

September 28, 2023

AEY-UCG-001

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-001

Reference: July 7, 2023-2024 AEY Application

Request:

- (a) Provide details of all customer and stakeholder consultations conducted by ATCO Electric Yukon during development of this application prior to submitting it to the YUB.
- (b) Provide specific details on how AEY's customers were informed of proposals being considered for inclusion in the application and how input from customers was used to develop details of the application.
- (c) Provide all documentation related to issues discussed during these consultations and a list of all parties involved in the consultations.
- (d) Provide how and when the leadership / owners of AEY approved the General Rate Application as provided to the YUB. Please identify the dates on which these approvals were provided.

Response:

- (a-c) Development of this Application required significant consultation to determine all cost and revenue on an actual and forecast basis with respect to the areas discussed below:

- Sales and revenue.
 - Determination of customer counts and electricity usage as determined through discussion with customers, consultants, suppliers, communities and local developers. AEY is in communication with municipal and territorial governments, First Nations, communities, builders, manufacturers, suppliers, property managers etc.

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AEY-UCG-001

- Purchase power in consultation with Yukon Energy Corporation to forecast costs related to securing wholesale electricity and to review system project requirements.
- Fuel cost forecasts based on projections for each diesel community.
- Operation and maintenance forecasts:
 - Labour costs consultation including employees, labour associations, human resource groups, ATCO Electric, training and safety, pension and benefits managers.
 - A forecast of Non-labour areas is developed to determine ongoing operational and administrative activities. Areas of consultation include affiliate companies, insurance companies, accountants, auditors and numerous material and service providers.
- Capital additions for electrical system upgrades and additions as well as for property and other equipment are determined based on forecasts to meet customer needs. The diversity of projects involves a wide variety of stakeholders.

Following submission of the Application with the YUB, AEY published, in display-ad format, a Notice of the Application and Hearing in the local papers. AEY's Application was uploaded to AEY's website¹ and the YUB website² for public access. In addition, on July 27, 2023, AEY held a procedural conference that was open to the public.

- (d) AEY received approval on July 6, 2023, from its executive leadership to file the GRA following their review. The Application was filed on July 7, 2023.

¹ <https://www.atcoelectricityukon.com/en-ca/customer-billing-rates/2023-general-rate-application.html>.

² <https://yukonutilitiesboard.yk.ca/proceedings/atco-electric-yukons-2023-2024-general-rate-application/>.

September 28, 2023

AEY-UCG-002

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-002

Reference: July 7, 2023 Application page 2 of 4

AEY states: "As such, both parties would propose to address any required changes and/or updates to the T&Cs sometime in mid to late 2024, as a standalone limited scope filing, rather than including any changes as part of a GRA."

Request:

- (a) As YEC is proposing a GRA in late August, will AEY commit to working with YEC to file a T&C at the time of this hearing process.

Response:

- (a) AEY continues to plan on working with YEC to address any required changes and/or updates to the T&Cs sometime in mid to late 2024, as a standalone limited scope filing, rather than including any changes as part of a GRA.

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AEY-UCG-003

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-003

Reference: July 7, 2023 Application pages 1&2 of 4

AEY states: "In Section 13 of this Application, AEY has requested approval of a 6.68 percent Interim Refundable Rate Rider (Rider R) for electrical consumption between August 1, 2023 and December 31, 2023. By implementing the rate adjustment on August 1, 2023, Rider R will refund approximately 40 percent of its forecast surplus in 2023. AEY submits that its proposal to refund approximately 40 percent of its forecast surplus is reasonable, like the approach approved by the Board for AEY's 2016 Interim Refundable Rider in Board Order 2016-02 and will reduce future true-ups. For this reason, AEY respectfully requests approval of Rider R by July 21, 2023, to implement the new Rider R on August 1, 2023.

Also, in Section 13, AEY is requesting approval for an Interim Refundable Rider R of 13.50 percent effective January 1, 2024. The derivation of the Rider R adjustment for 2024 is like the calculation for the proposed 2023 Rider R adjustment. Based on the expected timing of the Board Order and Compliance Filing to AEY's 2023-2024 GRA, being similar to AEY's 2016-2017 GRA process, AEY estimates that updated Rider R rate adjustments, in the middle of 2024, will result in minimizing future true-ups and promoting rate stability."

Request:

- (a) Please provide details of all expected recoveries through Rider R by month for the period August 2023 through end December 2024 including all recoveries by Yukon Energy Corporation.
- (b) Please provide details of how much of AEY's 2024 revenue shortfall will be recovered from AEY customers and details of how much will be recovered from customers of Yukon Energy Corporation.

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AEY-UCG-003

- (c) Please explain why customers of Yukon Energy Corporation are required to pay a higher Rider R to allow AEY to recover additional revenues.
- (d) Provide bill calculations for each of these proposed rate adjustments.

Response:

- (a) In Board Order 2023-22 received on September 15, 2023, the Board denied AEY's requested 2023 Rider R rate decrease and approved an Interim Rate Adjustment Rider R increase of 2.5 percent resulting in a total Rider R of 10.8 percent effective January 1, 2024. The calculations below are based on the approved Rider R rate.

As AEY expects final rates by mid-2024, the expected Rider R recoveries are provided for January to June 2024:

Total Rider R of 10.8%

AEY	\$3.2 million
YEC	\$1.0 million

- (b) Expected Recovery of Shortfall January – June 2024:

Incremental Rider R of 2.5%

AEY	\$0.7 million
YEC	\$0.2 million

- (c) The postage stamp rate design in the Yukon and relevant rate design regulations, including OIC 1995/090¹ requires that "rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers" in the Yukon. Therefore, rates are designed in such a way that AEY and YEC customers pay the same rates. With respect to bill charges and revenue collection, AEY's

¹ OIC 1995/90, Section 2.1.

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AEY-UCG-003

Rider R revenue that YEC collects from its customers flows through to AEY, and YEC's Rider J revenue that AEY collects from its customers flows through to YEC.

- (d) Please refer to AEY-UCG-003(d) Attachment 1 for sample bill calculations based on current rates and the approved Interim Rate Rider R of 10.8 percent effective January 1, 2024 for a typical non-government residential customer using 800 kWh.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Sample Monthly Residential Bill - Non-government Hydro Rate 1160
Proposed 6.68% Rider R Effective: October 1, 2023

Line No.

1	Consumption	800 kWh				
2						
3						
4	Customer Charge (per month)		\$	14.65		\$ 14.65
5						
6	Block 1 Energy Charge 1000 (\$/kWh)		\$	0.1214	x	800
7	Base Rate					\$ 97.12
8						\$ 111.77
9	Fuel Adjustment Rider \$/KW.h		\$0.01635	x	800	\$ 13.08
10	Rider J and J1 YEC Shortfall		37.85%	x	\$ 111.77	\$ 42.30
11	Rider R and R1 AEY Adjustment		6.68%	x	\$ 111.77	\$ 7.47
12	Rider S Purchase Power Adjustment Rider		\$0.00100	x	800	\$ 0.80
13	Interim Electrical Rebate		-\$0.02262	x	800	\$ (18.10)
14	Sub-Total					\$ 157.32
15						
16	GST		5.0%	x	\$ 157.32	\$ 7.87
17	TOTAL including GST					\$ 165.19

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Sample Monthly Residential Bill - Non-government Hydro Rate 1160
Approved 10.8% Rider R (Board Order 2023-22) Effective: January 1, 2024

Line No.						
1	Consumption	800 kWh				
2						
3						
4	Customer Charge (per month)		\$	14.65		\$ 14.65
5						
6	Block 1 Energy Charge 1000 (\$/kWh)		\$	0.1214	x 800	\$ 97.12
7	Base Rate					\$ 111.77
8						
9	Fuel Adjustment Rider \$/KW.h		\$0.01635	x	800	\$ 13.08
10	Rider J and J1 YEC Shortfall		37.85%	x	\$ 111.77	\$ 42.30
11	Rider R and R1 AEY Adjustment		10.80%	x	\$ 111.77	\$ 12.07
12	Rider S Purchase Power Adjustment Rider		\$0.00100	x	800	\$ 0.80
13	Interim Electrical Rebate		-\$0.02262	x	800	\$ (18.10)
14	Sub-Total					\$ 161.92
15						
16	GST		5.0%	x	\$ 161.92	\$ 8.10
17	TOTAL including GST					\$ 170.02

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AEY-UCG-004

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-004

Reference: July 7, 2023 Application, Appendices pages iii and iv AEY charts out for Business Cases for: 2016-2017 (#1-3); 2018-2022 (#4-21); 2023-2024 Test Years (#22-38); and Significant Expenditures Outside of Test Years (#39-41).

Request:

- (a) For the years 2016-17 provide same chart with \$ amount for each project #'s 1-3 and explain how each was accounted for in rate base. Explain if these were referenced and accounted for in the 2016-17 rate base.
- (b) For years 2018-2022 (#'s 4-21) provide same chart with the \$ amount of each project and explain if these were accounted for in the rate base and for which year. If these were added to the rate base for each of those non-test years, explain under which part of the *Public Utilities Act* this can be done.
- (c) For the years 2023-2024 Test Years #'s 22-38 provide on the same chart with the \$ amount for each project proposed to place into the rate base for each of the test years.
- (d) For the proposed significant expenditures outside of test years #'s 39-41 provide the same chart with the forecast \$ amount of each project and whether AEY plans to place these into the rate base outside of the test year period.

Response:

- (a-d) Please refer to AEY-YUB-046(a) Attachment 1 for an itemized list showing which projects have a Business Case for 2016-2024. These projects are added to rate base when they go into service. As stated in AEY-UCG-065(b), the net cost of capital has been included in the 2023-2024 Revenue Requirement on a prospective basis and AEY is not seeking retroactive recovery of returns or depreciation costs incurred for the period since its last GRA. Opening rate base continues to be within scope for the Board's review and approval as part of this Application.

September 28, 2023

AEY-UCG-005

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-005

Reference: July 7, 2023 Application, page 1-5

1.8 Deferral Accounts

16, The previously accepted criteria for establishing a deferral account have not changed from AEY's 2016-17 Phase 1 GRA. The criteria are as follows:

- (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 order.

Deferral Accounts requested:

- Sec. 1-B Board Orders or Legislative Changes
- Sec. 2- Industrial Rider R Flow Through
- Sec. 3- Purchase Power Flow Through
- Sec. 3- IPP Flow Through
- Sec. 4- Diesel Fuel Deferral Account (Rider F)

Request:

- (a) Please fully explain (b) above. Does this mean that AEY plans to have a variance for surplus/ or loss of earnings that will be returned/charged to ratepayers?
- (b) Will AEY be applying for Federal or Territorial grants for the Energy Transition proposals or fuel charges or other charges by various governments for climate change rebates? If not, why not?
- (c) Will the Industrial Rider R extra earned income be returned to ratepayers?
- (d) Will AEY confirm to working with YEC to propose a new wholesale rate during the upcoming YEC GRA?

September 28, 2023

AEY-UCG-005

- (e) Is this Purchase Power Flow Through the same as ERA? Explain.
- (f) Explain why an IPP flow-through mechanism is necessary when you have a contract with the providers.
- (g) For Diesel Rider F will there not be a diesel cost true-up for 2023 test year?
- (h) Provide all the Rider F regulatory reports for actual costs from January to August 2023 and the Sept. to Dec.2023 forecast.
- (i) Provide the Rider F reports for forecast 2024 test year.

Response:

- (a) Part (b) of the Deferral account criteria refers to the potential for an account variance to be materially positive or negative and have a substantial impact on returns. This impact can result in higher or lower returns, depending on how actual costs compare to the original forecast. These savings or additional costs will be flowed through to customers.
- (b) Yes. AEY intends to apply for any applicable Federal and Territorial grants.
- (c) Please refer to the responses to AEY-YUB-006(a) and (b) for details respecting the deferral treatment of AEY's Industrial Rider R revenue.
- (d) Not confirmed.
- (e) No, the Purchase Power Flow Through deferral is not the same as ERA. The Purchase Power Flow Through deferral account has most recently been approved in Board Order 2017-01 and was also considered as part of AEY's Rider S Application, approved in Board Order 2023-17. The Purchase Power Flow Through deferral account includes any increases or decreases to the purchase power rate, including any ERA amounts.
- (f) The IPP deferral account is necessary. Please refer to AEY-YUB-002(b)(ii) for the explanation.

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- (g) Subject to the Board's direction on AEY's 2023-2024 GRA, AEY will true up the fuel variance amounts in the Compliance Filing.
- (h-i) As Rider F is a joint account with YEC and future fuel costs are unknown and unpredictable due to economic conditions, AEY is unable to produce an accurate forecast for the Rider F balance. Please refer to AEY-UCG-005(h) Attachment 1 for the most recent Rider F report up to June 2023. Third quarter balances are unavailable at this time and will be filed with the Yukon Utilities Board when available.



September 20, 2023

Mr. Richard Buchan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. Buchan:

Re: Rider F - Quarterly Report - Period Ending June 30, 2023

Yukon Utilities Board ("Board") Order 2010-13 directs the companies as follows:

" ... to allow all interested parties to monitor the balance in the Rider F account, the Companies are to provide the Board quarterly acknowledgement filings stating the balance in the Rider F account... "

Please find attached the Q2 2023 report regarding the Companies' combined Diesel and LNG Fuel Price Variance ("FPVA/Rider F") account balance. The account balance exceeded the +/- \$200,000 threshold set by the Board, therefore, to address the account balance, on November 29, 2022 the Companies filed Rider F rate change advisory letter with the Board with Rider F rate of 1.635 cents/kWh effective January 1, 2023.

The Board in its letter dated July 6, 2023 noted that "in the YEC Excel workbook, the totals from the YEC fuel variance calculations spreadsheet (columns C-E, row 207) do not match the totals in the FPVA Q1 2023 spreadsheet (column B rows 7-9). The Utilities, on a go forward basis, are to provide a reconciliation and explanation between the two worksheets." The numbers in the "FPVA 2023 balance" tab of the excel file are now linked to the YEC Fuel variance calculations with the explanation note added under the table for the variances in the monthly numbers [the variance for January 2023 in column B was corrected in the February 2023 row and the total for Jan-Feb at \$431,665 reconciles to Jan-Feb fuel variance in "YEC Fuel variance calculations" tab].

The Board in its letter also noted that AEY "will provide a continuity schedule (for the interim period since its last compliance filing) for its DFPVA starting with the next quarterly filing." Attachment 2 to this report includes a continuity schedule for AEY fuel variance calculations since its last compliance filing. During the review, AEY identified an error in fuel variance calculations. AEY has corrected the necessary working papers and the variance is reflected in the FPVA balance as an adjustment.

As directed in Order 2010-13, this report will also be posted concurrently on the Companies' websites for public access. If any interested party has questions regarding Rider F, please contact one of the undersigned.

Sincerely,

ATCO ELECTRIC YUKON

A handwritten signature in black ink, appearing to read 'Beth Rogers'.

Beth Rogers
Director, Regulatory

elizabeth.rogers@atco.com

YUKON ENERGY CORPORATION

A handwritten signature in black ink, appearing to read 'Jason Epp'.

Jason Epp
Vice President, Finance and
Chief Financial Officer
Jason.Epp@yec.yk.ca

Rider F – Quarterly Report
For the Period Ended – June 30, 2023

	Combined Company Balance				
	Fuel Price Variance ¹	RS 32 – SS Adjustment	Rider F Surcharge	Cumulative Balance	Monthly Change
Dec-22				(6,684,651)	
Jan-23	(906,386)	-	723,510	(6,867,527)	(182,876)
Feb-23	(397,005)	-	770,289	(6,494,243)	373,284
Mar-23	(522,603)	-	838,863	(6,177,982)	316,261
Apr-23	(379,851)	-	798,505	(5,759,329)	418,654
May-23	(141,719)	-	608,568	(5,292,480)	466,849
Jun-23	(397,507)	-	519,121	(5,170,865)	121,614

(1) Including AEY's correction adjustment

Notes:

- Positive balances represent amounts to the benefit of ratepayers.
- Negative balances are amounts owing to the companies.

Effective Date		Rider F (¢ / kWh)
August 1, 2022	December 31, 2022	0.865 cents per kWh charge
January 1, 2023	Current	1.635 cents per kWh charge

September 28, 2023

AEY-UCG-006

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-006

Reference: July 7, 2023 Application, page 1-5

AEY states: "For 2023, in-scope (subject to Collective Agreement) labour has been escalated by 2.00 percent. This escalation is based on AEY's existing Collective Agreement that expires on December 31, 2023. For 2023, out-of-scope (not subject to a Collective Agreement) labour has been escalated by 2.90 percent, which is consistent with approved increases in Alberta. For 2024, in-scope and out-of-scope labour has been escalated by 2.50 percent. This escalation rate is consistent with the inflationary increase being applied for and approved in Alberta for 2024.

Request:

- (a) Provide copies of the referenced Alberta approvals.
- (b) Provide details of the labour cost escalation rates in the Yukon for 2023 and the source of the documents for these forecasts.
- (c) What labour escalation rates are currently used for 2023 by Fortis BC Utilities, which AEY uses as their proxy? Provide details from Fortis.

Response:

- (a) Please refer to Decision 27062-D01-2023, ATCO Electric 2023-2025 GTA and NSA (AEY-UCG-006(a) Attachment 1) and the AET 2023-2025 GTA Negotiated Settlement Agreement (AEY-UCG-006(a) Attachment 2) for details of the approved inflation rates.
- (b) The Yukon's 2023–24 Fiscal and Economic Outlook (AEY-UCG-018(a) Attachment 1) is forecasting an increase in household income of 6.3 percent and CPI inflation of 3.8 percent for 2023.
- (c) Please refer to the response to AEY-UCG-007(c).



ATCO Electric Ltd.

2023-2025 General Tariff Application and
Negotiated Settlement Agreement

May 5, 2023

Alberta Utilities Commission

Decision 27062-D01-2023

ATCO Electric. Ltd.

2023-2025 General Tariff Application and Negotiated Settlement Agreement

Proceeding 27062

May 5, 2023

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The Commission may, no later than 60 days from the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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Alberta Utilities Commission
Calgary, Alberta

ATCO Electric Ltd.
2023-2025 General Tariff Application and
Negotiated Settlement Agreement

Decision 27062-D01-2023
Proceeding 27062

1 Decision summary

1. This decision provides the Alberta Utilities Commission's determinations regarding ATCO Electric Ltd.'s (ATCO Electric or AET) application for approval of a Negotiated Settlement Agreement (NSA) regarding its 2023-2025 general tariff application (GTA). It also provides the Commission's determinations on two issues that were excluded from the NSA by the Commission and a further issue that was initially part of the negotiated settlement process (NSP), but in respect of which parties were unable to reach agreement.

2. The Commission finds that the NSA between ATCO Electric and interveners was negotiated under a fair process, is in the public interest and results in just and reasonable rates. Therefore, the Commission approves the NSA application. Of the three issues that were not part of the NSA, the Commission has:

- (i) Determined that the vegetation management reserve will apply to ATCO Electric's 2023 vegetation management costs only and approves the elimination of the vegetation management reserve beginning in 2024.
- (ii) Approved ATCO Electric's amendments to the Variable Pay Program (VPP) reserve.
- (iii) Denied ATCO Electric's request to collect \$7.5 million in depreciation related to the Jasper Palisades amounts that were incorrectly accounted for, and determined that the correct undepreciated balance in relation to the Jasper Palisades switchgear assets should be \$0.

3. The Commission requires ATCO Electric, in its compliance filing to this decision and on a go-forward basis, to continue to present its tax schedules identifying permanent and temporary differences, including presenting the equity portion of allowance for funds used during construction (AFUDC) as a permanent difference.

4. The Commission directs ATCO Electric to provide construction work in progress (CWIP) continuity schedules as requested by the Commission in its letter of July 13, 2022,¹ and in Section 6.1 below, in future GTAs.

5. ATCO Electric is to file its compliance filing to this decision no later than June 12, 2023. As detailed in Decision 26573-D01-2023,² ATCO Electric is to incorporate the findings,

¹ Exhibit 27062-X0242, Further process, paragraphs 12-14.

² Decision 26573-D01-2023: ATCO Electric Ltd., Disposal of 2018-2021 Transmission Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 26573, April 26, 2023.

conclusions and directions of the Commission in that decision together with its compliance filing addressing the Commission's directions in this decision.

2 Introduction and background

6. ATCO Electric is a transmission facility owner that provides regulated electric transmission service in Alberta. ATCO Electric recovers the costs of providing electric transmission service through its transmission tariff, which must be approved by the Commission. Once approved, ATCO Electric recovers its tariff amounts from Alberta ratepayers through the Alberta Electric System Operator (AESO), which collects the costs from the ratepayers' respective distribution facility owners, and from ratepayers directly connected to the transmission system.

7. ATCO Electric made the following applications seeking various approvals from the Commission in each of them:

- (i) ATCO Electric's 2023, 2024 and 2025 GTA; and
- (ii) the 2021 settlement of deferral accounts and adjustment balances.

8. In its letter,³ dated July 13, 2022, the Commission:

- (i) Determined that additional information was required in order for the Commission to consider the application complete, which included providing missing business cases, missing IBM/Kyndryl information technology (IT) Master Service Agreement and IBM/Kyndryl 2021 and 2022 IT cost information and confirmation of accounting policy updates.
- (ii) Required supplementary information that included the CWIP continuity schedules for capital programs.
- (iii) Denied ATCO Electric's request to update inflation parameters and isolated generation fuel forecast costs with its rebuttal evidence; and
- (iv) Directed ATCO Electric to move its 2021 settlement of deferral accounts and adjustment balances from the 2023-2025 GTA to Proceeding 26573,⁴ where the Commission was considering similar issues as part of ATCO Electric's 2018-2020 deferral application.

9. On July 28, 2022 ATCO Electric filed a motion asking the Commission to reconsider its ruling denying its request to update its proposed inflation factors and fuel prices when rebuttal evidence is filed. ATCO Electric admitted in its motion that it believed its originally filed application would not result in just and reasonable rates.⁵ The Commission exercised its discretion to reconsider its July 13, 2022, ruling given the new information provided in ATCO Electric's motion. ATCO Electric was directed to submit its updated application, including

³ Exhibit 27062-X0242.

⁴ Proceeding 26573, ATCO Electric Transmission, Application for Disposal of 2018-2020 Transmission Deferral Accounts and Annual Filing for Adjustment Balance.

⁵ Exhibit 27062-X0243, paragraph 6.

revised inflation and fuel prices, no later than September 5, 2022. The Commission also set out the issues list, provided its approval for ATCO Electric and interveners to enter into an NSP on all matters with the exception of two issues,⁶ and established the proceeding process schedule.

10. In its ruling, dated October 21, 2022, the Commission granted ATCO Electric's request for additional time to respond to information requests (IRs) and revised the proceeding schedule.⁷ On December 21, 2022, ATCO Electric filed a letter⁸ with the Commission advising that it had reached a NSA in principle with the intervening parties.⁹ The Commission approved ATCO Electric's proposed timeline for the remainder of the proceeding process that concluded with oral argument and reply argument.¹⁰ The Commission considers the close of record to be February 7, 2023, the date of oral reply argument.

11. The Commission has reviewed the entire record in coming to this decision; lack of reference to a matter addressed in evidence or argument does not mean that it was not considered.

12. This decision addresses the contentious cost items forecast in the application, and any matters that the Commission has otherwise determined are required to be specifically addressed. If a matter is not specifically addressed in this decision, it is because the Commission finds the applied-for costs associated with the matter to be reasonable and the applicant's request is therefore approved as filed. All directions in this decision are subject to all findings and other directions made elsewhere in this decision.

13. The Commission directs ATCO Electric to submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before June 12, 2023.

3 Negotiated settlement

3.1 Requirements governing negotiated settlements

14. Section 6 of Rule 018: *Rules on Negotiated Settlements* under Section 132 of the *Electric Utilities Act*¹¹ sets out requirements for the contents of a negotiated settlement application, and places the onus on the applicant to provide sufficient evidence to support the application and to enable the Commission to understand and assess the agreement. Section 7 of Rule 018 includes requirements for the Commission's assessment of the agreement. The Commission structured the settlement process in this proceeding in accordance with Rule 018.

15. The Commission has previously considered negotiated settlements in rate cases where there has been unanimous agreement. The Commission has consistently indicated that the test requires consideration of three questions: (i) was the negotiation process fair, including with

⁶ Those two issues were removal of the vegetation management reserve and modifications to the VPP reserve.

⁷ Exhibit 27062-X0328, AUC letter - Ruling on ATCO Electric's request for time extension to file responses to information requests.

⁸ Exhibit 27062-X0486, Letter to AUC re NSA - December 21 2022.

⁹ Intervening parties included: Consumers' Coalition of Alberta, the Office of the Utilities Consumer Advocate, The City of Calgary, the Industrial Power Consumers Association of Alberta and the City of Grande Prairie

¹⁰ Exhibit 27062-X0487, AUC letter - Ruling and process schedule update – negotiated settlement process.

¹¹ Section 132 of the *Electric Utilities Act* requires that the Commission recognize or establish rules, practices and procedures to facilitate the negotiated settlement of matters arising under the act.

respect to notice and the conduct of the process itself; (ii) will the settlement result in just and reasonable rates; and (iii) are any of the settlement provisions, individually or collectively, patently against the public interest or contrary to law?¹² Performing this assessment requires the Commission to review both the individual provisions of the NSA and the NSA as a whole.

16. In considering these requirements, the Commission has taken into account the direction of the Alberta Court of Appeal as set out in *ATCO Electric Limited v Alberta (Energy and Utilities Board)*¹³ (ATCO Electric decision). In that decision, the court found that the ultimate responsibility for approving negotiated settlements resides with what is now the AUC. The Commission proceeds on that basis herein, as it has in the past, with a view to ensuring that the NSA will result in just and reasonable rates, that none of the NSA provisions, individually or collectively, are patently against the public interest or contrary to law, and that the process used to arrive at the NSA was fair.

17. In assessing a negotiated settlement, the Commission is aware that, while one or more of the interested parties to a settlement may represent certain stakeholders, none will represent all stakeholders. Further, as noted by the court at paragraph 138 of the ATCO Electric decision, "... even a broad range of Interveners will not necessarily translate into a wide spectrum of positions since parties may make trade-offs which leave other issues unresolved, unaddressed or compromised."¹⁴ Consequently, the NSP and NSA do not replace a full and informed review by the Commission as to what is in the overall public interest. Because ATCO Electric had requested and received Commission approval to negotiate a settlement; subsequently negotiated with parties representing ratepayers; executed the NSA; and then applied to the Commission for approval of the NSA in its entirety, the Commission has proceeded on the basis that the NSA satisfies ATCO Electric's interests and has only assessed the NSA from the point of view of ratepayers. This is consistent with the ATCO Electric decision.¹⁵

18. Given the statutory requirements, Rule 018 and the relevant case law, the Commission has considered all of the following factors in making its determination on whether the NSA should be accepted or rejected in its entirety:

- **Review of the NSP:** Was the NSP procedurally fair, both with respect to adequate notice having been served and with respect to the conduct of the negotiation process itself?

¹² See, for example, Decision 21149-D01-2016 (Errata): ENMAX Power Corporation, Distribution 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor, Proceeding 21149, October 3, 2016, paragraph 29; Decision 25726-D01-2021: ENMAX Power Corporation, 2021-2022 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 25726, June 16, 2021, paragraph 23; Decision 23966-D01-2020 (Corrigenda): ENMAX Power Corporation, 2018-2020 General Tariff Application Negotiated Settlement Agreement and Excluded Matters, Proceeding 23966, July 30, 2020; and Decision 26207-D01-2021: Direct Energy Regulated Services, 2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement, Proceeding 26207, June 4, 2021, paragraph 18.

¹³ *ATCO Electric Limited v Alberta (Energy and Utilities Board)*, 2004 ABCA 215.

¹⁴ ATCO Electric decision, paragraph 138.

¹⁵ ATCO Electric decision, paragraph 146.

- **Review of the NSA**

- Does the settlement result in rates, and terms and conditions that are just and reasonable?
- Is the settlement patently against the public interest or contrary to law?

19. The Commission's findings on the NSP and on the provisions of the NSA are discussed below. The Commission notes that while parties were permitted to negotiate the issue of ATCO Electric's proposed treatment of the one-time depreciation adjustment for the Jasper Palisades isolated generation plant, they did not reach a settlement on this matter. ATCO Electric's proposed treatment of the one-time depreciation adjustment for the Jasper Palisades isolated generation plant and the Commission excluded matters¹⁶ are therefore addressed in Section 4.

3.2 Review of the NSP

20. The first factor that the Commission considers is whether the NSP that resulted in the NSA was fair.

21. Starting with the conduct of the negotiation process, ATCO Electric submitted that the settlement negotiations were fair, and that all parties were well-informed and able to meaningfully participate.¹⁷ The CCA, the UCA, The City of Calgary, the City of Grande Prairie and the Industrial Power Consumers Association of Alberta also filed correspondence with the Commission attesting to the fair and open manner in which the negotiation was conducted.¹⁸ The Commission notes that all participants in the negotiations are sophisticated parties, and considers that they represent a reasonable cross-section of ratepayers. The Commission is satisfied that parties had the opportunity to participate meaningfully, and that the negotiations were conducted in an open and fair manner.

22. Turning to the issue of adequate notice, Section 3 of Rule 018 deals with the provision of notice by a utility to parties who may be interested in participating in negotiations. Under Section 3, the Commission requires a statement in a settlement agreement confirming that proper notice was provided by the applicant to all interested parties. ATCO Electric submitted that adequate notice was provided to parties, noting that the Commission's approval of the NSP was posted on the public record of the proceeding, and that the NSA includes a statement confirming that ATCO Electric provided proper notice to all interested parties.¹⁹ The Commission finds that ATCO Electric provided adequate notice to parties.

23. Finally, Section 6(1) of Rule 018 provides that, when an agreement is reached on all or some of the issues, the text of the agreement, including a representation that no party has withheld relevant information, must be circulated to all parties to the agreement. ATCO Electric

¹⁶ Exhibit 27062-X0273: In its letter dated August 5, 2022, the Commission gave its approval for ATCO Electric and interveners to enter into an NSP on all matters with the exception of the following two items: (i) Removal of the vegetation management reserve; and (ii) modifications to the variable pay program reserve

¹⁷ Exhibit 27062-X0495.01, paragraphs 47-50.

¹⁸ Exhibits 27062-X0489, 27062-X0490, 27062-X0491, 27062-X0493 and 27062-X0494.

¹⁹ Exhibit 27062-X0495.01, paragraphs 19-21 and Section 8(b) on PDF page 27.

addressed this requirement under Section 8 of the NSA.²⁰ The Commission finds that the requirements of Section 6(1) of Rule 018 have been met with respect to relevant information.

24. In view of the above and having considered the parties' submissions with respect to the NSP, the Commission is satisfied that the NSP was fair and that ATCO Electric has complied with the requirements set out in sections 3, 6(1) and 6(3) of Rule 018.

3.3 Review of the NSA

25. The second factor the Commission must consider is whether the NSA is in the public interest, including whether it will result in just and reasonable rates, Section 8(1) of Rule 018. The Commission is also guided by the *Electric Utilities Act* and Rule 018 and, in particular, Section 8(2) of Rule 018, which states that the Commission must intervene if it determines that a unanimous settlement agreement is patently against the public interest or contrary to law.

26. In conducting the public interest assessment, the Commission considered each individual element of the NSA and the NSA as a whole. As to what constitutes the public interest when assessing the attributes and merits of an NSA, the Commission followed the guidance provided by the Alberta Court of Appeal in the ATCO Electric decision discussed above. That is, it considered the public interest from the perspective of ratepayers. In arriving at its findings, the Commission reviewed each of the material provisions of the NSA to determine if any of these provisions appears to be unusual, contrary to accepted regulatory practices, or could result in undue rate effects, service concerns, preferences or other concerns in future rate applications. The Commission has also considered whether the effect of the NSA would lead to rates and terms and conditions of service that are just and reasonable.

27. ATCO Electric submitted that the NSA results in just and reasonable tariffs for 2023, 2024 and 2025, is in the public interest and is not contrary to law.²¹

28. ATCO Electric filed a summary of the terms of the NSA for ATCO Electric's 2023-2025 GTA, reproduced in Table 1 below. All adjustments to the revenue requirement listed in Table 1 are in addition to the errors and omissions updates that were included in response to a Commission IR.²² In total, the adjustments resulting from the NSA amount to a \$113.8 million²³ reduction to ATCO Electric's 2023-2025 revenue requirements.

Table 1. Impact to revenue requirement of agreed adjustments

	2023	2024	2025
	(\$ million)		
O&M [operating and maintenance] Negotiated Items			
Diesel Fuel Volume Reduction	(0.3)	(0.3)	(0.3)
Vacancy Rate	(0.5)	(0.6)	(0.7)
Inflation - In/Out Scope, Contractor and Other	(1.0)	(1.5)	(1.8)
USA 560 - Supervision and Engineering	(0.1)	(0.1)	(0.1)
USA 561 - Control Centre Operations	(0.2)	(0.2)	(0.2)

²⁰ Exhibit 27062-X0495.01, PDF page 27.

²¹ Exhibit 27062-X0495.01, paragraph 59.

²² AET-AUC-2022SEP21-130.

²³ = \$34.5 million + \$38.2 million + \$41.1 million.

	2023	2024	2025
	(\$ million)		
USA 562 - Station Equipment Expenses	(0.4)	(0.5)	(0.6)
Insurance Premiums	(0.3)	(0.2)	(0.2)
Variable Pay Program	(0.6)	(0.7)	(0.8)
Shared Services FTE Reduction	(0.2)	(0.2)	(0.1)
IT Transition Costs & Reduction of IT Costs per Decision 26616-D01-2022	(0.5)	(4.6)	(1.5)
General O&M Reduction	(0.3)	(0.3)	(0.3)
Total O&M Negotiated Items	(4.3)	(9.0)	(6.5)
Capital Negotiated Items			
IT Capital – Reduction to Opening Rate Base	(1.1)	(1.1)	(1.0)
Removal of DA Capital (CETO/PENVT)	0.0	0.2	(6.7)
Global TCM 7.5% Reduction	(0.2)	(1.2)	(2.0)
One-time TCM Reduction	(0.0)	(0.2)	(0.2)
Return on Increased Rate Base due to FIT Reserve Refund	0.6	2.0	3.3
Increase to Income Tax Expense due to Increase to Return on Rate Base	0.1	0.3	0.5
Total Capital Negotiated Items	(0.5)	0.0	(5.9)
Future Income Tax (FIT) Reserve Refund	(22.9)	(22.5)	(22.1)
Decrease to Income Tax Expense due to FIT Reserve Refund	(6.8)	(6.7)	(6.6)
Total Negotiated Reduction	(34.5)	(38.2)	(41.1)

Source: Exhibit 27062-X0495.01, Table 1, PDF page 11.

29. Parties to the NSA also agreed to implement two new deferral accounts in the test period, and to extend ATCO Electric's existing deferral account for statutory tax rates to include changes to income tax legislation or policy that relate to the ability to claim accelerated capital cost allowance. The NSA also includes commitments made by ATCO Electric to provide certain information in its next GTA. These commitments are included in Section 5 of the NSA, found in [Appendix 4](#).

30. The NSA represents a unanimous agreement reached as a result of a successful negotiation. Such negotiations and the resultant NSA typically reflect a number of compromises of different interests and positions of the parties. The signatories to the NSA in this case, with the exception of the City of Grande Prairie, have historically participated in the testing of ATCO Electric's GTAs and represent a broad cross-section of Alberta ratepayers. The involvement of sophisticated participants representing a number of different constituencies supports a finding that the NSA is in the public interest.

31. Having reviewed the individual provisions of the NSA and considered the NSA as a whole as described above, along with the detailed analysis of the application and IR responses, the Commission finds that the NSA, taken as a whole, is not patently against the public interest or contrary to law, and finds that the NSA results in rates and terms and conditions that are just

and reasonable, as required by Section 8 of Rule 018. Accordingly, the Commission approves the NSA as filed, and attached as Appendix 4 to this decision.

4 Excluded matters

32. In its August 5, 2022, letter, the Commission gave its approval for ATCO Electric and interveners to enter into an NSP on all matters with the exception of the following two items: (i) removal of the Vegetation Management reserve; and (ii) modifications to the Variable Pay Program reserve.²⁴

33. ATCO Electric subsequently advised, as part of its NSA submission, that parties were unable to agree on the treatment of the \$7.5 million undepreciated balance for the Jasper Palisades isolated generation plant. As a result, the Commission must likewise separately determine this issue (along with the other two formally excluded matters).²⁵

34. In the following sections, the Commission provides its findings with respect to these three matters.

4.1 Vegetation management reserve

Why is ATCO Electric asking the Commission to remove the vegetation management reserve account?

35. ATCO Electric requested that the vegetation management reserve be discontinued because the reasons it was originally created no longer apply.²⁶ In particular, ATCO Electric indicated that the variances between forecast expenditures and actual expenditures that were once a concern to the Commission have diminished to the point where they are no longer material. ATCO Electric explained that it has diversified its contractor resources and converted its vegetation management program from mechanical removal to predominantly herbicide treatment, resulting in smaller and more predictable vegetation treatment volumes.²⁷

Why was the vegetation management reserve established?

36. In Decision 20272-D01-2016,²⁸ the Commission expressed concern with the historical variances between forecast and actual vegetation management costs. The Commission found that a significant amount of ATCO Electric's 2015 actual vegetation management costs and its 2016 forecast costs had been deferred from prior years.²⁹ ATCO Electric attributed its inability to complete the vegetation management work from prior years to the unavailability of contractors and weather related difficulties.³⁰ As a result, the Commission determined that electricity ratepayers should not bear a disproportionate share of the risk that ATCO Electric may be unable to complete its forecast vegetation management work and therefore retain, for the benefit of its

²⁴ Exhibit 27062-X0273, AUC letter - Ruling on ATCO Electric motion to update application for inflation and fuel, issues list, negotiated settlement and process schedule, PDF pages 5-6.

²⁵ Exhibit 27062-X0273, AUC letter - Ruling on ATCO Electric motion to update application for inflation and fuel, issues list, negotiated settlement and process schedule, paragraph 27.

²⁶ Exhibit 27062-X0014.02, PDF page 17.

²⁷ Transcript, Volume 1, page 17, lines 8-25.

²⁸ Decision 20272-D01-2016: ATCO Electric Ltd. 2015-2017 Transmission General Tariff Application, Proceeding 20272, August 22, 2016.

²⁹ Decision 20272-D01-2016, paragraphs 256-259.

³⁰ Decision 20272-D01-2016, paragraph 260.

shareholders, revenues that were collected from ratepayers for forecast costs of vegetation management that were not spent.

The Commission has previously ruled on ATCO Electric requests to remove its vegetation management reserve account

37. ATCO Electric has requested the removal of the vegetation management reserve in each of its tariff applications following the Commission's direction in Decision 20272-D01-2016.

38. In Decision 22742-D01-2019,³¹ the Commission denied ATCO Electric's request to remove the vegetation management reserve account. In that decision, the Commission found that there was merit in maintaining the reserve account, as it supported stability and aided ATCO Electric in managing its forecast costs.³²

39. In Decision 24964-D02-2021,³³ the Commission again denied ATCO Electric's request to remove the vegetation management reserve account. While the Commission acknowledged ATCO Electric's improved forecast accuracy and a trend of cost reductions, it denied ATCO Electric's request for the following reason:³⁴

196. However, the Commission finds that these improved costs do not outweigh the fact that the execution of ATCO Electric's Vegetation Management Program remains, to a large degree, unpredictable and subject to forecast risk. As acknowledged by ATCO Electric, weather conditions and contractor availability are factors that can influence the success of ATCO Electric's Vegetation Management Program.

Projected treatment volumes are based on ideal weather conditions and contractor availability. Actual treatment volumes may be different than projected volumes due to abnormally warm winters that increase the cost and reduce the productivity associated with mulching operations, or abnormally wet or windy summers that reduce the window for effective herbicide application.¹⁷³

¹⁷³ Exhibit 24964-X0001.03, application update, paragraph 226, PDF page 189.

Is there sufficient support to justify removing the vegetation management reserve in the current proceeding?

40. In an IR from the Commission, ATCO Electric was asked to provide detailed vegetation management information by line number and substation that included the year work was deferred from (if applicable), removal method, volume of work performed and cost information.

³¹ Decision 22742-D01-2019: ATCO Electric Ltd. 2018-2019 Transmission General Tariff Application, Proceeding 22742, July 4, 2019, paragraphs 209-211.

³² Decision 22742-D01-2019: paragraph 211

³³ Decision 24964-D02-2021: ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 19, 2021, paragraphs 195-197.

³⁴ Decision 24964-D02-2021, paragraph 196.

41. As part of its response to the Commission's IR,³⁵ ATCO Electric stated the following:

The information by line does not include any "Year work deferred from" information, as AET no longer defers vegetation work on lines. Lines are patrolled every three to four-years and assessed for vegetation risk. AET focuses its vegetation management activities on a risk-based approach. Work is done, as required, based on AET's risk assessment and timing of next planned patrol/program.³⁶

42. While ATCO Electric explained that its lines are patrolled every three to four years, it did not indicate when the last patrol was done and what test period years' costs were forecast based on its last line patrol and risk assessment. The Commission therefore cannot ascertain whether the vegetation management forecasts in the test periods currently under consideration were all the subject of a risk-based assessment conducted following line patrols.

43. The Commission has reviewed the proportion of the actual costs and volumes of vegetation management work completed, to the approved forecast costs and volumes of work in past GTAs.

44. Based on the information provided by ATCO Electric in its IR response, it has spent almost 94 per cent (on average) of its approved forecast for line clearing, and completed 90 per cent of the work volume (on average) approved in its last GTA.

45. The Commission observes that ATCO Electric, in total, has managed its vegetation management spending to be in line with its approved forecast costs. It has also completed the volume of work it had forecast over the prior GTA period. The 2023 to 2025 test period forecast volume of work is less than in prior GTAs, which, in the Commission's view, reduces the risk that ATCO Electric will be unable to complete it. Given that the evidence demonstrates that ATCO Electric's forecasts have been more closely aligned with its actual vegetation management, the Commission finds that it is reasonable to transition away from the vegetation management reserve over the 2023-2025 test period as directed below.

46. The Commission directs ATCO Electric to maintain the reserve account treatment for 2023, but approves the elimination of the vegetation management reserve beginning in 2024. This transition period will permit the Commission to monitor the vegetation management program to ensure continued alignment of forecast and actual costs and work volumes at the time of the next GTA. For all test period years in the current and next GTA, ATCO Electric is directed to provide the same information that it filed in response to 27062-X0416, updated for the appropriate years. Should significant variances reoccur in the costs and volumes for ATCO Electric's vegetation management program, the Commission may reinstate the past reserve treatment.

³⁵ Exhibit 27062-X0330.02, AET Responses to AUC IRs, AET-AUC-2022SEP21-114, PDF pages 621-625; and exhibits 27062-X0416, AET-AUC-2022SEP21-114 Attachment 1, and 27062-X0417, AET-AUC-2022SEP21-114 Attachment 2.

³⁶ Exhibit 27062-X0330.02, AET Responses to AUC IRs, AET-AUC-2022SEP21-114, PDF page 622.

4.2 Variable Pay Program reserve

ATCO Electric's requested changes to the VPP reserve account

47. ATCO Electric requested two changes to its VPP reserve mechanics. In particular, it sought to:

- (i) Exclude direct assigned capital VPP from the VPP reserve account; and
- (ii) Include the revenue requirement amount related to the portion of capitalized VPP amounts in the reserve account, rather than the total amount of the non-direct assigned capital VPP forecast costs.

48. ATCO Electric explained that in Decision 24964-D02-2021, it was directed to manage the VPP reserve account by disaggregating O&M, direct assigned, and non-direct assigned capital VPP amounts effective January 1, 2020, and to prepare the continuity Schedule of Reserve for VPP on a disaggregated basis. As a result of that direction, ATCO Electric separately examined the mechanics of the O&M VPP, direct assigned capital VPP and non-direct assigned VPP components.³⁷

49. In its application, ATCO Electric proposed to exclude direct assigned capital VPP from the VPP reserve account because differences between forecast and actual direct assigned capital amounts are already trued up through the settlement of the direct assigned capital deferral account.

50. ATCO Electric also submitted that the amount to include in the non-direct assigned VPP reserve account should never exceed the revenue requirement amount actually collected (being an amount equal to non-direct assigned VPP amounts capitalized). ATCO Electric argued that the revenue requirement impact is the appropriate amount to include in the reserve as it is the amount which ATCO Electric actually collects as a result of having the forecast VPP included in its rate base.

Why was the variable pay program reserve established?

51. In Decision 2013-358,³⁸ the Commission explained that deferral account treatment had originally been applied to VPP costs³⁹ because it was a new program and, absent a deferral account, the utility might be incented to keep, for the benefit of shareholders, funds collected from ratepayers to support the utility's recruitment and retention efforts. In Decision 2013-358, the Commission determined that deferral treatment was no longer required because ATCO Electric had established a history of paying the VPP amounts.

52. In Proceeding 27062, the Commission observed that ATCO Electric had not fully paid out VPP amounts in 2013 and 2014, and planned to withhold all VPP amounts initially forecast to be paid in 2015. It was unclear to the Commission, at that time, whether ATCO Electric would pay VPP to its employees in 2016 and 2017.

³⁷ Exhibit 27062-X0014.02, paragraphs 679-680.

³⁸ Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application, Application 1608610, Proceeding 1989, September 24, 2013.

³⁹ The deferral account for ATCO Electric's VPP was first approved in EUB Decision 2006-024: ATCO Electric Ltd. General Tariff Application, Application 1399997, March 17, 2006, PDF page 80.

53. In Decision 20272-D01-2016, the Commission directed ATCO Electric to establish a reserve account for its ratepayer funded VPP. The reserve account mechanics were structured such that ATCO Electric could not recover costs in excess of its approved VPP forecast amounts for a given year, nor carry over any unused VPP funds into a future test period. The Commission-approved, but unused, VPP amounts in any given GTA test period would be added to the VPP reserve account for the next GTA test period. As detailed in Decision 2013-358,⁴⁰ the VPP reserve was designed to address ATCO Electric's need to fund VPP in support of its recruitment, retention and operational performance goals, while ensuring that any incentive to withhold VPP amounts to increase the utility's retained earnings was removed.

54. The mechanics of the VPP reserve have evolved since its inception to ensure that the reserve continues to meet these objectives.

55. In reply argument, the CCA stated that it did not oppose ATCO Electric's proposed modifications to the VPP reserve or how the components were calculated.⁴¹

Are ATCO Electric's proposed changes to the VPP mechanics reasonable?

56. For the reasons set out below, the Commission finds that ATCO Electric's proposed changes to the mechanics of the VPP reserve are reasonable and approves them as filed.

57. The Commission agrees with ATCO Electric that as a result of disaggregating the three components of the VPP,⁴² and given that variances between actual and approved capitalized expenditures are settled through the direct assigned capital deferral account, there is no need to track these costs through the VPP reserve. The Commission also acknowledges ATCO Electric's reply argument, in which it stated that "in future direct-assign capital deferral accounts, AET will continue to report on VPP paid and remove any amounts in excess of approved VPP amounts."⁴³

58. The Commission also accepts ATCO Electric's proposed treatment of non-direct assigned capital VPP. A reserve account is used to fund specific expenses that are paid out infrequently or at unpredictable intervals, and are funded in advance through rates. Now that the VPP reserve account has been disaggregated, the revenue requirement amount related to the portion of capitalized VPP amounts in the reserve account, rather than the total amount of the non-direct assigned capital VPP forecast costs, is the proper amount that should be reflected in the VPP reserve account. This is because these amounts reflect what ATCO Electric has collected from ratepayers over each of the test periods towards the funding of ATCO Electric's non-direct assigned VPP, prior to ATCO Electric actually distributing the VPP payout to its employees.

⁴⁰ Decision 2013-358.

⁴¹ Transcript, Volume 2, page 134, lines 5-18.

⁴² The three components being O&M, non-direct assigned capital and direct assigned capital.

⁴³ Transcript, Volume 2, page 143, lines 1-9.

4.3 Proposed one-time adjustment to depreciation expense for the Jasper Palisades isolated generation plant

59. ATCO Electric proposed a one-time \$7.5 million adjustment to its 2023 depreciation expense to correct an accounting error it made in recording certain Jasper Palisades switchgear assets (that are no longer in service)⁴⁴ to an incorrect depreciable asset account.

60. The Commission denies ATCO Electric's proposed adjustment to its 2023 depreciation expense. As detailed in the reasons that follow, ATCO Electric has failed to persuade the Commission that it is just and reasonable, in the circumstances of this case, for: (i) ATCO Electric to recover the undepreciated capital amounts associated with the Jasper Palisades switchgear assets which arose as a result of its historical accounting errors; and (ii) current Alberta electricity ratepayers to bear the financial burden of ATCO Electric's accounting errors in relation to the Jasper Palisades switchgear assets.

Background – Supply of electricity to Jasper

61. Prior to 2021, the Municipality of Jasper, Jasper National Park and the surrounding area were not connected to the Alberta Interconnected Electric System (AIES). Since 1975, these areas received electricity service from natural gas and diesel-powered generation produced by the Jasper Palisades Power Plant, which ATCO Electric owned and operated.

62. The Jasper Palisades Power Plant is an isolated generating unit under the *Isolated Generating Unit and Customer Choice Regulation (Iso Gen Regulation)*.

63. In 2018, the Commission approved an application filed by ATCO Electric and AltaLink to construct and operate a transmission line, the Jasper Transmission Interconnection, that would connect the Municipality of Jasper, Jasper National Park and the surrounding area to the AIES.⁴⁵ The Jasper Palisades Power Plant would no longer be required once the Jasper Transmission Interconnection was placed into service.

64. In 2019,⁴⁶ the Commission authorized ATCO Electric to discontinue operation of the Jasper Palisades Power Plant, and to decommission and salvage it.

⁴⁴ The Jasper Palisades Power Plant comprises several isolated generation units.

⁴⁵ Decision 22125-D01-2018. Jasper Interconnection Project, Alberta Electric System Operator, Needs Identification Document, Application 22125-A001; AltaLink Management Ltd., Facility Applications, Applications 22125-A002 and 22125-A003; ATCO Electric Ltd., Facility Applications, Applications 22125-A004 to 22125-A006, May 4, 2018.

⁴⁶ Decision 24183-D03-2019: ATCO Electric Ltd., Decommission and Salvage of Palisades Power Plant, Proceeding 24183, Application 24183-A001, January 21, 2019.

Background – depreciation

65. At the time of ATCO Electric’s last depreciation study, it anticipated that 2020 would be the year of final retirement for all of the assets comprising the Jasper Palisades Power Plant.^{47 48 49} Accordingly, commencing in 2021, ATCO Electric set a depreciation rate for all Jasper Palisades Power Plant asset accounts to zero per cent, notwithstanding that ATCO Electric intended to continue to record an annual amortization of reserve differences true up amount over the 2023-2025 test period. ATCO Electric indicated that it would calculate an updated amortization of reserve differences true-up amount for the Jasper Palisades Power Plant asset accounts at the time of its next depreciation study. ATCO Electric anticipated that it would file its next depreciation study in its next GTA (commencing in 2026).⁵⁰

66. The currently approved annual amortization of reserve differences true-up for the Jasper Palisades Power Plant assets, which was calculated as of December 31, 2018,⁵¹ consists of a refund of “life” depreciation expense of \$2.05 million and collection of “net salvage” depreciation expense of \$3.37 million; or a net \$1.32 million increase to depreciation expense in each of 2023-2025.

67. For greater clarity, the recovery of the net \$1.32 million in each of the test years is part of the Commission-approved NSA. These amounts will be recovered through the amortization of reserve differences mechanism, do not include amounts requested by ATCO Electric in respect of the Jasper Palisades switchgear assets discussed below, and are unaffected by the findings below.

Discovery and nature of error

68. ATCO Electric advised that it discovered an accounting error “in the process of preparing the sales offering for the Jasper Palisades Isolated Generation plant.”⁵² ATCO Electric indicated that the error arose because certain Jasper Palisades assets (primarily “switchgear assets”)⁵³ had

⁴⁷ Proceeding 24964, Exhibit 24964-X0033.02, Appendix D, Depreciation Study, PDF pages 43-44: In ATCO Electric’s depreciation study, the year of final retirement for all Jasper Palisades power plant isolated generation facilities was expected to be 2020.

⁴⁸ Decision 24964-D02-2021, Appendix 3, PDF pages 106-106. Please refer to the following accounts for Jasper Palisades isolated generation plant facilities:

USA 341.10 – Gas turbine structures;

USA 341.20 – Internal combustion structures – Palisades;

USA 343.10 – Gas turbine generators;

USA 342.20 – Internal combustion fuel holders – Palisades;

USA 343.25 – Internal combustion generators – Palisades;

USA 345.10 – Gas turbine accessory electric equipment;

USA 345.20 – Internal combustion accessory electrical equipment - Palisades;

USA 346.10 – Gas turbine miscellaneous equipment and

USA 346.20 – Internal combustion miscellaneous electrical equipment – Palisades.

⁴⁹ Exhibit 27062-X0529, AET-AUC-2023FEB01-001, Table 1, PDF page 5: As of December 31, 2022, for all Jasper Palisades isolated generation assets there is Original Cost of \$52.8 million, Accumulated Depreciation – Life of \$41.4 million and Accumulated Depreciation – Net Salvage of \$17.2 million for a net book value of \$(5.9) million before additional sales proceeds or dismantling costs.

⁵⁰ Exhibit 27062-X0525.01, AET-AUC-2023FEB01-001(e), PDF page 6.

⁵¹ Exhibit 27062-X0015.02, MFR Schedule 6-4.1, Life Analysis, and Schedule 6-4.2, Net Salvage Analysis.

⁵² Exhibit 27062-X0014.02, application, PDF page 297, paragraph 285.

⁵³ Exhibit 27062-X0014.02, application, PDF page 297, paragraph 285: “... AET identified that a switchgear building and associated equipment for the Palisades Isolated Generation plant had been misclassified as transmission assets upon capitalization rather than Isolated Generation assets.”

been incorrectly recorded in the transmission function and general plant accounts, rather than the correct Jasper Palisades internal combustion accessory electrical equipment account (USA 345.20). ATCO Electric submitted that, as a result, from 2009 to 2020 these switchgear assets were depreciated incorrectly at depreciation rates consistent with longer-lived transmission and general plant assets, rather than at a depreciation rate reflecting the expected shorter-lived Jasper Palisades Power Plant assets. ATCO Electric indicated that in 2021 it transferred the historical cost and accumulated depreciation balances for these switchgear assets from the four incorrect transmission and general plant accounts to the correct account, being the Jasper Palisades internal combustion accessory electrical equipment account (USA 345.20), and which is applicable to the switchgear assets at issue.⁵⁴

69. Had the assets been placed in the correct account from the outset, they would have been fully depreciated by the end of 2020. However, the accounting error resulted in a remaining undepreciated balance of \$7.5 million at the time all Jasper Palisades Power Plant assets were removed from service. This was acknowledged by ATCO Electric in its application where it stated:

AET has included a one-time adjustment of \$7.5 million to its 2023 depreciation expense.... Had the switchgear building and associated equipment been appropriately classified as a Jasper Palisades Isolated Generation asset in Account 345.20 Accessory Electric Equipment in AET's last depreciation study filed in the 2020-2022 GTA, its original cost would have been fully reserved / depreciated by December 31, 2020 - the updated year of final retirement for the Jasper Palisades Isolated Generation site forecast in AET's last depreciation study.⁵⁵

70. The following table identifies the historical cost and accumulated depreciation associated with each of the four (incorrect) accounts in which the switchgear assets resided, between 2009 and 2020, as well as the total combined amount that was transferred into the correct account, being USA 345.20.

Table 2. Commission-prepared summary of historical cost and accumulated depreciation for Jasper Palisades switchgear assets as of 2020 on a mid-year basis

	USA 353.00 Transmission substation	USA 353.10 Communication equipment	USA 390.00 Structures and improvements	USA 350.10 Land rights	USA 345.20* Jasper Palisades internal combustion accessory electrical equipment Total historical cost and accumulated depreciation transferred from incorrect accounts.
	(\$ million)				
Historical cost of additions:					
2009	9.6	0.4			10.0
2010			0.1		0.1
2015	0.1		0.1		0.2
Total historical cost 2020	9.7	0.4	0.2	0.0	10.3

⁵⁴ Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112 (a)(i), PDF pages 616-617.

⁵⁵ Exhibit 27062-X0014.02, application, PDF page 297, paragraphs 285-286.

	USA 353.00 Transmission substation	USA 353.10 Communication equipment	USA 390.00 Structures and improvements	USA 350.10 Land rights	USA 345.20* Jasper Palisades internal combustion accessory electrical equipment Total historical cost and accumulated depreciation transferred from incorrect accounts.
Less: accumulated depreciation as of 2020	2.6	0.2	0.0	0.0	2.8
Net book value 2020	7.1	0.2	0.2	0.0	7.5

Source: Summarized from Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112, tables 1 and 2, PDF pages 619-620. Rounding may result in zero amounts reported.

*In Exhibit 27062-X0525.01, AET-AUC-2023FEB01-001, footnote to Table 1, PDF page 4, ATCO Electric has also identified this account as Account 345.25: "The historical cost and accumulated depreciation of the switchgear building and associated equipment are included in Account 345.25 (USA Account 345.20) Int Combust Accessory Electric Equipment. ..."

Request to recover \$7.5 million through the tariff

71. ATCO Electric submitted that it is just and reasonable for the Commission to approve the proposed \$7.5 million one-time true-up of the switchgear assets in its 2023 tariff because, among other things, ATCO Electric must have a reasonable opportunity to recover the costs and expenses associated with its prudent capital investment in the utility, including depreciation.

72. In the alternative, ATCO Electric argued that it was entitled to this amount under Section 22 of the *Iso Gen Regulation*, and would seek recovery of amounts not approved in this decision in a forthcoming *Iso Gen Regulation* application.

73. ATCO Electric explained that its proposed \$7.5 million one-time true-up in 2023 of the Jasper Palisades switchgear assets would align with the anticipated timeline of the settlement process outlined in Section 22 of the *Iso Gen Regulation*. The provisions of the regulation allow ATCO Electric to seek recovery of (or provide payment for) any remaining net book value (NBV), which it had not recovered (or had over-recovered) from (to) the Balancing Pool. ATCO Electric expected that the currently outstanding decommissioning and salvaging activities for the Jasper Palisades isolated generation site would be completed in 2024. Accordingly, it said that the timelines between the Balancing Pool settlement and final decommissioning and salvaging activities were generally aligned with ATCO Electric's proposed 2023 true-up.⁵⁶

74. As noted earlier, ATCO Electric stated that at the time of its next depreciation study, it will update the amortization of reserve differences true-up to incorporate any additional information available with respect to remediation and reclamation of the entire Jasper Palisades isolated generation site. This will result in a final true-up for the amortization of reserve differences for all Jasper Palisades isolated generation facilities and will occur after reclamation and remediation is complete, forecast as 2030.⁵⁷

75. ATCO Electric further clarified that once the Jasper Palisades power plant isolated generation site has been "fully decommissioned, remediated and reclaimed" in 2030, all Jasper

⁵⁶ Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112 (a)(i), (b), PDF pages 616-617 and 620.

⁵⁷ Exhibit 27062-X0525.01, AET-AUC-2023FEB01-001, PDF pages 5-6.

Palisades isolated generation plant assets will be retired from the accounting records.⁵⁸ Until that time, ATCO Electric indicated that the historical cost of all Jasper Palisades isolated general plant asset accounts and the corresponding accumulated depreciation balances will remain on the accounting records of ATCO Electric, notwithstanding that the assets are no longer being used for the provision of utility service. This includes those assets that were held and depreciated within the wrong accounts during the period 2009-2020.

76. ATCO Electric submitted that Section 20 of the *Iso Gen Regulation* provides it with an entitlement to recover the undepreciated capital cost of an isolated generating unit, which it said is “even stronger and more specific” than the right of every owner of an electric utility, pursuant to Section 122 of the *Electric Utilities Act*, to a reasonable opportunity to recover its capital investment.⁵⁹ Specifically, ATCO Electric submitted that Section 20 of the *Iso Gen Regulation* constrains the Commission’s authority to deny ATCO Electric’s entitlement to the undepreciated capital costs of the Jasper Palisades switchgear assets at issue (which ATCO Electric submitted was \$7.5 million). While ATCO Electric indicated that it was reasonable for the Commission to approve the \$7.5 million as part of ATCO Electric’s tariff in this proceeding, ATCO Electric argued that if the Commission did not approve the full amount, then it was entitled to collect the outstanding amount in a forthcoming Section 20 *Iso Gen Regulation* application.⁶⁰

77. The CCA, the UCA and The City of Calgary, opposed ATCO Electric’s request for a \$7.5 million one-time adjustment to its depreciation expense.

78. Dustin Madsen, on behalf of the CCA, likened the proposed one-time adjustment to a “write-off of unrecovered investment” as opposed to a depreciation charge. Further, D. Madsen submitted that the requested adjustment does not fall within the amortization of reserve differences mechanism: first, because the amortization for reserve differences is intended to correct for a change in estimate, not for the correction of an error and second, because the Jasper Palisades assets no longer exist. Specifically, D. Madsen indicated that “it would be inappropriate to amortize the remaining cost of an asset over the life of other assets when the asset in question is no longer in service.”⁶¹ D. Madsen stated that the NBV of the assets should be recognized as a loss in 2021, not as an adjustment in any period in 2023 to 2025.

79. The UCA stated that ATCO Electric has already had an opportunity to recover the cost of the switchgear assets and was effectively asking to retroactively adjust past approved revenue requirements in the year 2023. The UCA also alleged that ATCO Electric would have earned a return during 2020-2022 on the switchgear assets in addition to charging depreciation expense for 2021 and 2022. This was in addition to ATCO Electric asking for the full \$7.5 million (as of 2020) which it said constituted “double dipping” that the Commission should not permit.⁶² The Commission discusses ATCO Electric’s over recovery of return on rate base as a result of the rate base value declining more slowly than it would have had the switchgear assets been in the correct account in paragraph 94 below.

⁵⁸ Exhibit 27062-X0330.02, AET-AUC-2022SEP21-112 (a)(i), (b), PDF pages 616-617 and 620.

⁵⁹ Transcript, Volume 2, pages 145-149.

⁶⁰ ATCO Electric anticipated that further applications to settle amounts owing to and received from the Balancing Pool under the *Iso Gen Regulation* would be completed by 2024.

⁶¹ Exhibit 27062-X0450, CCA evidence of Dustin Madsen, PDF page 79.

⁶² Transcript, Volume 1, pages 95-97.

80. According to Calgary, the question to be addressed is who should bear the “responsibility and risk for the utility error or misallocation”⁶³ with respect to the switchgear assets. Calgary argued that ATCO Electric has had a number of opportunities to adjust for the “misallocation,” and stated that the Commission elsewhere has set a two-year limitation period⁶⁴ for adjustments to the extent they arose due to the utility’s own error. Calgary questioned whether, because the assets were no longer in service after 2020, the costs for those assets should be recovered from ratepayers who will receive no benefit of any service from those assets.⁶⁵ Calgary also made submissions with respect to the appropriateness of using of the amortization of reserve differences mechanism in the circumstances of this case.

Commission findings

81. For the reasons that follow, the Commission is not persuaded that it is reasonable to allow ATCO Electric to recover \$7.5 million in depreciation expense (through a one-time adjustment or otherwise) related to the Jasper Palisades amounts that were incorrectly accounted for, and finds that the correct undepreciated balance in relation to the Jasper Palisades switchgear assets should be \$0.

