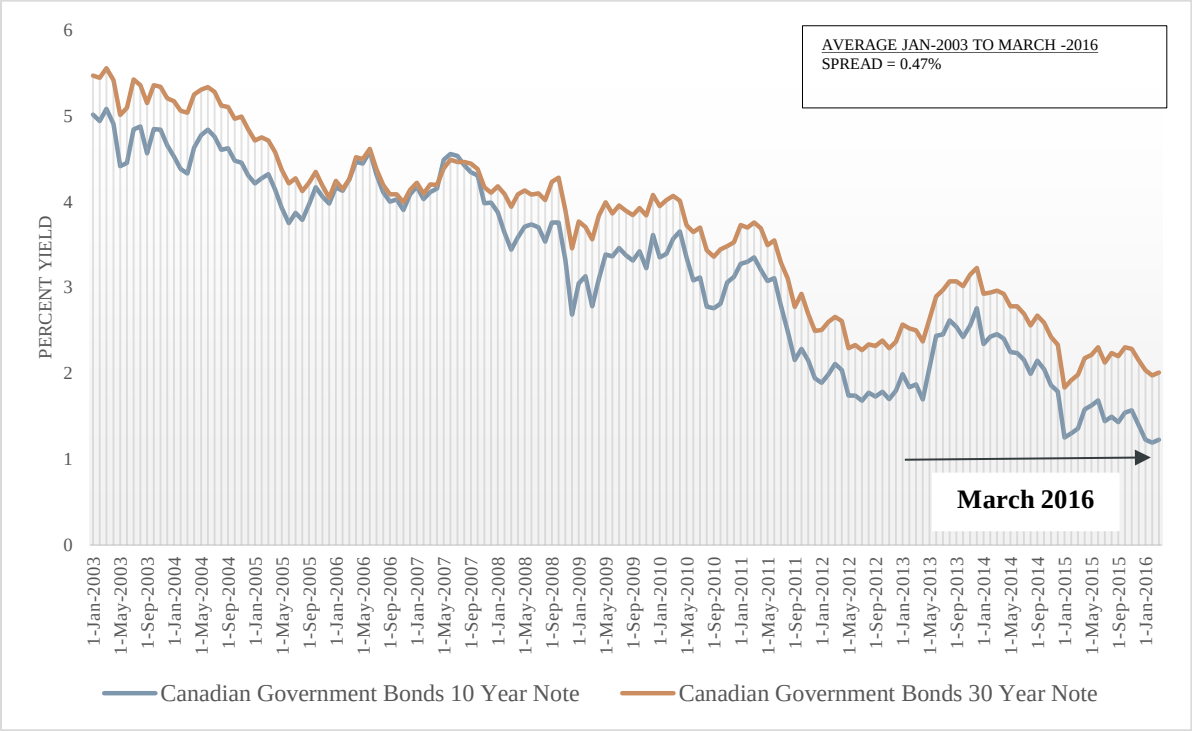
C. Interest Rates and Capital Market Conditions

Government bond yields remain near all-time lows and reflect the prolonged period of accommodative monetary policy in Canada and the U.S. following the 2008-2009 financial crisis. As shown in Figure 3, the 30-day average yields on 10- and 30-year long-term Canadian government bonds were 1.23 percent and 2.01 percent, respectively, in March 2016.

[24] For Yukon, economic indicators are as reported by the Department of Economic Development for the Yukon Government (February 2014 Outlook; October 2015 Outlook). For Canada, economic indicators are from The Conference Board of Canada and the World Bank.

[25] According to the Yukon Economic Outlook published in January 2015, actual GDP growth for 2013 was (0.7%) as reported by Statistics Canada.

Figure 3: Canadian Government Bond Yields, 10-Year and 30-Year



Source: Bloomberg series GCAN10YR, GCAN30YR

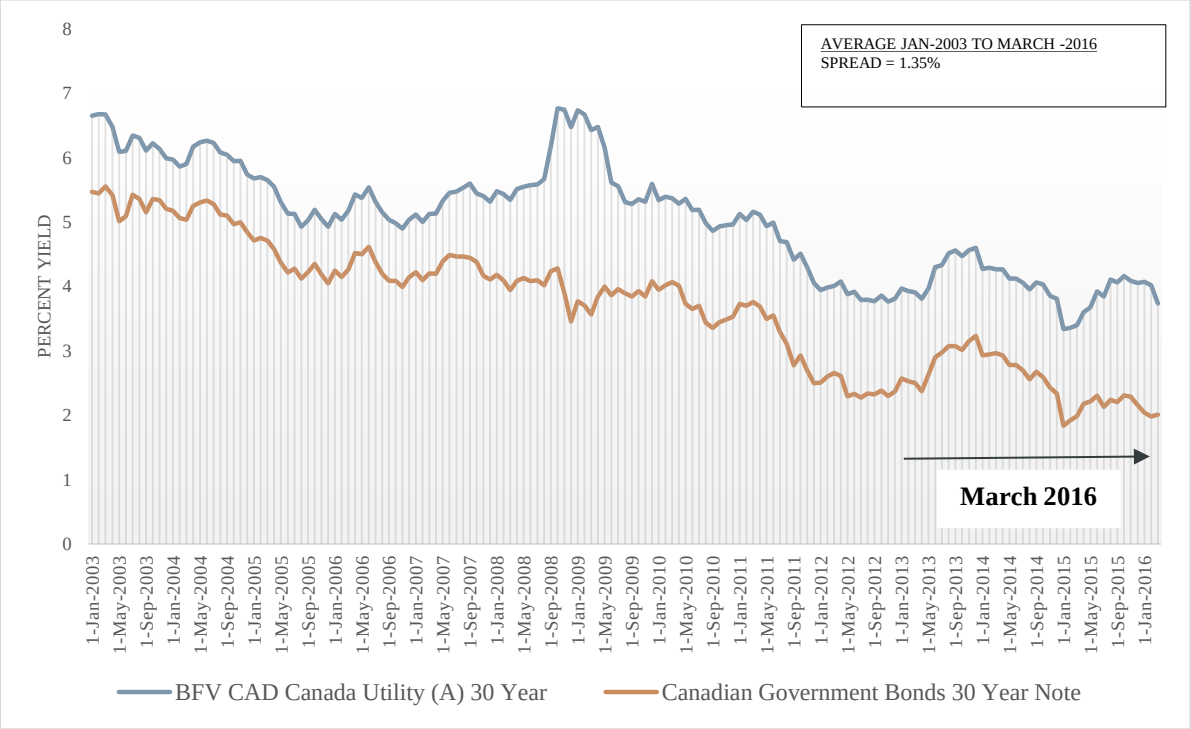
The Bank of Canada surprised investors in both January and July 2015 when it cut short-term interest rates by 0.25 percent each time, citing concerns about the Canadian economy due to the rapid drop in oil prices and weak exports. The Canadian economy saw a return to economic growth in the third and fourth quarters of 2015, led by improvement in the non-resources sectors. In the U.S., the Federal Reserve raised short-term interest rates by 0.25 percent in December 2015. According to Blue Chip Financial Forecast, 100 percent of economists and market participants surveyed expect the U.S. Federal Reserve to continue raising short-term interest rates in 2016, with 73 percent expecting the next increase to occur at the June 2016 FOMC meeting.[26]

Despite currently low government bond yields, yields on corporate bonds and credit spreads have been increasing. As Figure 4 shows, the Canadian Utility A-rated bond index yield has

[26] Blue Chip Financial Forecast, Volume 35, Issue No. 3, March 1, 2016, at 14.

increased over the past year and stood at 3.73 percent in March 2016, while long-term government bond yields remain near 2.00 percent due to accommodative monetary policy.

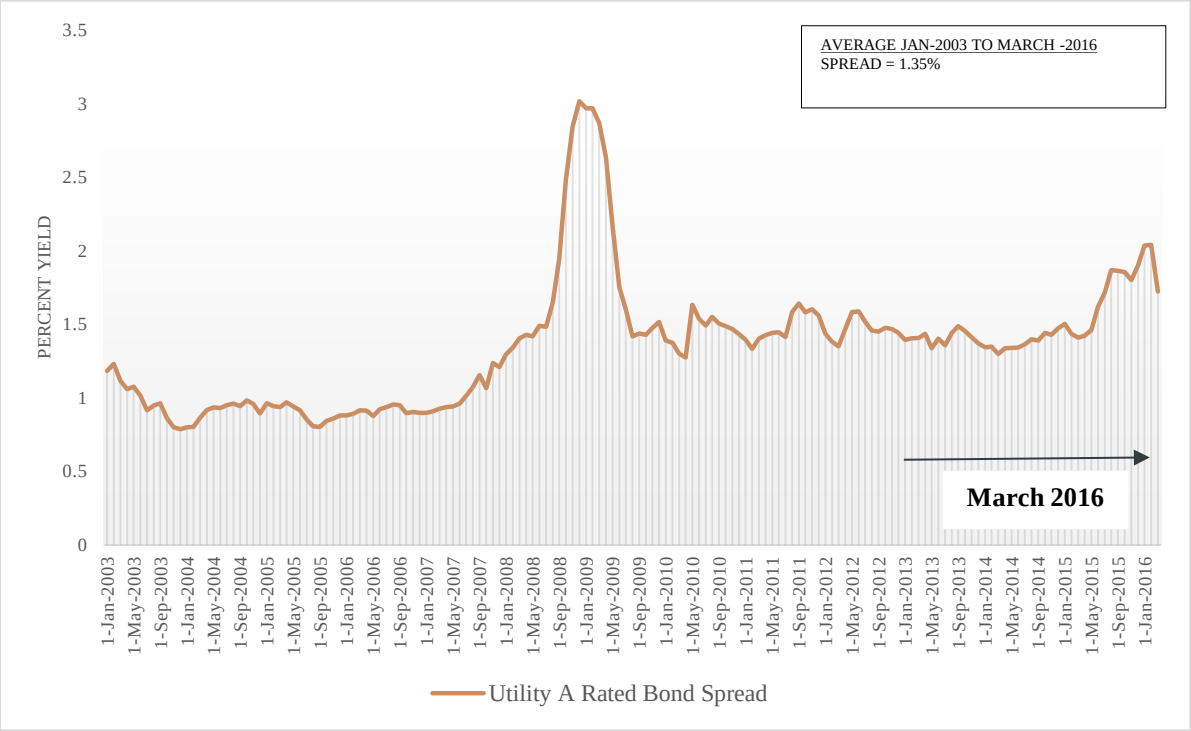
Figure 4: Canadian Utility A-Rated Bond vs. 30-Year Canada Long Bond



Source: Bloomberg series C29530Y, GCAN30YR

Figure 5 shows that the spread between Canadian Utility A-rated bonds and the 30-year Canada long bond has increased substantially in the last two years. The 30-day average spread in March 2016 was 1.72 percent, and spreads in recent months have been higher than at any time since the credit market crisis in 2008-2009, suggesting that default risk has increased for corporate and utility bonds and that investors require greater compensation over the risk-free return.

Figure 5: Canadian Utility A-Rated Bond Spread vs. 30-Year Canada Long Bond



Source: Bloomberg series C29530Y, GCAN30YR

Overall, capital markets in Canada have stabilized and generally improved as economic growth has resumed after the financial crisis and recession of 2008-2009. The low interest rate environment, especially for long-term government bonds, has coincided with an increase in equity valuations. Investor expectations call for tighter monetary policy in the upcoming year, leading to higher government bond yields. Corporate and utility debt costs have already moved higher. Recent volatility in equity markets is a reminder that global forces are at play in the Canadian and U.S. economies that can cause unanticipated market disruptions.

IV. RISK ASSESSMENT

Concentric generally examines risk from two primary perspectives:

1) Business risk: For a regulated utility, business risk encompasses both operational risk (e.g., customers served, size of service territory, weather/climate, volume/demand risk, economic conditions, etc.) and regulatory risk (e.g.,

opportunity for timely recovery of prudently incurred costs). Business risk results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including the fair return on, and of, its capital in a timely manner.

2) Financial risk: Financial risk primarily relates to the risk associated with the way in which a company has financed its business, as evidenced by the relative percentages of debt and equity in the capital structure. To the extent the company is more highly leveraged, it requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders.

Taken together, business risk and financial risk are the primary elements of investment risk that investors consider when establishing their return requirements.

The Board has consistently determined that an equity ratio of 40 percent is reasonable for AEY. Taking into account AEY's 40.0 percent equity ratio, Concentric's risk analysis is focused primarily on an assessment of the relative business risk of AEY to the BCUC benchmark and other selected electric and gas distribution utilities in Canada.

A. Analysis of AEY's Business Risk Compared to Other Distribution Utilities

AEY is primarily an electric distribution utility serving approximately 17,600 residential and commercial customers in 19 communities across Yukon. In 2015, the Company had an electric rate base of approximately $93 million and delivered 315,886 MWh of power.

Concentric compared the business risk of AEY to that of FortisBC Energy, the BCUC's benchmark utility, as well as to other investor-owned electric and gas distribution companies in Canada, including:

1) FortisBC Electric;
2) Newfoundland Power Inc.;
3) Maritime Electric Company Limited;
4) ATCO Electric Distribution; and

5) Pacific Northern Gas – West.

The results of those comparisons are presented in this section of the report. Profiles of each comparator company are provided in Attachment JMC-2.

The companies in the comparison group meet the following criteria: 1) smaller operating utilities that provide distribution service in British Columbia (in the case of FortisBC Electric and PNG-West); 2) smaller operating utilities that provide electric distribution service and own limited generation assets (in the case of Newfoundland Power and Maritime Electric); and 3) smaller electric distribution utility and affiliate of ATCO Electric (in the case of ATCO Electric Distribution).[27]

The following investor-owned electric utilities and gas distribution companies were not included in the comparator group: 1) Nova Scotia Power, due to the fact that it owns significant regulated generation assets and is much larger than AEY; and 2) Enbridge Gas Distribution, Union Gas Ltd. and ATCO Gas due to the fact that they are gas distribution utilities and are much larger than AEY.

Based on my risk analysis, I conclude that AEY has higher business risk than FortisBC Energy and these other investor-owned electric and gas distribution companies in Canada with the exception of PNG-West. 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.

[27] Northland Utilities Ltd. was excluded due to the substantially smaller size of these companies. Northland is also a subsidiary of ATCO Electric Ltd., with two operating utilities: NWT and NUY. NWT provides electrical service to approximately 2,700 customers and operates five diesel power plants, in addition to receiving energy from the Taltson Hydro System. Approximately 83 percent of NWT's total required power supply is purchased from Northwest Territories Power Corporation ("NTPC"), a crown corporation. NWT's return on equity and capital structure were established as part of the 2014-2015 Negotiated Settlement Agreement. The authorized ROE is set at 35 basis points above the Alberta Generic Cost of Capital rate of 8.30 percent, and the equity ratio is 43 percent. NUY acquired the Yellowknife electrical distribution system in 1993 from Centra Power and distributes electricity to approximately 6,800 residential customers and 1,200 commercial customers. All supply on the Yellowknife distribution system is purchased from the NTPC. NUY's return on equity and capital structure were established as part of the 2011-2013 Negotiated Settlement Agreement. The authorized ROE is 9.30 percent (or 30 basis points above the then-approved Alberta benchmark ROE of 9.0 percent) and the common equity ratio is 43.5 percent.

1. Small Size

Figure 6 and Figure 7 show that AEY is smaller than any of these investor-owned electric and gas distribution utilities, both in terms of retail customers served and regulated rate base.

Figure 6: Small Size of AEY Comparison of 2014 Retail Electric Customers

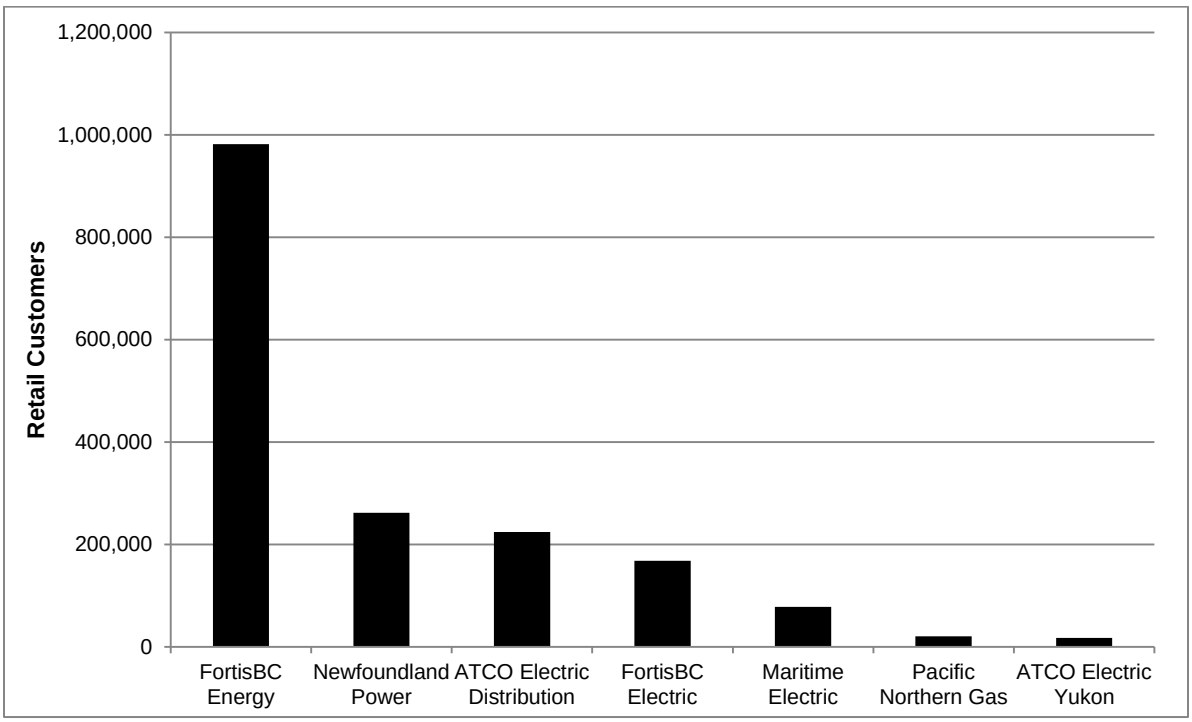
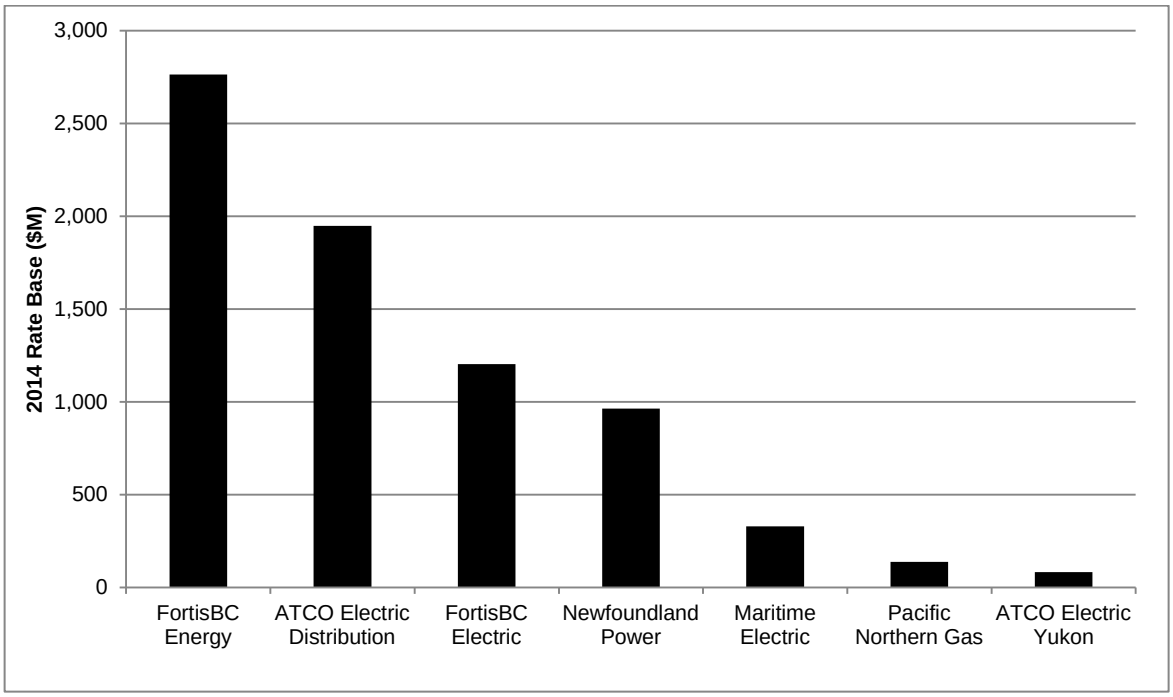


Figure 7: Small Size of AEY Comparison of 2014 Rate Base



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. Morningstar explains:

> Most criticisms of the use of the size premium do not address the underlying reasons for its existence. Small-cap stocks are still considered riskier investments than large-cap stocks. Investors require an additional reward, in the form of additional return, to take on the added risk of an investment in small cap stocks. It is unlikely that in the future investors will require no compensation for taking on this additional risk.[28]

In addition to contributing to higher investment risk, the small size of AEY magnifies the risk associated with other factors. 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. Moreover, the small size of AEY also limits the Company's financial flexibility when it comes to raising capital.

[28] Morningstar, 2015 Ibbotson SBBI Classic Yearbook, at 113.

AEY's small size also magnifies the risk associated with severe weather conditions because AEY serves very remote locations, making it more difficult to respond in the event of a service disruption.

In addition to size, Concentric's assessment of business risk also considered the following factors:

2) Generation risk;
3) Fuel and purchased power cost risk;
4) Volume/demand risk;
5) Regulatory environment;
6) Deferral/Variance accounts; and
7) Competition from alternative fuels.

Each of these factors is discussed in the following section of the report.

2. Generation Risk

AEY purchases approximately 91 percent of its electricity supply from YEC, a crown corporation, while the remaining 9 percent comes from Company-owned hydro and diesel generation facilities. AEY is very similar in this regard to Newfoundland Power, which purchases approximately 93 percent of its electricity supply from Newfoundland and Labrador Hydro, a crown corporation, while generating the remaining 7 percent through company-owned facilities. Likewise, Maritime Electric purchases approximately 76 percent of its electricity supply from New Brunswick Power, which is provincially owned, while the remaining 24 percent comes from Company-owned generation facilities. FortisBC Electric purchases approximately 55 percent of its electricity supply and generates the other 45 percent of its supply requirements through company-owned facilities. The two gas distributors in the comparator group (FortisBC Energy and PNG-West) do not own electric generation assets.

Companies that own electric generation facilities are generally considered more risky by credit rating agencies than companies that only own transmission and distribution facilities, or than gas distribution companies and gas transportation pipelines. For example, Moody's states:

> Generation utilities and vertically-integrated utilities generally have a higher level of business risk because they are engaged in power generation… We

> view power generation as the high-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.
>
> Other types of utilities may have lower business risk … due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural disasters. For instance, we tend to view many U.S. natural gas local distribution companies and certain U.S. electric transmission and distribution companies (which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers.[29]

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. Newfoundland Power has an authorized ROE of 8.80 percent on 45 percent common equity. AEY has slightly less generation risk than Maritime Electric, which purchases about 75 percent of its electricity supply, and lower generation risk than FortisBC Electric, which purchases 55 percent of its electricity supply. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity, and FortisBC Electric has an authorized ROE of 9.15 percent on 40 percent common equity. AEY has higher generation risk than the two gas distribution companies – FortisBC Energy and PNG-West – in the proxy group.

3. Fuel and Purchased Power Cost Risk

As part of its 2016-2017 General Rate Application, AEY is reapplying for two variance accounts that allow the Company to recover differences between forecasted and actual fuel prices (not volume) and purchased power costs (not volume). AEY previously had both variance accounts in effect for 2013-2015, but the accounts have expired. By comparison, variances in fuel and purchased power costs for Newfoundland Power are recovered on a monthly basis through a

[29] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, December 23, 2013, at 23-24.

revenue stabilization account, but under this mechanism, Newfoundland Power's risk of recovery of supply costs is limited to +/- $640,000. Both FortisBC Electric and Maritime Electric have an annual fuel and purchased power cost recovery mechanism. The Alberta electric utilities, including ATCO Electric Distribution, are not responsible for the generation or retail transmission function. Among gas distributors, FortisBC Energy and PNG-West both have quarterly purchased gas adjustment mechanisms that allow them to pass through the commodity cost to customers.

With the exception of Newfoundland Power, which has slightly more risk associated with recovery of variations in fuel or purchased power costs, AEY and the other Canadian electric and gas distribution companies in the comparator group are not at risk for recovery of fuel and purchased power costs. AEY, like Newfoundland Power and Maritime Electric, is dependent on a single source of electric supply, creating greater supply risk than utilities such as FortisBC Electric or the Alberta utilities that rely on a more diverse mix of generation and/or market sources.

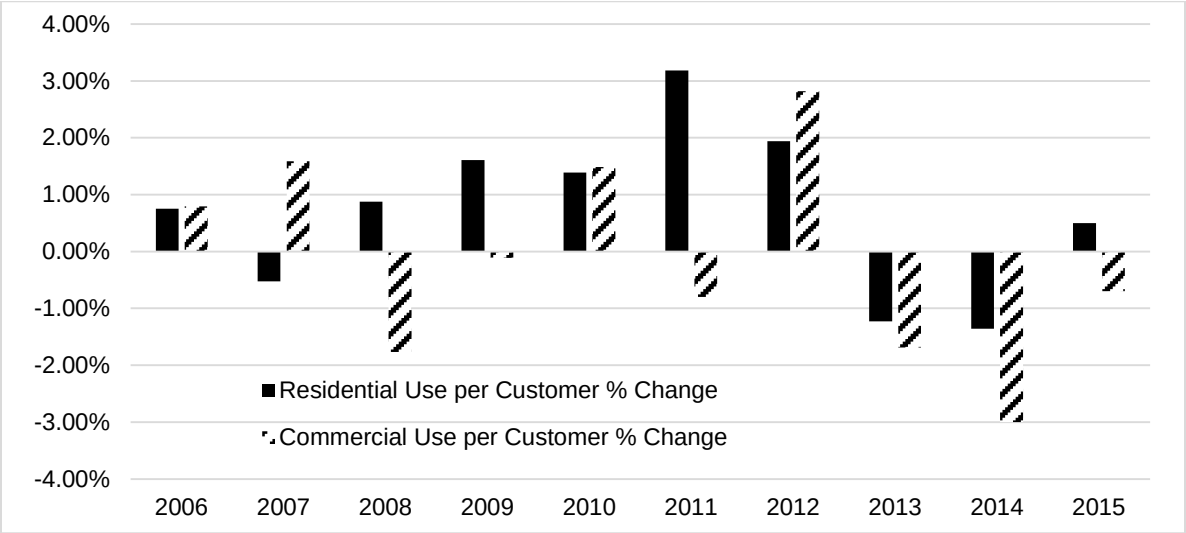
4. Volume/Demand Risk

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. In addition, PNG-West has full revenue decoupling, which allows the company to effectively break the link between revenues and volume/demand and to recover its revenue requirement through a true-up account. ATCO Electric Distribution is subject to a performance based regulation plan that adjusts revenues annually based on inflation less a productivity factor; however, the PBR plan for ATCO Electric does not include protection against changes in volume/demand. On this basis, AEY has higher volume/demand risk than the other electric and gas distribution companies in the proxy group with the exception of ATCO Electric Distribution, which is equivalent to AEY in this respect.

Weather-related variance accounts are common among Canadian distribution companies that provide space heating to a significant share of their customers. This applies not only to gas distributors such as FortisBC Energy and PNG-West, but also to electric distributors such as Newfoundland Power and Maritime Electric, which have significant market share of electric heating customers. In Yukon, electric space heating has become much more common in new residential housing developments 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 of Yukon households in 2003.[30] I understand this increase in electric space heating has made it more difficult for AEY to accurately forecast its sales, especially among residential customers. As shown in Figure 8, AEY's residential and commercial weather-normalized use per customer has fluctuated by up to 3 percent from year-to-year since 2006.

Figure 8: Variability in Use Per Customer

Residential and Commercial: Year to Year Percent Change[31]



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

30 Yukon Bureau of Statistics, Yukon Energy Facts 2013, at 4.

31 Source: AEY, Weather Normalized.

use those alternative fuels for space heating rather than electricity. The fact that AEY does not have a variance account for changes in demand due to abnormal weather conditions or DSM/energy efficiency programs makes the Company more risky than other electric and gas distribution companies, with the exception of ATCO Electric Distribution. In addition, as discussed in more detail in the section on governmental policies, the Yukon provincial government has been pursuing a policy that encourages micro generation. 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.

5. Regulatory Environment

AEY recovers its costs under traditional cost of service regulation. Like most Canadian regulated utilities, the Company uses a forecasted test year and earns a return on an average rate base. Among the electric and gas distribution companies in the proxy group, Newfoundland Power, Maritime Electric and PNG-West are under cost of service regulation, while FortisBC Energy, FortisBC Electric, and ATCO Electric Distribution operate under performance-based or incentive regulation plans. 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. All of the companies in the comparator group use a forecasted test year and an average or mid-year rate base.

In summary, AEY operates in a regulatory environment that generally supports cost recovery and allows the Company to earn its allowed ROE in most years. However, the Board historically has not accepted the Stand-Alone principle, which is inconsistent with general practice among other regulators in Canada including the BCUC and the AUC. In addition, AEY has somewhat higher than average regulatory risk than the comparator companies because it does not have a variance account for weather-related volume/demand risk.

6. Deferral/Variance Accounts

Regulators in Canada have typically used variance and deferral accounts to mitigate the risks associated with costs that (1) tend to fluctuate substantially from year to year, (2) are significant

in magnitude, and (3) are generally beyond the control of utility management. Concentric has examined five categories of operating costs that tend to distinguish specific areas of costs where cost recovery mechanisms vary between jurisdictions. As shown in Figure 9, AEY has deferral/variance accounts for pension expenses and DSM costs, while other Canadian investor-owned electric and gas distribution companies have varying levels of cost recovery protection.

Figure 9: Variance/Deferral Accounts

Cost	Pension/OPEB Expense	Bad Debt Expense	Storm Costs	Change in Interest Rates	Energy Efficiency and DSM Costs
AEY	Yes	No	Yes	No	Yes
FortisBC Energy	Yes	No	No	Yes	Yes
FortisBC Electric	Yes	No	No	Yes	Yes
ATCO Electric	No	N/A	No	Yes[32]	N/A
Newfoundland Power	Yes	No	No	No	Yes
Maritime Electric	Yes	No	No	No	Yes
Pacific Northern Gas	No	Yes	No	Yes	Yes

7. Competition from Alternative Fuels

As discussed in the section above on volume/demand risk, AEY's residential customers tend to switch between various fuels for electric space heating depending on the relative price of those fuels.[33] In particular, when the price of heating oil and propane was higher several years ago, more AEY residential customers relied on electricity for their space heating. As heating oil and propane prices have declined in the past years, AEY customers have been more likely to move away from electricity. In addition, wood pellet stoves are another source of competition for space heating in Yukon. By comparison, Newfoundland Power and Maritime Electric also face competition from heating oil for the space heating needs of residential customers. FortisBC Energy, a gas distributor, faces competition from electric heat among residential customers in British Columbia. To a lesser degree, ATCO Electric Distribution and PNG-West face competition from alternative fuels.

[32] Changes in interest rates are partially incorporated through the capital tracker mechanism of Alberta's current PBR regime.

[33] Source: AEY.

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.

8. Conclusions on Business Risk Relative to Other Distribution Utilities

Concentric concludes that AEY has relatively higher business risk than the other electric and gas distribution utilities in the proxy group with the exception of PNG-West. In particular, factors contributing to this higher risk profile include AEY's small size, its dependence on one supplier, its exposure to volume/demand risk, and an undiversified local economy and generally weak macroeconomic conditions in the territory as compared to the remainder of Canada.

The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY.

Among the group of distribution utilities, only PNG-West has higher business risk than AEY. PNG-West is slightly larger than AEY in terms of retail customers served, and PNG-West's rate base is approximately 67 percent greater than AEY. As recognized by the BCUC in the Stage 2 GCOC decision, PNG-West has higher risk than AEY due to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012). 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.

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. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY

supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk. FortisBC Electric has protection against volumetric risk due to abnormal weather, while AEY does not.

AEY's generation profile and customer mix is more comparable to Newfoundland Power, which supplies about 7 percent of its load requirements through company-owned regulated generation assets and also serves only residential and commercial customers. Newfoundland Power has 15X more retail electric customers, and its rate base is approximately 12X greater than AEY. 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. Newfoundland Power's currently allowed ROE is 8.80 percent, with a deemed equity ratio of 45 percent, as compared to 40 percent for AEY.

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, 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.

ATCO Electric Distribution is purely a distribution utility that does not own generation. ATCO Electric Distribution is approximately 13X larger than AEY in terms of customers served and 23X larger in terms of 2014 rate base. ATCO Electric Distribution operates under an incentive regulation framework, as opposed to the cost of service regime for AEY. In 2015, the AUC reduced the allowed ROE for all electric and gas utilities in Alberta from 8.75 percent to 8.30 percent. The 2016 Generic Cost of Capital proceeding is currently before the Alberta Utilities Commission with a decision expected later this year. 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.

B. Change in Business Risk since 2009 for AEY

In addition to considering AEY's relative business risks compared to other Canadian electric and gas distribution companies, Concentric also evaluated whether there have been any changes in AEY's business risk since 2009 that would materially impact the Company's risk profile as compared to the time when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable and appropriate.

1. Weather-related Risk

One of the most important operating risks for AEY is weather-related service disruptions. Specifically, AEY's service territory is characterized by severe cold and high winds in the winter and hot temperatures in the summer. The need to address supply disruptions caused by severe weather conditions involves unanticipated and potentially volatile capital and operating costs. In addition to the risk caused by the small size of AEY, which has limited resources to respond to service disruptions and outages, the Company provides service in very remote locations across a large service territory. AEY's capital structure and allowed ROE must be sufficient to provide the Company with the financial flexibility necessary to respond to unforeseen capital and operating costs in order to restore electric service promptly to customers. While this risk has not materially changed since 2009, it is very important that AEY has the financial flexibility to respond to these events as they arise.

2. Power Supply Risk

AEY purchases approximately 91 percent of its power supply from Yukon Energy Corporation, while generating the remaining 9 percent using company-owned hydro-electric and diesel plants. The price of AEY's electricity supply has increased by approximately 20 percent (from $0.082/kWh to $0.098/kWh) since 2009. AEY has traditionally been allowed to recover differences between forecasted and actual fuel prices (not volume), as well as differences in purchased power costs (not volume) through two deferral accounts. AEY is requesting that the purchased power deferral account and the fuel deferral account be renewed as part of this GRA filing. Assuming that the deferral accounts are renewed by the Board, AEY's power supply risk has not changed in any material way since 2009. If the deferral accounts for purchased power and fuel prices are not approved, this would have a material impact on AEY's risk profile as

compared to 2009. All of the other electric and gas distribution companies in the proxy group have fuel cost mechanisms that allow for adjustments due to variations in forecasted and actual fuel and purchased power costs, so those companies are not subject to material risk for fuel or purchased power costs. Without such deferral accounts, AEY would have higher risk associated with recovery of purchased power costs and fuel prices than the distribution companies in the comparator group.

3. Competition from Alternative Fuels

The use of alternative fuels such as wood pellets, fuel oil, and propane is very fluid in Yukon among residential customers depending on the relative price of electricity and these other fuel sources for space heating purposes. As a result of fuel switching, residential demand forecasting has become more difficult for AEY over the past decade. As the residential load has become less predictable for AEY, the variability in the Company's sales has increased, which in turn increases the risk that AEY's revenues will not be sufficient to recover its costs and earn its authorized ROE. Several factors have contributed to higher variability in AEY's demand, including more new housing developments installing electric space heating (which makes demand more dependent on weather conditions), implementation of energy efficiency and DSM programs, and weak economic conditions in the Yukon economy from 2013-2015.

4. Governmental Policies

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. Furthermore, the Yukon government has expressed an interest in carbon taxes and other energy policies that would result in fuel being used more efficiently. Concentric does not view these policies as increasing the business risk of AEY at this time;

however, they could potentially impact the Company's risk profile over the longer-term if customer demand is reduced.

5. Conclusions on Changes in Business Risk since 2009

In most respects, AEY's business risk has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. The most important change has been the uncertainty and unpredictability associated with usage per customer, especially among the residential class. This is driven by several factors, including fuel switching as electricity prices become less competitive with alternative fuels, by the DSM program which was implemented by AEY in 2012, and by the general downturn in economic conditions over the past three years in Yukon. Fluctuations in customer usage have made it more difficult for AEY to accurately forecast sales.

V. COMPARISON TO OTHER BENCHMARKS

As another point of comparison, Concentric also considered the authorized ROE and equity ratio for transmission and distribution utilities in the U.S. from January 2014 through March 2016. During that period, the average authorized ROE for T&D utilities in the U.S. was 9.41 percent, and the allowed common equity ratio was 49.36 percent.[34] The vast majority of these companies are substantially larger than AEY. In my experience, the operating risks for U.S. electric utilities are similar to those in Canada. Similarly, the cost recovery provisions and regulatory regimes in the U.S. and Canada are comparable. As such, my conclusion is that the U.S. utilities have lower business risk than AEY, due primarily to the extremely small size of AEY. The authorized ROE of 9.41 percent would provide a 66 basis point risk premium above the benchmark utility in British Columbia, while the allowed common equity ratio is more than 9 percent higher than AEY's deemed equity ratio of 40 percent.

VI. RISK ANALYSIS CONCLUSIONS

Based on the results of the business risk analyses discussed throughout this report, Concentric concludes that:

[34] SNL Financial. Rate Case History, January 1, 2014 through March 31, 2016.

- The business risk of AEY is higher than that of FortisBC Energy, the benchmark utility in British Columbia, which has an authorized ROE of 8.75 percent on 38 percent common equity.
- The business risk of AEY is higher than that of other Canadian electric and gas distribution utilities with the exception of PNG-West;
- In most respects, the business risk of AEY has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. Weak economic conditions in the province, coupled with the impact of energy efficiency and DSM programs, and increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales;
- The business risk profile of AEY is most similar to that of Maritime Electric, which derives a higher percentage of its electricity supply from company-owned generation than AEY, but which serves five times more retail customers. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity;
- The business risk profile of AEY is also similar in many respects to that of Newfoundland Power, except that AEY is substantially smaller in terms of both customers served and rate base. Newfoundland Power has an ROE of 8.80 percent on 45 percent common equity; and
- The business risk of AEY is lower than that of PNG-West, which is similar in size but faces more risk than AEY due to the loss of a major customer that caused throughput to decline by 87 percent from 2003-2012. PNG-West has an authorized ROE of 9.50 percent (or 75 basis points above the BC benchmark) on 46.5 percent common equity.

Based on the foregoing, I conclude that an ROE risk premium between 40 and 75 basis points is appropriate for AEY. This range is framed by FortisBC Electric on the lower end and by PNG-West on the upper end in relation to the benchmark, FortisBC Energy. From within that range,

a ROE risk premium for AEY of 60 basis points is reasonable because it would be consistent with the recent 9.35 percent ROE award for Maritime Electric, a company with similar business risk as AEY and a deemed equity ratio of 40.9 percent. At a minimum, the risk premium for AEY should be set no lower than 40 basis points, which is what the BCUC has awarded to FortisBC Electric, a company which is much larger than AEY in terms of retail customers served and rate base and which operates in a service territory that has a stronger and more diversified economy.

James M. Coyne
Senior Vice President

Mr. Coyne provides financial, regulatory, strategic, and litigation support services to clients in the natural gas, power, and utilities industries. Drawing upon his industry and regulatory expertise, he regularly advises utilities, public agencies and investors on business strategies, investment evaluations, and matters pertaining to rate and regulatory policy. Prior to Concentric, Mr. Coyne worked in senior consulting positions focused on North American utilities industries, in corporate planning for an integrated energy company, and in regulatory and policy positions in Maine and Massachusetts. He has authored numerous articles on the energy industry and provided testimony and expert reports before the Federal Energy Regulatory Commission and numerous jurisdictions in the U.S. and Canada. Mr. Coyne holds a B.S. in Business from Georgetown University with honors and an M.S. in Resource Economics from the University of New Hampshire.

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony Experience

- Vermont Gas Systems, Inc.: Before the Vermont Public Service Board, provided expert testimony on the cost of capital and business risk for the Company's gas distribution operations. (Docket No. ___)
- Northern States Power Co.: Before the Minnesota Public Utilities Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. E002/GR-15-826)
- Maritime Electric: Before the Island Regulatory and Appeals Commission, provided expert testimony on the cost of capital for the Company's electric distribution operations. (Docket No. UE20942)
- Newfoundland Power Inc.: Before the Newfoundland and Labrador Board of Commissioners of Public Utilities, provided expert testimony on the cost of capital and business risk for the Company's electric distribution operations. (2016/2017 General Rate Application)
- FortisBC Energy Inc.: Before the British Columbia Utilities Commission, provided expert testimony on the cost of capital and business risk for the Company's BC gas distribution operations. (Docket No. 3698852)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on performance based regulation recommendations for the Company's Québec electric transmission and distribution businesses, with Robert Yardley. (R-3897-2014)
- Green Mountain Power Company: Before the Vermont Public Service Board, provided expert testimony on the cost of capital for the Company's Vermont Electric Utility Business. (Docket No. 8191)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-119)
- Hydro-Québec: Before the Régie de l'énergie, filed expert testimony on the cost of capital and business risk for the Company's Québec electric transmission and distribution businesses, with John Trogonoski. (R-3842-2013)
- Enbridge: Before the Ontario Energy Board, filed expert testimony with Jim Simpson and Melissa Bartos in support of the Company's proposed 2nd Generation Incentive Regulation plan. Our work

focused on development of a proposed plan consistent with the OEB's objectives for such plans, while recognizing the Company's operating environment and business objectives, and capitalizing on the experience with other IR programs. Concentric conducted a series of analyses, including industry benchmarking, and productivity analyses for the industry and Enbridge using both total factor productivity "TFP" analysis and partial factor productivity ("PFP") analysis. These analyses produced productivity measures ("X factors") for both Enbridge and the industry peer group that were utilized to test parameters for the proposed IR plan. Concentric also evaluated alternative measures of inflation ("I factors") for utility inputs. Lastly, we examined Enbridge's anticipated 2014 to 2016 costs, and evaluated the ability of a traditional I-X framework to accommodate the Company's cost profile. (EB-2012-0459)

- Gaz Métro: Before the Régie de l'énergie, filed expert testimony on the cost of capital, business risk, and capital structure for the Company's Québec gas distribution operations. (R-3809-2012)
- Startrans IO, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate cost of equity for the Startrans transmission facilities in Nevada and California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER13-272-000, and EL13-26-000)
- Nova Scotia Power: Before the Nova Scotia Utility and Review Board, provided direct and rebuttal evidence on the business risk of Nova Scotia Power in relation to its North American peers for purposes of determining the appropriate cost of capital. (Docket No. 2013 GRA)
- FortisBC Utilities: Before the British Columbia Utilities Commission, provided direct evidence and a supporting study on formulaic approaches to the determination of the cost of capital. (BCUC 2012 Generic Cost of Capital Proceeding)
- Northern States Power Company: Before the South Dakota Public Utilities Commission provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL12 -)
- Vermont Gas Systems, Inc: Before the Vermont Public Service Board, filed expert testimony on the appropriate cost of equity and capital structure. (Docket No. 7803A)
- Northern States Power Company: Before the South Dakota Public Utilities Commission, provided expert testimony on the appropriate cost of capital for the company's South Dakota electric utility operations. (Docket No. EL11-019)
- Public Service Commission of Wisconsin: Provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, filed expert testimony on the appropriate rate of return for the Path 15 transmission facilities in California, and the economic and business environment for transmission investments. (FERC Dockets Nos. ER11-2909 and EL11-29)
- Enbridge: Cost of capital witness for the company's 2013 rate filing, providing testimony on recommended ROE and capital structure for the company's Ontario gas distribution business, and a separate benchmarking analysis designed to illustrate the efficiency of the company's operations in relation to its' North American peers. (EB-2011-0354)
- Northern States Power Company: Before the Public Service Commission of Wisconsin, provided expert testimony on the cost of capital for the company's Wisconsin electric and natural gas utility operations. (Docket No. 4220-UR-117)
- FortisBC Energy, Inc: Provided a detailed study of alternative automatic adjustment mechanisms for setting the cost of equity, filed with the British Columbia Public Utilities Commission, December, 2010. (In response to BCUC Order No. G-158-09)

- Commonwealth of Massachusetts, Superior Court, Central Water District vs. Burncoat Pond Watershed District: Provided expert testimony on the appropriate method for computing interest in an eminent domain taking. (Civil Action No. WDCV2001-01051, May 2010)
- Retained by the Ontario Energy Board to evaluate the existing DSM regulatory framework and guidelines for gas distributors, and based on research on best practices in other jurisdictions, make recommendations and lead a stakeholder conference on proposed changes. (2009-2010)
- ATCO Utilities: Primary cost of capital witness on behalf of ATCO Utilities in the 2009 Alberta Generic Cost of Capital proceeding, for the establishment of the return on equity and capital structure for each of Alberta's gas and electric utilities. (AUC Proceeding ID. 85)
- Enbridge: Primary cost of capital witness before the Ontario Energy Board in its Consultative Process on the Board's policy for determination of the cost of capital. (EB-2009-0084)
- Provided written comments to the Ontario Energy Board on behalf of Enbridge Gas Distribution, and separately for Hydro One Networks and the Coalition of Large Distributors in response to the Board's invitation to interested stakeholders to provide comments to help the Board better understand whether current economic and financial market conditions have an impact on the reasonableness of the Cost of Capital parameter values calculated in accordance with the Board's established Cost of Capital methodology; and to help the Board determine if, when, and how to make any appropriate adjustments to those parameter values. (2009)
- Atlantic Path 15, LLC: Before the Federal Energy Regulatory Commission, provided expert testimony on the appropriate rate of return, capital structure, and rate incentives for the development and operation of the Path 15 transmission facilities in California. (FERC Docket ER08-374-000)
- Wisconsin Power and Light Company: Before the Public Service Commission of Wisconsin, on establishing ratemaking principles for the company's proposed wind and coal electric generation facility additions, providing expert testimony on the appropriate return on equity. (PSCW Docket Nos. 6680-CE-170 and 6680-CE-171, 2007)
- Aquarion Water Company: Before the Connecticut Department of Public Utility Control, providing expert testimony on establishing the appropriate return on equity for the Company's Connecticut operations. (DPUC Docket No. 07-05-19, 2007)
- Central Maine Power Company: Before the Maine Public Utilities Commission, provided expert testimony on the theoretical and analytical soundness of the Company's sales forecast for ratemaking purposes. (MPUC Docket No. 2007-215, 2007)
- Vermont Gas Systems, Inc.: Before the State of Vermont Public Board, on the company's petition for approval of an alternative regulation plan, provided expert testimony on models of incentive regulation and their relative benefits for VGS and its ratepayers. (VPSB Docket No. 7109, 2006)
- Texas New Mexico Power Company: Before the Public Utility Commission of Texas, on the approval of the company's stranded cost recovery associated with the auction of the company's generating assets. (PUC Docket No. 29206, 2004)
- TransCanada Corporation: Provided an independent expert valuation of a natural gas pipeline, filed with the American Arbitration Association. (AAA Case No. 50T 1810018804, 2004)
- Advised the Board of Directors of El Paso Corporation on settlement matters pertaining to western power and gas markets before FERC. (2003)
- Conectiv: Before the New Jersey Board of Public Utilities, on the approval of the proposed sale of Atlantic City Electric Company's fossil and nuclear generating assets. (NJBPU Docket No. EM00020106, 2000-2001)
- Bangor Hydro Electric Company: Before the Maine Public Utilities Commission, on the approval of the proposed sale of the company's hydroelectric and fossil generation assets. (MPUC Docket No. 98-820, 1998)

- Maine Office of Energy Resources: Before the Maine Public Utilities Commission on behalf of the Maine Office of Energy on the establishment of avoided costs rates for generators under PURPA. (1981-1982)

Regulatory Support Experience

- Provided consulting services to Hydro One Networks for the Company's 2015 – 2019 Custom Distribution Rate Application to the OEB. Assisted the Company in developing its proposal for specific performance metrics for the Plan; reviewed the comments of stakeholders on performance metrics; reviewed the Company's existing performance metrics; reviewed the fastest growing areas of budgeted expenditures for their performance metric potential; developed a set of recommended metrics for review with the Company; and assisted the Company with drafting its submission to the OEB. (2014)
- Advised the Ontario Power Authority (OPA) on appropriate efficiency metrics to utilize in measuring the effectiveness of the organization in response to a directive by the Ontario Energy Board. Conducted research and analysis to examine efficiency metrics used in the industry to measure the effectiveness of organizations with similar responsibilities to those of the OPA. This analysis was designed to help facilitate the OPA's recommended metrics to the OEB. (2013)
- Retained by Gaz Métro to provide an independent assessment of the comprehensive incentive rate mechanism designed to improve the performance of Gaz Métro, and evaluate the proposed mechanism resulting from the Company's collaboration with a stakeholder working group. (R-3693-2009, 2011)
- For the Canadian Gas Association, facilitated workshops between Canadian regulators and utility executives on regulatory and utility responses to a low carbon world, and drafted follow-up white paper to facilitate further discussion on emerging industry issues. (2010-2013)
- Retained by Ontario's Coalition of Large Distributors (Enersource Hydro, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian Connections) to examine the cost of capital for Ontario's electric utilities in relation to those in other provinces and in the U.S. (2008)
- Retained by the Ontario Energy Board to analyze ROE awards for the past two years in Ontario, and compare against other jurisdictions in Canada, the U.S., the U.K., and select other European jurisdictions. Differences in awarded ROEs were examined for underlying factors, including ROE methodology, company size, business risks, tax issues, subsidiary vs. parent, and sources of capital. The analysis also addressed the question of whether Canadian utilities compete for capital on the same basis as U.S. utilities. (2007)
- Retained by the Nantucket Planning and Economic Development Commission to educate government officials and island residents on the wind industry, and provide analysis leading to constructive input to the Army Corps of Engineers and the Minerals Management Service on the siting of proposed wind projects. (2004-2007)
- Interim manager of Government and Regulatory affairs for Boston Generating, LLC. Coordinate activities and interventions before FERC, NE-ISO, state regulatory agencies, and local communities hosting Boston Generating power plants. (2004)
- Facilitated the development of an Alternative Regulation Plan with the Department of Public Service and Vermont Gas Systems providing research and advice leading to a rate proposal for the Vermont Public Service Board. Conducted several workshops including the major stakeholders and regulatory agencies to develop solutions satisfying both public policy and utility objectives. (2004-2005)
- For an independent power company, perform market analysis and annual audits of its utility power contract. Services provided include verification of the contract price as a function of its index components, surveys of regional competitive energy suppliers, and analysis of regional spot prices for

an independent benchmark. Meet with PUC staff to discuss and represent the company in its annual adjustment process, and report results to the company and its creditors. (2003-2004)

Areas of Expertise

- Energy Regulation
  - Rate policy
  - Cost of capital
  - Incentive regulation
  - Fuels and power markets
- Management and Business Strategy
  - Fuels and power market assessments
  - Investment feasibility
  - Corporate and business unit planning
  - Benchmarking and productivity analysis
- Financial and Economic Advisory
  - Valuation analysis
  - Due diligence
  - Buy and sell-side advisory

PUBLICATIONS AND RESEARCH

- "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" (with Robert Yardley), prepared for the Canadian Gas Association and Canadian Electricity Association, May, 2015.
- "Autopilot Error: Why Similar U.S. and Canadian Risk Profiles Yield Varied Rate-making Results" (with John Trogonoski), Public Utilities Fortnightly, May 2010
- "A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Dan Dane and Julie Lieberman), prepared for the Ontario Energy Board, June, 2007
- "Do Utilities Mergers Deliver?" (with Prescott Hartshorne), Public Utilities Fortnightly, June 2006
- "Winners and Losers: Utility Strategy and Shareholder Return" (with Prescott Hartshorne), Public Utilities Fortnightly, October 2004
- "Winners and Losers in Restructuring: Assessing Electric and Gas Company Financial Performance" (with Prescott Hartshorne), white paper distributed to clients and press, August 2003
- "The New Generation Business," commissioned by the Electric Power Research Institute (EPRI) and distributed to EPRI members to contribute to a series on the changes in the Power Industry, December 2001
- Potential for Natural Gas in the United States, Volume V, Regulatory and Policy Issues (co-author), National Petroleum Council, December 1992
- "Natural Gas Outlook," articles on U.S. natural gas markets, published quarterly in the Data Resources Energy Review and Natural Gas Review, 1984-1989

SELECTED SPEAKING ENGAGEMENTS

- "Innovations in Utility Business Models and Regulation", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2015 Energy Regulation Course, Queens University, Kingston, Ontario, June 2015

- "M&A and Valuations," Panelist at Infocast Utility Scale Solar Summit, September 2010
- "The Use of Expert Evidence," The Canadian Association of Members of Public Utility Tribunals (CAMPUT) 2010 Energy Regulation Course, Queens University, Kingston, Ontario, June 2010
- "A Comparative Analysis of Return on Equity for Utilities in Canada and the U.S.", The Canadian Association of Members of Public Utility Tribunals (CAMPUT) Annual Conference, Banff, Alberta, April 22, 2008
- "Nuclear Power on the Verge of a New Era," moderator for a client event co-hosted by Sutherland Asbill & Brennan and Lexecon, Washington D.C., October 2005
- "The Investment Implications of the Repeal of PUCHA," Skadden Arps Client Conference, New York, NY, October 2005
- "Anatomy of the Deal," First Annual Energy Transactions Conference, Newport, RI, May 2005
- "The Outlook for Wind Power," Skadden Arps Annual Energy and Project Finance Seminar, Naples, FL, March 2005
- "Direction of U.S. M&A Activity for Utilities," Energy and Mineral Law Foundation Conference, Sanibel Island, FL, February 2002
- "Outlook for U.S. Merger & Acquisition Activity," Utility Mergers & Acquisitions Conference, San Antonio, TX, October 2001
- "Investor Perspectives on Emerging Energy Companies," Panel Moderator at Energy Venture Conference, Boston, MA, June 2001
- "Electric Generation Asset Transactions: A Practical Guide," workshop conducted at the 1999 Thai Electricity and Gas Investment Briefing, Bangkok, Thailand, July 1999
- "New Strategic Options for the Power Sector," Electric Utility Business Environment Conference, Denver, CO, May 1999
- "Electric and Gas Industries: Moving Forward Together," New England Gas Association Annual Meeting, November 1998
- "Opportunities and Challenges in the Electric Marketplace," Electric Power Research Institute, July 1998

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2006 – Present)
Senior Vice President
Vice President

FTI Consulting (Lexecon) (2002 – 2006)
Senior Managing Director – Energy Practice

Arthur Andersen LLP (2000 – 2002)
Managing Director, Andersen Corporate Finance – Energy and Utilities

Navigant Consulting, Inc. (1996 – 2000)
Managing Director, Financial Services Practice
Senior Vice President, Strategy Practice

TotalFinaElf (1990 – 1996)
Manager, Corporate Planning and Development
Manager, Investor Relations

Manager of Strategic Planning and Vice President, Natural Gas Division

Arthur D. Little, Inc. (1989 – 1990)
Senior Consultant – International Energy Practice

DRI/McGraw-Hill (1984 – 1989)
Director, North American Natural Gas Consulting
Senior Economist, U.S. Electricity Service

Massachusetts Energy Facilities Siting Council (1982 – 1984)
Senior Economist – Gas and Electric Utilities

Maine Office of Energy Resources (1981 – 1982)
State Energy Economist

EDUCATION

M.S., Resource Economics, University of New Hampshire, with Honors, 1981
B.S., Business Administration and Economics, Georgetown University, Cum Laude, 1975

DESIGNATIONS AND AFFILIATIONS

NASD General Securities Representative and Managing Principal (Series 7, 63 and 24 Certifications), 2001
NARUC, Advanced Regulatory Studies Program, Michigan State University, 1984
American Petroleum Institute, CEO's Liaison to Management and Policy Committees, 1994-1996
National Petroleum Council, Regulatory and Policy Task Forces, 1992
President, International Association for Energy Economics, Dallas Chapter, 1995
Gas Research Institute, Economics Advisory Committee, 1990-1993
Georgetown University, Alumni Admissions Interviewer, 1988 – current

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Company: ATCO Electric Yukon

Regulatory Authority	Yukon Utilities Board
Utility Type	Vertically-integrated Electric Utility
Parent Company	ATCO Electric Ltd./Canadian Utilities Inc.
Cost of Capital	Equity Ratio 40.0% Return on Equity 8.75% Currently no risk premium above BCUC benchmark utility
Credit Rating	A (S&P) for parent company (CUI)
Generation Ownership	Owns 16 MW of regulated generation assets, which provides approximately 9% of supply requirements Purchases remaining 91% of electricity supply from Yukon Energy Corp., a crown corporation
Commodity Costs	Fuel and purchased power adjustment mechanism recovers price variance in forecasted vs. actual commodity costs
Size	Provides electric distribution service to 17,600 retail customers 2014 Rate Base of $83.0 million 2014 Regulated Revenues of $59.0 million Transmission and distribution system – 1,383 km
Regulatory Regime	Cost of Service Forecasted test year Average rate base
Operating Cost Recovery	No weather normalization clause No revenue decoupling mechanism Deferral/variance accounts for:[1] Pension costs Storm Costs DSM/Energy Efficiency Costs
Capital Cost Recovery	Approved forecast of capital costs
Competition from Alternative Fuels	Competition from propane gas, wood pellets, and fuel oil for residential space heating