The unrecovered capital for the switchgear assets arose because of ATCO Electric’s error

82. First, the Commission disagrees with ATCO Electric’s description of the circumstances leading up to its request for a one-time collection of depreciation expense related to the Jasper Palisades switchgear assets. In particular, the Commission finds ATCO Electric’s explanation of how the \$7.5 million undepreciated balance arose to be incomplete. ATCO Electric emphasized its right to recovery of its prudently incurred investment in these assets and either downplayed, or offered no mention whatsoever of, specific events subsequent to that investment which, in the Commission’s view, resulted in the \$7.5 million undepreciated balance that it now seeks to collect from ratepayers.

83. In the Commission’s view, the \$7.5 million amount arose from the following three events:

- (i) ATCO Electric’s investment in the switchgear assets in 2009;
- (ii) ATCO Electric’s error in booking the investment in these assets into four incorrect uniform system of accounts at the time the investment was made. This resulted in ATCO Electric depreciating the investment at a rate that returned capital to ATCO Electric more slowly compared to the depreciation rate that would have been applied had the investment been booked into the correct Jasper Palisades uniform system of account; and
- (iii) ATCO Electric’s ongoing failure to discover and correct its error over a continuous period of at least 12 years, despite reasonable opportunities to do so, such that the

⁶³ Transcript, Volume 1, page 99.

⁶⁴ Transcript, Volume 1, page 101, referring to Decision 2006-042: ATCO Gas, A Division of ATCO Gas and Pipelines Ltd., (This Decision is also applicable to Direct Energy Regulated Services and AltaGas Utilities Inc.), Deferred Gas Account Limitation Period, Application 1407502, May 11, 2006.

⁶⁵ Transcript, Volume 1, page 101, referring to Decision 2006-042.

accumulated depreciation for the Jasper Palisades switchgear assets was \$7.5 million less than it would have been had the assets been booked into the correct account.

84. Without events (ii) and (iii) above, ATCO Electric would not have applied to collect \$7.5 million in this proceeding for the switchgear assets, as detailed in paragraph 68 above.

85. In so far as the existence of reasonable opportunities for ATCO Electric to discover and correct its mistake is concerned, it is noteworthy that, in 2016 in Decision 20272-D01-2016, the Commission directed ATCO Electric to confirm that its then calculated accumulated depreciation balances for the Jasper Palisades Power Plant were accurate. The Commission stated:

660. The Commission accepts ATCO Electric's revised year of final retirement of 2018 and net negative salvage estimates for Jasper Palisades generation assets as being related to the energization of the Jasper transmission interconnection thereby eliminating the need for the Jasper Palisades isolated generation plant.

661. However, as part of ATCO Electric's compliance filing, **the Commission requires confirmation that ATCO Electric's calculated accumulated depreciation balances related to life and net salvage as of December 2017 are correct in that approximately \$12.7 million in life and net salvage remains to be recovered in the year 2018 and beyond. ATCO Electric is directed to provide the requested confirmation and explain why the unrecovered balance is so large. ATCO Electric is also directed to describe the proposed method and period of recovery of the \$12.7 million.** [emphasis added]

86. Despite being required to verify its unrecovered balance regarding all of the Jasper Palisades Power Plant assets, ATCO Electric did not disclose any error with respect to the (misclassified) switchgear assets when it responded to this Commission direction in Proceeding 22050. There, ATCO Electric did disclose an error related to the balance of unrecovered investment, but that error did not relate to the switchgear assets at issue in this proceeding. ATCO Electric disclosed the following:

AET has updated 20272-X1275.01 with the revised depreciation rates reflecting the 2018 year of final retirement. AET notes that 20272-X1275.01 erroneously excluded depreciation incurred in 2014. Inclusion of depreciation incurred in 2014 as well as the updated rates as provided by Gannett Fleming results in an updated forecast of \$14.2 million rather than \$12.7 million as indicated in the above direction.

As shown in Schedule 6-3 of AET's 2015-17 compliance filing, AET's previous depreciation parameters were based on a forecast year of final retirement of 2026 to 2038 depending on the asset class. **With the proposed Jasper interconnection project scheduled to be completed by 2018, AET has adjusted the year of final retirement to 2018 and is recovering the remaining undepreciated capital cost and associated net salvage over this accelerated time frame.**

AET will update the amount to be recovered in 2018 as part of its next GTA. At that time, it is expected that forecasts for future removal costs and capital requirements will be known with more certainty.⁶⁶ [emphasis added]

⁶⁶ Proceeding 22050, Exhibit 22050-X0019.01, AET 2015-2017 GTA Compliance Filing, PDF pages 69-70.

87. Had ATCO Electric, during the course of its response to the Commission direction, uncovered the error and thus properly verified the remaining unrecovered balances for all its Jasper Palisades isolated generation assets, including the switchgear assets, the matter would have been placed squarely before the Commission much earlier and under a different set of factual circumstances.

88. The Commission also disagrees with ATCO Electric that the Commission must approve its requested one-time collection to comply with the *Electric Utilities Act*, Section 122(1)(a). That section requires the Commission to have regard for the principle that a tariff approved by the Commission must provide a utility with a reasonable opportunity to recover its prudently incurred costs and expenses associated with capital related to the owner's investment in the electric utility, including depreciation.

89. ATCO Electric had a reasonable opportunity to recover its investment in the switchgear assets under its tariff from 2009 to 2020. The Commission's approved depreciation parameters for the Jasper Palisades assets, from which depreciation rates for these assets were derived, would have fully returned ATCO Electric's capital in the switchgear assets, had ATCO Electric not erroneously placed the switchgear assets into four incorrect asset accounts. There was no way for the Commission or ratepayers to know that the investment was being depreciated in the incorrect accounts. When the Commission flagged a concern regarding the size of the undepreciated balance in the Jasper Palisades isolated generation asset accounts, ATCO Electric did not apply sufficient diligence in addressing the Commission's direction to detect its longstanding error. The Commission finds that ATCO Electric had a reasonable opportunity to recover its investment in the assets, but through its own errors, on two separate occasions in relation to the same assets, was not able to realize on that opportunity.

90. When viewed in this context, the error that resulted in the \$7.5 million in undepreciated capital costs associated with the switchgear assets can more fairly be characterized as ATCO Electric's forgone reasonable opportunity to recover its prudently incurred investment related to the switchgear assets under its approved tariff from 2009 to 2020.

Should Alberta ratepayers bear the risks associated with ATCO Electric's error?

91. In the Commission's view, the fundamental question raised by ATCO Electric's request is whether it is just and reasonable for Alberta's current ratepayers to bear the risk and associated costs of an electric utility's accounting error in relation to assets that were used by past ratepayers, whatever the circumstance. In other words, does Section 122 of the *Electric Utilities Act* guarantee the recovery of⁶⁷ a utility's investment, regardless of whether that utility exercised reasonable diligence in terms of its accounting practices, in relation to that investment? ATCO Electric did not persuade the Commission that this should be the case.⁶⁸

⁶⁷ Section 122 of the *Electric Utilities Act* requires the Commission to provide the owner of an electric utility with a reasonable opportunity to recovery of and a return on its investment in the electric utility, but the Commission is here only concerned with the recovery "of" ATCO Electric's investment.

⁶⁸ The Commission has considered the evidence of ATCO Electric's depreciation expert, Larry Kennedy, regarding transfers of assets necessitated and/or occasioned by new depreciation studies, but finds that evidence to be neither particularly relevant nor helpful in the circumstances of ATCO Electric's current request.

92. Under the legislative scheme, the Commission has broad discretion to set just and reasonable rates.⁶⁹ In the circumstances of this case and for the reasons below, the Commission finds it neither just nor reasonable to impose upon current Alberta ratepayers, the costs associated with ATCO Electric's ongoing and discoverable accounting error. The Commission equally finds that it is neither just nor reasonable to shield ATCO Electric from the consequences of its accounting error and associated failure to take advantage of the reasonable opportunities available to it to recover its investment. ATCO Electric had a span of more than a decade in which to recover its capital investment. It is now requesting that current Alberta ratepayers bear (i) the risk of such error (over which Alberta ratepayers had no control or awareness); and (ii) the associated cost burden of keeping ATCO Electric financially whole despite having caused the error itself. In other words, ATCO electric is seeking to use Section 122 of the *Electric Utilities Act*, or, in the alternative, the *Iso Gen Regulation*, to be fully indemnified for its own errors in relation to the accounting treatment of the switchgear assets.

Incentives

93. The Commission finds that placing costs associated with ATCO Electric's error on Alberta ratepayers provides the wrong incentives to ATCO Electric. Doing so, does not incent ATCO Electric:

- (i) to accurately record its investment in the proper USA account applicable to that investment;
- (ii) to proactively review its books and accounts for errors either on its own initiative or in response to Commission directions; and
- (iii) to raise with the Commission any errors that are found, as soon as possible after they are detected.⁷⁰

94. The Commission's concerns about incentives are elevated in this case. Here, ATCO Electric has earned a greater return than it otherwise would have earned had it placed the switchgear assets in the correct account in 2009. This is because the switchgear assets were being depreciated (in the incorrect transmission accounts) over a longer period of time resulting in an overstated rate base between the years 2009 and 2022. As a result, since 2009 ATCO Electric has benefited from a higher return on rate base in relation to the Jasper Palisades Power Plant switchgear assets than would otherwise be the case had the assets been depreciated in a manner consistent with Commission-approved depreciation parameters. Indeed, ATCO Electric has asked to be held whole for the return of its capital investment without consideration of (and without accounting for) the additional return on rate base it has earned since 2009.⁷¹

⁶⁹ See, e.g., *Equus Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142, paragraph 91; *ATCO Electric Ltd v Alberta Utilities Commission*, 2023 ABCA 129, paragraph 44.

⁷⁰ The Commission is not suggesting that in the present instance ATCO Electric in any way delayed disclosing to the Commission the particulars of its accounting error upon having discovered it. The Commission's point here relates solely to the absence of an incentive for prompt disclosure of newly discovered accounting errors if indemnification for those errors is automatic whatever the circumstances.

⁷¹ In its response to Exhibit 27062-X0353, AET-UCA-2022SEP27-006(a), PDF pages 4-6, ATCO Electric provided "a schedule separately indicating the impact to the depreciation and return on rate base components of the 2020 through 2022 revenue requirement related to the Jasper Palisades assets if they had been properly recorded in the correct property accounts" to be a net increase in revenue requirement of \$1.4 million.

Intergenerational equity

95. The Commission is also concerned about intergenerational equity issues that would arise if current Alberta ratepayers were required to bear the risk of ATCO Electric's error in this case. If the Commission were to approve ATCO Electric's request, Alberta's 2023 ratepayers would be responsible for paying \$7.5 million attributable to switchgear assets that are no longer used to provide electricity service. ATCO Electric also seeks to recover the costs of assets from a generation of ratepayers, some of whom will have received no benefit whatsoever from the Jasper Palisades switchgear assets. The duration of the accounting error (over 12 years) and the magnitude of the amount to be recovered relative to the original historical cost of the assets⁷² are also significant considerations for the Commission in coming to this finding.

Improper use of the amortization reserve for differences mechanism

96. ATCO Electric also argued that its adjustment was appropriate because it would be consistent with the amortization reserve for differences mechanism.

97. The amortization of reserve differences is a mechanism approved by the Commission that, in general terms, is used by utilities to recover no more or no less than their full capital investment in utility assets. The mechanism trues up differences between estimates of depreciation parameters, such as estimated versus actual services lives of assets, among other things.⁷³ This implies that the depreciation parameter elements (used by the utility to determine depreciation rates) are interim until better information becomes available. In the case before the Commission, however, ATCO Electric seeks a permanent true-up of capital costs that is unrelated to past mis-estimates of depreciation parameters.

98. The Commission finds that ATCO Electric's request is inconsistent with the purpose of the amortization of reserve differences mechanism, in the specific circumstances of this case and for reasons already discussed. In particular, the Commission rejects ATCO Electric's suggestion that this mechanism, in effect, confers a specific entitlement that provides it with an indemnity for its errors related to mass property accounting and depreciation practices.

The Iso Gen Regulation does not entitle ATCO Electric to recovery of the undepreciated capital

99. ATCO Electric relied heavily on the *Iso Gen Regulation* in support of its request. ATCO Electric points to the word "entitle" in Section 20 of the *Iso Gen Regulation*, as constraining the meaning of undepreciated capital cost, under both Section 122 of the *Electric Utilities Act* and Section 20 of the *Iso Gen Regulation*.

100. The Commission disagrees with ATCO Electric's interpretation.

101. The *Iso Gen Regulation* does not confer an unconstrained right on ATCO Electric to recover from the Balancing Pool amounts recorded on its books of account as undepreciated capital.

102. Section 20(1)(a)(i) of the *Iso Gen Regulation* is the relevant provision that applies in this case. Section 20(1)(a)(i) provides that the owner of an isolated generating unit is entitled to

⁷² As noted in Table 4 above: As of 2020, the \$7.5 million of undepreciated capital of the switchgear assets comprises \$10.3 million historical cost less accumulated depreciation of \$2.8 million.

⁷³ These include average service life, Iowa curve, net salvage per cents and capital-related forecasts.

receive from the Balancing Pool the undepreciated capital cost of the isolated generating unit. The Commission observes that the phrase “is entitled to receive” expresses a right to receive something or be benefited in some respect, and puts emphasis on the subject of the provision’s claim. In this context, Section 20 of the *Iso Gen Regulation* creates a legal right for the owner to receive payment from the Balancing Pool (this is the right to receive a benefit) for the amount of the undepreciated capital cost of the generating unit, **as determined by the Commission** (this is the quantum of the benefit), which the Balancing Pool must honour.

103. The Commission emphasizes that the benefit at issue is “as determined by the Commission.” The regulation confers discretion upon the Commission to make a determination about the amount of undepreciated capital cost of the isolated generating unit. The regulation would not have conferred upon the Commission that discretion, if the Commission had no choice but to accept that cost from ATCO Electric’s books of account. The Commission is not persuaded by ATCO Electric’s argument that the regulation’s use of language highlighting an owner’s claim to a benefit changes the nature of the benefit itself, particularly given that the Commission has discretion to determine the amount of benefit.

104. The discretion conferred on the Commission allows the Commission to order an amount to be paid to the Balancing Pool by, or from the Balancing Pool to, the owner of an isolated generating unit in cases where that amount is different from the amount set out on the owner’s books of account. While in the normal course there is often no difference between the amount on an owner’s books of account and what the Commission would order to be paid to or by the Balancing Pool, the circumstances of this case are not the normal course given ATCO Electric’s failures already outlined.

105. In addition, the Commission is mindful that the *Iso Gen Regulation* is made under the *Electric Utilities Act*. It is presumed that subordinate legislative provisions are meant to work with their own enabling legislation. If conflict is unavoidable, in the absence of a contrary legislative intent, the statutory provision prevails.⁷⁴ Conflict should be avoided through interpretation, rather than resolved through paramountcy, if possible.

106. In reaching its conclusion on ATCO Electric’s ability to recover any of the undepreciated capital cost of the switchgear assets, the Commission is of the view that the undepreciated capital cost of these assets is the same under either the *Electric Utilities Act* or the *Iso Gen Regulation*. Otherwise, this would mean that for regulatory purposes the same assets can have two different values. In the Commission’s view, this result is nonsensical. Whether the costs are refunded or recovered through ATCO Electric’s tariff or paid to or from the Balancing Pool, in either case recovery flows to Alberta ratepayers through the Independent System Operator tariff.⁷⁵ The amount of undepreciated capital cost should be the same for tariff-making purposes under the *Electric Utilities Act* and the *Iso Gen Regulation*.

Conclusion

107. The Commission finds that the \$7.5 million of undepreciated capital cost connected with Jasper Palisades switchgear assets is not recoverable from current ratepayers and is a permanent

⁷⁴ *Friends of Oldman River Society v Canada (Minister of Transport)*, [1992] 1 SCR 3, paragraph 38.

⁷⁵ Transcript, Volume 1, page 29.

capital disallowance. ATCO Electric is directed to remove the historical cost and accumulated depreciation related to these assets from the accounting records of its regulated utility assets.

5 Compliance with prior directions

108. In its application, ATCO Electric responded to one direction issued in Decision 24964-D01-2021⁷⁶ and to four directions issued in Decision 24964-D02-2021⁷⁷ with respect to the ATCO Electric 2020-2023 GTA, one direction from Decision 26264-D01-2021⁷⁸ regarding the ATCO Electric 2018-2019 General Tariff Application Second Compliance Filing, and two directions from Decision 26519-D01-2021⁷⁹ from the ATCO Electric Stage 2 Review and Variance of 2018-2019 General Tariff Application Compliance.

109. The Commission asked ATCO Electric to confirm that the negotiated settlement made no determination in relation to compliance with prior outstanding Commission directions. In response, ATCO Electric stated:⁸⁰

... The NSA is intended to be a comprehensive settlement of AET's revenue requirement, except for the Excluded Matters. As such, to the extent that the Commission were to consider that AET's compliance with any prior Commission direction impacts AET's 2023-2025 revenue requirement, then the NSA is intended to settle any such revenue requirement impact. Regardless, however, should the Commission consider that further actions are required by AET in respect of the above-reference directions, AET submits that such further actions could be the subject of a further Commission direction, including for AET's next general tariff application.

110. In the current decision, the Commission has reviewed the record as it pertains to all outstanding directions. Where the Commission has identified issues or concerns with ATCO Electric's responses to a direction, the Commission has provided reasons for its specific findings. Where no specific finding is provided, the Commission has determined that ATCO Electric's responses comply with the directions given and that no further action is required.

111. In Decision 26519-D01-2021, the Commission issued the following direction:⁸¹

In the Commission's July 8, 2021, letter, the Commission took note of ATCO Electric's treatment of the equity portion of AFUDC as a temporary rather than a permanent tax difference, despite acknowledgment by ATCO Electric that the equity portion of AFUDC is a permanent difference. The Commission confirms that it will consider, in ATCO Electric's next GTA, whether the collection of future income tax should continue. The Commission's consideration will also include whether ATCO Electric should be permitted to continue to treat the equity portion of AFUDC as a temporary rather than a

⁷⁶ Decision 24964-D01-2021: ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 1, 2021.

⁷⁷ Decision 24964-D02-2021: ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, Proceeding 24964, March 19, 2021.

⁷⁸ Decision 26264-D01-2021: ATCO Electric Ltd. 2018-2019 General Tariff Application Second Compliance Filing, Proceeding 26264, June 29, 2021.

⁷⁹ Decision 26519-D01-2021: ATCO Electric Ltd., Stage 2 Review and Variance of 2018-2019 General Tariff Application Compliance, Proceeding 26519, October 6, 2021.

⁸⁰ Exhibit 27062-X0505, AET Information Responses Round 2 to AUC, AET-AUC-2023JAN25-002, PDF page 6.

⁸¹ Decision 26519-D01-2021, paragraph 30.

permanent tax difference in the calculation of its tax expense. ATCO Electric is therefore directed to provide relevant evidence on this issue in its next GTA.

112. In response to Decision 26519-D01-2021, Direction 3, ATCO Electric stated:⁸²

Given AET has proposed to discontinue collection of FIT in this application, the distinction between permanent and temporary differences is no longer relevant. Amounts collected based on the previous classification are held in no cost capital and will be refunded when appropriate. Refer to Section 7 where AET has proposed to discontinue the collection of FIT for the Test Period.

113. The Commission disagrees with ATCO Electric's assertion that the distinction between permanent and temporary differences is no longer relevant. First, ATCO Electric stated, in response to the direction, that the previously collected FIT amounts accumulated in the reserve account (no cost capital) will be refunded when appropriate. In its application, however, ATCO Electric did not provide a refund proposal nor an appropriate time to refund the accumulated FIT amounts. Ratepayers have funded the FIT reserve balance to offset current tax expense, at some future date, when the net income for tax purposes exceeds the calculated financial accounting net income. At a minimum, it would be appropriate for the accumulated FIT amounts in the reserve to be refunded to ratepayers when that occurs, regardless of whether ATCO Electric continues to collect FIT expense. In addition, Schedule 5 – Summary of utility income tax, in Rule 005⁸³ requires utilities to report on their permanent differences. The MFRs filed with a utility's tariff application should provide detailed support of the information disclosed in that utility's Rule 005 submissions.

114. ATCO Electric is directed in its compliance filing to this decision, and on a go-forward basis, to continue to present its tax schedules identifying permanent and temporary differences. This also includes presenting the equity portion of the AFUDC tax adjustment as a permanent difference.

6 Other – Proceeding efficiencies

115. The Commission continues to emphasize the importance of increasing regulatory efficiency. It has implemented a number of changes to its application review processes, including its GTA review process. Examples of the Commission's efforts in the current proceeding include the use of an issues list, establishing a limit on the number of IRs, limiting parties to one round of IRs, encouraging parties from the start of the proceeding process to pursue – to the extent possible – a negotiated settlement of the issues, holding a virtual process meeting regarding ATCO Electric's request for an extension to respond to IRs, undertaking a fully written evidentiary process, and the use of oral argument and reply argument.

116. The Commission emphasizes, however, that regulatory efficiency is a shared responsibility and the ability to achieve a more streamlined regulatory process requires effort and commitment by the Commission, applicants and interveners. For certain portions of ATCO Electric's application, the record was sufficient to support ATCO Electric's applied-for amounts. However, the Commission also identified deficiencies in the information on the record and was

⁸² Exhibit 27062-X0014.02, application, PDF page 174.

⁸³ Rule 005: *Annual Reporting Requirements of Financial and Operational Results*, Appendix 1 – Schedules for an electric utility.

required to request information to consider ATCO Electric's application complete, such as missing business cases and missing IT cost information.

117. The Commission also notes that there were instances where information was ultimately provided, but not without significant process. An example of this is the Commission granting ATCO Electric approximately one month to revise its application for updates to the applied-for inflation factors and fuel prices, even though ATCO Electric should have filed its application using the inflation factors and fuel prices that it considered would result in just and reasonable rates when its application was first submitted. In addition, in its November 21, 2022, letter, the Commission identified a number of responses that required further and better responses, and also provided ATCO Electric further opportunity to provide more substantive responses to other Commission IRs that it deemed to be deficient or created factual discrepancies and further questions.⁸⁴

118. The Commission has no statutory obligation to provide ATCO Electric the opportunity to repair its deficient responses to IRs or even to point them out after they have been made. ATCO Electric should consider the opportunity provided by the Commission to supplement responses an exception, and not an expectation going forward. The Commission expects that an applicant will provide all information necessary to support its requests in its application and will fully respond to all Commission IRs at the first instance or to clearly explain if the information cannot be provided. The onus is on ATCO Electric to show that its forecast tariffs are just and reasonable, and it must provide the necessary supporting evidence to make its case.

119. In the following two subsections, the Commission describes, as specifically as possible, what better information ATCO Electric must provide should it seek approval of costs for similar projects or programs in future GTAs. The Commission's intention is not to encourage ATCO Electric to file a greater volume of information. Rather, it is to ensure that future proceedings are more efficient, which requires a record that contains the specific and relevant information necessary for the Commission and parties to test the applied-for revenue requirement amounts and for the Commission to be able to more efficiently and effectively adjudicate ATCO Electric's GTAs.

6.1 Capital information

120. The Commission observed, in its initial review of ATCO Electric's application, that some of ATCO Electric's capital program business cases lacked specific information to evaluate their reasonableness. In several instances, ATCO Electric's business cases for individual projects also included several subprojects. However, in other instances, ATCO Electric aggregated the costs of several subprojects into a single line item identified as a capital expenditure (on a project level and not on a subproject level). This type of aggregation impairs the ability of the Commission and parties to scrutinize ATCO Electric's forecast costs.

121. In its July 13, 2022, letter,⁸⁵ the Commission directed ATCO Electric to provide the following supplemental information for each capital program, consistent with the requirements of Bulletin 2006-25:⁸⁶

⁸⁴ Exhibit 27062-X0442, Process for further and better responses to Commission information requests.

⁸⁵ Exhibit 27062-X0242, AUC letter - Further process.

⁸⁶ Bulletin 2006-25, Announcing the Approval in Principle of the Form and Content of a Uniform System of Accounts and Minimum Filing Requirements for Alberta Electric Utilities, July 12, 2006.

- (i) CWIP continuity schedule consisting of opening CWIP balances;
- (ii) capital expenditures;
- (iii) capital additions; and
- (iv) closing CWIP balances detailed and identified by each individual project name (and subproject if multiple subprojects are included within a business case), and the applicable project number for all capital categories (transmission capital maintenance, Telecommunication, Supervisory Control and Data Acquisition/ Energy Management System, Direct General Property Plant and Equipment, Software, Buildings).

122. In response, ATCO Electric indicated that the detail requested by the Commission, by project level, was not available for every individual subproject identified in its Business Cases. ATCO Electric was able to provide additional detail in response to the request that was consistent with the level of detail that AltaLink was able to provide in its 2022-2023 GTA. ATCO Electric stated in order to provide the level of detail by each individual project or program identified in its Business Cases, it would have been required to update its Project Management and Regulated Project Accounting processes and procedures, and as a result the requested level of information would only be available for the year 2023 and beyond.⁸⁷

123. ATCO Electric is directed to provide the project CWIP continuity schedules as requested by the Commission in its July 13, 2022, letter,⁸⁸ in all future GTA submissions.

6.2 Shared services, head office and common group allocations

124. In this proceeding, the Commission sought to obtain head office and shared services group information through the IR process. ATCO Electric stated it required additional time to respond. In a virtual process meeting, held October 20, 2022, to discuss ATCO Electric's extension request, ATCO Electric made submissions about the scope of work required by ATCO Electric employees and the need to co-ordinate with ATCO Electric's affiliates to complete the responses.⁸⁹

125. Given the past Commission direction, quoted below, the Commission expected ATCO Electric to have the information that was requested in the IRs readily available.

126. In Decision 22859-D01-2018,⁹⁰ the Commission stated:

49. As noted above, the Commission did not find credible ATCO Electric - Transmission's explanation that it could not reconcile its updated placeholder amounts to the requested common group compliance filing amounts. In this regard, ATCO Electric has not met its onus. The limited information detailing the substantive adjustments that occurred in creating and supporting the entire pool of "common group" FTEs and costs is inadequate in justifying the portion of costs allocated to ATCO Electric's transmission

⁸⁷ Exhibit 27062-X0243, AET Letter enclosing Supplemental Information.

⁸⁸ Exhibit 27062-X0242, AUC letter - Further process.

⁸⁹ Exhibit 27062-X0328, AUC letter - Ruling on ATCO Electric's request for time extension to file responses to information requests.

⁹⁰ Decision 22859-D01-2018: ATCO Electric Ltd. Transmission Common Group Compliance Filing, Proceeding 22859, March 20, 2018, paragraph 49.

function. The Commission acknowledges that ATCO Electric - Distribution is under performance-based regulation (PBR) and is only subject to minimum filing requirement (MFR) schedules. However, further information about common costs is required in future GTAs to support the costs allocated to ATCO Electric - Transmission. **ATCO Electric Ltd. is directed, on a go-forward basis, to provide all cost-information for every ATCO affiliate, comprising the total costs and supporting detail, that substantiate and justify the costs allocated to, or from, ATCO Electric's transmission function.**⁹¹
[footnotes removed; emphasis added]

127. The Commission also notes that ATCO Electric's responses to some shared services and head office IRs were deficient. In particular, ATCO Electric's response to an IR asking it to describe new initiatives and services gave no indication of how the identified work or initiative related to transmission utility service.

128. The Commission expects that this information will be provided in compliance with the above direction in ATCO Electric's future GTAs. Should that not be the case, and to promote regulatory efficiency, the Commission cautions ATCO Electric that it may apply Section 6.3 part (b) or (c), of Rule 001 where information that is the subject of an ongoing direction or is otherwise fundamental to its GTA, is not provided as part of its application filings.⁹²

7 Order

129. It is hereby ordered that:

- (1) ATCO Electric submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before June 12, 2023. As detailed in Decision 26573-D01-2023, ATCO Electric is to incorporate the findings, conclusions and directions of the Commission in that decision together with its compliance filing to the Commission's determinations in this decision.

Dated on May 5, 2023.

Alberta Utilities Commission

(original signed by)

Kristi Sebalj
Vice-Chair

⁹¹ Decision 22859-D01-2018: ATCO Electric Ltd., Transmission Common Group Compliance Filing, Proceeding 22859, March 20, 2018, PDF pages 16-17.

⁹² Rule 001: *Rules of Practice*.

(original signed by)

Matthew Oliver, CD
Commission Member

(original signed by)

Vera Slawinski
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ATCO Electric Ltd. (ATCO Electric or AET) Bennett Jones LLP Osler, Hoskin & Harcourt LLP
Consumers' Coalition of Alberta (CCA) J. Wachowich, KC Bema Enterprises LTD. Emrydia Consulting Corporation
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP InterGroup Consultants
The City of Calgary (Calgary) McLennan Ross Barristers & Solicitors
Industrial Power Consumers Association of Alberta Richard Penn
City of Grande Prairie Michelle Gairdner

Alberta Utilities Commission
Commission panel
K. Sebalj, Vice-Chair
M. Oliver, CD, Commission Member
V. Slawinski, Commission Member
B. Romaniuk, Acting Commission Member
Commission staff
J. Graham (Commission counsel)
C. Strasser
A. Starkov
E. Chu
E. Davis
L. Mullen

Appendix 2 – Virtual oral argument and reply argument – registered appearances

Name of organization (abbreviation) Name of counsel or representative
ATCO Electric Ltd. (ATCO Electric or AET) Deirdre Sheehan
Consumers' Coalition of Alberta (CCA) James Wachowich, KC
Office of the Utilities Consumer Advocate (UCA) Thomas Marriott, KC Keegan Rutherford
The City of Calgary (Calgary) Douglas Evanchuk

Appendix 3 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Commission directs ATCO Electric to submit a compliance filing that reflects the findings, conclusions and directions of the Commission in this decision on or before June 12, 2023. paragraph 13
2. The Commission directs ATCO Electric to maintain the reserve account treatment for 2023, but approves the elimination of the vegetation management reserve beginning in 2024. This transition period will permit the Commission to monitor the vegetation management program to ensure continued alignment of forecast and actual costs and work volumes at the time of the next GTA. For all test period years in the current and next GTA, ATCO Electric is directed to provide the same information that it filed in response to 27062-X0416, updated for the appropriate years. Should significant variances reoccur in the costs and volumes for ATCO Electric’s vegetation management program, the Commission may reinstate the past reserve treatment. paragraph 46
3. The Commission finds that the \$7.5 million of undepreciated capital cost connected with Jasper Palisades switchgear assets is not recoverable from current ratepayers and is a permanent capital disallowance. ATCO Electric is directed to remove the historical cost and accumulated depreciation related to these assets from the accounting records of its regulated utility assets. paragraph 107
4. ATCO Electric is directed in its compliance filing to this decision, and on a go-forward basis, to continue to present its tax schedules identifying permanent and temporary differences. This also includes presenting the equity portion of the AFUDC tax adjustment as a permanent difference. paragraph 114
5. ATCO Electric is directed to provide the project CWIP continuity schedules as requested by the Commission in its July 13, 2022, letter, in all future GTA submissions. paragraph 123

Appendix 4 - NSA

[\(return to text\)](#)



Appendix 4 - NSA

(consists of 23 pages)

NEGOTIATED SETTLEMENT AGREEMENT

ATCO ELECTRIC LTD. 2023-2025 GENERAL TARIFF APPLICATION

THIS NEGOTIATED SETTLEMENT AGREEMENT for the negotiated settlement of the 2023-2025 General Tariff Application, which is the subject of Alberta Utilities Commission Proceeding No. 27062, is made and entered into as of **January 19, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("AET")

- and -

CONSUMERS' COALITION OF ALBERTA (the "CCA")

- and -

**OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the
"UCA")**

- and -

THE CITY OF CALGARY ("Calgary")

- and -

**INDUSTRIAL POWER CONSUMERS ASSOCIATION OF
ALBERTA ("IPCAA")**

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a "**Party**" and collectively, the "**Parties**"

WHEREAS:

- A. AET ("the **Applicant**") submitted its 2023-2025 General Tariff Application ("**Application**") to the Alberta Utilities Commission ("**AUC**" or "**Commission**") on May 19, 2022 for the purpose of

obtaining approval for its revenue requirement for the 2023-2025 Test Period, which is the subject of AUC Proceeding No. 27062;

- B. On May 26, 2022, the Commission issued a Notice of Application informing potentially interested parties that it would be considering the Application, and inviting submissions for participation in AUC Proceeding 27062;
- C. The CCA, the UCA, Calgary, IPCAA and Grande Prairie (collectively, the "**Intervenors**") are participants in Proceeding 27062;
- D. On August 5, 2022, the Commission issued an initial process schedule and an issues list for Proceeding 27062 and provided its approval for the Parties to enter into a negotiated settlement process under AUC Rule 018. The Commission directed that:
 - (i) the following issues be excluded from the negotiated settlement process: (a) removal of the Vegetation Management reserve; and (b) Modifications to the Variable Pay Program reserve; and
 - (ii) if the Parties negotiated on full-time equivalents ("**FTEs**"), then the negotiated settlement agreement identify whether the FTE adjustment was made to capital FTEs or to operations and maintenance ("**O&M**") FTEs, and which O&M USA the adjustment is applicable to.
- E. AET filed supplemental information for the Application on July 28, 2022 and an application update on September 6, 2022;
- F. AET responded to information requests from the AUC and the Intervenors on October 18 and November 4, 2022, with further responses provided on November 14-15, 18, and 25, 2022;
- G. The Intervenors filed evidence on December 2, 2022;
- H. The Parties (AET, the CCA, the UCA, Calgary, IPCAA and Grande Prairie) entered into a negotiated settlement process commencing with a preliminary meeting on September 16, 2022, with settlement negotiations taking place from December 12 through 20, 2022;
- I. On December 20, 2022, the Parties reached an agreement in principle for a negotiated settlement on all elements of AET's 2023-2025 GTA, except for specifically excluded matters identified in section 2 below;
- J. The term of this settlement is the 2023-2025 Test Years Period ("**Test Period**").

IN CONSIDERATION of the mutual promises made in this negotiated settlement agreement ("**Settlement Agreement**") and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Scope of this Settlement Agreement**

- (a) This Settlement Agreement settles all aspects of and relief requested in the Application, except for the Excluded Items identified in section 2 below.

- (b) Unless otherwise agreed by the Parties in writing, if the AUC declines to approve this Settlement Agreement in its entirety, the Settlement Agreement will be of no force and effect, in accordance with Section 135 of the *Electric Utilities Act*.

2. Excluded Matters

- (a) AET and the Interveners agree that the following matters are specifically excluded from this Settlement Agreement:
 - (i) the removal of the Vegetation Management reserve;
 - (ii) modifications to the Variable Pay Program reserve; and
 - (iii) Issue 8(b) from the Commission's approved Issues List - Proposed treatment of the one-time depreciation adjustment for the Jasper Palisades Isolated Generation Plant of depreciation related to the Jasper Palisades Isolated Generation Plant;

collectively referred to herein as the "**Excluded Matters**".

3. Revised Revenue Requirement

- (a) The overall revenue requirement adjustments agreed to in this Settlement Agreement are set out in Schedule 3-1 attached hereto as Appendix "A".
- (b) Revised Minimum Filing Requirement ("**MFR**") schedules that reflect the specific adjustments and modifications agreed to herein are attached hereto as Appendix "A". A Summary of Changes to AET's Revenue Requirement is attached as Appendix "B" to this Settlement Agreement.
- (c) Except for the Excluded Matters, the Parties agree that the AUC should approve the Application, with the specific adjustments and modifications identified in this Settlement Agreement and in Appendix "A" hereto. The Parties agree to support AET's application to the AUC for approval of this Settlement Agreement.

4. Specific Adjustments and Modifications

- (a) **Errors and Omissions:** In addition to the adjustments and modifications identified herein, the revenue requirement shall reflect AET's correction of errors and omissions described in AET's response to AET-AUC-2022SEP21-130 filed on the record of Proceeding 27062.
- (b) **Diesel Fuel Volume Forecast:** The forecast diesel fuel volumes set out in Table 4.2 of the Application, with the corrections identified in response to AET-AUC-2022SEP21-105(d), will be reduced by 5% in each year of the Test Period.
- (c) **Fuel Price Deferral Account:** A fuel price deferral account, as proposed in the Application, will be implemented for the Test Period.
- (d) **Vacancy Rate:** AET will apply a vacancy rate of 5% in each year of the Test Period. A schedule identifying the impact of the 5% vacancy rate to capital FTEs and O&M FTEs, and to O&M USAs, is attached hereto as Appendix "C".

- (e) **Inflation Assumptions ("Other"):** Forecast inflation assumptions for "Inflation - Other" will be 4.4% in 2023, 3.0% in 2024, and 2.2% in 2025.
- (f) **Information Technology ("IT") Transition Costs:** The Parties agree to the implementation of a temporary deferral account for potential IT transition costs following a competitive bidding process for IT managed services in advance of the expiry of the current IBM/Kyndryl MSA in 2025 as described in the Application, with a placeholder amount of \$0.00 for such costs in the Test Period. The deferral account will have an opening balance of \$0 and the disposition of any non-zero balance in this deferral account will be reviewed as part of AET's next general tariff application, including the prudence and recovery of any such costs incurred in AET's revenue requirement.
- (g) **Supervision and Engineering (USA Acct No. 560):** Forecast costs for USA 560 will be \$3.3 million in 2023, \$3.4 million in 2024, and \$3.5 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.
- (h) **Control Centre Operations (USA Acct No. 561):** Forecast costs for USA 561 will be \$5.4 million in 2023, \$5.6 million in 2024, and \$5.8 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.
- (i) **Station Equipment Expenses (USA Acct No. 562):** Forecast costs for USA 562 will be \$9.9 million in 2023, \$10.0 million in 2024, and \$10.1 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.
- (j) **Insurance Premiums (USA Acct No. 924):** Forecast costs for insurance premiums included in USA 924 will be \$5.3 million for 2023, \$5.4 million for 2024, and \$5.6 million for 2025.
- (k) **Variable Pay Program ("VPP"):** Forecast VPP for the Test Period will be \$4.5 million in 2023, \$4.6 million in 2024, and \$4.7 million in 2025.
- (l) **In-scope Salaries:** Forecast in-scope salary inflation will be 1.0% in 2022, 2.5% in 2023, 3.0% in 2024, and 1.8% in 2025.
- (m) **Out-of-Scope Salaries:** Out-of-scope salary inflation will be 2.9% in 2022, 2.9% in 2023, 2.5% in 2024, and 2.5% in 2025.
- (n) **Income Tax:** AET agrees to expand the scope of its current deferral account for statutory tax rates during the Test Period, to include changes to income tax legislation or policy that relate to the ability to claim accelerated capital cost allowance ("ACCA"), including if the ability to claim ACCA is discontinued or enhanced. To clarify, this deferral will capture such changes to non-direct assigned capital only, as direct assigned capital tax impacts are currently captured in the direct assigned capital deferral account.
- (o) **Shared Services FTEs:** Forecast pre-allocated Shared Services Innovation Function FTEs will be 10.4 FTEs in each year of the Test Period, consistent with 2021 actuals. Forecast pre-allocated Shared Services Indigenous and Government Relations & Sustainability Function FTEs will be 11.0 FTEs in each year of the Test Period, consistent with FTE

levels approved in Proceeding 24964. The impact of these FTE adjustments to capital FTEs and O&M FTEs, and to O&M USAs, is included in Appendix "C" attached hereto.

- (p) **Additions to Opening 2023 Rate Base for 2022 Forecast IT Capital:** Forecast 2022 additions to GP&E Software opening rate base will be \$12.3 million.
- (q) **General Reductions in Operating Costs:** AET's applied-for forecast operating costs shall reflect a reduction in the amount of \$0.25 million for each year in the Test Period. This reduction is not tied to any specific USA account or accounts, but is a holistic reduction that AET may apply to any operating expense, USA account or accounts as it sees fit. For presentation purposes, AET has included this adjustment within USA 566.
- (r) **Project 57259 ("PENVTD"):** The forecast capital addition of \$60.1 million associated with PENVTD will be removed from the Test Period.
- (s) **Project 58112 ("CETO"):** For the purpose of setting interim rates for the Test Period, AET agrees to remove the financial impact of the forecast \$141.1 million addition for the December 2025 energization of CETO Project from the Application. For clarity, AET's deferral application to establish the final revenue requirement related to CETO Project will be based on and include the financial impacts of the actual in-service date of the CETO Project.
- (t) **Transmission Capital Maintenance ("TCM") and General Property and Equipment Projects ("GPE"):** AET agrees to an overall reduction of 7.5% to its combined TCM and GPE capital forecast over the Test Period and a one-time reduction of \$2 million in 2023 to its combined TCM and GPE capital forecast. These reductions are not tied to any specific project or program, but are holistic reductions that AET may apply as it sees fit. AET shall retain discretion to manage the forecast reduction from projects or programs in assessing the impact on the safety and reliability of its assets.
- (u) **Federal Future Income Taxes ("FIT"):** AET will discontinue the collection of Federal FIT as applied-for in the Application, and AET will refund \$30 million of previously collected FIT in each year of the Test Period.
- (v) AET has assessed and confirms that the reductions in revenue requirement identified herein, according to the facts currently known by AET and to the best of AET's knowledge, will not compromise the provision of safe and reliable transmission service during the Test Period.

5. Prospective Commitments

- (a) AET will conduct an analysis of property insurance level of deductibles and potential self-insurance and present the findings of this analysis in its next general tariff application.
- (b) AET will present a refund strategy in its next general tariff application for refunding the remaining FIT reserve balance.
- (c) AET agrees to review its existing risk assessment for Capital Maintenance programs, including enhancements to the numerical quantification of costs and benefits, and to report on this review in its next general tariff application. This review will focus on at least five new or existing sub-programs forecast in the next general tariff application test period.

- (d) AET's operations and maintenance forecasts are activity-based. AET agrees to review and examine the level of detail provided to support its activity-based forecasts for USA 560, 561, 562 and 563/9. AET agrees to provide additional detail supporting these activity-based forecasts in its next general tariff application. Such additional details will include activities, activity volumes, time and costs to complete the activities, as applicable.
- (e) AET will review and examine the data, the data's integrity, and its current processes supporting the Transmission Line to Ground Clearance Mitigation ("LGCM") and the Cross-Arms and Insulator Replacement programs and provide an update on its findings in its next general tariff application. The update will include additional explanation of how such data will be used in the next general tariff application test period to support the strategies chosen to correct LGCM issues and for cross-arm and insulator replacements, or if not used, a full justification as to why not.
- (f) AET agrees to develop and maintain a contamination map of its service area depicting zones of contamination and insulation values based on IEC 60815-1-2-3, and to present the findings of such map and the associated potential implications for future transmission capital maintenance and operations and maintenance costs in the next general tariff application. Forecast costs for Project 50020 will be increased by \$0.3 million in 2023 to fund the development of the contamination map.
- (g) AET agrees to provide additional detail regarding the value engineering (whether different methods can be identified to provide the required function, and an assessment of the tradeoff between cost, risk and performance in evaluating alternatives) applied to LGCM, significant cross-arms and insulator replacements, and line rebuilds in its next general tariff application.
- (h) AET agrees that, before undertaking any broad mitigation application to address performance issues of synthetic or polymer insulation effects, where Corona Rings are a potential solution, it will complete a full electrical and mechanical assessment by an independent lab on such suspect insulation according to specific manufacturer and specific insulator type before any installation of Corona Rings on synthetic or polymer insulators. AET agrees to report the results of these activities (if any) in its next general tariff application. The commitment is intended to capture a larger application of corona rings (for instance an entire line that has polymer/ synthetic lines performance issues) as opposed to mitigation of unique or isolated structures.
- (i) AET agrees to provide the detailed information on total IT expenditures in one place in its next GTA, as was directed in Decision 26616-D01-2022 paragraph 390, for the ATCO Distribution Utilities. This information will include information on total IT expenditures (including IT O&M (direct, shared services, head office), and IT capital (including additions, indirect and direct capital)), the MFR accounts in which these costs are recorded, an identification of all IT corporate costs, and the method used to allocate IT costs to ATCO distribution and transmission utilities.
- (j) AET will review and report on any savings or reduction to costs in the 2023-2025 Test Period realized from Project 82664 and Project 82660, in its next general tariff application.

6. Prudence

- (a) The Parties agree that nothing in this Settlement Agreement, including the reductions to the 2023-2025 GTA revenue requirement, is an admission by AET that those revenue requirement amounts are imprudent. The Parties further agree that no Party may rely on anything in this Settlement Agreement as evidence in any future proceeding that any revenue requirement amounts are either prudent or imprudent.

7. Confidentiality and Privilege Without Prejudice

- (a) The negotiated settlement reflected in this Settlement Agreement is a compromise and was reached in part as a result of the desire of the Parties to avoid the significant resources associated with a fully litigated process. This Settlement Agreement is for the purpose of AET's 2023-2025 GTA only, unless expressly stated otherwise, and it is without prejudice to the positions that any of the Parties may take in any subsequent negotiations and regulatory proceedings. For greater clarity, the Parties' proposal, which was accepted by the Commission, to not expend resources on advancing the preparation and filing of Information Request responses and rebuttal evidence on the issues included in this Settlement Agreement, does not constitute an admission by any Party that it accepts or agrees with the positions or evidence advanced in intervenor evidence or information requests.
- (b) All discussions among the Parties during the negotiated settlement process are privileged and confidential, and no matter discussed and no information provided during the negotiated settlement process may be disclosed to any person or to the AUC without the express written consent of all Parties.

8. General

- (a) Each Party represents that it has not withheld relevant information.
- (b) The Parties agree that proper notice of the negotiated settlement process was provided to all interested parties.
- (c) The Parties further agree:
 - (i) The division of this Settlement Agreement into headings and paragraphs is for convenience and reference only and should not affect the interpretation or construction of this Settlement Agreement.
 - (ii) This Settlement Agreement sets out the entire understanding and agreement of the Parties and there are no representations, warranties, covenants, conditions or other agreements, express or implied, collateral, statutory or otherwise, among the Parties in connection with the subject matter of this Settlement Agreement except as specifically set out herein.
 - (iii) Any alteration or amendment of this Settlement Agreement must be in writing and signed by the Parties. This Settlement Agreement will be binding upon and inure to the benefit of the Parties and each of their respective successors and permitted assigns. A Party may not assign their rights and/or obligations under this Settlement Agreement without the consent of all other Parties, provided such

consent is not unreasonably withheld. This Settlement Agreement may be executed in any number of counterparts.

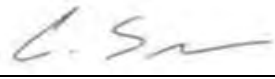
- (iv) This Settlement Agreement is to be interpreted pursuant to the laws of the Province of Alberta.
 - (v) If any provision of this Settlement Agreement is found to be invalid by a court of law, this Settlement Agreement will be read and interpreted as if the provision were omitted.
 - (vi) The failure of any Party to exercise any right, power or option given to it under this Settlement Agreement or to insist upon the strict compliance with any of the terms or conditions in this Settlement Agreement will not constitute a waiver of any provision with respect to any other or subsequent breach.
 - (vii) Unless otherwise stated, any dollar amounts, prices or amounts stated in this Settlement Agreement are in the lawful currency of Canada.
 - (viii) Unless otherwise stated, all accounting matters or terms in this Settlement Agreement will be interpreted and construed in accordance with International Financial Reporting Standards.
 - (ix) References to any statute, legislation or regulation include all subsequent additions, amendments, re-enactments or replacements enacted from time to time during the period covered by this Settlement Agreement.
- (d) This Settlement Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

2023-2025 General Tariff Application and Negotiated Settlement Agreement
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IN WITNESS WHEREOF, the Parties have duly executed this Settlement Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per: 

Name: Corinne Severson
Title: Vice President, Regulatory

Per: 

Name: Melanie Bayley
Title: President ATCO Electric

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name:
Title:

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

Per: _____
Name:
Title:

THE CITY OF CALGARY

Per: _____
Name:
Title:

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

Per: _____
Name:
Title:

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

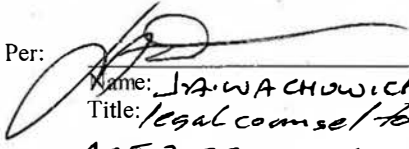
9 of 9

IN WITNESS WHEREOF, the Parties have duly executed this Settlement Agreement as of the date set out above.

ATCO ELECTRIC LTD.

CONSUMERS' COALITION OF ALBERTA

Per: _____
Name: _____
Title: _____

Per:  _____
Name: J.A. WACHOWICZ
Title: legal counsel to CCA
AET 2023-2025 GTA
I.D. 27062 / Jan 20 2023

Per: _____
Name: _____
Title: _____

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

2023-2025 General Tariff Application and Negotiated Settlement Agreement
9 of 9

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Per: _____
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Per: _____
Name:
Title:

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: C. W. Hunt
Name: Chris Hunt
Title: Executive Director, UCA

Per: _____
Name:
Title:

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

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9 of 9

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Per: _____
Name: _____
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Per: _____
Name: _____
Title: _____

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

Per: 
Name: E. Lynne Davies
Title: Director - Law on behalf of the City Solicitor & General Counsel

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

CITY OF GRANDE PRAIRIE

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Name: _____
Title: _____

Per: _____
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Title: _____

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Title: _____

Per: _____
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Title: _____

**OFFICE OF THE UTILITIES CONSUMER
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THE CITY OF CALGARY

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Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

Richard Penn
Executive Director
IPCATA

9 of 9

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Title: _____

**OFFICE OF THE UTILITIES CONSUMER
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THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: 
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAjG7vm11Q1w0BT5ynoqTio1gacYoU5cX0X

WSLEGAL\008794\0300\33365887v1

AMENDING AGREEMENT

ATCO ELECTRIC LTD. 2023-2025 GENERAL TARIFF APPLICATION

THIS AMENDING AGREEMENT is made and entered into as of **January 31, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("AET")

- and -

CONSUMERS' COALITION OF ALBERTA (the "CCA")

- and -

**OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the
"UCA")**

- and -

THE CITY OF CALGARY ("Calgary")

- and -

**INDUSTRIAL POWER CONSUMERS ASSOCIATION OF
ALBERTA ("IPCAA")**

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a **"Party"** and collectively, the **"Parties"**

WHEREAS:

- A. The Parties entered into a Negotiated Settlement Agreement made as of January 19, 2023 (the **"Settlement Agreement"**) in respect of the negotiated settlement of the Application, which is the subject of AUC Proceeding No. 27062 (the **"Proceeding"**);
- B. On January 25, 2023, the Commission issued an information request to AET which raised questions regarding provision 4(u) of the Settlement Agreement related to Federal Future Income Taxes (**"FIT"**);
- C. Having reviewed such information request, AET acknowledges the presentation of the proposed FIT refund in the Settlement Agreement, including Appendix "A", did not properly account for the income tax impact of the FIT refund;

- D. In order to address this, the Parties have agreed to enter into this Amending Agreement pursuant to the terms and conditions contained herein.

IN CONSIDERATION of the mutual promises made in this Amending Agreement and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Definitions**

- (a) Unless otherwise specified herein or unless otherwise required by the context hereof, capitalized terms utilized herein, including the recitals hereof will have the meanings given to them in the Settlement Agreement.

2. **Amendments to the Settlement Agreement**

- (a) The Settlement Agreement is hereby amended as follows:
- (i) Section 4(u) of the Settlement Agreement: Section 4(u) of the Settlement Agreement is amended by deleting the paragraph in its entirety and replacing it with the following:
- "(u) Federal Future Income Taxes ("FIT"):** AET will discontinue the collection of FIT as applied-for in the Application, and AET will refund previously collected FIT of \$22.9 million in 2023, \$22.5 million in 2024 and \$22.1 million in 2025, and reflect the resulting impacts of such refunds on income tax expense and return on rate base in revenue requirement in each year of the Test Period."
- (ii) Appendix "A" to the Settlement Agreement: Appendix "A" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix A – Revised MFRs Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0496.01.
- (iii) Appendix "B" to the Settlement Agreement: Appendix "B" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix B – Summary of Changes to Rev Req Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0497.01.

3. **General**

- (a) **Continuity:** The provisions of the Settlement Agreement shall, save as amended by this Amending Agreement, continue in full force and effect, and shall be read and construed as one document with this Amending Agreement.
- (b) **Governing Law:** Section 8(c)(iv) of the Settlement Agreement shall apply to this Amending Agreement *mutatis mutandis*.
- (c) **Counterparts:** This Amending Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if

2023-2025 General Tariff Application and Negotiated Settlement Agreement

3 of 4

all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

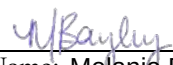
IN WITNESS WHEREOF, the Parties have duly executed this Amending Agreement as of the date set out above.

ATCO ELECTRIC LTD.

CONSUMERS' COALITION OF ALBERTA

Per: 
 Name: Corinne Severson
 Title: Vice President, Regulatory

Per: _____
 Name: _____
 Title: _____

Per: 
 Name: Melanie Bayley
 Title: President, Electric

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

THE CITY OF CALGARY

Per: _____
 Name: _____
 Title: _____

Per: _____
 Name: _____
 Title: _____

INDUSTRIAL POWER CONSUMERS ASSOCIATION OF ALBERTA

CITY OF GRANDE PRAIRIE

Per: _____
 Name: _____
 Title: _____

Per: _____
 Name: _____
 Title: _____

4 of 4

IN WITNESS WHEREOF, the Parties have duly executed this Amending Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per: _____

Name:

Title:

Per: _____

Name:

Title:

CONSUMERS' COALITION OF ALBERTA

Per: _____

Name:

Title:

JAMES A. WACHOWICH
Legal Counsel to CCA
27062 Amended NSA - Ycopy
Jan 31/2023

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

Per: _____

Name:

Title:

THE CITY OF CALGARY

Per: _____

Name:

Title:

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

Per: _____

Name:

Title:

CITY OF GRANDE PRAIRIE

Per: _____

Name:

Title:

2023-2025 General Tariff Application and Negotiated Settlement Agreement
4 of 4

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Name:
Title:

Per: _____
Name:
Title:

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: C. W. Hunt
Name: Chris Hunt
Title: Executive Director, UCA

Per: _____
Name:
Title:

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
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4 of 4

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Per: _____
Name:
Title:

Per: _____
Name:
Title:

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: _____
Name:
Title:

Per:  _____
Name: Lynne Davies
Title: Director, Law by delegated
authority from the City Solicitor's
General Counsel

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
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4 of 4

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OFFICE OF THE UTILITIES CONSUMER
ADVOCATE

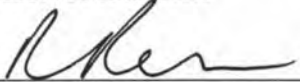
THE CITY OF CALGARY

Per: _____
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INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA

CITY OF GRANDE PRAIRIE

Per: 
Name: _____
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Richard Penn
Executive Director - IPCAA

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**OFFICE OF THE UTILITIES CONSUMER
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THE CITY OF CALGARY

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Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: 
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAkFrhWszNt6P8mW1Ju32ms31QTW7QDhgg



January 23, 2023, as updated February 3, 2023

Alberta Utilities Commission
Eau Claire Tower
1400, 600 Third Avenue S.W.
Calgary, Alberta T2P 0G5

**Attention: Cameron Strasser
Lead Application Officer**

**Re: ATCO Electric Transmission (AET)
2023-2025 General Tariff Application (2023-2025 GTA)
Proceeding 27062
Negotiated Settlement Agreement (Settlement Agreement)**

Pursuant to Rule 018: Rules on Negotiated Settlements, enclosed for the Alberta Utilities Commission's (Commission or AUC) consideration are the following:

1. An application for approval of the negotiated settlement in respect of AET's 2023-2025 GTA, as encompassed in the Negotiated Settlement Agreement executed by AET, the Consumers' Coalition of Alberta, the Office of the Utilities Consumer Advocate, the City of Calgary, the Industrial Power Consumers Association of Alberta, and the City of Grande Prairie; and
2. A copy of the Negotiated Settlement Agreement, including the following Appendices:
 - a. Appendix A – Revised 2023-2025 GTA MFR Schedules;
 - b. Appendix B – Summary of Changes to Revenue Requirement; and
 - c. Appendix C – Summary of Changes to FTEs.

AET acknowledges that per the Commission's correspondence of December 22, 2022,¹ AET was to file the Settlement Agreement on January 20, 2022. AET advised the Commission on January 20, 2023² the signing of the Settlement Agreement was delayed until January 23, 2023, due to a delay in signing by the City of Calgary.

¹ Exhibit 27062-X0487.

² Exhibit 27062-X0492.



February 3, 2023 Update

Amending Agreement and Revised Exhibits

As discussed in AET's response to the Commission's Information Request AET-AUC-2023JAN25-001,³ the presentation of the proposed Federal Future Income Taxes ("FIT") refund in the Settlement Agreement, including Appendix "A", did not properly account for the income tax impact of the FIT refund. To address this, the Parties to the Settlement Agreement have agreed to enter into an Amending Agreement that amends section 4(u) and Appendices "A" and "B" of the Settlement Agreement.

As a result, AET is filing the following revised Exhibits:

- (a) This Exhibit 27062-X0495.01: AET 2023-2025 GTA Negotiated Settlement Agreement Amended January 31, 2023;
- (b) Exhibit 27062-X0496.01: Appendix A – Revised MFRs Amended January 31, 2023; and
- (c) Exhibit 27062-X0497.01: Appendix B – Summary of Changes to Rev Req Amended January 31, 2023.

AET has made necessary revisions to the enclosed application for approval of the negotiated settlement, originally filed as part of Exhibit 27062-X0495, in this revised Exhibit 27062-X0495.01.

Clarification Note Regarding the Presentation of Amended Appendices "A" and "B"

Revised Exhibits 27062-X0496.01(BL) and 27062-X0497.01(BL) are the Appendices "A" and "B" that were circulated to and agreed upon by the Parties to the Amending Agreement. Revisions as per the Amending Agreement are blacklined in orange within the aforementioned Exhibits.

As explained in AET's application for approval of the negotiated settlement, enclosed,⁴ the originally-filed version of Exhibit 27062-X0496 was a blackline that uses yellow

³ Exhibit 27062-X0505, PDF pp. 1-4.

⁴ See para. 33.



highlighting to show the differences between the MFR schedules filed in response to AET-AUC-2022SEP21-130⁵ and the MFR schedules generated in accordance with the terms and conditions of the Settlement Agreement. Consistent with the presentation of the originally-filed version, the yellow highlighting in revised Exhibit 27062-X0496.01 shows the differences between the MFR schedules that AET filed in response to AET-AUC-2022SEP21-130⁶ and the revised MFR schedules generated in accordance with the terms and conditions of the amended Settlement Agreement.

Should you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Yours truly,

Heather Goode, CPA, CA
Director, Regulatory

⁵ Exhibit 27062-X0330.02.

⁶ Exhibit 27062-X0330.02.

I. INTRODUCTION

1. ATCO Electric Transmission ("**AET**") applies to the Alberta Utilities Commission ("**AUC**" or "**Commission**") pursuant to sections 134 and 135 of the *Electric Utilities Act*, SA 2003, c E-5.1 ("**EUA**") for approval of a negotiated settlement agreement, as amended January 31, 2023 (the "**Settlement Agreement**", attached to this Application) between AET, the Consumers' Coalition of Alberta ("**CCA**"), the Office of the Utilities Consumer Advocate ("**UCA**"), the City of Calgary ("**Calgary**"), Industrial Power Consumers Association of Alberta ("**IPCAA**"), and the City of Grande Prairie ("**Grande Prairie**" and, collectively with the CCA, UCA, Calgary, and IPCAA, the "**Intervenors**") in respect of AET's 2023-2025 General Tariff Application (the "**2023-2025 GTA**"). AET and the Intervenors are collectively referred to herein as the "**Parties**."

2. This is AET's application for approval of the Settlement Agreement pursuant to AUC Rule 018 – Rules on Negotiated Settlements ("**Rule 018**").

3. As explained herein, AET submits that the negotiated settlement set out in the Settlement Agreement results in just and reasonable rates and that it is in the public interest and not contrary to law. As such, AET respectfully requests that the Commission approve the Settlement Agreement in its entirety.

4. In support of this application, AET relies on the following information and submissions:

- The 2023-2025 GTA and materials filed on the record of Proceeding 27062;
- The Settlement Agreement attached to this application, including its Appendices; and
- The information and submissions contained in this application.



II. PROCEDURAL HISTORY

5. AET submitted the 2023-2025 GTA to the Commission on May 19, 2022, in AUC Proceeding 27062, for the purpose of approving its Revenue Requirement for the 2023-2025 Test Period.

6. The Commission issued a Notice of Application on May 26, 2022. Each of the CCA, UCA, Calgary, IPCAA, and Grande Prairie submitted Statements of Intent to Participate in Proceeding 27062.¹

7. On August 5, 2022, the Commission issued an initial process schedule and issues list for Proceeding 27062. It also granted approval for AET and the Interveners to enter into a Negotiated Settlement Process ("**NSP**") pursuant to AUC Rule 018.² The Commission issued two directions with respect to the NSP:

- (a) that the following issues be excluded from the NSP: (i) removal of the Vegetation Management reserve; and (ii) Modifications to the Variable Pay Program reserve (together, the "**Commission Excluded Matters**"); and
- (b) that if AET and the Interveners negotiated on full-time equivalents ("**FTEs**"), then the negotiated settlement agreement identify whether the FTE adjustment was made to capital FTEs or to operations and maintenance ("**O&M**") FTEs, and which O&M USA the adjustment is applicable to.³

8. In its August 5, 2022 Ruling, the Commission set out an NSP timeline and directed AET to file any resulting Negotiated Settlement Agreement or notice that a settlement

¹ Exhibit 27062-X0242.

² Exhibit 27062-X0273, para 27.

³ Exhibit 27062-X0273, para 28.



could not be reached no later than October 28, 2022.⁴ This process was subsequently extended to December 22, 2022.⁵

9. AET filed supplemental information for the Application on July 28, 2022, and an application update on September 6, 2022.⁶

10. AET responded to information requests from the AUC and the Interveners on October 18 and November 4, 2022, with further responses provided on November 14-15, 18, and 25, 2022.⁷

11. The Interveners filed evidence on December 2, 2022 ("**Intervener Evidence**").⁸

12. AET and the Interveners entered into a NSP commencing with a preliminary meeting on September 16, 2022, with settlement negotiations taking place from December 12 through 20, 2022.

13. Extensive negotiations occurred among AET and the Interveners, resulting in all Parties' agreement in principle to a negotiated settlement on December 20, 2022, on all aspects of the Application, with the exception of the Commission Excluded Matters and the following additional matter –

Issue 8(b) from the Commission's approved Issues List - Proposed treatment of the one-time depreciation adjustment for the Jasper Palisades Isolated Generation Plant (the "**Parties Excluded Matter**"). The Commission Excluded Matter and the Parties Excluded Matter are collectively referred to herein as the "**Excluded Matters**."

14. On December 21, 2022, AET formally advised the Commission that a negotiated settlement had been agreed to in principle amongst the Interveners and AET. AET

⁴ Exhibit 27062-X0273, para 29.

⁵ Exhibit 27062-X0328, para 11.

⁶ Exhibits 27062-X0243 to 27062-X0271; Exhibits 27062-X0282 to 27062-X0285.

⁷ Exhibits 27062-X0302 to 27062-X0327; Exhibits 27062-X0329 to 27062-X0362; Exhibit 27062-X0440; Exhibits 27062-X0443 to 27062-X0448.

⁸ Exhibits 27062-X0450 to 27062-X0466, Exhibits 27062-X0468.



requested an extension to January 20, 2022, to allow the Parties additional time to reach agreement on the language and terms of a final written negotiated settlement agreement and to review and complete documentation for AET's submission of the agreement and application to the Commission.⁹

15. In a letter dated December 22, 2022, the Commission approved AET's request to file the Settlement Agreement and application for approval with the Commission on January 20, 2023.¹⁰

III. AET'S SETTLEMENT APPLICATION COMPLIES WITH ALL REQUIREMENTS OF RULE 018

All Participants Had Full Access to All Relevant Information (Section 6(1) of Rule 018)

16. Prior to the Parties commencing settlement negotiations, AET responded to extensive information requests, the Commission made a number of rulings with respect to the 2023-2025 GTA, and the Interveners filed Intervener Evidence. Therefore, in addition to the comprehensive evidence provided by AET in its 2023-2025 GTA, all Parties had the benefit of extensive information discovery through information responses from AET, and the analysis undertaken by Interveners in their Intervener Evidence, to inform the NSP.

17. The Settlement Agreement attached hereto was circulated to and signed by all of the Parties.

18. Section 8(a) of the Settlement Agreement contains a representation that no party has withheld relevant information, in compliance with Section 6(1) of Rule 018.

⁹ Exhibit 27062-X0486.

¹⁰ Exhibit 27062-X0487.



All Interested Parties Had Adequate Notice (Section 6(3)(a) of Rule 018)

19. As set out in Section 8(b) of the Settlement Agreement, AET confirms that proper notice of the NSP was provided to all interested parties.

20. The Commission's approval to initiate the NSP was filed on the public record of Proceeding 27062,¹¹ thereby providing notice of the NSP to all parties interested in the Application and to the public generally. AET invited the Interveners to participate in the NSP, with a first meeting to discuss the NSP held on September 16, 2022. On October 20, 2022, the Commission held a virtual process meeting at which the participants provided the Commission with an update on the NSP. At that meeting, the participants noted that there was benefit in maintaining a NSP in the proceeding schedule and expressed interest to participate in settlement negotiations.¹²

21. Each of the Interveners was given the opportunity to participate fully in the NSP and have their respective issues addressed. All materials filed by AET and the Interveners, including Intervener Evidence, were available to the Interveners prior to the commencement of negotiation discussions.

The Settlement Agreement (Section 6(3)(b) of Rule 018)

22. A copy of the Settlement Agreement resulting from the NSP is attached to this Application.

Details of Issues Not Resolved (Section 6(3)(c) of Rule 018)

23. With the exception of the Excluded Matters, the Parties reached an agreement on all issues relating to AET's 2023-2025 GTA.

24. The details of the Commission Excluded Matters are included in the 2023-2025 GTA at Sections 5.3.21 (removal of the vegetation management reserve account) and 29.1.3 (modifications to the Variable Pay Program reserve), and the details

¹¹ Exhibit 27062-X0273.

¹² Exhibit 27062-X0328, para. 11.



of the Parties Excluded Matter (Jasper Palisades one-time depreciation adjustment) are included in the Application at Section 6.1.¹³

Outline of Issues Where Acceptance is Not Unanimous (Section 6(3)(d) of Rule 018)

25. The Parties reached unanimous agreement on all issues other than the Excluded Matters, as identified above.

The Rates That Will Result From the Settlement (Section 6(3)(e) of Rule 018)

26. The rates that will result from the Settlement Agreement are set out in the Revised 2023-2025 Negotiated Settlement GTA MFR Schedules and Summary of Changes to AET's Revenue Requirement, attached to the Settlement Agreement as Appendix A and Appendix B, respectively. Section VI of this application provides additional explanation regarding the rates that will result from the settlement.

The Text of Any Changes to the Terms and Conditions of Service (Section 6(3)(f) of Rule 018)

27. The Settlement Agreement does not contemplate any changes to the Terms and Conditions of Service.

A Description of Any Outstanding Issues (Section 6(3)(g) of Rule 018)

28. The Settlement Agreement is a comprehensive settlement. The only outstanding issues are the Excluded Matters, each of which is described above and in the above-referenced sections of the 2023-2025 GTA.

29. Through the NSP negotiations, the Parties successfully reached agreement on all other aspects of, and relief requested in the 2023-2025 GTA.

¹³ Exhibit 27062-X0014.02.

Settlement Brief (Section 6(3)(h) of Rule 018)

30. A settlement brief explaining the Settlement Agreement and how it meets the interests of the Parties, and the public interest is contained below in Section IV of this application.

IV. SETTLEMENT BRIEF

A. Basis for Settlement

31. The terms of the negotiated settlement are set forth in the Settlement Agreement, which is attached to this application. As set out in Section 3(c) of the Settlement Agreement, the Parties agree that, except for the Excluded Matters, the Commission should approve the 2023-2025 GTA with the specific adjustments and modifications identified in the Settlement Agreement.

Adjustments to Revenue Requirement

32. The Settlement Agreement, if approved, results in an adjustment to AET's revenue requirement of \$35.2 million, \$38.9 million, and \$41.8 million for the 2023-2025 Test Years respectively, as detailed in Table 1 below.

33. In addition to the above adjustments, the Parties agreed that the revenue requirement, should the Settlement Agreement be approved, will reflect AET's correction of errors and omissions described in AET's response to AET-AUC-2022SEP21-130.¹⁴ As such, Appendix A reflects the MFR schedules filed in response to the above referenced IR and have been blacklined for the specific adjustments and modifications outlined in Section 4 of the NSA.

34. The adjustments and reductions agreed upon in the Settlement Agreement are itemized in Table 1 below and are detailed within Section 4 of the Settlement Agreement:

¹⁴ Exhibit 27062-X0330.02.



Table 1: Summary of AET's Negotiated Settlement Revenue Requirement Reductions (\$Millions)

	2023	2024	2025	Total Test Period	Reference to Settlement Agreement
O&M Negotiated Items					
Diesel Fuel Volume Reduction	(0.3)	(0.3)	(0.3)	(0.8)	4(b)
Vacancy Rate	(0.5)	(0.6)	(0.7)	(1.7)	4(d)
Inflation - In/Out Scope, Contractor and Other	(1.0)	(1.5)	(1.8)	(4.3)	4(e), 4(l), 4(m)
USA 560 - Supervision and Engineering	(0.1)	(0.1)	(0.1)	(0.2)	4(g)
USA 561 - Control Centre Operations	(0.2)	(0.2)	(0.2)	(0.6)	4(h)
USA 562 - Station Equipment Expenses	(0.4)	(0.5)	(0.6)	(1.5)	4(i)
Insurance Premiums	(0.3)	(0.2)	(0.2)	(0.7)	4(j)
Variable Pay Program	(0.6)	(0.7)	(0.8)	(2.2)	4(k)
Shared Services FTE Reduction	(0.2)	(0.2)	(0.1)	(0.5)	4(o)
IT Transition Costs & Reduction of IT Costs per Decision 26616-D01-2022	(0.5)	(4.6)	(1.5)	(6.6)	4(f)
General O&M Reduction	(0.3)	(0.3)	(0.3)	(0.8)	4(q)
Total O&M Negotiated Items	(4.3)	(9.0)	(6.5)	(19.7)	
Capital Negotiated Items					
IT Capital – Reduction to Opening Rate Base	(1.1)	(1.1)	(1.0)	(3.2)	4(p)
Removal of DA Capital (CETO/PENVT)	0.0	0.2	(6.7)	(6.5)	4(r), 4(s)
Global TCM 7.5% Reduction	(0.2)	(1.2)	(2.0)	(3.3)	4(t)
One-time TCM Reduction	(0.0)	(0.2)	(0.2)	(0.4)	4(t)
Return on Increased Rate Base due to FIT Reserve Refund	~~1.0~~ <u>0.6</u>	~~3.1~~ <u>2.0</u>	~~5.2~~ <u>3.3</u>	~~9.3~~ <u>6.0</u>	
<u>Increase to Income Tax Expense due to Increase to Return on Rate Base</u>	<u>0.1</u>	<u>0.3</u>	<u>0.5</u>	<u>1.0</u>	
Total Capital Negotiated Items	~~(0.3)~~ <u>(0.5)</u>	~~0.8~~ <u>0.0</u>	~~(4.6)~~ <u>(5.9)</u>	~~(4.1)~~ <u>(6.5)</u>	
Future Income Tax (FIT) Reserve Refund	~~(30.0)~~ <u>(22.9)</u>	~~(30.0)~~ <u>(22.5)</u>	~~(30.0)~~ <u>(22.1)</u>	~~(90.0)~~ <u>(67.5)</u>	4(u)
<u>Decrease to Income Tax Expense due to FIT Reserve Refund</u>	<u>(6.8)</u>	<u>(6.7)</u>	<u>(6.6)</u>	<u>(20.1)</u>	
Total Negotiated Reduction	(34.5)	(38.2)	(41.1)	(113.8)	



35. The negotiation of the adjustments and reductions set out above involved various concessions and tradeoffs from each of AET and the Interveners, and is a compromise amongst the Parties. AET submits that this resulting compromise will result in just and reasonable rates.

Deferral Accounts

36. In the Settlement Agreement, the Parties agreed on the implementation of two new deferral accounts in the Test Period, both of which were proposed in the 2023-2025 GTA, and an expansion of AET's existing Deferral Account for Statutory Tax Rates:

- (a) The Fuel Price Deferral Account (Section 4(c) of the Settlement Agreement): This new deferral account shall operate as proposed in the AET's 2023-2025 GTA and applies to the diesel unit price.¹⁵ As noted in the 2023-2025 GTA, recent geopolitical events have led to volatility and uncertainty impacting AET's ability to forecast fuel prices for the 2023-2025 Test Period, resulting in a high risk of material forecast variances. AET's 2023-2025 GTA sets out how the Fuel Price Deferral Account meets the factors for evaluating deferral accounts.¹⁶
- (b) The Temporary Deferral Account for Potential IT Transition Costs (Section 4(f) of the Settlement Agreement): This new, temporary deferral account will be implemented following a competitive bidding process for IT managed services in advance of the expiry of the current IBM/Kyndryl MSA in 2025, as described in the Application,¹⁷ to allow for the disposition of potential IT transition costs. AET's 2023-2025 GTA sets out how the Temporary Deferral Account for Potential IT Transition Costs meetings the factors for evaluating deferral accounts.¹⁸ However, instead of having a balance of \$5.1 million as proposed in the 2023-2025 GTA, it will have an opening

¹⁵ Exhibit 27062-X0014.02, s 4.3.

¹⁶ Exhibit 27062-X0014.02, s 4.3.

¹⁷ Exhibit 27062-X0014.02, ss 1.6, 25.2.13, paras. 625 to 632.

¹⁸ Exhibit 27062-X0014.02, paras. 625 to 632.



balance of \$0 and the disposition of any non-zero balance in the account will be reviewed as part of AET's next general tariff application, including the prudence and recovery of any such costs incurred in AET's rates.

- (c) Expansion of the Deferral Account for Statutory Tax Rates (section 4(n) of the Settlement Agreement): The Parties agreed on an expansion of the scope of AET's current deferral account for statutory tax rates¹⁹ during the Test Period, to include changes to income tax legislation or policy that relate to the ability to claim Accelerated Capital Cost Allowance ("**ACCA**"), including if the ability to claim ACCA is discontinued or enhanced. This deferral will capture such changes to non-direct assigned capital only, as direct assigned capital tax impacts are currently captured in AET's direct assigned capital deferral account. The expansion of the scope to include changes to income tax legislation or policy that relate to the ability to claim ACCA is consistent with the purpose of AET's existing Deferral Account for Statutory Tax Rates, as it captures a legislatively introduced impact which is beyond the control of AET.

Prospective Commitments

37. The Settlement Agreement, if approved, also includes a number of prospective commitments which AET is to undertake for its next GTA, as set out in Section 5 of the Settlement Agreement. These prospective commitments relate to the following issues:

- (a) Property insurance level of deductibles and potential self-insurance (Section 5(a)).
- (b) A refund strategy for the remaining FIT reserve balance (Section 5(b)).

¹⁹ Exhibit 27062-X0014.02, Table 1.5; Initial approval of the use of a deferral account for statutory tax rates in AUC Decision 2013-358: ATCO Electric Ltd., 2013-2014 Transmission General Tariff Application (September 24, 2013) at para 95.

- (c) Information regarding AET's risk assessment for Capital Maintenance programs (Section 5(c)).
- (d) Information regarding AET's activity-based forecasts for USA 560, 561, 562 and 563/9 (Section 5(d)).
- (e) Information regarding AET's Transmission Line to Ground Clearance Mitigation ("**LGCM**"), Cross-Arms and Insulator Replacement programs, and line rebuilds (Section 5(e) and (g)).
- (f) Information regarding the development of a contamination map in AET's service area (Section 5(f)).
- (g) The application of Corona Rings to address performance issues for synthetic or polymer insulation (Section 5(h)).
- (h) Information on total IT expenditures (Section 5(i)).
- (i) Information on IT savings or reduction to costs in the 2023-2025 Test Period realized from Project 82664 and Project 82660 (Section 5(j)).

38. The scope of these commitments is as set out in Section 5 of the Settlement Agreement.

B. The Commission's Assessment of the Settlement Agreement

39. The Commission has jurisdiction to approve settlements negotiated for issues within its jurisdiction pursuant to Section 134 of the *EUA*. The issue of regulated rate tariffs is within the Commission's jurisdiction to regulate electric utility tariffs under Part 9 of the *EUA*.

40. The Settlement Agreement reflects compromises regarding different interests and positions of all Parties involved and was negotiated as a package. The Settlement Agreement was negotiated on the basis that it is contingent on the Commission accepting

the entire settlement, with the result that in accordance with Section 135 of the *EUA*, the Commission must either approve the entire settlement or refuse it.

41. Pursuant to section 8 of Rule 018, when presented with a unanimous settlement, the Commission must intervene only if it determines that the unanimous settlement is patently against the public interest or contrary to law.

42. Notwithstanding the above, AET respectfully requests that if the Commission is considering rejecting the Settlement Agreement because it is concerned with one or more provisions, it indicate which of the provisions are the source of the Commission's concern and provide the Parties with an opportunity to re-negotiate or remove the provision(s) that are the source of the Commission's concern.

Considerations of the Commission

43. The Commission recently confirmed that when it considers unanimous negotiated settlements the following factors are assessed:

25. Given the statutory requirements, Rule 018 and the relevant case law, the Commission has considered all of the following factors in making its determination on whether the negotiated settlement should be accepted or rejected in its entirety:

- Fairness of the negotiated settlement process: assessing whether there was procedural fairness, both with respect to adequate notice having been served and with respect to the conduct of the negotiation process itself.
- Just and reasonable rates: considering the reasonableness of the NSA. The Commission will consider the reasonableness of the individual elements that make up the application to the extent they have been set out in the NSA.
- Patently against the public interest or contrary to law: conducting a review of each of the material provisions of the NSA in order for the Commission to determine whether these provisions, individually, appear contrary to accepted regulatory practices, or could resulting undue rate and service effects on customers or are clearly contrary to law.²⁰

²⁰ Decision 23848-D01-2020. Also refer to Decision 26617-D01-2020, ENMX Power Corporation, EPCOR Distribution & Transmission Inc., 2023 Cost-of-Service Review – Reasons for Approval of Negotiated Settlements (July 28, 2022) at para 11 [Decision 26617-D02-2022]. Also refer to AUC Decision 25726-D01-2021, ENMAX Power Corporation, 2021-2022 General Tariff Application, Negotiated Settlement Agreement and Excluded Matters (June 16, 2021) at para 23 [Decision 25726-D01-2021].

44. Section 8 of Rule 018 requires the Commission to assess if the negotiated settlement results in rates and Terms and Conditions that are just and reasonable. The Commission has recently confirmed that it must always "have regard to the requirements of Rule 018, including the fairness of the process" and that the central question to the Commission's public interest determination is whether the negotiated settlement will result in just and reasonable rates.²¹

45. With respect to fairness, the Commission has also recently commented that "[i]n order to demonstrate that an NSP is fair, the Commission must be satisfied that proper notice was given, that relevant information has been disclosed, and that parties were able to have meaningful participation."²²

46. The Commission considers the questions of whether the settlement results in just and reasonable rates as part of its determination of whether the negotiated settlement is in the public interest.²³

C. The Commission Should Approve the Negotiated Settlement

The NSP was Procedurally Fair

47. The NSP was procedurally fair. As discussed above and expressly acknowledged in Section 8(b) of the Settlement Agreement, adequate notice was provided with respect to the NSP. The Commission may also have regard to written confirmation filed by the Interveners as to the fairness of the negotiated settlement process, which are to be filed with the Commission by January 20, 2023.

48. Confidential and without-prejudice negotiations occurred between December 12, 2022 and December 20, 2022. Representatives from each of the Interveners (CCA, UCA, Calgary, IPCAA and Grande Prairie) were invited to, and attended, every session. Each Party was given a reasonable opportunity to raise and

²¹ Decision 26617-D02-2022, *ibid* at para 12.

²² AUC Decision 26207-D01-2021, Direct Energy Regulated Services, 2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement (June 4, 2021) at para 20 [Decision 26207-D01-2021].

²³ Refer to, e.g., Decision 26207-D01-2021, *ibid* at para 28; Decision 25726-D01-2021, *supra* note 20 at para 33.

discuss matters related to AET's application, and the negotiations included multiple videoconferencing sessions and the exchange of additional information. All Parties were active in the negotiations and are ultimately signatories to the Settlement Agreement.

49. Further, all parties were well-informed. There was a substantial evidentiary record in Proceeding 27062 before the Parties began negotiation meetings. As detailed above in the Procedural History, AET had provided IR responses and the Intervener Evidence was filed before the start of negotiations. The Parties exchanged information on a without prejudice basis in the course of settlement discussions and, as confirmed in section 8(a) of the Settlement Agreement, no party withheld relevant information. AET submits that Parties to the NSP were therefore reasonably informed and able to meaningfully participate in settlement discussions.

50. The UCA, CCA, and Calgary were represented by legal counsel and had the assistance of expert consultants. In its decision on the 2021 Direct Energy Regulated Services negotiated settlement agreement with respect to its 2020-2022 Default Rate Tariff ("**DRT**") and Regulated Rate Tariff ("**RRT**"), the Commission noted:

The Commission considers that the CCA and the UCA are sophisticated parties with significant experience in negotiated settlements and proceedings to establish the RRT and DRT. The CCA and the UCA represent the majority of DERS' RRT and DRT customers, with the CCA representing primarily residential customers, and the UCA mandated by the Alberta Government to represent the interests of residential, farm and small business customers.²⁴

51. The same considerations apply to the Settlement Agreement. The UCA, CCA, IPCAA and Calgary have historically participated in AET's general tariff application proceedings. In addition, Grande Prairie participated in the NSP, therefore expanding the group of the Interveners beyond those that have historically participated in AET's General Tariff Applications. The UCA, CCA, and IPCAA have all participated in negotiated settlements in the past and have extensive experience participating in Commission

²⁴ *Ibid* at para 26.

proceedings more generally.²⁵ The participation of these Parties in the NSP and as signatories to the Settlement Agreement speaks to its fairness.

52. Finally, the NSP did not involve any collusion. The Parties were at arms' length and were adverse of many issues. The Settlement discussions were confidential and without prejudice. However, the process of engaging in negotiations on matters where the Parties are adverse results in a compromise and informs the assessment that the Settlement Agreement is fair and results in just and reasonable rates.

The Settlement Agreement is Not Patently Against the Public Interest or Contrary to Law and Results in Just and Reasonable Rates

53. The Settlement Agreement meets the interests of the Parties and the public interest. As discussed above, the Settlement Agreement represents a unanimous agreement addressing all aspects of AET'S 2023-2025 GTA except the Excluded Matters.

54. As noted above, the Interveners, as Parties to the Settlement Agreement, represent a range of consumers and have also historically participated in the testing of AET's general tariff applications, such that the Commission can be confident that the Settlement Agreement meets the interests of the public.²⁶

55. Additionally, both the Commission and the courts have confirmed that there is a public interest in favour of settlements over litigated or contested processes. The Supreme Court of Canada stated in *Sable Offshore Energy Inc v Ameron International Corp* that "[s]ettlements allow parties to reach a mutually acceptable resolution to their dispute without prolonging the personal and public expense and time involved in litigation," and recognized the public interest in favour of settlement.²⁷ In previous approvals of unanimous negotiated settlements, the Commission has recognized that approval of the settlements would "provide certainty, plus savings in costs, resources and

²⁵ E.g., Exhibit 23848-X0204, Exhibit 25726-X0196.

²⁶ Refer to Decision 26207-D01-2021, *supra* note 22 at para 30; Decision 25726-D01-2021, *supra* note 20 at para 42.

²⁷ [2013 SCC 37](#) at para 11, citing *Sparling v Southam Inc*, 1988 CanLII 4694 (ON SC), 66 OR (2d) 225 (HCJ) at 230.

time that all parties would have otherwise expended in a fully litigated proceeding,"²⁸ and would result in "greater regulatory efficiency and cost savings to customers than would a contested process."²⁹ The same benefits apply here. The Settlement Agreement is unanimous and represents the interests of all Parties and the public interest. Its approval would result in greater efficiency and costs savings for the public by eliminating the need for an extended process before the Commission in Proceeding 27062.

56. As set out in Section 4(v) of the Settlement Agreement, AET has assessed and confirms that the reductions in revenue requirement identified therein, according to the facts currently known by AET and to the best of AET's knowledge, will not compromise the provision of safe and reliable transmission service during the Test Period. The Commission has previously noted such considerations as part of its determination that a negotiated settlement was in the public interest.³⁰

57. As such, the Settlement Agreement is not patently against the public interest and it is not contrary to law.

58. Further, the Settlement Agreement addresses all aspects of the Application except for the Excluded Matters. It results in a direct reduction of the transmission tariffs set forth in the 2023-2025 GTA of \$113.8 million as described in Table 1 above. This reduced revenue requirement, agreed-upon by AET and all Interveners in Proceeding 27062, results in just and reasonable rates, the details of which have been provided in the Appendices of the Settlement Agreement.

59. The Commission can rely on the fairness of the NSP and the fact that it meets the interests of the Parties and the public interest, as discussed above as evidence that it will result in just and reasonable rates. The Settlement Agreement is a comprehensive, unanimous agreement that is the product of fair and earnest negotiation by well-informed

²⁸ Decision 26617-D02-2022, *supra* note 20 at para 61.

²⁹ AUC Decision 21149-D01-2016, ENMAX Power Corporation, Distribution 2015-2017 Performance-Based Regulation – Negotiated Settlement Application and Interim X Factor (August 3, 2016) at para 48.

³⁰ Refer to Decision 26207-D01-2021, *supra* note 22 at para 30.



Parties, the majority of which were represented by legal counsel and supported by expert consultants. As set out in Section 3(c) of the Settlement Agreement, the Interveners have agreed that they will support this application and that the Commission should approve the AET's 2023-2025 GTA with the specific adjustments and modifications identified in the Settlement Agreement.

V. CONCLUSION: THE SETTLEMENT AGREEMENT IS IN THE PUBLIC INTEREST

60. The Settlement Agreement is a unanimous agreement of AET and the Interveners with respect to all elements of AET's 2023-2025 GTA, except the Excluded Matters.

61. The Settlement Agreement results in a reduction of capital and operating costs of \$113.8 million over the Test Period, resulting in a fair and reasonable tariff for 2023, 2024 and 2025. As discussed above, AET's Settlement Agreement is in the public interest and not contrary to law. Approval of the Settlement Agreement will bring finality and certainty and will avoid a costly litigated process.

62. For these reasons, AET respectfully requests the Commission to approve the Settlement Agreement in its entirety, together with the resulting adjustments to AET's applied-for revenue requirement.

**ALL OF WHICH IS RESPECTFULLY SUBMITTED ON this 23rd day of January, 2023,
AS REVISED ON this 3rd day of February, 2023.**

NEGOTIATED SETTLEMENT AGREEMENT

**ATCO ELECTRIC LTD.
2023-2025 GENERAL TARIFF APPLICATION**

THIS NEGOTIATED SETTLEMENT AGREEMENT for the negotiated settlement of the 2023-2025 General Tariff Application, which is the subject of Alberta Utilities Commission Proceeding No. 27062, is made and entered into as of **January 19, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("AET")

- and -

CONSUMERS' COALITION OF ALBERTA (the "CCA")

- and -

**OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the
"UCA")**

- and -

THE CITY OF CALGARY ("Calgary")

- and -

**INDUSTRIAL POWER CONSUMERS ASSOCIATION OF
ALBERTA ("IPCAA")**

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a "**Party**" and collectively, the "**Parties**"

WHEREAS:

- A. AET ("the **Applicant**") submitted its 2023-2025 General Tariff Application ("**Application**") to the Alberta Utilities Commission ("**AUC**" or "**Commission**") on May 19, 2022 for the purpose of

obtaining approval for its revenue requirement for the 2023-2025 Test Period, which is the subject of AUC Proceeding No. 27062;

- B. On May 26, 2022, the Commission issued a Notice of Application informing potentially interested parties that it would be considering the Application, and inviting submissions for participation in AUC Proceeding 27062;
- C. The CCA, the UCA, Calgary, IPCAA and Grande Prairie (collectively, the "**Intervenors**") are participants in Proceeding 27062;
- D. On August 5, 2022, the Commission issued an initial process schedule and an issues list for Proceeding 27062 and provided its approval for the Parties to enter into a negotiated settlement process under AUC Rule 018. The Commission directed that:
 - (i) the following issues be excluded from the negotiated settlement process: (a) removal of the Vegetation Management reserve; and (b) Modifications to the Variable Pay Program reserve; and
 - (ii) if the Parties negotiated on full-time equivalents ("**FTEs**"), then the negotiated settlement agreement identify whether the FTE adjustment was made to capital FTEs or to operations and maintenance ("**O&M**") FTEs, and which O&M USA the adjustment is applicable to.
- E. AET filed supplemental information for the Application on July 28, 2022 and an application update on September 6, 2022;
- F. AET responded to information requests from the AUC and the Intervenors on October 18 and November 4, 2022, with further responses provided on November 14-15, 18, and 25, 2022;
- G. The Intervenors filed evidence on December 2, 2022;
- H. The Parties (AET, the CCA, the UCA, Calgary, IPCAA and Grande Prairie) entered into a negotiated settlement process commencing with a preliminary meeting on September 16, 2022, with settlement negotiations taking place from December 12 through 20, 2022;
- I. On December 20, 2022, the Parties reached an agreement in principle for a negotiated settlement on all elements of AET's 2023-2025 GTA, except for specifically excluded matters identified in section 2 below;
- J. The term of this settlement is the 2023-2025 Test Years Period ("**Test Period**").

IN CONSIDERATION of the mutual promises made in this negotiated settlement agreement ("**Settlement Agreement**") and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Scope of this Settlement Agreement**

- (a) This Settlement Agreement settles all aspects of and relief requested in the Application, except for the Excluded Items identified in section 2 below.

- (b) Unless otherwise agreed by the Parties in writing, if the AUC declines to approve this Settlement Agreement in its entirety, the Settlement Agreement will be of no force and effect, in accordance with Section 135 of the *Electric Utilities Act*.

2. **Excluded Matters**

- (a) AET and the Interveners agree that the following matters are specifically excluded from this Settlement Agreement:
 - (i) the removal of the Vegetation Management reserve;
 - (ii) modifications to the Variable Pay Program reserve; and
 - (iii) Issue 8(b) from the Commission's approved Issues List - Proposed treatment of the one-time depreciation adjustment for the Jasper Palisades Isolated Generation Plant of depreciation related to the Jasper Palisades Isolated Generation Plant;
- collectively referred to herein as the "**Excluded Matters**".

3. **Revised Revenue Requirement**

- (a) The overall revenue requirement adjustments agreed to in this Settlement Agreement are set out in Schedule 3-1 attached hereto as Appendix "A".
- (b) Revised Minimum Filing Requirement ("**MFR**") schedules that reflect the specific adjustments and modifications agreed to herein are attached hereto as Appendix "A". A Summary of Changes to AET's Revenue Requirement is attached as Appendix "B" to this Settlement Agreement.
- (c) Except for the Excluded Matters, the Parties agree that the AUC should approve the Application, with the specific adjustments and modifications identified in this Settlement Agreement and in Appendix "A" hereto. The Parties agree to support AET's application to the AUC for approval of this Settlement Agreement.

4. **Specific Adjustments and Modifications**

- (a) **Errors and Omissions:** In addition to the adjustments and modifications identified herein, the revenue requirement shall reflect AET's correction of errors and omissions described in AET's response to AET-AUC-2022SEP21-130 filed on the record of Proceeding 27062.
- (b) **Diesel Fuel Volume Forecast:** The forecast diesel fuel volumes set out in Table 4.2 of the Application, with the corrections identified in response to AET-AUC-2022SEP21-105(d), will be reduced by 5% in each year of the Test Period.
- (c) **Fuel Price Deferral Account:** A fuel price deferral account, as proposed in the Application, will be implemented for the Test Period.
- (d) **Vacancy Rate:** AET will apply a vacancy rate of 5% in each year of the Test Period. A schedule identifying the impact of the 5% vacancy rate to capital FTEs and O&M FTEs, and to O&M USAs, is attached hereto as Appendix "C".

- (e) **Inflation Assumptions ("Other"):** Forecast inflation assumptions for "Inflation - Other" will be 4.4% in 2023, 3.0% in 2024, and 2.2% in 2025.
- (f) **Information Technology ("IT") Transition Costs:** The Parties agree to the implementation of a temporary deferral account for potential IT transition costs following a competitive bidding process for IT managed services in advance of the expiry of the current IBM/Kyndryl MSA in 2025 as described in the Application, with a placeholder amount of \$0.00 for such costs in the Test Period. The deferral account will have an opening balance of \$0 and the disposition of any non-zero balance in this deferral account will be reviewed as part of AET's next general tariff application, including the prudence and recovery of any such costs incurred in AET's revenue requirement.
- (g) **Supervision and Engineering (USA Acct No. 560):** Forecast costs for USA 560 will be \$3.3 million in 2023, \$3.4 million in 2024, and \$3.5 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.
- (h) **Control Centre Operations (USA Acct No. 561):** Forecast costs for USA 561 will be \$5.4 million in 2023, \$5.6 million in 2024, and \$5.8 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.
- (i) **Station Equipment Expenses (USA Acct No. 562):** Forecast costs for USA 562 will be \$9.9 million in 2023, \$10.0 million in 2024, and \$10.1 million in 2025, which amounts are inclusive of the vacancy, inflation and escalation rate adjustments identified in clauses 4(d), (e), (l) and (m) herein.
- (j) **Insurance Premiums (USA Acct No. 924):** Forecast costs for insurance premiums included in USA 924 will be \$5.3 million for 2023, \$5.4 million for 2024, and \$5.6 million for 2025.
- (k) **Variable Pay Program ("VPP"):** Forecast VPP for the Test Period will be \$4.5 million in 2023, \$4.6 million in 2024, and \$4.7 million in 2025.
- (l) **In-scope Salaries:** Forecast in-scope salary inflation will be 1.0% in 2022, 2.5% in 2023, 3.0% in 2024, and 1.8% in 2025.
- (m) **Out-of-Scope Salaries:** Out-of-scope salary inflation will be 2.9% in 2022, 2.9% in 2023, 2.5% in 2024, and 2.5% in 2025.
- (n) **Income Tax:** AET agrees to expand the scope of its current deferral account for statutory tax rates during the Test Period, to include changes to income tax legislation or policy that relate to the ability to claim accelerated capital cost allowance ("**ACCA**"), including if the ability to claim ACCA is discontinued or enhanced. To clarify, this deferral will capture such changes to non-direct assigned capital only, as direct assigned capital tax impacts are currently captured in the direct assigned capital deferral account.
- (o) **Shared Services FTEs:** Forecast pre-allocated Shared Services Innovation Function FTEs will be 10.4 FTEs in each year of the Test Period, consistent with 2021 actuals. Forecast pre-allocated Shared Services Indigenous and Government Relations & Sustainability Function FTEs will be 11.0 FTEs in each year of the Test Period, consistent with FTE

levels approved in Proceeding 24964. The impact of these FTE adjustments to capital FTEs and O&M FTEs, and to O&M USAs, is included in Appendix "C" attached hereto.

- (p) **Additions to Opening 2023 Rate Base for 2022 Forecast IT Capital:** Forecast 2022 additions to GP&E Software opening rate base will be \$12.3 million.
- (q) **General Reductions in Operating Costs:** AET's applied-for forecast operating costs shall reflect a reduction in the amount of \$0.25 million for each year in the Test Period. This reduction is not tied to any specific USA account or accounts, but is a holistic reduction that AET may apply to any operating expense, USA account or accounts as it sees fit.. For presentation purposes, AET has included this adjustment within USA 566.
- (r) **Project 57259 ("PENVTD"):** The forecast capital addition of \$60.1 million associated with PENVTD will be removed from the Test Period.
- (s) **Project 58112 ("CETO"):** For the purpose of setting interim rates for the Test Period, AET agrees to remove the financial impact of the forecast \$141.1 million addition for the December 2025 energization of CETO Project from the Application. For clarity, AET's deferral application to establish the final revenue requirement related to CETO Project will be based on and include the financial impacts of the actual in-service date of the CETO Project.
- (t) **Transmission Capital Maintenance ("TCM") and General Property and Equipment Projects ("GPE"):** AET agrees to an overall reduction of 7.5% to its combined TCM and GPE capital forecast over the Test Period and a one-time reduction of \$2 million in 2023 to its combined TCM and GPE capital forecast. These reductions are not tied to any specific project or program, but are holistic reductions that AET may apply as it sees fit. AET shall retain discretion to manage the forecast reduction from projects or programs in assessing the impact on the safety and reliability of its assets.
- (u) **Federal Future Income Taxes ("FIT"):** AET will discontinue the collection of Federal FIT as applied-for in the Application, and AET will refund \$30 million of previously collected FIT in each year of the Test Period.
- (v) AET has assessed and confirms that the reductions in revenue requirement identified herein, according to the facts currently known by AET and to the best of AET's knowledge, will not compromise the provision of safe and reliable transmission service during the Test Period.

5. **Prospective Commitments**

- (a) AET will conduct an analysis of property insurance level of deductibles and potential self-insurance and present the findings of this analysis in its next general tariff application.
- (b) AET will present a refund strategy in its next general tariff application for refunding the remaining FIT reserve balance.
- (c) AET agrees to review its existing risk assessment for Capital Maintenance programs, including enhancements to the numerical quantification of costs and benefits, and to report on this review in its next general tariff application. This review will focus on at least five new or existing sub-programs forecast in the next general tariff application test period.

- (d) AET's operations and maintenance forecasts are activity-based. AET agrees to review and examine the level of detail provided to support its activity-based forecasts for USA 560, 561, 562 and 563/9. AET agrees to provide additional detail supporting these activity-based forecasts in its next general tariff application. Such additional details will include activities, activity volumes, time and costs to complete the activities, as applicable.
- (e) AET will review and examine the data, the data's integrity, and its current processes supporting the Transmission Line to Ground Clearance Mitigation ("**LGCM**") and the Cross-Arms and Insulator Replacement programs and provide an update on its findings in its next general tariff application. The update will include additional explanation of how such data will be used in the next general tariff application test period to support the strategies chosen to correct LGCM issues and for cross-arm and insulator replacements, or if not used, a full justification as to why not.
- (f) AET agrees to develop and maintain a contamination map of its service area depicting zones of contamination and insulation values based on IEC 60815-1-2-3, and to present the findings of such map and the associated potential implications for future transmission capital maintenance and operations and maintenance costs in the next general tariff application. Forecast costs for Project 50020 will be increased by \$0.3 million in 2023 to fund the development of the contamination map.
- (g) AET agrees to provide additional detail regarding the value engineering (whether different methods can be identified to provide the required function, and an assessment of the tradeoff between cost, risk and performance in evaluating alternatives) applied to LGCM, significant cross-arms and insulator replacements, and line rebuilds in its next general tariff application.
- (h) AET agrees that, before undertaking any broad mitigation application to address performance issues of synthetic or polymer insulation effects, where Corona Rings are a potential solution, it will complete a full electrical and mechanical assessment by an independent lab on such suspect insulation according to specific manufacturer and specific insulator type before any installation of Corona Rings on synthetic or polymer insulators. AET agrees to report the results of these activities (if any) in its next general tariff application. The commitment is intended to capture a larger application of corona rings (for instance an entire line that has polymer/ synthetic lines performance issues) as opposed to mitigation of unique or isolated structures.
- (i) AET agrees to provide the detailed information on total IT expenditures in one place in its next GTA, as was directed in Decision 26616-D01-2022 paragraph 390, for the ATCO Distribution Utilities. This information will include information on total IT expenditures (including IT O&M (direct, shared services, head office), and IT capital (including additions, indirect and direct capital)), the MFR accounts in which these costs are recorded, an identification of all IT corporate costs, and the method used to allocate IT costs to ATCO distribution and transmission utilities.
- (j) AET will review and report on any savings or reduction to costs in the 2023-2025 Test Period realized from Project 82664 and Project 82660, in its next general tariff application.

6. Prudence

- (a) The Parties agree that nothing in this Settlement Agreement, including the reductions to the 2023-2025 GTA revenue requirement, is an admission by AET that those revenue requirement amounts are imprudent. The Parties further agree that no Party may rely on anything in this Settlement Agreement as evidence in any future proceeding that any revenue requirement amounts are either prudent or imprudent.

7. Confidentiality and Privilege Without Prejudice

- (a) The negotiated settlement reflected in this Settlement Agreement is a compromise and was reached in part as a result of the desire of the Parties to avoid the significant resources associated with a fully litigated process. This Settlement Agreement is for the purpose of AET's 2023-2025 GTA only, unless expressly stated otherwise, and it is without prejudice to the positions that any of the Parties may take in any subsequent negotiations and regulatory proceedings. For greater clarity, the Parties' proposal, which was accepted by the Commission, to not expend resources on advancing the preparation and filing of Information Request responses and rebuttal evidence on the issues included in this Settlement Agreement, does not constitute an admission by any Party that it accepts or agrees with the positions or evidence advanced in intervenor evidence or information requests.
- (b) All discussions among the Parties during the negotiated settlement process are privileged and confidential, and no matter discussed and no information provided during the negotiated settlement process may be disclosed to any person or to the AUC without the express written consent of all Parties.

8. General

- (a) Each Party represents that it has not withheld relevant information.
- (b) The Parties agree that proper notice of the negotiated settlement process was provided to all interested parties.
- (c) The Parties further agree:
 - (i) The division of this Settlement Agreement into headings and paragraphs is for convenience and reference only and should not affect the interpretation or construction of this Settlement Agreement.
 - (ii) This Settlement Agreement sets out the entire understanding and agreement of the Parties and there are no representations, warranties, covenants, conditions or other agreements, express or implied, collateral, statutory or otherwise, among the Parties in connection with the subject matter of this Settlement Agreement except as specifically set out herein.
 - (iii) Any alteration or amendment of this Settlement Agreement must be in writing and signed by the Parties. This Settlement Agreement will be binding upon and inure to the benefit of the Parties and each of their respective successors and permitted assigns. A Party may not assign their rights and/or obligations under this Settlement Agreement without the consent of all other Parties, provided such

consent is not unreasonably withheld. This Settlement Agreement may be executed in any number of counterparts.

- (iv) This Settlement Agreement is to be interpreted pursuant to the laws of the Province of Alberta.
 - (v) If any provision of this Settlement Agreement is found to be invalid by a court of law, this Settlement Agreement will be read and interpreted as if the provision were omitted.
 - (vi) The failure of any Party to exercise any right, power or option given to it under this Settlement Agreement or to insist upon the strict compliance with any of the terms or conditions in this Settlement Agreement will not constitute a waiver of any provision with respect to any other or subsequent breach.
 - (vii) Unless otherwise stated, any dollar amounts, prices or amounts stated in this Settlement Agreement are in the lawful currency of Canada.
 - (viii) Unless otherwise stated, all accounting matters or terms in this Settlement Agreement will be interpreted and construed in accordance with International Financial Reporting Standards.
 - (ix) References to any statute, legislation or regulation include all subsequent additions, amendments, re-enactments or replacements enacted from time to time during the period covered by this Settlement Agreement.
- (d) This Settlement Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties have duly executed this Settlement Agreement as of the date set out above.

ATCO ELECTRIC LTD.

Per:



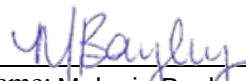
Name: Corinne Severson
Title: Vice President, Regulatory

CONSUMERS' COALITION OF ALBERTA

Per:

Name:
Title:

Per:



Name: Melanie Bayley
Title: President ATCO Electric

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

Per:

Name:
Title:

THE CITY OF CALGARY

Per:

Name:
Title:

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

Per:

Name:
Title:

CITY OF GRANDE PRAIRIE

Per:

Name:
Title:

9 of 9

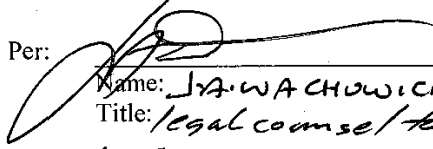
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ATCO ELECTRIC LTD.

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

CONSUMERS' COALITION OF ALBERTA

Per:  _____
Name: J.A. WACHOWICZ
Title: legal counsel to CCA
AET 2023-2025 GTA
I.D. 27062 / Jan 20 2023

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

Per: _____
Name: _____
Title: _____

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

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Title: _____

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CONSUMERS' COALITION OF ALBERTA

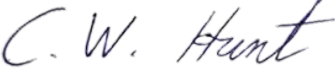
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Per: _____
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Title:

Per: _____
Name:
Title:

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: 
Name: Chris Hunt
Title: Executive Director, UCA

Per: _____
Name:
Title:

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

Per: _____
Name:
Title:

9 of 9

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Per: _____
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Per: _____
Name:
Title:

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: _____
Name:
Title:

Per: 
Name: E. Lynne Davies
Title: Director - Law on behalf
of the City Solicitor & General Counsel

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name:
Title:

Per: _____
Name:
Title:

9 of 9

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**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

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Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

Richard Penn
Executive Director
IPCATA

9 of 9

IN WITNESS WHEREOF, the Parties have duly executed this Settlement Agreement as of the date set out above.

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Per: _____
Name: _____
Title: _____

Per: _____
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Name: _____
Title: _____

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: 
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CBJCHBCAABAAG7vm11Qtw0BT5ynoqTio1gacYoU5cX0X

AMENDING AGREEMENT

**ATCO ELECTRIC LTD.
2023-2025 GENERAL TARIFF APPLICATION**

THIS AMENDING AGREEMENT is made and entered into as of **January 31, 2023**.

AMONG:

ATCO ELECTRIC LTD. ("AET")

- and -

CONSUMERS' COALITION OF ALBERTA (the "CCA")

- and -

**OFFICE OF THE UTILITIES CONSUMER ADVOCATE (the
"UCA")**

- and -

THE CITY OF CALGARY ("Calgary")

- and -

**INDUSTRIAL POWER CONSUMERS ASSOCIATION OF
ALBERTA ("IPCAA")**

- and -

CITY OF GRANDE PRAIRIE ("Grande Prairie")

each, a **"Party"** and collectively, the **"Parties"**

WHEREAS:

- A. The Parties entered into a Negotiated Settlement Agreement made as of January 19, 2023 (the **"Settlement Agreement"**) in respect of the negotiated settlement of the Application, which is the subject of AUC Proceeding No. 27062 (the **"Proceeding"**);
- B. On January 25, 2023, the Commission issued an information request to AET which raised questions regarding provision 4(u) of the Settlement Agreement related to Federal Future Income Taxes (**"FIT"**);
- C. Having reviewed such information request, AET acknowledges the presentation of the proposed FIT refund in the Settlement Agreement, including Appendix "A", did not properly account for the income tax impact of the FIT refund;

- D. In order to address this, the Parties have agreed to enter into this Amending Agreement pursuant to the terms and conditions contained herein.

IN CONSIDERATION of the mutual promises made in this Amending Agreement and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions hereinafter set out, the Parties agree as follows:

1. **Definitions**

- (a) Unless otherwise specified herein or unless otherwise required by the context hereof, capitalized terms utilized herein, including the recitals hereof will have the meanings given to them in the Settlement Agreement.

2. **Amendments to the Settlement Agreement**

- (a) The Settlement Agreement is hereby amended as follows:
- (i) Section 4(u) of the Settlement Agreement: Section 4(u) of the Settlement Agreement is amended by deleting the paragraph in its entirety and replacing it with the following:
- "(u) Federal Future Income Taxes ("FIT"):** AET will discontinue the collection of FIT as applied-for in the Application, and AET will refund previously collected FIT of \$22.9 million in 2023, \$22.5 million in 2024 and \$22.1 million in 2025, and reflect the resulting impacts of such refunds on income tax expense and return on rate base in revenue requirement in each year of the Test Period."
- (ii) Appendix "A" to the Settlement Agreement: Appendix "A" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix A – Revised MFRs Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0496.01.
- (iii) Appendix "B" to the Settlement Agreement: Appendix "B" to the Settlement Agreement is amended by rescinding it in its entirety and replacing it with the amended "Appendix B – Summary of Changes to Rev Req Amended January 31, 2023" attached hereto and to be filed in the Proceeding as Exhibit 27062-X0497.01.

3. **General**

- (a) **Continuity:** The provisions of the Settlement Agreement shall, save as amended by this Amending Agreement, continue in full force and effect, and shall be read and construed as one document with this Amending Agreement.
- (b) **Governing Law:** Section 8(c)(iv) of the Settlement Agreement shall apply to this Amending Agreement *mutatis mutandis*.
- (c) **Counterparts:** This Amending Agreement may be executed in any number of counterparts (including by facsimile or other electronic means) with the same effect as if

3 of 4

all signing Parties had signed the same document. All counterparts shall be construed together and constitute the same agreement.

[Signature page follows]

IN WITNESS WHEREOF, the Parties have duly executed this Amending Agreement as of the date set out above.

ATCO ELECTRIC LTD.

CONSUMERS' COALITION OF ALBERTA

Per: 
Name: Corinne Severson
Title: Vice President, Regulatory

Per: _____
Name: _____
Title: _____

Per: 
Name: Melanie Bayley
Title: President, Electric

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

4 of 4

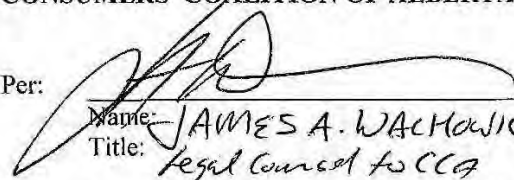
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ATCO ELECTRIC LTD.

Per: _____
Name: _____
Title: _____

Per: _____
Name: _____
Title: _____

CONSUMERS' COALITION OF ALBERTA

Per: 
Name: JAMES A. WACHOWICH
Title: Legal Counsel to CCA
27062 Amended NSA-ycopy
Jan 31/2023

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

Per: _____
Name: _____
Title: _____

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
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4 of 4

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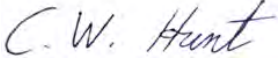
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Per: _____
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Title: _____

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per:  _____
Name: Chris Hunt
Title: Executive Director, UCA

Per: _____
Name: _____
Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
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4 of 4

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Per: _____
Name: _____
Title: _____

**OFFICE OF THE UTILITIES CONSUMER
ADVOCATE**

THE CITY OF CALGARY

Per: _____
Name: _____
Title: _____

Per: 
Name: Lynne Davies
Title: Director, Law by delegated
authority from the City Solicitor's
General Counsel

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
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4 of 4

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**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

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Richard Penn
Executive Director - IPCAA

4 of 4

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CONSUMERS' COALITION OF ALBERTA

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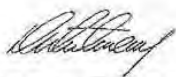
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Title: _____

**INDUSTRIAL POWER CONSUMERS
ASSOCIATION OF ALBERTA**

CITY OF GRANDE PRAIRIE

Per: _____
Name: _____
Title: _____

Per: 
Name: Danielle Whiteway
Title: Chief Financial Officer

Adobe Acrobat Sign Transaction Number: CB1CHBCAABAAKFrhWszkt6P8mW1Ju32ms31QTW7QDhag

September 28, 2023

AEY-UCG-007

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-007

Reference: July 7, 2023 Application, page 1-5

AEY states "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 percent inflation rate has also been used for 2017."

Request:

- (a) Provide details of the actual monthly inflation rate for the Yukon for 2016 to date and forecast and copies of the related source documents.
- (b) Please confirm that Yukon Economic Outlook released in May 2016 indicates that following deflation in 2015, the Whitehorse CPI is expected to grow by 2.0 per cent in 2016 and just under 2.0 per cent in 2017.
- (c) Provide non-labour escalation rates are currently used for 2023 and 2024 by FortisBC Utilities. Please provide copies of the reference material relating to these rates.

Response:

- (a) Please refer to AEY-UCG-007(a) Attachment 1.
- (b) Confirmed. The Whitehorse CPI was expected to grow by 2.0 percent in 2016 and just under 2.0 percent in 2017.¹

¹ https://emrlibrary.gov.yk.ca/EcDev/Yukon_Economic_Outlook/2016-May.pdf, PDF pp. 3-4.

September 28, 2023

AEY-UCG-007

- (c) FortisBC has applied for a blended labour/non-labour rate of 4.517 percent for 2023² and 4.080 percent for 2024.³

² https://docs.bcuc.com/documents/proceedings/2022/doc_67371_b-2-fbc-2023-annualreview-application.pdf, PDF p. 22.

³ https://docs.bcuc.com/documents/proceedings/2023/doc_72776_b2fbc2024annualreviewratesapplication.pdf, PDF p. 23.

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

Actual Monthly Inflation Rate for Whitehorse

Line No.		January	February	March	April	May	June	July	August	September	October	November	December
1	2016	0.00%	-0.32%	0.40%	0.16%	0.64%	1.12%	-0.16%	0.00%	-0.40%	0.16%	0.00%	0.00%
2	2017	0.63%	0.08%	0.39%	0.08%	0.16%	-0.39%	-0.08%	-0.47%	0.55%	0.00%	1.34%	-0.16%
3	2018	0.08%	0.47%	0.39%	0.31%	0.15%	0.31%	0.69%	-0.23%	-0.84%	0.38%	-0.08%	0.38%
4	2019	-0.38%	0.15%	0.38%	0.46%	0.53%	0.90%	0.75%	-0.22%	-0.96%	0.30%	0.00%	0.67%
5	2020	0.74%	0.07%	-0.59%	-1.11%	-0.37%	0.90%	-0.07%	-0.45%	0.22%	0.45%	0.22%	0.07%
6	2021	0.89%	0.22%	0.15%	0.88%	0.15%	0.36%	0.94%	0.36%	0.14%	0.43%	-0.57%	0.36%
7	2022	0.21%	0.99%	1.68%	0.62%	1.44%	0.88%	0.94%	0.27%	0.00%	0.53%	0.13%	0.13%
8	2023	0.07%	0.13%	0.26%	0.85%	0.45%	0.97%	1.28%					

9

10 Data source

11 <https://www150.statcan.gc.ca/>

12 Table: 18-10-0004-01

13 Released 2023-08-15

14 Monthly CPI for Whitehorse 2016 - 2023

Line No.	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
1																								
2																								
3	124.1	123.7	124.2	124.4	125.2	126.6	126.4	126.4	125.9	126.1	126.1	126.1	126.9	127	127.5	127.6	127.8	127.3	127.2	126.6	127.3	127.3	129	128.8
4																								
5	15-Dec																							
6																								
7	124.1																							

Line No.	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
1																								
2	2002=100																							
3	128.9	129.5	130	130.4	130.6	131	131.9	131.6	130.5	131	130.9	131.4	130.9	131.1	131.6	132.2	132.9	134.1	135.1	134.8	133.5	133.9	133.9	134.8
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Line No.	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
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3	135.8	135.9	135.1	133.6	133.1	134.3	134.2	133.6	133.9	134.5	134.8	134.9	136.1	136.4	136.6	137.8	138	138.5	139.8	140.3	140.5	141.1	140.3	140.8
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ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Actual Monthly Inflation Rate for Whitehorse

[illegible]

September 28, 2023

AEY-UCG-008

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-008

Reference: July 7, 2023 Application, page 1-5

AEY states: 20. A vacancy rate of 3.65 percent (approximately three FTEs) has been applied to labour expenses for the 2023-2024 Test Period. This is based on a five-year historical average normalized for exogenous events, such as vacancies driven by vaccine policies, 1 Decision 27062- D01-2023, ATCO Electric 2023-2025 GTA and NSA. 2023-2024 General Rate Application (GRA) 1-7 which AEY believes to be reasonable and is consistent with the methodology approved in Board Orders 2014-06 and 2017-01.

Request:

Please provide details of the calculation of the 5-year vacancy rate for ATCO Electric Yukon including details of the positions that were vacant at any time.

Response:

Please refer to the response to AEY-YUB-003(c).

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AEY-UCG-009

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-009

Reference: July 7, 2023 Application, page 1-7 Staff Positions

AEY proposes: 22. The additional positions outlined below are required to manage system growth over the six-year period and continuing into the test period and energy transition. 23. Growth to new extension has grown 4% requiring adequate numbers to accommodate capital program; maintenance requirements in both distribution and production. According to chart 9 additional staff are required.

Request:

- (a) Explain how these job responsibilities identified for the new positions are or will be currently fulfilled.
- (b) Provide details of the total additional costs included in the 2023 and 2024 revenue requirements for these new positions.
- (c) Please provide details on the alternatives that were considered to hiring new staff.

Response:

- (a) AEY is unclear on what the IR is asking. AEY is assuming the UCG asked for an explanation of how these job responsibilities are identified. Identifying job responsibilities for new positions typically involves a process that can be broken down into the following key steps:
 - Assessment: determine why the new position is necessary and needed, specific goals or problems it aims to address. Identify the job purpose and desired outcomes.
 - Job Analysis: perform job analysis for the new position, this involves breaking down the job duties and responsibilities. Analyze the current state

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of the organization and the gap that the new positions are required to fill. This analysis process involves:

- o Review existing roles and responsibilities to avoid redundancy.
 - o Gather input from relevant stakeholders, department managers, and executives to identify the needs and pain points.
 - Job Description: document detailed job description for the new positions, which outlines the Job titles, purpose of the roles, qualifications, responsibilities, qualifications.
 - Internal or External Recruitment: decide whether to fill the new position internally or externally. Evaluate if existing employees have the potential to fulfill the job responsibilities through training and professional development or external hiring.
 - Onboarding and Training Plan: develop onboarding and training plan to ensure that new employees will be well-prepared to meet the job responsibilities. This includes orientation, training, and mentoring.
 - Regular Review and Update: Job responsibilities should be reviewed and updated periodically to ensure that they remain relevant and aligned with updated needs and goals.
- (b) Please refer to the table below for the total additional costs included in the 2023 and 2024 revenue requirement for these new positions.

**Table 1: Total Costs for New Positions
(\$000)**

	Capital	O&M
Total Labour costs	577	681

- (c) AEY continuously evaluates the most efficient way to manage human capital to ensure optimization. Additional positions were required to manage system growth over the six-year period since AEY's 2016-2017 GRA and remain required into the Test Period. AEY has also reviewed current duties and priorities to assess existing

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capacity. There are also several other alternatives considered prior to hiring new employees, as described below:

- Outsourcing: the quality of work or services provided by external vendors can dissuade companies from outsourcing. So that in-house teams are better equipped to maintain and improve quality. Reliability can also be a concern when it comes to outsourcing. Temporary workers or contractors might be a good option for short-term projects, but they typically are not committed to the long-term success of the company. This can lead to a lack of commitment to the company and potential shortfall of labour in the future.
- Specialized Skills: the additional positions require highly specialized skills or expertise that are not readily available within the existing workforce. Hiring new staff with the required qualifications is essential.
- Higher Workload: when the workload increase is expected to be ongoing and permanent, full-time staff are the preferred option. This ensures continuity in operations, lower risk, and lower costs. Short term increases in workload can be managed with overtime and temporary workers, but these alternatives are generally more expensive.

AEY's forecast of additional FTEs considers all of the factors noted above.

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AEY-UCG-010

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-010

Reference: July 7, 2023 Application, page 1-7 Staff Positions

AEY identifies 3 new positions being added in Engineering including Engineering Technologist and Supervisor, Business Support Services.

Request:

- (a) Have these positions already been filled? If yes, when?
- (b) Was the position for Engineering Technologist and Supervisor not provided for in the 2016 GRA?

Response:

- (a) Yes. The three engineering positions were for two electrical engineers and one mechanical engineer. Please refer to the table below for when these positions were filled:

Table 1: Engineering Positions

Position	Year
Electrical Engineer	2019
Mechanical Engineer	2019
Electrical Engineer	2023

- (b) No.

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
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Received: September 6, 2023**

AEY-UCG-011

Reference: July 7, 2023 Application, page 1-7 Staff Positions

AEY states: The remaining added FTEs address the need of a growing number of customers, vendors and employee expense payment volumes, additional reporting and energy transition planning and communications.

Request:

- (a) How many inter-office personnel did you have in your Whitehorse office in 2016? How many of these same positions will you have in your Whitehorse office in 2023?
- (b) How much for each of the test year revenue requirements will go to head office support for regulatory work, billing and other? Explain each.

Response:

- (a) Please refer to the table below for the FTEs:

Inter-Office Personnel FTEs

Location	2016	2023
Whitehorse office	62.96	69.91

- (b) Please note this is an excerpt taken from AEY 2023-2024 AEY General Rate Application, Schedule 5-3, lines 9 and 11.

**Head Office Support
(\$000s)**

Head Office Costs	2023	2024
Governance, HR, and Health & Safety	121	112
Financial Reporting and Regulatory Support	697	792

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**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-012

Reference: July 7, 2023 Application, page 1-5 May 11, 2016 Application, page 18-1 Energy Transition.

AEY states: Meeting these targets (i.e., Federal Government 2030 Carbon Emissions and Yukon Government Our Clean Energy Future) is having a dramatic impact on AEY's business responsibility to provide safe and reliable electricity at an affordable cost.

Request:

- (a) Give examples of these impacts with forecasted costs associated.
- (b) How much of these costs will be covered by Federal or Territorial grants application?

Response:

- (a) AEY has undertaken a number of initiatives and programs in response to the Federal and Territorial targets, specifically Grid Modernization, Independent Power Production (IPP), EV Chargers, and Micro-Generation.¹ Not all costs associated with these initiatives are being tracked separately, nor have they been realized as some of these programs are in very early stages. However, some examples of the costs included within the application are the addition of two new positions related to Renewables and Grid Modernization² and costs related to IPP projects, specifically the establishment of Electricity Purchase Agreements with IPP's, which are captured in the EPA/IPP Deferral Account.³

¹ 2023-2024 AEY GRA, Section 1B, PDF pp. 22-25.

² 2023-2024 AEY GRA, Section 1.10, PDF p. 16.

³ 2023-2024 AEY GRA, Regulatory Schedules, Schedule 8.8, Line No. 54-58.

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AEY has included forecast MWh of IPP and Micro Generation in its forecast power supply. These amounts have been excluded from forecast wholesale purchases and diesel generation costs and included in supply at the established electricity purchase rate. Over the long term, with expected reductions in diesel consumption, AEY anticipates longer periods between required maintenance of diesel generators.

- (b) IPP projects, and their interconnection to the utility grid, are fully contributed by the proponents. AEY is unable to determine how much Federal or Territorial grants will cover “Our Clean Future” costs; however, AEY is actively investigating the availability to apply for funding. It is important to note that any costs covered by Territorial or Federal funding would be excluded from revenue requirement.

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AEY-UCG-013

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
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Received: September 6, 2023**

AEY-UCG-013

Reference: July 7, 2023 Application, page 1-5 May 11, 2016 Application, page 18-2

AEY states: The AMI solution will eliminate the need for a person to physically read the meters for billing purposes.

Request:

- (a) How much will this save AEY?
- (b) Demonstrate how these savings will be adjusted to the revenue requirement.
- (c) Will AMI give the consumer options for choice or will AEY control the residential systems, i.e., turn devices within the residences on and off at their whim?

Response:

- (a) AEY has not fully forecast savings related to the installation of AMI meters. The AMI program over the Test Period is limited in scope to approximately 1,500 meters located in the Whistle Bend Subdivision. It is anticipated that there will be savings realized from the following: reduced fleet O&M due to fewer truck rolls (situations in which AEY must dispatch a vehicle to physically address a meter issue); lower labour costs as a result of not having to add additional FTE's to the complement to accommodate reading the increase in meter installs due to population growth; and less rework due to weather events. For example, in extreme cold some of the digital displays do not work and AEY has to go out a second time to read, if a read is missed due to deep snow, do not have to go to site to get it as a reading can be pulled from the system.

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- (b) There are no anticipated adjustments to the revenue requirement with this program with such a small scale of deployment.
- (c) AEY is still exploring the options that will be available to consumers as the result of the installation of the AMI network. These may include the option for the customer to participate in future programs where electrical devices behind the meter could be controlled by the utility during peak events or unplanned outage restoration.

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AEY-UCG-014

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-014

Reference: July 7, 2023 Application, page 18-3

AEY states: AEY is requesting deferral on costs associated with the IPPs.

Request:

Give examples of costs that could be associated with IPPs that are to be added to normal business costs.

Response:

Examples of costs that could be included in the deferral account are constraint payments required to be paid to the IPP facility owner in the event that the facility is unable to deliver electricity to the grid as a result of damage to, or a failure of, infrastructure or equipment for which AEY is responsible. Please refer to YUB-002(b)(ii) for other associated costs.

Once the IPP facility is integrated into the grid and has met the Commercial Operation Date, and all requisite conditions for operation, the ongoing operation and maintenance of the Battery Energy Storage System (BESS) and Micro Grid Controller (MGC) are AEY's responsibility similar to other grid electrical infrastructure required to provide electrical service to the community. Examples of maintenance expenses related to the BESS/ MGC can be found in the response to AEY-JM-013(b).

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AEY-UCG-015

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-015

Reference: July 7, 2023 Application, page 18-4

AEY states: Micro generation may lead to policy changes in MG program that will lead to changes to the electrical grid.

Request:

- (a) Give forecast costs associated with these possible changes.
- (b) Will these costs be covered by the YG initiative and the AMI program changes?

Response:

- (a) AEY is not able to provide a forecast for costs related to unknown policy changes. Due to the uncertainty of these costs, AEY is requesting a zero-balance deferral for Board Orders or Legislative Changes to ensure any savings or costs associated are captured and flow through to customers.
- (b) No.

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AEY-UCG-016

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-016

Reference: July 7, 2023 Application, page 18-4

AEY states: Deferral Account for Board Orders and Legislative Changes

Request:

- (a) Does AEY expect to oversee this account?
- (b) How does AEY propose to handle savings related to this proposal.

Response:

- (a) Yes. AEY would oversee this deferral account as it does with all currently approved deferral accounts. Settlement of the proposed deferral account would be subject to review and approval of the Board.
- (b) Once approved by the Board, AEY proposes that any savings eligible for treatment under this deferral be treated consistent with other deferral accounts that flow the savings through to customers through a rider.