[1] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

Company: FortisBC Energy

Regulatory Authority	British Columbia Utilities Commission
Utility Type	Natural Gas Distribution
Parent Company	Fortis Inc.
Cost of Capital	Equity Ratio 38.5% Return on Equity 8.75% Benchmark utility in British Columbia
Credit Rating	A- (S&P)
Generation Ownership	Gas distribution utility, does not own regulated generation assets
Commodity Costs	Purchased gas adjustment mechanism recovers variance in forecasted vs. actual gas costs on a quarterly basis
Size	Provides gas distribution service to 982,000 retail customers 2014 Rate Base of $2.765 billion 2014 Regulated Revenues of $1.489 billion Distribution system – 27,651 miles Transmission system – 1,864 miles
Regulatory Regime	Performance-based regulation plan (2014-2019) Going in rates for PBR plan are based off forecast costs Average rate base
Operating Cost Recovery	Revenue decoupling mechanism Deferral/variance accounts for:[2] Pension costs Interest rate tracker DSM/Energy Efficiency Costs
Capital Cost Recovery	Pre-approval of capital costs Cost tracking mechanism for large projects
Competition from Alternative Fuels	Competition from electricity for space heating

[2] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

Company: FortisBC Electric

Regulatory Authority	British Columbia Utilities Commission
Utility Type	Vertically-integrated Electric Utility
Parent Company	Fortis Inc.
Cost of Capital	Equity Ratio 40.0% Return on Equity 9.15% Risk premium of 40 basis points above benchmark utility
Credit Rating	A- (S&P)
Generation Ownership	Owns 225 MW of regulated generation assets, which provide approximately 45% of supply requirements
Commodity Costs	Fuel and purchased power adjustment mechanism recovers variance in forecasted vs. actual commodity costs
Size	Provides electric distribution service to 166,400 retail customers 2014 Rate Base of $1.204 billion 2014 Regulated Revenues of $317.3 million Transmission and distribution system – 6,800 km
Regulatory Regime	Performance-based regulation plan (2014-2019) Going in rates for PBR plan are based off forecast costs Average rate base
Operating Cost Recovery	Revenue decoupling mechanism Deferral/variance accounts for:[3] Pension costs Interest rate tracker DSM/Energy Efficiency Costs
Capital Cost Recovery	Pre-approval of capital costs Cost tracking mechanism for large projects
Competition from Alternative Fuels	Competition from natural gas, alternative technologies

[3] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

Company: Newfoundland Power

Regulatory Authority	Public Utilities Board of Newfoundland and Labrador
Utility Type	Vertically-integrated Electric Utility
Parent Company	Fortis Inc.
Cost of Capital	Equity Ratio 45% Return on Equity 8.75%
Credit Rating	Baa1 (Moody's)
Generation Ownership	Owns 139 MW of regulated generation assets, which provide approximately 7% of supply requirements. Purchases remaining 93% of electricity supply from Newfoundland and Labrador Hydro, a crown corporation.
Commodity Costs	Rate Stabilization Account allows for recovery of variations in production costs, and recovers or credits variations in supply costs due to changes from test year energy and demand costs. Limits risk of recovery of supply costs to approximately +/- $640,000.
Size	Provides electric distribution service to 262,000 retail customers 2014 Rate Base of $965 million 2014 Regulated Revenues of $630 million Transmission and distribution system – 11,000 km
Regulatory Regime	Cost of Service Forecasted test year Average rate base
Operating Cost Recovery	Weather normalization clause No revenue decoupling mechanism Deferral/variance accounts for:[4] Pension costs DSM/Energy Efficiency Costs
Capital Cost Recovery	Pre-approval of capital costs
Competition from Alternative Fuels	Competition from heating oil for residential space heating

[4] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

Company: Maritime Electric

Regulatory Authority	Island Regulatory and Appeals Commission
Utility Type	Vertically-integrated Electric Utility
Parent Company	Fortis Inc.
Cost of Capital	Equity Ratio 40.9% Return on Equity 9.35%
Credit Rating	BBB+ (S&P)
Generation Ownership	Owns 150 MW of regulated generation assets, which provide approximately 24% of supply requirements. Purchases remaining 76% of electricity supply from New Brunswick Power
Commodity Costs	Fuel and purchased power adjustment mechanism recovers variance in forecasted vs. actual commodity costs
Size	Provides electric distribution service to 78,000 retail customers 2014 Rate Base of $330 million 2014 Regulated Revenues of $181 million Transmission system – 600 km Distribution system – 4,440 km
Regulatory Regime	Cost of Service Forecasted test year Average rate base
Operating Cost Recovery	Weather normalization clause No revenue decoupling mechanism Deferral/variance accounts for:[5] Pension costs DSM/Energy Efficiency Costs
Capital Cost Recovery	Pre-approval of capital costs
Competition from Alternative Fuels	Limited competition from heating oil for residential space heating

[5] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

Company: ATCO Electric Distribution

Regulatory Authority	Alberta Utilities Commission
Utility Type	Electric Distribution Utility
Parent Company	Canadian Utilities Inc.
Cost of Capital	Equity Ratio 38.0% Return on Equity 8.30%
Credit Rating	A (S&P) (CUI)
Generation Ownership	Does not own regulated generation assets
Commodity Costs	N/A Does not provide retail services to customers
Size	Provides electric distribution service to 224,000 customers 2014 Rate Base of $1.949 billion 2014 Regulated Revenues of $1.61 billion Distribution system – 69,000 km
Regulatory Regime	Performance based regulation plan (2013-2017) Going in rates for PBR plan are based off forecast costs Average rate base
Operating Cost Recovery	No weather normalization clause No revenue decoupling mechanism Deferral/variance accounts for:[6] Interest rate tracker (for changes in interest rates that are incorporated through the capital tracker mechanism of Alberta's current PBR regime)
Capital Cost Recovery	Pre-approval of forecast capital costs with true-up
Competition from Alternative Fuels	Limited

[6] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

Company: Pacific Northern Gas – West

Regulatory Authority	British Columbia Utilities Commission
Utility Type	Natural Gas Distribution
Parent Company	AltaGas
Cost of Capital	Equity Ratio 46.5% Return on Equity 9.50% Risk premium of 75 basis points above benchmark utility
Credit Rating	BBB (S&P) for parent company
Generation Ownership	Gas distribution utility, does not own regulated generation assets
Commodity Costs	Purchased gas adjustment mechanism recovers variance in forecasted vs. actual gas costs
Size	Provides gas distribution service to 20,400 retail customers 2014 Rate Base of $138.6 million 2014 Regulated Revenues of $34.5 million Distribution system – 1,180 km Transmission system – 887 km
Regulatory Regime	Cost of Service Forecasted test year Average rate base
Operating Cost Recovery	Revenue decoupling mechanism Deferral/variance accounts for:[7] Bad debt expense Interest rate tracker DSM/Energy Efficiency Costs
Capital Cost Recovery	Capital costs approved or denied as forecast as part of Revenue Requirement Application
Competition from Alternative Fuels	Competition from electricity for space heating
Other	Loss of major customer reduced total system throughput by 87% from 2003-2012

[7] Attachment JMC-2 lists the deferral/variance accounts for each company from among the five accounts that were sampled in Figure 9 of the report. This is not a complete list of all deferral/variance accounts for each company.

ATCO Electric
YUKON

ATCO Electric Yukon
Reserve for Injuries and Damages Claim
Beaver Creek House Fuel Spill
Date of Incident: April 2015

Description of Asset Damaged:

Area beneath the building footprint of Company Owned House, Lot 36, Beaver Creek, YT

Incident Summary:

In April 2015 a release of an estimated 600L of heating fuel from an above-ground storage tank was discovered by ATCO Electric Yukon staff. ATCO Electric Yukon retained Arctic Backhoe Services Ltd. to complete the remedial excavation of soils.

Approximately 116m3/s of contaminated soil was relocated under Relocation Permit #23-661 to the McLean Lake permitted Land Treatment Facility in Whitehorse, YT.

Confirmatory samples were collected from the base and walls of the remedial excavation beneath the buildings footprint and concluded that remediation was successful and no further environmental assessment or remediation work is recommended.

Incident Costs:

Total Cost of Remediation ($000s)

Remediation Reporting	13.4
Removal and Relocation of Soil	84.2
Engineering & Supervision	12.1
	109.7

ATCO Electric Yukon has included the $109,700 in its RID account for 2015.

ATCO Electric Yukon
Reserve for Injuries and Damages Claim
Fish Lake Ditch #1 Spillway Failure
Date of Incident: January 2015

Description of Asset Damaged:

The apron and headwall had lifted to create a void, which was open to the water column within Ditch #1.

Incident Summary:

A significant amount of water was found entering into Ditch #1 and was flowing through the Ditch #1 embankment and underneath the Spillway #1 culvert. It was discovered that the apron and headwall had lifted 11 cm along the leading edge of the apron slab, to create the void, which was open to the water column within Ditch #1.

Initial assessment and emergency repairs have been undertaken to limit the water flow. This incident is currently under investigation by ATCO Electirc Yukon's insurance company.

Incident Costs:

Total Estimate Costs – this project is not fully completed and therefore the total costs of this project have not been finalized.

ATCO Electric Yukon has included the $100,000 insurance deductible in its RID account related to this event. If the total expenditures are not recovered through insurance, ATCO Electric Yukon will include any amounts into its RID account for future recovery.

Section 9 – Capital Additions

Overview

The capital expenditures and additions included in this Application are outlined in Schedule 9.1 and are as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Capital expenditures	15,358	16,837	10,694	15,048	15,318
Capital additions to rate base	14,321	18,849	10,252	14,234	14,907

The capital additions as summarized on Schedule 9.1 are broken down into the following categories:

Generation

Generation assets are continually monitored through power plant inspections and monitoring. Components are repaired or replaced due to unacceptable performance, discontinuation by manufacturer, in accordance with manufacturer specifications, on planned replacement intervals or at the end of their useful life. The reliability and integrity of the power generation system is a key consideration when critical replacement decisions are being contemplated. Other considerations include load growth on a power plant and/or specific generation units, premature failure, safety requirements, and environmental regulations which can dictate the need for additional generation assets to be put in place. Additionally, ATCO Electric Yukon considers that the integration of renewables and the impact on the automation/control of the isolated generation facilities may trigger capital expenditures over the test period. An estimate is developed by determining what generating units are due for replacement and other upgrades or replacements required to the generating facilities. Were possible, forecast costs take into account the following: preliminary engineering and design work, historical costs of comparable projects and any results of a tender process.

New Extensions

Customer requests for a new service typically require extensions of the distribution system. ATCO Electric Yukon develops its new extension capital forecast based on discussions with the Yukon Government, the City of Whitehorse and First Nation Governments. ATCO Electric Yukon also holds a seat on the Development Review Committee with the City of Whitehorse that puts ATCO Electric Yukon in contact with Developers and Engineering Firms which informs the new extension forecast. ATCO Electric Yukon assesses the ability of the existing infrastructure to accommodate the proposed growth taking into account the specific service requirements of the customer. An estimate is developed for the facilities required for each of the new extensions and inserted into the annual forecast. In addition, ATCO Electric Yukon considers historical customer additions to account for walk-in customers that are expected to require service.

Distribution Improvements

Distribution improvement projects generally fall into four major categories:

1. System Performance Projects – are required to maintain system performance at an acceptable level. This category includes system protection, voltage, current and line clearance projects.

2. Life Extension Projects – are required to increase the operating life of the distribution system. This category includes electrical equipment refurbishments or upgrades, voltage conversions and reconductor projects.

3. System Replacement Projects – are required to replace distribution system facilities on a planned basis when they have reached the end of their useful life. This includes replacement of distribution poles, ground systems, as well as overhead and underground system equipment replacements.

4. Forced Projects – are required to correct unplanned system failures and upgrades due to other projects in the area or a new development.

In addition to the above, ATCO Electric Yukon tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. Additionally, ATCO Electric Yukon reviews unplanned outages that may be attributed to system deficiencies and implements corrective action. Costs for distribution improvements are forecast based on preliminary engineering design work and considers historical project costs for comparable projects.

Street and Sentinel Lights

Expenditures are required to provide new street and sentinel lighting in ATCO Electric Yukon's service area. Streetlights that require replacement due to poor condition assessment are included in this category. A condition assessment is based on performance of street lights, deficiencies or substandard conditions and the general physical condition. Inspection of the general physical condition includes the base and metal structure for deterioration, rust, broken bolts and damage. New installations or requests from customers and developers are also included. The forecast is determined based on known areas of development in the communities, as well as a review of historic replacement requirements.

Conversion of Existing LED Streetlights

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.

Meters

Capital meter additions include new meters installations that are required to replace end of life meters as identified by Measurement Canada. This category also includes the installation of new meters required to accommodate load growth associated with customer requests for service. These expenditures allow ATCO Electric Yukon to meet its obligation to provide metered service connections. The capital meter additions are forecasted based on known areas of development and expected connection requests.

General Property and Equipment

This portion of the capital forecast provides for replacement of equipment and for the purchase of new equipment required to support ATCO Electric Yukon's operations. These include tools, office furniture, office computer equipment and software communication equipment, transportation equipment, lands and buildings. Estimates are developed by determining what the needs are for upgrade, purchase or replacement of general property and equipment and developing a forecast based on historical and market prices.

Capital Project Delivery

ATCO Electric Yukon has a project process in place for the identification, planning and execution of its capital projects. The general project process is followed for Generation, New Extensions, Distribution Improvements, Street Lights and General Property and Equipment projects.

At the initiation a new project, either requested by a new customer or required for system improvement, the general scope of the project is identified and the appropriate internal employees are engaged. As the general scope of a project is further defined, a more detailed review is completed that identifies the needs of the new customer or the deficiency in the power system that needs to be addressed. The engineering department will establish the total scope of the effort, define the project objectives,

develop a cost estimate, projected schedule, and the resources required to successfully complete the project.

Where appropriate, business cases and/or engineering studies also completed to ensure the most reasonable alternative is selected and that the solution meets both the needs of the system and the customer.

The Operations department will review the current power system in consideration of the new project with the key consideration being the safe integration of the project in to the power system. If it's a new customer extension project, a review of substation(s) and feeder loading as well as the condition of existing electrical equipment will be completed.

As the project proceeds, regular reporting by construction crews, warehouse personnel and engineering assistants keep the project lead informed of the overall schedule and emerging issues that can affect scope, schedule, or costs so that mitigation strategies can be developed to minimize their impact.

2016-2017 Business Cases

A listing of the capital expenditures for 2016-2017 is provided in Attachment 9.1 and 9.2 which includes a project description for those projects greater than $100,000. Full business cases for the following major capital projects ($500,000 or greater) are included in Appendix 1 - 11.

Business Cases for Test Period Projects

Fish Lake Ditch #3 Diversion Replacement	Appendix 1
Fish Lake 2 Head Pond Spillway Replacement	Appendix 2
Watson Lake Bi-Fuel	Appendix 3
Watson Lake Unit #2 Replacement	Appendix 4
Old Crow Unit #3 Replacement	Appendix 5
Destruction Bay Unit #2 Replacement	Appendix 6
Whistle Bend Stage 3	Appendix 7
McIntyre Subdivision Rebuild	Appendix 8
Downtown Whitehorse Capacity Upgrade	Appendix 9
Paint Mountain Conductor Replacement	Appendix 10
Destruction Bay Unit #3 Replacement (completed 2014)	Appendix 11

For the 2013-2015 period, business cases for major capital projects were provided as part of the 2013-2015 General Rate Application. Destruction Bay Unit #3 Replacement had an approved forecast of $450,000 in 2014. Actual costs exceeded $500,000; therefore a business case has been included in Appendix 11.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Plant Additions
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Work in progress, Beginning of Year		2,094	2,094	3,131	1,561	1,119	961	1,561	2,375
2										
3	**Generation:**									
4	Generating Plants		5,574	5,964	8,599	7,387	3,060	2,900	6,630	5,316
5			5,574	5,964	8,599	7,387	3,060	2,900	6,630	5,316
6	**Distribution:**									
7	New Extensions		2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
8	Distribution Improvements		4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
9	Street and Sentinel Lights		536	420	322	945	466	813	585	1,132
10	Meters		308	600	166	204	234	207	200	204
11	Meters - AMR		-	-	-	-	-	-	-	-
12	Transformers and Regulators		72	10	75	10	108	10	368	92
13			7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994
14	**General Property and Equipment:**									
15	Tools, Instruments & Equipment		159	117	142	167	110	115	149	166
16	Office Furniture & Equipment		-	44	20	42	3	34	20	20
17	Office Computer Equipment		159	5	243	5	29	5	8	42
18	Software		84	700	41	2	-	52	-	-
19	Fish Lake Water License Renewal		841	650	-	-	-	-	-	-
20	Demand Side Management Costs		75	75	-	-	-	-	-	-
21	Communication Equipment		34	65	22	11	143	12	117	161
22	Transportation Equipment		471	424	858	995	1,076	850	370	317
23	Land and Buildings		693	1,131	676	321	41	312	94	301
24			2,516	3,210	2,002	1,544	1,402	1,380	759	1,008
25										
26	Miscellaneous Other		-	-	-	-	-	-	-	-
27										
28	**Total Capital Expenditures**	S.9.2 L.219	15,358	19,259	16,837	19,692	10,694	14,484	15,048	15,318
29										
30	Less:									
31	Transfers to Rate Base	S.8.6 L.5	(14,321)	(19,792)	(18,849)	(20,292)	(10,252)	(14,484)	(13,872)	(14,907)
32	Transfers to Deferred Charges	S.8.8 L.36	-	-	-	-	-	-	(362)	-
33			(14,321)	(19,792)	(18,849)	(20,292)	(10,252)	(14,484)	(14,234)	(14,907)
34										
35	Work in Progress, End of Year	S.8.5 L.5	3,131	1,561	1,119	961	1,561	961	2,375	2,786

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

Line No	Project Name	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	**Generation**									
2	Fish Lake Unit 1 Turbine and Building Replacement		1,409	1,798	426		15		-	-
3	Fish Lake Dyke Upgrade	Attachment 11.1	326	300	2,226	1,420			-	-
4	Fish Lake Unit 2 Siding Replacement		51	35					-	-
5	Louise Lake Control Structure		49	-					-	-
6	Fish Lake Unit 1 Fiber Communication		45	20					-	-
7	Fish Lake Unit 2 SCADA		44	50					-	-
8	Fish Lake Unit 2 Penstock Improvements		43	40					-	-
9	Fish Lake Unit 1 Spillway Diversion Structure	Attachment 9.2, pg 1	22	20		100			-	413
10	Fish Lake Unit 2 Building Improvements		20	20					-	-
11	Fish Lake Unit 2 Vibration Monitoring		19	20					-	-
12	Fish Lake Ditch 3 Diversion Replacement	Appendix 1	16	-	51	1,640	67		2,915	-
13	Fish Lake Unit 2 Head Pond Low Level Outlet Pipe					30			-	-
14	Fish Lake Unit 1 Needle Detach Failure						21		-	-
15	Fish Lake Unit 2 Assessment	Attachment 9.1, pg 1							100	-
16	Fish Lake Water Monitoring Upgrades								25	26
17	Fish Lake #2 Head Pond Spillway Replacement	Appendix 2	30	30					20	593
18	Louise Lake Containment Dyke Seismic Analysis								40	-
19	Fish Lake Ditch 1 Intake Building - Design								-	31
20	Watson Lake Unit 4 Replacement		979	1,120	28				-	-
21	Watson Lake Unit 6 Major Overhaul		243	250					-	-
22	Watson Lake Bi-Fuel	Appendix 3	221	-	82	-	59		-	2,759
23	Watson Lake Unit 5 Major Overhaul				239	200			-	-
24	Watson Lake Replace ABB 5HK Breakers				187	180	220	200	-	-
25	Watson Lake Unit 1 Major Overhaul						278	250	-	-
26	Watson Lake Unit 2 Replacement	Appendix 4						1,350	1,390	-
27	Watson Lake Plant Fire Alarm System - Design	Attachment 9.2, pg 2							-	102
28	IRC Chargers								-	22
29	Old Crow Plant Expansion	Attachment 11.2	599	300	2,707	1,650	1,260		-	-
30	Old Crow Unit 4 Addition				504	500	108		-	-
31	Old Crow Unit 3 Replacement	Appendix 5					213	500	1,049	-
32	Old Crow Unit 2 Replacement	Attachment 11.7					161		-	-
33	Old Crow Unit 2 Generator Refurbishment								75	-
34	Old Crow Original Plant Rebuild	Attachment 9.2, pg 1					90		-	250
35	Old Crow Unit 2 - External Equipment								-	51
36	Beaver Creek Programmable Logic Control (PLC) Upgrade	Attachment 11.3	346	180	31				-	-
37	Beaver Creek Unit 2 Replacement		271	600	455				-	-
38	Beaver Creek Unit 1 Replacement				397	600	260		-	-
39	Beaver Creek Fuel Line Upgrade						77		-	-
40	Destruction Bay Plant Foundation Refurbishment		131	150					-	-
41	Destruction Bay Unit 3 Replacement	Appendix 11			616	450	18		-	-
42	Destruction Bay Programmable Logic Controller Upgrade	Attachment 9.2, pg 1			83	300	26		-	307
43	Destruction Bay Unit 2 Replacement	Appendix 6				-	136	600	622	-
44	Destruction Bay Fuel Line Upgrade	Attachment 9.1, pg 1							106	-

ATCO Electric Yukon
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Continuity of Capital Expenditures
($000s)

Line No	Project Name	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
45	**Generation Continued**									
46	Pelly Crossing Fuel System Upgrade	Attachment 9.2, pg 1							-	153
47	Pelly Crossing Ventilation System Upgrade								-	26
48	Pelly Crossing Unit 2 Silencer								-	20
49	Ross River Replace ABB 5HK Breakers					45			95	-
50	Ross River Electrical Service Panel Upgrade								25	-
51	Stewart Crossing Plant Improvements					180			-	-
52	Stewart Crossing - Spare Fuel Injector				28				-	-
53	Swift River Unit 2 Replacement		49	30					-	-
54	Swift River Unit 1 Replacement								80	61
55	Teslin Plant Assessment	Attachment 9.2, pg 2							-	102
56	Teslin PLC Replacement - Design	Attachment 9.2, pg 1							-	105
57	Haines Junction Fuel Containment Upgrade								-	31
58	500kW Mobile Generator		361	750	514		25		-	-
59	New 250kW Mobile Generator		211	175					-	-
60	OSS Control Upgrade		21						-	-
61	Mobile Generator 250kW Voltage and Frequency Protection								35	-
62	Mobile Generator 225 kW Refurbishment								20	-
63	Fuel System Assessment								-	99
64	PLC Replacement Stage 1	Attachment 9.2, pg 2							-	103
65	Mobile Generator 350 kW Refurbish Enclosure								-	19
66	Other Projects Less Than $20,000		68	76	25	92	26		33	43
67	**Generation Total**		**5,574**	**5,964**	**8,599**	**7,387**	**3,060**	**2,900**	**6,630**	**5,316**
68	**New Extensions**									
69	New General Overhead Services - Various Subdivisions	Attach. 9.1 pg 2, 9.2 pg 3	811	3,509	699	2,900	826	4,030	987	1,009
70	New Underground Line Extensions	Attach. 9.1 pg 2, 9.2 pg 3	834	600	712	1,000	852	1,000	1,013	1,035
71	Annual Land Rights	Attach. 9.1 pg 2, 9.2 pg 3	45	190	64	190	121	190	120	123
72	General Drafting and Mapping		44	80	66		34		40	41
73	Whistle Bend Subdivision Stage 1 & 2	Attachment 11.8	273	-	138		102		-	-
74	Whistle Bend Underground Residential Service	Attachment 11.9					116		-	-
75	Whistle Bend Stage 3	Appendix 7				977			-	1,180
76	City of Whitehorse Range Road Widening	Attachment 11.10	188	-					-	-
77	Yukon Government Teslin Sawmill Subdivision		132	75					-	-
78	Whitehorse Municipal Services Building			420					-	-
79	Lot 11 Marion Crescent			53					-	-
80	Lot 1000 Airport Road			53					-	-
81	Other Projects Less Than $20,000		23	53	14	80	47	80	-	-
82	**New Extensions Total**		**2,350**	**5,033**	**1,693**	**5,147**	**2,098**	**5,300**	**2,160**	**3,388**

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Continuity of Capital Expenditures
($000s)

Line No	Project Name	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
83	**Distribution Improvements**									
84	Annual Right of Way Widening	Attach. 9.1 pg 3, 9.2 pg 4	364	374	403	389	402	405	440	450
85	General Pole Replacements	Attach. 9.1 pg 3, 9.2 pg 4	147	260	96	260	111	260	298	286
86	PCB Identification and Transformer Change Outs	Attachment 9.1, pg 3	103	175	29	100	101	100	150	51
87	Vault Replacements	Attachment 9.2, pg 5			20		21		40	102
88	General Clearance Upgrades/Fixes		26	65	78	70	20		50	51
89	Test and Treat Pole Program		-	110		120		130	-	-
89	McIntyre Subdivision Rebuild	Attach. 11.4, Appendix 8	656	475	418	250	379		565	930
90	Downtown Whitehorse 25kV Conversion	Appendix 9			361	450	519	450	-	-
91	Downtown Whitehorse Capacity Upgrade	Appendix 9							1,455	368
92	Hillcrest Subdivision Conversion	Attachment 9.2, pg 4	337	275	29	250	314		-	153
93	4L314 Chilkoot Way Upgrade	Attachment 11.11	483	-					-	-
94	Downtown Whitehorse 4L313 Labert Street to Elliot Street			424					-	-
95	Crestview to Mayo Road 5L628 Upgrade to 266 MCM		364	250					-	-
96	Hotsprings Road Main Line Relocation and Upgrade		338	325					-	-
97	Old Alaska Highway Bypass		212	248					-	-
98	Tagish 5L600 Rebuild		151	300			184	276	-	-
99	Jack Hulland School Upgrades		135	100					-	-
100	Teslin Area Pole Upgrades		93	53					-	-
101	Firth Breaker Replacement		60						-	-
102	McIntyre Substation Change Switches and Busswork		45						-	-
103	600 Amp Feeder from Tamarack to Evergreen		45						-	-
104	97 Lewes Blvd Upgrade		39						-	-
105	Lot 1037 Range Road Line Upgrade		37	34					-	-
106	Ion Meter Upgrade		29						-	-
107	Ross River Recloser for S7580		29						-	-
108	Shipyards Substation Upgrades		28						-	-
109	Lot 1037 Range Road Trespass		22						-	-
110	Watson Lake Substation Ground Grid Upgrade		22						-	-
111	Downtown Whitehorse 4L316 6th Avenue 266 Reconductor			250		300			-	-
112	Carmacks North Main Line Rebuild			100					-	-
113	Whitehorse Asset Management			75	28	75	73		-	-
114	Whitehorse Safety Code Corrections			30					-	-
115	Whitehorse 5L628 and New 34.5kV Build		156		1,790	1,890			-	-
116	Takhini/Marwell 4L315 Upgrades				263	250	71	350	-	-
117	Deep Creek Subdivision Connection	Attachment 11.5			182		31	60	-	-
118	Nisutlin Bridge Cable Tray Upgrade				97				-	-
119	Marwell Lot 14 Transformer Upgrade				68				-	-
120	Yukon Wildlife Preserve Powerline Rebuild				54				-	-

ATCO Electric Yukon
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Continuity of Capital Expenditures
($000s)

Line No	Project Name	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
121	**Distribution Improvements Continued**									
122	Lewes Lake Substation Conversion						157	146	-	-
123	Azure Road Extension	Attachment 11.12					151		-	-
124	Teslin Sawmill Road Feeder Upgrade			38			130		-	-
125	2nd Ave Relocation	Attachment 11.13					115		-	-
126	MacDonald Road Pole Change						103	250	-	-
127	Watson Lake Underground Subdivision Replacement						78		-	-
128	McLintock Substation Upgrade						76	90	-	-
129	Spirit Lake Substation Upgrade						70	88	-	-
130	Upper Liard – Replace Liard River Crossing						70		-	-
131	Takhini/Marwell Completion of Mountain Air Subdivision						67	300	-	-
132	Lane Rebuild - 30 Tagish Road						31		-	-
133	Install Interface Metering for 5L655						28		-	-
134	Whitehorse Hotsprings Road 3 Phase Conversion						20	363	-	-
135	Riverdale Line 4L317 Tagish Road							250	-	-
136	Whitehorse Airport Hanger D Area Rebuild	Attachment 9.2, pg 5						140	-	143
137	Grey Mountain 4L320 Tie Upgrade							65	-	-
138	Stewart Crossing West Town Conversion							60	-	-
139	Upgrade of S2278							45	-	-
140	Range Road Rebuild	Attachment 9.1, pg 4							110	-
141	Upgrade Underground Line Into Services and Shipyard Sub	Attachment 9.1, pg 4							102	-
142	McCrae Substation Second Feeder Breaker	Attachment 9.1, pg 3							415	-
143	McCrae Substation Transformer Upgrade to 10 MVA	Attachment 9.1, pg 3							298	-
144	5L622 - Lewes River Bridge Crossing Replacement	Attachment 9.1, pg 4							140	-
145	Carcross Nares Bridge Relocation								90	-
146	Whistle Bend Way Underground Crossing								60	-
147	Fault Indicators in Padmount Equipment								50	-
148	Paint Mountain Conductor Replacement	Appendix 10							-	562
149	Replace Watson Lake Substation Transformer T2	Attachment 9.2, pg 4							-	358
150	400 Amp Regulators in Logan Substation	Attachment 9.2, pg 5							-	123
151	400 Amp Regulators in Arkell Substation	Attachment 9.2, pg 5							-	123
152	Shipyards Spare 25kV Breaker	Attachment 9.2, pg 5							-	102
153	Replace Underground Cables at Whitehorse Airport								-	85
154	Rebuild Line Behind City Municipal Services Building								-	82
155	Haines Junction OSS Replacement								-	51
156	Single Regulator 5L631								-	31
157	Steward Crossing Ferry Hill Line Rebuild - Design								-	31
158	McRae Substation Regulator Upgrade								-	20
159	Other Projects Less Than $20,000		81	60	92	53	77	47	83	76
160	**Distribution Improvements Total**		**4,002**	**4,021**	**4,008**	**4,457**	**3,399**	**3,875**	**4,346**	**4,178**