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AEY-UCG-017

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-017

Reference: July 7, 2023 Application, page 2-1 Table 2.1 Sales by Customer Class

Request:

- (a) Please confirm that the electricity sales by customer class shown at the top of page 2-1 are weather normalized.
- (b) Has the YUB approved a forecast wholesale sales level for 2023 and 2024 for Yukon Energy Corporation? If yes, what is the amount.
- (c) Please provide details on when AEY's current sales forecasts for 2023-2024 were determined for this rates application.
- (d) Please identify the impact that demand side management had on sales levels in 2018, 2019, 2020, 2021 and 2022. Explain how this impact has been incorporated into the sales forecast for 2023 and 2024 and provide a revised version of Schedule 2.1 showing the actual and forecast sales for 2023-2024 with DSM impacts isolated.
- (e) Please provide an updated table with the 2023 Forecast reflecting 6 months of actuals and the impact this would have on the 2023 forecast.

Response:

- (a) Not confirmed.
- (b) No, the YUB has not yet approved YEC's wholesale sales forecast for 2023 and 2024.
- (c) AEY's current sales forecast for 2023-2024 was completed in May 2023.

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- (d) AEY is not able to quantify the precise impact of DSM on the sales forecast as no detailed studies have been completed.
- (e) Please refer to the table below for an updated Table 2.1 which incorporates six months of actuals into the 2023 sales forecast:

**Table 2.1 AEY Sales by Customer Class
(MWh)**

	2016	2017	2018	2019	2020	2021	2022	2023 ¹	2024
	Actual							Test Period	
Residential	151,351	165,654	167,596	166,455	185,235	188,526	188,388	187,840	195,966
Commercial	157,662	165,924	168,285	168,680	163,933	166,022	168,541	170,146	175,244
Street Lights	3,923	3,942	3,951	3,876	3,889	3,937	3,884	3,878	3,883
Private Lights	496	495	486	480	452	452	456	441	431
Total Retail Primary	313,432	336,016	340,318	339,491	353,508	358,936	361,269	362,304	375,523
Secondary Sales	4,835	8,385	258	1	479	4,430	3,439	1,861	2,931
Wholesale Sales	548	584	636	693	704	487	420	456	451
Total Company	318,815	344,985	341,212	340,184	354,691	363,853	365,128	364,621	378,905

1. 2023 Forecast includes 6 months of actuals for January, February, March, April, May and June.

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AEY-UCG-018

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-018

Reference: July 7, 2023 Application, page 2-1 Sales by Customer Class AEY states; AEY forecasts the total primary retail sales to increase 0.2 per cent in 2023 and to increase 3.7 per cent in 2024. The forecast growth in retail sales for 2023 and 2024 follows year over year growth averaging approximately 1.1 per cent over the period 2020 to 2022.

Request:

- (a) Please provide details of the referenced population growth analysis undertaken by AEY and copies of the reference documents.
- (b) Please provide specific detail on the impact that DSM and other energy efficient initiatives have had on electricity sales for 2020, 2021 and 2022 including how AEY has determined the impact of these initiatives.

Response:

- (a) AEY referenced multiple pieces of information to determine an economic outlook for the Yukon. AEY relied on documents sourced from the Yukon Bureau of Statistics and Yukon Economic Development. Please refer to AEY-UCG-018(a) Attachment 1 for copies of the documents.
- (b) Please refer to the response to AEY-UCG-017(d).

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Introduction

The 2023–24 Fiscal and Economic Outlook presents the territory's current fiscal and economic position and expectations for the medium term. The Government of Yukon is moving the territory toward a sustainable and prosperous future while ensuring responsible fiscal management across all government programs and services. The Yukon is recovering from the impacts of the pandemic and the economic outlook is positive.

Despite the recent challenges created by higher rates of inflation, expectations are that the Yukon will build on 2022's robust economic growth, with further real Gross Domestic Product (GDP) gains and an outlook highlighted by a strong labour market and additional population growth. The government remains committed to working closely with partners in the public and private sectors, including First Nations governments, to ensure a strong, diversified and sustainable economy for all Yukoners. Overall, the territory's economy is well-positioned to address the challenges ahead and continue growing in the coming years.

Part 1: The Yukon's finances

In the 2023–24 Budget, the Yukon government is delivering on its longstanding commitment to growing the economy while ensuring strong, sustainable fiscal management. The government projects a surplus of \$48.2 million in 2023–24 and projects to remain in a surplus position throughout the duration of this fiscal outlook. A surplus of 2-3 per cent of the total budget is a prudent fiscal management tool and demonstrates the ability of the government to address unforeseen events without going into deficit. Maintaining a surplus position lessens the government's potential need to borrow funds and reduces the net debt position. The expected fiscal position in 2023–24 reflects a focus on strategically allocating resources to the ongoing priorities of Yukoners.

Table 1. Fiscal summary

(\$ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Revenue ^{1,2}	1,460.2	1,504.5	1,575.4	1,663.5	1,719.2
Expense ³	(1,644.6)	(1,683.8)	(1,642.4)	(1,716.5)	(1,769.1)
Contingency for Anticipated Expenses	(10.0)	(10.0)	(50.0)	(50.0)	(50.0)
Accounting Adjustments ⁴	233.9	233.2	165.2	161.7	144.9
Surplus/(Deficit) ⁵	39.5	43.9	48.2	58.8	45.1
Net Financial Assets/(Debt), end of year ⁶	(207.5)	(298.5)	(374.8)	(453.0)	(528.0)

Source: Department of Finance. Numbers may not add due to rounding.

1. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are included in the Accounting Adjustments in this table.

2. Figures for revenue, contingency for anticipated expenses and surplus (deficit) are found on Pages S-8 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

3. Figures for expense and accounting adjustments are found on Pages S-18 of the 2023–24 Main Estimates and equivalent pages of budget documents for other periods.

4. Accounting Adjustments are the sum of "Tangible Capital Assets (net)," "Investment in Land Development," "Expenditures on Loan Programs," and "Other Adjustments (net)," on Page S-9 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

5. Surplus/(Deficit) is the sum of Revenue, Expense, Contingency for Anticipated Expenses, and Accounting Adjustments.

6. Found on Page S-9 of the 2023–24 Main Estimates.

Net financial debt, or net debt as it is often known, is expected to increase by \$76.3 million in 2023–24 to a total of \$374.8 million. Recent increases to the government's net financial debt position were incurred to fund ongoing maintenance of the territory's infrastructure and to invest in new projects that will benefit Yukoners now and well into the future. In standard accounting, net financial debt is a measure of how much the government would need to pay if all of its liabilities were due immediately. It does not mean government needs to borrow those funds. Most of the government's net debt position is for long-term liabilities that will not be realized all at once.

Part of the changes to net debt reflect a new accounting standard that came into effect in April 2022. These new rules require the government to record and measure future financial obligations to retire government assets from service, such as buildings or equipment, once they are no longer of productive use. The estimated future costs to retire an asset are then recognized over an asset's productive life. The increase to net debt from 2022–23 includes an additional \$54.3 million to reflect accounting changes to align with the new standard. The new standard is also expected to increase net debt by approximately \$1.6 million annually.

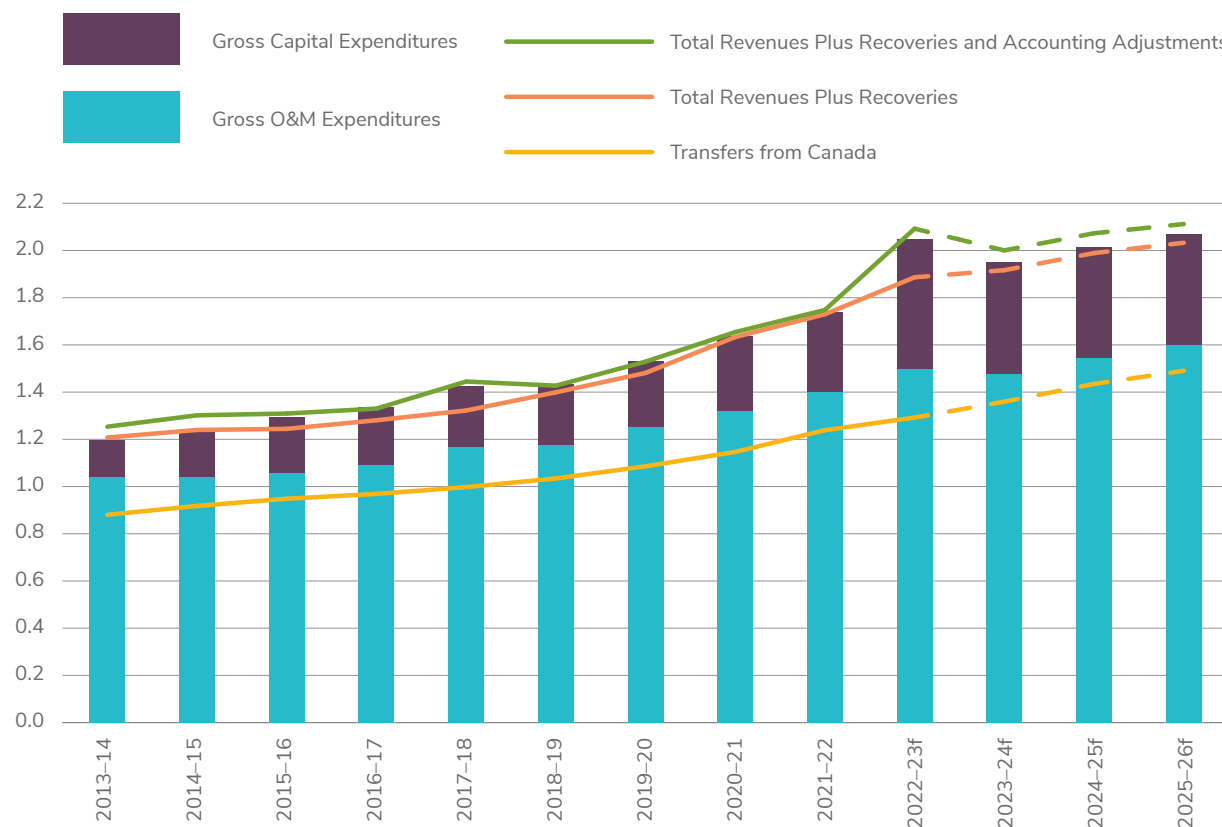
The government is committed to maintaining fiscal sustainability. To achieve this, the government has reviewed spending commitments to ensure expenditures are effectively being used within the framework of expected revenues. These measures will help to ensure that the government is able to meet its spending commitments while maintaining a healthy fiscal position. Capital expenditures are forecast to decrease by \$35.2 million or 9.9 per cent, net of recoveries, from the 2022–23 Main Estimates to preserve the government's strong fiscal standing and address increasing inflation while continuing to invest in priority areas. The decrease to capital spending is partially offset by an increase to the forecast for Operations and Maintenance (O&M) expenditures of \$33.0 million or 2.6 per cent, net of recoveries, from the 2022–23 Main Estimates.

The government's fiscal summary for 2023–24 also includes a \$50 million contingency for areas of expected, but presently undefined, expenditures. The government has benefitted from this realistic approach to budgeting in recent years for COVID-19 spending and we are continuing this approach for expected cost pressures. These costs are not presented in departmental budgets in the coming fiscal year as the expenditures are not yet known. They are included in the overall financial framework so that they will not affect the Yukon's forecast fiscal position, should they be needed. This allows the government to remain transparent about potential pressures and would require legislative authority.

In Chart 1, forecast spending and revenue for the Yukon, including recoveries, from 2022–23 through 2025–26, are compared to historical spending as reported in the Yukon's Public Accounts. In recent fiscal years, growth in government spending has increased in line with revenue growth. For the fiscal years between 2013–14 and 2022–23, O&M expenditures have grown by 5.1 per cent annually and revenues have grown by 5.0 per cent annually, on average. For 2023–24 to 2025–26, expenditures and revenues are expected to change at a similar pace, with expenditures growing by an annual average of 2.3 per cent, while government revenues are expected to grow at an average of 2.5 per cent annually.

Chart 1. Government of Yukon fiscal indicators^{7,8}

Expenditures and revenues (\$ billions)



Source: Department of Finance

f = forecast

7. Fiscal years 2013–14 to 2021–22 represent actuals as reported in the Yukon's Public Accounts. For comparability, forecasts for fiscal years 2022–23 to 2025–26 use the same methodology, which differs from the presentation in Table 1 above.

8. To align with the presentation in the Yukon's Public Accounts, revenues and recoveries do not include those collected by the Yukon Housing Corporation, which are netted-out of the gross expenditures presented in this chart.

Revenue

Government revenues rely heavily on transfers from the Government of Canada, supplemented by own-source revenues that are mostly driven by economic activity. The Yukon government's revenue is critical to ensuring that the government has the resources needed to meet its spending commitments. As shown in Table 2, total revenue, excluding recoveries, is expected to be \$1.58 billion in 2023–24. This represents an increase of \$70.9 million, or 4.7 per cent, from the most recent estimates in the 2022–23 Supplementary Estimates #2. This increase is primarily driven by the territory's economic position and a changing fiscal situation across Canada, which affects federal transfers.

Table 2. Revenue by type^{9,10}

(\$ millions)	2022–23 Main Estimates	2022–23 Supplementary Estimates #2	2023–24 Main Estimates	2024–25 Plan	2025–26 Plan
Transfers from Canada	1,244.4	1,261.4	1,327.0	1,400.3	1,454.7
Tax revenue	157.7	175.0	170.9	177.2	182.2
Personal income tax	89.9	100.7	98.4	102.4	105.6
Corporate income tax	24.4	32.0	27.4	27.8	28.4
Property tax	7.0	7.0	7.2	7.6	7.7
Fuel oil tax	9.7	8.7	8.8	8.8	8.9
Tobacco and alcohol taxes	18.6	18.4	20.0	20.7	21.1
Insurance premium tax	8.1	8.2	9.0	9.9	10.6
Other revenue	58.1	68.1	77.5	85.9	82.3
Liquor profit	9.4	7.5	8.8	8.8	9.1
Licenses, fees, registrations and permits	17.6	17.1	18.3	18.7	19.2
Sale of land	19.2	20.8	32.3	34.2	31.3
Other revenue	12.0	22.8	18.1	24.2	22.6
Total revenue	1,460.2	1,504.5	1,575.4	1,663.5	1,719.2

Source: Department of Finance. Numbers may not add due to rounding.

9. All revenue figures are found on Pages S-14 and S-15 of the 2023–24 Main Estimates, and equivalent pages of budget documents for other periods.

10. To align with the presentation in the Yukon's Public Accounts, revenues do not include those collected by the Yukon Housing Corporation.

Transfers from Canada

Transfers from Canada, which includes the Territorial Formula Financing grant, represent about 84 per cent of the Yukon's total revenue in 2023–24. Territorial formula financing helps to reduce the gap between the Yukon's ability to raise revenue and its spending needs for core services.

The grant is responsive to changing economic and demographic circumstances in the territory compared to the rest of the country. This includes changes in public spending across the country, which are increasing due to the high inflationary environment and associated inflation relief programs. The growth in spending for other provinces and territories have an upward impact on the Yukon's Territorial Formula Financing grant. However, the improved outlook on the grant is being offset somewhat by growth in resource revenues. Resource revenues in the territory are expected to increase as royalties increase, which would have a downward impact on revenue from the Territorial Formula Financing grant. Under the Devolution Transfer Agreement with Canada, the Yukon's grant is reduced dollar for dollar of resource revenues in excess of \$6 million in any given year. Resource revenues subject to offset were \$10.2 million in 2021–22, meaning the grant in 2023–24 will be reduced by \$4.2 million.

At the time that the 2023–24 Main Estimates were prepared, the Yukon government, along with other provinces and territories, were discussing increases to the Canada Health Transfer that could strengthen the healthcare system for the benefit of all Canadians. The Canada Health Transfer forms part of the overall transfers from Canada. Increases to the Canada Health Transfer have not yet been included in expected revenues for 2023–24.

Taxation revenue

The Yukon's own-source revenue from taxation is forecast to decrease in 2023–24 from the 2022–23 Supplementary Estimates #2. Personal and corporate taxation revenues are expected to be strong in 2023–24, but are forecast to be lower than current estimates for 2022–23 primarily due to a non-recurring adjustment for the 2021 tax year in 2022–23. Adjustments for prior tax years are common due to the timing of final reconciliations of tax assessment information. Corporate income tax projections for 2022–23 have been revised upward from stronger than expected corporate profits but are expected to return to trend in 2023–24.

Personal income tax revenues are expected to continue to be strong due to high inflation and the territory's strong labour market performance, which is increasing individual taxable incomes. Business performance continues to be strong in the territory, but corporate income tax revenue can see large variations from year-to-year. The outlook for corporate taxation, while still expected to increase, has also been reduced from projections in previous years due to a change in federal tax provisions that increases the scope of businesses eligible for the small business tax rate. In the Yukon, the small business tax rate is zero per cent.

The forecast for tax revenue from tobacco products has increased. The *Tobacco Tax Act* links changes to the tax rate to changes in the Consumer Price Index (CPI), so the tax rate increased from 31 cents to 32 cents per cigarette as of January 1, 2023. Under the current outlook for inflation, the tax rate for tobacco products is expected to increase to 37 cents per cigarette by the end of 2027.

Expectations for fuel tax revenue in 2023–24 are lower than in the 2022–23 Main Estimates. Fuel tax revenues have not returned to pre-pandemic levels, which could be partly explained by the tourism industry continuing to operate below levels experienced prior to the start of the pandemic. The ongoing outlook for fuel taxes is expected to be mostly flat as more Yukoners adopt electric vehicles and make other transportation choices that are consistent with the Yukon's *Our Clean Future* strategy.

Aside from changes to the tobacco tax, there are no changes to tax rates proposed as part of the 2023–24 budget.

Other revenue

In addition to transfers from Canada and taxation revenue, the government also generates revenue from other sources. These include liquor profit, licenses, fees, registrations, permits and proceeds from land sales. Revenue from these sources are expected to exceed recent levels, in part due to elevated revenue from land sales.

Operations and maintenance expense

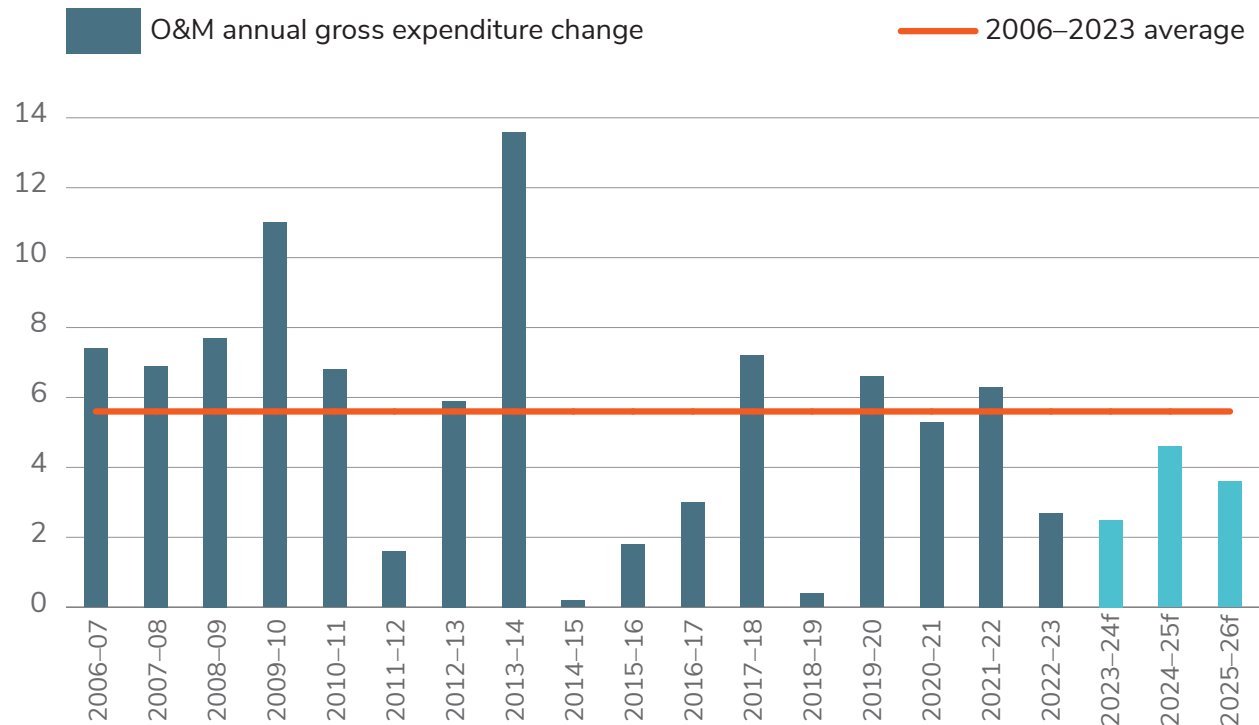
O&M spending for 2023–24 is budgeted at \$1.45 billion, which reflects a \$35 million, or 2.5 per cent, increase over the previous year's Main Estimates. The increase in spending is primarily for:

- making day-to-day life more affordable for Yukoners;
- investing in the Yukon's health and social system;
- addressing the substance use health emergency;
- improving sustainability and preserving the territory's environment;
- investing in housing and related services, particularly for the most vulnerable; and
- continuing to build relationships and foster reconciliation with Yukon First Nations.

Chart 2 compares forecast gross O&M spending from 2022–23 through 2025–26 to actual historical O&M spending as reported in the Yukon’s Public Accounts. The average annual growth in O&M spending between 2006–07 and 2022–23 was 5.6 per cent. Forecast O&M spending growth in 2024–25 and 2025–26 is anticipated to remain below the average at approximately 4.5 per cent and 3.5 per cent, respectively.

Chart 2. Annual growth in O&M budgets

Change in Government of Yukon gross O&M spending (per cent)



Source: Department of Finance

f = forecast

Higher rates of inflation continue to be the reality for Yukoners, and family budgets are becoming tighter. The government continues to take steps to provide targeted inflationary relief to families, especially the most vulnerable. The government continues to assess how inflation is impacting Yukoners. In 2023–24, the government is extending the Inflation Relief Rebate Program, which provides a \$50 per month rebate on ATCO Electric and Yukon Energy utility bills for the April and May billing periods, along with an additional three months later in the year. Other measures in the 2023–24 Budget to help make life more affordable for Yukoners include funding for food in Yukon schools, the timber harvesting incentive to boost fuelwood supply, a quarterly top-up of \$150 to eligible recipients of the Yukon Senior Income Supplement and a \$100 monthly increase to eligible Social Assistance recipients.

With the COVID-19 State of Emergency coming to an end in March 2022, the Yukon is now adapting to living with the risks from COVID-19 while continuing to support Yukoners' well-being. However, healthcare systems across Canada, including the Yukon, continue to be strained following the pandemic. Healthcare workers are experiencing stress and burnout, and people seeking health services are experiencing long wait times due to staff shortages. The 2023–24 Budget includes funding to improve supports for critical staff, including recruitment and retention bonuses for nurses, negotiated increases with the Yukon Medical Association, a human resources strategy to improve health care worker recruitment and adding nursing positions in rural locations. The government also continues to act on the recommendations from the *Putting People First* report. This includes funding for the territory's dental plan, early learning and childcare.

In 2023–24, the government will continue to support the needs of individuals and communities impacted by the substance use health emergency. This includes additional funding to address the harms of substance use, combat the supply of harmful substances through additional RCMP supports, and help youth with substance use challenges. Together, these initiatives support people who are struggling with addiction and mental health issues and help to reduce the harm caused by substance use in communities.

Many areas across Canada are facing housing shortages and challenges with housing affordability. In 2023–24, the government will continue working to meet the housing needs of Yukoners, including partnering with the private sector on lease costs and supportive services for seniors at the new Normandy Living facility in Whitehorse. The Budget also includes funding to ensure the Yukon Housing Corporation's housing stock remains safe and well maintained.

The government remains fully committed to supporting reconciliation and respectful partnerships with Yukon First Nations governments. The government is working in partnership with Yukon First Nations on key priorities in 2023–24. This includes funding for Community Safety Officers and policing initiatives in communities, and support for the community safety planning priorities of Yukon First Nations governments in their communities.

The government continues to make progress on the implementation of *Our Clean Future* and protect the environment. The Yukon government is working in partnership with the Government of Canada to advance land use planning and species-at-risk protection in the Yukon through the *Bilateral Nature Agreement*. Through this, government will advance work towards the federal government's mandate to conserve and protect 25 per cent of land by 2025, and 30 per cent by 2030.

Five-Year Capital Plan update

With the 2023–24 Main Estimates, the Yukon government is publishing its sixth annual plan for its capital investment priorities over the next five years. The plan helps drive transparency, certainty and coordination with businesses, First Nations governments and municipalities.

Table 3. Five-Year Capital Plan gross expenditures by category

(\$millions)	2023–24	2024–25	2025–26	2026–27	2027–28	Totals
Climate change, energy and green economy	36	43	47	42	29	197
Land development, housing, education and health	133	84	78	81	93	470
Community and First Nations infrastructure	78	75	75	60	65	352
Transportation infrastructure	160	177	197	123	123	779
Real property and asset management	33	46	46	51	35	211
Information technology	45	51	18	17	14	146
Totals	484	475	462	374	359	2,155

Source: Capital Planning Office. Numbers may not add due to rounding.

The 2023–24 Five-Year Capital Plan includes approximately \$2.15 billion in capital spending over the next five years. These investments will focus on improving access to stable and affordable housing, increasing accessibility to healthcare services, providing modern school facilities and advancing the territory’s climate change goals. The government continues to leverage funding from the federal government and other partners to find offsets for over one-third of the capital spending in the plan.

The capital budget for 2023–24 is projected to be \$483.8 million, a modest decrease from the 2022–23 Main Estimates. The government remains committed to robust and steady investments in the territory’s infrastructure. However, it is prudent for the government to carefully consider how it is investing in capital projects to address increasing inflation by reducing previously planned capital spending in its *Five-Year Capital Plan*. The government has reviewed planned projects in the Plan to ensure it is maintaining its current assets while delivering on the new critical infrastructure that Yukoners need. For certain capital projects, the government is exploring innovative ways to deliver these projects, including partnering with municipalities or First Nations governments in the development of new infrastructure. This approach has resulted in a lower total spend in the next few years compared to earlier projections, while creating a more stable outlook for capital spending.

The government remains committed to robust and steady investments in the territory's infrastructure.

The government is making priority capital investments across six main areas in the 2023–24 Five-Year Capital Plan:

- \$197 million for climate change, energy and green economy projects to continue to advance the *Our Clean Future* strategy and invest in sustainable jobs in the territory. In 2023–24, this includes investing in renewable energy projects, such as solar installations and biomass, through the Green Infrastructure Program; and helping Yukoners increase the energy efficiency of their homes and businesses through the Better Buildings energy retrofit loans program.
- \$470 million for land development, housing, education and health projects to ensure the territory can meet the housing, educational and healthcare needs of a growing population and economy. In 2023–24, this includes completing the Old Crow 10-unit mixed-use housing project and work on the Kêts'ádań Kù School in Burwash Landing.
- \$352 million for community and First Nations infrastructure to meet infrastructure needs in communities across the territory, including working in partnership with Yukon First Nations and municipal governments on their priorities. In 2023–24, this includes work on a new Fire Hall building in Carmacks; upgrades to the existing Public Works building in Carmacks; and upgrades to the Teslin Tlingit Council community hub.
- \$779 million for transportation infrastructure to invest in the territory's transportation system to keep Yukoners and the economy moving and advance the sustainability of supply chains critical to the Yukon. In 2023–24, this includes ongoing work on critical components of the Yukon's transportation infrastructure like the Nisutlin Bay Bridge project, Erik Nielsen Whitehorse International Airport runways and upgrades to the North Klondike Highway.
- \$211 million for real property and asset management projects to build and maintain assets that are essential to the delivery of government services. In 2023–24, this includes continuing to retrofit the Old Territorial Administration Building in Dawson City and work on conceptual designs for potential expansions and recreational activities at several campgrounds across the territory.
- \$146 million for information technology projects to enhance the territory's vital technological links to Canada and the world. In 2023–24, work will continue on the Dempster Fibre project, which will provide redundancy, increase reliability and reduce the risk of outages in the territory's critical telecommunications infrastructure.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.

Some important recently-completed projects include:

- \$22 million, along with funding from Canada, for the Mayo to McQuesten Transmission Line replacement project, which came online in 2021 and is improving the quality and reliability of electricity infrastructure in the area;
- \$22 million, in partnership with Canada, for the Faro Public Works & Fire Hall Building and the Watson Lake Municipal Services Building, which combine public works and fire services into a single shared space, saving money on both construction and long-term operating costs; and
- \$21 million for the 47-unit residential housing complex at 401 Jeckell Street, completed in January 2023 in partnership with the Canada Mortgage and Housing Corporation. It is providing affordable homes of various sizes for low-income and vulnerable families, seniors and individuals.

In recent years, the government has made substantial capital investments to help sustain and build upon critical infrastructure for the benefit of Yukoners now and for generations to come.



Part 2: Economic overview

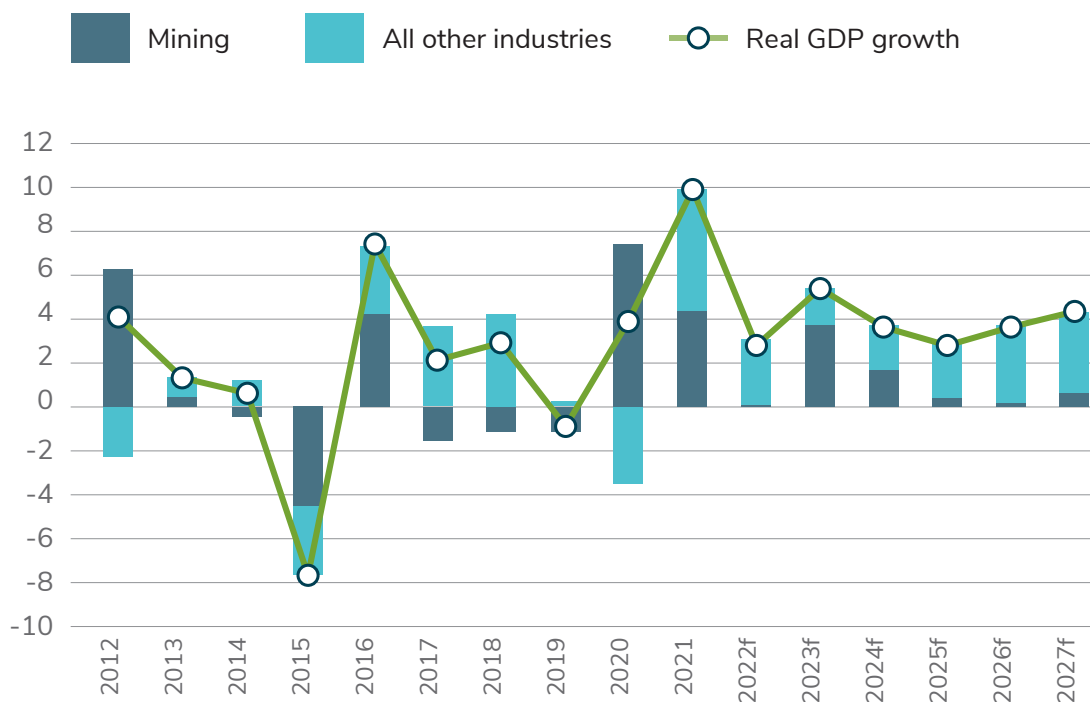
Positive outlook for real GDP growth

The outlook for the Yukon's economy remains positive. A strong labour market is leading to job growth and low unemployment. Tourism is coming back to the territory and the construction sector is busy. Inflation remains higher than anticipated but is expected to moderate with the stabilization of energy prices, improvements to global supply chains and an increase in interest rates that is beginning to absorb excess demand in the Canadian economy.

The Yukon's real GDP is expected to continue to expand. The Yukon led the country in real GDP growth in both 2020 and 2021, with 2021's increase of 10 per cent being the strongest in 13 years. The pace of this expansion returned to more normal levels in 2022 with estimated real GDP growth of 3.1 per cent, close to the Canadian growth estimate of 3.5 per cent. Last year's performance was impacted primarily by the mining sector with disruptions at the Eagle Gold mine and a temporary suspension of operations at the Keno Hill mine.

Chart 3. Further gains in real GDP expected in all years of the forecast

Contribution to real GDP growth (percentage points)



Source: Statistics Canada, Department of Finance

f = forecast

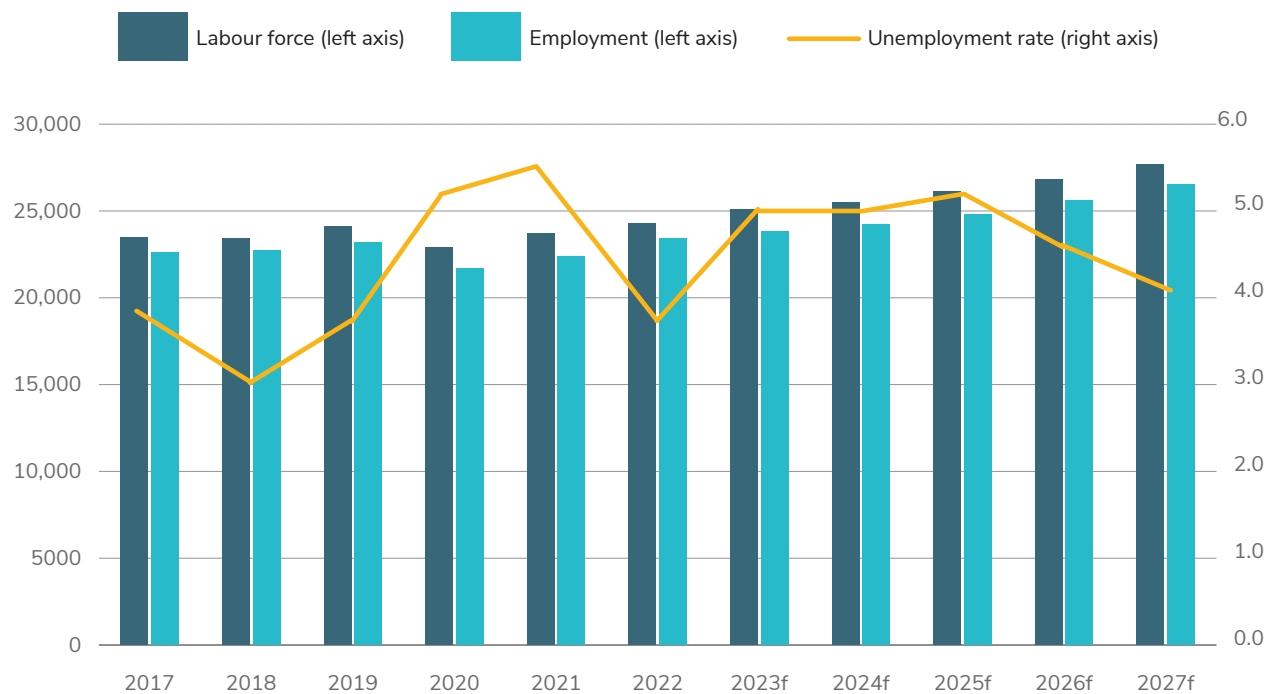
Production at Eagle Gold is expected to ramp up this year and operations at the Keno Hill mine are expected to resume in the third quarter. Higher mineral production and continued recovery of the tourism sector are expected to result in real GDP growth of 5.4 per cent in 2023 followed by 3.7 per cent growth in 2024. Further growth is projected throughout the remainder of the forecast, averaging 3.7 per cent growth through 2025 to 2027.

Further gains in the labour force and employment expected over the medium term

Strong demand for labour and increased economic activity spurred growth in the size of the labour force and employment as both reached record highs in 2022. Employment growth of 4.5 per cent last year outpaced the increase in the labour force and translated into a substantial decline in the territory's unemployment rate. At 3.7 per cent for the year, the Yukon's unemployment rate matched 2019's level and was the lowest in Canada.

Chart 4. Growth in employment and the labour force

Labour force (persons), employment (persons), unemployment rate (per cent)



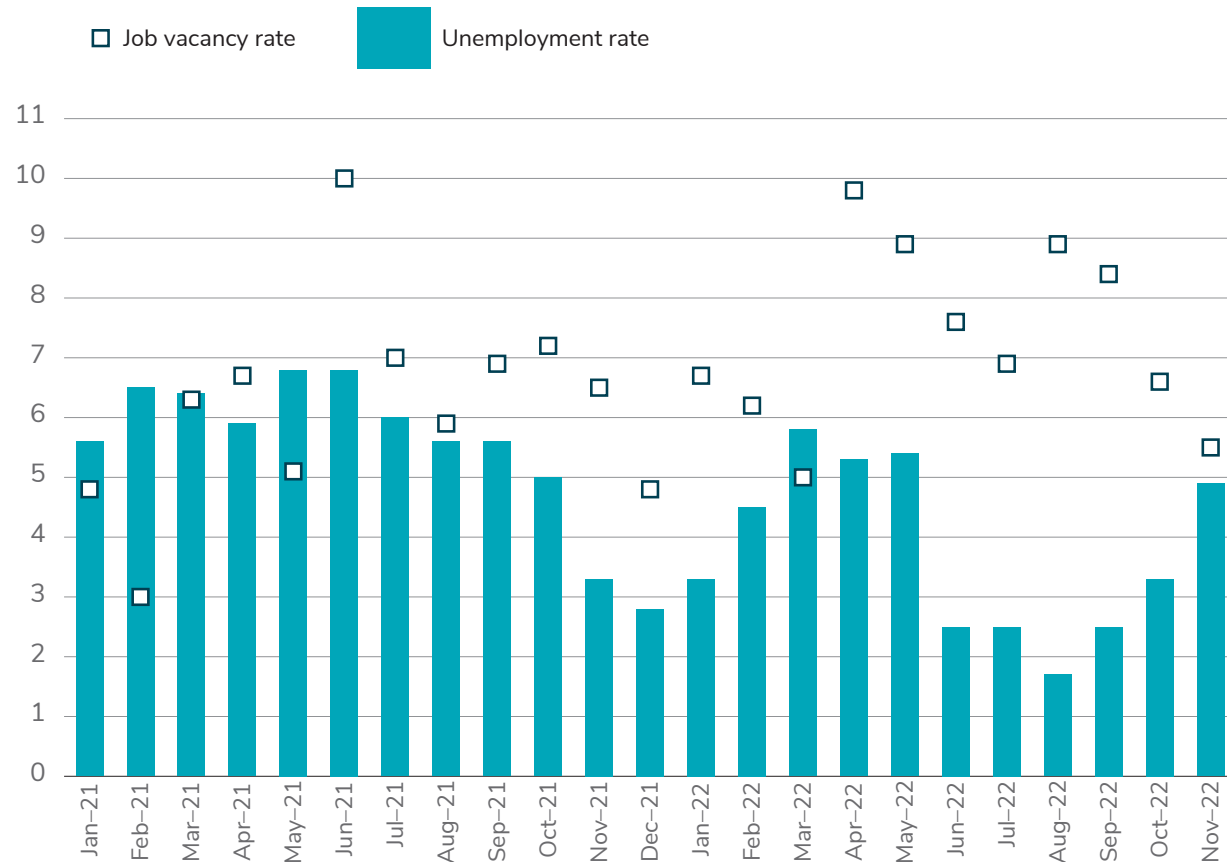
Source: Statistics Canada, Department of Finance

f = forecast

Many employers in the Yukon and across the country have had difficulty finding workers. Job vacancies have been elevated in the territory throughout 2022, with the Yukon's job vacancy rate¹¹ among the top two highest rates in the country for all but one month. Like the experience of many jurisdictions in Canada, the job vacancy rate for the Yukon has recently been higher than the unemployment rate¹², further evidence of a tight labour market (Chart 5).

Chart 5. 2022 has seen tightness in the labour market return

Labour market indicators (per cent)



Source: Statistics Canada

11. The job vacancy rate is the number of job vacancies expressed as a percentage of labour demand, defined as all occupied and vacant jobs.

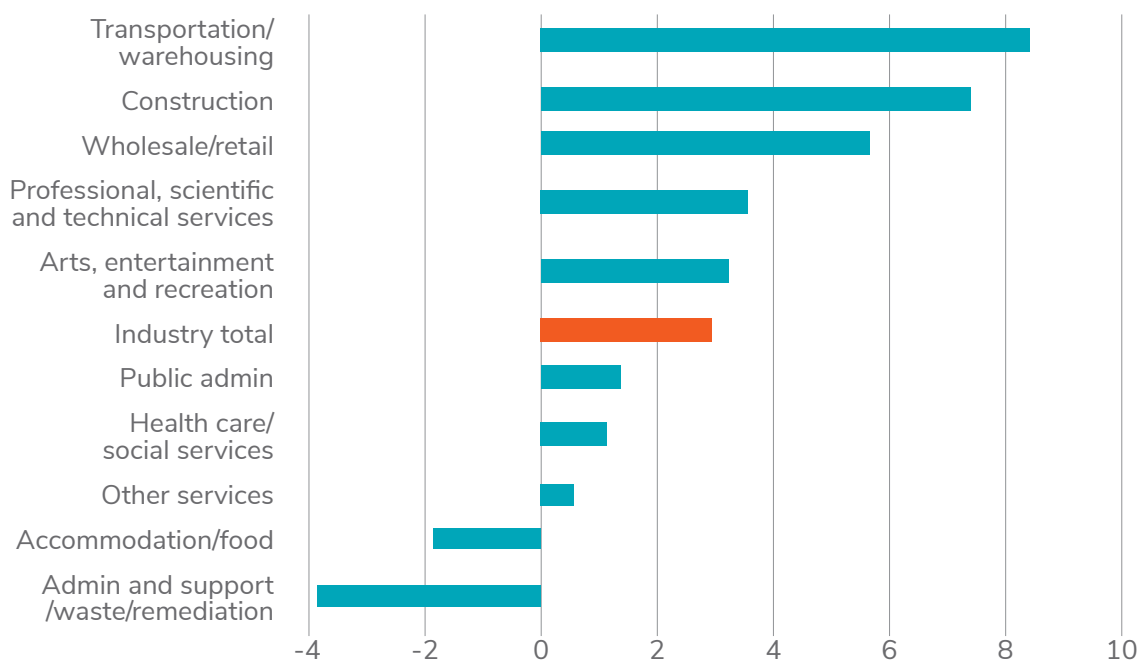
12. When the job vacancy rate exceeds the unemployment rate, this means there are proportionally more jobs seeking workers than workers seeking jobs.

Strong demand for workers at a time when supply is tight is placing upward pressure on wages and earnings. The average offered wage for vacant positions in the Yukon was the third highest in the country at \$26.20 per hour in the third quarter of 2022¹³, well above the national average of \$24.20 per hour and up almost 10 per cent from 2021.

The recent increase in weekly earnings was not as pronounced as the increase in offered wages, but earnings are up across most industries (Chart 6). The average worker in the territory earned \$1,334 per week through the first eleven months of 2022, up 2.9 per cent from the same period in 2021. Average weekly earnings for the Yukon ranked third in the country, behind only Nunavut and the Northwest Territories, and were well above the national average of \$1,166 per week. While in some cases wages are not keeping pace with inflation, rising incomes have helped to mitigate the inflationary impacts being felt.

Chart 6. Wage pressures reflected in higher earnings across most industries

Average weekly earnings, seasonally adjusted, Jan–Nov 2022 change from Jan–Nov 2021 (per cent)



Source: Statistics Canada

Over the medium term, higher earnings are expected to draw more people into the labour force. The Yukon's labour force is projected to grow slightly faster than employment over the forecast period. This results in a higher projected unemployment rate in the neighbourhood of five per cent. While up from historic lows in recent years, the unemployment rate is projected to remain relatively low, and continue to be one of the lowest in Canada.

13. Average offered wage data is from Statistics Canada table 14-10-0325-01 and is available on a quarterly basis starting with the first quarter of 2015.

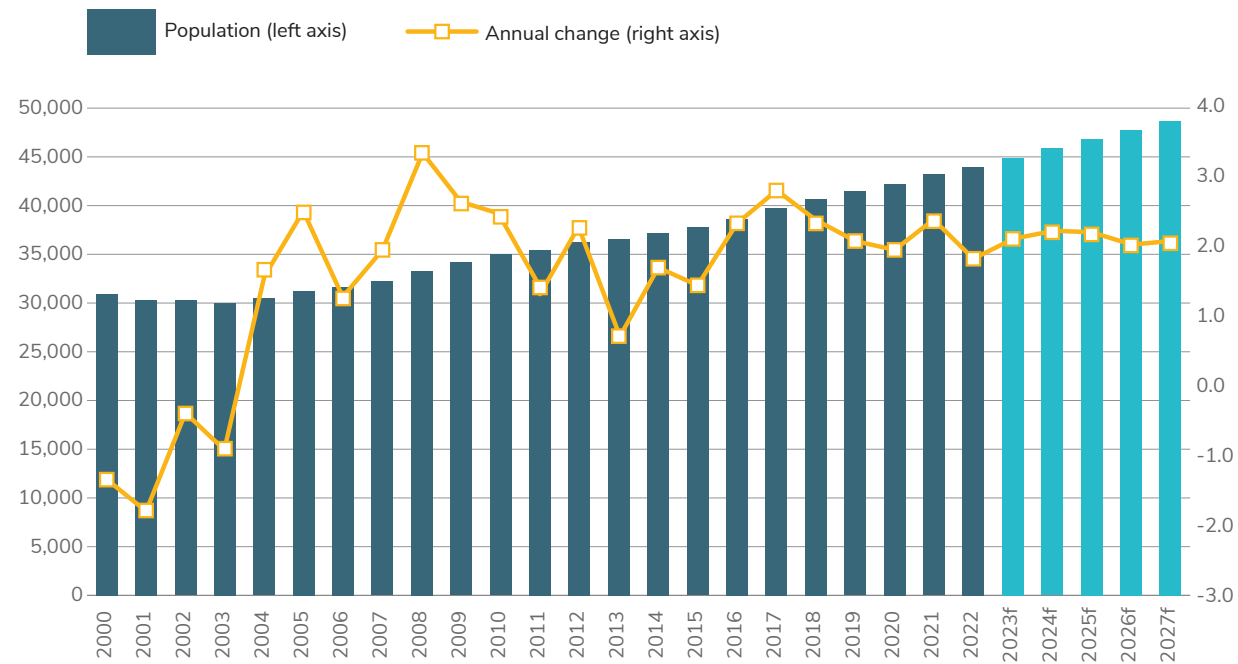
Further population gains anticipated in 2023

At 43,964 on June 30, 2022, the Yukon's population was up 1.8 per cent from 2021.¹⁴ Growth in 2022 was driven primarily by net international migration of 550, which was the highest ever reported.¹⁵ Over the last 20 years, the Yukon's population has grown just over 44 per cent. This growth was second only to Alberta (45.2 per cent) among all provinces and territories and was well ahead of the national growth of 24 per cent. A positive outlook for the territory's economy and labour market is expected to support strong migration into the Yukon and population growth over the medium term.

The federal government is targeting nearly 1.5 million new permanent residents over the 2023 to 2025 period.¹⁶ High levels of immigration should increase the local supply of labour and help alleviate some of the tightness in the labour market. While helping on the labour front, more people moving to the territory has the potential to place further strain on the Yukon housing market, as supply has struggled to keep pace with demand in recent years.

Chart 7. Population is forecast to approach 49,000 by 2027

Population (persons), annual change (per cent)



Source: Yukon Bureau of Statistics

f = forecast

14. June 30 estimates are considered annual estimates.

15. Statistics Canada's table 17-10-0005-01 reports data for population estimates by age and sex as of July 1.

16. Government of Canada's *Immigration Levels Plan for 2023–2025*. Immigration, Refugees and Citizenship Canada (November 1, 2022).

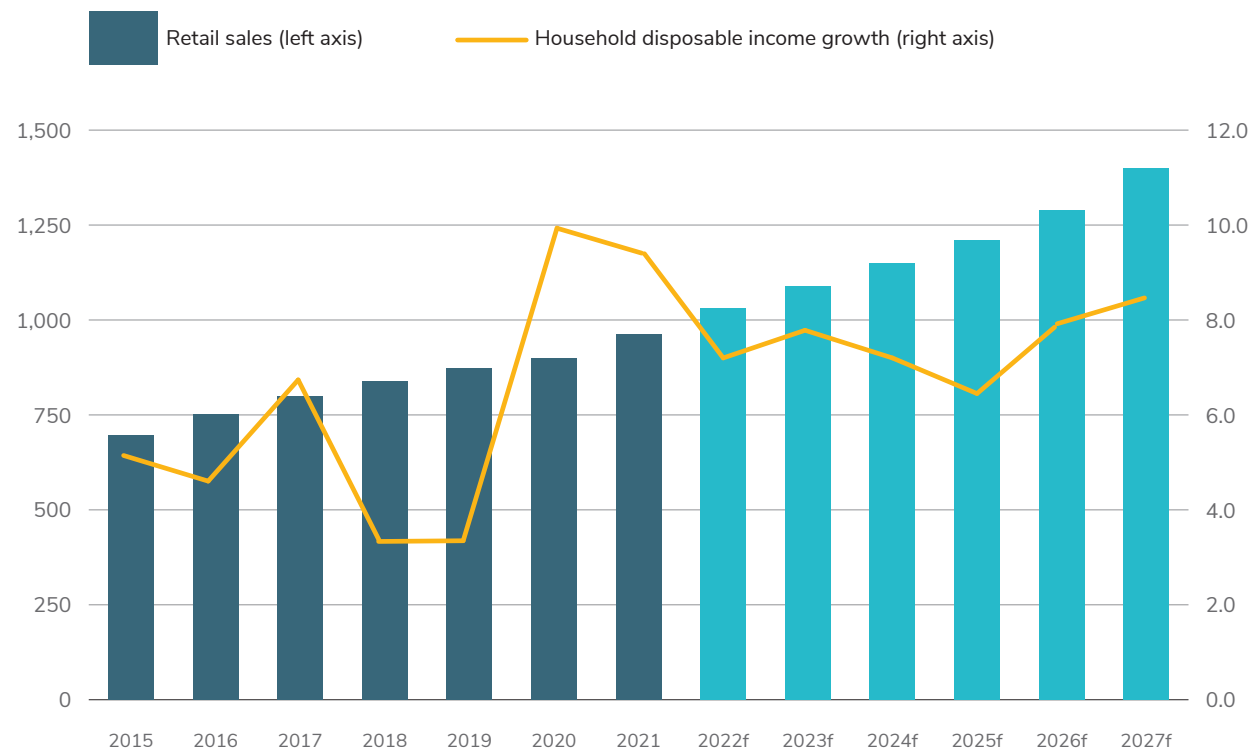
Countering some of the gains in international migration in 2022 was a net outflow of interprovincial migration resulting in 83 fewer residents. This was the first time net interprovincial migration was negative since 2013. Population is projected to increase in every year of the current forecast with growth averaging 2.1 per cent per year. By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.

Retail sales exceeded \$1 billion in 2022

Retail sales exceeded one billion dollars for the first time in 2022. Estimated growth of 6.8 per cent in 2022 is more than double the growth rate from the previous year. Prices were the primary driver of last year's growth in retail sales, with the estimated percentage increase in retail sales equivalent to the 6.8 per cent increase noted in the Whitehorse CPI. The current forecast has retail sales growing every year by an average of 6.3 per cent per year, significantly higher than the projected CPI increases over the same time span.

Chart 8. Income growth a key driver of retail sales growth

Retail sales (\$ millions), Household disposable income growth (per cent)



Source: Statistics Canada, Department of Finance f = forecast

By 2027, the last year of the forecast, the Yukon's population is expected to be near 49,000.



Inflation has increased globally

Global supply chain disruptions and the war in Ukraine contributed to higher food and energy prices in 2022 and added to inflationary pressures noted all over the world. In Canada, domestic factors, including excess demand for labour and other inputs, have also fueled price growth, with the national inflation rate touching levels in 2022 not seen since the early 1980s.

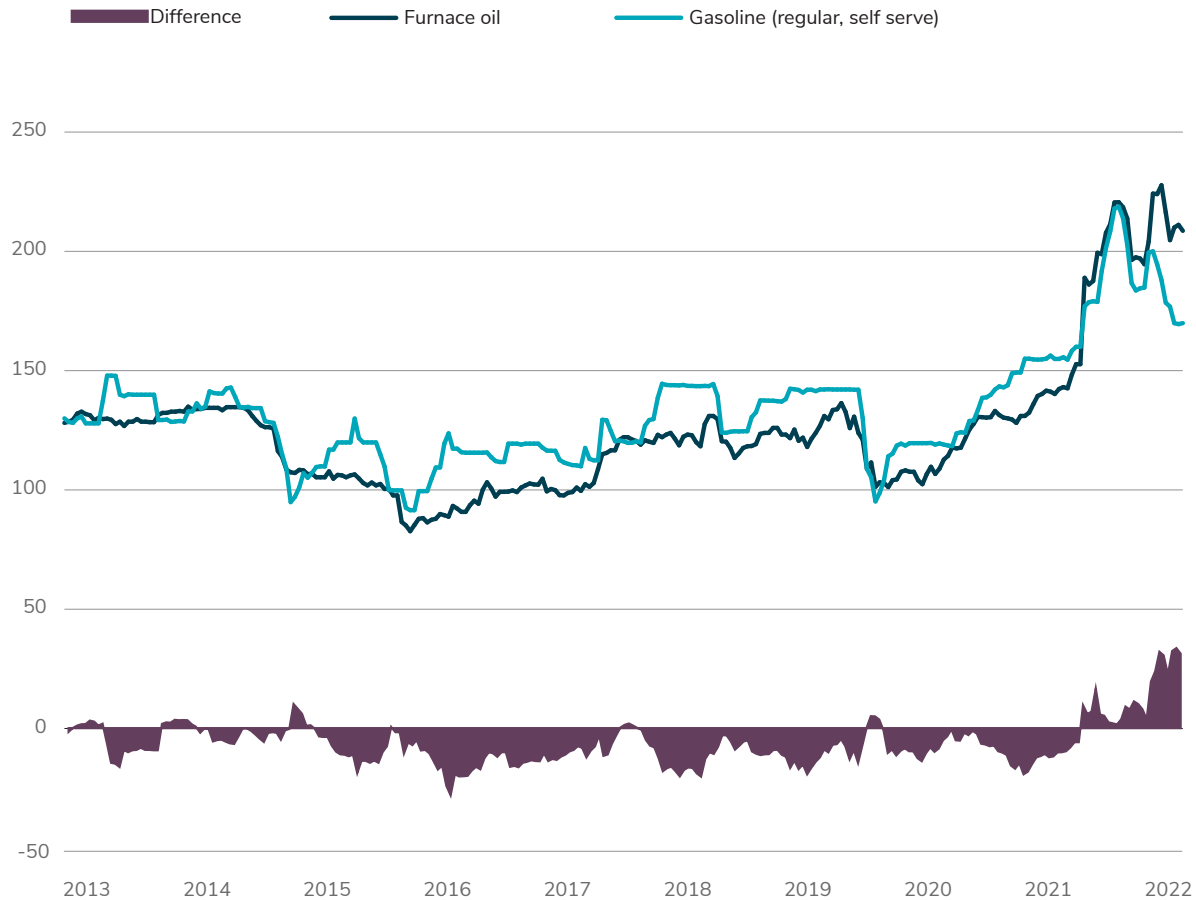
Rapid appreciation of prices for a large variety of consumer goods and services has also been the reality for Yukoners. The inflation rate in Whitehorse¹⁷ averaged 6.8 per cent in 2022, the highest rate for the Whitehorse CPI since records began in 1982. Prices were up across most categories.

Higher fuel prices in 2022 were a prominent driver of overall inflation, with the price of gasoline up 29 per cent, and the price of fuel oil up 47 per cent compared to 2021. While gasoline prices have fallen by over 20 per cent from the peak in June, the price of fuel oil has remained elevated (Chart 9). This reflects global trends. US inventories of distillate fuels, including home heating oil and diesel, are at multi-year lows. Sanctions on Russia have led to Europe shifting towards non-Russian imports. While prices have stabilized, futures prices suggest that diesel and fuel oil prices are likely to remain at a hefty premium to gasoline in the near term.

17. Data are not available for the Yukon, only Whitehorse.

Chart 9. Gap between gasoline and other fuels has widened due to distillate shortage

Whitehorse fuel prices (cents per litre)



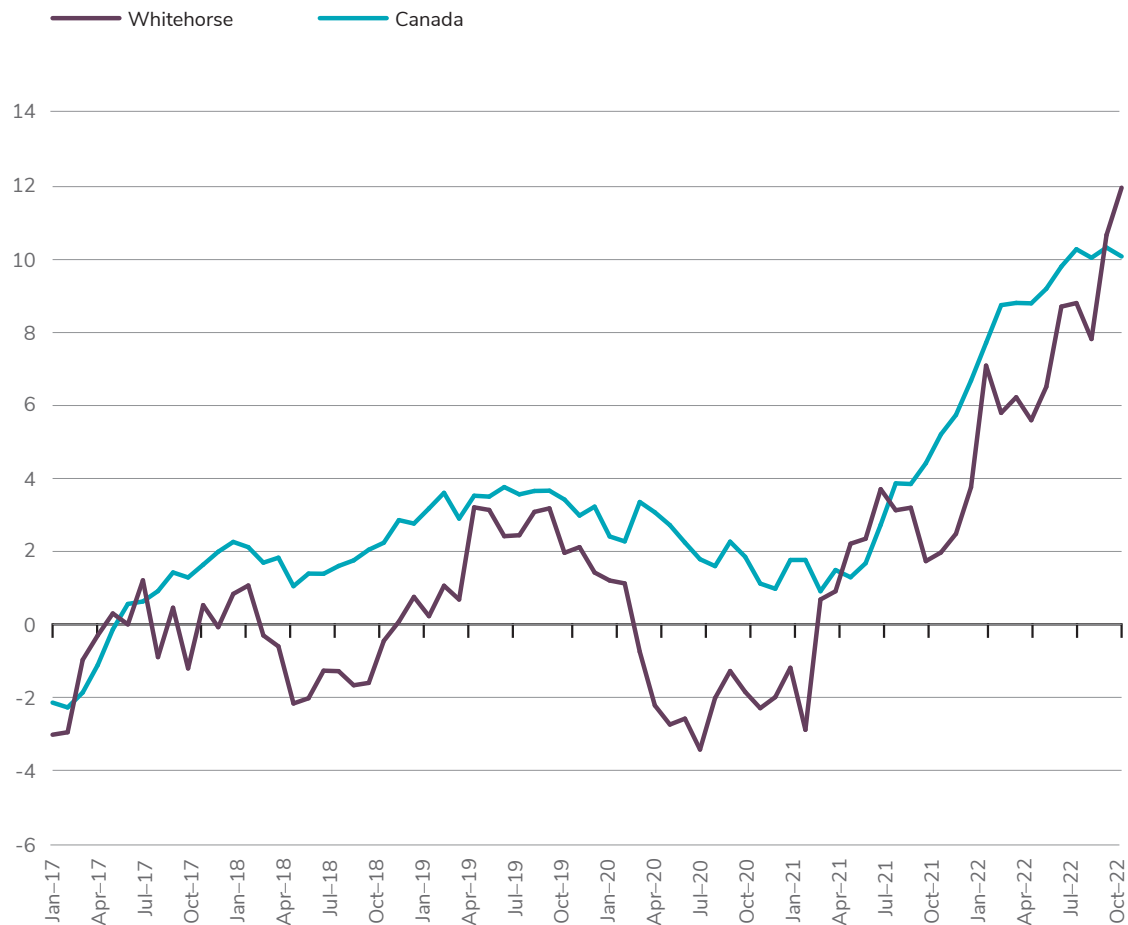
Source: Yukon Bureau of Statistics

Fuel oil is weighted heavier in the Whitehorse CPI than in the national index, because a substantially higher share of Yukoners use fuel oil for heat. This higher weighting is one of the reasons why inflation of 8.1 per cent in Whitehorse as of December was higher than the national rate of 6.3 per cent.

Another factor is that price pressures on food were slower to materialize in the Yukon than in the rest of Canada (Chart 10). Food prices in Canada rose throughout the pandemic, whereas in Whitehorse, they did not start to increase in earnest until later. Ultimately, prices in Whitehorse follow national trends closely and food prices have started to catch up. Inflation in Whitehorse was lower at the beginning of the year and higher at the end, averaging out over the course of the year with annual inflation for both Canada and Whitehorse coming in at 6.8 per cent.

Chart 10. Food price inflation was slower to materialize in Whitehorse

Year-over-year per cent change in the food component of CPI



Source: Statistics Canada

On January 25, 2023, the Bank of Canada increased its policy interest rate to 4.5 per cent to try to reduce the excess demand in the economy. The Bank signaled that it expects to “hold the policy rate at its current level while it assesses the impact of the cumulative interest rate increases.”¹⁸ The Bank has increased the policy rate by 4.25 percentage points since last March, the most in such a short span since the Bank began targeting interest rates in the early 1990s.

18. News release – Bank of Canada increases policy interest rate by 25 basis points, continues quantitative tightening. Bank of Canada. (January 25, 2023).

Most forecasters expect inflation in Canada will move towards historic norms over the next couple of years as supply chain problems subside and the effect of higher interest rates move through the economy. Canadian inflation is expected to decline from near 7 per cent in 2022, to between 3.5-4.0 per cent in 2023, and many forecasts are calling for inflation in 2024 to approach the midpoint of the Bank of Canada's target range of 1-3 per cent. Similarly, the average annual rate of inflation for Whitehorse is projected to fall from 6.8 per cent in 2022 to 3.8 per cent in 2023 and 2.5 per cent in 2024.

The housing market remains relatively strong but there are signs of cooling

Locally, housing prices have been strong for several years, driven in part by high demand. A generally strong economy has drawn people to the territory. Housing supply has struggled to keep pace with demand, and this has been reflected in upward pressure on housing prices. Prices in Whitehorse across all housing types have seen notable growth in recent years. The average weighted price of single detached homes, duplexes and mobile homes all reached record highs in 2022. Condominium prices in 2022 were down slightly from the 2021 record high.

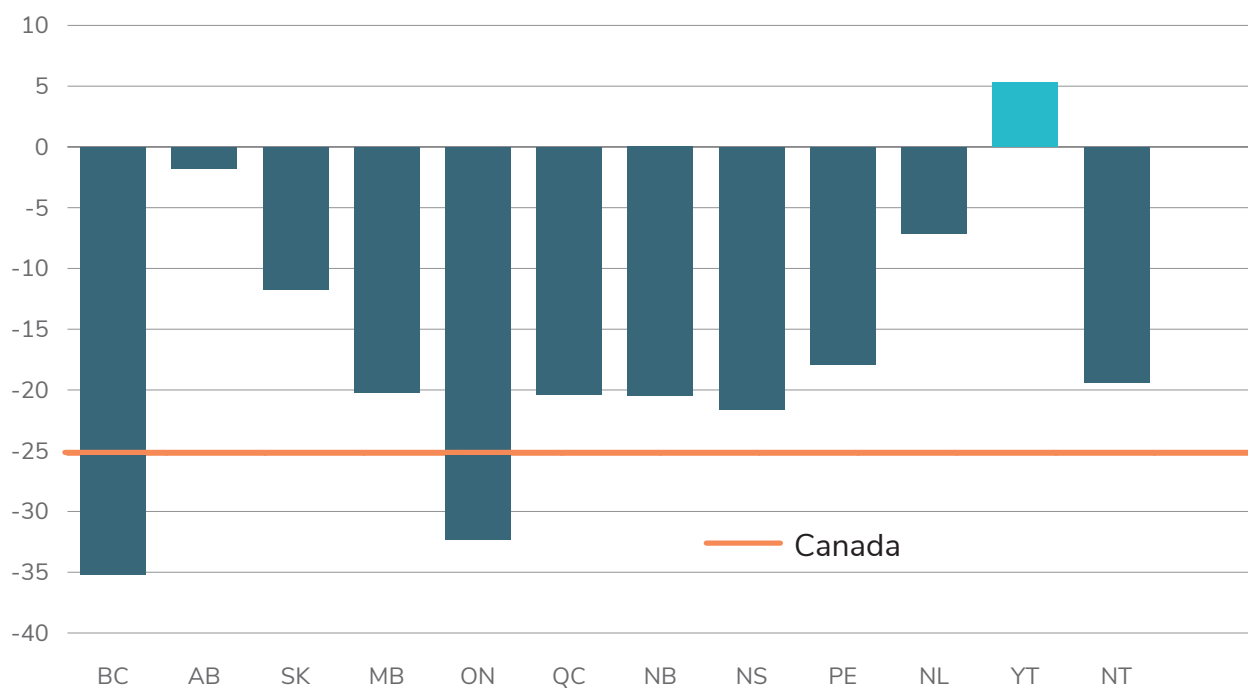
Even during an extended period of very low interest rates and growing household earnings, housing affordability has been eroding due to higher prices. More recently, rapid growth in interest rates has increased borrowing costs for new homebuyers and those on variable rate mortgages. Higher costs will filter through to fixed rate mortgages as they come up for renewal.