ATCO Electric Yukon
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Continuity of Capital Expenditures
($000s)

Line No	Project Name	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
161	**Street and Sentinel Lighting**									
162	General Streetlight Replacements	Attach. 9.1 pg 5, 9.2 pg 6	244	330	213	450	178	330	200	256
163	New Customer Streetlight Installations	Attach. 9.1 pg 5, 9.2 pg 6	138	-	34		172	483	200	204
164	Whistle Bend Streetlights	Appendix 7	142	75		450			-	350
165	McIntyre Subdivision Streetlight Rebuild	Appendix 8							175	256
166	Watson Lake Street Light Replacement								-	41
167	Other Projects Less Than $20,000		12	15	47	45	43		10	25
168	**Street and Sentinel Lighting Total**		**536**	**420**	**294**	**945**	**393**	**813**	**585**	**1,132**
169	**Meters**									
170	Replacement of Meters and New Installations	Attach. 9.1 pg 6, 9.2 pg 7	308	600	166	204	234	207	200	204
171	**Meters Total**		**308**	**600**	**166**	**204**	**234**	**207**	**200**	**204**
172	**Transformers & Regulators**									
173	General Capitalizable Transformers	Attach 9.1 pg 7, 9.2 pg 8	72	10	75	10	108	10	90	92
174	Spare 10 MVA Transformer	Attachment 9.1, pg 7	-	-	-	-	-	-	220	-
175	Spare Padmount Regulator for Shipyards Substation		-	-	-	-	-	-	58	-
176	**Transformers & Regulators Total**		**72**	**10**	**75**	**10**	**108**	**10**	**368**	**92**
177	**GP&E**									
178	Downtown Office Building Envelope Upgrades		224	600	365				-	-
179	Whitehorse Service Complex Pole Storage		229	150					-	-
180	Downtown Office Interior Renovations		53	100	47				-	-
181	Whitehorse Service Complex Parking Lot Improvements		117	100					-	-
182	Whitehorse Service Complex Office Area Renovations		60	80					-	-
183	Whitehorse Service Complex - Exterior & Service Bay Upgrades			70					-	-
184	Whitehorse Service Complex - Fence Extension		12	20					-	-
185	Downtown Office Paving & Drain				31				-	-
186	Old Crow Staff Accommodations	Attachment 11.6			233	100	41		-	-
187	Watson Lake Power Plant Connection to Town Water Supply					100			-	-
188	Whitehorse Various Service Complex Renovations					100			-	-
189	Whitehorse Service Complex Yard Extension							300	-	-
190	Furnace Replacements - Watson Lake								25	-
191	Service Complex Heating System								40	26
192	Watson Lake Septic Upgrade								-	51
193	Service Complex Boiler Replacement								-	72
194	Watson Lake Storage Solutions								-	93
195	Communication Equipment		34		22	11	86	12	18	13
196	AEY SCADA Upgrades						57		49	67
197	Windows XP Conversion for Operations Dispatch								30	-
198	Form 6 Substation Controls								20	-
199	Whitehorse SCADA Dispatch UHF Repeater								-	36
200	Replace XP Operating Systems - iFix PCs								-	46
201	Office Furniture & Equipment			44	20		3	34	20	20
202	Miscellaneous Tools and Instruments	Attach. 9.1 pg 8, 9.2 pg 9	159	117	142	167	110	115	149	166
203	Fish Lake Water License Renewal		841	650					-	-

ATCO Electric Yukon
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Continuity of Capital Expenditures
($000s)

Line No	Project Name	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
204	**GP&E Continued**									
205	Display Change to Yukon Electrical Billing Statements			259					-	-
206	Windows 7 Upgrades		49	146		-			-	-
207	E-Post Billing		31	125	107	-			-	-
208	Demand Side Management Costs		75	75		-		-	-	-
209	Field Collection System		58	55					-	-
210	Field Collection System - Report Development (ITBS)			43					-	-
211	Yukon Electrical Website Improvements			35					-	-
212	New Cashier System			25	50				-	-
213	Oracle R12 Upgrade		35	-	41				-	-
214	One Time Credit Card Changes			-	-	-			-	-
215	Transportation Equipment	Attach. 9.1 pg 8, 9.2 pg 9	471	424	858	995	670	400	370	317
216	Replacement of Unit 989 - 1995 Hot Line Bucket Truck						406	450	-	-
217	Other Projects Less Than $20,000		68	93	86	69	29	68	38	101
218	**GP&E Total**		**2,516**	**3,211**	**2,002**	**1,542**	**1,402**	**1,379**	**759**	**1,008**
219	**Grand Total**	S.9.1 L.28	**15,358**	**19,259**	**16,837**	**19,692**	**10,694**	**14,484**	**15,048**	**15,318**

2016-2017 General Rate Application

2016 Capital Expenditure Information

GENERATION PLANTS **$6,630,000**

- Fish Lake Ditch 3 Diversion Replacement $2,915,000

  Please refer to Appendix 1.

- Watson Lake Unit 2 Replacement $1,390,000

  Please refer to Appendix 4.

- Old Crow Unit 3 Replacement $1,049,000

  Please refer to Appendix 5.

- Destruction Bay Unit 2 Replacement $622,000

  Please refer to Appendix 6.

- Destruction Bay Fuel Line Upgrade $106,000

  The fuel system that supplies the power plant with diesel needs to be upgraded to ensure proper operation of the generating units. The upgrade will ensure that the system meets all current code requirements and provides adequate measures to address an uncontrolled fuel release.

- Fish Lake Unit 2 Assessment $100,000

  Fish Lake Unit 2 is a 1958 Gilkes hydro turbine. This assessment will determine the overall operating condition of the power plant and related infrastructure. The assessment will identify life extension, major refurbishment and/or replacement options.

- Other Projects less than $100,000 $448,000

  Please refer to the detailed project listing in Schedule 9.2.

DISTRIBUTION NEW EXTENSIONS **$2,160,000**
(Gross of Customer Contribution)

Capital expenditures required for the connection of new residential and commercial customers in ATCO Electric Yukon's service area. ATCO Electric Yukon's investment in new extension projects is based on the maximum investment levels included in the Board-approved Terms and Conditions.

New extensions include:

- New Underground Line Extensions $1,013,000

  New services installed to serve various customers in underground distribution areas.

- New General Overhead Services – Various Subdivisions $987,000

  Capital expenditures required for the connection of new residential and commercial customers in ATCO Electric Yukon's service area in compliance with Terms and Conditions. New extensions (driven by a customer) that are under $25,000 are included in this grouping.

- Annual Land Rights $120,000

  The costs charged to this annual project are incurred to obtain easements once property is registered in land titles. Specific costs include monitoring title status, drafting of easements and obtaining easements.

- Other Projects less than $100,000 $40,000

  Please refer to the detailed project listing in Schedule 9.2.

DISTRIBUTION IMPROVEMENTS **$4,346,000**

Major improvements include:

- Downtown Whitehorse Capacity Upgrade $1,455,000

  Please refer to Appendix 9.

- McIntyre Subdivision Rebuild $565,000

  Please refer to Appendix 8.

- Annual Right of Way Widening $440,000

  Brushing completed to widen existing rights of way (ROW) to allow for access, wild fire reduction, and reliability.

  Locations Included: 5L631 – Pineridge, Wolf Creek subdivsions. 9L - Judas Creek to Squanga Lake area. 5L622 – Teslin area. 5L600 – Taku subdivision. 5L638 – Stewart Crossing.

- McCrae Substation Second Feeder Breaker $415,000

  An additional breaker is required in the McCrae substation to support load growth and system coordination. The second breaker will allow system load in the area to be sectionalized.

- General Pole Replacements $298,000

  Various deficient poles are identified through distribution system inspections and in unplanned situations. System inspections identify ground rot, pest infestation, broken or damaged poles and electrical degradation. Unplanned situations include emergency situations and forced outages due to failure of the pole.

- McCrae Substation Transformer Upgrade to 10 MVA $298,000

  System load growth south of Whitehorse has met the load limit of the current 5 MVA in the McCrae substation.

- PCB Identification and Transformer Change Outs $150,000

  Identification of Polychlorinated Biphenyl (PCB) content of all oil-filled equipment, in compliance with the Canadian Environmental Protection Act 1999. Oil-filled equipment containing PCBs in a concentration of at least 50 mg/kg but less than 500 mg/kg is being removed from service.

- 5L622 – Lewes River Bridge Crossing Replacement $140,000

  Replacement of the conductors at the 34.5 kV river crossing is required. To replace the conductors the existing single pole structures will need to be replaced with new structures. The River Crossing will have enough clearance to avoid impeding standard boat traffic and will be designed with special consideration of ice and wind loading.

- Range Road Rebuild $110,000

  This project is to upgrade and relocate six power poles due to the configuration and proximity of the roadway.

- Upgrade Underground Line Into Services & Shipyard Sub $102,000

  The underground 34.5 kV cables that supply Services & Shipyards substations are approaching maximum capacity and need to be upgraded.

- Other Projects less than $100,000 $373,000

  Please refer to the detailed project listing in Schedule 9.2.

STREET AND SENTINEL LIGHTING **$585,000**

- General Streetlight Replacements $200,000

  Planned replacement program based on street light inspections and condition assessment of infrastructure. Condition assessment is based on performance of street lights, deficiencies or substandard conditions and the general physical condition includes the base and metal structure for deterioration, rust, broken bolts and damage.

- New Customer Streetlight Installations $200,000

  These street lights are installed at new customer requests. The design and engineered standards are completed in conjunction with the customer requesting service. ATCO Electric Yukon invests in compliance with Terms and Conditions. Projected cost of project is based on historical data and known projects identified by customers.

- McIntyre Subdivision Streetlight Rebuild $175,000

  Please refer to Appendix 8.

- Other Projects less than $100,000 $10,000

  Please refer to the detailed project listing in Schedule 9.2.

METERS **$200,000**

- Replacement of Meters and New Installations $200,000

  The installation of new meters is required to accommodate load growth associated with customer requests for service. These expenditures allow ATCO Electric Yukon to meet its obligation to provide metered service connections. The capital meter additions are planned based on known areas of development and expected connection requests. New meters are also required to replace end of life meters as identified by Measurement Canada.

TRANSFORMERS & REGULATORS	**$368,000**
· Spare 10 MVA Transformer	$220,000
Contingency requirement as there are 3 of these transformers in various substations in the Whitehorse area.	
· General Capitalizable Transformers	$90,000
· Other Projects less than $100,000	$58,000

Please refer to the detailed project listing in Schedule 9.2.

GENERAL PROPERTY & EQUIPMENT **$759,000**

- Transportation Equipment $370,000

  Replacement of Unit 643, a 1996 GMC Topkick vehicle with bucket and material handler attachment.

- Miscellaneous Tools and Instruments $149,000
  - Underground Line Tools
  - GPS Survey equipment
  - Fire Retardant Clothing for High Voltage Electrical Work
  - Miscellaneous Small Tools and Equipment

- Other Projects less than $100,000 $240,000

  Please refer to the detailed project listing in Schedule 9.2.

2016-2017 General Rate Application

2017 Capital Expenditure Information

GENERATION PLANTS **$5,316,000**

- Watson Lake Bi-Fuel $2,759,000

  Please refer to Appendix 3.

- Fish Lake #2 Head Pond Spillway Replacement $593,000

  Please refer to Appendix 2.

- Fish Lake Unit 1 Spillway Diversion Structure $413,000

  This Spillway Diversion Structure is located at the northwest corner of the Unit #1 plant yard. It is required to divert and control all water from Ditch #1 Spillway to separate channels forming the entrances of West McIntyre Creek and Porter Creek. The existing structure is built of plywood and dimensional lumber that are at the end of their useful life. A new and adequately engineered structure is required.

- Destruction Bay Programmable Logic Controller Upgrade $307,000

  Replacement of circa 1982 IDEC PLC as this control equipment is no longer supported or available from the manufacturer. The software driver is not compatible with the next generation of System Control and Data Acquisition (SCADA) program.

- Old Crow Original Plant Rebuild $250,000

  This project is to complete an engineered design of a building refurbishment based on the engineering condition assessment completed in 2015 for the legacy Old Crow power plant. The design will include considerations for electrical, mechanical, structural and insulation upgrades.

- Pelly Crossing Fuel System Upgrade $153,000

  The fuel system that supplies the power plant with diesel needs to be upgraded to ensure adequate fuel release containment. There are deficiencies in the existing containment system. The upgrade will ensure that the system meets all current code requirements and provides adequate measures to address an uncontrolled fuel release.

- Teslin PLC Replacement – Design $105,000

  This project involves the replacement of the existing IDEC PLC. This multiyear project will be carried out in two stages; year one will be design and procurement and year two will be construction and commissioning.

- PLC Replacement Stage 1 $103,000

  As of 2015 GE has identified the PLC 90-30 product line as mature. Once identified as mature GE will only provide sales of this line for 2 more years before discontinuing. PLC's are utilized to provide the majority of control for plants and prime movers used for generation. ATCO Electric Yukon currently utilizes a number of discontinued modules in its facilities.

- Teslin Plant Assessment $102,000

  The existing generating unit is contained in a trailered building on a concrete foundation. During inspections it was noted that there is considerable difference in elevation throughout the plant floor. The assessment will identify foundation and/or building deficiencies.

- Watson Lake Plant Fire Alarm System – Design $102,000

  Project to carry out replacement of existing fire alarm system in the Watson Lake Plant. Newly installed system will provide enhanced detection over previous smoke and heat detectors.

- Other Projects less than $100,000 $429,000

  Please refer to the detailed project listing in Schedule 9.2.

DISTRIBUTION NEW EXTENSIONS **$3,388,000**
(Gross of Customer Contribution)

Capital expenditures required for the connection of new residential and commercial customers in ATCO Electric Yukon's service area. ATCO Electric Yukon's investment in new extension projects is based on the maximum investment levels included in the Board-approved Terms and Conditions

New extensions include:

- Whistle Bend Stage 3 $1,180,000

  Please refer to Appendix 7.

- New Underground Line Extensions $1,035,000

  New services installed to serve various customers in underground distribution areas.

- New General Overhead Services – Various Subdivisions $1,009,000

  Capital expenditures required for the connection of new residential and commercial customers in ATCO Electric Yukon's service area in compliance with Terms and Conditions. New extensions (driven by a customer) that are under $25,000 are included in this grouping.

- Annual Land Rights $123,000

  The costs charged to this annual project are incurred to obtain easements once property is registered in land titles. Specific costs include monitoring title status, drafting of easements and obtaining easements.

- Other Projects less than $100,000 $41,000

  Please refer to the detailed project listing in Schedule 9.2.

DISTRIBUTION IMPROVEMENTS **$4,178,000**

Major improvements include:

- McIntyre Subdivision Rebuild $930,000

  Please refer to Appendix 8.

- Paint Mountain Conductor Replacement $562,000

  Please refer to Appendix 10.

- Annual Right of Way Widening $450,000

  Widen existing rights of way (ROW) to allow for access, wild fire reduction, and increased reliability.

  Locations included: 5L600 - Tagish main line. 9L - Squanga Lake south. 5L631 – Mary Lake and Spruce Hill subdivisions. 5L645 – North Klondike Highway. 5L623 – South Klondike Highway.

- Downtown Whitehorse Capacity Upgrade $368,000

  Please refer to Appendix 9.

- Replace Watson Lake Substation Transformer T2 $358,000

  The existing transformer is rated at 3 MVA which is smaller than the peak load in Watson Lake. The substation is configured with two transformers that can independently supply the community, one 3 MVA and one 5 MVA. There presently is no spare for the substation.

- General Pole Replacements $286,000

  Various deficient poles are identified through distribution system inspections and in unplanned situations. System inspections identify ground rot, pest infestation, broken or damaged poles and electrical degradation. Unplanned situations include emergency situations and forced outages due to failure of the pole.

- Hillcrest Subdivision Conversion $153,000

  This is the final stage of the project to convert the subdivision from 12.5 kV line 4L306 to the 25 kV line 5L630.

- Whitehorse Airport Hanger D Area Rebuild $143,000

  This area of distribution has been identified in system inspections as deficient. The infrastructure is 1960s vintage with deficiencies with regard to the structural integrity of the poles, clearance of power lines from road surfaces as well as general condition of transformers and wires. In designing a replacement option, ATCO Electric Yukon will be maintaining compliance with Transport Canada regarding proximity of structures to the airport runway.

- 400 Amp Regulators in Arkell Substation $123,000

  Routine maintenance shutdowns and contingency situations, where load normally supplied by another substation is directed to Arkell substation, have identified the need to upgrade the voltage regulators to ensure continued adequate system performance.

- 400 Amp Regulators in Logan Substation $123,000

  Routine maintenance shutdowns and contingency situations, where load normally supplied by another substation is directed to Logan substation, have identified the need to upgrade the voltage regulators to ensure continued adequate system performance.

- Shipyards Spare 25 kV Breaker $102,000

  Purchase and store off site a pad mounted 12kV breaker that can quickly be installed in Shipyards substation. Load growth in the downtown area has outgrown the contingencies in place for key pieces of equipment such as S1010 and S1012 The study accompanying the Downtown Whitehorse Capacity Increase project business case outlines the effects of an S1010 or S1012 failure.

- Vault Replacements $102,000

  Replace transformer pads with vaults. Splice high voltage cable onto existing cable to allow for routine safe switching of padmount equipment.

  Locations Included: Watson Lake, Whitehorse.

- Other Projects less than $100,000 $478,000

  Please refer to the detailed project listing in Schedule 9.2.

STREET AND SENTINEL LIGHTING **$1,132,000**

- Whistle Bend Streetlights $350,000

  Please refer to Appendix 7.

- General Streetlight Replacements $256,000

  Planned replacement program based on street light inspections and condition assessment of infrastructure. Condition assessment is based on performance of street lights, deficiencies or substandard conditions and the general physical condition includes the base and metal structure for deterioration, rust, broken bolts and damage.

- McIntrye Subdivision Streetlight Rebuild $256,000

  Please refer to Appendix 8.

- New Customer Streetlight Installations $204,000

  These street lights are installed at new customer requests. The design and engineered standards are completed in conjunction with the customer requesting service. ATCO Electric Yukon invests in compliance with Terms and Conditions. Projected cost of project is based on historical data and known projects identified by customers.

- Other Projects less than $100,000 $66,000

  Please refer to the detailed project listing in Schedule 9.2.

METERS **$204,000**

· Replacement of Meters and New Installations $204,000

The installation of new meters is required to accommodate load growth associated with customer requests for service. These expenditures allow ATCO Electric Yukon to meet its obligation to provide metered service connections. The capital meter additions are planned based on known areas of development and expected connection requests. New meters are also required to replace end of life meters as identified by Measurement Canada.

TRANSFORMERS & REGULATORS	**$92,000**
· General Capitalizable Transformers	$92,000

GENERAL PROPERTY & EQUIPMENT **$1,008,000**

- Transportation Equipment $317,000

  Replacement of Units 092, 096, 099, 776 & 884.

- Miscellaneous Tools and Instruments $166,000
  - Underground Line Tools
  - Electrical Testing Equipment
  - Fire Retardant Clothing for High Voltage Electrical Work
  - Miscellaneous Small Tools and Equipment

- Other Projects less than $100,000 $525,000

  Please refer to the detailed project listing in Schedule 9.2.

Section 10 - Income Tax

Overview

The income tax expense included in this Application is outlined in Schedule 10.1 and is as follows:

	2013 Actual	2014 Actual	2015 Actual ($000s)	Test Period 2016	Test Period 2017
Income Tax Expense	(714)	(120)	74	(235)	261

ATCO Electric Yukon continues to use the flow through method in calculating the income tax expense. Under the flow through method, ATCO Electric Yukon calculates the income tax expense based on taxable income, which is minimized by claiming the maximum of all available deductions including capital cost allowance (CCA). ATCO Electric Yukon also does not book deferred taxes under this methodology.

The increase in income tax expense between 2013 and 2014 is mainly due to lower tax deductions for Fish Lake Water License costs and capitalized purchase power. The increase in income tax expense between 2014 and 2015 is mainly due to higher Utility earnings before taxes. The decrease in income tax expense between 2015 and 2016 is mainly due to higher net deductions including deductions related to the deferred charges incurred in the test year and higher CCA deductions as a result of increased rate base, partially offset by higher Utility income before taxes. The increase in tax expense between 2016 and 2017 is mainly due to lower net deductions due to timing of the occurrence of deferred charges.

Income Tax Rate Deferral

Beginning in 2016, ATCO Electric Yukon requests an Income Taxes deferral on the enacted Federal and Territorial Statutory Rates of 15% and 15% respectively. Any changes from these rates will be used to determine an updated revenue requirement. This updated revenue requirement will be compared to the final Board approved revenue requirement for the year in question and any difference will be either refunded to or collected from customers.

ATCO Electric Yukon
2016 - 2017 General Rate Application
Income Tax Expense
($000s)

Line No.	Description	Cross Ref.	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Test Period 2016	Test Period 2017
1	Utility Earnings Before Tax		2,101	2,107	2,512	3,141	2,903	3,613	3,944	3,728
2	**Add:**									
3	Depreciation	S.1.1 L.11	4,382	4,520	4,895	5,252	5,412	5,778	5,792	6,283
4	Amortization of Contributions	S.1.1 L.12	(1,545)	(1,444)	(1,459)	(1,557)	(1,460)	(1,749)	(1,504)	(1,570)
5	Non-Allowable Expenses		36	25	77	25	49	25	50	51
6	Deferred Charges Write-off	S.8.8 L.11	18	18	18	18	17	17	632	832
7	Injuries & Damages Write-off	S.8.4 L.27	618	618	618	618	618	618	112	112
8	Charges to Deferred Pension & OPEB		718	473	619	412	384	412	436	436
9	Sub-Total		4,227	4,210	4,768	4,767	5,020	5,100	5,517	6,144
10										
11	**Deduct:**									
12	CCA		4,260	4,449	4,909	5,375	5,500	5,870	6,823	6,658
13	Rate Case Expenditure	S.8.8 L.26	386	417	(113)	193	36	-	586	-
14	Injuries & Damages Costs	S.8.4 L.28	83	100	-	100	208	100	100	100
15	Fish Lake Water Licence Costs	S.9.1 L. 19	841	650	-	-	-	-	-	-
16	Pension & OPEB payments	S.8.4 L.14 + L.21	719	728	475	643	505	643	623	623
17	Inventory Pool Costs Capitalized		285	287	320	297	317	290	326	336
18	Study Costs	S.8.8 L.35,L.36,L.69,L.77	1	-	-	-	8	-	662	300
19	Dismantling Costs	S.8.6 L.22	277	70	499	70	44	70	50	50
20	Demand Side Management Costs	S.8.8 L.60	205		220		178		136	-
21	Purchase Power Capitalized	S.3.1 L.13	402		-		72		110	86
22	Cumulative Eligible Capital		10	10	25	10	30	10	28	26
23	ES&G & Other Deductible Costs		1,223	993	1,127	688	777	688	800	824
24	Sub-Total		8,085	7,704	7,242	7,376	7,675	7,670	10,244	9,003
25										
26	Taxable Income		(1,757)	(1,387)	38	532	248	1,043	(784)	868
27	Tax Rate		30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
28	Income Tax		(527)	(416)	11	160	74	313	(235)	261
29	Book to Filing Adjustment		(187)	-	(131)	0	-	-	-	-
30	Total Current Provision	S.1.1 L.15	(714)	(416)	(120)	160	74	313	(235)	261

Section 11 – Prior Board Directions

Summary

The following section provides a response, or a reference to a response in this Application, to the applicable Board Directions from previous Board Order 2014-06, Appendix A.

Direction No. 8, Reference: Page 51

The Board agrees with the submissions of UCG that no assessment has been provided within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear.

The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.

ATCO Electric Yukon's Response

ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an analysis as to whether a risk premium over the BCUC GCOC benchmark utility is appropriate and if so, the quantum of such premium. Their analysis is contained in Attachment 8.1 included in Section 8 of this Application.

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.

ATCO Electric Yukon's Response

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.

Direction No. 13, Reference: Page 64

YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100 percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL in future applications is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.

ATCO Electric Yukon's Response

ATCO Electric Yukon has included project completion summaries for all projects listed below that were forecast in the 2013-2015 GRA where actual costs were 100 percent and $100,000 greater than the original forecast. In addition, ATCO Electric Yukon has included a project completion summary for the Fish Lake Dyke Upgrade to explain the varience in actual costs to forecast for that project.

Project Completion Summaries

Fish Lake Dyke Upgrade	Attachment 11.1
Old Crow Plan Expansion	Attachment 11.2
Beaver Creek Programmable Logic Control (PLC) Upgrade	Attachment 11.3
McIntyre Subdivision Rebuild	Attachment 11.4
Deep Creek Subdivision Connection	Attachment 11.5
Old Crow Staff Accommodations	Attachment 11.6

Business cases have also been provided for completed projects where the actual costs were in excess of $100,000 and for which no business case was provided in the 2013-2015 GRA. ATCO Electric Yukon has included Business Cases for the completed projects listed below in Attachments 11.7 through Attachment 11.13.

Business Cases for Projects Completed in 2013-2015

Old Crow Unit #2 Replacement	Attachment 11.7
Whistle Bend Subdivision Stage 1 & 2	Attachment 11.8
Whistle Bend Underground Residential Service	Attachment 11.9
City of Whitehorse Range Road Widening	Attachment 11.10
4L314 Chilkoot Way Upgrade	Attachment 11.11
Azure Road Extension	Attachment 11.12
2nd Ave Rebuild	Attachment 11.13

Direction No. 14, Reference: Page 70

The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast."[1] *Bearing this in mind, in order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL in future GRAs to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.*

ATCO Electric Yukon's Response

In Section 9, Schedule 9.2 of this Application, ATCO Electric Yukon has provided a detailed listing of all projects completed and actual amounts spent by project from 2013 through 2015. ATCO Electric Yukon has continued to group various projects in the "Other projects less than $20,000" category in Schedule 9.2, and submits this approach is appropriate considering the aggregate totals in this category are under the threshold of $100,000 highlighted in Direction #13.

[1] YECL reply argument, paragraph 138

Direction No. 15, Reference: Page 71

The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudency. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than $500,000.

ATCO Electric Yukon's Response

On Schedule 9.2 of the Application, ATCO Electric Yukon has included the reference to where the business cases can be found in either the (2013-2015 GRA or in Appendix 1-11 of this Application). Business cases have been provided for all projects that span multiple years where costs were expected to be greater than $500,000.

Direction No. 20, Reference: Page 101

As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the Utilities benefit, but if participation rates are higher than expected, the Utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the Utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA.

Further, the Board affirms it does not approve the program for the five-year term requested and that the Utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.

ATCO Electric Yukon's Response

The DSM programming costs approved in Board Order 2014-06 for the 2014 and 2015 test period have been tracked as directed in deferred charges. ATCO Electric Yukon was unable to complete the program as originally designed and spend all of the approved DSM program costs in 2014 and 2015 period; therefore the remaining approved amount will be spent in 2016. ATCO Electric confirms that it has not changed the scope of the approved DSM program. In this Application, ATCO Electric Yukon is applying for recovery of these previously approved costs (incurred from 2014 through 2016) over the next five years in a manner consistent with the previously approved DSM costs.

Fish Lake Dyke Upgrade

Project Summary and Description

This project was required to meet the December 2012 Inflow Design Flood (IDF) passage requirements and identified in the 2012 Dam Safety Report. Upgrades to the Fish Lake Dyke were done to ensure efficient use of the infrastructure as well as complying with items 36 and 27 ATCO Electric Yukon's water license HY12-065.

Upgrades included:

- Installation of two Polyvinyl Chloride (PVC) pipes east of the existing intake structure complete with 3.3m tall winged concrete headwall housing both conduits;
- The top width of the dyke was increased to 5.0m;
- Elevation was increased to a uniform 1,114.0m above sea level (ASL);
- Installation of a layer of EPDM geomembrane (high performing rubber liner) placed on the dyke face extending 14m laterally from the intake; and
- A 12m wide rock lined auxiliary spillway channel was also constructed to ensure the IDF can be safely passed.

Following commissioning of the new control structure, the old system was decommissioned and replaced with fill and armour protection.

Project Cost Update

Actual and approved costs for this project were as follows:

	Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
Labour	75	97	22	29%
Contract Services	1,645	2,455	810	49%
	1,720	**2,552**	**832**	**48%**

Contract services were higher than approved mainly due to:

- Material costs increased the cost of the project by $610,000.
    a. Detailed engineering work revealed additional earthen materials were required; and
    b. Cost of materials were higher than originally forecast, as the cost of quarry materials is highly variable and subject to availability and market demand.

- Project Scope increased cost of the project by $200,000. Once the project began it was determined that:
    a. additional sub excavation and infilling work was required; and
    b. access driveability improvements were required.

The increased scope of the project required additional project management and engineering work which is the main driver for the additional labour costs of $22,000.

Old Crow Plant Expansion

Project Summary and Description

The original generating plant in Old Crow did not have the physical capacity to house newer engines of the same or higher kW rating as the existing units reach end of life. It also did not have the space for additional units which are required as the community continues to experience load growth. Aside from the unit housing issues, the existing plant also did not have adequate floor or wall space to facilitate the installation of new control equipment. In order to address these issues and ensure contingencies are in place to minimize outages in the community, ATCO Electric Yukon installed a second 1,350 square foot generating building adjacent to the existing Old Crow plant.

Both the original and additional building have sufficient space to house two diesel generators and the associated equipment as well as provide sufficient working space for regular work to be performed safely.

Project Cost Update

Original estimates for this project were $1,950,000 but, despite ATCO Electric Yukon's best efforts to minimize the costs while meeting the requirements of a safe reliable system, increased scope and unforeseen circumstances caused actual costs to be significantly higher than previously approved.

Actual and approved costs for this project were as follows:

	Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
Labour	60	238	178	297%
Contract Services	1,890	3,417	1,527	81%
Materials	-	336	336	-
Other	-	575	575	-
	1,950	**4,566**	**2,616**	**134%**

<u>Building & Electrical Design (approx. $1,300,000 additional costs)</u>

A portion of the cost overrun is due to the updated design of the building structure. Original engineering and design provided to ATCO Electric Yukon at the time of the preparation of the 2013-2015 General Rate Application were preliminary. Additional detailed engineering and design work to integrate the updated building design with the existing system resulted in increased work scope and materials required.

The original forecast also did not include the electrical equipment required for the switchgear component for the additional building.

Construction, Installation & Commissioning Costs (approx. $900,000 additional costs)

Conditions in the community significantly impacted the cost of this project. During construction, two other projects were being carried out in the community, which reduced availability of accommodations resulting in large increase of pricing. As a result contract workers, materials and resources within Old Crow were limited.

The existing store in the community closing prior to opening of the new store, due to construction delays of the new store. As a result food was either flown in or local catering services were utilized at an additional cost. Furthermore in part due to the new fuel depot construction, the community experienced occasional fuel shortages which resulted in additional delays or time onsite.

Whenever possible, ATCO Electric Yukon was diligent to use the lowest cost option. However, due to the size of the community and the limited resources available there was often only a single option to continue with construction of the project.

The quotes provided to ATCO Electric Yukon for the original design also did not compensate for the poor working conditions of the existing plant. More time was required to complete the work to integrate the two plants due to the space constraints and overall poor condition of the existing facility.

There was also additional unplanned site drainage work required in 2015, due in part to seasonal movement of disturbed permafrost from the excavation of the foundation in 2013.

Unforeseen situations such as weather conditions, flight availability, community events and aircraft mechanical issues, also resulted in delays which impacted work schedules resulting in additional labor and project management costs.

Freight (approx. $100,000)

Old Crow is a fly in community with only one dedicated supplier of regular passenger and freight air service. A combination of other community projects and regular community demands limited the availability of transporting equipment and workers in and out of the community. As a result, additional costs for transporting equipment to site were encountered to ensure a timely delivery.

The charter of one Hercules aircraft was required in fall of 2015 to bring in the electrical switchgear plus construction material. Unfortunately, the only Canadian supplier of this service ceased operation in the spring of 2015. As a result Lynden transport out of Alaska was the only source available. In order to accommodate the delivery by Lynden all material had to be imported into the US (Alaska) to be exported back into Canada. Additional project management time was required to document and provide all the required information for the brokerage of this material.

Other (approx. $100,000 additional cost)

Due to the large nature of the project various other incidental items increased the costs and additional timelines resulted in additional supervision and project management costs.

Economic conditions also impacted that cost of this project. At the time of the application the Canadian dollar was near par with the US dollar. The Canadian dollar steadily declined through the entire scheduled project timeline. Materials and the cost to fly in the switchgear were higher than ATCO Electric Yukon had anticipated partially due to the disparity between the Canadian and US dollar at the time of construction.

Other Considerations

Throughout the project, scope and costs were reviewed and revisited to ensure that ATCO Electric Yukon could address the load growth and provide adequate contingency to the community of Old Crow at a prudent cost.

As project scope and costs related to the building increased, modular options were explored. Quotes for this option came back between $400,000-$500,000 higher than the site built option and did not meet ATCO Electric Yukon's operational and maintenance requirements. There were significant costs related to transporting prefabricated structures to a community as remote as Old Crow. This modular unit did not have room for growth; it had space for one unit. The modular option would require an addition in the future in order to house additional or larger units as the community grows.

As there was still a need for a new building and Old Crow has been experiencing load growth over the last few years, ATCO Electric Yukon proceeded with the updated design. The building construction was tendered and the lowest bid was awarded the contract.

Beaver Creek Programmable Logic Control (PLC) Upgrade

Project Summary and Description

This project was undertaken to replace the existing PLC and associated control wiring and components in ATCO Electric Yukon's Beaver Creek isolated generation facility.

The 1982 IDEC PLC was no longer supported or available from the manufacturer and the software driver was not compatible with the next generation Supervisory Control and Data Acquisition (SCADA) program.

Project Cost Update

Actual and approved costs for this project were as follows:

	Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
Labour	25	102	77	308%
Contract Services	50	140	90	180%
Materials	96	112	16	17%
Other	9	23	14	156%
	180	**377**	**197**	**109%**

Labour costs were higher than planned mainly due to additional unanticipated technical work required. The work was completed by ATCO Electric Yukon technicians in Whitehorse with coordination with the manufacturer of the equipment. This unanticipated work delayed the project and the original contract crew was released. ATCO Electric Yukon personnel were required to spend additional time with the new crew once the technical work was completed to provide project orientation and review safety protocols.

Contract services were higher than planned mainly due to the need to send out a second crew due to project delays. Additional contract labour was also required complete the commissioning work.

McIntryre Subdivision Stage 1

Project Summary and Description

The project was planned for two years of field work to complete the first stage of replacing the underground electrical system in the McIntyre subdivision. The existing infrastructure was built in late 1970's and was deemed to have reached end of life. The end of life assessment was based on the degradation of cables and electrical equipment as well as inoperability at many locations within the subdivision due to safety reasons.

Project Cost Update

Actual and approved costs for this project were as follows:

	Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
2013	475	656	181	38%
2014	250	418	168	67%
2015	-	379	379	-
	725	**1,453**	**728**	**100%**

The first stage of the project, which took place from 2013-2015, had a significant change in scope. The original scope was to install a new 25kV underground electrical system in close proximity to the existing 35kV system. The two separate underground systems would continue to operate in parallel as various streets and areas of the subdivision were converted to the new system. As streets throughout the subdivision were converted to the new system, the old system would be decommissioned and abandoned in place.

As the original project proceeded it became apparent that the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This made the field construction more time consuming due to difficult digging conditions and safety concerns. These issues, coupled with time constraints imposed on construction permits from Kwanlin Dun First Nation, required a new project scope to be developed to complete the project in an acceptable timeframe and budget. The new project scope involved the installation of a temporary overhead shadow electrical system which would allow construction crews to install the new underground system with the old underground system safely deenergized. This would allow the construction crews to work at a similar pace to a Greenfield project. The work would also include the installation of low voltage pedestals to connect to the overhead system and a new main underground feed to the subdivision.

Table 1 shows the breakdown of the cost variances on this project by type.

Table 1: McIntyre Subdivision Replacement Stage 1 Cost Variances by Type

Description	Variance ($000s)	Variance Explanation
Install Overhead line (2013-2014)	175	The project scope changed significantly from installation and operation of a 2nd underground electrical system to an overhead electrical system
Connection of existing low voltage underground system to the new overhead system (2013-2014)	174	Construction and operation of a new hybrid system (overhead and underground) for the subdivision
Installation of Main Underground feed in to subdivision (2015)	379	Not originally included in original business case scope.
Total	**728**	

Deep Creek Subdivision Connection

Project Summary and Description

This project was required for ATCO Electric Yukon to maintain service to the Deep Creek Subdivision as the Yukon Energy Corporation's nearby substation was nearing capacity. The project involved building new powerline, paying for the use of existing poles owned by Northwest Tel and stringing new conductor from the Whitehorse distribution system to Deep Creek.

Project Cost Update

Actual and approved costs for this project were as follows:

Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
60	213	153	255%

Costs were higher than approved costs mainly due to:

- Line Construction ($94)
  - Costs were higher due to additional crews required as a result of digging conditions, additional required engineering work and added anchoring and pole class.
- Brushing ($38)
  - Required brushing was heavier than expected.
- Other ($21)
  - Additional costs due to the need for a protective device that was not originally planned for.

The alternative to the project as constructed was for the Yukon Energy Corporation to upgrade their substation to accommodate the load in the area. The cost of this potential project was estimated to be over $400,000. As the cost of this project was less than the other alternative, it was determined this was the most prudent option.

Old Crow Staff Accommodations

Project Summary and Description

This project was undertaken to transport new accommodations from Whitehorse to Old Crow. The existing bunkhouse was removed and the new accommodations were located onsite and connected to the existing addition and heat/power services. The existing accommodation was in disrepair and operational and construction staff are required to stay and work in the community of Old Crow on a regular basis. Alternative accommodation in the community is not consistently available.

Project Cost Update

Actual and approved costs for this project were as follows:

Approved ($000s)	Actual ($000s)	Variance ($000s)	Variance (%)
100	274	174	174%

The actual costs were higher than approved mainly due to the discovery of various issues within the replacement bunkhouse after it was transported to Old Crow. Various repairs were required to remediate the following issues:

- Mold found inside of exterior walls in the kitchen, bathroom, and one bed room, as a result significant work was required in those rooms.
- Condensation was discovered around the water tank due to lack of air flow, causing water damage on nearby walls. Access to the walls required a smaller tank to be installed and repairs to the walls were required.
- Roof line and insulation inadequacies in the addition led to leaks that drove the need for a new roof on the addition.
- The existing addition was not self-supporting. Therefore, a structural wall was added to allow for it to remain.

In addition to the repairs and structure upgrades required, a custom heat exchanger was needed due to the standard size not fitting and a new electrical panel was required.

Transportation costs were in excess of original forecast and two sea cans for storage of distribution and generation materials were added to the project scope to achieve economies of scale as they could be transported at the same time.

Old Crow Unit #2 Replacement

Project Summary and Description

The replacement of Old Crow Unit #2 was originally forecasted to occur in 2016, as outlined in the 2013-2015 GRA response to information request YEC-YECL-19(a). The original forecasted 2016 replacement was based on the unit being due for a major overhaul at approximately 75,000 hours. ATCO Electric Yukon's current practice is to replace high speed machines near 80,000 hours or the closest life extension to 80,000 hours.

The scope of this project was to cover the supply, shipping, and installation of one 3421 long block for Old Crow Unit 2. Also included in the scope was disconnection, reconnection, new fluids, start up, commissioning, and return of existing block. Existing generator and skid were reused, with the generator to be serviced at a later date.

Project Costs

The project was completed in 2015 and the project costs were as follows:

Description	Actual ($000s)
Old Crow Unit 2 Replacement	161
Total	**161**

Business and Technical Drivers

The original replacement date of 2016 was based on the 5 year average of the unit's operational hours. In 2013 the 5 year average was 5,881 hours, as of January 2016 the 5 year average increased to 6,093. The primary driver for the increase in operational hours is community load growth.

Throughout the 3rd quarter of 2015 the operation of Unit 2 continued to deteriorate with increased oil consumption, smoking, and valve wear. Due to the condition of the unit, there was a high probability that required replacement could not be delayed until the original forecast of 2016.

Alternatives

Alternative #1 - Purchase long block and replace existing engine - This option ensures the work will be completed before winter and the unit will physically fit in the power plant. The cost is comparable to a major overhaul with a higher probability of increased operational life.

Alternative #2 - Life extension on existing unit (major overhaul)- Perform major life extension on Unit 2 and operate in Old Crow for an additional 20,000 hours until replacement. While this

option would have delayed the purchase of a new unit, concerns around the downtime for the work were considered.

Alternative #3 - Replace unit with similar unit from Pelly Crossing - Pelly Crossing Unit 2 is a newer machine rated for 600kW and is the best match for the existing control system. However, the compatibility of the unit with existing mechanical equipment (exhaust silencer, radiator, and primary cable) would not allow it to handle 100% of the 600kW rated load.

Alternative #4 - Perform top end service, operate until April 2016 - A top end service is a minor over haul that is part of a regular maintenance schedule. It was determined that this maintenance service may not address the mechanical issues that are currently affecting the unit.

Alternative #5 - Accelerate the whole replacement of the unit to 2015 - Unable to procure a replacement unit and install before the winter season.

Recommendation

ATCO Electric Yukon determined that the best solution was the purchase of a refurbished long block and replacement of the existing engine of Old Crow Unit #2 and completed this work in 2015.

Whistle Bend Subdivision Stage 1 & 2

Project Summary and Description

Design, build and install fully contributed electrical infrastructure to service a new subdivision in Whitehorse in agreement with the developer and in accordance with the approved Terms and Conditions.

ATCO Electric Yukon will design electrical service to all properties, procure material, install electrical infrastructure, commission, and energize Whistle Bend subdivision stages 1 & 2 in coordination with the developer (Yukon Government). This project is a customer driven and was performed in compliance with the Yukon Utilities Board (YUB) approved Terms and Conditions.

Project Costs

Project costs were incurred throughout the 2013-2015 timeframe and costs were contributed by the customer as per the approved Terms and Conditions.

Description	Actual ($000s)			
	2013	**2014**	**2015**	**Total**
Whistle Bend Subdivision Stage 1 & 2	273	138	102	513
Total	**273**	**138**	**102**	**513**

Business and Technical Drivers

This project was completed at the request of the customer and ATCO Electric Yukon has an obligation to serve customers within its service area. Design and build of the electrical infrastructure is in accordance with the applicable Utility Code and Regulations. ATCO Electric Yukon is committed to provide service per the guidelines approved in the terms and conditions.

Alternatives

No other viable alternatives exist.

Whistle Bend Underground Residential Service

Project Summary and Description

This project represents the cost for bringing underground residential service to each newly built home in the Whistle Bend subdivision in Whitehorse. The project involved trenching from a pre-installed duct near the property line and installing cable in duct to each home. The cost represents ATCO Electric Yukon's investment in each new service. Historically, all underground new service costs were captured under one blanket project. As directed in Decision 2014-06 Whistle Bend has been separated and included as its own project.

This project is a customer driven at the request of the developer (Yukon Government) and was performed in compliance with the Yukon Utilities Board (YUB) approved Terms and Conditions.

Project Costs

Project costs were incurred in 2015 and were as follows:

Description	Actual ($000s)
Whistle Bend Underground Residential Service	116
Total	**116**

Business and Technical Drivers

This project was completed at the request of the customer and ATCO Electric Yukon has an obligation to serve customers within its service area. Design and build of the electrical infrastructure is in accordance with the applicable Utility Code and Regulations. ATCO Electric Yukon is committed to provide service per the guidelines approved in the terms and conditions.

Alternatives

No other viable alternatives exist.

City of Whitehorse Range Road Widening

Project Summary and Description

The City of Whitehorse undertook at road widening construction project on Range Road from Mountainview Drive to Crow Street in Whitehorse. As such, ATCO Electric Yukon was contacted to relocate the infrastructure to a new location in order for the road work to proceed. This project was fully contributed by the customer.

Project Costs

The project was completed in 2015 and the project costs were as follows:

Description	Actual ($000s)
City of Whitehorse Range Road Widening	188
Total	**188**

Business and Technical Drivers

This project was required at the request of the customer in order for them to complete a road widening project. ATCO Electric Yukon has an obligation to operate and maintain the system in a safe and reliable manner.

Alternatives

No other viable alternatives exist.

4L314 Chilkoot Way Upgrade

Project Summary and Description

This project was identified during the detailed engineering assessment of a different project- 4L316 6th Avenue 266 Reconductor. The 4L316 6th Avenue 266 Reconductor project was approved in the 2013-2015 GRA application. During the detailed engineering work it was discovered that a system deficiency caused by a conductor capacity limitation required mitigation closer to the source substation than the originally proposed 4L316 6th Avenue 266 Reconductor project. Therefore in order to address the system deficiency the 4L314 Chilkoot Way Upgrade project was done in place of the original project.

Project Costs

The project was completed in 2013 and the project costs were as follows:

Description	Actual ($000s)
4L314 Chilkoot Way Upgrade*	483
Total	**483**

*The approved dollars for the "Downtown Whitehorse 4L316 6th Avenue 266 Reconductor" were $550,000 (2013-$250,000 and 2014-$300,000).

Business and Technical Drivers

The need for the Downtown Whitehorse 4L316 6th Avenue 266 Reconductor project was to address capacity limitations on the distribution system. The work completed as part of the 4L314 Chilkoot Way Upgrade project addressed the capacity concerns identified in the original approved project. The business drivers for the projects are the same and the outcome of the new project provides the same power system benefits at a lower cost than the original approved 4L316 6th Avenue 266 Reconductor project. Therefore, the original project was not required to be completed.

Alternatives

No other viable alternatives. This project was selected to address the capacity limitations as an alternative to the previously approved Downtown Whitehorse 4L316 6th Avenue 266 Conductor project.

Azure Road Extension

Project Summary and Description

The Government of Yukon contacted ATCO Electric Yukon in March 2015 to initiate this road construction project. As the road authority, the Government of Yukon required ATCO Electric Yukon's infrastructure to be re-aligned by August 2015 to accommodate their road works. ATCO Electric Yukon was 100% responsible for the costs of this project in accordance to its highways permits allowing it to place infrastructure in the highway right of way.

Project Costs

The project was completed in 2015 and the project costs were as follows:

Description	Actual ($000s)
Azure Road Extension	151
Total	**151**

Business and Technical Drivers

This project was required at the request of the Government of Yukon in order for them to complete a road construction project. ATCO Electric Yukon has an obligation to operate and maintain the system in a safe and reliable manner.

Alternatives

No other viable alternatives exist.

2nd Ave Relocation

Project Summary and Description

In order to accommodate future development work, ATCO Electric Yukon's facilities needed to be relocated. The line was re-designed to accommodate the development and allow for future development in the area.

Project Costs

The project was completed in 2015 and the project costs were as follows:

Description	Actual ($000s)
2nd Ave Relocation	115
Total	**115**

Business and Technical Drivers

This project was required as ATCO Electric Yukon has an obligation to operate and maintain the system in a safe and reliable manner.

Alternatives

No other viable alternatives exist.

Section 12 – Diesel Displacement

In recent years, Federal, Territorial, Municipal and First Nation governments and the general public have indicated a desire to see the displacement or elimination of diesel power generation in remote communities through the development of renewable generation facilities. At the same time, diesel prices have dropped dramatically making the economic feasibility of renewable generation challenging.

In July 2015, the Canadian Council of the Federation announced work on a Canadian Energy Strategy which reinforced Canada's commitment to secure a supply of energy for all Canadians, support energy innovation and address climate change.

Shortly thereafter, 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. This was reinforced in March 2016 in Vancouver at the First Ministers' meeting where Prime Minister Justin Trudeau and the provincial and territorial Premiers announced they would take action to eliminate the dependence on diesel in Indigenous, remote and northern communities with renewable, clean energy[1].

ATCO Electric Yukon generates and delivers electricity in five communities that remain off-grid, isolated from the Yukon's hydro-based Integrated Electrical System (i.e., Old Crow, Beaver Creek, Burwash Landing/Destruction Bay, Swift River and Watson Lake). ATCO Electric Yukon is committed to working with governments, First Nation communities and customers to reduce the environmental impact of power generation in the Yukon. ATCO Electric Yukon is proposing to complete a Renewable and Alternative Energy Study as well as the Watson Lake Bi-Fuel project as discussed in Appendix 3 of this Application as part of its continuous efforts to explore ways to displace some of the diesel we currently use with renewable or alternative fuel sources

[1] http://www.cbc.ca/news/politics/first-ministers-premiers-trudeau-1.3474380

or to more efficiently use our existing diesel generation within in each of our off-grid communities.

In addition to applying to the Board for funds to complete this study and at a later date, to develop the viable solutions identified in the study, ATCO Electric Yukon intends to pursue additional funding from the Federal and Yukon Territorial Governments to fund:

1. Research to understand how renewable and alternative energy sources being proposed by third-party power producers (micro-generation and IPPs), which are not under any dispatchable control, in each of ATCO Electric Yukon diesel-powered communities will impact the existing isolated electrical systems and the modifications required to ATCO Electric Yukon's power system to successfully integrate the type and amount of renewable or alternative fuel proposed by the third-party.
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.

Renewable and Alternative Energy Study

ATCO Electric Yukon plans to complete a Renewable and Alternative Energy Study that will identify the potential, optimal size and configuration of company built, owned and operated renewable and alternative energy generation in each of the five isolated communities we serve that currently rely on diesel power generation. The study will also assess energy storage systems and possible energy efficiency improvements through district heating or co-generation opportunities in each community.

Once the Renewable and Alternative Energy Study is complete, ATCO Electryc Yukon proposes that any projects identified that are technically and economically feasible will be brought forward in business cases in a stand-alone proceeding for approval by the YUB. It is not possible to bring forth any specific renewable or alternative energy

projects at this time; however, ATCO Electric Yukon wants to ensure customers get the benefit of these projects as soon as practical without needing to wait for a subsequent GRA.

Study Overview

ATCO Electric Yukon's Renewable and Alternative Energy Study will identify the technical and economic feasibility of integrating new company-owned and dispatch controlled renewable and alternative energy generation sources, energy storage, control schemes and energy efficiency enhancements into ATCO Electric Yukon's diesel generation facilities, including:

- Technology recommendations
- Desktop resource assessments for each generation source using commercially available data
- Collection or acquisition of field data where necessary (e.g., wind speed)
- Optimization of generation penetration under two scenarios:
    - Renewable – Diesel Generation (no storage) hybrid
    - Renewable – Diesel Generation & Energy Storage hybrid system
- Recommendations for cost effective energy efficiency enhancements to the diesel generating plants (district heating or co-generation)
- Identification of potential users, associated costs and commercial offerings for any plant supplied district heating
- System integration, protection and control of the grid, with consideration given to legacy diesel assets to minimize capital cost impacts to existing customers
- Capital and operating estimates
- Projected savings relative to business-as-usual case

System reliability is paramount for ATCO Electric Yukon. Intermittent generation sources (e.g., wind or solar PV) and their penetration levels into the energy supply mix can impact the existing power plant. Careful consideration of the renewable generation and energy efficiency options are necessary to prevent negative impacts to system reliability. Any options for renewable generation or alternative energy projects that may cause instability in the isolated grids will either be mitigated with an adequate technical and economic solution or rejected if the technical solution is not economically feasible.

Scope

Prefeasibility Study

- Identify existing or planned renewable installations within the community
- Evaluation of available commercial technology and suppliers, including discussions with industry, government , other utilities, the NSERC Industrial Research Chair in Northern Energy and Yukon's Indigenous communities on lessons learned and their recommendations
- Desktop performance assessments:
    - Identify optimal generation technology for each site based on commercially available resource assessment data (e.g., wind speed mesoscale maps and hourly solar data)
    - Optimization of generation, storage and historical load data from each community
    - Identify potential energy efficiency upgrades, such as waste heat recovery for district heating or supplemental power generation
- Estimate integration costs

- Preliminary economic analysis, including capital and operating estimates of each site based on resource assessment
- Discuss funding opportunities with Federal and Territorial agencies
- Consultation with Indigenous groups
- Identification of potential users, associated costs and commercial offering for any plant supplied district heating

Feasibility Study

The detailed assessment of projects to integrate renewables, energy efficiency upgrades and/or energy storage that appear economically and technically feasible in the prefeasibility study.

- Site selection for renewable generation and storage projects
- Identify interconnection points for generation projects
- Review of existing electrical and generation infrastructure, including gen-sets, substation, distribution network, protection and control logic
- Identify the potential impacts of the various renewable energy penetration levels to system stability and if required, determine strategies to reduce risk
- Conceptual design identifying the integration of potential generation and storage projects
- Generation dispatch strategies
- Data collection - Installation of Met masts at sites which appear technically viable for wind generation
- Refine capital and operating cost estimates
- Define the business case for each viable project
- Continue to consult with Indigenous groups

- Continue to advance any funding opportunities with Federal or Territorial agencies

Study Costs

ATCO Electric Yukon's Renewable and Alternative Energy Study is forecast to cost $500,000 in the 2016 and 2017 the test period and has been included in Schedule 8.8.

Watson Lake Bi-Fuel

The Watson Lake Bi-Fuel project aligns with ATCO Electric Yukon's commitment to review and implement alternatives to diesel generation in isolated communities. Appendix 3 of the Application provides the details of the Watson Lake Bi-Fuel project as well as the proposed cost and timelines. 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. Further, this project aims to shield Yukon customers from fluctuation in oil prices by reducing fuel costs of the Watson Lake generation facility.

Renewable energy solutions, such as wind and solar, require contingent thermal fuel based energy sources to maintain reliable service. Even with robust energy storage options in place, there are situations where thermal units need to operate to make up any renewable generation deficiency.

ATCO Electric Yukon's proposal includes both renewable and alternative energy initiatives in addition to a Bi-Fuel system in order to maximize economic benefits while displacing diesel generation.

Section 13 – Interim Refundable Rate Rider

ATCO Electric Yukon is requesting that the AEY Rate Adjustment Rider, Rider R, be increased by 4.42% from the currently approved 7.20%. The resulting interim 11.62% Rider R will be applied to all ATCO Electric Yukon and Yukon Energy's primary base revenues beginning July 1, 2016. A copy of the proposed interim rider schedule is provided in Attachment 13.1.

The derivation of the interim Rider R increase, shown in Schedule 13.1, is consistent with ATCO Electric Yukon's previous Interim Refundable Rate Rider calculation, which was applied for in the 2013-2015 GRA and approved in Decision 2013-05. In particular, ATCO Electric Yukon is requesting to recover approximately one-half of the applied-for revenue requirement increase for 2016, net of the impact of fuel costs adjustments recovered through Rider F, on an interim refundable basis.

In the Board findings found in Appendix A of Board Order 2013-05, the Board confirmed that: "interim refundable rates promote rate stability and are just and reasonable to both the utility and consumers". The Board has also stated in that Decision that "retroactive rate-making does not apply to the proposed interim rates because the interim rates requested are for the forward period of July 1, 2013 to December 21, 2013."

For these reasons ATCO Electric Yukon submits that the applied for interim rate increase is appropriate and should be approved effective July 1, 2016.

ATCO ELECTRIC YUKON
Determination of the 2016 Interim Rate Adjustment Rider R
Effective July 1, 2016

Line	Description	Source	
1	**Revenues**		
2	2016 Retail Revenue Requirement ($000s)	S2.1 L.52	53,890
3	2016 Retail Revenue on Existing Rates($000s)	S2.1 L.52	51,454
4	**Revenue Shortfall ($000s)**	(2) - (3)	**2,436**
5	**Percentage of Revenue Shortfall**		50%
6	**Percentage of Revenue Shortfall ($000s)**	(4) * (5)	1,218
7	**2016 Primary Sales Revenues on existing Primary Rates ($000s)**		
8	AEY: July - December 2016 ($000s)		23,355
9	YEC: July - December 2016 ($000s)		4,208
10	**Total Primary Sales Revenues ($000s)**	(8)+(9)	**27,563**
11	**Incremental Rate Adjustment Rider R effective July 1, 2016**	(6)/(10)*100	**4.42%**
12	**Existing Approved Rate Adjustment Rider R**	Decision 2014-09	**7.20%**
13	**Rate Adjustment Rider R effective July 1, 2016**	(11) + (12)	**11.62%**

THE YUKON ELECTRICAL COMPANY LIMITED
An ATCO Company

YUKON ENERGY

Effective: 2016 07 01
Supercedes: 2015 08 01

RIDER R
YUKON ELECTRICAL RATE ADJUSTMENT RIDER

AVAILABLE: To all electric service throughout the Yukon Territory.