Higher interest rates took steam out of housing markets across the country. Average home prices in most Canadian markets fell over the second half of 2022. This effect was slower to materialize in the Yukon, which was the only jurisdiction that saw higher home sales in 2022 than in 2021 (Chart 11). It wasn't until the fourth quarter that signs of cooling showed in the Yukon data.¹⁹ While increasing on average in 2022, average sales prices were down in the fourth quarter of last year across all housing types. Compared to the fourth quarter of 2021, prices were down by 1.2 per cent for single-detached, 3.9 per cent for duplexes, 11.4 per cent for condominiums and 1.6 per cent for mobile homes.

Chart 11. The Yukon experienced growth in the number of residential sales in 2022²⁰

Residential sales, 2022 change from 2021 (per cent)



Source: The Canadian Real Estate Association

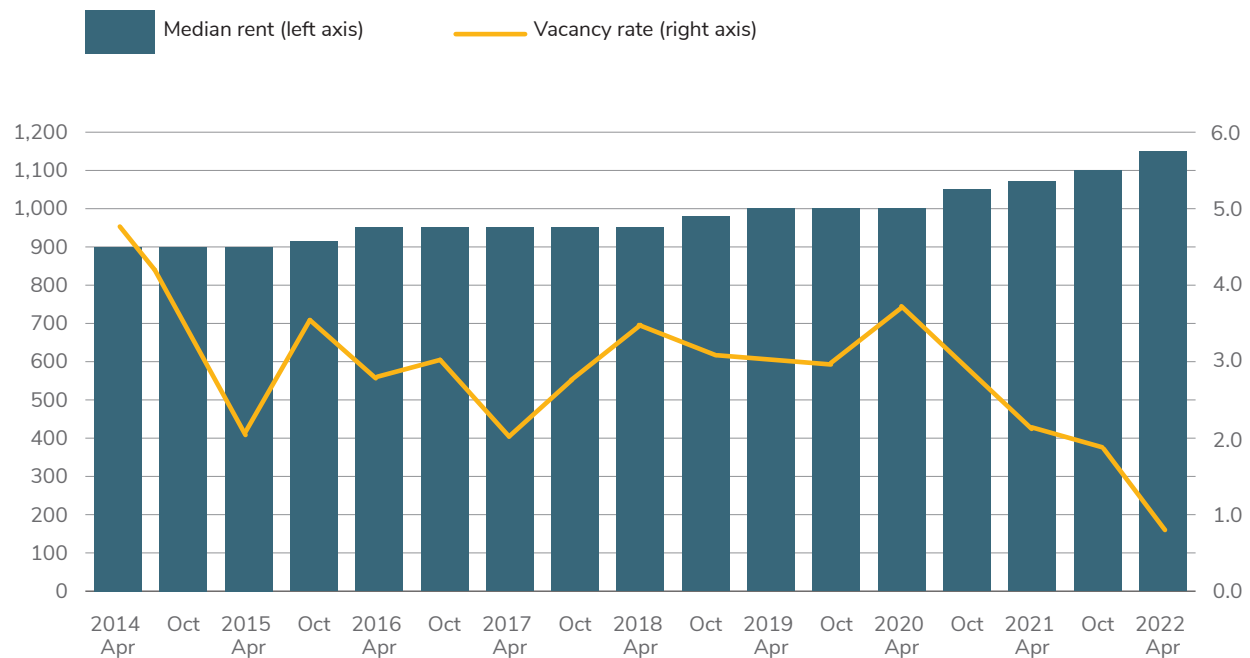
19. Yukon Real Estate Report Fourth Quarter, 2022. Yukon Bureau of Statistics. (February 2023).

20. The Canadian Real Estate Association does not publish data for Nunavut.

On the rental side, the market in recent years has been one of limited supply and increasing rents. The vacancy rate in buildings with three-or-more units fell to 0.8 per cent in April 2022, well below the 1.9 per cent reported in October 2021.²¹ High demand and a lack of vacant units has translated into higher rents, with a median rent of \$1,150 in April of last year, up 4.5 per cent from the October 2021 figure and 7.4 per cent higher than the April 2021 figure.

Chart 12. Recent history of rental market is one of few vacancies and increasing rents

Whitehorse median rent (\$) and vacancy rate (per cent), units in buildings with 3+ rental units



Source: Yukon Bureau of Statistics

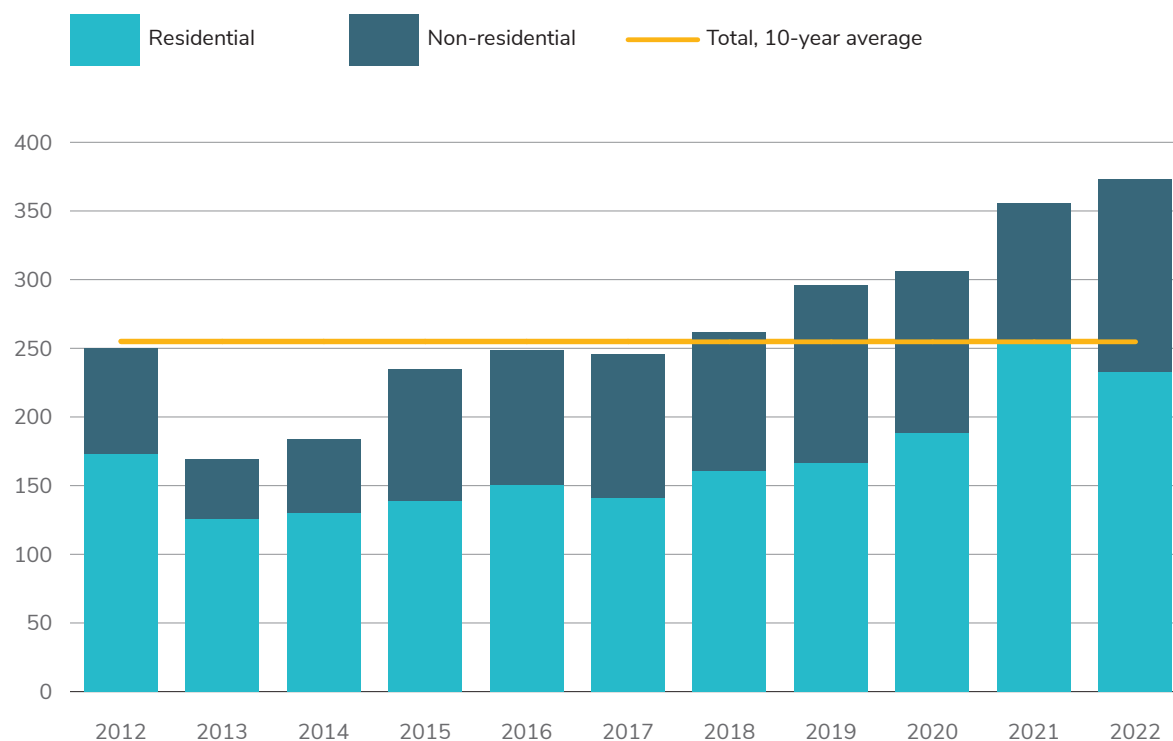
21. Yukon Rent Survey April 2022. Yukon Bureau of Statistics. (August 2022).

Residential investment remained strong in 2022

While below 2021's record level, investment in residential construction in 2022 continued to exceed investment on the non-residential side. Residential construction investment totalled \$232.6 million in 2022, 62 per cent of the total \$373.2 million in building construction reported for the period, and well above the ten-year average of \$163 million for residential construction (Chart 13). The recent approval of phases 10 to 13 of the Whistle Bend subdivision will contribute to housing supply going forward.²²

Chart 13. 2022 was another strong year for building construction

Investment in building construction (\$ millions)



Source: Statistics Canada

22. More phases of Whistle Bend subdivision approved (January 19, 2023). [Whitehorse Star](#).

Construction sector supported by commercial and government projects

The decline in residential spending from record highs was more than offset by increased non-residential spending. Investment in non-residential building construction totalled \$140.6 million in 2022 and was up nearly 39 per cent from 2021 (Chart 13). Similarly, building permits for non-residential work were up substantially in 2022, growing 61 per cent to \$150.7 million.

Government-related activities continue to be a primary driver of activity on the non-residential side. Growth was noted in both investment in building construction and building permits associated with institutional and governmental projects, up 83 per cent and 13 per cent, respectively. On the building permits side, construction of a new elementary school in Whitehorse's Whistle Bend subdivision and renovation of the Elijah Smith School were prominent contributors to last year's gains. Commercial permits also showed strong growth in 2022, more than doubling from \$44.1 million to \$97.0 million. Permit value was supported by construction of a three-storey office building in Whitehorse, renovation of the Old Territorial Administration building in Dawson City and work related to the Whitehorse Battery Energy Storage project.

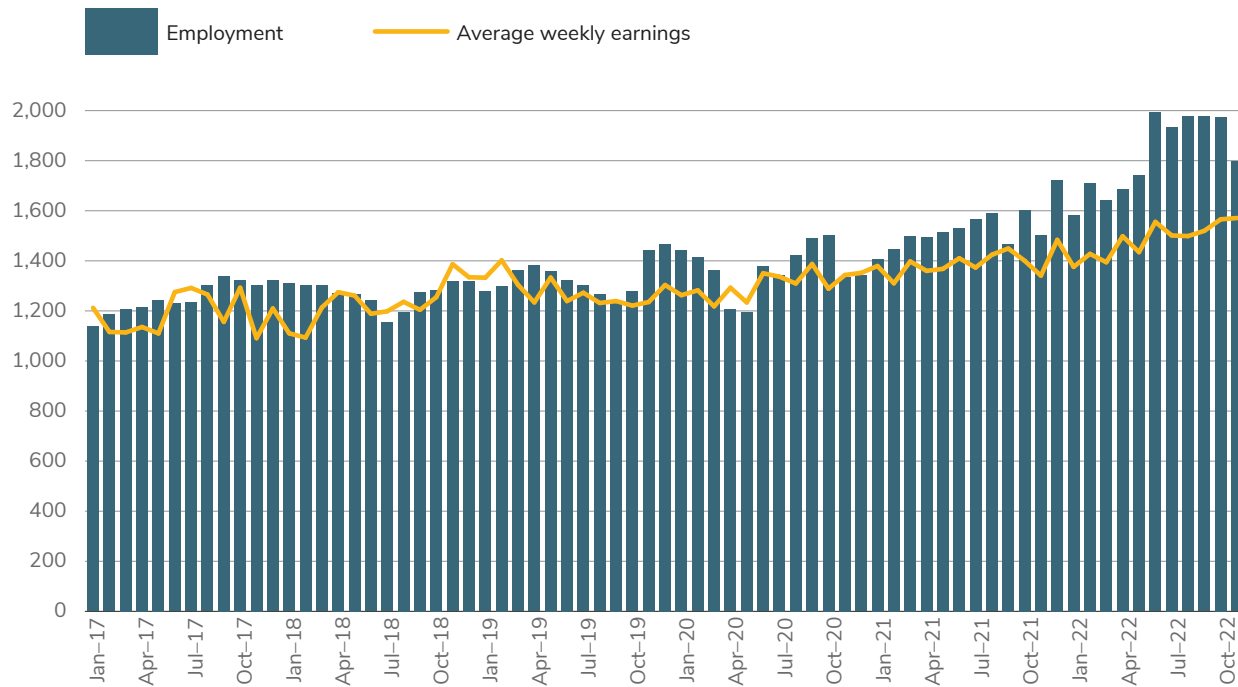
Higher input and labour costs continue to factor into some of the recent gains in building construction investment, due in part to supply chain constraints and stiff competition for tradespeople. Nationally, residential construction costs, on average, were 19 per cent higher and non-residential costs 13 per cent higher in 2022 compared to 2021.²³

Increased activity created jobs in the construction sector and boosted wages. Construction employment reached an all-time high of 1,993 in June 2022 (Chart 14), up more than 50 per cent versus June 2019. Through the first eleven months of 2022, construction workers earned \$1,486 per week on average, an increase of 7.4 per cent from 2021.

23. National figures are based on a composite of 11 census metropolitan areas.

Chart 14. Busy construction sector reflected in growth in construction employment and earnings

Employment (persons), Average weekly earnings (\$)



Source: Statistics Canada

The Government of Yukon's *Five-Year Capital Plan* outlines spending to the end of fiscal year 2027–28 of \$2.15 billion and includes significant spending in several priority areas such as 'transportation infrastructure', 'land development, housing, education and health' and 'community and First Nations infrastructure'. Projects such as the Nisutlin Bay Bridge, the Dempster Fibre project and the new elementary school in Whistle Bend are examples of investment in critical infrastructure included in the latest Capital Plan. In addition to Government of Yukon projects, the City of Whitehorse also factors into expectations of construction activity with over \$130 million in planned spending on capital projects over 2023 to 2026.²⁴

24. Spending figure is from the City of Whitehorse's *Capital Expenditure Program 2023–2026* released on November 14, 2022. Figure includes all approved spending, including spending of approximately \$75 million that is subject to external funding approval.

Mineral production forecast to be strong over the medium term

The Yukon's mining industry has remained resilient in the face of major headwinds in 2022. High winter precipitation resulted in a heavy spring thaw that hindered mineral production, as both the Eagle Gold and Minto mines lost a month of operations and the sluicing season for placer miners was delayed. The sector has been facing a shortage of workers coming out of the pandemic, hampering some operations. High fuel prices and supply chain issues also presented challenges in 2022.

In addition to disruptions during the spring thaw, operation at Eagle Gold was stalled for three weeks in the third quarter due to the failure of the belt on the overland conveyor. These operational issues caused gold production to fall to 150,182 ounces in 2022, below the previous year's production of 164,222 ounces. With production from Keno Hill underperforming expectations, Alexco Resource Corporation halted operations in June 2022 to focus on mine development. Operations remained suspended following the acquisition of Alexco by Hecla Mining Company in September.

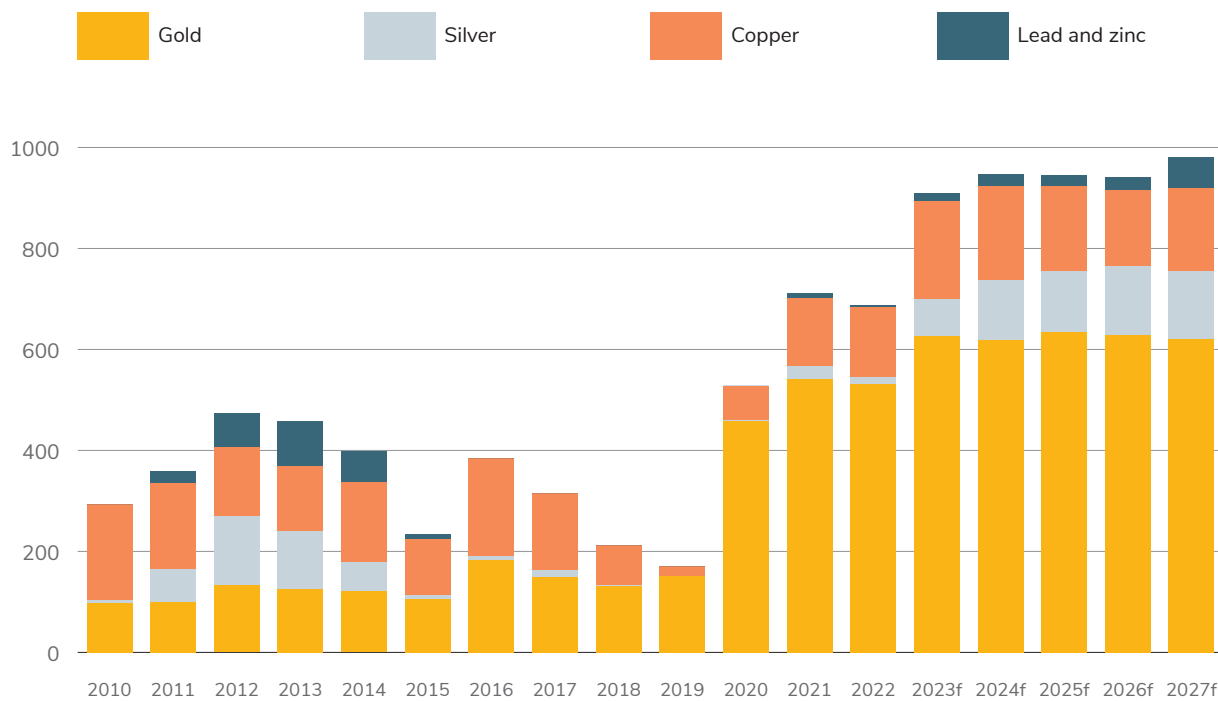
Production for the fourth quarter for the Minto mine was unavailable at the time of writing, but public statements from the President of Minto Metals Corporation in November 2022 noted that the expectation was that annual production would fall within their 2022 production guidance of 28-31 million pounds of copper.²⁵

Placer miners also saw higher production. Placer gold production, according to export tax reporting, was 82,420 crude ounces (65,936 fine ounces), up from production of 80,484 crude ounces (64,387 fine ounces) in the previous year. At \$154 million, the value of placer gold production accounted for about 22 per cent of 2022's total estimated mineral production.

25. News release – Minto Metals announces 2022 third quarter results, revenue increased by 17% over the same quarter in previous year. Minto Metals Corporation (November 17, 2022).

Chart 15. Mineral production value forecast to approach \$1 billion²⁶

Value of metal production in the Yukon (\$ millions)



Source: Natural Resources Canada, Department of Energy, Mines and Resources, Department of Finance

f = forecast

The Yukon's quartz miners expect to recover from the various setbacks that hindered 2022 production. Victoria Gold expects production at Eagle Gold to rebound in 2023 with production well above 2022's output as the project operator continues to work towards its annual target of 250,000 ounces. Hecla Mining Company announced earlier this year that mine development is ahead of schedule and that they plan to resume operations at Keno Hill in the third quarter of 2023. This, along with anticipated higher production at the Minto mine and sustained placer production, is expected to lead mineral production to rebound to \$910 million in 2023 and exceed \$900 million in all subsequent years of the forecast (Chart 15).

26. Due to data suppression of Statistic Canada's estimates, data presented for 2019, 2020 and 2021 are based on internal estimates.

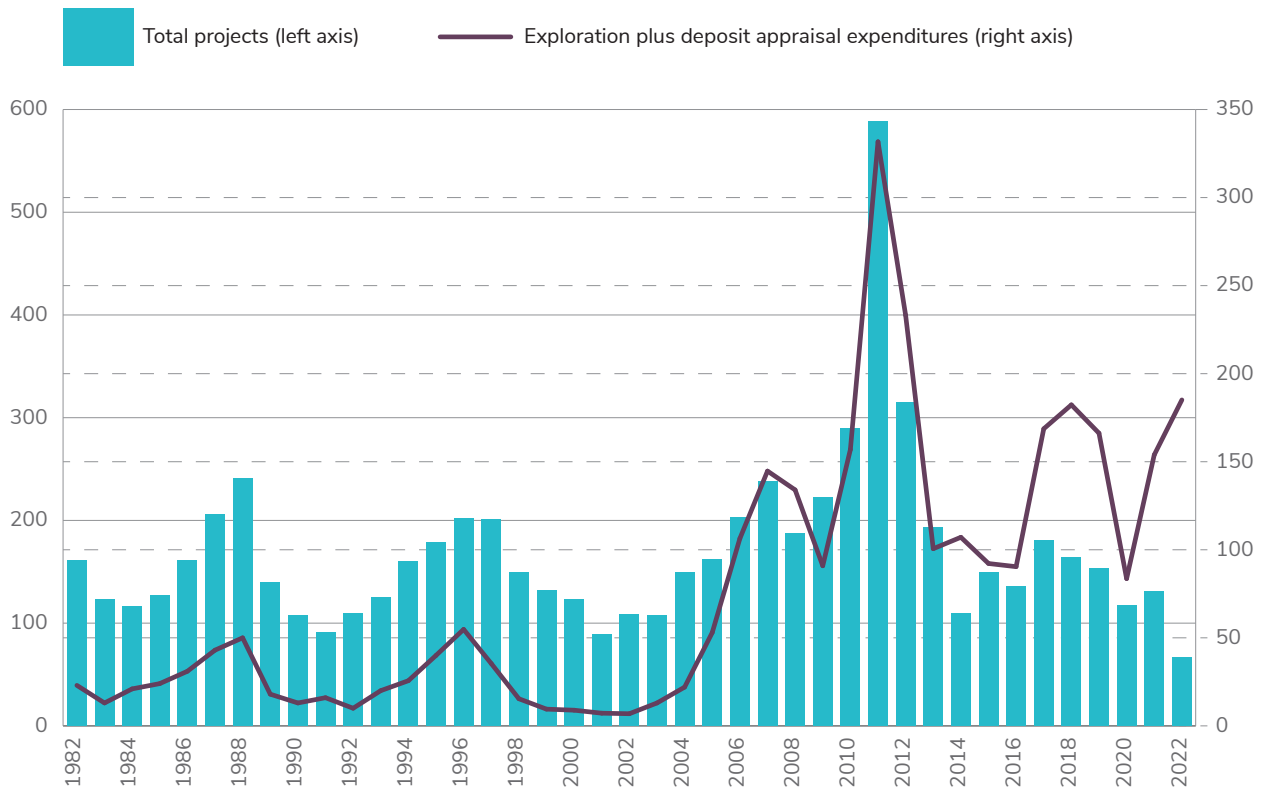
Mineral prices remain supportive of future development

Metals prices rallied to close out 2022 and, though down from earlier highs, remain well above pre-pandemic levels. This could spur development over the medium term for projects such as BMC Minerals Limited's Kudz Ze Kayah mine, Newmont Corporation's Coffee Gold project and Sabre Gold Mine Corporation's Brewery Creek project. Over the longer term, the advancing of the Casino project, a major global copper resource, may attract interest due to the pivotal role copper will play in the green economy and global electrification.

Higher metal prices offer investors the potential of better returns from the discovery of new deposits and exploration activities on current mining plays. Exploration spending has rebounded from pandemic lows. Revised spending intentions from Natural Resources Canada noted exploration spending in 2022 of about \$185 million, up 20 per cent from \$154 million in 2021 (Chart 16).

Chart 16. Number of active exploration projects trending down even as overall exploration spending has rebounded

Number of active projects, Exploration expenditures (\$ millions)



Source: Department of Energy, Mines and Resources, Natural Resources Canada

Recent spending has been increasingly concentrated in a smaller set of mature projects, rather than early-stage projects. The number of exploration projects has fallen over the last several years to a 40-year low in 2022, despite overall spending rebounding.

Spending on exploration for precious metals accounted for 70 per cent of exploration spending in 2022, with the remainder on exploration for base metals. Precious metals are expected to continue to draw most of the interest in exploration activity over the forecast. This mix may eventually be impacted by Canada's critical minerals strategy (see Box 1), which seeks to increase the output of minerals deemed critical to the transition to green energy.

Box 1: Critical minerals a potential opportunity for the local mining industry and for the Yukon's energy goals

The release of *The Canadian Critical Minerals Strategy* in December 2022, along with an almost \$4 billion commitment in Budget 2022, is a clear signal of the interest the federal government has in developing the country's critical minerals.

Ultimately, minerals noted as 'critical' reflect societal needs and values at a point in time. Canada's critical minerals strategy notes critical minerals as the building blocks of the green and digital economies, highlighting that "there is no energy transition without critical minerals: no batteries, no electric cars, no wind turbines and no solar panels."

Most of the 31 minerals that the Canadian government has published as being "critical" to Canada have known deposits or documented occurrences in the Yukon. While the territory's current production of critical minerals is quite modest, limited to copper production from the Minto mine and recent production of zinc and indium as a by-product at the Keno Hill mine, there is potential for production from existing identified deposits. Critical minerals are identified as prominent outputs of several potential mines including, Kudz Ze Kayah (zinc, copper); Casino (copper, molybdenum); Nickel Shāw (nickel, cobalt, platinum, palladium, copper) and Mactung (tungsten).

Given commitments by Canada and the Yukon to reduce carbon emissions, as well as the need to ensure future energy security, there is clear motivation to develop a reliable supply of critical minerals. With climate change and economic opportunity acting as strong motivators for development, critical minerals have the potential to be a prominent contributor to the local mining industry and the broader economy over the coming years.

Signs of a solid rebound in tourism activity, but a return to pre-pandemic levels will take time

The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

Several key tourism metrics for the territory show significant improvement from the worst of the pandemic. The number of international border crossings into the Yukon totalled just over 168,000 in the first eleven months of 2022, almost five and a half times the number of crossings in the same period of 2021, and well above the 63,657 crossings reported for all of 2020 and 2021 combined when COVID-19 related travel restrictions weighed on visitation.

The tourism sector has proven to be resilient in the face of what was an historic disruption to global travel.

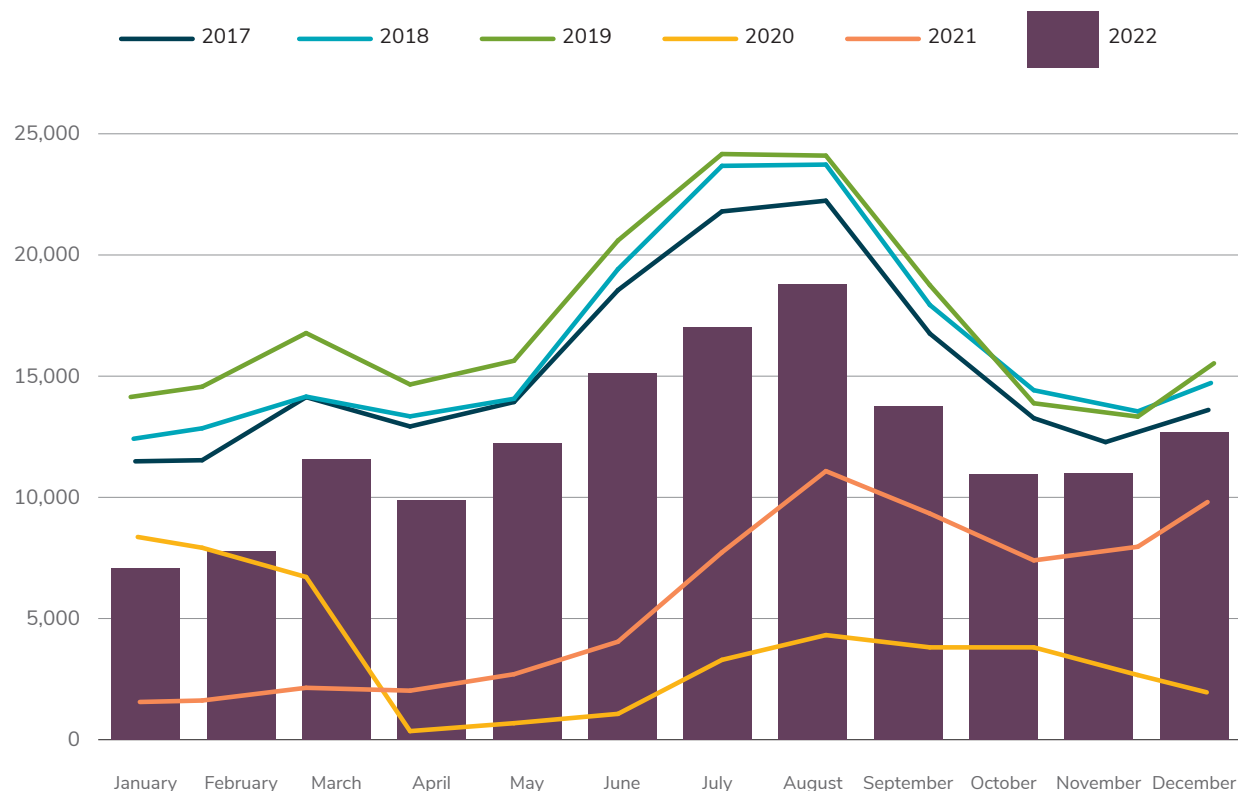


Like international border crossings, other indicators of performance are much improved from recent lows but continue to underperform pre-pandemic levels. Data for the first nine months of 2022 show international overnight visitation to be more than double the same period of 2021, but nearly 30 per cent lower than the five-year average.²⁷ Increased visitation is also reflected in increased hotel occupancy in 2022,^{28,29} with data published by CBRE Hotels showing much higher occupancy rates in every month from January to November with the average of 56 per cent over this period, well ahead of the 41 per cent reported for the same period of 2021.³⁰

An increased number of air arrivals in 2022 are another sign of the return of travel. Arrivals at Erik Nielsen Whitehorse International Airport were 2.2 times the number of arrivals from 2021 (Chart 17).

Chart 17. Air arrivals much improved from the last two years

Arrivals (deplaning passengers, thousands) at Erik Nielsen Whitehorse International Airport



Source: Statistics Canada

27. Yukon Tourism Visitation Report, January to September 2022. Department of Tourism and Culture. (December 22, 2022).

28. Occupancy rate is the percentage of occupied rooms expressed as percentage of the total available rooms at a given time.

29. Figures for the occupancy rate do not capture all hotel rooms in the Yukon, with about 600 rooms captured in this calculation.

30. Data taken from various CBRE Hotels monthly reports: Trends in the Canadian Hotel Industry – National Market Report.

Even with strong growth in 2022, air arrivals came in at only 72 per cent of arrivals in 2019, suggesting that there is still more room for recovery from the COVID-19 pandemic.

Tourism activity is increasing, but a variety of headwinds are slowing the recovery. Inflation is running at, or near, many decade highs, and is expected to remain elevated throughout much of 2023. Higher fuel costs have eaten into the bottom-lines of some service providers, particularly those that are fuel intensive such as providers of charter flights and tours.³¹ Local tourism-service providers also continue to struggle with finding staff. Labour shortages in the accommodation and food services sector are more severe in the Yukon than they are in the rest of the country. Demand could also be impacted as higher interest rates lead to less discretionary spending.

Further improvement in key tourism metrics is expected. The Conference Board of Canada's latest Travel Markets Outlook supports this improving outlook for tourism, noting an expectation that visitation to the territory will reach pre-pandemic levels by 2024 or 2025, and that overnight visits will recover by 2024.³² In addition, positive news, like White Pass Railroad's resumption of service to Canada in the summer of 2023, provides further evidence of a return to normalcy for the tourism sector.³³

31. *Travel Exclusive Winter 2022/23 Travel Intentions Survey*. Canadian Tourism Research Institute. The Conference Board of Canada (December 2022).

32. *Emerging from the Wilderness – Yukon's Travel Markets Outlook to 2026*. The Conference Board of Canada. (January 24, 2023).

33. *White Pass Railroad to resume service to Canada this summer* (January 13, 2023). KHNS FM.

Appendix:

Key economic indicators

	2021	2022	2023f	2024f	2025f	2026f	2027f
Gross Domestic Product (GDP)							
Real GDP by Industry (2012\$ millions)	3,045	3,138 (f)	3,308	3,431	3,534	3,666	3,831
Per cent change	10.0	3.1	5.4	3.7	3.0	3.7	4.5
Nominal GDP (\$ millions)	3,704	4,049 (f)	4,432	4,795	5,093	5,480	5,948
Per cent change	14.3	9.3	9.4	8.2	6.2	7.6	8.5
Mineral Production *							
Metal production (\$ millions)	710	690 (f)	910	950	950	940	980
Labour market							
Labour force *	23,700	24,300	25,100	25,500	26,100	26,800	27,700
Employment *	22,400	23,400	23,800	24,200	24,800	25,600	26,500
Unemployment rate	5.5	3.7	5.0	5.0	5.1	4.5	4.1
Participation rate	72.3	72.8	73.0	72.4	72.1	72.2	72.6
Income							
Household income (\$ millions)	2,440	2,664	2,849	3,029	3,210	3,463	3,760
Per cent change	11.4	9.2	6.9	6.3	6.0	7.9	8.6
Consumers							
Consumer price inflation [^]	3.3	6.8	3.8	2.5	2.0	2.0	2.0
Retail sales (\$ millions) *	963	1,030 (f)	1,090	1,150	1,210	1,290	1,400
Population							
Population*	43,190	43,964	44,900	45,900	46,800	47,700	48,700
Per cent change	2.3	1.8	2.1	2.2	2.1	1.9	2.0
Key Assumptions							
Gold (USD/t oz)	1,800	1,809	1,760	1,670	1,650	1,650	1,650
Silver (USD/t oz)	25.15	22.16	21.85	21.68	22.00	22.00	22.00
Copper (USD/lb.)	4.23	3.99	3.48	3.71	3.55	3.55	3.55
Zinc (USD/lb.)	1.36	1.58	1.33	1.25	1.23	1.15	1.15
Lead (USD/lb.)	1.00	0.97	0.91	0.91	0.93	0.93	0.93
Can/US exchange rate	0.80	0.77	0.75	0.77	0.78	0.78	0.78

f = forecast

[^] = CPI available only for Whitehorse, annual average.

* = Forecasts are rounded. Annual per cent change based on unrounded figures.

Source: Statistics Canada, Bank of Canada, Yukon Bureau of Statistics.

Population projections are produced by Yukon Bureau of Statistics. Metal prices forecasts are informed by prominent forecasters. All other forecasts are produced by the Department of Finance's Economic Research branch based on data available as of February 13, 2023.





Yukon Bureau of Statistics

Population Projections, 2021-2040 Updated February 2023

Population Projection Methodology

Yukon Bureau of Statistics (YBS) developed new models for population projection in 2016. In the new demographic projection model, various demographic trends (e.g., births, deaths, in-migration and out-migration) are analysed using simple trend analyses and segmented regressions based on best-fit of linear segments of the data. Then three scenarios — Low Growth, Medium Growth, and High Growth — are developed by applying sets of weights to the model parameters.

In addition to the demographic projection model, another projection model — the DemEcon model — is estimated with net migratory growth as a function of economic growth and a projection scenario is developed based on the model parameters.

A fourth projection scenario, the Preferred Projection, is finally derived as a weighted average of the Medium Growth scenario of the demographic projection model and the scenario developed with the results of the DemEcon model. YBS considers this fourth projection scenario to be the most likely scenario.

The demographic projection models are updated every five years when postcensal population estimates (i.e., Census population adjusted for net undercoverage) become available. However, the DemEcon model and the Preferred Projection are updated every year using changed forecasts of economic growth.

Population Projection and Growth Rate by Broad Age Group, Yukon, 2021 to 2040

Year	Projection: Preferred Total	Projected Growth Rate	Projection: Preferred 0 to 14 years	Projected Growth Rate	Projection: Preferred 15 to 64 years	Projected Growth Rate	Projection: Preferred 65 years and over	Projected Growth Rate
2021	43,190	2.4%	6,935	1.4%	30,166	1.9%	6,089	5.5%
2022	43,964	1.8%	7,040	1.5%	30,546	1.3%	6,378	4.7%
2023f	44,880	2.1%	7,248	3.0%	30,961	1.4%	6,671	4.6%
2024f	45,850	2.2%	7,468	3.0%	31,403	1.4%	6,979	4.6%
2025f	46,830	2.1%	7,613	1.9%	31,927	1.7%	7,290	4.5%
2026f	47,730	1.9%	7,757	1.9%	32,420	1.5%	7,553	3.6%
2027f	48,680	2.0%	7,896	1.8%	32,900	1.5%	7,884	4.4%
2028f	49,770	2.2%	8,056	2.0%	33,469	1.7%	8,245	4.6%
2029f	50,760	2.0%	8,202	1.8%	33,958	1.5%	8,600	4.3%
2030f	51,520	1.5%	8,310	1.3%	34,291	1.0%	8,919	3.7%
2031f	52,490	1.9%	8,450	1.7%	34,756	1.4%	9,284	4.1%
2032f	53,520	2.0%	8,601	1.8%	35,252	1.4%	9,667	4.1%
2033f	54,030	1.0%	8,668	0.8%	35,399	0.4%	9,963	3.1%
2034f	54,260	0.4%	8,691	0.3%	35,358	-0.1%	10,211	2.5%
2035f	54,290	0.1%	8,680	-0.1%	35,188	-0.5%	10,422	2.1%
2036f	54,660	0.7%	8,725	0.5%	35,235	0.1%	10,700	2.7%
2037f	55,530	1.6%	8,849	1.4%	35,598	1.0%	11,083	3.6%
2038f	56,420	1.6%	8,973	1.4%	35,971	1.0%	11,476	3.5%
2039f	57,210	1.4%	9,083	1.2%	36,269	0.8%	11,858	3.3%
2040f	57,990	1.4%	9,192	1.2%	36,558	0.8%	12,240	3.2%

f = forecast

Population Projection by Age Group, Yukon, 2021 to 2040

Year	1 to 12 months	1 to 4 years	5 to 9 years	10 to 14 years	15 to 19 years	20 to 24 years	25 to 29 years	30 to 34 years	35 to 39 years	40 to 44 years
2021	391	1,842	2,412	2,290	2,155	2,489	2,978	3,702	3,810	3,129
2022	415	1,825	2,445	2,355	2,190	2,421	2,961	3,781	4,032	3,247
2023f	452	1,937	2,487	2,372	2,122	2,409	3,049	3,912	3,844	3,178
2024f	491	2,055	2,531	2,391	2,112	2,398	3,117	3,947	3,742	3,184
2025f	498	2,103	2,581	2,431	2,104	2,319	3,181	4,089	3,721	3,191
2026f	505	2,149	2,627	2,476	2,100	2,297	3,205	4,202	3,710	3,204
2027f	513	2,188	2,674	2,521	2,099	2,284	3,231	4,267	3,765	3,222
2028f	521	2,233	2,729	2,573	2,098	2,295	3,259	4,347	3,834	3,285
2029f	530	2,274	2,778	2,620	2,106	2,300	3,278	4,415	3,894	3,340
2030f	536	2,304	2,815	2,655	2,104	2,294	3,301	4,457	3,927	3,379
2031f	545	2,343	2,863	2,699	2,109	2,295	3,342	4,513	3,974	3,428
2032f	553	2,385	2,916	2,747	2,115	2,297	3,384	4,570	4,020	3,484
2033f	555	2,404	2,939	2,770	2,100	2,276	3,398	4,577	4,024	3,507
2034f	555	2,411	2,948	2,777	2,074	2,244	3,397	4,555	4,003	3,512
2035f	551	2,409	2,945	2,775	2,039	2,202	3,391	4,517	3,965	3,504
2036f	553	2,422	2,960	2,790	2,018	2,173	3,412	4,502	3,948	3,517
2037f	559	2,457	3,003	2,830	2,013	2,163	3,451	4,534	3,972	3,563
2038f	565	2,492	3,045	2,871	2,009	2,153	3,495	4,566	3,995	3,608
2039f	570	2,523	3,083	2,907	1,999	2,138	3,534	4,585	4,007	3,647
2040f	575	2,554	3,121	2,942	1,988	2,121	3,581	4,597	4,015	3,686

Year	45 to 49 years	50 to 54 years	55 to 59 years	60 to 64 years	65 to 69 years	70 to 74 years	75 to 79 years	80 to 84 years	85 to 89 years	90 to 99+ years
2021	2,907	2,759	3,103	3,134	2,443	1,745	1,000	507	253	141
2022	2,962	2,826	2,973	3,153	2,525	1,763	1,127	537	271	155
2023f	3,019	2,897	3,186	3,345	2,644	1,908	1,129	553	285	152
2024f	3,079	2,973	3,377	3,474	2,769	2,056	1,132	570	300	152
2025f	3,145	3,050	3,523	3,604	2,886	2,208	1,136	594	313	153
2026f	3,206	3,130	3,662	3,704	2,999	2,316	1,142	618	324	154
2027f	3,267	3,203	3,753	3,809	3,117	2,428	1,198	642	338	161
2028f	3,337	3,251	3,837	3,926	3,247	2,549	1,259	670	352	168
2029f	3,400	3,293	3,895	4,037	3,373	2,669	1,319	697	367	175
2030f	3,446	3,318	3,935	4,130	3,486	2,779	1,373	721	379	181
2031f	3,505	3,357	3,991	4,242	3,615	2,903	1,435	750	394	187
2032f	3,572	3,399	4,051	4,360	3,750	3,032	1,500	779	410	196
2033f	3,604	3,406	4,070	4,437	3,851	3,134	1,552	803	422	201
2034f	3,618	3,396	4,069	4,490	3,933	3,221	1,596	823	432	206
2035f	3,617	3,373	4,052	4,528	4,001	3,297	1,634	839	441	210
2036f	3,640	3,371	4,060	4,594	4,094	3,393	1,682	862	453	216
2037f	3,695	3,399	4,105	4,703	4,226	3,522	1,748	893	470	224
2038f	3,751	3,428	4,151	4,815	4,362	3,655	1,814	926	487	232
2039f	3,800	3,450	4,190	4,919	4,492	3,785	1,879	958	504	240
2040f	3,849	3,471	4,227	5,023	4,623	3,915	1,944	990	520	248

f = forecast

February 2023

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September 28, 2023

AEY-UCG-019

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-019

Reference: July 7, 2023 Application, page 2-4 AEY Residential and Commercial Customers and Sales by Community AEY state: For the 2023-24 sales forecast AEY reviewed its two-step approach for determining weather normalized UPC. AEY has maintained the same 10-year timeframe for UPC regression and normalizing HDD as last Board Compliance Order.

Request:

- (a) Provide evidence and statistical analysis that this 10- year average methodology is a superior forecasting tool when compared to the 20-year average methodology.
- (b) Confirm or deny that the proposed 10-year average methodology will be more volatile than the longer-term methodology. Explain.
- (c) Provide Board Order referenced.

Response:

- (a) AEY has created 10-year and 20-year regression models to determine the normalized UPC for the aggregated commercial and residential rate classes. As shown in the table below, the resulting R Square for both residential and commercial rate classes is higher using a 10-year model versus using a 20-year model.

September 28, 2023

AEY-UCG-019

RESIDENTIAL 10YR		RESIDENTIAL 20YR	
<i>Regression Statistics</i>		<i>Regression Statistics</i>	
Multiple R	0.879348196	Multiple R	0.857485186
R Square	0.773253249	R Square	0.735280844
Adjusted R Square	0.771331667	Adjusted R Square	0.734168579
Standard Error	124.5941627	Standard Error	118.9895003
Observations	120	Observations	240

COMMERCIAL 10YR		COMMERCIAL 20YR	
<i>Regression Statistics</i>		<i>Regression Statistics</i>	
Multiple R	0.819017185	Multiple R	0.813842541
R Square	0.670789149	R Square	0.662339681
Adjusted R Square	0.667999227	Adjusted R Square	0.66092094
Standard Error	389.7395353	Standard Error	356.5270987
Observations	120	Observations	240

- (b) AEY is uncertain whether using a 10-year average methodology is more volatile than using a 20-year average methodology. Notwithstanding, AEY considers the 10-year average methodology to be more representative of recent trends in UPC and weather patterns.
- (c) Please refer to AEY-UCG-019(c) Attachment 1. The referenced Board Order can be found in paragraph 40.

Yukon Utilities Board

Board Order 2017-01

Appendix A: Reasons for Decision

April 27, 2017

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1 Introduction

1. On May 11, 2016, pursuant to the *Public Utilities Act* and Order-in-Council 1995/90, the Yukon Electrical Company Limited (YECL or Applicant),¹ carrying on business as ATCO Electric Yukon (AEY), filed an application with the Yukon Utilities Board (Board) requesting an order approving forecast revenue requirements for the years 2016 and 2017 (test period) (Application). AEY is seeking approval of a revenue requirement of \$53,890,000 for 2016 and \$56,173,000 for 2017. The applied-for revenue requirement represents cumulative rate increases of 4.4 percent for 2016 and 7.5 percent for 2017, and year-over-year rate increases of 4.4 percent and 3.1 percent respectively.

2. Additionally, AEY sought approval of:

- an interim refundable rate rider of 11.62 percent, effective July 1, 2016;
- the continued use of currently approved deferral accounts, including purchase power flow-through, fuel price flow-through, and defined benefit pension costs during the test period; and
- new deferral accounts related to liquefied natural gas (LNG) fuel price changes, statutory tax rate changes, feasibility studies, and costs arising from Board Orders or legislative provisions not currently contemplated.

3. AEY is a private investor-owned utility serving more than 17,000 customers in 19 communities in the Yukon. AEY purchases power from Yukon Energy Corporation (YEC) for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek and a variety of rural areas surrounding Whitehorse. The company maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption. AEY also owns and operates the Fish Lake Hydro plant which generates power, and generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River.

4. On May 27, 2016, the Board issued Board Order 2016-01, in which the Board ordered AEY to publish a Notice of Application and Hearing for the General Rate Application (GRA) no later than June 3, 2016 in appropriate local news publications in AEY's service area to provide adequate notice to the public. AEY was also directed to make the Application and supporting materials available on its website: www.atcoelectricityukon.com, as well as in hardcopy upon request to AEY. Board Order 2016-01 set out a process schedule, pending ministerial approval, for the Application, with a hearing to commence on November 1, 2016.

5. On June 17, 2016, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to section 50 of the *Public Utilities Act*.

¹ Yukon Electrical Company Limited is the legal entity, and ATCO Electric Yukon is the brand name that is now used for the company's utility service operations in Yukon.

6. The Board, through Board Order 2016-02, issued June 24, 2016, granted intervenor status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (JM)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)

7. In Board Order 2016-02, the Board also approved a 9.41 percent interim, refundable rate adjustment rider, effective July 1, 2016. Subsequently, in Board Order 2016-02 Errata, the Board changed the interim rate adjustment rider to 11.62 percent, in order to account for a calculation error.

8. In its intervenor registration letter, dated June 17, 2016, and subsequently, UCG indicated that it had contacted the Pacific Economics Group (PEG) to help UCG determine if it was possible to benchmark the costs and productivity of AEY. UCG requested that the Board issue a letter to PEG so it can be assured that it would have an opportunity to access recovery of its costs through the cost claims process set by the Board. UCG also indicated that the process schedule would need to be altered to allow for a series of interrogatories to determine if benchmarking was possible.

9. On June 21, 2016, the Board set out a process to address UCG's request. Submissions were received from AEY and UCG. On July 4, 2016, after consideration of the UCG request and parties' submissions, the Board, in Board Order 2016-03, denied the UCG request for a letter of comfort to PEG. No revision to the process schedule was required.

10. On August 12, 2016, UCG submitted a motion requesting that the Board issue an order requiring AEY to provide adequate responses to certain UCG Information Requests (IRs). The Board invited comments from AEY on the UCG motion and reply comments from UCG. In Board Order 2016-04, issued on September 2, 2016, the Board ruled on the UCG motion and directed AEY to provide further and better information responses by September 9, 2016. In that Board Order, the Board amended the process schedule to allow UCG to file its evidence after the receipt of the additional information responses.

11. The Board held an oral public hearing in Whitehorse, Yukon from November 1 to 3, 2016. The Board was comprised of Robert Laking, Chair, and members Andre Fortin, Meagan Hannam, Bonnie King and Phillip Fitzgerald.

12. At the hearing, the Board confirmed that Final Argument was due on November 24, 2016 and Reply Argument on December 15, 2016. The Board considers the record of the proceeding closed on December 15, 2016.

13. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this Board Order to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be

taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 AEY Sales and Revenue

2.1 Overview

14. AEY stated that its sales and revenue forecast was based on a detailed analysis of historical sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. This data consists of information gathered by AEY staff who work in the communities as well as information resulting from consultation with the City of Whitehorse, Yukon government officials and various local agencies and developers.

15. The following table summarizes AEY's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013 to 2014, and 2015:

Table 1. **AEY energy sales by customer class – 2013 to 2017 (MWh)**

Customer class	Actuals			Forecasts (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	313,372	306,272	308,356	303,735	309,433
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total	316,687	312,182	315,816	313,592	319,289

Source: Application, Table 1, page 2-1.

16. Due to the changes in the energy sales by customer class, AEY's total primary non-industrial sales are forecast to decrease by 1.5 percent in 2016, and increase by 1.9 percent in 2017.

17. AEY provided an update to its test-period sales forecast to include nine months of actuals to September 30, 2016, as shown in the following table:

Table 2. **AEY updated test period sales forecast by customer class (MWh)**

Customer Class	Forecasts (Test Period)	
	2016	2017
Residential	146,698	153,275
Commercial	153,635	154,639
Street lights	3,922	3,978
Private lights	496	480
Total retail primary	304,751	312,373

Secondary sales	9,429	9,429
Wholesale sales	427	427
Total	314,607*	322,229

Source: Exhibit B-20, AEY undertaking; *Corrected for addition.

2.2 Views of the Applicant

18. In 2015, AEY 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 percent from 2014 levels. This increase follows decreases of 2.0 and 0.6 percent respectively in 2014 and 2013, from prior year levels.

19. After experiencing strong growth in the Yukon from 2004 to 2012, AEY submitted that the pace of economic activity in the Yukon has slowed down significantly. Slower population growth has also contributed to minimal customer gains in the residential and commercial sectors of AEY. It expected that the overall impact of the economic and population growth slowdown to continue to impact AEY's customer growth and sales over the test period.

20. AEY added that its demand-side management (DSM) program and the Yukon government's energy initiatives, such as those related to the commercial energy incentive program and micro-generation, which were introduced in the Yukon over the last few years, have also contributed to lower electricity sales experienced in the period from 2013 to 2015.

21. AEY reviewed its two-step approach for determining weather-normalized use per customer (UPC), where:

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.²

22. In its Application, AEY proposed to update the timeframes used to determine the weather-normalized UPC. The existing methodology uses a longer time period and the proposed methodology uses the last three years of data, as illustrated in the table below:

Table 3. **Comparison of weather-normalized UPC methodologies**

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

Source: Application, page 2-5.

² Exhibit BB-1, Application, page 2-5, lines 3-7.

23. In the proposed methodology, AEY would apply the growth rates experienced over the period from 2013 to 2015 to derive the forecast UPC for the test period.

24. In support of its proposal, AEY stated:

... 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.³

25. AEY submitted that using the 2013 to 2015 timeframe for weather-normalizing and forecasting the UPC was more appropriate, as it encompasses trends occurring in the Yukon over the last few years.

2.2.1 Residential sales forecast

26. Respecting its residential sales forecast, AEY stated that the forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.

27. AEY submitted that the residential average UPC for all communities (except for Keno City, Stewart Crossing and Swift River) is calculated by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC. For Keno City, Stewart Crossing and Swift River, AEY used the actual UPC of the previous year as a base⁴ and applied the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC for these communities was “used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature.”⁵ The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.2 Commercial sales forecast

28. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.

29. AEY stated that Whitehorse’s commercial UPC for the test period is forecast using the weather-normalized UPC of the previous year and applying the 2013 to 2015 growth in weather-normalized UPC. AEY added that it expects three new large commercial customers to be added during the test period in Whitehorse. AEY added:

³ Exhibit BB-1, Application, page 2-5, lines 14-19.

⁴ Exhibit B-9, YUB-YECL-7 (a): “For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year.”

⁵ Exhibit BB-1, Application, page 2-6, lines 11-12.

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.⁶

30. With the exception of Whitehorse, AEY submitted that the commercial UPC forecast for all communities is determined by using the actual UPC of the previous year, and applying the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC 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.

31. In response to UCG, AEY reiterated that three main factors have contributed to the declining trend in residential and commercial UPC, and these factors support the updated forecast methodology. These are:

- (a) the economic slowdown in the Yukon;
- (b) a continuous warming trend, starting in 2013; and
- (c) recent energy conservation initiatives, which have been implemented in the Yukon.

32. AEY added that the proposed change from 15 years to three years to run its regression model for UPC and HDDs results in a more accurate portrayal of the current context in which AEY operates, and is necessary in order to appropriately account for the factors that have led to the change in UPC behaviour since 2012.⁷

33. During the oral hearing, AEY updated its sales forecasts to incorporate nine months of actuals, as of September 2016. The updated sales forecast provided in a table in response to the undertaking showed energy sales to be with 0.3 percent of actuals.⁸

2.2.3 Views of interveners

34. Mr. Maissan noted that residential and commercial sales are expected to decrease slightly in 2016 and then increase modestly in 2017. Mr. Maissan further noted the secondary sales were forecast to increase by 2.4 GWH in the test years. Mr. Maissan recommended that the Board accept AEY's sales forecast as filed.

35. UCG pointed out that AEY has consistently realized sales that were below the approved amounts. UCG submitted that this is in part due to AEY's forecasting methodology, as well as under-estimating the impact of weather, the economy and DSM initiatives. Given the downturn in the Yukon economy and the uncertainty created by a new territorial government, UCG submitted that AEY had erred in simply applying the

⁶ Exhibit BB-1, Application, page 2-6 (lines 26 to 27) to page 2-7 (lines 1 to 3)

⁷ YECL Final Argument, paragraph 24.

⁸ Transcript, Volume 2, November 2, 2016, page 347, lines 1 to 4.

sales growth rates experienced over the 2013-2015 period to derive the weather-normalized UPC for the test period.⁹

36. UCG submitted that AEY should be directed to update its most recent sales forecast provided in its undertaking found at Exhibit B-2 with actuals from 2016 and 2017. This update should be provided when AEY submits its compliance filing and should use the most recent actuals and forecast to determine revenue requirements.

2.2.4 Views of the Board

37. The Board notes that AEY argued that the major reason for the shift in timeframe from 15 years to three years regarding its running of the regression model for UPC and HDDs was due to the shift and the change in direction respecting UPC starting in 2012.¹⁰ AEY has affirmed the contributing factors as being the downturn in the economy and conservation initiatives.¹¹

38. The Board finds that recent trends in the Yukon underpin AEY's proposed change in its methodology but the Board has concerns that a recent trend may or may not be reflective of future forecasts required in a test period. The Board considers it important that a methodology be adopted that is representative of energy sales and reflective of UPC and HDD in future years. The Board has concerns that if, for example, there is economic growth prior to the next GRA, a further adjustment to the methodology will be required due to a short time period being used to forecast energy sales.

39. With respect to its updated sales forecast, AEY's original forecast was within 0.3 percent compared to actuals for the 2016 test year. However, the Board notes that there is a one-percent variance in total retail primary sales for 2017 when the updated forecast is compared to the original forecast.

40. The Board notes AEY's submission that, "Had AEY not revised its methodology... AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016."¹² Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data.¹³ Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast,

⁹ UCG Final Argument, paragraph 76.

¹⁰ Transcript, Volume 2, November 2, 2016, page 341 (line 24) to page 342 (line 2).

¹¹ Transcript, Volume 2, November 2, 2016, page 342, lines 4 to 22.

¹² AEY Final Argument, paragraph 26.

¹³ Transcript, Volume 2, November 2, 2016, page 343, lines 17 to 20.

incorporating its prior methodology¹⁴ using a 10-year timeframe for UPC regression and normalizing HDD.

3 Purchase power

41. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table shows the actual and forecast purchase power over the period from 2013 to 2017:

Table 4. **Actual and forecast purchase power – 2013 to 2017 (\$000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized¹⁵	(402)	-	(72)	(110)	(86)
Total Purchase Power¹⁶	25,442	24,918	25,107	24,756	25,250

Source: Exhibit BB-1, Application, page 3-1.

42. The purchase deferral account is related to increases or decreases to the cost of purchased power, which is based on YEC's rates for primary energy sales and secondary sales.

43. AEY submitted that the test period purchase power forecast takes into account the Fish Lake hydro generation output, which is based on the lifetime average output for Fish Lake Unit #2 from 1960-2015 plus the two-year average for the new Fish Lake Unit #1 adjusted for planned decreases in generation due to capital builds.¹⁷ The drivers of the forecasts for 2016 and 2017 were stated as:

The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.¹⁸

44. Furthermore, consistent with the approach approved in Board Order 2014-06, AEY submitted that lines losses are calculated on a five-year average and total 6.2 percent.¹⁹

¹⁴ The methodology used in its 2013-2015 GRA.

¹⁵ Exhibit BB-1, Application, page 3-1, footnote 1: "Consistent with Board Order 2009-2, AEY will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds."

¹⁶ Rider J has not been included, as these are flow-through amounts to YEC.

¹⁷ Exhibit BB-1, Application, page 3-1 (lines 17-18) to 3-2 (lines 1-2).

¹⁸ Exhibit B-9, YUB-YECL-9(a).

¹⁹ AEY Final Argument, paragraph 31.

3.1 Views of interveners

45. UCG submitted that the incremental purchased power costs to be capitalized should only relate to planned capital projects and not maintenance or other projects that were not included in the capital budget reviewed by the Board.²⁰

3.2 Applicant responses to interveners

46. In response to UCG's submission, AEY stated that its understanding of Board Order 2009-02 is consistent with UCG's on this matter.

3.3 Views of the Board

47. The Board's determination in Board Order 2009-02 respecting the capitalization of purchase power costs required because of the Fish Lake hydro was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with Fish Lake hydro rebuilds."²¹ The Board directed AEY, at the time of its next GRA, to provide clear documentation of these incremental power purchases due to the Fish Lake hydro rebuilds.

48. In the current Application, AEY has capitalized the forecast purchased power costs related to the Fish Lake hydro rebuilds for 2016 and 2017. In the Board's view, this is consistent with directions provided in Board Order 2009-02:

The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time. *(footnotes omitted)*²²

49. The Board approves the forecast primary and secondary purchase power costs as filed because the methodology used is reasonable and consistent with the previous GRA.

3.4 Deferral Account — Purchase Power Flow-Through

50. AEY requested a Purchase Power Flow-Through Deferral Account (PPFTDA). AEY noted that the cost of purchase power in the Application is based on rates from YEC for primary energy and secondary sales and do not include any adjustments due to YEC's energy reconciliation adjustment (ERA). Any increases or decreases to the YEC rates or any ERA adjustments are to be flowed through to customers.

3.4.1 Views of interveners

51. UCG acknowledged that a deferral account is a reasonable way to track unforeseen changes in costs related to purchased power. However, UCG submitted that

²⁰ UCG Final Argument, paragraph 89.

²¹ Board Order 2009-02, Appendix A, Reasons for Decision, page 9.

²² Board Order 2009-02, Appendix A, Reasons for Decision, page 10

AEY must ensure that it limits as much as possible the charges from YEC by actively participating in reviews of YEC revenue requirements and implementing DSM initiatives that reduce the need for purchased power.²³

3.4.2 Applicant responses to interveners

52. AEY responded to the UCG submission that AEY has participated in YEC regulatory applications that impact both AEY's customers and its share-owners and will continue to do so. AEY also submitted that it expects to continue working collaboratively with YEC on initiatives that impact Yukon electricity customers.²⁴

3.4.3 Views of the Board

53. The Board notes AEY's responses to IRs on the PPFTDA. More specifically, the Board takes note of the response to YUB-YECL-47(b), in which AEY stated:

... under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate... AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.²⁵

54. Further, AEY stated that this account will ensure that there is an additional margin²⁶ if sales are greater than forecast.²⁷ Parties were asked to comment on that additional margin in argument²⁸, but no comments were received.

55. The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

4 Fuel costs

56. Fuel costs included in the AEY Application are reproduced in Table 5 below:

²³ UCG Final Argument, paragraph 88.

²⁴ AEY Reply Argument, paragraph 27.

²⁵ Exhibit B-9, YUB-YECL-47(b).

²⁶ By allowing the PPFTDA, a positive margin is maintained on incremental sales as incremental costs are covered through the deferral account.

²⁷ Transcript Vol. 3, page 520, lines 19-23.

²⁸ Transcript Vol 3., page 518, lines 13-19.

Table 5. **Actual and forecast fuel costs — 2013 to 2015 (\$000s)**

Actuals				Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Fuel Costs	6,708	6,760	6,621	5,225	5,268

Source: Exhibit BB-1, Application, page 4-1.

57. AEY explained that it purchases fuel on an ongoing basis for each of its five isolated plants via a diesel fuel tendering process, where a vendor is selected to be the provider of diesel fuel to AEY. AEY further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

58. AEY stated that the forecast cost decrease in 2016 is mainly due to lower fuel prices than previously approved, which are currently used as the base fuel prices in Rider F. AEY added that the fuel costs forecast is a function of forecast sales, line losses, plant efficiencies and delivered prices. The fuel-deferral methodology used for this account was described, as follows:

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.²⁹

59. AEY submitted that the variance between actual and forecast fuel prices is refunded to or recovered from customers by means of Rider F, a fuel-price flow-through rider.

4.1 Views of the Board

60. The Board accepts and approves AEY's fuel cost forecast, as filed. AEY is proposing to continue the deferral for fuel prices for the test period.

4.2 Deferral Account — LNG Fuel

61. Notwithstanding the above, if the Watson Lake bi-fuel project is approved, AEY anticipated that, beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. Accordingly, AEY submitted that it required 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. AEY explained that:

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

²⁹ Exhibit BB-1, Application, page 4-2, lines 20-24.

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.³⁰

62. AEY went on to explain that 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.

63. AEY proposed to include the LNG price variances in the Rider F deferral account, stating that the principles supporting a diesel price variance deferral are the same as those supporting an LNG price variance deferral or a fuel price variance deferral, namely:

- Commodity prices are subject to material fluctuations outside the utilities' control; and
- It is not in ratepayers', the Board's, or the utilities' interests to speculate on these price fluctuations.³¹

64. AEY argued that it is well within the Board's authority to approve deferral accounts in general. Furthermore, should the Board determine that the wording of the Order in Council does not allow for the inclusion of LNG price variances in the existing Rider F, AEY submitted that a new deferral account and subsequent rider should be approved. Such a rider should operate in the same manner as Rider F.³²

4.3 Views of interveners

65. UCG noted that Rider F was last approved in Board Order 2012-02, dated February 29, 2012. Noting that the Board, in Board Order 2011-15, confirmed that Rider F applies to all diesel fuel consumed in a period, UCG submitted that it is unclear whether AEY has applied to the Board for the inclusion of LNG price variances in Rider F.

66. Given that AEY is not using LNG at this time and only anticipates using LNG-fuelled generators late in 2017, at the earliest, UCG submitted that the Board should not allow AEY to establish a LNG-related deferral account until a need is established and an application has been made to change Rider F.

67. UCG further submitted that the Board cannot approve the proposed changes to Rider F for fuel used in Watson Lake without changes to section 8 of Order-in-Council 1995/90 to account for LNG use.

4.4 Applicant responses to interveners

68. AEY responded that section 8 of Order-in-Council 1995/90 provides for fuel-price adjustments and sets out that the Board must allow AEY and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to

³⁰ Exhibit BB-1, Application, page 4-3, lines 7-12.

³¹ Exhibit B-6, UCG-AEY-22

³² Exhibit B-6, UCG-AEY-22

reflect fluctuations in the price for diesel fuel, without the requirement for specific application to and approval from the Board. However, simply because AEY is entitled to flow-through diesel fuel prices without Board approval, it does not mean that it is somehow prevented, upon Board approval, from flowing through the impact of changes to LNG prices.

4.5 Views of the Board

69. Considering the Board's determination in section 9.7.2 of this decision with respect to the Watson Lake bi-fuel project, the Board does not approve the LNG deferral account.

5 Operations and maintenance (O&M) expense

70. For 2016 and 2017, AEY requested approval of O&M expenses, totalling \$11.993 million and \$12.181 million respectively. The following table shows forecast and actual amounts for the period 2013-2015, and the forecast for the test years:

Table 6. Operations and maintenance expense (\$000)

2013		2014		2015		2016	2017
Approved	Actual	Approved	Actual	Approved	Actual	Forecast	Forecast
11,604	11,718	11,882	11,698	11,944	11,616	11,993	12,181

Source: Exhibit BB-1, Application, Schedule 5.1

5.1 Labour

71. In the Application, AEY forecasted a complement of 70.38 full-time equivalents (FTEs) for each of the test years. This was an increase of 1.25 FTEs over the actual complement at the end of 2015.

72. AEY discussed labour costs in section 5 of the Application and stated that labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. The labour costs are then distributed to O&M accounts or capital accounts, depending on the nature of work being performed by the staff in the job class. Further, in section 1 of the Application, under the heading "Key Assumptions", AEY provided the following:

Table 7. 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%

Source: Exhibit BB-1, Application, page 1-5.

5.1.1 Labour complement

73. AEY proposes a labour complement of 70.38 FTEs for each of the test years.

5.1.2 Views of interveners

74. Intervenors did not provide any direct comments with regard to AEY's labour complement levels.

5.1.3 Views of the Board

75. Staff complement is one of the elements reviewed by the Board in relation to labour costs and the Board is concerned with the escalation of labour costs and the growth of Administration and General (A&G) costs. In this Application, AEY has requested an increase in its complement by two positions (an Engineering Technologist (1 FTE) and a Supervisor, Business Support Services (0.25 FTE)).

76. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change³³ in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY.³⁴ This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a position that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY.³⁵ Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the position be removed from AEY's complement.

77. As of the close of record, the Engineering Technologist position has yet to be filled. AEY did not provide any evidence that the work forecast for the Engineering Technologist position was not already being done by any of the other two existing engineering technologist positions or other members of the two engineering groups.

78. In Board Order 2014-16, AEY was directed to remove the corporate accountant position (1 FTE). It did not do so and did not request a review and variance of that direction.³⁶ To continue the position or rename the position as an Operational Accountant ignores the direction and concerns of the Board.

79. Therefore, AEY's requested approval for a complement of 70.38 FTEs for both test years is not approved. The Board approves a complement of 68.13 FTEs. The

³³ Referring to the change from reporting to the Manager (Whitehorse-based) to the Business Support Services Supervisor (Yellowknife-based).

³⁴ Transcript Vol 2, page 365, lines 1-13.

³⁵ Exhibit B-9, YUB-YECL-34(a).

³⁶ Transcript Volume 2, page 372, lines 1-17.

complement level of 68.13 FTEs is determined by removing the Engineering Technologist position (1 FTE), the Supervisor, Business Support Services position (0.25 FTE), and the Corporate/Operational Accountant position (1 FTE) as directed in the 2013-2015 GRA. AEY is to reflect this finding in its compliance filing to this decision.

5.2 Vacancy rate

80. As noted above, AEY has forecasted a vacancy rate for each of the test years of 4.0 percent, or approximately three FTEs. AEY said that the vacancy rate is based on a five-year historical average and is consistent with the methodology approved in Board Orders 2009-02 and 2014-06.

5.2.1 Views of interveners

81. Intervenors did not comment on AEY's proposed vacancy rates.

5.2.2 Views of the Board

82. The Board has reviewed the submissions of AEY on its vacancy rate in this proceeding. The Board finds the vacancy rate requested is reasonable because it is based on a five-year historical average and is consistent with the methodology approved in Board Order 2009-02 and applied in Board Order 2014-06.³⁷ For these reasons, the Board approves a vacancy rate for AEY of 4.0 percent for each of the test years.

5.3 Labour inflation

83. AEY stated that the labour escalation for 2016 was based on AEY's existing collective agreement which covers in-scope employees and AEY applied the escalators in that agreement to both in-scope and out-of-scope employees.

84. AEY reiterated its submission from the Application (section 5) that its inflationary increases were consistent with several decisions in Alberta.³⁸ It added that AEY was appropriately staffed and did not undergo the growth incurred by ATCO Electric prior to the economic downturn in Alberta; therefore, it was not impacted by the economic downturn in Alberta or the ATCO Group reorganization.³⁹

5.3.1 Views of interveners

85. In argument, intervenors did not make any specific comments on labour inflation. However, in Reply Argument, UCG stated "... it is inconsistent to have labour inflation rates from another jurisdiction dictate what Yukoner ratepayers should pay when Yukon-specific labour and wages information is readily available. UCG submits that AEY's labour inflation should be held to the most recent Yukon statistics available."⁴⁰

³⁷ Appendix A to Board Order 2014-06, section 5.2.2, page 23.

³⁸ AEY noted the following decisions in its argument: 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff), 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA), 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker) and 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker), at paragraph 66 of AEY's Final Argument.

³⁹ AEY Final Argument, paragraph 68.

⁴⁰ UCG Reply Argument, paragraph 20.

86. In addition, several of the interveners expressed concerns regarding AEY's costs. CW was concerned with AEY's pattern of over-forecasting.⁴¹ John Maissan observed that AEY is able to control overall O&M costs.⁴² UCG supported CW's concerns regarding over-forecasting, additionally mentioning "artificial inflation of rates".⁴³

5.3.2 Views of the Board

87. The Board notes that, in the September 9, 2016 updated response to YUB-YECL-27(a), AEY stated that in 2015, 10 employees (15 percent of staff) did not receive wage increases, and in 2016, 11 employees (17 percent of staff) did not receive wage increases.

88. In response to Board questioning, AEY confirmed that the staff who did not receive wage increases in 2015 and 2016 were all out-of-scope employees.⁴⁴ Further, AEY stated that for the 2016 and 2017 test years, the labour inflation forecast was based on AEY's existing collective agreement, which expires on December 31, 2016. The labour-escalation rate for the test period is forecast to be 3.25 percent. AEY did not submit any information that a new collective agreement had been reached or would be in place for January 1, 2017. The Board considers that the 2017 forecast labour escalator is not based on a collective agreement that would be in force in 2017.

89. The Board notes that built into the determination of revenue requirement for 2015 was labour inflation of 3.5 percent. However, out-of-scope employees did not receive inflation increments for that year, nor for 2016. In-scope employees received 2015 and 2016 labour-inflation increments of 3.25 percent. For 2015, this was 0.25 percent lower than what was built into the 2015 revenue requirement.

90. As a result, for out-of-scope employees, the Board awards, for 2016, a labour-inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision.

91. For in-scope employees, the Board considered that a collective agreement was in place for the 2016 test period and approves the labour-inflation rate of 3.25 percent as requested for that year.

92. However, for 2017, since the Board has no evidence of the existence of a collective agreement, the Board has to determine the inflationary increase to be awarded for in-scope and out-of-scope employees. In making its determination, the Board considered the May 2016 *Yukon Economic Outlook*.⁴⁵ The Board notes that, based on the *Yukon Economic Outlook*, Yukon experienced an economic downturn in 2015 due to reasons such as:

- 2015 GDP was down by 3.8 percent;

⁴¹ Exhibit C3-3, CW Evidence; CW Final Argument, paragraph 27.

⁴² JM Final Argument, page 4.

⁴³ UCG Final Argument, paragraph 98.

⁴⁴ Transcript Volume 3, pages 400, line 16, to 401, line 8. .

⁴⁵ Exhibit B-9, YUB-YECL-30(a), Attachment 1.

- Average employment was down slightly;
- Unemployment rate was up 2.0 percent;
- Building permits were down 9.7 percent; and
- A modest decrease in the CPI for Whitehorse of 0.2 percent.

93. The preliminary forecast for 2017 discussed in the outlook is for Yukon's real GDP to fall by 5.7 percent, and employment and the labour force to be relatively flat. The Consumers Price Index (CPI) for Whitehorse is expected to be just under 2.0 percent.

94. For these reasons, the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction.

5.4 Pension matters

5.4.1 Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account

95. AEY provided the following placeholder amounts for pension costs in its Application:⁴⁶

Table 8. 2013 to 2017 placeholder amounts for pension costs (\$000s)

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
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

Source: Exhibit BB-1, Application, page 5-3.

96. AEY sought Board approval for these amounts to be tied to the outcome of the upcoming ATCO Utilities Pension Application, to be filed before the Alberta Utilities Commission (AUC). In addition, AEY is seeking continuation of its pension deferral account to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. For the defined contribution pension plan, AEY noted that the company's contributions rate was set at 6.0 percent.⁴⁷

97. In an update⁴⁸ to defined benefit pension costs, AEY stated the costs for 2016 are forecasted to be \$505,000, assuming a COLA of 100-percent CPI.

98. Further, AEY confirmed that if the deferral account is granted for pension costs, ratepayers would experience "actual cost" rather than placeholder amounts⁴⁹ and also

⁴⁶ Exhibit BB-1, Application, page 5-3.

⁴⁷ Exhibit BB-1, Application, page 5-3.

⁴⁸ Exhibit B-9, YUB-YECL-36(f).

⁴⁹ Exhibit B-5, JM-AEY-9.

confirmed that AEY would exclude any amounts the AUC does not approve for inclusion in utility rates in the Alberta 2016 pension application.⁵⁰

99. In argument, AEY submitted that the assumption for 2016 of the COLA at 100 percent is based on changed circumstances, as the pension has moved from an unfunded liability to a funding-excess position.⁵¹

100. In its submission, UCG recommended that if the defined benefit pension deferral account was to be continued, its intended use should be clear, along with how it is to be used.⁵² No other interveners made submissions on pension costs or this deferral account.

5.4.2 Views of the Board

101. The Board finds the requested pension amounts are reasonable. As a result, the Board approves the revised defined benefit pension amounts of \$505,000 for each of the test years. The Board also approves the defined contribution rate of 6.0 percent, to be applied to the labour rates determined in section 5.3.1 of this decision.

102. Further, the Board approves AEY's request to continue with the Defined Benefit Pension Deferral Account (DBPDA). The Board finds that adjusting for the result of the ATCO Utilities 2016 Pension Application is a reasonable approach because it will reflect actual pension costs.

5.5 Other Inflation

103. As noted in the key assumptions,⁵³ AEY has requested other inflation of 2.20 percent for each of the test years. AEY stated that this forecast for the 2016 test year was based on the *Yukon Economic Outlook* dated October 2015. AEY added that since no public forecast was available for Yukon for 2017, it applied the 2016 forecast for that test year.

5.5.1 Views of interveners

104. Parties did not provide any specific comments on Other Inflation.

5.5.2 Views of the Board

105. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response.⁵⁴ In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent⁵⁵ for 2017. AEY is directed to reflect this change in its compliance filing to this decision.

⁵⁰ Exhibit B-4, CW-YECL-15(b).

⁵¹ AEY Final Argument, paragraph 71.

⁵² UCG Reply Argument, paragraph 21.

⁵³ Exhibit BB-1, Application, page 1-5.

⁵⁴ Exhibit B-9, YUB-YECL-30(a), Attachment 1.

⁵⁵ Exhibit B-9, YUB-YECL-30(b).

5.6 Non-labour costs

106. Non-labour costs were discussed in the Application. Schedule 5-1 provided a summary of actual and forecast costs. Schedule 5-2 provided year-over-year variance explanations.

107. AEY stated that non-labour costs are forecasted in two parts: (1) ongoing operational and administrative activities, and (2) new programs or projects. AEY added that it was not forecasting any new programs or projects for this test period.⁵⁶

108. For ongoing operational and administrative activities, the forecast was based on historic spending and adjusted for known changes in work to be completed in the forecast period.

5.6.1 Views of interveners

109. CW submitted evidence challenging the forecast accuracy of AEY, stating:

When the actual costs are systematically lower than forecast, one must question the reasonableness of the forecasts. When the approved forecast is continually higher than the actual costs for a cost category or item, it means customers are paying for costs the utility will not incur. While the utility is entitled to benefit from efficiency gains in the test period, the regulator must ensure that savings are from efficiency gains, and not the result of over forecasting. When there is a continual pattern of over-forecasting, that usually means that there is an issue with the forecast, and the subsequent forecast should be adjusted. Further, these savings should be captured in the subsequent rate application, to the benefit of customers.⁵⁷

110. CW asserted that a pattern of over-forecasting for the production, distribution and general functions existed.⁵⁸ CW recommended that production costs be reduced by 15 percent⁵⁹ and that distribution and general costs be reduced by \$272,000 in 2016 and \$369,000 in 2017.⁶⁰

111. UCG argued that "... there has been a pattern of over-forecasting and artificial inflation of rates in 2013-2015 with respect to O&M costs related to AEY's production facilities (\$938,000) and overspending on administration and general (\$458,000)."⁶¹ UCG noted the variance between approved and actual affiliate charges for the 2013-2015 period. It recommended that affiliate charges should be reduced by 25 percent.

112. John Maissan submitted that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. He recommended that forecasted O&M costs for the 2016-2017 test years should be reduced by 1.1 percent.⁶²

⁵⁶ Exhibit BB-1, Application, page 5-3.

⁵⁷ Exhibit C3-3, CW evidence, A5, pages 2-3.

⁵⁸ Exhibit C3-3, CW evidence, A6, pages 3-4.

⁵⁹ CW equated the 15-percent reduction in production costs to be \$314,000 in 2016 and \$306,000 in 2017.

⁶⁰ Exhibit C3-3, CW evidence, A7, pages 4-5.

⁶¹ UCG Final Argument, paragraph 98.

⁶² JM Final Argument, page 4, point 6.

113. In Reply Argument, UCG submitted:

... that AEY has not provided the Board or interveners any alternative but to review O&M cost components. The only way to justify AEY's claim that O&M should only be reviewed in aggregate is if AEY has presented an integrated business strategic plan upon which its O&M is based.⁶³

114. With respect to production costs, CW stated:

... that in assessing the likely accuracy of any forecast in the application, the Board can and should take into account a pattern of over-forecasting in areas where that can be demonstrated.⁶⁴ (*underlining omitted*)

5.6.2 Views of the Applicant

115. In argument, AEY stated:

Furthermore, the Bell Evidence does not take into account the oral testimony provided by Mr. Massie where he described a forecasting process that continuously informs the process with the best available information. Adjustment to the process are made based on historical costs and known costs looking forward. As noted by Mr. Massie, adjustments have been made to accounts going forward and these changes are reflected in the 2016-2017 test year forecasts.⁶⁵ (*footnotes omitted*)

116. AEY later added that it is more appropriate to look at total O&M costs and not isolate only those functions that are experiencing increases. In terms of \$/MWh and O&M cost per customer, AEY argued that those metrics are influenced by the level of retail sales and those sales were actually decreasing by 1.5 percent. The forecasted average annual O&M cost per customer is flat with historical actuals.⁶⁶

117. In reply to CW, AEY noted that CW did not provide any evidence as to why its method of forecasting is appropriate for the O&M categories in question. AEY went on further to say that CW failed to account for inflationary increases, based on the table provided in its argument that AEY has a history of accurately forecasting its O&M expenses.⁶⁷

118. In reply to John Maissan's recommendation that O&M costs should be reduced by 1.1 percent, AEY said Mr. Maissan's recommendation ignored inflation as well as known increases in excess of inflation.⁶⁸

119. In Reply Argument, AEY challenged UCG's request that affiliate charges be reduced by 25 percent. AEY stated that the difference between 2014-2015 actual amounts for affiliate charges related to the change in service provider and that change was fully reflected in the forecast for each of the test years.

⁶³ UCG Reply Argument, paragraph 17.

⁶⁴ CW Reply Argument, paragraph 7.

⁶⁵ AEY Final Argument, paragraph 54.

⁶⁶ AEY Final Argument, paragraphs 58-59.

⁶⁷ AEY Reply Argument, paragraph 33.

⁶⁸ AEY Reply Argument, paragraph 35.

120. Regarding Administration and General O&M costs per customer, AEY countered the UCG argument by referring to corrected tables filed on November 10, 2016 to replace the original response to CW-YECL-13 Attachments 1 and 2. The update showed Administration and General O&M costs per customer to be less for the 2017 forecast than the 2015 actual.

121. AEY stated that its submissions for Financial Reporting and Regulatory Support affiliate costs should be seen as reasonable in comparison to 2013 amounts, especially given the regulatory events expected in 2017.⁶⁹

5.6.3 Views of the Board

122. The Board is of the view, based on the evidence of CW, that AEY appears to have, at a high level, over-forecasted for each year in the 2013-2015 period. The Board views each year separately and not in aggregate. The forecast for each year is driven by different assumptions and different stages of planned programs. However, the Board agrees with AEY that the high-level approach submitted by CW can be overly simplistic. It is beneficial to have such a high level review, but the trend uncovered by that type of review should be the starting point for further investigation and not taken at face value. From an O&M perspective, deviations can occur due to changes in the capital/O&M mix. Deviations can also be related to deferring planned programs or increased work in other functions. Identifying a trend is insufficient. Identifying root causes and making recommendations for specific accounts or functions are necessary.

123. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.

124. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period.⁷⁰ However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also

⁶⁹ The content of the preceding three paragraphs was derived from the AEY Reply Argument, paragraphs 36-41.

⁷⁰ Transcript Volume 3, page 444, lines 2-25.

directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs.

125. The Board will now discuss costs at the function level. Changes due to complement levels, vacancy rates, and inflation rates (labour and other) are discussed in earlier sections of this decision and those determinations impact production, distribution, public information and customer accounting function costs.

126. Other⁷¹ costs, as provided in general function costs — in particular, Account 88800 (Maintenance for Company-Owned Houses), Account 88900 (Warehouse and Office Maintenance) — and administration and general function costs — particularly Account 72100 (Administrative) — are discussed in the following paragraphs.

127. **Account 88800 (Maintenance for Company-owned Houses).** “Other” costs were provided in AEY’s response to City of Whitehorse’s IRs. ⁷²Variance explanations were provided in Schedule 5.2 of the Application but only for Account 88900 and only for the change from the year 2013 to 2014. The following table shows the actual and forecast “Other” costs for this account:

Table 9. **Account 88800 — Maintenance, Company-Owned Houses — “Other” costs (\$000s)**

Account 88800				
2013	2014	2015	2016	2017
Actual	Actual	Actual	Forecast	Forecast
18	27	41	54	51

Source: CW-YECL-14(a), Attachment 1, page 3.

128. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “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.”⁷³ However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800 and \$7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other” (Account 88800) is \$47,000, and the 2017 balance for “Other” (Account 88800) is \$44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

⁷¹ Other costs do not include the labour and fringe elements as provided in Attachment 1 of CW-YECL-14(a).

⁷² CW-YECL-14(a), Attachment 1.

⁷³ Exhibit BB-1, Application, page 5-3.

129. **Account 88900 (Maintenance, Warehouse and Office).** “Other” costs were provided in Attachment 1 to CW-YECL-14(a) and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the forecast and actual “Other” costs for this account:

Table 10. **Account 88900 — Maintenance, Warehouse and Office — “Other” costs (\$000s)**

Account 88900				
2013	2014	2015	2016	2017
Actual	Actual	Actual	Forecast	Forecast
137	156	133	150	153

Source: CW-YECL-14(a), Attachment 1, page 3.

130. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “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.”⁷⁴ However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800, and \$7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is \$143,000, and the approved 2017 balance for “Other” (Account 88900) is \$146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

131. **Administrative and General function costs.** Schedule 5.2 provided explanations for the labour portions but did not explain the increase in “Other”. Except for an explanation related to \$21,000 for employee association agreement negotiations.

132. **Account 72100 (Administrative).** “Other” costs were provided in Attachment 1 to CW-YECL-14(a), and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the actual and forecasted “Other” costs for this account:

Table 11. **Account 72100 Administrative — “Other” costs (\$000s)**

Account 72100				
2013	2014	2015	2016	2017
Actual	Actual	Actual	Forecast	Forecast
1,481	1,541	1,256	1,556	1,585

⁷⁴ Application, page 5-3.

Source: CW-YECL-14(a), Attachment 1, page 3.

133. In YUB-YECL-45, AEY was asked to explain the increases in each of the “Admin and General” Accounts (Accounts 72100 through 72900). AEY provided explanations; for Account 72100, the explanation chiefly related to labour costs.

134. The three-year average (2013-2015) for “Other” for Account 72100 is \$1,426,000. The Board finds that it is reasonable to use the three-year average for this account. \$1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the \$1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be \$1,455,000. For 2017, the forecast value is \$1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision.

6 Taxes Other Than Income

135. Taxes Other Than Income consist of property taxes paid to communities for AEY’s office building, generation facilities, substation properties and power lines.

136. The following table summarizes AEY’s recently approved, actual and forecasted amounts for property taxes:

Table 12. **Approved, actual and forecast property taxes 2013 to 2017 (\$000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	257	265	273		
Actual (A) / Forecast (F)	273	251	256	262	267
Actual (under) or over approved	16	(14)	(17)		

Source: Exhibit BB-1A, 2016-2017 GRA Schedule S1.1, line 10.

137. AEY stated that the increase in actual 2013 property taxes over the approved amount was due to payments made to the Town of Watson Lake.⁷⁵ Increases in property taxes that had been forecast for the years 2014 and 2015 did not occur because planned capital work, upon which property tax calculations are in part determined, did not materialize. Therefore, any year-over-year increases in property taxes paid during 2014 and 2015 were due primarily to inflation.

138. AEY has forecasted property taxes in the amount of \$0.262 million for the year 2016 and \$0.267 million for the year 2017.

139. AEY stated that property tax increases in the amounts of \$0.006 million and \$0.005 million for 2016 and 2017 respectively are due to inflationary increases applicable to each test year.

⁷⁵ Exhibit B-6, YECL Responses to UCG requests, UCG-AEY-28(b), PDF, page 150 of 260.

6.1 Views of interveners

140. In argument, UCG stated that AEY should not be allowed to increase property taxes for the test years due to a lack of evidence, such as the utility's property tax assessments.

6.2 Applicant responses to interveners

141. AEY replied that the position of UCG constituted new evidence that should be struck from the record or be given no weight by the Board.

6.3 Views of the Board

142. The Board considers that it is reasonable for AEY to forecast its 2016-2017 Taxes Other Than Income based on the application of relevant inflation rates by using, as a starting point, its 2015 actual property taxes paid. With respect to the issue of property tax assessments raised in Final Argument, the Board does not have sufficient information on the record of the current proceeding to determine that consideration of property tax assessments is required. If UCG wishes to explore the issue of whether property tax assessments should be provided in support of AEY's Application, it may bring forward this issue for examination in AEY's next GRA.

143. The Board approves AEY's "Taxes Other Than Income" amounts forecasted in the amount of \$0.262 million for the year 2016 and \$0.267 million for the year 2017, as filed.

7 Depreciation

144. In its Application, AEY forecasted depreciation expense in the amount of \$5.792 million for the year 2016 and \$6.283 million for the year 2017. This resulted in an increase from 2015 actual expense in the amount of \$0.380 million in 2016 and \$0.491 million in 2017. AEY explained that the increases were the result of forecasted growth in property, plant and equipment and subject to depreciation expense.

145. AEY stated that the depreciation rates used in the calculations of 2016 and 2017 depreciation expense were developed by way of a technical update, which relied on the depreciation parameters approved by the Board in Board Order 2014-06 for AEY's 2013-2015 GRA. In that application, AEY submitted a full depreciation study in support of the depreciation parameters ultimately approved by the Board. AEY also stated that in 2016 and 2017, it would continue to record the annual amortization of the accumulated depreciation reserve differences credit in the amount of \$0.402 million,^{76 77} which was at the same level approved in Board Order 2014-06.

146. The following table summarizes AEY's recently approved, actual and forecast amounts for depreciation expense:

⁷⁶ This would have the effect of reducing YECL annual depreciation expense by \$0.402 million.

⁷⁷ YECL 2016-2017 GRA Schedules, Schedule S7.4, line 50.

Table 13. **Approved, actual and forecast depreciation expense — 2013 to 2017**
(\$000s)

	2013	2014	2015	2016 (F)	2017 (F)
Approved	4.520	5.252	5.778		
Actual (A)/Forecast (F)	4.382	4.895	5.412	5.792	6.283
Actual (under) or over approved	(0.138)	(0.357)	(0.366)		

Source: Exhibit 2016-2017 GRA Schedule S1.1, line 11.

147. During the course of this proceeding, three issues were raised with respect to depreciation, each of which is discussed in the sections that follow.

7.1 Technical update to determine updated depreciation rates

7.1.1 Views of interveners

148. There were concerns raised by UCG that AEY had not indicated nor requested approval in its application of the revised depreciation rates used in its calculation of depreciation expense for the test years stemming from the results of a technical update to its previous depreciation study.

149. UCG argued that since actual depreciation expense incurred for the 2013-15 test period had been lower than the amount approved to be recovered through AEY's tariff, this was evidence of an over-recovery of depreciation expense in the amount of \$1.1 million⁷⁸ over the 2013-15 period.

150. UCG submitted that AEY's request for increases to its depreciation expense should be denied because of these two issues.

7.1.2 Views of the Board

151. The Board observes that there appears to be some confusion by parties pertaining to certain depreciation-related elements. The Board has provided the following general information with respect to the differences between a full depreciation study and a technical update to a depreciation study.

152. Depreciation expense typically encompasses three components of capital cost recovery: (1) the depreciation related to the original cost of the asset; (2) estimations related to net salvage costs (also referred to in this proceeding as future removal and site restoration); and (3) in some circumstances, the amortization of accumulated reserve differences that arise, in part, from changes in depreciation methodologies or depreciation parameters determined during the course of a depreciation study.

153. Periodically, a new depreciation study is conducted and three depreciation "parameters" — consisting of the average service life, the standard "Iowa curve" and dispersion pattern (collectively referred to as the life-curve parameters) and the net salvage percent parameter — are confirmed or revised. The actual accumulated depreciation recorded to date, based on the prior approved depreciation parameters,

⁷⁸ UCG Final Argument, PDF page 21 of 40.

can differ from the theoretical amount of accumulated depreciation that would have been recorded for each account using the updated parameters. The resulting difference — termed the accumulated reserve difference or variance — is measured in dollars and may be recovered or refunded through depreciation expense as a stand-alone true-up amount, or may be combined into a depreciation rate that includes the amortization of the accumulated reserve differences true-up amount.

154. During the preparation of full depreciation studies, technical updates are often conducted. The purpose of a technical update (which is less costly to prepare than a depreciation study) is to apply the currently approved depreciation parameters to the recent actual plant balance information provided by the utility in order to develop the most current and relevant depreciation rates for the test years. The most recent plant balances will reflect both plant additions and retirements occurring since the time of the last depreciation study or technical update.

155. To summarize, it is during the course of examining a depreciation study that the depreciation parameters of life-curve, net salvage percentages and the amortization of accumulated reserve differences are approved. The rates that are proposed by the utility are used as an input in depreciation expense calculations and are a direct result of the depreciation parameters being applied to the most recent actual plant-in-service information. During the course of a technical update, approved depreciation parameters are similarly applied to the most recent plant balances for the purposes of updating depreciation rates, which will then be used in depreciation expense calculations.

156. In its 2016-17 GRA, AEY submitted a technical update to its December 31, 2011 depreciation study, which had been submitted as part of the record in the 2013-15 GRA.

157. The technical update undertaken by AEY relied on currently approved life-curve depreciation parameters to determine updated depreciation rates for the 2016 and 2017 test years based on December 31, 2015 plant-in-service balances. The result was a total decrease in depreciation expense of approximately \$0.100 million over the test years.⁷⁹

158. In the case of AEY, and consistent with past Board Orders, there is no estimation made for recovery of any future net salvage costs. As a result, there is no depreciation parameter related to or reflective of a net salvage percent that would otherwise form a part of AEY's depreciation rates and therefore depreciation expense.

159. Furthermore, AEY has historically recovered any amortization of accumulated reserve differences as a dollar amount, which is generally determined and approved during the course of examining a depreciation study.

160. With respect to the 2016-17 amortization of accumulated reserve differences amount, AEY stated that it had "... simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences..."⁸⁰ The

⁷⁹ Transcript, Volume 1 page 148.

⁸⁰ Transcript, Volume 3, page 424.

result was a credit, or refund, of depreciation expense in the amount of \$0.402 million per year.

161. Based on the foregoing, the Board is not convinced by the concerns raised by UCG that there is a need to deny or adjust AEY's depreciation expense calculations due to its December 31, 2015 technical update. Consistent with common depreciation practice, AEY's technical update relied on currently approved life-curve depreciation parameters applied to its most recent plant balances for the purposes of updating its depreciation rates, which were used to inform its 2016-17 depreciation expense calculations. The Board finds there is not an issue with the derivation of AEY's forecast depreciation expense.

162. With respect to UCG's assertion of over-collection of depreciation expense for the years 2013-15, the Board determines the revenue requirement on a prospective basis. Depreciation parameters and the resultant rates are estimates applied to forecasted plant balances to determine forecasted depreciation expense. While the depreciation rates themselves will remain static during the test years, actual plant balances — upon which those rates are applied — may differ from those forecasted by the utility. The end result, as observed by UCG, may be differences between approved and actual depreciation expense.

163. For the purpose of calculating AEY's depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense.

7.2 Use of the mid-year convention for calculation of depreciation expense

164. During the oral hearing, Board counsel questioned AEY as to why, in its depreciation expense calculation for Account 493 — Demand Side Management, the mid-year convention had not been applied. The question posed was directed toward a common regulatory convention related to depreciation expense calculations whereby only a half-year of depreciation expense is taken in the year in which an asset has been capitalized into rate base, followed by full-year depreciation expense calculations in subsequent years. This mid-year convention supports that in the absence of having to consider individual and exact dates of capitalization for any given asset, an assumption can be made for depreciation purposes that, on average, all assets are capitalized at the mid-point of the year.

165. An examination of AEY's schedules indicated that depreciation expense had not been taken for any of the amounts on Account 493 — Demand Side Management 2016 capital addition. The amounts had been deferred to the year 2017 where a full year depreciation expense was recorded.

166. AEY witness, James Grattan, advised that if the Board determined that coincident with the capitalization of the asset in 2016 it should attract a half-year of depreciation expense in that same year, he would not be opposed to this calculation.⁸¹

7.2.1 Views of the Board

167. The Board considers that consistent with AEY's depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

168. For clarity, the Board confirms AEY's use of a five-year amortization period is acceptable for this depreciation expense calculation, in accordance with the findings in Board Order 2014-06.⁸²

7.3 Supporting documentation for the amortization of accumulated depreciation reserve differences

169. During the IR process, AEY confirmed that costs related to net salvage had not been included in the depreciation expense for the years 2013-2017.⁸³

170. AEY also confirmed during the oral hearing that despite its Schedule 7.4 — Schedule of Amortization of Differences identified for each account number, negative net salvage in varying percentages, the schedule did not include any costs related to the recovery of net salvage. James Grattan, witness for AEY, stated that Schedule 7.4 "... simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences..."⁸⁴

7.3.1 Views of the Board

171. The Board is satisfied that the 2016-2017 depreciation expense calculated by AEY, including the calculation related to its amortization of accumulated depreciation reserve differences, does not include any amounts related to the recovery of net salvage.

172. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.

⁸¹ Transcript, Volume 3, page 427.

⁸² Board Order 2014-06, Appendix A, page 101..

⁸³ Exhibit B-6, UCG-AEY-29(a).

⁸⁴ Transcript, Volume 3, page 424.

8 Return on rate base

173. AEY included the following information on return on rate base:

Table 14. **Return on rate base — 2013 to 2017 (\$000s)**

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

Source: Exhibit BB-1, Application, page 8-1.

AEY explained that the growth in rate base is a result of capital additions and an increase in the return on equity (ROE). This resulted in the increase in return on rate base for the forecast period.

8.1 Cost of capital

174. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding as the benchmark for determining ROE. In addition, AEY is seeking a 60-basis-point risk premium over the BCUC GCOC benchmark to determine its ROE for each of the test years.

8.1.1 Rate of return on capital

175. In response to YUB-YECL-50, AEY cited the BCUC's most recent GCOC decision (G-75-13) but did not provide that decision as requested. In that decision, the benchmark rate was determined to be 8.75 percent.

176. AEY, YEC⁸⁵ and John Maissan⁸⁶ accepted the BCUC rate. CW did not comment on the rate established by the BCUC. UCG recommended that the Board use the most recent GCOC decision from the AUC.⁸⁷

177. UCG added that given AEY's direct tie to the Alberta market, AEY should not be allowed to link its ROE for the 2016-2017 test period to the recently approved BCUC GCOC benchmark rate of 8.75 percent plus a risk premium of 0.60 percent.

178. YEC disagreed with the UCG position and stated:

The Board has previously determined that the BCUC model is the precedent for Yukon; as such, in Yukon Energy's view there is no basis for using a different benchmark ROE for the current review.⁸⁸

8.1.2 Applicant responses to interveners

179. AEY submitted that UCG has ignored past decisions of the Board and the clear statements of the Board as they relate to equity ratio and ROE in Board Order 2014-06.

⁸⁵ YEC Final Argument, page 3.

⁸⁶ JM Final Argument, page 6.

⁸⁷ UCG Final Argument, paragraphs 137-150.

⁸⁸ YEC Reply Argument, pages 3-4.

8.1.3 Views of the Board

180. In Board Order 2009-02, the Board ruled that the BCUC generic cost of capital (GCOC) model is the most appropriate and is generally accepted by parties.⁸⁹

181. The Board, in Board Order 2009-08 stated:

The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.

The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.

Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board.⁹⁰

182. The Board continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon for the reasons set out above. The Board does not agree with the submissions of UCG on this issue as no evidence was filed to persuade the Board to change its approach. Accordingly, the Board finds that AEY is to use the BCUC GCOC benchmark for ROE of 8.75 percent.

8.1.4 Equity premium

183. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what that risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.⁹¹

184. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore warrants a risk premium. Concentric submitted that the premium should be 60 basis points.⁹²

185. Concentric, based on its research, recommended a risk premium of between 40 and 75 basis points in comparison to the BCUC benchmark utility. The range was framed by FortisBC Electric at a 40-basis-point premium and PNG-West (Pacific Northern Gas-West), representing the upper boundary. Concentric chose 60 basis points, as it matched the 9.35-percent ROE awarded to Maritime Electric, a utility Concentric submitted had similar business risk as AEY but had a deemed equity ratio of 40.9 percent.⁹³

⁸⁹ Board Order 2009-02 Appendix A: Reasons for Decision, page 29.

⁹⁰ Board Order 2009-08, paragraphs 280-282.

⁹¹ Exhibit BB-1, Application, page 8-3.

⁹² Exhibit BB-1, Application, page 8-4.

⁹³ Exhibit BB-1, Application, Attachment 8.1, page 6.

186. Concentric added:

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.⁹⁴

187. AEY submitted that the business risks it faces encompass market demand, operational risks, small size and geographic environment and that these risks expose it to a higher degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.⁹⁵

8.1.4.1 Views of interveners

188. YEC took the position that it is appropriate to use the BCUC benchmark ROE of 8.75 percent as the foundation, and that for Yukon utilities, it is appropriate to “apply a risk premium adder above the benchmark in order to reflect additional risks faced by northern utilities on an isolated grid.”⁹⁶ However, YEC said that AEY’s proposal deviates from the BCUC approach and from past Yukon precedent. AEY’s approach maintains a requirement for expert evidence and testimony to determine ROE for Yukon utilities that potentially increases both the cost and complexity of these proceedings.

189. YEC recommended that the Board use the same methodology and justification for determining ROE that was established in the 2005 GRA — that is, a point midway between YEC and FortisBC Electric of 48.5 basis points.⁹⁷

⁹⁴ Exhibit BB-1, Application, Attachment 8.1, page 32.

⁹⁵ Exhibit BB-1, Application, page 8-3.

⁹⁶ YEC Final Argument, page 3.

⁹⁷ YEC Final Argument, page 5.

190. In Reply Argument, YEC stated:

BCUC decisions referenced in the current Board proceedings have confirmed the requirement for a risk premium relative to the approved benchmark for various BC utilities to reflect the relative size of the utility and the characteristics of its service area.⁹⁸

191. YEC later added that in Board Order 2009-02, the Board stated:

... that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.⁹⁹

192. YEC then stated that the bookends for assessing a risk premium against the BCUC benchmark are FortisBC Electric and PNG-West.¹⁰⁰

193. John Maissan argued that the position that AEY faces increased sales forecast risk due to customers switching home heating sources is speculative. Based on the conclusion of Concentric, the sales forecast risk does not have a material effect on the risk profile for AEY.¹⁰¹

194. Mr. Maissan noted that the concern regarding variation in earnings did not appear to hold. He referred to YUB-YECL-63(b), arguing that in spite of significant economic variations and sales variabilities in 2014 and 2015, AEY, with the exception of 2015, has consistently earned above approved ROE levels.¹⁰²

195. Mr. Maissan recommended:

... that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor [sic] is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more that adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%.¹⁰³

196. CW noted that Concentric concluded that, "In most respects, the business risk of AEY has not materially changed since 2009..."¹⁰⁴ CW submitted that the request for a risk premium was unwarranted.¹⁰⁵

197. UCG argued that the appropriate benchmark should be based on the latest AUC GCOC proceeding and therefore did not make any recommendation with respect to an equity premium.¹⁰⁶

⁹⁸ YEC Reply Argument, page 4.

⁹⁹ Board Order 2009-02, Appendix A: Reasons for Decision, page 29.

¹⁰⁰ YEC Reply Argument, page 5.

¹⁰¹ JM Final Argument, page 5.

¹⁰² JM Final Argument, page 6.

¹⁰³ JM Final Argument, page 6.

¹⁰⁴ Exhibit BB-1, Application, Attachment 8.1 (Concentric Report), page 31. Concentric did subsequently state that "the most important change has been uncertainty; and unpredictability associated with usage per customer, especially among the residential class".

¹⁰⁵ CW Final Argument, paragraph 26.

¹⁰⁶ UCG Final Argument, paragraphs 137-150.

8.1.4.2 Applicant responses to interveners

198. AEY challenged CW's interpretation that the Board, in Board Order 2014-06, ruled that a risk premium was not necessary or that there was no incremental business risk. Rather, AEY submitted that the Board ruled that the determination of whether a risk premium should be applied was not clear, and the Board directed AEY to provide justification in its next GRA.¹⁰⁷

199. AEY contended that Mr. Maissan's position that the Board only use the BCUC benchmark ignores the evidence that FortisBC Energy has lower business risk than AEY.¹⁰⁸

200. In response to YEC argument, AEY said the approach it took was in response to a direction from Board Order 2014-06. Further, AEY disagreed with the submission of YEC that AEY's business risks have not changed, noting that AEY's usage per customer has made it more difficult to accurately forecast sales.¹⁰⁹

201. For risk due to small size, Concentric stated:

Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).¹¹⁰

8.1.4.3 Views of the Board

202. The Board made its determinations with respect to an ROE risk premium in Board Order 2009-02 and 2009-08 as follows:

Should a risk premium be applied?

In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation.

¹⁰⁷ AEY Reply Argument, paragraphs 57-63.

¹⁰⁸ AEY Reply Argument, paragraphs 64-66.

¹⁰⁹ AEY Reply Argument paragraphs 77 and 80.

¹¹⁰ Exhibit B-9, YUB-YECL-62(a).

The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

What risk premium should be applied to YECL?

In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.¹¹¹ *(footnotes omitted)*

203. The Board continues to maintain this view. For this Application, as in past GRA decisions, the Board does not have a recent YEC decision to determine one of the bookends for the risk premium range and to use to calculate an ROE premium as it did for Board Order 2009-02.

204. The Board notes that Concentric concluded that AEY's business risks have not materially changed since 2009.¹¹² Further, Concentric stated that weak economic conditions in Yukon, coupled with the impact of energy efficiency and DSM programs, as well as increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales.

205. However, although forecasting sales volume may be more difficult, the table in the preamble to YUB-YECL-52 shows that AEY's actual sales — with the exception of one major growth year (2012) — are consistently within two percent of the previous year's levels. Further, Concentric concluded that sales forecast risk due to changing heating fuel sources does not have a material effect on the risk profile of AEY.¹¹³

206. Additionally, AEY testified:

That we, as a utility, should be able to do come up with a forecast that's somewhat accurate to what our actual sales are going to be. It's changing and there's lot of challenges. You've got weather. You've got all the new demand side management programs, including micro-grid generation. There's lots to it. But I think it should be something that is expected that we should be able to take a guess at. Better than a guess. We should be able to do a thorough analysis and come up with a reliable forecast...¹¹⁴ I would just add that we did know the existence or lack of existence of a weather-normalization account for ATCO Electric, but we didn't frame it as an adder to the risk premium per se.¹¹⁵

¹¹¹ Appendix A to Board Order 2009-02: Reasons for Decision, page 29 of 49.

¹¹² Exhibit BB-1, Application, Attachment 8.1, page 29.

¹¹³ Exhibit BB-1, Application, Attachment 8.1, page 27.

¹¹⁴ Transcript Volume 1, page 86, lines 2-13.

¹¹⁵ Transcript Volume 1, page 87, lines 9-12.

207. Based on AEY testimony, sales volume risk is a risk AEY can manage and, in the Board's view, it is a risk that does not attract a risk premium. However, through the submissions of YEC and AEY and the comparisons with FortisBC Energy (the BCUC benchmark utility), the Board is persuaded that AEY can be eligible for a risk premium relative to the BCUC benchmark utility to mitigate risks other than those related to sales volume. The following paragraphs discuss the Board's determination of the appropriate level of the risk premium.

208. The Concentric report made the following comparisons:

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...¹¹⁶ 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.¹¹⁷

209. "Section IV — Risk Assessment" of the Concentric report listed the following risks:

- small size,
- generation risk,
- fuel and purchased power risk,
- volume/demand risk,
- regulatory environment,
- deferral/variance accounts, and
- competition from alternative fuels.¹¹⁸

210. The Board considers the two greatest risks to be size and generation. Discussion of the remaining listed risks follows. Fuel and purchased power are addressed through

¹¹⁶ Exhibit BB-1, Application, Attachment 8.1, pages 4-5.

¹¹⁷ Exhibit BB-1, Application, Attachment 8.1, page 5.

¹¹⁸ Exhibit BB-1, Application, Attachment 8.1, page 1.

deferral accounts. AEY has stated its preference to manage volume/demand risk. Regarding regulatory environment, Concentric has stated that traditional cost of service regulation is generally considered less risky than incentive regulation.¹¹⁹ AEY is under cost-of-service regulation, while FortisBC Energy and FortisBC Electric are under incentive regulation. Concentric did conclude that AEY was at higher risk than other companies due to not having a variance account for weather-related volume risk. As AEY prefers to manage its sales volume risk, the Board does not accept Concentric's conclusion that AEY faces increased regulatory risk because it does not have a weather-related volume risk deferral account. The Board's view is that AEY faces less regulatory risk than FortisBC Energy and FortisBC Electric because it is under cost-of-service regulation. Additionally, Concentric did not state that AEY deserved a risk premium for variance/deferral accounts.¹²⁰ Regarding competition for alternative fuels, Concentric submitted that FortisBC Energy faced competition from electric heat among residential customers and to a lesser extent than did PNG-West. However, Concentric concluded that this type of risk was difficult to quantify and likely does not have a material effect on the risk profile of AEY.¹²¹

211. Based on the foregoing, the Board concludes that in determining relative risk for AEY, the Board should look at size and generation risk.

212. For the comparators provided by Concentric,¹²² the Board does not accept the use of FortisBC Electric for the lower boundary. Although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY. Concentric referenced the BCUC GCOC Stage 2 proceeding¹²³ and the awarding of a 40-basis-point risk premium to FortisBC Electric. Part of the determination of the risk premium for FortisBC Electric was:

The evidence supports the findings that FBC [FortisBC Electric] faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk.¹²⁴

213. Price competitiveness was a major factor in determining the risk premium for FortisBC Electric. Concentric concluded that competitiveness (from alternate supply) did not have a material impact on the risk profile of AEY. Generation assets for FortisBC Electric are materially higher than for AEY. Similarly, the generation assets for Maritime Electric are materially higher than those of AEY. Maritime Electric procures its power from a different jurisdiction.¹²⁵ Due to these factors (competitiveness, relative amount of generation assets), the Board finds that AEY is not directly comparable to FortisBC

¹¹⁹ Exhibit BB-1, Application, Attachment 8.1, page 25.

¹²⁰ Exhibit BB-1, Application, Attachment 8.1, page 26.

¹²¹ Exhibit BB-1, Application, Attachment 8.1, pages 26-27.

¹²² FortisBC Electric for the lower boundary, PNG-West for the upper boundary, and settling on an ROE equivalent to Maritime Electric.

¹²³ Exhibit BB-1, Application, Attachment 8.1, page 5. The reference was to BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014 at page 113.

¹²⁴ Exhibit BB-1 BCUC Generic Cost of Capital Proceeding Stage 2 Decision, Order G47-14, March 25, 2014, page 86 (public document available at www.ordersdecisions.bcuc.com)

¹²⁵ Exhibit BB-1, Application, Attachment 8.1, page 21. The Board views cross-jurisdictional transactions as facing higher regulatory risk than those transactions occurring within a single jurisdiction.

Electric or Maritime Electric. Accordingly, the Board does not find generation to be a significant risk for AEY in relation to the risk of Fortis BC.

214. Further, in terms of comparisons to Maritime Electric, the Board notes that its ROE was determined through a settlement agreement. There is no evidence on the record of this proceeding indicating the trade-offs that may have occurred during the negotiation process or how the ROE level was determined. As a result, the Board gives little weight to the ROE determined by way of a settlement agreement.

215. Concentric stated that PNG-West was larger than AEY and added that PNG-West was awarded a higher risk from the BCUC 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). Concentric referenced the BCUC GCOC Stage 2 decision for this information. These circumstances do not apply for AEY. Therefore, the Board concludes that AEY is not directly comparable to PNG-West.

216. Although earnings variability has been mentioned by Concentric, the Board also notes that AEY has been able to consistently meet or exceed forecast earnings levels.¹²⁶

217. The Board took note of Concentric's view that the extremely small size of AEY is an important risk factor for the purposes of establishing an appropriate risk premium for AEY.¹²⁷

218. Based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY.

219. The evidence on this record shows that BCUC has set a premium for a small size utility at 25 basis points.¹²⁸ This Board accepts that a 25-basis-point premium over the BCUC benchmark utility is reasonable for this jurisdiction.

220. Further, as AEY will have an equity thickness¹²⁹ greater than that of the BCUC benchmark utility, the Board is of the view that this will compensate AEY for the other differences between it and the benchmark utility.

221. Therefore, the Board approves an ROE of 9.00 percent for AEY for both test years. AEY is to reflect this change in its compliance filing to this decision.

8.1.5 Common equity ratio

222. AEY requests to maintain the previously approved common equity ratio of 40 percent for each of the test years of 2016 and 2017.

223. John Maissan supported AEY's request for an equity thickness of 40 percent.¹³⁰

¹²⁶ Exhibit B-9, YUB-YECL-63(b).

¹²⁷ Exhibit BB-1, Application, Attachment 8.1, pages 19-20.

¹²⁸ Exhibit B-9, YUB-YECL-62(a).

¹²⁹ Equity thickness refers to the ratio of debt to equity of a utility.

¹³⁰ JM Final Argument, page 6.

224. UCG submitted:

... that linking AEY's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of equity thickness of AEY's capital structure. UCG submits that AEY's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility.¹³¹

8.1.5.1 Views of the Board

225. In Board Order 2014-06, the Board states:

In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application... Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.¹³²

226. The Board continues to view that an equity thickness of 40 percent for AEY is reasonable for the reasons set out above. No evidence was presented in this proceeding in support of another approach. The Board does not accept the submissions of UCG on this issue because no evidence was presented in support of these submissions or the use of an Alberta utility as a comparator in the current proceeding. The Board finds that AEY is to maintain an equity thickness of 40 percent.

8.1.6 Cost of debt

227. AEY discussed its forecast for long-term debt rates in the Application.¹³³ AEY used an average long Canada bond rate and applied a spread to determine the forecast debenture rate. The following was provided by AEY:

Table 15. **Forecast long-term debt rates**

	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%

¹³¹ UCG Final Argument, paragraph 136.

¹³² Board Order 2014-06, Appendix A: Reasons for Decision, page 54.

¹³³ Exhibit BB-1, Application, pages 8-4 to 8-5.

Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-in Rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 8-5.

228. AEY updated its cost of debt numbers in its October 24, 2016 update. The all-in rates were revised to 3.77 percent for 2016 and 4.07 percent for 2017.

8.1.6.1 Views of interveners

229. CW argued that AEY's cost of new debt has a pattern of over-forecasting, and noted that in 2014, the cost of debt was 0.96 percentage points lower than forecasted and for 2015, new debt was 1.08 percentage points lower than forecasted. CW further stated that AEY was protected in 2013 when actual cost was higher than forecasted, as actual cost was determined and approved by the Board for that year.¹³⁴

230. John Maissan argued that for the years 2008-2015, the actual rates for cost of debt were never above the approved rates for cost of debt, but were usually below the approved rates. Mr. Maissan referenced the response to JM-AEY-14 in support of this argument and recommended a cost of debt rate of 4.35 percent for both test years.¹³⁵

231. UCG, based on Board Order 2013-01, recommended that the Board adopt a historic formulaic approach of 120 basis points for forecasting future debt costs.¹³⁶

8.1.6.2 Applicant responses to interveners

232. AEY argued that CW's evidence in relation to a pattern of over-forecasting debt rates should be ignored because AEY actually under-forecasted the rate for cost of debt in one of the years used by CW. AEY added that its October 24, 2016 update to the rate for cost of debt exceeded the recommended reduction in debt rates recommended by CW.¹³⁷

233. AEY submitted that the UCG recommendation that the historical formulaic approach for determining rates for cost of debt should be used for AEY should be rejected due to lack of evidentiary support.¹³⁸

8.1.6.3 Views of the Board

234. The Board notes that AEY did update its cost of debt in its October 24, 2016 update and that update was in response to YUB-YECL-73. The Board also notes that in Argument and Reply Argument, none of the interveners commented on the update to cost of debt.

235. The Board has reviewed the submissions on cost of debt. Originally, AEY forecasted the long Canada bond rate to be 2.50 percent for 2016 and 3.0 percent for

¹³⁴ CW Final Argument, paragraph 33.

¹³⁵ JM Final Argument, page 4.

¹³⁶ UCG Final Argument, paragraphs 152-154.

¹³⁷ AEY Final Argument, paragraphs 98-99.

¹³⁸ AEY Reply Argument, paragraph 81.

2017. In its update, AEY revised those long Canada bond rates to 1.92 percent for 2016 and 2.22 percent for 2017. It appears that AEY has maintained a credit spread of 1.8 percent.

236. The Board is persuaded by the submissions of Mr. Maissan that the AEY response to JM-AEY-14 show that actual costs of debt are never above and are consistently below forecast levels. For this reason, the Board rejects AEY's forecast for 2016 cost of debt.

237. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November¹³⁹ of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

238. Further, in YUB-YECL-73(b), AEY was asked to provide the sources for the long Canada bond rate and credit spreads. Although AEY did provide sources, AEY did not explain the manner in which it determined its credit spreads.

239. In response to YUB-YECL-73(a), AEY provided its historical long Canada bond rates and credit spreads for the years 2011-2015. For that period, the average credit spread was approximately 1.6 percent.

240. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017. The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision.

8.2 No Cost Capital

241. AEY discussed No Cost Capital (NCC) in its Application. It stated that NCC related to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans and the Reserve for Injuries and Damages (RID).

242. OPEB plans are administered on a combined basis with Canadian Utilities Limited and AEY is assessed a percentage of its payroll at a rate calculated for the plan as a whole. AEY continues to use the cash basis for its pension plan and the OPEB plan. The OPEB plan covers such items as drug, health and dental costs for retirees.

¹³⁹ 2012 is the only year where the issuance was after November 1. The issuance date for that year was November 14.

243. The RID is as an account used for uninsured and uninsurable losses and the deductible portion of insurance claims. Attachments 8.2 (Beaver Creek House Fuel Spill — \$109,700) and 8.3 (Fish Lake #1 Spillway Failure — \$100,000) to the Application provided details of the two incidents that have been included in the RID account.

244. The following continuity schedule for NCC was provided by AEY:

Table 16. **Continuity for NCC Mid-Year Balance — 2013 to 2017 (\$000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Total No Cost Capital	165	(24)	446	660	667

Source: October 24, 2016 Update, Schedule S8.4.

8.2.1 Views of the Board

245. The Board finds AEY's updated NCC costs to be reasonable and approves the updated amounts, subject to any impacts from other sections of this decision.

9 Capital additions

246. AEY submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. AEY's actual and forecasted capital expenditures and additions to rate base for the period from 2013 to 2017 are shown in the following table:

Table 17. **AEY Capital Expenditures and Additions – 2013 to 2017 (\$000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Generation	5,574	8,599	3,060	6,630	5,316
Distribution	7,268	6,236	6,232	7,659	8,994
General Property & Equipment	2,516	2,002	1,402	759	1,008
Capital expenditures total	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

Source: Application, Page 9-1; Application, Schedule 9.1.

247. Using the numbers in the above table, the capital expenditures for the test period are forecasted to increase by approximately 40 percent each year when compared to 2015. Capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively, when compared to 2015.

248. Generally, with the exception of projects described in the following sections, AEY's capital additions are categorized as generation, new extensions, distribution improvements, street and sentinel lights, meters and general property and equipment. Generic descriptions of each category are provided in pages 9-1 to 9-5 of the Application, while a listing of the projects that make up the dollars shown Table 17

(above) of this order are provided in Schedules 9.1 and 9.2 of the Application. A listing of the capital expenditure information for 2016 and 2017, as well as project descriptions for those projects greater than \$100,000, are found in Attachment 9.1 and Attachment 9.2, respectively. Full business cases for major capital projects, \$500,000 or greater, are included in the Application's appendices.

249. AEY provided the following information that shows that its controllable capital was within 3.2 percent the capital expenditure amounts approved in Board Order 2014-06 for its 2013-2015 GRA. The following table shows the variances in AEY's controllable capital expenditures between its actual and approved amounts for 2013-2015:

Table 18. **Controllable Capital Expenditures — 2013 to 2015 (\$000s)**

2013-2015 GRA			
	Actual	Approved	Variance (%)
New Extensions	6,141	15,480	60.3%
Contributions	(4,866)	(13,039)	62.7%
Net New Extensions	1,275	2,441	47.7%
"Controllable" Capital	36,748	37,955	3.2 %
Total Net Capital	38,023	40,396	5.9%

Source: Exhibit B-4, CW-YECL-1.

9.1 Views of interveners

250. Mr. Maissan pointed out that the projects listed in Attachments 11-1 to 11-6 of the Application,¹⁴⁰ relating to project cost overruns, exceeded the forecast budgets by a total of \$4.7 million. The 2013 to 2015 forecast controllable project expenditures spent is \$32.048 million. Mr. Maissan stated that AEY underspent by \$5.947 million or by 15.65 percent of the original forecast. Mr. Maissan went on to state:

... a significant number of forecasted capital projects did not get done, had they been done the "controllable" capital budget would have been exceeded by \$4.7 million or more. Many projects have been dropped or deferred, but AEY provided no information on them.¹⁴¹

251. Mr. Maissan recommended that the Board order AEY to provide detailed information on capital projects that have been deferred or dropped, and the level of detail should be commensurate with the detail required for AEY capital forecasts. Mr. Maissan further recommended that the Board reduce the controllable capital budget, after any and all other adjustments, by three percent. The Board should further order AEY to indicate in a compliance filing where these cuts were made.¹⁴²

¹⁴⁰ Exhibit BB-1, Application, Project Completion Summaries Table, page 11-3.

¹⁴¹ JM Final Argument, page 7.

¹⁴² JM Final Argument, page 7.

9.2 Applicant responses to interveners

252. Responding to Mr. Maissan's submission, AEY referred to its response to YUB-YECL-11(b) Attachment 1, a spreadsheet that includes a list of all projects approved capital projects and deemed capital projects from the 2013-2015 period. AEY pointed out that in this spreadsheet, projects with variances of 10 percent and greater than \$50,000 are accompanied by a corresponding explanation. AEY noted that in its Application it had resubmitted updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but have been deferred to the 2016-2017 test period.¹⁴³

253. AEY stated that the arbitrary reduction of the capital forecast, as recommended by Mr. Maissan, ignores the significant amount of evidence on the record supporting the need and prudence of the capital projects within the capital forecast, pointing out that the capital program throughout 2013-2015 was significantly higher than what AEY has experienced in recent years. AEY submitted that it has incorporated the learnings gained from this experience into its capital forecast by making adjustments in its forecasting methodology and assumptions. AEY submits that the evidence on record does not support Mr. Maissan's recommended reduction.

9.3 Views of the Board

254. The Board has reviewed AEY's capital addition forecasts and corresponding information and considers that AEY has provided sufficient support for its capital forecast for 2016-2017. Although the increase in capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively from 2015, the capital additions are reasonable when compared to the prior three years' actual capital additions. Subject to the Board's findings in the subsections that follow, the forecast capital additions and capital expenditures have been supported by business cases and the Board accepts the explanations in the updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but were deferred.

255. For these reasons, Mr. Maissan's recommendation for a general cut for AEY's controllable capital budget is not warranted.

9.4 Distribution Plant additions

256. AEY provided the following information related to distribution plant additions for the period 2013 to 2017:

Table 19. **Distribution Plant Additions — 2013 to 2017 (\$000s)**

	Actual 2013	Approved 2013	Actual 2014	Approved 2014	Actual 2015	Approved 2015	Forecast	
							2016	2017
New Extensions	2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
Distribution Improvements	4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
Street & Sentinel Lights	536	420	322	945	466	813	585	1,132
Meters	308	600	166	204	234	207	200	204

¹⁴³ AEY Reply Argument, paragraph 96.

Transformers & Regulators	72	10	75	10	108	10	368	92
Distribution in Total	7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994

Source: AEY Application, Schedule 9.1.

257. AEY pointed out that, as a result of AEY's forecasting, the 2016 forecasts represent a 41-percent reduction compared to the 2015 approved forecast.¹⁴⁴

9.4.1 Views of interveners

258. UCG noted that total actual distribution plant additions for the 2013 to 2015 timeframe were \$19.736 million, compared to the approved forecast amount of \$31.051 million. UCG submitted that ratepayers have paid the costs of \$11.315 million in forecasted distribution plant additions that never took place within the test years.

259. Given this recent track record of overestimating plant additions, UCG recommended that the distribution plant forecast for the 2016-2017 test period be reduced by 40 percent.¹⁴⁵

9.4.2 Views of the Board

260. Regarding the UCG comments that forecasted capital additions were greater than actual capital additions, the Board notes that the approved forecasted plant additions (\$31.051 million) for 2013 to 2015 have been subsequently trued up to now reflect the actual plant additions (\$19.736 million) for 2013 to 2015. It is the actual plant additions that are now reflected in the 2015 actual closing balances that are used to inform the 2016 test year opening capital balances. Furthermore, this is standard process for forward-looking (or prospective) cost-of-service jurisdictions.

261. The Board has reviewed AEY's forecasted planned additions to distribution and corresponding information and considers that AEY has provided sufficient support for its distribution plant additions for 2016-2017. With respect to AEY's test year distribution forecasts compared to previous year's actual and approved numbers, it appears that the primary reason for the increase is related to distribution improvements. The Board's findings related to distribution improvements are addressed in section 9.4.4. Subject to the findings in that section, the Board considers AEY forecasts to be reasonable for distribution plant additions and does not agree with UCG's recommendation to reduce the 2016-2017 test-period forecasts.

9.4.3 New Extensions

262. With respect to New Extensions, AEY stated that the forecast is based on discussions with the Yukon government, the City of Whitehorse and First Nation governments. AEY holds a seat on the Development Review Committee with the City of Whitehorse. As a result, AEY has contact with developers and engineering firms, which informs the new extension forecast. AEY submitted that it also considers historical customer additions in formulating its forecasts to specifically account for walk-in customers who may require service during the test years.

¹⁴⁴ AEY Reply Argument, paragraph 126.

¹⁴⁵ UCG Final Argument, paragraphs 175 to 176.

263. AEY submitted that the reason for lower new extensions expenditures as compared to previously approved numbers is slower economic growth than previously anticipated. AEY added that new extensions are a capital cost not at the control of AEY and are dependent on development within the communities in which the company operates.¹⁴⁶

264. AEY submitted that it uses the best information available when preparing its forecasts, which includes any lessons learned from past test periods. AEY reiterated that its new extension forecast is based on “historical actual experience and incorporated information from the Yukon Government, the City of Whitehorse, and First Nation Governments ... there is no systemic forecast error and ... the forecast has no relation to, or correlation with the 2013-2015 forecast.”¹⁴⁷

9.4.3.1 Views of interveners

265. CW noted that AEY admitted it over-forecasted capital additions related to new extensions over the 2013 to 2015 period. Furthermore, taking customer contributions into account, the forecast for net new extensions over the period is 47.7 percent higher than actuals. CW submitted that the systematic over-forecasting results in customers paying for capital that is not actually put into service. Accordingly, CW recommended the Board reduce the 2016-2017 test period forecast for net new extensions by 47.7 percent to account for the systemic forecast error.¹⁴⁸

9.4.3.2 Views of the Board

266. With respect to the argument put forth by CW, the Board is not convinced that a three-year period of actuals being lower than approved amounts can be classified as systemic. The Board accepts Mr. Tenney’s testimony on behalf of AEY that overall, the three-year forecast period was fairly accurate.¹⁴⁹ However, the Board notes that might not be true on a line-item-by-line-item basis. Mr. Tenney also stated in testimony:

With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that the need to move forward.¹⁵⁰

267. Mr. Massie added:

And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I’d say that we’ve reflected it in our ’16 and ’17 forecasts.¹⁵¹

268. The Board accepts AEY’s testimony that it has adjusted its test period forecasts to account for historical over forecasting. The Board does not accept CW’s and UCG’s recommendations to reduce AEY’s new extension forecast.

¹⁴⁶ Exhibit B-4, CW-YECL-1.

¹⁴⁷ AEY Final Argument, paragraph 130.

¹⁴⁸ Exhibit C3-3, CW Evidence, A8.

¹⁴⁹ Transcript, Volume 3, page 441, lines 13 to 14.

¹⁵⁰ Transcript, Volume 3, page 442, lines 6 to 9.

¹⁵¹ Transcript, Volume 3, page 442, lines 17 to 22.

269. Furthermore, the Board notes that the 2016 new extension forecast is three percent greater than 2015 actuals, and the 2017 forecast is 2.2 percent greater than the 2016 forecast, after the Whistle Bend Stage 3 project is accounted for in the forecast.