APPLICABLE: To all classes of service except Rate Schedule 32, Rate Schedule 42 and Rate Schedule 43.

RATE: All base rate revenue will be adjusted by the following rate:

11.62%

NOTE: Yukon Energy Corporation recoveries under this rider are to flow through to Yukon Electrical Company Limited.

2016-2017 General Rate Application

Appendix #1

Fish Lake Ditch 3 Diversion Replacement

Executive Summary

Fish Lake Ditch 3 is not able to adequately handle a 100-Year Inflow Design Flood (IDF) event, as required to comply with recommendation item 2013-2 of the 2012 Dam Safety Report and ATCO Electric Yukon's current water licence HY12-065. In the event of an IDF event, the Ditch 3 infrastructure, including the Drop Box, would be at risk of catastrophic failure and risks impacting all remaining downstream infrastructure. As a result, ATCO Electric Yukon is planning to replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the IDF flow rates.

Background

On May 31, 2013, ATCO Electric Yukon was granted a 25 year extension to water use licence HY12-065. During the application process it was identified that Ditch 3 Diversion structure and spillway were not adequately built to withstand a 100 year flood event (Inflow Design Flood). ATCO Electric Yukon is planning to replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the Inflow Design Flood rates and complies with the terms outlined in the water licence. Please refer to Attachment 1 of this business case for a map of the Fish Lake facilities.

Project Description

Reestablishment of the Fish Lake Ditch 3 Diversion will allow water to escape the Fish Lake hydro system through a control structure and ditch to Franklin Lake. This project will construct a diversion structure and spillway ditch capable of diverting all water flows in excess of 4.4 m3/s (maximum capability of the Drop Box) out of Ditch 3 and into Franklin Lake prior to entering Ditch 3.

Project Schedule & Cost

This is a multi-year project. The draft design and spillway channel brushing occurred in 2014. Spillway channel surveying occurred in 2015, allowing ATCO Electric Yukon to update the design model and adjust the design accordingly. Rough grading, general fill, rip rap and filter rock supply and placement, and new discharge structure construction are scheduled to occur in 2016.

This project that was approved in ATCO Electric Yukon's 2013-2015 GRA for $1,640,000. The updated cost forecast of $3,049,000 is as follows:

Year	Actual ($000s)	Forecast ($000s)	Total ($000s)
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	**134**	**2,915**	**3,049**

The primary drivers for the cost increase between the previous forecast submitted in the 2013-2015 GRA are as follows:

Spillway Structure

The draft design consisted of a rock lined soil berm as a fixed crest overflow and included a single 600mm diameter culvert complete with slide gate/headwall. The final spillway design changed from the original concept of a simple fixed crest weir to the current 4 gated box culvert design and resulted in a $480,000 increase to the forecast.

Operationally, the fixed crest weir would not have functioned well as a control point for regulating Franklin Levels as required within ATCO Electric Yukon's water licence HY12-065. Flow within the single culvert would have required very high levels in the ditch with minimal freeboard. Secondly, the Ditch would have had to reach near full capacity prior to the spillway becoming active (reactive control to an event). The new design allows controlled flow to Franklin Lake for regulating levels all while Ditch 3 levels are normal. Further, the spillway can be utilized pro-actively in the case of an event that can be reasonably forecasted.

Rock Quantity within Spillway Channel

The required rock quantity within the spillway channel increased as a result of detailed survey information that was not possible at the time of the conceptual design. This resulted in a $530,000 increase to the forecast.

The channel had to be extended 50 meters at the Franklin Lake end to ensure the still basin would discharge at or near operational levels in Franklin Lake. Approximately 20 meters of additional channel was realized due to modifications to the spillway pilot channel and overall channel alignment. Overall, the channel saw approximately 10% increase in length. The lineal channel greater than 5.5% slope increased by 7%. The steeper channel requires additional rock armor protection.

Business Drivers and Benefits

Water Licence Compliance

ATCO Electric Yukon is required to comply with recommendation item 2013-2 of the 2012 Dam Safety Report and current water licence HY12-065. ATCO Electric Yukon is required to be able to adequately and safely manage a flood event. ATCO Electric Yukon also seeks to minimize the use of the Louise Lake Auxiliary Spillway and provide controlled inflows into Franklin Lake.

Protection of Existing Infrastructure

With the current inability to release water from the Fish Lake Hydro system upstream of Ditch 3, the Drop Box and Ditch 3 infrastructure poses a risk of catastrophic failure and risks of impact to all remaining downstream infrastructure during an IDF event.

Evaluation of Viable Alternatives

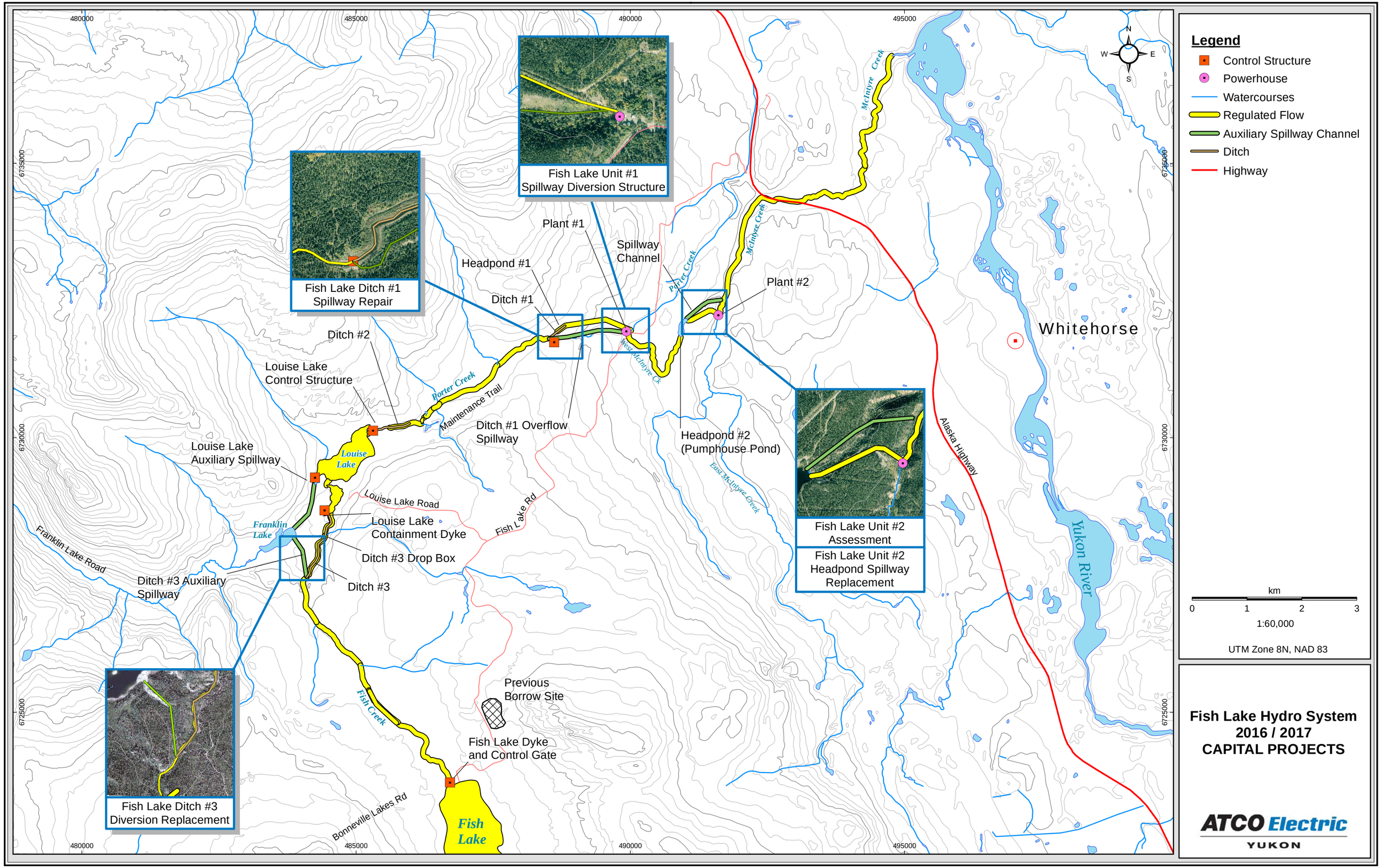
Alternative #1: Status Quo. This alternative could lead to future compliance issues with ATCO Electric Yukon's current water licence HY12-065. It also risks Fish Lake Ditch 3 infrastructure during an IDF event.

Alternative #2: Build a bypass structure at the Drop Box on Ditch 3. The bypass alternative was designed and studied; however the structure could still not adequately bypass 15.2m3/s of water flow which is the Inflow Design for Ditch 3. Ditch 3 infrastructure would still be at risk.

Alternative #3: Replace and upgrade the Ditch 3 Diversion structure and spillway to an engineered design that meets the IDF flow rates.

Recommendation

Replace and upgrade the Ditch 3 Diversion structure and spillway.


Legend
Control Structure
Powerhouse
Watercourses
Regulated Flow
Auxiliary Spillway Channel
Ditch
Highway
km
0
1
2
3
1:60,000
UTM Zone 8N, NAD 83
Fish Lake Hydro System
2016 / 2017
CAPITAL PROJECTS
ATCO Electric
YUKON
Fish Lake Unit #1
Spillway Diversion Structure
Fish Lake Ditch #1
Spillway Repair
Fish Lake Unit #2
Assessment
Fish Lake Unit #2
Headpond Spillway
Replacement
Fish Lake Ditch #3
Diversion Replacement
Plant #1
Plant #2
Spillway
Channel
Headpond #1
Ditch #1
Ditch #2
Ditch #1 Overflow
Spillway
Headpond #2
(Pumphouse Pond)
Louise Lake
Control Structure
Louise Lake
Auxiliary Spillway
Louise Lake
Containment Dyke
Ditch #3 Drop Box
Ditch #3
Ditch #3 Auxiliary
Spillway
Previous
Borrow Site
Fish Lake Dyke
and Control Gate
Whitehorse
Yukon River
Alaska Highway
Porter Creek
Maintenance Trail
Louise Lake Road
Fish Lake Rd
Franklin Lake Road
Bonneville Lakes Rd
Fish Creek
West McIntyre Ck
East McIntyre Creek
McIntyre Creek
Louise Lake
Franklin Lake
Fish Lake
480000
485000
490000
495000
6735000
6730000
6725000
N
S
E
W

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Appendix #2

Fish Lake #2 Head Pond Spillway Replacement

Executive Summary

The Fish Lake Hydro system was built around 1950 and has aging infrastructure that is coming to the end of useful life. Investigative repairs of Fish Lake #2 Head Pond Spillway structure identified that the structure was in need of replacement. ATCO Electric Yukon will replace the existing spillway structure to adequately handle IDF flows while maintaining safe access to ATCO Electric Yukon generation facilities.

Background

In 2013 the existing structure was scheduled to undergo investigative repairs due to obvious signs of aging. These repairs were expedited when a sink hole was noted in the dam immediately adjacent to the structure in the summer of 2013.

During the investigative repair work it was apparent the structure had come to the end of its lifespan and needed significant repairs. The 2014 Dam Safety Report (recommendation #2014-09) identified the structure required replacement by the end of 2017.

Project Description

The scope of the project is to design and replace the existing concrete and wood structure with a new structure, capable of handling the IDF flows of 8.5m3/s.

Project Costs & Schedule

The project is scheduled to be designed in 2016 with construction completed in 2017. Design and engineering is estimated to be $20,000 and the current construction costs is forecast to be $593,000.

Project Schedule

The design of this project is scheduled to be completed in 2016 and construction is scheduled for 2017.

Business Drivers and Benefits

The main driver for this project is aging infrastructure. This project will ensure ATCO Electric Yukon complies with recommendation #2014-09 of the 2014 Dam Safety Report and item 42 of water license HY12-065.

Evaluation of Viable Alternatives

Alternative 1: Replace the aging structure. This alternative ensures ATCO Electric Yukon is compliant with the terms of the water license and ensures safe and reliable operation of the Fish Lake Hydro system.

Alternative 2: Replace after the structure fails. Failure of this structure inhibits ATCO Electric Yukon's ability to manage a flood event and poses significant risk to the remaining structures within the system.

Recommendation

ATCO Electric Yukon recommends replacing the existing spillway structure as recommended in the 2014 Dam Safety Report. This alternative mitigates the risks associated with a failure of the structure and aligns with ATCO Electric Yukon's commitment to provide safe, reliable service.

2016-2017 General Rate Application

Appendix #3

Watson Lake Bi-Fuel Project

Executive Summary

The Federal and Yukon governments have indicated a strong desire to reduce or eliminate dependence on diesel fuel in northern and remote communities. The Yukon government has also expressed an interest in findings ways to help Yukoners manage their monthly electricity bills. In support of these objectives, ATCO Electric Yukon is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to Bi-Fuel beginning in 2016.

- Phase 1: 2016 – 2017: Source Liquefied Natural Gas (LNG) storage equipment; upgrade Watson Lake plant to meet the safety standard for LNG equipment; install Bi-Fuel technology to one of the six engines; and conduct environmental assessment of engines as directed by Yukon Environmental and Socio-economic Assessment Board (YESAB).

- Phase 2: 2018: Source and install Bi-Fuel technology to the remaining five diesel engines at the Watson Lake plant and increase the volume of LNG storage onsite.

The Watson Lake Bi-Fuel Project achieves the Federal and Yukon governments' goals of displacing diesel and managing electricity costs by:

1. Using LNG as an alternative fuel source, ATCO Electric Yukon aims to reduce diesel consumption of its power generation plant in Watson Lake by 50%. While ATCO Electric Yukon continues to pursue solutions to generate electricity with renewable resources, in ATCO Electric Yukon's view fossil-fueled base load generation source will continue to be required in each of ATCO Electric Yukon's diesel generation facilities at least in the medium term to provide stable and reliable base load electricity and service to customers when renewable energy is not available.

2. Using LNG, often cheaper fuel source than diesel, ATCO Electric Yukon expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project**.** These savings would be passed directly to customers.

ATCO Electric Yukon estimates the total cost of the three-year project to be approximately $4.97 million; however, at this time, ATCO Electric Yukon is seeking approval for $3.26 million to implement Phase 1 of the project.

Background

ATCO Electric Yukon originally proposed this project in the 2013-2015 GRA and there continues to be clear benefits to Yukon customers. In its 2013-2015 GRA business case, ATCO Electric Yukon proposed contracting services with an affiliate, ATCO Gas, on the project. ATCO Electric Yukon is no longer proposing that ATCO Gas be involved in providing any of the services to the Bi-Fuel project in Watson Lake. ATCO Electric Yukon will own all of the assets required.

ATCO Electric Yukon has received YESAB approval for Phase 1 – the conversion of a single generating unit to Bi-Fuel operation. The required licenses and permits for Phase 2 of the project will be obtained should the Yukon Utilities Board approve this project.[1]

Project Description

The first phase of the project will modify Unit #5 through the installation of a Bi-Fuel system which allows natural gas to be added to the air intake upstream of the diesel turbo unit. The natural gas will be trucked to Watson Lake as LNG. Once onsite, the LNG will be transferred to a storage tank until the LNG is required for use in the power plant. The LNG will then be re-gasified through a vaporization unit utilizing heat recovered from the power plant. The resulting natural gas will be piped to the power plant and mixed with air and diesel fuel before combustion in the existing generating unit. The installed diesel units at Watson Lake will require a portion of the fuel to contain diesel for lubrication, cooling and combustion.

Once configured with the appropriate technology, each diesel generating unit will be capable of displacing up to a maximum of 70% of the diesel required with natural gas, however for the purpose of this business case, unit performance is anticipated to average a displacement of 50% of diesel fuel consumption. An assessment of the operation of the unit will be carried out as part of Phase 1, as specified in YESAB's 2013-0009 Decision Document as a condition before obtaining approval to convert the remaining diesel generators to Bi-Fuel.

During Phase 2 of the project, the remaining diesel-only units (five remaining units) will be converted to Bi-Fuel with a target average diesel displacement of 50% for the entire generating facility. In the event of any supply interruptions, the Watson Lake Generating Station will have the option to revert back to 100% diesel powered generation to maintain service to the community.

Without refrigeration, LNG naturally begins to vaporize over time as it slowly gains energy from the ambient atmosphere, making long term storage expensive. Continuous operation mitigates the challenge of long term storage, as the LNG is consistently drawn down and replenished, keeping the system cool. 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.

Following Board approval, the project will be separated into the following components and each component will be competitively tendered:

[1] YCS-YECL-2-1 Attachment 1 (filed July 18, 2013)

1. Fuel Supply
    - LNG is available from a FortisBC Energy Inc. facility in Delta, BC
    - AltaGas Ltd. is expected to have an LNG facility in Dawson Creek, BC, in-service Q4 2016
2. Transportation of LNG to Watson Lake
    - LNG is currently being transported through the Yukon in specialized LNG storage tanks
    - ATCO Electric Yukon will explore what synergies exist, if any, in collaborating with the other large LNG users in the NWT and Yukon
3. LNG Onsite Infrastructure
    - Bi-Fuel kits for the diesel generating units
4. Installation and Commissioning of LNG Infrastructure
    - Civil works including foundations and berm
    - New gas distribution system from the vaporizer to each generating unit
    - Electrical interconnection
    - Bi-Fuel kit installation
    - Feedback and controls integration into existing plant PLC
    - Safety upgrades including natural gas detection equipment inside the generating station
5. Scheduled Maintenance of LNG Equipment
    - Current plant staff are capable of operating the proposed LNG infrastructure, however, periodic maintenance performed by specialists will be necessary on the LNG equipment to ensure ongoing safe, reliable operation

ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.

ATCO Electric Yukon 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, eliminating the need for additional fuel consumption to enable vaporization.

Project Schedule

Assuming Board approval in Q1 2017, Phase 1 could be completed as early as Q3 of 2017. Phase 2 is proposed to be completed following YESAB approval of the first Phase.

Project Cost

ATCO Electric Yukon will competitively tender each of the major elements of the project as described in the Project Description, excluding the equipment purchased from ATCO Gas. All values presented below are budgetary with the exception of the costs incurred to date related to the project.

Costs associated with Phase 1 included in this GRA are $3.26 million. Phase 2 costs will be applied for in a subsequent application.

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 Vaporizor and LNG Storage Tank			$1,470,000	
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			$3,261,000	$1,710,000
Total				**$4,971,000**

Maintenance Costs

Periodic preventative maintenance is expected on the specialized LNG equipment and the provision of this service will be competitively tendered. In preparing ATCO Electric Yukon's Review and Variance of Board Order 2014-06, ATCO Electric Yukon ran a competitive process to determine maintenance costs for 10 year quarterly maintenance costs and filed them with the Board. Based on these quotes, ATCO Electric Yukon estimates that annual incremental O&M costs to the Watson Lake Generating Facility will be approximately $50,000 per year for business planning purposes. Periodic maintenance will be competitively tendered following Board approval.

Benefits to Customers / Financial Performance

Implementing the Watson Lake Bi-Fuel Project is expected to:

- Support 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, and
- Shield Yukon customers from fluctuation in oil prices by reducing fuel costs of the Watson Lake generation facility.

Cost savings that customers will experience with the implementation of the Watson Lake Bi-Fuel Project is dependent on future commodity prices.

Forecast savings are based on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. In the case of LNG, the bulk of the delivered price can be attributed to the cost of liquefaction and transportation fees. Therefore, even if both commodities double in price from current levels, the savings when consuming LNG increases, as the liquefaction and transportation fees will be escalated at a lower negotiated rate, as depicted in Figure 1 below.

ATCO Electric Yukon has used FortisBC Energy Inc.'s Rate Schedule 46 and an indicative quote from AltaGas based on preliminary expected annual volumes for the entire conversion of Watson Lake Generating Station to Bi-Fuel operation. These values presented below are subject to change before contracts are in place with a LNG supplier and a LNG transporter.

The cost to source LNG from FortisBC is based on:

- Flow through of the commodity price at BC's Sumas Station
- Liquefaction charge of approximately $0.18/Litre Diesel Equivalent (LDE), escalated at the greater of 2% or the BC CPI
- Transportation from Delta, BC at approximately $0.32/LDE

The cost to source LNG from AltaGas is based on:

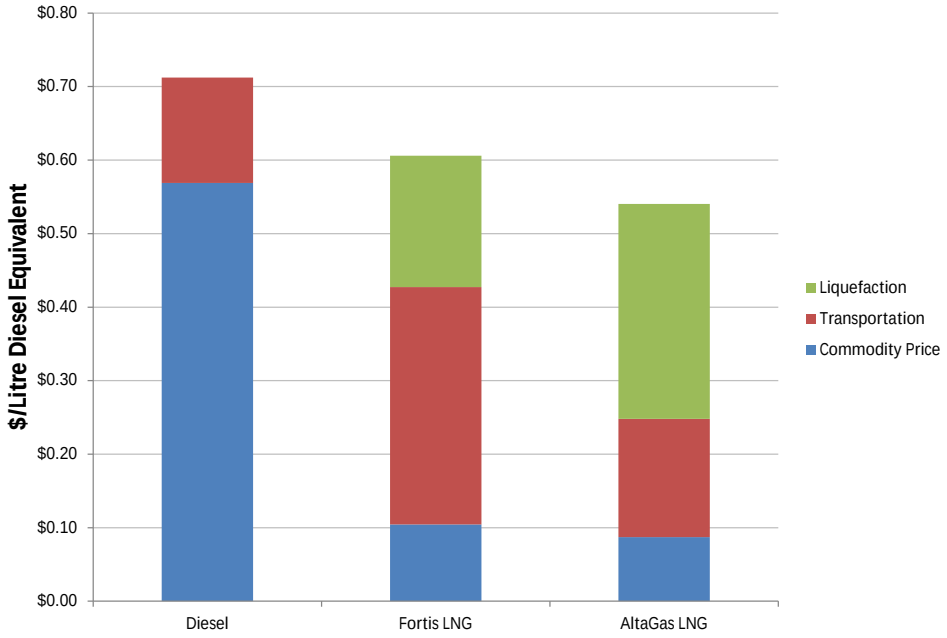
- Flow through of the commodity price at BC's Station 2
- Liquefaction charge of approximately $0.29/LDE, with escalation dependant on contract commitments
- Transportation from Dawson Creek, BC at approximately $0.16/LDE

Diesel prices in Watson Lake are based on:

- Rack prices in Vancouver
- Transportation from Vancouver at approximately $0.14/LDE

Note: There has been no inclusion of any future Yukon or Federal carbon tax in this analysis.

Figure 1: Comparison of Delivered Fuel Sources in 2017



Future fuel commodity prices introduce uncertainty into the projected customer savings as a result of this project. ATCO Electric Yukon has utilized a commodity price forecast from Sproule – Worldwide Petroleum Consultants[2]. As well, based on the understanding that current prices for both gas and oil prices are near the bottom of the market, a fuel price escalation scenario that escalates gas and oil at approximately twice that of inflation was also considered. The determination of the fuel savings, capital costs and operations and maintenance costs were calculated based on the LNG supplier and fuel price forecast and a simple payback and net present value were calculated and are shown in Table 2.

[2] http://www.sproule.com/forecasts

Table 2: Comparison of Potential Suppliers and Fuel Price Forecasts

	Supplier	Simple Payback (years)	20 Year NPV ($M)
Sproule Price Forecast	Fortis	12	$0.4
	AltaGas	10	$2.1
Both Commodities Escalates at 5%	Fortis	11	$2.7
	AltaGas	9	$5.6

ATCO Electric Yukon submits that both of these commodity price scenarios reflect a reasonable assessment of the fuel savings that customers can expect from the Watson Lake Bi-Fuel Project. ATCO Electric Yukon believes that implementing this project will result in customer savings when fuel savings are compared to the capital and operations / maintenance costs.

In addition, ATCO Electric Yukon is of the opinion that should a Yukon or Federal carbon tax be imposed in the future, it will likely favour the use of natural gas for electricity generation in Watson Lake. ATCO Electric Yukon would expect that a Yukon or Federal carbon tax will have an impact on 100% of the delivered diesel cost and a smaller percentage impact on the delivered LNG cost.

Business Drivers and Benefits

Meeting Federal and Yukon Goals

The Federal and Yukon governments have indicated a strong desire to reduce or eliminate dependence on diesel fuel in northern and remote communities. The implementation of the Watson Lake Bi-Fuel meets this goal while allowing for future renewable power generation. ATCO Electric Yukon and Independent Power Producers (IPPs) are pursuing the generation of electricity with renewable resources, however, it is almost certain that a fossil-fueled base load generation source will continue to be required in the short to medium term for reliability of the system. ATCO Electric Yukon believes the switch to a Bi-Fuel Project best accomplishes this base load generation need.

Cost Savings to Customers

Offsetting approximately 50% of the diesel consumed for power generation in Watson Lake will shield customers from fluctuations in oil prices. Until recently, there were few options to displace diesel with lower cost fuels, however, LNG supply is readily available in the Yukon.

Economies of Scale – Leveraging an Established Northern LNG Supply

LNG is currently transported through the Yukon for power generation by Yukon Energy Corporation in Whitehorse and the Northwest Territories Power Corporation in Inuvik. Increasing the volume of consumption could offer further advantages to customers through economies of scale.

Sensitivity Analysis of Commodity Price

ATCO Electric Yukon recognizes that there is uncertainty as to the future prices for oil and gas. The following table reflects the results of a sensitivity analysis escalating fuel prices from 2017 to 2037 at differing fixed rates from the 2015 historical price of diesel and natural gas.

Table 3: Alternative Fuel Escalation Scenarios

	Supplier	Simple Payback (years)	20 Year NPV ($M)
Scenario 3 Both Commodities Escalated at 2.5%	Fortis	15	$(0.9)
	AltaGas	11	$1.7
Scenario 4 Diesel Commodity Escalation at 5% Natural Gas Escalation at 2.5%	Fortis	11	$3.5
	AltaGas	9	$6.1
Scenario 5 Diesel Commodity Escalation at 2.5% Natural Gas Escalation at 5%	Fortis	17	$(1.7)
	AltaGas	11	$1.2
Scenario 6 Both Commodity Prices Doubled	Fortis	7	$7.1
	AltaGas	5	$10.2

Evaluation of Viable Alternatives

Alternative #1: Status quo; continue to generate power using only diesel. This would not address continued exposure to the increasing cost of diesel or further the federal or territorial governments desire to displace diesel in northern communities.

Alternative #2: Install a new dual fuel engine that runs on either 100% diesel or 100% natural gas. This would result in a project cost significantly higher than modifying the existing generating units.

Alternative #3: Modify existing generating units in a phased approach to utilize natural gas injection to displace the amount of diesel fuel used. This alternative minimizes the capital cost investment required by utilizing existing equipment and infrastructure while allowing optional flexibility to reliably revert back to full diesel operation.

Recommendation

Proceed with Alternative #3 on a phased approach to convert one unit in the first phase to verify operational requirements then proceed with the second phase of the project to modify the remaining five units.

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Appendix #4

Watson Lake Unit #2 Replacement

Executive Summary

ATCO Electric Yukon is scheduled to replace the existing Watson Lake Unit #2 (CUL 257), which is at the end of its life, with a new diesel generator. This 800 kW unit will be replaced with a 1,000 KW unit.

Primary drivers for this replacement are:

- unit age (1985);
- poor condition of the alternating current (AC) generator; and
- total operating hours and community loading.

The replacement unit is to have a larger generating capacity in comparison to the existing unit to handle load growth and contingency concerns.

Replacement of Watson Lake Unit #2 was approved in Board Order 2014-06 as part of the 2013-2015 General Rate Application. The project was originally planned to be completed in 2015. After the replacement of Watson Lake Unit #4 in early 2014 the new unit became the main unit in the Watson Lake power plant. This resulted in a decrease of operating hours on all units including Unit #2. As a result ATCO Electric Yukon was able to defer this project to 2016.

Background

Currently Watson Lake is serviced by six units with the following capacities:

- Unit 1 – CUL 422 800kW Unit
- Unit 2 – CUL 257 800kW Unit
- Unit 3 – CUL 352 1,000kW Unit
- Unit 4 – CUL 545 1,450kW Unit
- Unit 5 – CUL 466 650kW Unit
- Unit 6 – CUL 423 800kW Unit

Unit #2 has reached the end of its useful life and is due for replacement. The original scope of the project in the 2013-2015 General Rate Application was to replace the unit with a similar sized engine. At the time of unit tender and selection, capacity requirements were reviewed. This review determined that in order to meet contingency handling requirements a larger unit is required.

Project Description

ATCO Electric will tender and procure a 1,000 kW unit and remove CUL 257 and associated cooling, waste heat and exhaust equipment from the Watson Lake plant. In its place, install the new diesel generator with manufacturer-supplied, cooling, waste heat and exhaust equipment. The new unit will be integrated into the existing plant control system and switchgear.

Project Cost & Schedule

This project is scheduled to be completed in 2016 and is forecast to cost $1,390,000.