270. In the Board's view, AEY is taking into account current economic conditions in the Yukon and information available to it at the time of preparing the forecast. Moreover, the Board notes that AEY's submission that indicated that year-to-date costs for new extensions, as of October 31, 2016, are \$2.116 million, or 98 percent of the 2016 forecast.¹⁵²

271. For these reasons, the Board approves AEY's forecast as filed.

9.4.4 Distribution improvement projects

272. AEY submitted that distribution improvement projects generally fall into four major categories: (1) system performance projects, (2) life extension projects, (3) system replacement projects, and (4) "forced" projects. AEY clarified that these projects are required to maintain system performance at an acceptable level and that this category of capital projects includes system protection, voltage, current and line clearance projects.¹⁵³ AEY added that it tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.¹⁵⁴

273. AEY submitted that the proposed test period forecast distribution improvement projects are prudent in that they ensure the continued supply of safe and reliable electricity to AEY's customers at a reasonable price. Accordingly, AEY submitted that the Board should approve the 2016-2017 distribution improvements as applied for.¹⁵⁵

274. AEY pointed out that it files KPI (key performance indicators) reports on an annual basis. AEY submitted that the reports are available on the Board's website and added that the last such report for year 2015 was filed on May 4, 2016.¹⁵⁶

9.4.4.1 Views of interveners

275. UCG noted that system improvement expenditures increased an average of \$3.75 million per year over the period from 2010 to 2015. UCG further noted that AEY proposed system improvement expenditures of \$4.346 and \$4.178 million in 2016 and 2017 respectively, but has provided no evidence of expected system performance improvements with respect to line losses and interruption indices. UCG included the following in argument:

UCG submits that without an established benchmark, the Board and ratepayers cannot determine how well AEY is actually performing with respect to SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) reliability performance indices. UCG submits that the Board

¹⁵² AEY Reply Argument, paragraph 91; Transcript, Volume 3, page 509, line 25, to 510, lines 1-2.

¹⁵³ Exhibit BB-1, Application, Page 9-2.

¹⁵⁴ Exhibit BB-1, Application, Page 9-3,

¹⁵⁵ AEY Final Argument, paragraph 138.

¹⁵⁶ AEY Reply Argument, paragraph 46.

should establish performance and reliability benchmarks and AEY should be directed to report its actual performance against these benchmarks.¹⁵⁷

276. Considering the above, UCG submitted that AEY should be denied distribution expenditures in 2016 and 2017 since evidence has not been provided that demonstrates a benefit to customers.

9.4.4.2 Views of the Board

277. The Board approves AEY's proposed distribution improvement expenditures as filed. Nonetheless, with respect to system performance projects, the Board notes AEY submission that it:

... tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. To this end, AEY reviews unplanned outages that may be attributed to system deficiencies, prepares a report for each, and implements corrective action.¹⁵⁸

278. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings.

9.4.5 Meters

279. AEY submitted that capital additions for meters should include new meter installations that are required to replace end-of-life meters consistent with Measurement Canada requirements. This category of capital additions also includes the installation of new meters required to accommodate load growth associated with customer requests for service. The capital meter additions forecast is based on known areas of development and expected connection repairs.

280. AEY pointed out that it purchases meters from ATCO Electric at cost and, in so doing, is able to take advantage of the economies of scale realized by ATCO Electric in its meter purchases. This is a significant benefit to AEY and its customers. AEY submitted "this is undoubtedly the least cost alternative given that it is able to purchase its meters, but with the buying power of a utility the size of ATCO Electric."¹⁵⁹ Furthermore, other than AEY and its customers benefiting from this relationship, AEY submitted that it is unclear as to what benefit could be derived by the ATCO family of companies, given that the meters are purchased at cost.

¹⁵⁷ UCG Final Argument, paragraph 231.

¹⁵⁸ AEY Final Argument, paragraph 136.

¹⁵⁹ AEY Reply Argument, paragraph 136.

9.4.5.1 Views of interveners

281. With respect to meter replacement and new installations, UCG commented that over the period 2013-2015, AEY had actual expenditures of \$708,000 that were well below the approved \$1 million total. UCG submitted that this significant over-forecasting trend should be used to reduce the forecasts proposed for 2016 and 2017. UCG also referred to AEY's submission that it purchases meters from ATCO Electric's meter shop in Grande Prairie. UCG submitted that there should be further clarification on how this arrangement was determined to be the least cost alternative supply point and whether the affiliate relationship had been used to provide benefits to the ATCO family of companies.¹⁶⁰

9.4.5.2 Views of the Board

282. The Board accepts AEY's submission that it is able to purchase its meters at cost from ATCO Electric. Accordingly, the Board finds that no further information is required. The meters are supplied by the affiliate at cost, and the mere existence of the affiliate arrangement for the provision of these meters, in these circumstances, does not merit further clarification by AEY at this time. UCG's request is denied.

9.5 Conversion of existing LED streetlights

283. AEY indicated that it has been in discussions with its customers, some of which are municipalities, regarding recent developments related to the conversion of existing streetlights to light-emitting diode (LED) lamps. Considering there is capital outlay associated with the conversion of existing streetlights to LED, AEY submitted that it is seeking the Board's 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.¹⁶¹

284. AEY explained that the rationale for this project being a system cost would be that the initial streetlight cost was contributed by the customer when the streetlight was originally installed. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.¹⁶²

285. AEY acknowledged the benefit of reducing load on the electrical system and that the longer lifespan of equipment used under this project could lead to reduced costs in operation and maintenance of the lights. AEY submitted that converting all existing high-pressure sodium (HPS) streetlights to LED streetlights in AEY's communities would cost approximately \$2 million and the project would need to be completed over several years due to resource constraints.

¹⁶⁰ UCG Final Argument, paragraphs 221 to 222.

¹⁶¹ Exhibit BB-1, Application, page 9-3.

¹⁶² Exhibit B-9, YUB-YECL-10(c).

286. AEY provided two cost-benefit analyses for converting lights in thermal communities and hydro communities for each of the two options: customer contributions or system costs.¹⁶³ The cost-benefit analyses showed that a greater net present value (NPV) would result if the conversions were done in diesel-served (thermal) communities compared to hydro communities. AEY reiterated that it is not applying for approval of a wholesale replacement of all existing HPS streetlights but is seeking Board direction as to the appropriate method of accounting for the costs associated with customer conversions of existing streetlights to LED.¹⁶⁴

9.5.1 Views of interveners

287. Mr. Maissan indicated his support for the LED-conversion project and recommended that the Board direct AEY to proceed with the conversion of streetlights (i.e. HPS to LED lights) as a system cost and that priority be given to diesel-served communities.

288. CW indicated its support for the conversion of existing streetlights to LED lamps. However, CW submitted that it is inappropriate for AEY to request the Board to issue direction as to the method of accounting for the associated capital costs in the absence of a fully supported proposal by AEY on that issue. Accordingly, CW recommended that the Board direct AEY to submit a proposal, supported by evidence, which can be tested by the Board in order for it to make a determination on this issue.

9.5.2 Applicant responses to interveners

289. AEY submitted that it is not clear as to what additional information CW is proposing that AEY file with the Board. From AEY's perspective, the decision is relatively straightforward in that either the conversion costs are treated as a system cost or the local municipality must pay for the conversion cost as a contribution in aid of construction. AEY pointed out that economic analyses of both treatments as well as the total estimated costs involved are on the record. All parties have had an opportunity to submit IRs and cross-examine AEY with respect to the information. AEY submitted that the record is complete and the Board has ample information to render a decision on the treatment of costs for streetlight conversions.

Moreover, the treatment of such costs will likely inform the decisions of the relevant communities and/or municipalities with regard to such conversions.¹⁶⁵

290. AEY asserted that requiring it to come forward with a fully supported proposal is entirely unnecessary and would only serve to add inefficiencies to the regulatory process.

9.5.3 Views of the Board

291. The Board supports AEY's rationale for a streetlight project to be treated as a system cost, as outlined:

¹⁶³ Exhibit B-9, YUB-YECL-10(b) Attachment 1.

¹⁶⁴ Exhibit B-4, CW-YECL-27 (h).

¹⁶⁵ AEY Reply Argument, paragraph 95.

... the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.¹⁶⁶

292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.

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

9.6 Project cost overruns (related to Direction 13 — Board Order 2014-06)

294. Responding to Direction No. 13 of Board Order 2014-06, in relation to project cost overruns, AEY included project completion summaries for all projects that were forecast in AEY's 2013-2015 GRA for which actual costs were 100 percent and \$100,000 greater than the original forecast. AEY's compliance with Direction 13 is discussed in section 11 of this decision.

295. The following table contains the list of projects and the related attachment in section 11 of the Application wherein the project descriptions and summaries are provided. Actual and approved forecast costs are included in the summaries, as well as explanations for the variances:

Table 20. **Project Completion Summaries (\$000s)**

Project	Attachment	Approved Forecast	Actuals
Fish Lake Dyke Upgrade	Attachment 11.1	1,720	2,552
Old Crow Plant Expansion	Attachment 11.2	1,950	4,566
Beaver Creek PLC Upgrade	Attachment 11.3	180	377
McIntyre Subdivision Rebuild	Attachment 11.4	725	1,453
Deep Creek Subdivision Connection	Attachment 11.5	60	213
Old Crow Staff Accommodations	Attachment 11.6	100	274

Source: Exhibit BB-1, Page 11-3, Attachments 11.1 to 11.6.

¹⁶⁶ Exhibit B-9, YUB-YECL-10(c)

296. AEY provided business cases for projects where the actual costs were in excess of \$100,000 and for which no business case was provided. The following table includes the list of projects and the actual costs:

Table 21. **Business Cases for Completed Projects (\$000s)**

Project	Attachment	Actuals
Old Crow #2 Replacement	Attachment 11.7	161
Whistle Bend Subdivision Stages 1 & 2	Attachment 11.8	513
Whistle Bend Underground Residential Service	Attachment 11.9	116
City of Whitehorse Range Road Widening	Attachment 11.10	188
4L314 Chilkoot Way Upgrade	Attachment 11.11	483
Azure Road Extension	Attachment 11.12	151
2nd Ave Rebuild	Attachment 11.13	115

Source: Exhibit BB-1, Page 11-4, Attachments 11.7 to 11.13.

9.6.1 Views of interveners

297. With respect to the Old Crow plant expansion project, which went over-budget by \$2.616 million, Mr. Maissan asserted that AEY has been operating in Old Crow for many years and submitted that AEY should have suspended and re-assessed the project when it ran into design cost overruns and local logistical difficulties. Mr. Maissan recommended that the Board retain experts to review and audit the project execution process and cost, or the Board disallow \$1 million of the \$2,616 million cost overruns and remove it from rate base.¹⁶⁷ With respect to the Old Crow Unit 4 Addition project, Mr. Maissan recommended that the Board direct AEY to provide a business case for this project, as it was completed \$112,000 over budget.¹⁶⁸

298. UCG expressed concerns with the significant expenditures over approved budget amounts for many of the capital projects that had been previously approved. UCG submitted, "If there is no evidence that these extra costs were prudently incurred, they should not be allowed to be added to AEY's rate base."¹⁶⁹ UCG stated that additions to AEY's rate base should be limited to allowed cost estimates unless AEY can provide evidence that the cost overruns were prudently incurred. In particular, UCG submitted that the doubling of the cost for the McIntyre Subdivision Rebuild should be the responsibility of AEY, not ratepayers. It concluded with respect to the McIntyre Subdivision Rebuild:

AEY's evidence is that this project went well beyond the Board approved level because the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This along with other issues resulted in a requirement to develop an entirely new project scope. This resulted in AEY incurring an additional \$728,000 in costs (for a project originally assumed to cost \$725,000) and doubling the cost of the project.¹⁷⁰

¹⁶⁷ JM Final Argument, page 8.

¹⁶⁸ JM Final Argument, page 9.

¹⁶⁹ UCG Final Argument, paragraph 160.

¹⁷⁰ UCG Final Argument, paragraphs 177.

299. UCG further submitted that AEY should not be able to arbitrarily add capital projects to rate base that have not been previously approved by the Board.¹⁷¹ Furthermore, expressing concerns respecting the rapid increase in AEY's rate base in the 2013-2015 timeframe, UCG submitted that AEY should be required to submit detailed asset management plans and/or distribution system plans, the elements of which "will drive the development of investment and maintenance for the test year(s) and beyond."¹⁷²

9.6.2 Applicant responses to interveners

300. Notwithstanding the comprehensiveness of the Old Crow business case, as acknowledged by Mr. Maissan, AEY submitted that project timing was restricted given the timing of the construction of the ice road. Furthermore, the magnitude and extent of the many challenges that arose could not have been foreseen. AEY submitted that although the business and community need did not change, AEY proceeded with the project knowing the costs would be fully examined in a future GRA. AEY confirmed that it would be:

... submitting a Post Completion Summary of the project, that clearly indicates the variances, and gives the Board and Intervenors an opportunity to examine the Project during the entirety of a regulatory proceeding is the most appropriate process, without putting the supply of power to the community at risk.¹⁷³

301. Respecting Mr. Maissan's recommendation that AEY submit a business case for the Old Crow Unit 4 addition costs because project costs exceeded the original estimate by more than \$100,000, AEY pointed out that the costs did not exceed 100 percent of the approved forecast. As such, AEY submitted "the business case type description of the cost overrun sought by Maissan is not required" and AEY submitted that there is sufficient information on the record to deem the project useful and prudent.¹⁷⁴

302. Responding to UCG, AEY replied that it does not arbitrarily add capital projects to rate base. AEY's capital expenditure forecasts are based on the best available information at the time of its GRA. AEY submitted that unknown costs that arise and are not included in test period forecasts are subsequently included as actuals in future applications, thus providing the Board and intervenors with the opportunity to assess the need and prudence of such costs. AEY submitted that despite UCG's claims, there is ample evidence on the record to demonstrate that all costs related to McIntyre Stage 1 have been prudently incurred. AEY argued that project planning was comprehensive and many assumptions were validated. It could not have predicted what caused the project scope to be adjusted. AEY indicated that, "Project planning and execution was constantly reviewed and updated with the best available information, all while ensuring the customer and Project needs are addressed."¹⁷⁵

¹⁷¹ UCG Final Argument, paragraph 162

¹⁷² UCG Final Argument, paragraph 165

¹⁷³ AEY Reply Argument, paragraph 104.

¹⁷⁴ AEY Final Argument, paragraph 106.

¹⁷⁵ AEY Reply Argument, paragraph 129.

303. AEY added that there is no evidence on the record indicating that the “capital projects put forward by AEY are not needed or that they have not been completed prudently.”¹⁷⁶ With respect to the UCG submission that AEY provide a detailed asset management plan, AEY submitted that such an undertaking is beyond the scope of this proceeding and is being put forward by UCG with limited explanation and no evidence to justify such a request.¹⁷⁷

9.6.3 Views of the Board

304. The Board notes that in its Application, AEY has provided:

- (a) project completion summaries that were forecast in its 2013-2015 GRA, for which actual costs were 100-percent and \$100,000 greater than the original forecast; and
- (b) business cases for projects where actual costs were greater than \$100,000 and for which no business cases were provided.

305. As a result, AEY provided a business case (Appendix 11) for the Destruction Bay Unit 3 replacement where actual costs exceeded the \$450,000 forecasted by \$184,000. The Board further acknowledges that AEY provided a comparison of forecast and actual costs,¹⁷⁸ accompanied with an explanation for projects with variances of 10 percent and greater than \$50,000.

306. When costs are provided in a GRA on a forecast basis, the Board accepts the information available at the time of filing the Application or that becomes available prior to the close of record of the proceeding. Providing the Board with the best available information at the time that it must make its decision assists the Board in determining a revenue requirement for the utility that most closely matches a utility’s expected costs given facts known at the time the application was made or before the close of record. It is incumbent on the utility to do so, and for the utility to plan and budget in preparing its forecasts. Unforeseen projects may arise after a Board Order is issued with respect to the forecast test period. In these cases, the Board reviews the project costs and the variances in the subsequent GRA to ensure that the costs were prudently incurred by the utility.

307. Despite the magnitude of some of the variances between forecast and actual capital expenditures for certain capital projects, the Board accepts the variance explanations provided by AEY.

308. Considering the above, the Board accepts the information found in the project completion summaries and business cases for completed projects. No further direction from the Board is required. The projects and their corresponding costs are discussed in the following sections.

¹⁷⁶ AEY Final Argument, paragraph 122.

¹⁷⁷ AEY Reply Argument, paragraph 125.

¹⁷⁸ Exhibit B-9, YUB-YECL-11(b) Attachment 1.

9.7 Major capital projects

309. In the Application, AEY provided 11 business cases found in Appendix 1 to Appendix 11, in support of major capital projects where forecast costs were \$500,000 or greater. Major capital projects and the underlying business cases are discussed in the sections below.

9.7.1 Fish Lake System expenditures¹⁷⁹

310. AEY noted that the Fish Lake hydro system was built around 1950 and the aging infrastructure is coming to the end of its useful life. In order to maintain Inflow Design Flood (IDF) rates and comply with its water licence for Fish Lake, AEY proposed two projects: the Fish Lake Ditch 3 Diversion project and Fish Lake #2 Head Pond Spillway replacement.

9.7.1.1 Fish Lake Ditch 3 Diversion project (Appendix 1)

311. This project was previously approved in AEY's 2013-2015 GRA. On May 31, 2013, AEY was granted a 25-year extension to its water-use licence, HY12-065. AEY submitted that during the water licence application process, it was identified that the Fish Lake Ditch 3 diversion structure and spillway were not adequately built to withstand a 100-year flood event, which is required to meet IDF rates and comply with its water licensing requirements. AEY is planning to replace and upgrade the Ditch 3 diversion structure and spillway to an engineered design that will allow it to meet these requirements. Accordingly, AEY provided an updated cost forecast with respect to this project, which is reproduced below:

Table 22. **Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs (\$000s)**

Year	Actuals	Forecasts	Total
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

Source: Exhibit BB-1, Application, Appendix 1, page 2.

9.7.1.2 Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)

312. Investigative repairs of the Fish Lake #2 head pond spillway structure identified that the overall structure was in need of replacement. AEY explained that it will have to replace the existing spillway structure in order to adequately handle IDF flows while maintaining safe access to AEY generation facilities. AEY submitted that the project was designed in 2016 and construction is expected to be completed in 2017. Design and engineering costs are estimated to be \$20,000 and the current construction costs are forecasted to be \$593,000.

¹⁷⁹ Exhibit BB-1, Application: Appendix 1, Fish Lake Ditch 3 Diversion Replacement and Appendix 2, Fish Lake 2 Head Pond Spillway Replacement.

9.7.1.3 Views of interveners

313. UCG noted that over the period from 2006 to 2015, AEY has spent \$11.429 million in capital and \$1.96 million in O&M expenditures, while AEY, over the same period, has recovered \$5.87 million in revenue requirement from ratepayers. UCG pointed out that AEY is now looking to spend over \$3 million on the Fish Lake Ditch 3 replacement project and an additional \$0.593 million on the Fish Lake #2 Head Pond Spillway replacement project. Considering the limited amount of total load that is supplied via the Fish Lake plant, it is questionable whether spending this level of funds on a deteriorating plant is providing ratepayers value for their money.¹⁸⁰

9.7.1.4 Applicant responses to interveners

314. AEY submitted that the projects were being completed on water management structures that direct and control water and water flows in the Fish Lake system in compliance with AEY's water licence. AEY specified with respect to water licensing requirements that:

As indicated in the Water License, there are maximum and minimum flows that must be maintained throughout the system. Also, a condition of AEY's Water License is that works associated with the License will be maintained to a sound engineering standard (condition 27 of the Water License).¹⁸¹

315. AEY further clarified by stating that the specific recommendations for these projects can be found in its *2014 Dam Safety Report*.¹⁸²

9.7.1.5 Views of the Board

316. The Board accepts the need for both of these projects, as they are a condition of the water licence.

317. In the case of the Fish Lake Ditch 3 diversion project, a higher standard in regard to water licence HY12-065 was directed for this project. The change in standard caused a delay as draft designs and spillway channel brushing were required in 2014, additional surveying was necessary to enable updated design models and adjustments in 2015, and further construction and civil work was scheduled to be completed in 2016.

318. The requirement for the Fish Lake #2 Head Pond Spillway Project was not discovered until repairs in 2013 brought to light a sinkhole near this dam structure. Further, investigative work resulting in the 2014 Dam Safety Report recommended replacement of the structure by the end of 2017. Accordingly, the Board does not accept UCG's recommendation to deny the expenditures for this project.

319. The Board accepts the updated forecast costs for the Fish Lake Ditch 3 diversion project as these costs are necessary to meet the standards of the new water licence. The Fish Lake #2 Head Pond Spillway costs have not been challenged in this proceeding, and for the reasons provided in this decision, the Board finds these costs are reasonable.

¹⁸⁰ UCG Final Argument, paragraphs 218 to 220.

¹⁸¹ AEY Reply Argument, paragraph 134.

¹⁸² Exhibit B-9, YUB-YECL-14(a), Attachment 1.

9.7.2 Watson Lake Bi-Fuel Project (Appendix 3)

320. AEY is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to bi-fuel. The two phases were described as:

- 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.¹⁸³

321. If Board approval of the project is received in Q1 of 2017, AEY added that Phase 1 could be completed as early as Q3 of 2017. AEY submitted that Phase 2 of the project is expected to be completed following Yukon Environmental and Societal Assessment Board (YESAB) approval of Phase 1.¹⁸⁴

322. AEY submitted that this project achieves the federal and Yukon governments' goals of displacing diesel and managing electricity costs by using LNG as an alternative fuel source. Using LNG will reduce diesel consumption of its power generation plant in Watson Lake by approximately 50 percent because it is a cheaper fuel source than diesel. AEY asserted that it "... expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project" and that "These savings would be passed directly on to customers."¹⁸⁵

323. AEY pointed out that forecasted cost savings are dependent on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. AEY added that the bulk of the delivered LNG price is attributed to the cost of liquefaction and transportation fees. Recognizing the uncertainty as to the future prices for diesel and natural gas, AEY provided 20-year NPV analyses using 12 different scenarios where fuel prices were escalated at differing fixed rates from the 2015 historical price of diesel and natural gas.¹⁸⁶

324. AEY estimated the total cost of this project to be approximately \$5 million, albeit at this time, AEY is seeking approval for \$3.3 million to implement Phase 1 of the project. AEY submitted that it will competitively tender each of the major elements of the project,¹⁸⁷ excluding the equipment purchased from ATCO Gas. Further:

ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for

¹⁸³ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.

¹⁸⁴ AEY Final Argument, paragraph 150.

¹⁸⁵ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.

¹⁸⁶ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, Table 2, page 7, and Table 3, page 8.

¹⁸⁷ The major elements of the project are described in the Application, Appendix 3, page 3.

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.¹⁸⁸

325. AEY estimates the annual incremental O&M costs that are not included in the 2016-2017 forecasted costs but will apply in future years to be approximately \$50,000 per year. AEY submitted that the O&M contract specific to the LNG equipment will be competitively tendered, will include periodic maintenance, and will involve additional safety training for AEY's operational staff.¹⁸⁹

326. Asked why it would choose a new unit that requires field modifications to burn both diesel and natural gas rather than purchasing a new unit that is factory capable of burning both fuels, and with nameplate performance ratings, AEY responded:

Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.¹⁹⁰

327. AEY submitted that all of the project-related costs presented in the following table are budgetary, except for the actual costs incurred to date:

Table 23. **Watson Lake bi-fuel project — Phase 1 and 2 capital costs**

	Phase 1			Phase 2
	2012-15	2016	2017	2018
Study costs	\$222,000			
Engineering, design, and permitting	\$272,000	\$55,000	\$152,000	\$105,000
LNG vaporizer and LNG storage tank			\$1,194,000	
Installation (civil, mechanical, and electrical) and boarding			\$1,090,000	
Conversion of remaining units to bi-fuel				\$700,000
Tank expansion, piping, cryopump and installation				\$905,000
Phase sub-total			\$2,985,000	\$1,710,000
Total				\$4,695,000

Source: Exhibit B-9, YUB-YECL-13(b).

328. AEY submitted that it believes there are environmental benefits to this project, which it has previously discussed and which have further been the subject of a review pursuant to the *Yukon Environmental and Socio-economic Assessment Act*. A decision document that supported the project was issued in August 2013.¹⁹¹

¹⁸⁸ Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 3.

¹⁸⁹ Exhibit B-9, YUB-YECL-13(e).

¹⁹⁰ Exhibit B-9, YUB-YECL-24(h).

¹⁹¹ AEY Final Argument, paragraph 143.

329. With respect to project expenditures, AEY submitted that Phase 1 expenditures are the only costs to be incurred within the test period and AEY is seeking to recover those as part of this GRA. AEY explained that Phase 2 of this project is necessary to provide all of the benefits to ratepayers and reduce costs over the long-term by increasing consumption of LNG over the life of the project. AEY submitted that the objective in this GRA is “to obtain Board approval to complete both phases of this Project and AEY will bring forth Phase 2 costs for a prudence determination as part of a future general rate application.”¹⁹²

9.7.2.1 Views of interveners

330. With respect to the results of the analysis provided by AEY in its business case¹⁹³ and the fuel price scenarios for diesel and natural gas over the period from 2017 to 2037, Mr. Maissan referred to the following:

Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below \$2 million in NPV. Four scenarios are at \$5 million NPV or higher.¹⁹⁴

331. Mr. Maissan pointed out that the analysis did not account for renewable generation and assumed that all electrical loads will be served by diesel or LNG for the next 20 years. Noting Mr. Tenney’s acknowledgement of this on behalf of AEY, Mr. Maissan pointed out that the Yukon’s Independent Power Producers (IPP) policy provides for 2,100 MWh of generation to be available to Watson Lake under the standing offer program portion of the IPP policy. Mr. Maissan submitted that any further generation added under the micro-generation program will displace more diesel generation and weaken the economics of the bi-fuel conversion project.¹⁹⁵

332. Mr. Maissan noted AEY’s submission that the project will break even over 20 years when the price per litre of LNG on a diesel-litre-equivalent basis (DLE) is 75.6 percent of the cost of delivered diesel. Considering the price of LNG over the past 12 months, Mr. Maissan argued that the project is uneconomical if LNG were sourced from FortisBC and is just economical if LNG is sourced from AltaGas in Alberta. Mr. Maissan suggested that in his view, there was a high likelihood that the price differential between natural gas and diesel would approach historic levels (i.e. natural gas prices growing closer to diesel prices). If this were to occur, it would make the project uneconomical regardless of which supplier is liquefying and transporting the natural gas.¹⁹⁶

333. Considering the above, Mr. Maissan recommended that the Board deny the Watson Lake bi-fuel project. Mr. Maissan further recommended that of AEY’s project-related costs to date, approximately \$549,000 (\$494,000 + \$55,000) be amortized over a five-year period. On a related matter, Mr. Maissan suggested that the

¹⁹² AEY Final Argument, paragraph 154.

¹⁹³ Exhibit BB-1, Application, Appendix 3, Table 3, page 8.

¹⁹⁴ JM Final Argument, page 12.

¹⁹⁵ JM Final Argument, page 13.

¹⁹⁶ JM Final Argument, page 14.

Board direct AEY to "... channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy."¹⁹⁷

334. Should the Board accept AEY's proposed Watson Lake bi-fuel project, UCG submitted that the associated Watson Lake study costs be rolled into capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.¹⁹⁸

335. YCS recommended that all project-related costs not be allowed into rate base. YCS argued that the project is not economically prudent nor is the project environmentally prudent. YCS submitted that AEY has not made a case for how this project would help governments meet goals to eliminate or reduce the dependence on diesel in indigenous, remote and northern communities with renewable, clean energy as submitted in its GRA filing. YCS also submitted that the project would not help Watson Lake integrate any new renewable energy, but would effectively act as a "barrier to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low."¹⁹⁹

336. With respect to AEY's claim that the project would result in cost savings for ratepayers, YCS described the claim as dubious and echoed Mr. Maissan's submission, stating the following:

... the Watson Lake LNG Bi-fuel project is already marginal even with the current fossil fuel prices. Depending on the fuel source, the project is already uneconomic from one supplier. Any shift toward the historical trend (LNG and diesel closer in cost) will make this project uneconomic regardless of which supplier is liquefying and transporting the natural gas.²⁰⁰

337. Additionally, YCS submitted that the AEY analysis did not consider the impacts of renewable energy inputs onto the Watson Lake grid within the project lifetime, did not calculate how that would reduce utilization of this project and, by extension, negatively affect the economics and business case. Therefore, considering that the project is not environmentally or economically prudent, the financial risk to the ratepayer from fuel price changes, and the addition of renewable energy to the Watson Lake grid, YCS recommended that the Board deny the Watson Lake bi-fuel project.²⁰¹

9.7.2.2 Applicant responses to interveners

338. Noting that Mr. Maissan and YCS criticized the project business case for not considering the impact of renewables, AEY submitted that it "must make decisions based on the best information it has available to it and there is no evidence of any IPP program developers proposing renewable energy projects in Watson Lake."²⁰² Given the restriction on nameplate capacity, AEY pointed out that it would take three separate projects to meet the limit of 2,100 MWh/year. Notwithstanding, in order to demonstrate the economic viability of the Watson Lake bi-fuel project, AEY submitted that it re-ran its

¹⁹⁷ JM Final Argument, page 14.

¹⁹⁸ UCG Final Argument, paragraph 172.

¹⁹⁹ YCS Final Argument, page 9.

²⁰⁰ YCS Final Argument, page 4.

²⁰¹ YCS Final Argument, page 5.

²⁰² AEY Reply Argument, paragraph 141.

model,²⁰³ assuming the availability of 2,100 MWh/year of renewable generation, as of January 1, 2020. AEY submitted that "... there still remains a positive NPV in all six scenarios using AltaGas pricing and three of the six scenarios using the Fortis pricing."²⁰⁴ Moreover, AEY stated that there is a positive 20-year internal rate of return in all 12 scenarios. AEY added the models were predicated on only two suppliers of LNG, but it is entirely reasonable to expect additional suppliers to come on-line in the near term.

339. AEY pointed out that the current economic evaluation included in the NPVs set out in Table 2 and Table 3 of Appendix 3, and later updated in response to YUB-YECL-13(b), do not include the impact of any Yukon territorial or federal carbon tax.²⁰⁵ However, should a carbon tax be imposed, AEY submitted that it would likely favour the use of natural gas for electricity generation, the effect of which would be that the NPV of the bi-fuel would increase.²⁰⁶

340. AEY submitted that there is no evidence to support any of the statements that YCS made regarding the environmental impacts or lack thereof of the Watson Lake bi-fuel project. AEY further submitted that the Yukon Environmental and Socio-economic Assessment Board heard and considered the environmental evidence in relation to this project and has approved Phase 1.

9.7.2.3 Views of the Board

341. In Board Order 2014-06, the Board stated with respect to this project:

The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."²⁰⁷ (*footnotes omitted*)

342. In Board Order 2014-06, the Board had also denied the project due to concerns regarding fair market value of certain equipment to be leased from ATCO Gas. On page 82 of that decision, the Board found that fair market value of the lease of equipment assets was best determined through a competitive tender process.

343. In this Application AEY proposed:

... 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.²⁰⁸

²⁰³ The model is embedded in the table provided in response to UCG-AEY-53(d), Attachment 1 (Exhibit B-9).

²⁰⁴ AEY Reply Argument, paragraph 144.

²⁰⁵ Exhibit BB-1, Application, Appendix 3, Page 5.

²⁰⁶ AEY Reply Argument, paragraph 146.

²⁰⁷ Board Order 2014-06 – Appendix A: Reasons for Decision, Page 81.

²⁰⁸ Exhibit BB-1, Application, Appendix 3, page 3.

344. The Board acknowledges that AEY indicated that the Watson Lake Phase 1 and Phase 2 bi-fuel projects were submitted to address the Board's concerns.

345. AEY provided the information related to a comparison of potential suppliers and fuel price forecasts, as well as alternative fuel-escalation scenarios. A compiled table of this information is below:

Table 24. **Comparison of potential suppliers and fuel price forecasts**

	Supplier	Simple Payback (years)	20-year NPV (\$M)	Supplier	Simple Payback (years)	20-year NPV (\$M)
Sproule price forecast	Fortis	12	0.4	Fortis	11	0.6
	AltaGas	10	2.1	AltaGas	9	2.4
Both Commodities escalate at 5%	Fortis	11	2.7	Fortis	11	3.0
	AltaGas	9	5.6	AltaGas	9	5.9
Scenario 3: both commodities escalated at 2.5%	Fortis	15	(0.9)	Fortis	15	(0.7)
	AltaGas	11	1.7	AltaGas	10	2.0
Scenario 4: diesel escalated at 5%; natural gas at 2.5%	Fortis	11	3.5	Fortis	11	3.7
	AltaGas	9	6.1	AltaGas	9	6.4
Scenario 5: diesel escalated at 2.5%; natural gas at 5%	Fortis	17	(1.7)	Fortis	16	(1.4)
	AltaGas	11	1.2	AltaGas	11	1.5
Scenario 6: both commodities doubled	Fortis	7	7.1	Fortis	6	7.4
	AltaGas	5	10.2	AltaGas	5	10.5

Source: Exhibit BB-1, Appendix 3: Table 2, Page 7; Table 3, Page 8.

Source: Exhibit B-9, response to YUB-YECL-13(b), Page 3 of 6.

346. With respect to Table 24, the Board notes that of the 12 original scenarios provided by AEY, two scenarios have negative-20-year NPVs, three scenarios have NPVs below \$2 million, and four scenarios have NPVs of \$5 million or higher. AEY provided a further 12 scenarios wherein it accounted for the decrease in costs related to the LNG vaporizer and the LNG storage tank. The table shows that the project economics improved only marginally under the additional 12 scenarios examined.

347. Further, when AEY re-ran the model assuming a scenario of 2,100 MWh/year of renewable generation as of January 1, 2020, the generation from the bi-fuel engines was reduced. However, three (instead of two) of the six scenarios using Fortis pricing were negative.²⁰⁹

348. That being said, the Board agrees with Mr. Maissan's concern that the economic comparison provided by AEY with respect to diesel and LNG in Watson Lake must sufficiently take into account potential fluctuations in the delivery costs²¹⁰ for these fuels.

²⁰⁹ AEY Reply Argument, paragraph 144.

²¹⁰ Delivery costs include the costs of liquefaction and transportation of LNG.

Mr. Maissan pointed out that the liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transporting diesel, and he submitted that the economic evaluations must include the delivered costs of these fuels. The Board notes AEY's submission that using "delivered diesel prices based on Sproule forecast, the LNG option breaks even at an average delivered-LNG-price-to-delivered-price ratio of 75.6 percent over the lifetime of the project."²¹¹

349. The Board further notes that it was established on the record that the price of energy in natural gas has historically been slightly less than the cost of energy in diesel. The ratio of price of energy in natural gas to the price of energy in diesel prior to 2006 ranged from 70 to 100 percent. In 2006, this ratio dropped to about 60 percent and, more recently, it is at approximately 36.2 percent.²¹² The Board agrees with Mr. Maissan that it would take only a small increase in the price ratio to make the LNG option uneconomical. In fact, AEY's data in Table 24, as well as AEY's Reply Argument, show that the project would be viable under some scenarios but not under other scenarios. While the Board understands that slightly positive or positive results are expected under some scenarios, the economic benefits of the Watson Lake project are not sufficiently supported given the outcomes of the various scenarios found in Table 24 and given the corresponding assumptions used by AEY that could impact the financial viability and resulting costs for this project.

350. Further, with respect to the Watson Lake bi-fuel project and the use of diesel units, AEY stated in its business case:

ATCO Electric Yukon and the 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.²¹³

351. Mr. Tenney, in testimony, confirmed that while there is development of future technologies, stand-alone bi-fuel units are not currently available other than for marine applications and that is why conversion units are proposed for this project.²¹⁴ Conversion units have not been previously utilized by AEY for utility service to Yukon customers. Conversion of the existing diesel units to bi-fuel is the only option proposed other than use of existing diesel, and in fact, conversion to bi-fuel may be the only other option currently available for the use of LNG at the Watson Lake plant. This raises the issue of whether a bi-fuel conversion should be done at this time given emerging plant technologies related to bi-fuel and LNG instead of relying on the existing diesel units at Watson Lake without bi-fuel conversion. Given the state of emerging technologies and the prospect that such technologies may affect the economic benefits associated with

²¹¹ Exhibit B-5, JM-AEY-24(d).

²¹² Exhibit B-5, JM-AEY-24(a).

²¹³ Exhibit BB-1, Application, Appendix 3, Watson Lake Bi-Fuel Project, Page 7.

²¹⁴ Transcript, Volume 3, page 473, lines 13 to 23, Mr. Tenney stated, "So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant. So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants."

bi-fuel conversion, the Board finds that the approval of the project as proposed by AEY is not reasonable. Because the impact of the conversion of an individual bi-fuel unit on efficiency, the actual capital costs for conversion as well as the benefits to customers are not sufficiently known and base load generation is currently being supplied to the Watson Lake area by the existing diesel units.

352. The Board is also concerned with AEY's request that the Board approve Phase 1 of the Watson Lake bi-fuel project along with Phase 2 of the project, which will occur entirely in a future test period. Between Phase 1 and Phase 2, the total project costs are \$4,695,000 for conversion of diesel units in the power plant that serves Watson Lake and surrounding area, in accordance with AEY's obligation to provide electricity to that area.

353. While the Board acknowledges AEY's position that Phase 2 would be required if Phase 1 is approved and undertaken, the Board does not consider that it is reasonable to approve the need for Phase 2 without the conversion of the unit under Phase 1 given the forecasted costs for the bi-fuel conversion project as proposed.

354. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision.

9.7.3 Old Crow Unit 3 replacement (Appendix 5)

355. AEY submitted that load growth and load duration of the community of Old Crow have steadily diminished the utilization of the 170-kW Old Crow unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, AEY 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 be able to fit in the existing building.

356. Based on the 2012 load data provided in AEY's 2013-2015 GRA, AEY submitted that the existing 170-kW unit was approved to be replaced with a 250-kW unit. Notwithstanding the Board's approval, in preparation for tender of the new unit in 2015, AEY submitted that 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 recommended to meet load requirements.

9.7.3.1 Views of interveners

357. Mr. Maissan submitted that the desire to have two independent and completely redundant power plants in the community of Old Crow is well beyond any planning criteria approved by the Board. Mr. Maissan went on to state that the need to have a second building is not in question, but "what is in question is the prudence of the decisions about what size generators to put into this plant which operates as an extension of the existing plant."²¹⁵ Mr. Maissan pointed out that a 400-kW generator

²¹⁵ JM Final Argument, page 9.

would be running below manufacturers' recommendation "that units are operated in the range of 50-80% of rated capacity."²¹⁶ AEY's 50-percent loading target appeared tenuous to Mr. Maissan when he noted that additional solar photovoltaic (PV) capacity is planned for Old Crow. Mr. Maissan submitted that plant efficiency will suffer as the larger generators will be very lightly loaded. In addition, Mr. Maissan submitted that a 400-kW unit could be transported into the community easier than a 600-kW unit. Moreover, considering that more solar PV capacity is planned for Old Crow, Mr. Maissan recommended that the Board reject the plan to install a 600-kW generator in Old Crow and authorize the installation of a 400-kW unit at a cost of \$612,000, plus \$100,000 to allow for cost increases from the previous 2014-2015 timeframe for this project.²¹⁷

9.7.3.2 Applicant responses to interveners

358. AEY replied that, in his argument, Mr. Maissan failed to take into account the Old Crow peak loading table that clearly demonstrates the need for a 600-kW unit. AEY submitted that it would not be prudent for AEY to invest in assets such as lower-capacity units which do not meet long-term generation needs, based on the assumption that a non-dispatchable renewable resource (i.e. solar PV capacity) may potentially be installed. Furthermore, there is no evidence that the possible installation of a solar generation resource, even with a storage battery, will supply any firm capacity to be relied upon to meet the capacity needs of the community. AEY submitted that this project ensures a continued safe, reliable power source for the community.²¹⁸

9.7.3.3 Views of the Board

359. The Board accepts the proposal as submitted by AEY. The peak loading table included in the Application²¹⁹ shows continuous growth since 2012 and the need for a higher-capacity generator. Further, as Old Crow is an isolated community, the Board accepts the submissions²²⁰ of AEY that a full contingency backup for that community is required.

9.7.4 Destruction Bay unit replacement

360. The communities of Destruction Bay and Burwash Landing are serviced by three units located at the Destruction Bay generating plant. The Board approved AEY's request to replace two units in Board Order 2014-06 related to AEY's 2013-2015 GRA.

9.7.4.1 Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)

361. AEY submitted that the replacement of Destruction Bay Unit #2 was one of the units approved in Board Order 2014-06. The original scope of the project in AEY's 2013-2015 GRA was to replace the unit with a similar sized unit (300 kW). At the time of the unit tender and selection, capacity requirements were reviewed, and as a result, AEY submitted that it will tender and procure a 400-kW unit. The total cost of this project

²¹⁶ Exhibit B-5, JM-AEY-27 (b).

²¹⁷ JM Final Argument, pages 9 and 10.

²¹⁸ AEY Reply Argument, paragraphs 107 to 109.

²¹⁹ Exhibit BB-1, Application, Appendix 5, pages 1 and 2.

²²⁰ Transcript Volume 3, starting at page 483, line 12 and ending page 485, line 23.

is forecasted to be \$758,000, compared to the \$600,000 capital expenditure previously approved by the Board. AEY indicated that receipt of the unit and installation is scheduled to be completed in 2016.

362. AEY submitted that the replacement of Destruction Bay Unit #3 was one of the units approved in Board Order 2014-06. AEY clarified that the existing 220-kW unit was to be replaced with a larger unit (250 kW) in order to ensure that the unit would continue to operate for a reasonable amount of hours to meet load requirements.

363. AEY stated that the purchase of a new 250-kW unit was put out to tender in 2013; however, none of the bidders in the RFP process submitted bids for a 250-kW unit. Of the bids received, and after a further analysis of best fit for the power plant and community load profile, AEY selected a 312-kW unit. Receipt of the unit and installation was scheduled to be completed in 2014. The total cost of this project was \$634,000, compared to the approved cost of \$450,000.²²¹

364. AEY explained that the actual 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.”²²² AEY confirmed that receipt of the unit and installation was “completed, prior to the recent installation of the increased amount of solar PV generation.”²²³

9.7.4.2 Views of interveners

365. With respect to AEY’s proposal to replace the two smaller units in the Destruction Bay diesel plant with larger units, Mr. Maissan pointed out that a fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW in the area. Mr. Maissan expressed concerns that AEY is opting for larger diesel generators than necessary for reasons other than efficient plant performance, and the reasons for his position include that AEY is:

...providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project — which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing...²²⁴

366. Mr. Maissan recommended that the Board direct AEY to replace one of the existing smaller units with the installation of one 400-kW unit. Mr. Maissan also recommended that the Board direct the replacement of Destruction Bay Unit #3 (CUL 230 220 kW unit) with a unit no larger than 250 kW. AEY should be directed to provide the 2015 load duration curves for Destruction Bay plant in its compliance filing. Mr. Maissan recommended:

²²¹ Exhibit BB-1, Application, Appendix 11, page 1.

²²² Exhibit BB-1, Application, Appendix 11, page 1.

²²³ Exhibit B-5, JM-AEY-27 (a).

²²⁴ JM Final Argument, page 15.

... that the Board order AEY, in negotiations for an IPP with the proponents of the Kluane wind project [sic] to allow diesel displacement down to a load level to the lowest normal 2015 dispatch level without penalty or cost to the proponent.²²⁵

9.7.4.3 Applicant response to interveners

367. AEY pointed out that the two Destruction Bay unit replacement projects were scheduled — and in the case of Unit #3 replacement, completed — prior to the recent installation of solar PV generation in the Destruction Bay and Burwash communities. AEY acknowledged that the Burwash Landing wind project may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid. However, AEY submitted that:

... it is not prudent or common practice for a utility to reduce the installed capacity of its generation facilities as a result of the possible installation of a non-dispatchable renewable resource, regardless of whether it is owned and operated by a third party or the utility itself.²²⁶

368. With respect to determining the size of Destruction Bay Unit #2, AEY considered the capacity as well as operational efficiency requirements. AEY submitted that replacement of Unit #2 with a new unit of the same size (300 kW) would not have allowed AEY to meet operational efficiency requirements, as units would have been under or overloaded during automated dispatch. AEY added:

... at the current dispatch level there are times in which Unit 2 is operated at an overload condition in respect to its prime rating. The only solutions to this overload issue are to de-rate the unit or replace it with a larger unit. If the de-rate option was selected, it would negatively impact the operation of Unit 1, forcing it to run in a low loading mode. Selecting a larger unit allows Unit 2 and Unit 1 to be dispatched in a more efficient manner.²²⁷

369. AEY submitted that contrary to Mr. Maissan's assertions, the sizing considerations were done to meet firm capacity requirements and to allow for an efficient dispatch of the units, all of which are in line with AEY's obligation to serve customers with safe and reliable electricity.

9.7.4.4 Views of the Board

370. Destruction Bay Unit #3 was approved in AEY's 2013-2015 GRA. The unit was substantially completed and operational in 2014, with final acceptance in 2015. Further, the Board notes that Unit #3 replacement was completed prior to the recent installation of solar PV generation in Destruction Bay and Burwash Landing.

371. AEY determined through the tender process that the best fit for the power plant and community load profile was a 312-kW unit rather than the originally forecast capacity of 250 kW. The final cost of the project was \$184,000 over the GRA-approved forecast. AEY indicated that the variance between the actual and forecast costs was

²²⁵ JM Final Argument, page 15.

²²⁶ AEY Reply Argument, paragraph 112.

²²⁷ AEY Reply Argument, paragraph 117.

due to foundation issues discovered subsequent to the initial forecast and additional control work. AEY added that movement to the larger generator capacity would increase operational hours of the unit and concomitantly increase the units' efficiency.²²⁸

372. The Board finds the reasons provided by AEY — operational efficiency, community and load profile²²⁹ — support the need for the larger capacity unit. In addition, the cost for the larger unit and the need to mitigate the foundation issues identified are acceptable reasons for the cost variance. The Board approves the costs as filed. Although wind capacity may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid, the Board accepts AEY's submission that wind generation will not contribute to firm capacity requirements within the test period.

373. With respect to Unit #2, the Board notes AEY's submission that replacement of this unit with a similar-sized unit would not have allowed AEY to meet the Operational Efficiency Requirements, as units in the generation plant would have been under or overloaded during automated dispatch. Therefore, the Board approves the additional costs associated with the larger 400-kW unit.

374. Considering the above, the Board approves AEY's replacement of Destruction Bay Units #2 and #3, as filed.

9.7.5 McIntyre subdivision rebuild (Appendix 8)

375. The McIntyre subdivision rebuild is a multi-phase project to replace the existing end-of-life underground electrical infrastructure serving the McIntyre subdivision in the City of Whitehorse. The original forecast for Stage 1 was approved as part of AEY's 2013-2015 GRA in Board Order 2014-06.

376. AEY referred to this project as being a complex "brownfield" infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35 kV and was installed circa 1977. The proposed project will convert the subdivision's operating voltage to the standard 25-kV system. AEY indicated that 25-kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers.

377. The original scope of the project was to install a new 25-kV underground electrical system in close proximity to the existing 35-kV system. As Stage 1 was underway, AEY discovered that the location 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. Time constraints imposed on construction permits from the Kwanlin Dun First Nation (KDFN) made it necessary that a new project scope be developed. AEY explained the change in project scope due to installation issues:

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

²²⁸ Exhibit BB-1, Application, Appendix 11, page 2.

²²⁹ Exhibit BB-1, Application, Attachment 11.4, page 1.

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.²³⁰

378. The following table shows approved costs, AEY's actual costs, and its forecast costs for the McIntyre subdivision replacement project:

Table 25. **McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs (\$000s)**

Year	Actual/Forecast	Streetlights	Total	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, and 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
Total	4,348	781	5,129	

Source: Exhibit BB-1, Application, Appendix 8, Table 1, Page 3.

379. In a letter²³¹ dated October 24, 2016, AEY submitted that it is seeking Board direction as to the appropriate treatment of the potential cost savings, should the KDFN accept one of the alternatives such as "Alternative 2" in the business case provided in Appendix 8 of the Application. The business case included the following:

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.²³²

380. AEY submitted that it is anticipated that "Alternative 2" would alter the work required and result in a potential cost savings in 2018-2020, which is outside of the test years. AEY clarified that it is requesting the Board to provide direction as to whether or not the expected costs savings could be applied as an offset to the contribution required by the KDFN in the future.

9.7.5.1 Views of the Board

381. The Board notes that interveners did not comment on AEY's request.

382. During the hearing, the Board notes AEY's submission that it had extensive meetings with KDFN. AEY submitted, "It's very clear that they want to have an underground power system when we're done in there... that's what they would like to have when we leave that subdivision at the end of the project."²³³ Moreover, the Board

²³⁰ Exhibit BB-1, Application, Attachment 11.4, page 1.

²³¹ Exhibit B-13, YECL letter to YUB re corrections, updates and clarifications, October 24, 2016.

²³² Exhibit BB-1, Application, Appendix 8, McIntyre Subdivision Rebuild, page 3.

²³³ Transcript, Volume 1, page 151, lines 1 to 5.

notes AEY submission that "... there was an original customer contribution when the original system went in back in the '70s, so we wouldn't be asking the customer to recontribute."²³⁴

383. The Board notes that the ultimate scope of the project has not been determined by AEY at this time. AEY submitted two project alternatives: (1) an underground system, or (2) a hybrid system (combination of overhead and underground).

384. The Board accepts AEY's test-period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA.

385. If AEY's proposal for "Alternative 2" (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings.

386. The Board will provide further direction in the next GRA regarding AEY's request as to whether or not the expected cost savings could be applied as an offset to the contribution required by the KDFN.

9.7.6 Significant capital projects

387. In Board Order 2009-2, the Board directed "YECL to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."²³⁵ In Attachments 9.1 and 9.2 of the Application, AEY provided a listing of capital expenditures for 2016-2017, which included project descriptions for projects greater than \$100,000. AEY also provided business cases for all major capital projects (\$500,000 or greater) in Appendix 1 to Appendix 11 of the Application.²³⁶

388. UCG noted the Board's consideration in its January 2007 Report to the Commissioner in Executive Council re YEC's 20-year resource plan²³⁷ that given the smaller rate base in the Yukon and the small number of ratepayers in the Yukon, a \$1-million threshold would be appropriate for capital expenditures to be reviewed by the Board pursuant to Part 3 of the *Public Utilities Act*.

389. Considering the above, UCG recommended that the following projects should be reviewed pursuant to Part 3 of the *Public Utilities Act*:

- (a) McIntyre subdivision rebuild;²³⁸
- (b) Watson Lake bi-fuel projects;²³⁹
- (c) Watson Lake Unit #2 replacement;²⁴⁰

²³⁴ Transcript, Volume 1, page 152, lines 5 to 8.

²³⁵ Board Order 2009-2, Appendix A: Reasons for Decision, page 37.

²³⁶ Exhibit BB-1, Application, page 9-5.

²³⁷ Yukon Utilities Board Recommendations YEC 20-Year Resource Plan: 2006-2025, Page 28, issued January 15, 2007.

²³⁸ UCG Final Argument, paragraph 187.

²³⁹ UCG Final Argument, paragraph 192.

²⁴⁰ UCG Final Argument, paragraph 197.

- (d) Downtown Whitehorse capacity improvement project;²⁴¹
- (e) Old Crow Unit #3 replacement;²⁴²
- (f) Whistle Bend Subdivision Stage 3-C project;²⁴³ and
- (g) Fish Lake Ditch #3 diversion replacement project.²⁴⁴

9.7.6.1 Views of the Board

390. With respect to UCG's submission that the above-mentioned projects be reviewed pursuant to Part 3 of the *Public Utilities Act*, the Board considers that this request is premature because neither application has been made to the minister under section 39 of the *Public Utilities Act*, nor has the minister designated any of the projects as a regulated project under section 37 of the *Public Utilities Act*. Moreover, the Board does not determine that projects are Part 3 projects under the *Public Utilities Act*, but makes recommendations on energy projects only when the minister refers them to the Board. Accordingly, the Board finds that UCG's recommendations on Part 3 projects and associated capital expenditures do not apply.

10 Income tax

391. In its Application, AEY continued to use the flow-through method for calculating income tax expense. This method was approved by the Board in Board Order 2014-06. AEY argued that since the use of the flow-through method was not raised as an issue by any party during the testing of its Application, the Board should continue to approve the use of this method.

10.1 Views of the Board

392. The Board agrees with AEY that there is no reason to change the currently approved flow-through income tax method used by AEY in its Application. AEY's method of determining income tax expense to be recovered through rates is approved as filed.

11 Previous Board directions

393. AEY provided the following responses to prior Board directions from Appendix A: Reasons for Decision from Board Order 2014-06:

Board Direction	AEY Response	Board Comment
<i>Direction 8, Page 51.</i> The Board agrees with the submissions of UCG that no assessment has been provided	<i>Application, page 11-1,</i> ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No

²⁴¹ UCG Final Argument, paragraph 202.

²⁴² UCG Final Argument, paragraph 207.

²⁴³ UCG Final Argument, paragraph 212.

²⁴⁴ UCG Final Argument, paragraph 217.

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.	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.	further response is required.
<i>Direction 12, page 62.</i> 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.	<i>Application, page 11-2.</i> 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.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

<i>Direction 13, page 64.</i> 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 nine 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.	<i>Application, page 11-3 to 11-4.</i> 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 variance in actual costs to forecast for that project. 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.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
<i>Direction 14, page 70.</i> 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." Bearing this in mind, in	<i>Application, page 11-5.</i> 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.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

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.		
<i>Direction 15, page 71.</i> 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 prudence. 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.	<i>Application, page 11-6.</i> 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.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
<i>Direction 20, page 101.</i> 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	<i>Application, page 11-7.</i> 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.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response required.

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.		

12 Deferral accounts

394. In its Application, AEY proposed deferral-account treatment for three new cost categories, while maintaining deferral treatment for those categories previously approved by the Board. AEY's summary of existing and proposed deferral accounts is shown in the following table:

Table 26. **Summary of existing and proposed deferral accounts**

Name of existing or proposed deferral account	Existing	Proposed
Rate case costs	X	
Defined benefit pension plan	X	
Feasibility study or program: DSM program (approved program) Watson Lake LNG — phase I (approved study) Renewables study (proposed study) Joint grid study (proposed study)	X	
Purchase power flow-through	X	
Diesel fuel	X	
LNG fuel		X
Board order or changes in legislative provisions		X
Statutory Federal and Territorial income tax rates		X

Source: Summarized from Application

395. The Board has considered the five existing deferral accounts and finds that their respective intent and scope have not changed. AEY's existing deferral accounts continue to be approved.

396. In the following sections, the Board will discuss the three new deferral account categories proposed in AEY's Application and whether they should receive deferral-account treatment.

12.1 LNG Fuel Deferral

397. Please refer to the section 4.5 of this decision.

12.2 Board Orders or Changes in Legislative Provisions Deferral

398. In its Application, AEY sought 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 AEY operates under for the 2016-2017 test period.

399. The IPP Policy for Standard Offer Prices was cited as one example in support for this deferral account.

400. In argument, AEY claimed that in future, there is no guarantee of stakeholder input or significant lead time. AEY added that it has no control over these policies or programs and has no way to forecast with certainty the impact related to these types of programs, and therefore seeks deferral account treatment.²⁴⁵ In reply, AEY challenged the assertions of Mr. Maissan about the micro-generation program, stating that the response to JM-AEY-5(c-d)²⁴⁶ did not include the full costs incurred by AEY (such as administrative costs), adding that there is no certainty of that program continuing to operate in its current manner.²⁴⁷

401. AEY did agree with Mr. Maissan in that it is a stakeholder in relation to the development of the IPP program. However, AEY countered that it does not control the actual implementation of the program and that it would be at risk for any changes until its next GRA.²⁴⁸

12.2.1 Views of interveners

402. John Maissan did not support the AEY request for a Board Orders or Changes in Legislative Provisions Deferral Account. Mr. Maissan noted that the micro-generation program provided net benefits to AEY. In regard to the IPP program, AEY has been an active participant along with the Yukon government, Yukon Development Corporation (YDC) and YEC .

403. The effects of the commercial energy incentive program run by the Yukon government were another reason cited by AEY for this deferral account. Mr. Maissan argued that the effects of this program are captured within AEY's load-forecasting process, and thus had minimal impact.²⁴⁹

404. UCG stated that a deferral account to track costs related to Board Orders or legislative provisions does not provide AEY with the ability to flow costs through, dollar for dollar, to ratepayers. A deferral account simply tracks costs for review and possible recovery at a later time.²⁵⁰

12.2.2 Views of the Board

405. In AEY's 2013-2015 GRA, AEY requested a deferral account to flow through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions

²⁴⁵ AEY Final Argument, paragraphs 11-12.

²⁴⁶ Exhibit B-5 — YECL Responses to Maissan Requests

²⁴⁷ AEY Reply Argument, paragraph 13.

²⁴⁸ AEY Reply Argument, paragraph 14.

²⁴⁹ JM Final Argument, page 1.

²⁵⁰ UCG Reply Argument, paragraph 13.

resulting in changes to the rules or parameters that AEY operates under or that bear on the nature and extent of AEY's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement.²⁵¹

406. In Board Order 2014-06, the Board ruled that:

... on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented... The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any GRA filing. Therefore the Board rejects YECL's request for this deferral account.²⁵²

407. The Board's views have not changed. The evidence in this proceeding is that AEY has been able to actively participate in potential legislative changes respecting the implementation of new programs, so AEY has not shown the need for such a deferral account. The Board notes Mr. Maissan's comments about little or no impacts of the programs referred to by AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

12.3 Statutory Federal and Territorial Income Tax Rates Deferral

408. In its Application, AEY requested deferral-account treatment for income tax beginning in the year 2016. The deferral amounts would be based on any deviance from enacted federal and territorial statutory rates, which were each currently set at 15 percent. AEY submitted that any changes from these rates would be used to determine an updated revenue requirement that, when compared to final approved revenue requirement, would initiate either a refund to or collection from customers for the difference.

409. AEY cited uncertainty with respect to global economics and recent federal government changes as increasing the possibility of significant tax changes between GRAs. During the hearing, AEY witness James Grattan indicated a further potential for changes to the territorial statutory rate depending on the outcome of the territorial election.

410. In argument, AEY summarized:

- (a) Changes in statutory tax rates can be material;
- (b) Given that the statutory rates are set by the Territorial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding forecast accuracy;
- (c) The statutory rates are determined by the Territorial and Federal Governments, and are therefore beyond AEY's control; and

²⁵¹ Board Order 2014-06 – Appendix A: Reasons for Decision, page 1.

²⁵² Board Order 2014-06 – Appendix A: Reasons for Decision, page 103.

- (d) AEY is not typically at risk with respect to items that are beyond its control and that are material.²⁵³

12.3.1 Views of the Board

411. The Board considers that the need for a deferral account has not been shown given the two-year test period. Further, the criterion for a deferral account is that AEY is typically at risk with respect to items that are beyond its control and that are material. In the Board's view, AEY has not shown that it is at risk or that any risks are material from changes in federal or territorial income tax rates. For these reasons, the Board denies AEY's request for a deferral account for statutory federal and territorial income tax rates.

12.4 Deferred Charges and Credits

412. For those account categories currently approved for deferral-account treatment, AEY monitors charge and credit transactions.²⁵⁴ Generally, AEY will incur the deferral-account related expenditures over time and will subsequently recover the approved costs through deferral account revenue requirement. This is currently the treatment ascribed to hearing costs and deferred pension costs, each of which were forecasted to be recovered in revenue requirement evenly over the years 2016 and 2017.

413. In its Application, AEY proposed similar treatment for the tracking and recovery of costs related to feasibility or other studies, such as those pertaining to Watson Lake, Renewables and Alternative Energy, and a Joint Smart Grid. In some cases, after the study was completed, AEY proposed to recover the study costs within its deferral accounts over a period of two years. In the alternative, and as is the case with the deferred DSM program costs, AEY proposed to capitalize the costs into rate base and amortize them over a specified period of time.

414. UCG provided a general comment that, "All deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."²⁵⁵

415. UCG submitted that study costs do not meet the "used or required to be used" test for consideration as a utility asset providing utility service to customers, despite that the costs may have been incurred prudently.²⁵⁶

416. Interveners raised other concerns with respect to AEY's proposed recovery of these study-related costs, each of which are discussed in the four sections that follow.

12.4.1 Demand Side Management (DSM) Program Study Deferral Account

417. AEY proposed²⁵⁷ to move costs related to the approved DSM program study out of the deferral account and into rate base. Notwithstanding an issue related to the use of the mid-year convention for depreciation purposes addressed elsewhere in this

²⁵³ AEY Final Argument, paragraph 164.

²⁵⁴ Exhibit BB-1A AEY GRA Schedules, schedule S8.8.

²⁵⁵ UCG Final Argument, paragraph 30.

²⁵⁶ UCG Final Argument, paragraphs 166-174.

²⁵⁷ AEY Final Argument, paragraphs 115-118.

decision, AEY stated that the use of a five-year amortization period (2014-2018) for cost recovery was consistent with the Board's direction in section 12.1 of Board Order 2014-06.

418. AEY stated that evidence of prudent expenditures related to the DSM program was provided in interim evaluation reports and these reports concluded that the DSM programs were well-received by Yukoners, were cost-effective, and that participation met or exceeded most KPIs.

419. In response to UCG's recommendation that deferred study costs should be removed from rate base, and either amortized outside of rate base or rolled into a related capital asset, AEY stated that the DSM program study costs in this case were for programs previously approved by the Board.

12.4.1.1 Views of interveners

420. UCG²⁵⁸ questioned why the deferred DSM program costs would subsequently be treated as a capital item and attract carrying costs like other assets placed into rate base. UCG submitted that AEY was entitled only to the return of, and not a return on, prudently incurred DSM costs.

421. YEC²⁵⁹ disagreed with UCG's suggestion that the DSM study costs should not be treated as capital assets earning a return on the same basis as other rate base elements. YEC submitted that UCG's recommendation should be disregarded by the Board.

12.4.1.2 Views of the Board

422. The Board can find no basis to consider UCG's recommendation that AEY was entitled only to the return of, and not return on, the DSM program study costs. AEY's treatment of these costs — by way of capitalization into rate base, and the attendant calculations of depreciation and return — is consistent with the Board's direction in section 12.1 of Board Order 2014-06. For this reason, the Board does not accept the recommendation made by UCG. The Board approves the transfer of the DSM program study costs out of the deferral account and into rate base to be amortized over a period of five years, as proposed by AEY.

12.4.2 Watson Lake LNG Study Deferral Account

423. In its Application, AEY requested approval for \$494,000 in study and development costs related to the Watson Lake bi-fuel project. AEY proposed to recover these forecast costs evenly over the 2016-2017 test period through the study's associated deferral account. AEY submitted that the study costs were incurred prudently and should be recovered from customers whether or not any of the Watson Lake bi-fuel project capital costs are approved.²⁶⁰

²⁵⁸ UCG Final Argument, paragraph 228.

²⁵⁹ Yukon Energy Reply Argument, pages 9-10.

²⁶⁰ AEY Final Argument, paragraphs 105-108.

424. As an alternative, AEY stated that it was not opposed to capitalization of the study costs, should the Watson Lake project be approved, with subsequent cost recovery over the lifetime of the related assets.²⁶¹

12.4.2.1 Views of interveners

425. UCG argued that in Board Order 2013-01, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in “Work in Progress” until such time that the project is set aside or the utility comes before the Board for a prudence review. In Board Order 2014-06, the Board determined that Watson Lake bi-fuel project study costs would be held in “Work in Progress” until such time as the project may be completed.