This forecast is $40,000 higher than previously approved; this is due to the requirement for a larger sized engine.

Business Drivers and Benefits

End of Life Condition

The AC generator on the engine is 1974 vintage and was installed on CUL 257 with 51,404 operational hours from a previous unit in Watson Lake (CUL 192). As of January 1, 2016, CUL 257 had 88,850 operational hours which would put the total hours on the AC generator at 140,254 hours. This generator failed in 2011 and was sent out for repair. At that time, the repair facility assessed the overall condition of this generator as poor and repairs where undertaken on a best attempt basis. The purchase cost for a new AC generator unit is approximately $100,000. Based on the engine's advanced age and forecasted hours of operation to end of life replacement, a whole unit replacement approach was determined to be prudent.

Life Extension

CUL 257 is scheduled for its next major overhaul to occur at 91,734 hours, which based on average annual operational hours, could occur in the second quarter of 2016. Based on the same work completed to a similar unit, the cost for this work will be approximately $300,000. In reviewing the advanced age of the unit, the total operating hours at the time of major overhaul and the poor condition assessment of the AC generator; further investment in a life extension that does not guarantee fully reliable operation is not considered to be prudent.

Unit Availability

As stated previously, the condition of the AC generator is poor. If failure of this unit was to occur and a new AC generator was required, the lead time could be as long as a year and the loss of this unit would affect plant capacity and contingency.

Additional Generation Capacity Required to Meet Electrical Load

The Watson Lake plant had a recent peak of 3,205kW recorded for the community. With the addition of the new hospital and other forecasted residential loads, this peak is expected to rise. In the case of an unplanned loss of the largest unit in the Watson Lake plant (Unit #4), the remaining generators would not be able to be taken out of service for regular maintenance without negatively impacting customers. A major overhaul of a unit is usually 4-6 weeks in length; the minor overhauls are 1-2 weeks, during which time the unit is out of service.

Figure 1 – Watson Lake Generating Capacity

Watson Lake Generating Facility		
Unit #	**Unit Name**	**Unit Size (kW)**
1	CUL 422	800
2	CUL 257	800
3	CUL 352	1,000
4	CUL 258	1,450
5	CUL 466	650
6	CUL 423	800
Installed Capacity (kW)		**5,500**
Firm Capacity (kW)		**4,050**

Evaluation of Viable Alternatives

Alternative #1: Perform major overhaul on CUL 257. Based on previous operational experience, ATCO Electric Yukon has seen marginal benefit in reliable operation of 1200RPM units that are overhauled past the 100,000 hour mark. The extensive hours on the unit have resulted in stresses and wearing that cannot be fully repaired. Factoring in the current age and state of the AC generator, this alternative does not return the unit to a satisfactory condition in terms of reliable and efficient operation.

Alternative #2: Replace AC generator and perform major overhaul on unit CUL 257. AC generators are expected to run the life of the engine unit. Purchasing a new unit for another 15,000hrs or less of service is not an effective solution. The generator could be removed and refitted to another unit once CUL 257 is retired; however, this is not ideal as new units are best specified as an engine and generator matched set. Also, coupling this used AC generator to a new unit may, as the engine accumulates hours, put ATCO Electric Yukon in a similar situation as it currently faces with CUL 257. As previously stated, a major overhaul and life extension on a diesel engine with more than 100,000 hours does not guarantee reliable operation.

Alternative #3: Replace CUL 257 with a new, larger size unit. This option addresses the end of life replacement of CUL 257 and the need for additional capacity in the Watson Lake facility.

Recommendation

Proceed with replacement of CUL 257 with a 1,000 kW unit in 2016 to continue to meet load requirements and provide reliable service to the community of Watson Lake.

2016-2017 General Rate Application

Appendix #5

Old Crow Unit #3 Replacement

Executive Summary

Load growth and load duration of the Old Crow community have steadily diminished the utilization of the existing 170 kW unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, ATCO Electric Yukon is proposing to purchase and install a new 600 kW unit to replace the existing undersized 170 kW unit. The new unit will be installed in the new building in Old Crow, as it will not physically fit in the existing building.

Business Case #15 "Old Crow Unit #3 Replacement" was submitted in the 2013-2015 General Rate Application and approved in Decision 2014-06. The unit tender and selection occurred in 2015; the unit will be received and installed in 2016.

Background

Based on the 2012 loading data (as submitted in the 2013-2015 General Rate Application), a project was identified that required a purchase of a 250 kW unit to replace the currently undersized 170kW unit in operation in the existing plant.

In preparation for tender of the new unit in 2015, a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was identified as being required.

Project Description

Multi-year project to replace the existing 170 kW unit, housed in the original Old Crow generating facility, with a larger 600 kW unit to be house in adjacent new building.

Manufacturer will also be responsible for disassembly and reassembly of unit to allow for transportation into the community via aircraft.

Unit will be installed within the new facility with structural, mechanical, and seismic engineering completed on the installation project to meet the applicable standards for a post disaster rated facility.

Project Schedule & Cost

This is a multi-year project. The tender and unit selection process occurred in 2015 with the unit scheduled to be installed in 2016. Total cost for this project is forecast to be $1,262,000.

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.

Overall the first two items were the most significant causes of the increased forecast. 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.

Business Drivers and Benefits

Load Growth

Load in Old Crow has been increasing over the last few years. Notable developments include the Water Treatment Center, Co-op Store, Fuel Depot, and new housing. Based on these developments and other factors within the community, a significant increase in peak load has occurred. With further potential development this peak is expected to rise. On average the peak has grown 4.023% based on 2008 – 2015 recorded values. The peak load has increased almost 21% since the original replacement unit was determined in 2012.

Old Crow Peak Loading 2008 – 2015

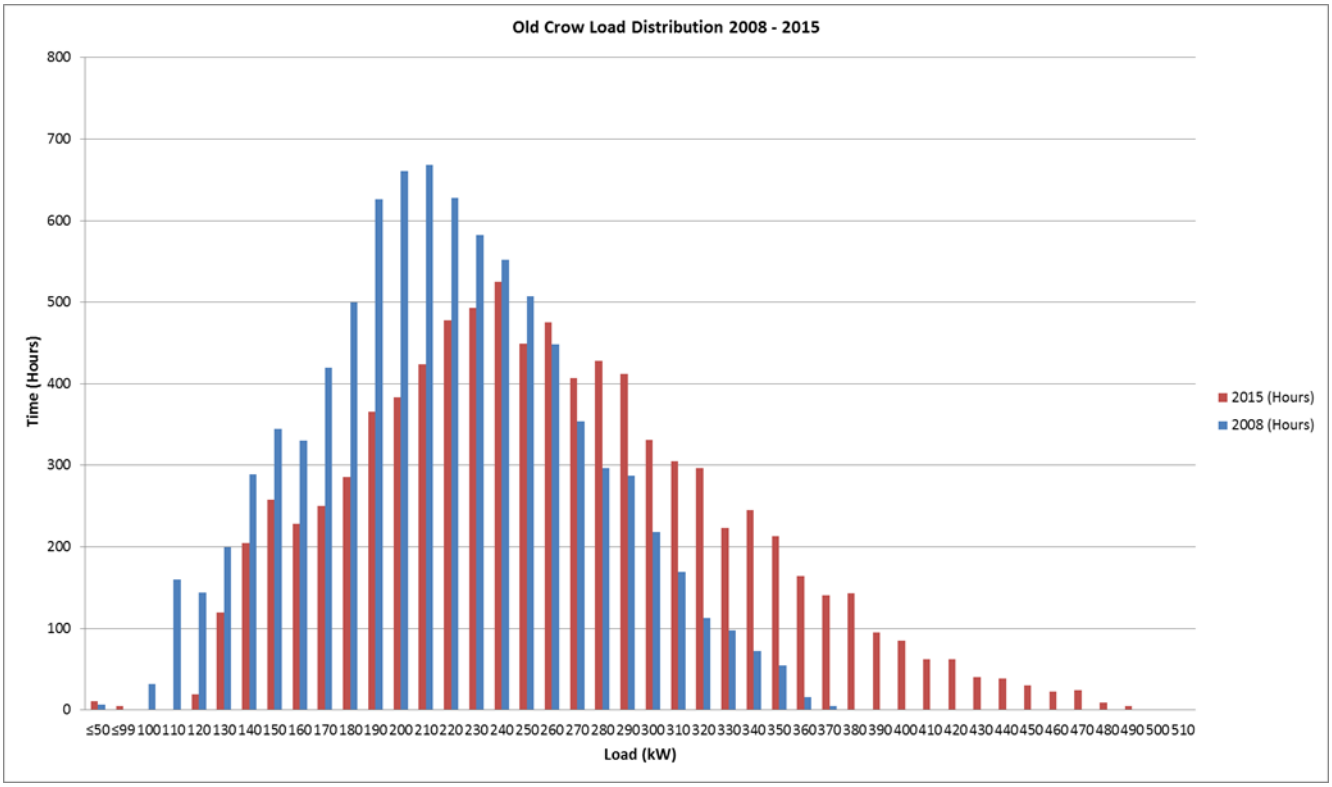
Year	Peak Load (kW)
2008	407
2009	460
2010	439
2011	478
2012	462
2013	481
2014	491
2015	558

Plant Efficiency

Sustained load growth within the community has impacted the overall load profile. As a result, the base load levels within the community have risen. Based on this trend, it is expected that the operational hours on a 250kW unit if installed would continuously decrease with load increase. This could result in the unit not operating under normal dispatch similar to the operation of the original 170kW unit.

Additionally this increase would reduce the possibility of the unit providing 100% community load under normal dispatch operation.

Old Crow Load Distribution 2008 / 2015



Contingency

The larger unit will not physically fit in the original facility where CUL 384 is currently housed. This new unit will be installed in the new plant adjacent to the original facility and provide additional contingency and mitigate the risk of long term outages within the community due to the loss of the original power plant for any reason.

Evaluation of Viable Alternatives

Alternative # 1: Leave existing 170kW unit in service. With continued load growth the unit will not run to provide 100% community supply under normal dispatch. The annual operating hours of the unit will continue to decrease.

Alternative # 2: Purchase and install 250kW unit as originally planned. Due to actual load growth, this alternative is not recommended, as it only provides short term solution. With continued load growth it is expected that this unit would see a continued decrease in hours of operation. Furthermore, the majority of project costs are related to logistics and installation, only a small differential in cost ($60,000) is related to the price of a 250kW vs 600kW unit.

Alternative # 3: Replace the existing unit with a 600kW unit. Unit will be able to meet supply requirements of present load and provide capacity for future load growth.

Recommendation

It is recommended to replace Old Crow Unit #3 with a 600kW unit in the new plant adjacent to the original facility. This will address the load growth issue and improve contingencies in Old Crow.

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Appendix #6

Destruction Bay Unit #2 Replacement

Executive Summary

ATCO Electric Yukon is scheduled to replace the existing Destruction Bay Unit #2 (CUL 372), which is at the end of its life, with a new diesel generator. This 300 kW unit will be replaced with a 400 kW unit.

The replacement unit is to have a larger generating capacity in comparison to the existing unit to handle overloading issues on the existing unit.

Replacement of Destruction Bay Unit #2 was approved in Board Order 2014-06 as part of the 2013-2015 General Rate Application (GRA). The project was scheduled to be completed in 2015. The tender and unit selection process was completed in 2015. The unit will be received and installed in 2016.

Background

Currently Destruction Bay is serviced by three units with the following capacities:

- Unit 1 – CUL 467 600kW Unit
- Unit 2 – CUL 372 300kW Unit
- Unit 3 – CUL 584 315kW Unit

Unit #2 has reached the end of its useful life and is due for replacement. The original scope of the project in the 2013-2015 GRA was to replace the unit with a similar sized engine. At the time of unit tender and selection, capacity requirements were reviewed. This review determined that at the current dispatch level there are times in which the unit is operated at an overload in respect to its prime rating. In order to address this without negatively impacting the other existing unit's performance and operation a larger unit is required.

Project Description

ATCO Electric Yukon will tender and procure a 400 kW unit and remove CUL 372 and associated cooling, waste heat and exhaust equipment from the Destruction Bay plant. In its place, install the new diesel generator with manufacturer-supplied, cooling, waste heat and exhaust equipment. The new unit will be integrated into the existing plant control system and switchgear.

Project Cost & Schedule

In the 2013-2015 GRA, the Board approved expenditures were $600,000 for 2015. The new unit was selected and the tender process was completed in 2015. Receipt of the unit and installation is scheduled to be completed in 2016. The total cost of this project is forecast to be $758,000.

Business Drivers and Benefits

End of Life Condition

As of January 1, 2016, CUL 372 had 107,765 operational hours. ATCO Electric Yukon's planning criteria for 1200 RPM units recommends replacement after 90,000 to 126,000 hours of operation.

Unit Availability

An unplanned failure of this unit would negatively affect plant capacity and contingency. If the failure was to occur in the winter the power plant would only have 1 generating unit capable of supplying power to the community.

Additional Generation Capacity Required to Address Overloading

Under current dispatch levels there are times where the current CUL 372 is overloading. Overload conditions reduce the life expectancy of engine parts and can reduce the overall time between maintenance intervals. De-rating the kW level at which this unit is dispatched would address the overloading situation at the cost of low loading another existing unit which will lead to inefficient and poor operation of that unit.

Evaluation of Viable Alternatives

Alternative #1: Perform major overhaul on CUL 372 at the scheduled 131,932 total operating hours. Based on previous operational experience, ATCO Electric Yukon has seen marginal benefit in reliable operation of 1200RPM units that are overhauled past the 100,000 hour mark. The extensive hours on the unit have resulted in stresses and wearing that cannot be fully repaired. The unit may not operate long enough to provide payback of the life extension investment. The result would be poor reliability which could lead to unplanned outages and poor system performance. Replacement of a failed unit in an unplanned situation would leave significant exposure time to inadequate capacity and the lead time to procure and obtain units of this rating can vary from three to nine months.

Alternative #2: Run unit to failure and not replace. The removal of Unit #2, without replacement, would not provide enough available generation to ensure 110% of peak loading with largest unit removed (N-1 criteria). Replacement of a failed unit in an unplanned situation would leave significant exposure time to inadequate capacity and the lead time to procure and obtain units of this rating can vary from three to nine months.

Alternative #3: Replace CUL 372 with a same sized 300kW engine. This option does not address the overloading issue of CUL 372. Overloading a generator will shorten the life and possibly cause poor electrical performance of the system.

<u>Alternative #4:</u> Replace CUL 372 with a 400kW engine. This option addresses the overloading issue of CUL 372, and is the best alternative to ensure the system is operating efficiently.

Recommendation

Proceed with replacement of CUL 372 with a 400kW unit to continue to maximize efficiency and provide reliable service to Destruction Bay/Burwash Landing.

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Appendix #7

Whistle Bend Subdivision

Stage 3C

Executive Summary

This customer driven project will design and build an electrical distribution system to service Stage 3C of the Whistle Bend subdivision in Whitehorse in compliance with the Yukon Utilities Board (YUB) approved Terms and Conditions for electrical service. Costs associated with this project will be significantly contributed by the customer as per the aforementioned Terms and Conditions.

Background

Whistle Bend Subdivision is planned to be Whitehorse's largest residential subdivision with room for 8,000 residents. Plans include future schools, retail shops, town square and parkland. Development began in 2006 under a joint agreement by the City of Whitehorse and the Government of Yukon. The Government of Yukon developed Stages 1 and 2. The City of Whitehorse plans to be the developer for Stage 3C in 2017 and Stage 3D, 3E and 4 in 2018 and later.

ATCO Electric Yukon has been planning the orderly development of electrical infrastructure in the area to meet the present and future demands of this large subdivision. Whistle Bend substation was completed in 2012 in large part to serve this growing area. ATCO Electric Yukon has plans for both high capacity feeders and low capacity feeders to appropriately meet the subdivision's electrical needs. The high level electrical plan created for the area by ATCO Electric Yukon can be seen in Attachment 1 to this business case.

Project Description

This project will engineer, procure and install:

- High voltage cable
- Low voltage cable
- Duct systems for cables
- Transformers
- Pad mounted switching devices
- Low voltage pedestals
- Streetlights

Detailed engineering is being coordinated with the City of Whitehorse, their consultants and with Northwestel.

Project Costs & Schedule

Construction of this phase of the Whistle Bend development is scheduled to commence and be completed in 2017. Total cost of $1,180,000 is forecast for the electrical infrastructure plus an additional $350,000 for streetlights.

Business Drivers and Benefits

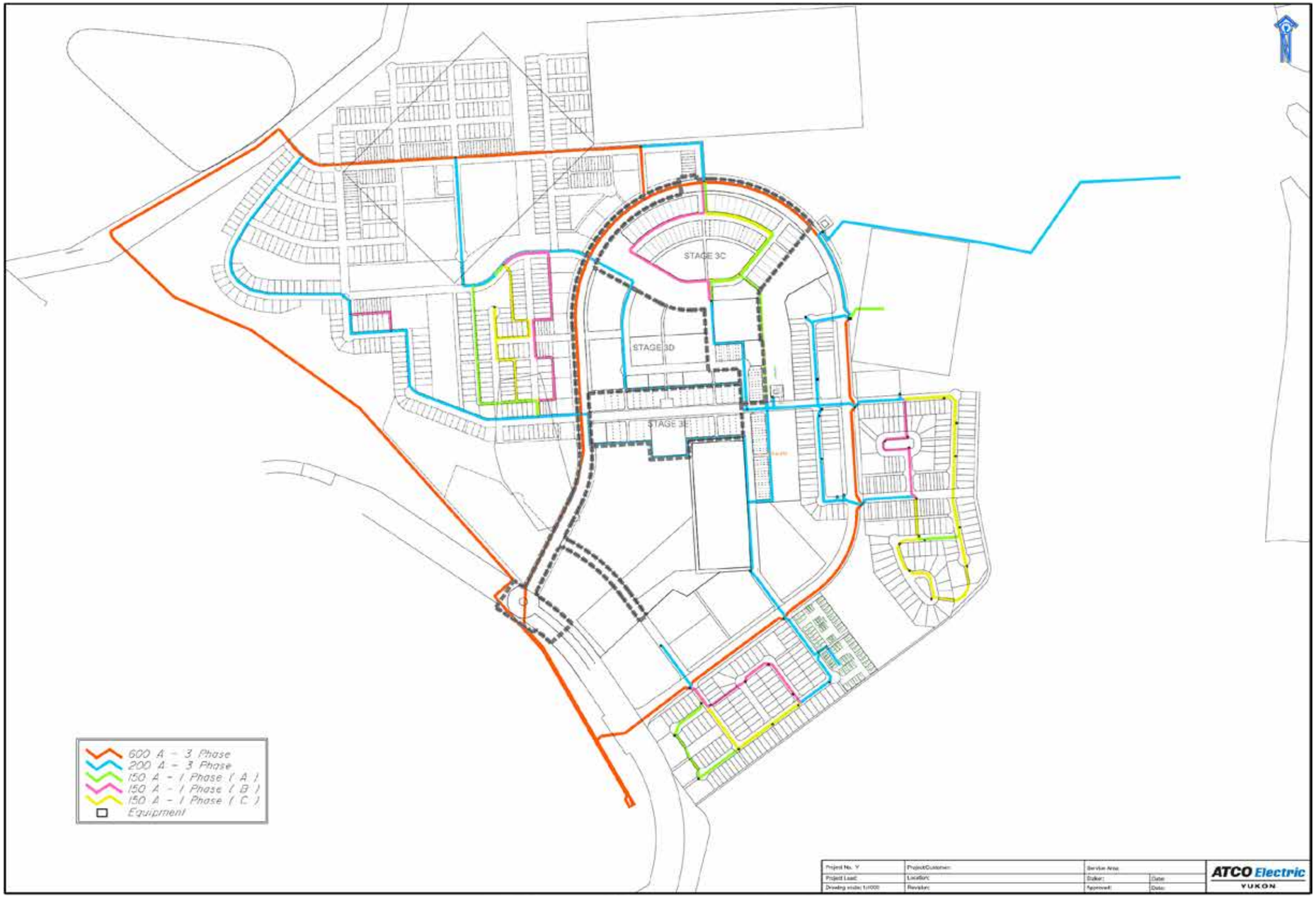
This project is customer driven.

Evaluation of Viable Alternatives

There are no other viable alternatives. ATCO Electric Yukon is committed to provide service per the guidelines approved in the Terms and Conditions.

Recommendation

ATCO Electric Yukon recommends proceeding with construction of Stages 3C of the Whistlebend subdivision as requested by the City of Whitehorse.


STAGE 3C
STAGE 3D
600 A - 3 Phase
200 A - 3 Phase
150 A - 1 Phase (A)
150 A - 1 Phase (B)
150 A - 1 Phase (C)
Equipment
ATCO Electric
YUKON

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Appendix #8

McIntyre Subdivision Replacement Project Update

Executive Summary

This is a multi-phase project to replace the existing end of life underground electrical infrastructure serving the McIntyre subdivision in Whitehorse. This project commenced in 2013 and is scheduled to be completed in 2020. The original forecast for Stage 1 was approved as part of the 2013-2015 General Rate Application (GRA) in Board Order 2014-06.

Background

The existing electrical system was installed circa 1977 and was one of the first underground high voltage cable installations in the City of Whitehorse.

The electrical infrastructure is now at its end of life. As described in Business Case #22 in the 2013-2015 GRA application deficiencies includes:

- Extended unplanned outages caused by failing high voltage cables;
- Transformers and switch cubicles that cannot be operated safely;
- Cable switch points that cannot be operated at all;
- Equipment that can't be operated effectively due to installation of direct buried cables; and
- Physical deterioration of metal equipment and street lights.

Project Scope

The McIntyre Subdivision Replacement project is a complex brownfield infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35kV and the project will result in a change to the standard 25kV system. 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.

The first stage of the project, which took place from 2013-2015, had a significant change in scope. The original scope was to install a new 25kV underground electrical system in close proximity to the existing 35kV system. The two separate underground systems would continue to operate in parallel as various streets and areas of the subdivision were converted to the new system. As streets throughout the subdivision were converted to the new system, the old system would be decommissioned and abandoned in place.

As explained in the Post Completion Summary Attachment 11.4 the project scope had to be adjusted.

The new project scope included:

- Installation of a temporary 25kV shadow overhead line complete with transformers and streetlights to serve the subdivision;
- De-energization and decommissioning of the old 35kV underground system;
- Installation, commissioning and energization of the new 25kV underground system;
- Removal the old 35kV cables where appropriate and electrical equipment; and
- Replacement of streetlights to the roadway lighting standard.

The objective of the project is to replace the existing end of useful life underground electrical system. This will include new high and low voltage cables, transformers, high voltage switch cubicles and streetlights. It will also include the eventual removal of the temporary 25kV overhead line.

Stage 1 of the project was completed from 2013-2015. It involved extensive site preparation, including the installation of the temporary overhead shadow electrical system which presently allows customers to continue to receive safe and reliable electrical service. ATCO Electric Yukon de-energized the old 35kV underground power system and also installed the final portion of the main underground feed to the subdivision.

The next phase of the project will take place in 2016 and 2017. In 2016, the work will include fully replacing the underground system along Hanna Crescent and McCandless Crescent. The new 25kV high voltage cables and equipment will be installed with corresponding low voltage system, transformers and associated electrical equipment. Once installed, commissioned and energized the overhead system will be removed. In 2017, the same work plan will be completed for McCrimmon Crescent, O'Brien Road and a portion of Murphy Road.

In 2018 the work will proceed to McClimon Crescent. In 2019, construction crews will complete the upgrade on Murphy Road and another portion of McIntyre Drive. In 2020 the 25kV cables will be installed up to Hamilton Boulevard and the temporary overhead line will be removed.

Attachment 1 of this business case shows the project phases by year as described above.

The project underway is estimated to cost $5,129,000 when all work is complete in 2020. Table 1 shows the total costs for the project.

Project Cost

Total Project Costs

Table 1 shows the actual costs to date and forecasted budgets until completion.

Table 1: Estimates for 2016 to 2020 work to complete McIntyre Subdivision Replacement

Year	Construction Actual/Forecast ($000s)	Streetlights Forecast ($000s)	Total ($000s)	Scope
2013 A	656	-	656	Temporary Overhead
2014 A	418	-	418	low voltage pedestals, connected to feeds
2015 A	379	-	379	main underground feed to the subdivision
2016 F	565	175	740	Hanna and McCandless
2017 F	930	256	1,186	Murphy (partial), O'Brien, McCrimmon
2018 F	500	100	600	McClimon
2019 F	600	150	750	Complete Murphy, McIntyre up to McCauly
2020 F	300	100	400	McCauly to Hamilton to McIntyre
	4,348	**781**	**5,129**	

Project Schedule Update

The project is forecast to be completed in 2020. The work has been broken into annual amounts that are manageable for construction resources and capital budgets.

Alternatives

Alternative 1: Leave the overhead distribution in place and remove the existing 35kV infrastructure. This lowers the standard of service the KDFN community receives with no corresponding benefit as the existing underground system would be converted to overhead.

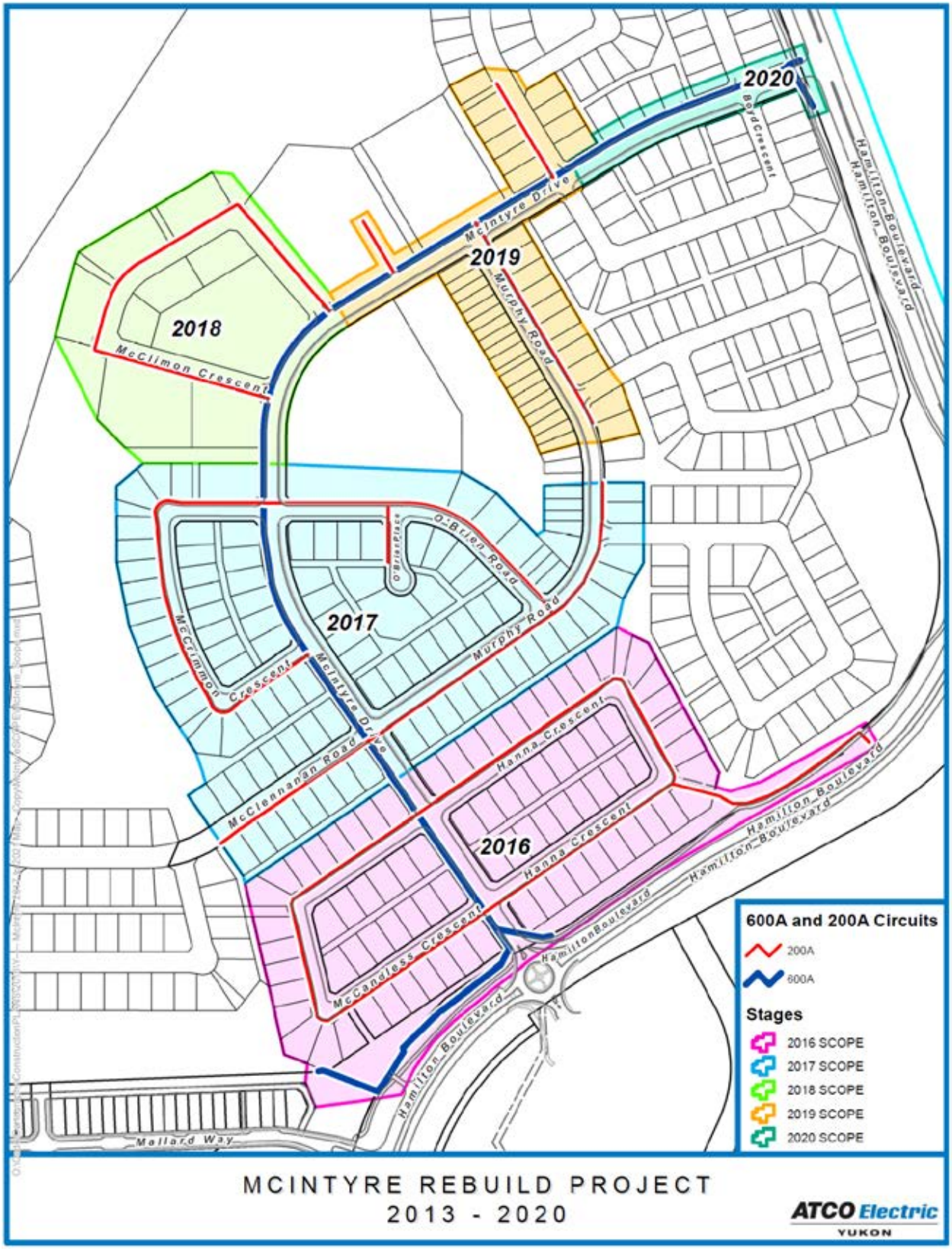
Alternative 2: Explore the benefits of utilizing some of the overhead system in coordination with some of the new underground electrical infrastructure. This would result in a hybrid system as it would be a combination of overhead and underground. This alternative would require the approval of the KDFN.

Alternative 3: Continue with the McIntyre Subdivision Replacement with the new project scope.

Recommendation

In order to provide safe, reliable service to the subdivision that meets current industry standards it is recommended to continue upgrading the underground electrical system in the McIntyre subdivision along Hanna Crescent, McCandless Crescent, McCrimmon Crescent, O'Brien Road and a portion of Murphy Road.

Appendix 8 – Attachment 1: Project Completion Phasing



2016-2017 General Rate Application

Appendix #9

Downtown Whitehorse Capacity Improvement

Executive Summary

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.

In addition to addressing the currently identified issues, the above mentioned projects are useful additions to the system for future work that may occur to meet longer-term electrical demand in downtown Whitehorse and other parts of the City.

Background and Business Drivers

The last significant upgrade to the electrical system in downtown Whitehorse was in the late 1970s when voltage of the electrical system at the time was converted from 7.2kV to 12.5kV. Over the last 35 years, ATCO Electric Yukon has continued to operate, maintain and perform isolated upgrades to the system to prolong the life and reliability of the electrical infrastructure.

For the last 10 years, Downtown Whitehorse has averaged approximately 2-4% peak load growth per year. This has pushed the power system close to its capacity limits which warrants immediate attention because overloading equipment will cause it to fail prematurely. Depending on the degree of overload this could mean something as benign as shortening the lifespan of a device by a few years to something as catastrophic as the explosion of oil-filled equipment.

The load increases are driven by load densification in the downtown and the move towards electric heat in new buildings. As newer and larger buildings take the place of older construction they increase the electrical demand by having more apartment units, offices or retail spaces available in the same lot area. New construction is also utilizing electric heat more often than in the past, further increasing the electrical load densification.

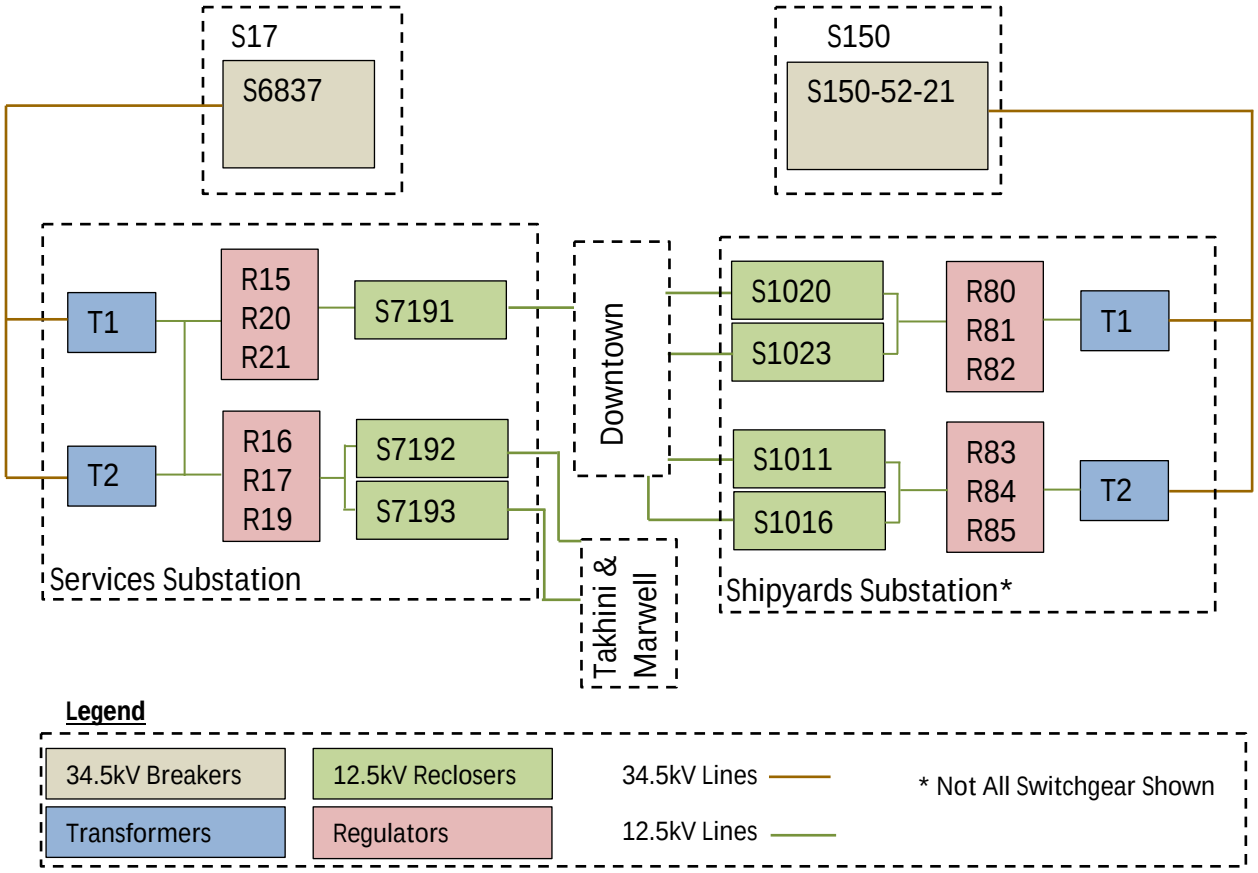
These were the drivers for the work identified in the "Downtown Whitehorse 25kV Conversion" in the 2103-2015 GRA. The 25kV conversion of downtown Whitehorse was planned to meet high load growth from 2010 to 2013. The first phase of the 25kV conversion was to install an underground loop to allow easier shifting of load on downtown infrastructure.

After 2013 the load growth slowed in the Whitehorse area overall leading ATCO Electric Yukon to evaluate the need for continuing the downtown conversion in 2016. An engineering study showed that if the proposed Downtown Whitehorse Capacity Increase project goes ahead the full 25kV conversion plan can be delayed until required by load growth.

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.

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. The normal operating configuration of the system is seen below:



Issue Summary

The following issues with downtown Whitehorse related to load growth have been identified.

Contingencies – *ability to continue to supply power during equipment failure*

- 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.
  - 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.
- Limited load capacity along 6th Ave and at the South River Crossing prevents some switching scenarios.

Power Restoration – *ability to restore power after an outage*

- 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.

Load Addition – *ability to supply more customers/load during regular system configuration*

- Regulators in Shipyards Substation will become overloaded within 5-10 years.
- Transformers in Shipyards Substation will become overloaded a few years after the regulators.

Project Scope

The preferred solution to address these issues is to install a new substation in Riverdale to feed the South end of Downtown. Adding an additional transformer and set of regulators increases the capacity of the system and performing related line work ensures that this capacity is able to be used where it is needed. This will offload Services and Shipyards Substations which in turn provides more capacity and more options for contingency and restoration scenarios.

The project consists of 3 stages:

1) **Install Selkirk Substation –** Install new 34.5kV to 12.5kV Substation in Riverdale with a 10MVA transformer, a set of 400A regulators, a 12.5kV recloser, and associated switches and controls. Tie-ins to 34.5kV and 12.5kV lines near to the substation location are also required;

2) **Reconductor South River Crossing –** Replace existing River Crossing with larger 266.8MCM ACSR overhead wire and 750MCM underground cable; and

3) **Install new Switching Points –** Install 2 new gang switches and replace 1 switch cubicle to allow for new switching configurations to better coordinate feeder loads.

Project Schedule & Costs

	Estimated Cost ($000s)	Target In-Service Date
Install Selkirk Substation *Includes tie lines and access road*	$1,300	2016
Reconductor South River Crossing	$368	2017
Install 6th Ave Gang Switch	$155	2016
Install 3rd Ave and Hoge Street Gang Switch		
Replace 3rd Ave and Strickland Switch Cubicle		
Total	**$1,823**	**2016/2017**

Evaluation of Viable Alternatives

Alternative 1 – Shipyards Substation Capacity Addition

Install an additional transformer bay in Shipyards Substation at forecast costs of $1,300,000.

- Install new transformer bay in Shipyards Substation
- Balance loads on Shipyards Substation

This alternative would result in complicated line work in a live substation and does not adequately address the load restoration concern and contingency issues.

Alternative 2 – 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, ATCO Electric Yukon would effectively double the capacity on the existing 12.5kV system.

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.

In order to convert the voltage of downtown, 25kV voltage sources to the south and north of downtown are required. Due to feeder location and land availability, there is one preferred option for a south 25kV voltage source, but because of potential cost, land, and operational issues two variations were considered for a north 25kV voltage source:

Alternative 2(a) - Install a 25kV substation at the top of Two Mile Hill; or

Alternative 2(b) - Install a 12.5kV/25kV substation at the bottom of Two Mile Hill

Alternative 2(a)	Alternative 2(b)

Phase 1 – South 25kV Source
· Install a new 25kV substation in Riverdale on Selkirk St.
· Install 300m 34.5kV tie to 19L (S150-52-17)
· Tie into 12.5kV circuit right outside the substation
 	
Phase 2 – North 25kV Source
· Install a new 25kV substation near the top of Two Mile Hill
· Install short 34.5kV tie to 5L526 (S6837)
· Tie into 12.5kV circuit right outside the substation
 	
Phase 3 – Voltage Conversion & Balance Loads
· Install gang switch to isolate Mountain View Substation
· Transfer load from S7193 to S7192 in Services Substation
· Transfer load from S6822 to S6817 in Lewes Blvd. Substation
· Convert to 25kV
  o Offload S1016 and S7191 onto respective 25kV substations
  o Replace overhead transformers as primary voltage is changed
  o Change bayonets and winding configuration on padmount transformers
· Perform switching to balance loads across downtown
· Salvage out unnecessary equipment from Services Substation
	Phase 1 – South 25kV Source
	· Install a new 25kV substation in Riverdale on Selkirk St.
	· Install 300m 34.5kV tie to 19L (S150-52-17)
	· 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
	· Install short 34.5kV tie to 5L526 (S6837)
	Connect into distribution lines
	
	Phase 3 – Voltage Conversion & Balance Loads
	· Install gang switch to isolate Mountain View Substation
	· Transfer 12.5kV load from Services Substation to north end substation
	· Transfer load from S6822 to S6817 in Lewes Blvd. Substation
	· Convert to 25kV
	  o Offload S1016 and S7191 onto respective 25kV substations
	  o Replace overhead transformers as primary voltage is changed
	  o Change bayonets and winding configuration on padmount transformers
	· Perform switching to balance loads across downtown
	· Salvage out Services Substation and reclaim land

Cost and Timelines

Work to be Done	Estimated Cost ($000s) Alternative 2(a)	Estimated Cost ($000s) Alternative 2(b)	Target In-Service Date
South 25kV Source	$1,300	$1,300	2016
North 25kV Source	$1,400	$2,500	2017
Voltage Conversion	$2,400	$2,500	2018
Total	**$5,100**	**$6,300**	**2018**

This alternative 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.

Alternative 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.

- 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
  - Estimate loads based on temperature & time of day for restoration

- Install additional switches
  - 6th Ave gang switch
  - 3rd Ave and Hoge St gang switch
  - 3rd Ave and Strickland St switch cubicle

- Install additional metering for the SCADA system at high risk points
  - 34.5kV Cables
  - River Crossing
  - 6th Ave
  - Transformer Temperature

Cost and Timelines

Work to be Done	Estimated Cost ($000s)	Target In-Service Date
Lock Regulators to ±5%	$5	2016
Dispatch Improvements	$50	2016
Switching Points	$155	2016
SCADA Metering	$100	2017
Total	**$310**	**2016/2017**

This alternative has been rejected as there is significant uncertainty as to whether any of the identified issues would be adequately addressed. Further, this solution is not scalable as load grows and increases the operational complexity.

Alternative 4 – Installation of Selkirk Substation & Line Work

Installation of Selkirk Substation and associated line work to adequately address upcoming system constraints caused by load growth. Specifically:

Category	Issue	Solution	Notes
Contingencies	Loss of Services – cannot transfer load from S7191	· Reconductor South River Crossing · Transfer some load onto Selkirk during regular operation	Can transfer on to Selkirk Substation Reduced load on S7191 makes contingency scenarios viable
	Loss of Shipyards – complex switching for loss of S1016	· Simple connection to Selkirk Substation	Can transfer on 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	Can transfer on to Selkirk 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	· Balance loads on Shipyards Substation · Transfer load from Services Substation on to Selkirk Substation	Reduced load on Services allows for load transfer of S1020 and S1011
	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	· Balance (reduce) load on reclosers · Install new switching points	In high load conditions multi-stage restoration (1-2) may still be required, but it is made easier by correctly located switching points
Load Addition	Shipyards Substation regs and transformers will become overloaded within 5-10 years	· Transfer load onto Selkirk Substation	Sufficient capacity for >10 years

In addition to addressing the currently identified issues, installing Selkirk Substation is a useful addition to the system for future work that may occur:

- It is conveniently located to provide support to Riverdale and (if expanded) could replace Lewes Boulevard Substation;
- It would be correctly located to enable a voltage conversion of Downtown and Riverdale to 25kV; and
- It supplies load off of a different 34.5kV feeder (19L) which alleviates overload concerns on the 34.5kV network that feeds downtown.

Recommendation

Delivering power safely and reliably is ATCO Electric Yukon's key mandate; load growth in downtown Whitehorse is expected to compromise system performance during contingency within 5 years. To address this, a review of the system, the issues, and the potential solutions has been undertaken.

ATCO Electric Yukon recommends the following solution:

- Install a new 34.5kV to 12.5kV 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 266.8MCM ACSR overhead wire and 750MCM underground cable; and
- Install new Switching Points to allow for new switching configurations.

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Appendix #10

Paint Mountain Cable Replacement

Executive Summary

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.

Background

ATCO Electric Yukon serves 3 communications sites and a seasonal fire lookout tower at the top of Paint Mountain near Haines Junction. The cable that feeds these loads, built in the 1960s to provide power to the first tower, is an armored 5kV cable installed directly on the ground. Based on industry experience, this sort of cable is expected to have a life of 30-50 years and so this installation has reached its end-of-life. The condition of this cable is known to be compromised. The cable has been spliced several times as past damage occurred, each splice adding a potential weak point to the cable. Furthermore one of the three wires in the cable has been permanently damaged and is no longer usable.

Most of the cable alignment is difficult to access – certain sections of the cable are on a near-vertical slope. A failure in this cable is likely to result in an outage lasting several days even in good weather conditions as special equipment and modes of transportation would first need to be secured in order for crews to find and repair the fault safely.

In Figure 1 below shows the existing cable route during a helicopter inspection in 2014.

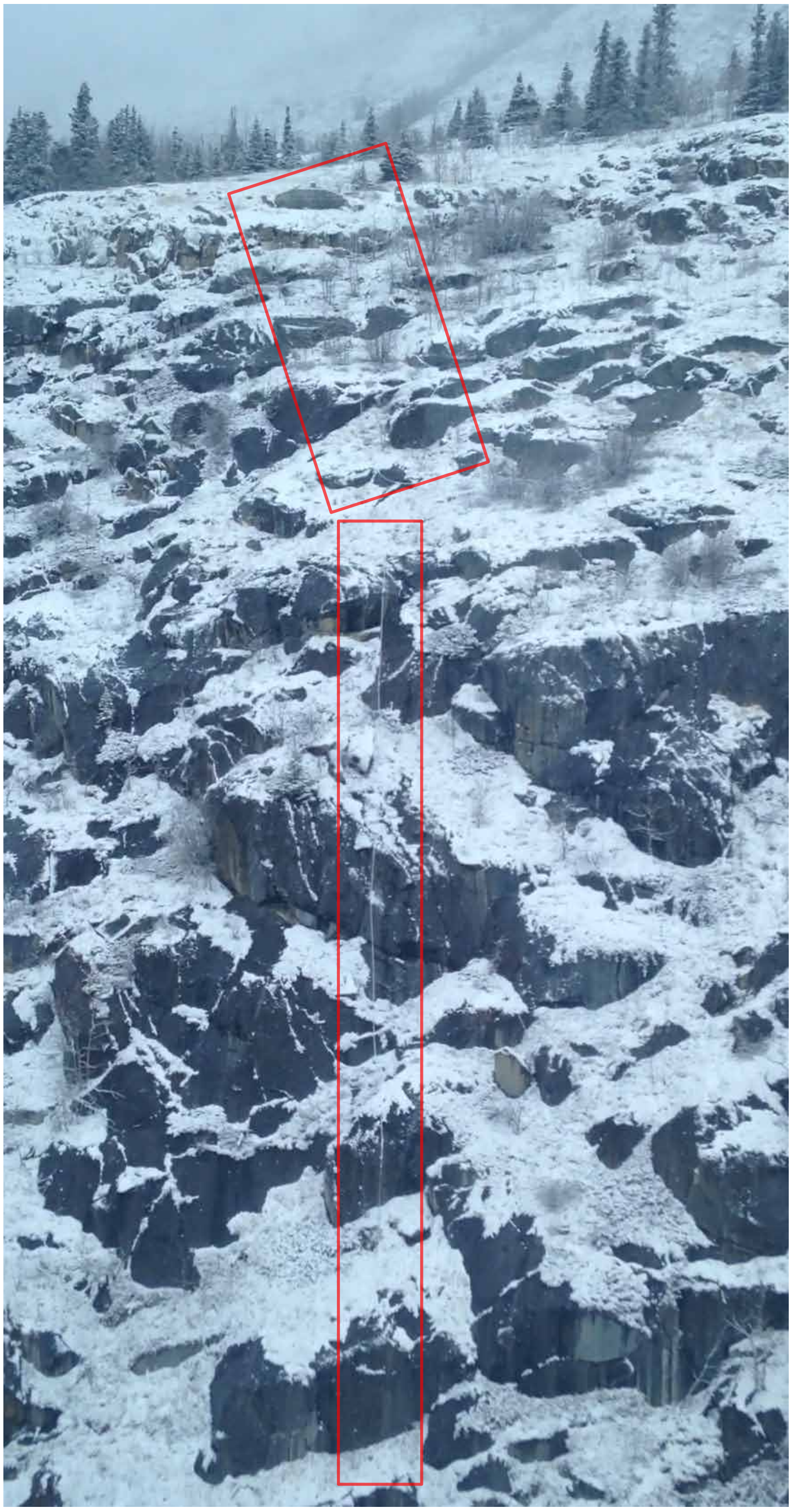


Figure 1: View of existing cable route

Project Description

Install 3 km of 14.4kV armoured cable along a new and more accessible route to serve ATCO Electric Yukon's existing customers on Paint Mountain. The new route will require brushing and several concrete vaults to allow for easily accessible splice locations if needed. The proposed route is shown on the attached map.

The project will include the replacement of the single existing transformer on Paint Mountain from 2400V/120/240V to a 14.4kV/120/240V transformer. The existing 14.4kV/2400V transformer at the base of the mountain would be dismantled and retired.

The map on the following page shows the route of the proposed project.

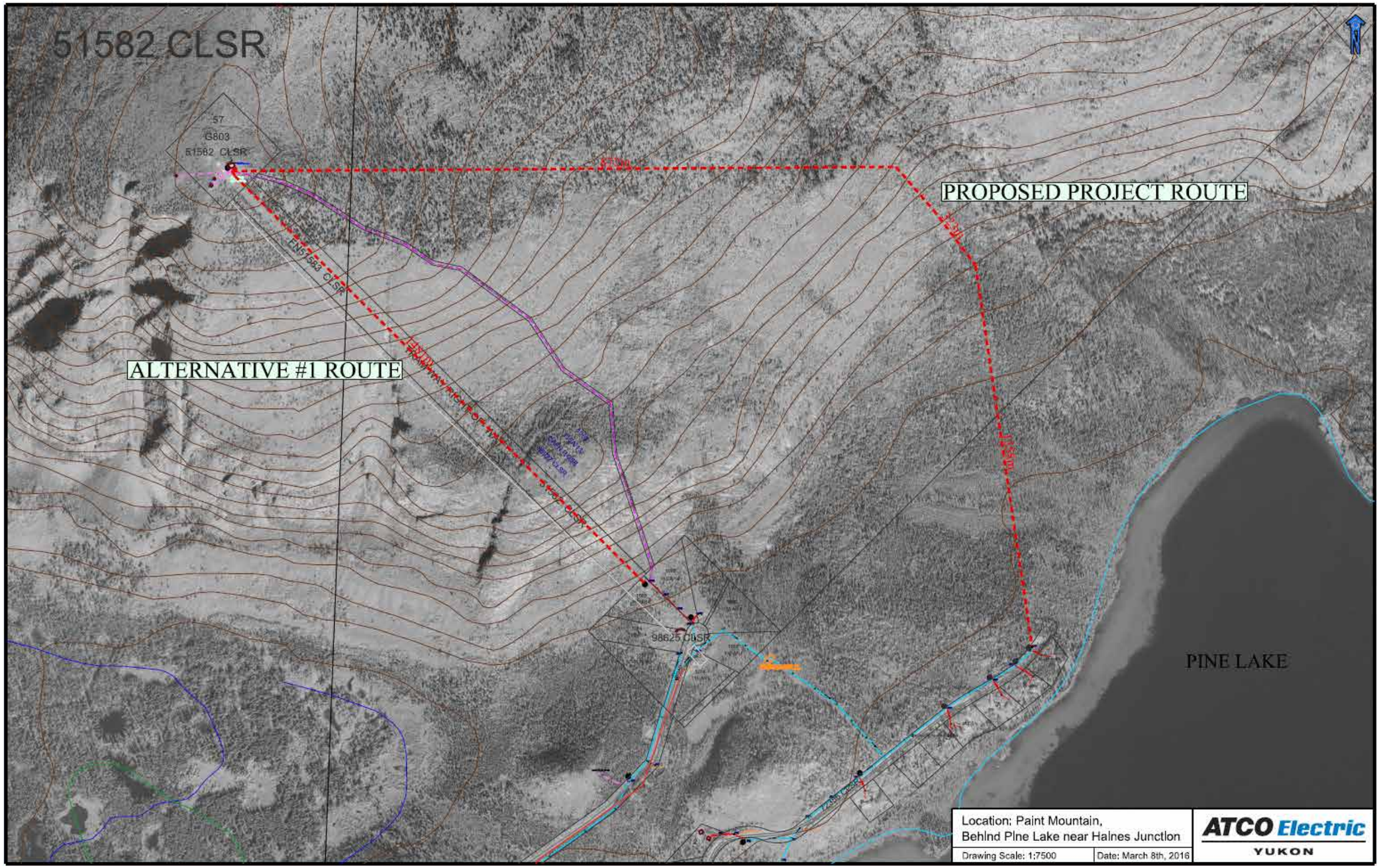
Project Cost & Schedule

The project is scheduled to be completed in 2017 and is forecast to cost $562,000.

Business Drivers and Benefits

This project is required to maintain service to existing electrical customers and to remove a potential safety hazard for the public that visit the area. This project will also address the following deficiencies and concerns with the existing installation:

Deficiency	Description	Solution
Cable is at end-of-life	· Expected lifespan of 30-50 years · Cable is >50 years old	Replace with new cable
Cable is in poor condition	· Several splices increasing vulnerability of cable failure · Permanently damaged conductor	Replace with new cable
Cable is inaccessible	· Sections of cable on near-vertical grades · Extended outages required for repair	Re-route cable


51582 CLSR
57
G803
51582 CLSR
PROPOSED PROJECT ROUTE
ALTERNATIVE #1 ROUTE
PINE LAKE
Location: Paint Mountain,
Behind Pine Lake near Haines Junction
Drawing Scale: 1:7500
Date: March 8th, 2016
ATCO Electric
YUKON

Evaluation of Viable Alternatives

Alternative 1: Replace the cable in the same or similar alignment using modern armoured cable. This is the lower cost alternative at an estimated $417,000, however, this alternative was rejected as it does not mitigate concerns about limited access to the cable and the risk of prolonged outage durations expected in case of a fault with the line in its existing location.

Alternative 2: Remove and retire the existing cable and replace it with a diesel-photovoltaic hybrid generation solution at the top of Paint Mountain near the customers. This alternative was evaluated at a high level and based on discussion with other utilities and suppliers experienced with this type of isolated hybrid generation. This alternative was rejected because the capital costs would be between $500,000 and $1,000,000. This alternative would also require ongoing maintenance costs for fuel, generator maintenance and multiple iterations of generation life would also need to be considered when compared to the expected lifetime of an armoured cable.

Alternative 3: Rejuvenate the cable with cable injection. This alternative was rejected as there are several splices in the existing cable making injection difficult, if not impossible, and costly. This alternative does not mitigate the access and outage duration problems with the existing alignment as well.

Alternative 4: Replace the cable and re-route it along a new and more accessible route. This alternative addresses all of the current system deficiencies at the lowest overall cost.

Recommendation

ATCO Electric Yukon recommends proceeding with the installation of 3km of 14.4kV armoured cable along a new and more accessible route to serve ATCO Electric Yukon's existing customers on Paint Mountain, including the replacement of the single existing transformer on Paint Mountain to a 14.4kV/120/240V transformer.

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Appendix #11

Destruction Bay Unit 3 Replacement

Executive Summary

ATCO Electric Yukon was scheduled to replace the existing Destruction Bay Unit 3 (CUL 230), which is at the end of its life, with a new diesel generator in 2014. The existing 220 kW unit was to be replaced with a 250 kW unit. The replacement of Destruction Bay Unit 3 was approved in Board Order 2014-06 as part of ATCO Electric Yukon's 2013-2015 General Rate Application.

The replacement unit was to have a larger generating capacity in comparison to the existing unit to ensure the unit would continue to see a reasonable amount of operating hours.

Background

The Destruction Bay/Burwash communities are serviced by three units:

- Unit 1 – CUL 467 600kW Unit
- Unit 2 – CUL 372 300kW Unit
- Unit 3 – CUL 230 220kW Unit

Unit 3 has reached the end of its useful life and is due for replacement. At the time of unit tender and selection, capacity requirements were reviewed. This review determined that at the current dispatch levels this unit operates less than 25% of the time. Operational time on a unit this size will only decrease as the community experiences load growth.

Project Description

ATCO Electric Yukon analyzed the unit selection criteria and put out to tender the purchase of a new 250 kW unit. Of the bids received, and after an analysis of best fit for the power plant and community load profile, ATCO Electric Yukon selected a 312 kW unit.

ATCO Electric Yukon will remove CUL 230 and associated cooling, waste heat and exhaust equipment from the Destruction Bay plant. In its place, install the new diesel generator with manufacturer-supplied, cooling, waste heat and exhaust equipment. The new unit will be integrated into the existing plant control system and switchgear.

Project Cost & Schedule

The new unit was selected and the tender process we initiated late in 2013. Receipt of the unit and installation was scheduled to be completed in 2014. The total cost of this project was $634,000.

This exceeds the forecast of $450,000 previously approved in the 2013-2014 General Rate Application. Costs were higher mainly due to foundation issues discovered, subsequent to the initial forecast, as well as additional control work required due to the delay of the Destruction Bay PLC Upgrade.

Business Drivers and Benefits

End of Life Condition

As of January 1, 2013, CUL 230 had 97,170 operational hours. ATCO Electric Yukon planning criteria for 1800 RPM units recommends replacement after 60,000 to 88,000 hours of operation.

Unit Availability

Unplanned failure of this unit would negatively affect plant capacity and contingency. If the unplanned failure was to occur in the winter the power plant would only have 1 generating unit (Unit 1) capable of supplying power to the community.

Additional Generation Capacity Required to Address Under Usage

Under current community load levels CUL 230 is operating less than 25% of the time as the unit is the smallest generator in the power plant. Load growth in the community will only decrease the operating hours and frequency at which the unit operates. Replacing CUL 230 with a larger unit would increase operational hours without negatively impacting the efficiency of the existing units.

Evaluation of Viable Alternatives

Alternative #1: Perform major overhaul on CUL 230. Based on previous operational experience, ATCO Electric Yukon has seen marginal benefit in reliable operation of 1800RPM units that are overhauled with significant lifetime operating hours. The extensive hours on the unit have resulted in stresses and wearing that cannot be fully repaired. The unit may not operate long enough to provide payback of the life extension investment. The result would be poor reliability which could lead to unplanned outages and poor system performance. Replacement of a failed unit in an unplanned situation would leave significant exposure time to inadequate capacity as the lead time to procure and obtain units of this rating can vary from three to nine months.

Alternative #2: Continue to operate unit until eventual failure and then replace. The unplanned loss of Unit #3 during peak loading would leave only one unit available to supply the community. Replacement of a failed unit in an unplanned situation would leave significant exposure time to inadequate capacity and the lead time to procure and obtain units of this rating can vary from three to nine months. The unit could fail catastrophically and affect the remaining units and/or power plant's ability to provide power to the community.

Alternative #3: Replace CUL 230 with a same sized engine. This option does not address the underutilization of the unit. The community load profile has grown enough to exceed the capabilities of a 220kW unit to provide efficient service.

Alternative #4: Replace CUL 230 with a slightly larger unit. This option addresses the underutilization of the unit and is the best alternative to ensure the power system continues to provide safe and reliable service efficiently.

Recommendation

Proceed with replacement of CUL 230 with a slightly larger unit to continue to maximize efficiency and provide reliable service to Destruction Bay/Burwash Landing.