426. UCG submitted that if the Board accepts the proposed Watson Lake bi-fuel project proposed by AEY, then \$494,000 in Watson Lake Study costs should be rolled into the capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.

427. Consistent with his views that the Watson Lake bi-fuel project itself be denied by the Board, Mr. Maissan recommended that all actual study costs expended to date should be amortized over a five-year period.²⁶²

12.4.2.2 Views of the Board

428. The Board does not consider that adding complexity with respect to the recovery of the Watson Lake LNG study costs is necessary. To recover the study costs over the life of the Watson Lake bi-fuel project, as was recommended by UCG, would require an allocation of the study costs to several individual account numbers, each with a unique service life. The Board has determined doing so would not result in an efficient or straightforward process of cost recovery and would be unduly onerous. Further, since in section 9.7.2 of this Order the Board has rejected the Watson Lake bi-fuel project, this issue of rolling the study costs into the capital costs is moot. For these reasons, UCG’s recommendation is denied.

429. The Board accepts Mr. Maissan’s recommendation that recovery of the Watson Lake study costs and development costs forecast in the amount of \$494,000 should be on the basis of an amortization period of five years. This period of time is consistent with that used for the recovery of the DSM program study costs. The Board finds this to be a reasonable approach for the recovery of the Watson Lake bi-fuel study costs.

12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account

430. AEY proposes to include \$300,000 in 2016 and \$200,000 in 2017 as charges related to work it has planned regarding the Renewable and Alternative Energy Feasibility study.²⁶³ The \$500,000 in costs for the study would be recovered through AEY’s deferral account in the amount of \$150,000 in 2016 and \$350,000 in 2017.

²⁶¹ AEY Final Argument, paragraph 108..

²⁶² JM Final Argument, page 15.

²⁶³ Also referred to in AEY’s application as the “Renewables Feasibility Study”; Exhibit BB-1, page 8-8 and Schedule 8.8.

431. AEY proposed to assess individual communities and retain third party expertise to carry out the studies through a combination of competitive processes and “sole-sourcing.”²⁶⁴ The studies are intended to identify the optimal size and configuration of company-built, -owned and -operated renewable and alternative energy generation in each of the five isolated communities served by AEY which currently rely on diesel power generation. The studies will also assess energy storage systems and potential improvement for energy efficiency through waste-heat recovery opportunities in each of the communities.

432. Once the studies are complete, AEY proposed that any technically and economically feasible projects identified therein would be brought forward as business cases in stand-alone proceedings for approval by the Board. This would ensure customers receive more immediate benefit of the studies and resulting projects, without the need to wait for a subsequent GRA.

433. Further, AEY indicated its commitment that, subject to any confidential or proprietary information contained in the renewable energy studies, they would be prepared to share the study publicly in connection with any resulting application or earlier in an appropriate forum, such as the utility’s website.

434. During the oral hearing, AEY witnesses confirmed that preparation of the renewables study was behind schedule and that no work had been completed at that time.²⁶⁵

435. In response to UCG’s recommendation that deferred study costs should be removed from rate base and either amortized outside of rate base or rolled into a related capital asset, AEY stated with respect to feasibility studies, such as the one proposed for renewables, deferral treatment for approved expenditures is appropriate given that such studies may not result in the construction of a project, or a near-term project.²⁶⁶

12.4.3.1 Views of interveners

436. Given that AEY had not commenced development of its proposed renewables study, Mr. Maissan argued it was unreasonable to expect that AEY could incur the entirety of its proposed expenditures in a prudent manner subsequent to a Board Order.

437. Mr. Maissan also took issue with AEY development of company-owned renewable and alternative energy sources, stating that such projects would be in direct competition with IPP proponents. Mr. Maissan viewed it to be inappropriate for ratepayers to fund AEY to, in essence, compete with the private sector, which is funded privately.

438. As an alternative to the Board approving a \$500,000 renewables study, Mr. Maissan recommended that the Board should approve (1) study costs of up to \$150,000 “to prepare for the significant displacement of diesel generation in Destruction

²⁶⁴ AEY Final Argument, paragraph 110..

²⁶⁵ Transcript, Volume 2, page 292.

²⁶⁶ AEY Reply Argument, paragraphs 88-90..

Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV”, and (2) study costs of \$50,000 “for a study on how to improve the fuel efficiency of AEY’s diesel plants, including the utilization of residual heat, that applies to all of AEY’s diesel plants.”²⁶⁷

439. With respect to each of his proposed studies, Mr. Maissan made further recommendation that the Board order AEY to submit detailed terms of reference, submit study reports upon their completion, and also seek Board approval before the implementation of any action arising out of the study findings.

440. YCS expressed similar views to that of Mr. Maissan in that the concept of the renewables study as pursuing a replacement for diesel fuel was flawed and should be denied by the Board. YCS stated that if ratepayers were being asked to pay for the study, then it must be shared as soon as completed and not withheld from viewing until the next GRA.²⁶⁸

441. YEC²⁶⁹ discounted Mr. Maissan’s argument that AEY developing renewable and alternative energy sources would be in competition with IPP proponents. YEC stated there was no basis for Board to restrict prudently incurred expenditures related to studies assessing renewable generation options.

442. YEC also addressed comments from Mr. Maissan and YCS requesting the sharing of any renewable study results prior to AEY’s next GRA, stating that there is no mandate for the Board to address such proposals. YEC expressed similar views with respect to AEY’s proposal to bring forward any business cases stemming from the renewables study in a stand-alone proceeding before the Board without waiting for a subsequent GRA.

12.4.3.2 Views of the Board

443. In this test period, AEY has requested various studies for Board approval to include amounts for studies in rates. The Board considers that such studies are best conducted by industry or funded by government initiatives.

444. In addition, the Board understands that it may be difficult for the utility look to government grants or other sources of funding through customer rates without a fully formulated proposal for a renewable or alternate energy project. This was explained by Mr. Tenney in his testimony:

Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been — become public since you filed your application and your IRs?

A. MR. TENNEY: Again, in one of the information responses, we did talk about the last — the 2016 federal budget that they earmarked, I believe it was \$10.6

²⁶⁷ JM Final Argument, page 12.

²⁶⁸ YCS Final Argument, page 9.

²⁶⁹ YEC Reply Argument, pages 7-9.

million for renewable energy programs. We have been working with the Federal Government to see if we can access that.

To date, the message — and I think we — in one of that - October 24th, I believe it was, update that we did, we had originally said that we hadn't included the watt — we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.

What we got back — what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project — the economics work to get it under construction.

So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.²⁷⁰

445. The Board is of the view that studies proposed in the Application would reasonably involve an assessment of need, feasibility and policy objectives that could involve government, academics, YEC, municipalities, customers or other stakeholders.

446. The legislative scheme is intended to provide for the regulation of utilities and to provide the Board with various responsibilities in the public interest, including the setting of rates of the utility in the provision of electricity to customers in the Yukon.

447. There is not sufficient evidence for the Board to approve the Renewable and Alternative Energy Feasibility Study proposed in the Application and, without further information, the Board is unable to assess whether or not these studies should be conducted given the need or feasibility of a study to support a renewable and alternative energy project or projects, and whether proposed costs for these studies should be recovered in customer rates. The Board considers that information that should be provided in support for these types of studies or initiatives would include, but is not limited to:

- An analysis of how the study or initiative proposed is related to the utility's statutory requirements of provision of utility service pursuant to the *Public Utilities Act* and its regulations;
- The drivers, need and feasibility for the study or initiative;
- The scope of the study or initiative;
- An expected budget for studies, preliminary reports, and any other primary or secondary reports, as well as a budget for any known implementation costs or an estimate of any expected implementation costs;

²⁷⁰ Transcript, Volume 3, page 453, lines 11 to 25 and 454 lines 1-15.

- The specific utility projects that are expected to be reviewed or impacted by the proposed initiative(s), as well as corresponding benefits to customers expected as a result of the study and initiative(s); and
- Whether cost-recovery studies and alternative-energy initiatives, energy-saving initiatives, or other initiatives have been explored through grants or other sources of funding, including shareholder funding.

448. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility Study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision.²⁷¹

449. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference, or filing any completed Renewable and Alternative Energy Feasibility Study.

450. Further to the request for two alternative studies as proposed by Mr. Maissan in argument, the Board finds the feasibility and the costs for AEY to undertake these studies has not been examined by the utility or the Board through a proceeding. These recommendations have not received the benefit of being tested by parties during the course of this proceeding. For these reasons, the Board does not support Mr. Maissan's request for AEY to undertake two alternative studies.

12.4.4 Joint Smart Grid Study Deferral Account

451. AEY requested approval for costs related to a Joint Smart Grid Study anticipated to be undertaken in 2017 in partnership with YEC at a cost of \$100,000. The study is intended to assess the potential fit and viability of a smart grid in the Yukon. AEY advised that it intends to have the completed smart grid study filed with the Board and made public.²⁷²

12.4.4.1 Views of interveners

452. Mr. Maissan supported the Board's approval of the \$100,000 budget for the proposed smart grid study, citing that there could be significant benefits to ratepayers in the long term if the utilities were to embrace a smart grid approach in the Yukon.²⁷³

12.4.4.2 Views of the Board

453. The Board considers that such studies are best conducted by industry or funded by government initiatives.

454. There is not sufficient evidence for the Board to approve the Joint Smart Grid Study proposed in the Application and, without further information, the Board is unable to assess whether these studies should be conducted given the need or feasibility of a

²⁷¹ For example, at Transcript, Volume 2, page 291, lines 6-10, Mr. Tenney confirmed that ATCO Electric Yukon is one of the members of the Northern consortium, together with three Crown corporations, that fund the research chair in Northern Energy Innovation at Yukon College.

²⁷² AEY Final Argument, paragraphs 119-122.

²⁷³ JM Final Argument, page 6.

study to support a smart grid project or projects, or whether proposed costs for these studies should be recovered in customer rates.

455. Further, there has been no substantive evidence submitted by parties that provided an indication of any benefits accruing to customers as a result of the proposed study.

456. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecasted expenditures and cost recovery related to its proposals in its compliance filing to this decision.

457. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference or filing any completed Joint Smart Grid Study.

Appendix A – Summary of Directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. The Board notes AEY's submission that, "Had AEY not revised its methodology... AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016." Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data. Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. Paragraph 40
2. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY. This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a position that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY. Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the position be removed from AEY's complement. Paragraph 76
3. As a result, for out-of-scope employees, the Board awards for 2016, a labour inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision. Paragraph 90
4. For these reasons the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction. Paragraph 94

5. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response. In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent for 2017. AEY is directed to reflect this change in its compliance filing to this decision. Paragraph 105
6. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual. Paragraph 123
7. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period. However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs. Paragraph 124
8. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, "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." However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800 and \$7,000 being removed from Account 88900. The revised balance

approved by the Board for 2016 “Other” (Account 88800) is \$47,000, and the 2017 balance for “Other” (Account 88800) is \$44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision..... Paragraph 128

9. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for \$32,000, which is the total variance. AEY stated in the Application that, “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.” However, the Board finds that \$14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the \$14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with \$7,000 being removed from Account 88800, and \$7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is \$143,000, and the approved 2017 balance for “Other” (Account 88900) is \$146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision. Paragraph 130
10. The three-year average (2013-2015) for “Other” for Account 72100 is \$1,426,000. The Board finds that it is reasonable to use the three-year average for this account. \$1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the \$1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be \$1,455,000. For 2017, the forecast value is \$1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision. Paragraph 134
11. For the purpose of calculating AEY’s depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense. Paragraph 163
12. The Board considers that consistent with AEY’s depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.
..... Paragraph 167

13. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.
..... Paragraph 172
14. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.
..... Paragraph 237
15. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017. The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision. Paragraph 240
16. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. Paragraph 278
17. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost. Paragraph 292
18. With respect to LED streetlight installations that are not conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. Paragraph 293

19. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision. Paragraph 354
20. The Board accepts AEY's test period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA. Paragraph 384
21. If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings. Paragraph 385
22. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. Paragraph 448
23. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. Paragraph 456

September 28, 2023

AEY-UCG-020

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-020

Reference: July 7, 2023 Application, page 2.1 and 2.6 Secondary Sales

Request:

- (a) For the Secondary Sales section of Table 2-1, please expand the table to include data row identifying the costs of providing Secondary Power and a calculation of net revenues.
- (b) Explain how secondary power sales income is documented and accounted in revenue requirement.

Response:

- (a) Please refer to the table below for AEY's calculation of net revenues, based on Secondary sales revenue and Secondary energy expense information:

**Secondary Sales Revenue and Costs
(\$000)**

Line		2016	2017	2018	2019	2020	2021	2022	2023	2024
	Secondary Sales									
(1)	Revenue ¹	296	553	21	0	34	361	401	390	390
	Purchase Power Expense									
(2)	Secondary Energy Expense ²	243	460	16	0	8	330	276	358	358
(3) = (1) - (2)	Net Revenue	53	93	5	0	26	31	124	32	32

1. AEY 2023-2024 GRA, S2.1, Line 36

2. AEY 2023-2024 GRA, S3.1, Line 12.

- (b) As shown in the table in part (a) above, Secondary sales are included on Line 36 of Schedule 2.1 and Secondary energy expenses are included on Line 12 of Schedule 3.1 of AEY's 2023-2024 GRA Schedules.

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AEY-UCG-021

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-021

Reference: July 7, 2023 Application, page 3-1

AEY claims Primary and Secondary Purchase Power costs are forecast to remain relatively flat over the Test Period.

Request:

- (a) Explain why and how AEY determined population growth no longer drives purchase power sales for each of the two test years.
- (b) Explain how possible low balling purchase power costs could result in a surplus for AEY.
- (c) What is AEY prepared to do to prevent the surplus cash cow for the utility that occurred for the prior 6 years?

Response:

- (a) AEY has neither determined nor stated that population growth no longer drives purchase power sales. AEY is of the view that the purchase power forecast is largely driven by the sales forecast and AEY has maintained the approved methodology for forecasting both purchase power and sales for the Test Years.
- (b) The purchase power is driven by the demand for energy, which is not controlled by AEY. The purchase power unit cost is driven by YEC, which is also not controlled by AEY. Therefore, the possibility of lower than reasonable purchase power costs is not applicable.
- (c) The premise of the request is argumentative and unfair. Under the regulatory framework, utilities are incentivized to find efficiencies and cost savings on a go-forward basis and are entitled to benefit from any efficiencies achieved until rates

September 28, 2023

AEY-UCG-021

are reset. For example, the efficiencies realized by AEY since its last GRA have been incorporated into the cost forecasts included in the Application and will be passed through to customers in the revenue requirements approved by the Board. Regulated utilities such as AEY are entitled to recover their prudent costs and to earn a fair return on and of capital. Both are widely accepted regulatory principles that the request appears to overlook. In accordance with the above referenced regulatory principles, AEY will continue to look for ways to find efficiencies to the benefit of both customers and its shareholders.

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AEY-UCG-022

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-022

Reference: July 7, 2023 Application, page 3-3

AEY justifies the creation of a deferral account based on the assumption that changes to purchased power costs may produce a loss or gain of substantial magnitude.

Request:

- (a) Please provide statistical analysis showing changes to the cost of purchased power for 2017 through 2023.
- (b) Please provide details of what AEY would classify as “a loss or gain of substantial magnitude” and why.

Response:

- (a) Please refer to the tables below for the summary of AEY's purchased power expenses and year-over-year (YoY) percentage changes over the period 2017 to 2023.

**Table 1: Purchase Power Expense
(\$000)**

	Actuals							Test Year
Description	2016	2017	2018	2019	2020	2021	2022	2023
Primary Energy Expense	25,108	27,069	27,658	27,507	28,817	28,959	28,796	29,015
Secondary Energy Expense	243	460	16	-	8	330	276	358
Shortfall Rider J	5,273	6,487	8,680	8,920	17,028	19,529	21,921	-
Less: Capitalized	(216)	(5)	-	(88)	-	-	-	(49)
Total Purchase Power	30,409	34,011	36,354	36,339	45,853	48,818	50,993	29,323

**Table 2: Purchase Power Expense
YoY Change
(%)**

	Actuals							Test Year
Description	2017	2018	2019	2020	2021	2022	Total	2023
Primary Energy Expense	6.4	1.7	-0.4	3.6	0.3	-0.3	11.3	0.8
Secondary Energy Expense	0.7	-1.3	0.0	0.0	0.7	-0.1	0.0	29.3
Shortfall Rider J	4.0	6.4	0.7	22.3	5.5	4.9	43.8	0.0
Less: Capitalized	0.7	0.0	-0.2	0.2	0.0	0.0	0.7	0.0
Total Purchase Power	11.8	6.9	0.0	26.2	6.5	4.5	55.8	-42.5

As noted in the tables above, while overall purchase power increased by approximately 56 percent over the period 2017 to 2022, the majority of the increase, (approximately 44 percent) is related to the flow-thru of YEC's Shortfall Rider J. The remaining 11 percent increase is mainly driven by the increase in AEY's load over that period. For the 2023 test year, the decrease in purchase power of -42.5 percent is mainly due to the removal of YEC's Shortfall Rider J from both purchase power (Schedule 3.1, Line 13) and revenue (Schedule 2.1, Line 51).

- (b) There is no defined dollar value for what would classify as a loss or gain of substantial magnitude. AEY is seeking the continuation of a deferral account for power purchase costs on the basis that it continues to meet the previously accepted criteria for establishing a deferral account. The power purchase costs for which AEY is seeking a deferral account are outside the control of the company and are not reasonably forecastable, or a variance in forecasting could produce a loss or gain of a substantial magnitude.

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AEY-UCG-023

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)****Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023****AEY-UCG-023****Reference:** July 7, 2023 Application, page 3-4

AEY states: Total forecast purchases are determined by applying a forecast line loss percentage to AEY's sales load forecast that was determined in Section 2. Line losses have been determined to be 6.1 percent and are calculated using a five-year historical average.

Request:

- (a) Provide 5-year statistics showing calculation of line losses.
- (b) Describe specific work AEY has undertaken and when this was done, to reduce the level of line losses since 2017.
- (c) Explain why this has not resulted in a reduced line loss since the last GRA.
- (d) Under the service contract with related party ATCO, has there been a load and line loss study since the last GRA? If yes, explain the outcome of the study. If not, explain why not.

Response:

- (a) Five-Year Historical Line Losses were calculated as follows:

**Table 1: Five-Year Historical Line Losses
MWh**

		2018	2019	2020	2021	2022
Total Generation & Purchases	(a)	361,811	359,760	376,475	387,440	385,092
Less:						
Total Energy Sale	(b)	341,212	340,184	354,691	363,853	365,128
Losses and Company Used	(c)	20,599	19,575	21,784	23,587	19,964
Losses %	(c)/(b)	6.0%	5.8%	6.1%	6.5%	5.5%
5-Year Average		6.0%				

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AEY-UCG-023

- (b) AEY reduces and minimizes line losses on an ongoing basis, through new extensions and system improvement projects that target poor performing lines and infrastructure. All new infrastructure is built to current engineering standards that inherently reduce losses, as AEY installs large ampacity conductors for all new extensions and system improvement distribution lines. This improves line losses when old smaller distribution lines are upgraded with larger conductors. Line losses are also reduced on system loading when the distribution voltages are increased in voltage conversion projects.
- (c) The line loss has dropped from 6.2 percent (approved line loss in 2016-2017 GRA) to 6.0 percent.¹
- (d) ATCO Electric has not performed a load and loss research study due to the stability of the system and, on that basis, AEY did not consider that incurring costs on an unnecessary study would be prudent.

¹ In preparing the response to this information request, AEY identified a rounding error within the Application. Line Losses on Line 4 of Sch. 3.2 should reflect 6.0% and will be updated as part of the compliance filing.

September 28, 2023

AEY-UCG-024

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-024

Reference: July 7, 2023 Application, page 4-1; Fuel Costs

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

Request:

- (a) Explain when the new tender for diesel fuel purchases will be effective and the associated costs.
- (b) Confirm that any new diesel fuel prices will be reconciled in fuel costs paid by Yukon ratepayers through the Rider F.

Response:

- (a) The diesel supply contract, for road accessed facilities, is effective January 1, 2020 until December 31, 2024. The price is a function of the fluctuating Edmonton rack price (supplier market price) for the product (winter or summer grade) plus a delivery fee (per km) plus an escalation of \$0.02/L (effective January 1, 2023) to address operating cost inflation.
- (b) Confirmed.

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AEY-UCG-025

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-025

Reference: July 7, 2023 Application, page 4-2

Regarding diesel fuel costs, AEY states *"Price forecasts for each community are based on the 2015 actual prices for diesel fuel"*.

Request:

Update Schedule 4.2 with the most recent actual diesel fuel prices for 2023 to date.

Response:

Please refer to AEY-UCG-025 Attachment 1 which reflects August 31, 2023 actual average diesel prices.

Line No.	Description	Cross Ref.	Actuals							Test Period		Approved	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
1	<u>Average Cost (in cents per litre)</u>												
2	Watson Lake	Note 1	73.41	83.65	100.05	99.11	74.97	95.71	147.46	124.37	124.37	76.18	76.18
3	Beaver Creek	Note 1	73.61	82.88	100.13	96.12	78.97	94.16	139.16	128.54	128.54	92.40	92.40
4	Destruction Bay	Note 1	71.35	79.98	97.55	93.11	76.93	92.37	137.66	121.98	121.98	91.90	91.90
5	Old Crow	Note 1	179.46	187.36	225.99	229.36	232.31	247.21	308.55	309.49	309.49	201.71	201.71
6	Swift River	Note 1	76.26	89.44	106.69	102.21	84.85	96.77	142.77	133.03	133.03	88.72	88.72
7	Standby Units	Note 1	100.74	98.38	61.85	96.10	94.18	98.95	122.94	124.76	124.76	97.81	97.81
8													
9	<u>Generation (MWh)</u>												
10	Watson Lake		14,992	15,296	15,386	15,171	14,756	15,140	15,116	14,892	15,195	14,690	14,688
11	Beaver Creek		1,792	2,006	1,911	1,837	1,841	1,803	1,745	1,706	1,627	1,820	1,908
12	Destruction Bay		1,556	1,880	1,936	1,966	2,017	1,958	1,923	2,000	2,142	1,782	1,756
13	Old Crow		2,278	2,575	2,522	2,569	2,853	2,567	2,517	2,907	2,365	2,216	2,309
14	Swift River		220	303	269	268	247	231	215	213	221	215	228
15	Standby Units		44	99	110	185	346	103	284	104	208	39	40
16			20,881	22,160	22,135	21,995	22,061	21,801	21,799	21,822	21,758	20,763	20,930
17													
18	<u>Net Heat Rate (kWh/litre)</u>												
19	Watson Lake		3.90	3.90	3.93	3.89	3.87	3.92	3.79	3.88	3.88	3.85	3.85
20	Beaver Creek		3.65	3.59	3.59	3.56	3.44	4.02	3.41	3.59	3.59	3.43	3.43
21	Destruction Bay		3.37	3.42	3.67	3.54	3.71	4.07	3.11	3.60	3.60	3.61	3.61
22	Old Crow		3.40	3.61	3.68	3.84	3.53	3.24	4.44	3.70	3.70	3.40	3.40
23	Swift River		2.76	3.02	2.97	2.33	2.88	2.72	2.43	2.65	2.65	2.68	2.68
24	Standby Units		3.14	3.20	3.03	3.20	3.28	1.85	3.00	2.94	2.94	2.20	2.20
25													
26	<u>Litres Consumed (000)</u>												
27	Watson Lake		3,846	3,922	3,911	3,898	3,810	3,863	3,992	3,838	3,916	3,817	3,816
28	Beaver Creek		491	559	533	517	536	448	512	475	453	531	557
29	Destruction Bay		515	551	528	555	544	481	617	556	596	493	486
30	Old Crow		702	714	685	670	809	793	567	786	640	652	680
31	Swift River		80	100	91	115	86	85	88	81	84	80	85
32	Standby Units		21	31	36	58	106	55	95	35	71	18	18
33			5,655	5,877	5,783	5,812	5,890	5,725	5,872	5,771	5,759	5,592	5,643
34													
35	Note 1 - 2023 and 2024 updated to average diesel fuel cost as of August 31, 2023												

September 28, 2023

AEY-UCG-026

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-026

Reference: July 7, 2023 Application, page 4-2; Fuel Costs

AEY states "Plant efficiencies are based on the average efficiencies of the previous five years adjusted for any changes due to the replacement of units".

Request:

- (a) Expand Table 4.1 to provide details of the diesel fuel efficiencies for the 5 years used to support the 2023 and 2024 forecasts including how they were measured.
- (b) Explain all work that AEY has undertaken in the last 5 years to improve diesel fuel efficiencies on its various systems and a statistical analysis showing the results.

Response:

- (a) Please refer to AEY-UCG-026(a) Attachment 1.
- (b) AEY has carried out projects in the last 5 years to replace end of life diesel gensets due to end-of-life. Any replacement diesel engine must meet emissions regulations and one of the criteria used for tender evaluation is fuel efficiency. AEY has not undertaken individual projects to improve fuel efficiency of existing diesel engines or reduce the heat rate at isolated power plants.

ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)

Net Heat Rate (kWh/litre)

Line No.	Description	2018	2019	2020	2021	2022	Average
1	<u>Generation (MWh)</u>						
2	Watson Lake	15,386	15,171	14,756	15,140	15,116	15,114
3	Beaver Creek	1,911	1,837	1,841	1,803	1,745	1,827
4	Destruction Bay	1,936	1,966	2,017	1,958	1,923	1,960
5	Old Crow	2,522	2,569	2,853	2,567	2,517	2,606
6	Swift River	269	268	247	231	215	246
7	Standby Units	110	185	346	103	284	206
8		22,135	21,995	22,061	21,801	21,799	21,958
9							
10	<u>Litres Consumed (\$000)</u>						
11	Watson Lake	3,911	3,898	3,810	3,863	3,992	3,895
12	Beaver Creek	533	517	536	448	512	509
13	Destruction Bay	528	555	544	481	617	545
14	Old Crow	685	670	809	793	567	705
15	Swift River	91	115	86	85	88	93
16	Standby Units	36	58	106	55	95	70
17		5,783	5,812	5,890	5,725	5,872	5,816
18							
19	<u>Net Heat Rate (kWh/litre)</u>						
20	Watson Lake	3.93	3.89	3.87	3.92	3.79	3.88
21	Beaver Creek	3.59	3.56	3.44	4.02	3.41	3.59
22	Destruction Bay	3.67	3.54	3.71	4.07	3.11	3.60
23	Old Crow	3.68	3.84	3.53	3.24	4.44	3.70
24	Swift River	2.97	2.33	2.88	2.72	2.43	2.65
25	Standby Units	3.03	3.20	3.28	1.85	3.00	2.94

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AEY-UCG-027

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-027

Reference: July 7, 2023 Application, page 4-2; Diesel Fuel Deferral Account

AEY states: *"The variance between actual and forecast fuel prices as outlined in Schedule 4-2." and "The previously approved methodology for the fuel deferral uses the Board approved calculation."*

Request:

- (a) Why is Schedule 4-2 not included at end of this Section? Cannot find this schedule.
- (b) Provide updated Board directed regulatory reporting for Rider F, for 2023 Jan.-Mar. and Feb.-June actuals.
- (c) Provide updated Board directed regulatory reporting for Rider F, for remainder of 2023 forecast.
- (d) Provide updated Board directed regulatory reporting for Rider F, for 2024 forecast.
- (e) What is AEY recommending to Board for fuel price reconciliation in this application?

Response:

- (a) Schedule 4.2 was included in the Excel workbook as part of AEY's Application filed on July 7, 2023, and is also included in the Excel workbook with the updated Schedules filed on September 11, 2023, with AEY's Depreciation Study. A copy of Schedule 4.2 has also been reattached in AEY-UCG-027(a) Attachment 1.
- (b) Please refer to the response to AEY-UCG-005(h).
- (c) Please refer to the response to AEY-UCG-005(h-i).

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- (d) Please refer to the response to AEY-UCG-005(h-i).
- (e) Following Board directions on AEY's 2023-2024 GRA following the hearing, AEY will true-up the fuel variance amounts in the Compliance Filing.

ATCO Electric Yukon (AEY)
2023 - 2024 General Rate Application (GRA)

Fuel Information

Line No.	Description	Cross Ref.	Actuals							Test Period		Approved	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
1	<u>Average Cost (in cents per litre)</u>												
2	Watson Lake		73.41	83.65	100.05	99.11	74.97	95.71	147.46	135.21	135.21	76.18	76.18
3	Beaver Creek		73.61	82.88	100.13	96.12	78.97	94.16	139.16	151.39	151.39	92.40	92.40
4	Destruction Bay		71.35	79.98	97.55	93.11	76.93	92.37	137.66	132.65	132.65	91.90	91.90
5	Old Crow		179.46	187.36	225.99	229.36	232.31	247.21	308.55	319.21	319.21	201.71	201.71
6	Swift River		76.26	89.44	106.69	102.21	84.85	96.77	142.77	147.47	147.47	88.72	88.72
7	Standby Units		100.74	98.38	61.85	96.10	94.18	98.95	122.94	122.94	122.94	97.81	97.81
8													
9	<u>Generation (MWh)</u>												
10	Watson Lake		14,992	15,296	15,386	15,171	14,756	15,140	15,116	14,916	15,195	14,690	14,688
11	Beaver Creek		1,792	2,006	1,911	1,837	1,841	1,803	1,745	1,684	1,627	1,820	1,908
12	Destruction Bay		1,556	1,880	1,936	1,966	2,017	1,958	1,923	2,067	2,142	1,782	1,756
13	Old Crow		2,278	2,575	2,522	2,569	2,853	2,567	2,517	2,714	2,365	2,216	2,309
14	Swift River		220	303	269	268	247	231	215	206	221	215	228
15	Standby Units		44	99	110	185	346	103	284	115	208	39	40
16			20,881	22,160	22,135	21,995	22,061	21,801	21,799	21,700	21,758	20,763	20,930
17													
18	<u>Net Heat Rate (kWh/litre)</u>												
19	Watson Lake		3.90	3.90	3.93	3.89	3.87	3.92	3.79	3.88	3.88	3.85	3.85
20	Beaver Creek		3.65	3.59	3.59	3.56	3.44	4.02	3.41	3.59	3.59	3.43	3.43
21	Destruction Bay		3.37	3.42	3.67	3.54	3.71	4.07	3.11	3.60	3.60	3.61	3.61
22	Old Crow		3.40	3.61	3.68	3.84	3.53	3.24	4.44	3.70	3.70	3.40	3.40
23	Swift River		2.76	3.02	2.97	2.33	2.88	2.72	2.43	2.65	2.65	2.68	2.68
24	Standby Units		3.14	3.20	3.03	3.20	3.28	1.85	3.00	2.94	2.94	2.20	2.20
25													
26	<u>Litres Consumed (000)</u>												
27	Watson Lake		3,846	3,922	3,911	3,898	3,810	3,863	3,992	3,844	3,916	3,817	3,816
28	Beaver Creek		491	559	533	517	536	448	512	469	453	531	557
29	Destruction Bay		515	551	528	555	544	481	617	575	596	493	486
30	Old Crow		702	714	685	670	809	793	567	734	640	652	680
31	Swift River		80	100	91	115	86	85	88	78	84	80	85
32	Standby Units		21	31	36	58	106	55	95	39	71	18	18
33			5,655	5,877	5,783	5,812	5,890	5,725	5,872	5,738	5,759	5,592	5,643

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AEY-UCG-028

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-028

Reference: July 7, 2023 Application, page 5-1; Operations and Maintenance Expenses

AEY states "The forecast 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 O&M accounts or capital accounts depending on the nature of work being performed by the staff in that job class."

Request:

- (a) Identify the number of employees compensated more than \$100,000 annually for each of the years from 2016 to 2022 and forecast for 2023 and 2024.
- (b) Identify each management position and amount of bonus received for each years 2018- 2022.
- (c) Provide a table showing employee complement history by function for each of the years from 2016 to 2022 and forecast for 2023 and 2024.

Response:

- (a) Given the small number of personnel employed by AEY, whose positions are well-known to the community, AEY is not able to provide the requested information.
- (b) Please refer to the response in part (a) above.
- (c) This information is not available and AEY respectfully declines to answer pursuant to Rule 14(4)(b) of the YUB Rules of Practice. AEY does not track employee complement by function. Employees code their timesheets to the activities they have been working on in each time period, which allows AEY to allocate their costs to the appropriate function and/or capital project. Providing the employee complement by function would be a significantly onerous and time-consuming task.

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AEY-UCG-029

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-029

Reference: July 7, 2023 Application, page 5-2; Operations and Maintenance Expense

AEY states: " The overall increases in O&M expense are mainly attributable to rising labour, contractor, and material costs due to inflation. In addition to incremental labour and non-labour costs driven by higher demands from customer growth and operating a more robust and complex electrical system."

Request:

- (a) If AEY was not a cost-plus regulated utility, would you not absorb many of these inflationary costs like other smaller Yukon businesses who wish to keep their customers? Explain answer.
- (b) Why has customer growth income not covered these perceived incremental costs?

Response:

- (a) If AEY were not a regulated utility, it would have to either absorb the inflationary costs or pass the costs on to customers through higher rates. If AEY absorbed the costs, it would need to implement rigorous cost management strategies to mitigate the impact of inflation on its operations, which could negatively impact customers due to service levels being potentially impacted.

Notwithstanding the above, regulated utilities are incentivized to find efficiencies and reduce costs, while maintaining safe and reliable service. These savings are ultimately passed on to customers by minimizing rate increases or even decreasing rates, as AEY has proposed for the 2023 Test Year.

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AEY-UCG-029

- (b) Although AEY has experienced customer growth, inflation is increasing at a higher rate. AEY is expecting an increase in customer growth of 2.5 percent in 2023 and 2.1 percent in 2024.¹ As seen in Table 1.1 of the Application,² inflation is expected to increase by 3.8 percent in 2023 and 2.5 percent in 2024, which is higher than the expected rate of customer growth. Furthermore, a portion of AEY's costs are fixed or semi-fixed, such as infrastructure maintenance, capital expenditures, information technology and labour costs. These costs may not decrease or increase in direct proportion to changes in customer numbers. In addition, customer growth alone does not guarantee increased revenue if customers reduce their consumption or become more energy efficient. Therefore, even if AEY experiences customer growth, it may not fully offset the impact of rising inflation on its costs.

¹ 2023-2024 AEY GRA Regulatory Schedules, Schedule 2.1, Line No. 45.

² 2023-2024 AEY GRA Application, PDF p. 10, Table 1.1.

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AEY-UCG-030

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-030

Reference: July 7, 2023 Application, page 5-2; Operations and Maintenance Expenses AEY claims an increase in asset base as driver to Test Years.

Request:

- (a) Explain what AEY has been doing in each of the years since 2017 to adequately upkeep aging production assets.

Response:

- (a) Production operations and maintenance activities include preventative and restorative tasks. Top end overhauls on engines are preventative activities, that are frequency or runtime scheduled, and result in variable costs landing year to year based upon operations. Occasionally, top end overhauls result in additional (i.e., beyond typical) work based on found condition and manufacturer tolerances. Below is a summary of larger cost activities / tasks by year:

Table 1: Production Maintenance

Year	Production & Maintenance Activities
2017	Top end overhauls: WL5, OC2, WL1 Fuel tank cleaning. Failure repairs: FL2
2018	Top end overhauls: BC1, DB3, DB2
2019	Top end overhauls: OC4, WL4, WL5
2020	Delays due to COVID Pandemic
2021	Cylinder packs, cuffed liners: WL4 Fuel tank cleaning.
2022	Top end overhauls: BC2, WL3 API tank inspections. Governor overhaul: FL2.

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AEY-UCG-030

AEY conducts inspections and predictive tests on equipment and monitors operating performance on local and remote instruments. AEY has found that auxiliary systems (i.e. to the gensets) at generation sites have required additional maintenance, as aging equipment results in more issues being identified and requiring repair.

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AEY-UCG-031

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)****Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023****AEY-UCG-031**

Reference: July 7, 2023 Application, page 5-3; Operations and Maintenance Expense

The table on page 5-1 shows AEY's actual operations and maintenance expenses for 2016 to 2022 and test period forecast for 2023 and 2024.

Request:

- (a) Provide same table showing non-fuel operating and maintenance costs per customer for each of the years above.
- (b) Provide details on what expenses are included in each of the above years under Public Information explaining labour and non-labour costs.

Response:

- (a) Please refer to AEY-UCG-031(a) Attachment 1.
- (b) Please refer to the table below:

**Table 1: Public Information costs
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
70100 - Public Information Administration									
Labour	10	10	10	15	16	13	14	15	16
Other	11	22	11	9	15	63	137	15	16
Total	21	32	21	24	31	76	151	30	32
70200 - General Public Information									
Labour	59	103	11	-	-	12	78	79	82
Other	14	56	26	50	53	68	20	70	72
Total	73	159	37	50	53	80	98	149	154

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AEY-UCG-031

Labour is for a communication advisor and head office marketing costs. Non labour costs are for sponsorship of community events and other marketing and promotional material. Please refer to the responses to AEY-JM-016(b) and AEY-YUB-017 for further details.

ATCO Electric Yukon
2023 - 2024 General Rate Application (GRA)

Operations and Maintenance Expenses per Customer
(\$ per Customer)

Line No.	Description	Cross Ref.	Actuals							Test Period		Approved	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2016	2017
1	Number of Customers	S.2.1 L.45	17,863	18,157	18,532	18,926	19,340	19,798	20,308	20,807	21,248	17,854	18,082
2													
3	Production												
4	62600 - Hydro Generation	S.5.2 L.5	16	12	15	11	11	17	15	24	16	15	15
5	64000 - Supervision and Engineering Diesel	S.5.2 L.19	3	4	8	9	9	10	12	10	10	4	4
6	64600 - Diesel Generation	S.5.2 L.29	25	20	23	21	24	27	24	27	28	28	28
7	82600 - Hydro Maintenance	S.5.2 L.46	3	11	11	5	6	6	9	11	11	4	4
8	84600 - Diesel Maintenance	S.5.2 L.59	73	81	65	66	46	69	94	90	80	64	59
9			119	128	123	112	97	130	153	162	146	115	109
10	Distribution												
11	87000 - Supervision	S.5.2 L.76	15	21	16	18	12	19	19	19	19	18	18
12	87100 - Brushing	S.5.2 L.88	26	38	15	24	24	40	45	29	29	23	23
13	87200 - Vehicle Depreciation	S.5.2 L.104	(15)	(17)	(18)	(17)	(18)	(17)	(18)	(17)	(17)	(12)	(12)
14	87300 - Maintenance	S.5.2 L.109	112	105	113	120	119	116	146	137	138	115	116
15	87310 - Service to Outside Parties	S.5.2 L.128	4	3	3	5	6	32	7	1	1	7	7
16	87400 - Underground Line Maintenance	S.5.2 L.136	10	11	12	7	6	4	8	8	8	8	8
17	87500 - Meter and Meter Testing	S.5.2 L.153	3	8	5	5	9	5	4	7	5	5	5
18	87700 - Transformer Repair and Replacement	S.5.2 L.165	2	1	0	1	1	0	1	1	1	3	3
19	87800 - Street Light Maintenance	S.5.2 L.170	10	7	12	6	9	15	9	14	14	14	14
20			166	177	158	169	168	215	221	198	197	182	183
21	General												
22	88400 - Communication	S.5.2 L.185	1	1	2	2	2	2	3	6	6	1	1
23	88800 - Maintenance Company-Owned Houses	S.5.2 L.192	4	6	(2)	1	2	2	1	2	2	3	3
24	88900 - Maintenance Warehouse and Office	S.5.2 L.201	8	9	11	10	11	18	22	10	10	9	9
25			12	17	11	13	15	22	26	18	18	13	13
26	Public Information												
27	70100 - Public Information Administration	S.5.2 L.219	1	2	1	1	2	4	7	1	2	1	1
28	70200 - General Public Information	S.5.2 L.226	4	9	2	3	3	4	5	7	7	7	8
29			5	11	3	4	4	8	12	9	9	8	8
30	Customer Accounting												
31	71000 - Supervision	S.5.2 L.245	2	2	2	2	1	2	2	2	2	3	3
32	71100 - Customer Applications and Service Orders	S.5.2 L.250	29	23	23	23	22	18	21	22	22	27	28
33	71200 - Meter Reading	S.5.2 L.261	37	39	41	39	36	35	36	38	38	35	35
34	71300 - Customer Billing and Accounting	S.5.2 L.272	25	25	22	28	28	29	29	38	52	35	35
35	71400 - Revenue Collections	S.5.2 L.285	10	9	10	11	11	11	11	11	11	10	10
36	71500 - Collection of Delinquent Accounts	S.5.2 L.292	8	6	8	5	6	6	5	5	5	7	7
37	71800 - Provision for Uncollectible Accounts	S.5.2 L.298	3	4	6	(2)	9	(0)	2	4	4	5	5
38			113	108	111	105	113	99	107	119	134	121	122
39	Administration and General												
40	72100 - Administrative	S.5.2 L.312	115	132	118	116	137	140	125	136	140	116	117
41	72200 - Administrative Corporate	S.5.2 L.340	20	15	10	12	13	5	5	5	6	8	8
42	72300 - Insurance	S.5.2 L.349	5	5	5	5	6	7	8	8	8	6	6
43	72400 - Injuries & Damages	S.5.2 L.357	6	6	6	6	6	6	6	(13)	(13)	6	6
44	72500 - Employee Expenses	S.5.2 L.362	22	20	16	6	8	8	9	9	9	19	19
45	72600 - Training and Safety	S.5.2 L.374	23	27	22	24	27	22	36	32	29	28	28
46	72700 - Relocation	S.5.2 L.390	9	1	4	7	9	8	5	7	3	20	20
47	72800 - Miscellaneous General	S.5.2 L.394	-	-	-	-	-	-	-	-	-	0	0
48	72900 - Audit/Legal Fees & Special Studies	S.5.2 L.401	9	9	12	8	17	27	15	13	13	10	10
49			208	215	193	184	222	223	208	196	193	213	214
50													
51	Total Operations and Maintenance Expenses per customer		624	655	600	587	619	696	727	702	697	652	650

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AEY-UCG-032

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-032

Reference: July 7, 2023 Application, page 5-4; Table 5.2 Labour Costs by Function

AEY also claims incremental and additional FTEs costs required.

Request:

- (a) Break down Public Information labour costs.
- (b) Break down Admin and General costs.
- (c) Explain savings from far less office staff FTEs who are now no longer needed due to download of office hours and little need for payment in office to balance out much of these incremental and additional FTE costs.

Response:

- (a) Please refer to the following table for the breakdown of Public Information labour costs.

**Table 1: Public Information Labour Costs
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
70100 -Public Information Administration	10	10	10	15	16	13	14	15	16
70200 - General Public Information	59	103	11	-	-	12	78	79	82
Total	69	113	21	15	16	25	92	94	98

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AEY-UCG-032

- (b) Please refer to the following table for the breakdown of Administrative and General Labour costs:

**Table 2: Administrative and General Labour Costs
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
72100 - Administrative	612	684	722	648	678	997	767	867	878
72500 - Employee Expenses	169	187	109	9	20	(22)	-	-	-
72600 - Training and Safety	343	365	330	341	452	380	583	518	524
72900 - Audit/Legal Fees & Special Studies	12	51	71	70	84	77	74	73	74
Total	1,136	1,287	1,232	1,068	1,234	1,432	1,424	1,458	1,476

- (c) Office employees are still required to perform all billing functions, which have increased due to the rise in the numbers of customer connections being performed. This includes accepting payments in person and by phone.

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AEY-UCG-033

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-033

Reference: July 7, 2023 Application, page 5-4 and 5-5; Operations and Maintenance costs by function i.e., Production

Request:

- (a) Give a cost/benefit analysis of Production from Fish Lake hydro generation plant.
- (b) Explain why you need additional labour requirements and a new team lead plant position if you are contracting out the work for incremental maintenance.
- (c) If many of your generation assets are nearing end-of-life why have you not invested in alternative renewables since the last GRA?

Response:

- (a) The Fish Lake hydro generation plant has allowed AEY to provide renewable energy to its customers for decades. The production of renewable electricity directly aligns with the lower carbon emissions targets set out by the Federal Government and the Our Clean Energy plan set out by the Territorial Government. As the electrical demand of the Yukon Integrated System (YIS) continues to increase, the ongoing production of the Fish Lake Hydro system continues to be important. The renewable electricity produced by the Fish Lake Hydro system offsets purchase power from YEC. This legacy renewable electricity is even more important in the winter months as it offsets incremental thermal generation required to meet the peak winter demand on the YIS.

The benefit of offsetting purchased power outweighs the maintenance costs of running the plant. Refer to the table below.

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**Purchase Power Offset vs. Maintenance Costs
(\$000)**

Description	Year								
	2016	2017	2018	2019	2020	2021	2022	2023	2024
Primary Energy Charge (\$ per MWh)*	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083	0.083
Hydro Generation (MWh)	8,051	7,103	5,458	4,973	5,034	9,843	9,597	9,522	10,143
Offset of Purchase Power	668	589	453	413	418	817	796	790	842
62600 - Hydro Generation	277	224	279	209	217	343	297	498	336
82600 - Hydro Maintenance	52	196	210	96	119	127	184	231	237
Total Maintenance Costs	329	420	489	305	336	470	481	729	573
Total Savings/(Overspend)	339	169	(36)	108	82	347	315	61	269

*Note that for 2023 and 2024, AEY is assuming the current purchase power rates, and if the YEC increase in its upcoming application is approved these savings would increase.

- (b) The Team Lead, Plant position description is located on page 1-9 of the Application. This position is to address job planning, supervision, reporting, and technical competency assurance focused on the mechanical discipline of generation. This position will offload operational responsibilities from the Team Lead, Electrical as that team is focused on the electrical discipline of generation and has an increasing maintenance and commissioning workload due to additional and upcoming distribution infrastructure (e.g., SCADA devices, IPPs, substations). Contractor resources, i.e., trade technicians, are needed to address incremental maintenance at generating facilities and to assist during vacancies.
- (c) AEY has invested in renewable hydro-generation at the Fish Lake facility and is proposing to progress a rebuild of FL#2 to modern standards (refer to Business Case #39), which would increase its production.

All isolated grids operated by AEY have existing diesel infrastructure which provides stable, reliable, and dispatchable power with spinning reserve. Some of these facilities are nearing the end of life and will require investment to continue

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AEY-UCG-033

providing the same level of utility service. The addition of larger capacity renewables (in proportion to total load) onto isolated grids in the Yukon has been successfully demonstrated by the integration of Old Crow's solar and battery energy storage system with thermal legacy baseload. AEY has been supportive of the establishment of further community owned renewable energy projects within its remote communities, in alignment with the Yukon IPP policy. These new generation sources can decrease thermal demand and therefore reduce noise pollution, air contaminants, and greenhouse gas emissions. However, the need for energy storage systems and micro-grid controllers to address the intermittent and variable nature of renewable sources results in significant capital cost additions that require financial incentive or support to be economic. This support is being provided by various governments as a customer contribution. AEY's role is to ensure these renewable IPP projects integrate safely and reliably into our microgrids. As facilities reach the end of life, options will be evaluated and presented to the Board in future GRAs.

For a Utility to consider a reduction in diesel capacity the renewable generation would need to match the performance and availability of the equipment it is replacing. The diesel generators used in Isolated Gen communities are rated Prime, Prime as defined by the ISO 3046 standard. The maximum power which a generator set can provide a variable electrical load for an unlimited number of hours per year. In addition, the maximum average load factor over a 24-hour period shall not exceed 70 percent of generators prime rating.

September 28, 2023

AEY-UCG-034

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-034

Reference: July 7, 2023 Application, page 5-5 and 5-6; Operations and Maintenance costs by function i.e., Distribution

Request:

- (a) Explain why there is not carry-over from the surplus of 2016 and 2017 actuals and 2017 approved?
- (b) Why has new income from incremental growth not covered incremental growth in costs in new extension projects? Explain.

Response:

- (a) There are two main reasons why the surplus from 2016 and 2017 cannot be carried forward: i) increases in inflation; and ii) increases in maintenance costs.

With respect to inflation, the world economy has experienced hyper-inflation and supply chain issues, which AEY has not been immune to. If AEY were to inflate 2017 actual productions and distribution Operations & Maintenance (O&M) costs using actual inflation for the period 2018 to 2022 and forecast inflation for 2023 to 2024, these increases alone account for over \$1 million dollars in extra O&M expense for production and distribution annually. Please refer to Table 1 below for the related impacts:

Table 1: Related Inflation Impacts vs 2017 Actual Costs

	Years							
	2017	2018	2019	2020	2021	2022	2023	2024
Inflation Rates	Actuals	2.40%	2.00%	1.00%	3.30%	6.80%	3.80%	2.50%
	Inflated 2017 Actuals (\$000)							
Production Costs	2,320	2,376	2,422	2,445	2,522	2,680	2,768	2,826
Distribution Costs	3,217	3,294	3,359	3,391	3,497	3,716	3,838	3,918
Total	5,537	5,670	5,781	5,836	6,019	6,395	6,606	6,744
Inflation Impacts vs 2017		133	244	299	482	858	1,069	1,207

With respect to maintenance costs, these costs have been increasing compared to 2017, above and beyond inflation. This increase is expected with aging infrastructure and increased load demands due to population growth in the area. As equipment ages and gets near the end of life, increased maintenance work is required to keep the system running efficiently.

- (b) Incremental revenue growth to incremental costs, from a rapidly increasing population, is not a one-to-one ratio. The rapid population growth is putting a larger strain on the load and on the current infrastructure that must be addressed to provide safe and reliable service. This additional load that is putting strain on the system will require more maintenance and capital costs, over and above what incremental revenue growth provides to fund AEY's operations.

September 28, 2023

AEY-UCG-035

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-035

Reference: July 7, 2023 Application, page 5-6 and 5-7; Operations and Maintenance costs by function i.e., General

Request:

- (a) Explain the new satellite phone and radio system, i.e., name and program with costs associated.
- (b) Explain Maintenance of Warehouse and Office expenses with costs associated for each planned work.

Response:

- (a) Please refer to Business Case #14 for a detailed explanation of the new satellite phone and radio system. Subscription is supplied through Roadpost Inc. and uses Iridium hardware with Iridium PTT extended plan service. The annual charge for this plan is \$0.06 million for 38 units.
- (b) Maintenance of Warehouse and Office expenses addresses deficiencies in the warehouse and yard due to aging. This includes maintenance on HVAC system, maintenance, and reinsulating of service complex. The forecasts for 2023 and 2024 are in line with inflated historical averages from 2016 to 2020. 2021 and 2022 were higher than normal, so this was adjusted out of the Test Period. AEY does not foresee any major building, warehouse, or yard deficiencies in the Test Period.

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AEY-UCG-036

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-036

Reference: July 7, 2023 Application, page 5-7; Operations and Maintenance costs by function i.e., Public Information

Request:

- (a) Explain why a communications advisor is needed and at what cost.

Response:

- (a) The following are the responsibilities of the AEY Communications Advisor:
- Develop and execute government and public stakeholder plans and community engagement plans that enhance the companies' presence in the communities in which it operates and to address any emerging issue.
 - Prepare news releases and backgrounders, respond to all media inquiries as the first point of contact, and act as corporate spokesperson, as required.
 - Coordinate and produce materials for external and internal communication including presentations, reports, brochures, web content, advertising, briefings, speeches, memos, etc.
 - Appropriately manage AEY's marketing plan and budget. Ensure all external advertising adheres to ATCO brand standards.
 - Oversee AEY's community investment plan and budget, including reviewing requests and fulfilling commitments made with community organizations.
 - Provide communications support in case of a crisis.
 - Be a member of AEY's Employees Participating in Communities (EPIC) and Social Committees and assist with the planning and execution of fundraising events.
 - The costs for the communication advisor are \$94,000 in 2023 and \$98,000 in 2024.

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AEY-UCG-037

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-037

Reference: July 7, 2023 Application, page 5-8; Operations and Maintenance costs by function i.e., Customer Accounting

Request:

- (a) Will AEY still need meter readers when AMI is initiated? If not, what are the predicted savings?
- (b) Break down various Customer Billing and Accounting costs.
- (c) Break down "Other" with costs associated with each.

Response:

- (a) The goal of having AMI is to significantly reduce the need for traditional meter readers. However, the need for meter readers may not be eliminated for following reasons:
 - Transition Period: during the transition from traditional meters to AMI, the meter readers are still needed to read older meters.
 - Exception Handling: if any issues arise with AMI, the meter reader may still be required to manually collect data in certain situations.
 - Customer Requests: customers may request manual readings that are not compatible with AMI; and
 - Maintenance and Repair: meter readers may still be needed for meter maintenance or replacement.

Thus, meter readers may still be needed depending on the progress of AMI implementation and new AMI technology reliability. Once AMI is implemented, the

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need for traditional meter readers will likely decrease, however it is too early to predict the cost savings now.

- (b) Please refer to the following table for breakdown of Customer Billing and Accounting costs:

**Table 1: Customer Billing and Accounting Breakdown
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Postage for customer billing	163	169	173	175	164	213	194	200	200
CCS Operating costs	-	-	-	-	-	-	-	180	489
Telephone and Mobility	15	13	13	15	14	13	11	15	15
Financial Services	87	71	35	81	68	49	41	55	56
Total	265	253	221	271	246	275	246	450	760

- (c) Please refer to the following table:

**Table 2: Other Costs Breakdown
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals				Test Period				
Revenue Collections	2	4	8	8	(2)	2	12	11	12
Collection of Delinquent Accounts	9	6	11	3	8	7	17	11	10
Provision for Uncollectible Accounts	53	67	112	(32)	178	(5)	50	78	78
Total	64	77	131	(21)	184	4	79	100	100

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AEY-UCG-038

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-038

Reference: July 7, 2023 Application, page 5-9 and 5-10; Operations and Maintenance costs by function i.e., Admin & General

Request:

- (a) Break down Administrative Services provided by ATCO Electric head office or affiliate companies with associated costs.
- (b) Break down Audit/Legal Fees & Special Studies with associated costs.
- (c) Break down addition of administrative positions with associated costs.
- (d) Explain reasons for large IT Charges increases for each of the test years.
- (e) Break down Financial Services with associated costs.
- (f) Breakdown Other with associated costs.

Response:

- (a) The detailed costs for head office services are shown in table below:

**Table 1: Head Office Costs
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Governance, HR, and Health & Safety	31	112	127	127	127	113	118	121	112
Financial Reporting & Regulatory Support ¹	456	494	413	428	410	397	241	697	792
Payroll, Use of Systems and IT	155	115	8	7	7	-	-	-	-
General Marketing	-	-	25	52	52	57	-	-	-
Total Head Office Fees	642	721	573	614	597	567	359	818	904

¹ Including Government Relations & Initiatives

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- (b) Breakdown for Audit/Legal Fee & Special Studies costs are shown in table below.

**Table 2: Audit/Legal Fees & Special Studies
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Audit Fees	107	104	143	78	100	143	125	139	143
Renewable Feasibility Study	-	-	-	-	-	188	-	-	-
Legal Fees	32	2	2	-	145	67	43	-	-
Industrial Research	-	-	-	-	-	50	50	50	50
Other	2	12	14	1	3	5	8	-	10
Total	142	118²	159	79	248	453	226	198	203

- (c) Please refer to the following table for the breakdown of additional administrative positions with associated costs of \$260,000.

Table 3: Addition of Administrative Positions

Position	FTE
Supervisor, Business Support Services	0.75
Head Office Personnel	1.18

- (d) IT costs for the test years include additional licenses from Microsoft mainly for cybersecurity as well as an increased user count for AEY. While there is a modest increase from 2022, the test years are lower than both 2020 and 2021.
- (e) Please refer to the following table for the breakdown of financial services. Please note this will be renamed to head office support in the Compliance Filing to this Application.

² To align Schedule 5.2 of the Application, a reclass of \$8K was made between Audit/Legal Fees & Special Studies (Table 2) and Other (Table 5) for 2017, compared to Table 5.8 of the Application Narrative.

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**Table 4: Details of Financial Services
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Governance, HR, and Health & Safety	31	112	127	127	127	113	118	-	-
Financial Reporting and Regulatory Support	456	494	413	428	410	397	241	697	792
Payroll, Use of Systems and IT	155	115	8	7	7	-	-	-	-
Total	642	721	548	562	544	510	360	697	792

(f) Please refer to the following table for the breakdown of Other.

**Table 5: Administrative & General Costs
Breakdown of Other
(\$000)**

	2016	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals							Test Period	
Bank fees	358	266	188	226	248	104	108	140	142
Employee Expense	216	182	180	112	130	181	180	177	181
Severance - Due to Covid Vaccine Policy	-	-	-	-	-	-	410	-	-
IT services	160	154	163	165	140	145	162	173	179
Injuries & Damages	112	112	112	112	112	112	112	(279)	(279)
Contract services & Consultants	96	154	166	273	249	274	208	276	278
Telephone	35	54	57	54	58	62	79	86	86
Travel	105	97	78	53	36	43	47	78	79
Office stationery	29	29	30	32	29	29	32	36	39
Printing	16	17	19	23	25	22	23	27	29
Material & Consumables	21	25	30	30	29	26	24	33	38
Courier and Freight	20	19	23	25	28	25	24	29	33
Business Promotion	24	25	34	35	39	29	25	35	44
Total	1,192	1,142³	1,080	1,140	1,123	1,052	1,434	811	849

³ To align Schedule 5.2 of the Application, a reclass of \$8K was made between Audit/Legal Fees & Special Studies (Table 2) and Other (Table 5) for 2017, compared to Table 5.8 of the Application Narrative.

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AEY-UCG-039

**ATCO Electric Yukon (AEY)
2023-2024 General Rate Application (GRA)**

**Information Responses Round 1 to:
The Yukon Utilities Consumers' Group (UCG)
Received: September 6, 2023**

AEY-UCG-039

Reference: July 7, 2023 Application, page 5-10; Related Party Costs

AEY states: "AEY 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".

Request:

- (a) Are there additional affiliate charges that are capitalized and do not show up on the O&M schedule 5-3? Provide details of these charges for 2017 through 2024.
- (b) Are there any outbound affiliate services? If yes, where are they identified?
- (c) Please provide copies of service level agreements for all affiliate services provided to and by AEY in 2013-2015 and forecast to be provided to and by AEY over the 2023- 2024 test period.
- (d) Please provide evidence demonstrating that it is more cost-effective to procure the services for 2017-2024 from affiliates than from other sources.

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AEY-UCG-039

Response:

(a) The following table shows capitalized affiliate charges from 2017 to 2024:

**Table 1: Capitalized Affiliate Charges
(\$000)**

	2017	2018	2019	2020	2021	2022	2023	2024
	Actuals						Test Period	
Capital Management Services	3	69	89	63	42	49	50	50
THELP Atlin DG Connection	-	-	-	-	39	47	-	-
CIS replacement	-	-	-	-	23	157	210	-
Upgrade 2.5 Element Meters	-	-	-	-	-	16	-	-
Generation Integration Upgrades	-	-	-	-	-	19	-	-
Nthn Energy Cap Haeckel Wind	-	-	-	-	-	31	-	-
Total	3	69	89	63	81	552	260	50

- (b) Yes. AEY employees supported outbound affiliate initiatives in 2021 and a portion in 2022. AEY provided labour support for ATCO's project to rebuild Puerto Rico's Electrical grid (LUMA Energy) in 2021 and 2022. AEY received revenues for all costs including any overhead.
- (c) Please refer to AEY-UCG-039(c) Attachment 1.
- (d) All services provided by ATCO Electric and ATCO Gas are based on a fully allocated cost methodology. No element of profit or return is included in the costs of the services. If the services were to be procured from a third party, the costs would include an element of profit to the provider, increasing the costs to AEY.

**NORTHLAND UTILITIES (NWT) LIMITED,
NORTHLAND UTILITIES (YELLOWKNIFE) LIMITED,
THE YUKON ELECTRICAL COMPANY LIMITED (“NORTH
OF 60 COMPANIES”)
and ATCO ELECTRIC LTD. (“ATCO ELECTRIC”)**

PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES

Services Agreement # 75

As amended December 1, 2018

Schedule "A" to the Master Services Contract
PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES
dated December 1, 2011 between
North of 60 Companies and ATCO Electric
As amended December 1, 2018

SCOPE OF SERVICES

ATCO Electric will make available to North of 60 Companies the following functions and activities listed in this agreement. Services included, but not limited to:

1. Finance
2. After Hours Assistance
3. Marketing & Communications
4. Regulatory
5. Human Resources
6. Business Technology Management
7. Customer Care & Billing
8. Supply Chain
9. Project Management
10. Engineering
11. Metering
12. Governance

Schedule "B" to the Master Services Contract
PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES
dated December 1, 2011 between
North of 60 Companies and ATCO Electric
As amended December 1, 2018

TERMS AND CONDITIONS

1. Term of Contract

This amended agreement shall commence December 1, 2018 and will remain in effect in perpetuity with an annual review.

In the event that amendments are required, an amended agreement will be negotiated one month prior to the new effective date of the agreement. If either party wishes to terminate the agreement, written notice is required at least one month in advance of the termination date.

2. Cost of Service Provided

The cost of services provided by ATCO Electric to North of 60 Companies are to be recovered on a Cost Recovery Basis, as outlined in ATCO Electric Accounting Policy G.5. For services that are reoccurring a fixed fee is provided in Appendix A and will be updated on an as-needed basis.

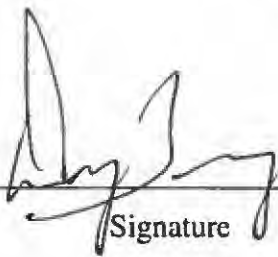
3. Billing

The Financial Services department of ATCO Electric will be responsible for allocating costs associated with this agreement through the intercompany debit note process and for providing details that support the charges. Settlement of these charges will be consistent with the normal settlement date for intercompany transactions.

Schedule "C" to the Master Services Contract
PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES
dated December 1, 2011 between
North of 60 Companies and ATCO Electric
As amended October 1, 2018

NORTH OF 60 COMPANIES' REPRESENTATIVE

Doug Tenney
Vice President, Northern Development


Signature

Nov. 23 / 18
Date

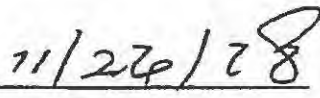
Schedule "D" to the Master Services Contract
PROJECT MANAGEMENT AND VARIOUS SUPPORT SERVICES
dated December 1, 2011 between
North of 60 Companies and ATCO Electric
As amended December 1, 2018

ATCO ELECTRIC'S REPRESENTATIVES

Karen Probert
Controller



Signature

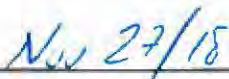


Date

Paul Goguen
Sr. VP & General Manager, Transmission & Distribution



Signature



Date

MASTER SERVICES CONTRACT

THIS MASTER SERVICES CONTRACT DATED effective the 1st day of January, 2003.

BETWEEN:

THE YUKON ELECTRICAL COMPANY LIMITED,
a body corporate,
incorporated under the laws of the Yukon,
with offices in Whitehorse, Yukon

and

NORTHLAND UTILITIES (NWT) LIMITED,
a body corporate,
incorporated under the laws of the Northwest Territories,
with offices in Hay River, Northwest Territories

and

**NORTHLAND UTILITIES (YELLOWKNIFE)
LIMITED,**
a body corporate,
incorporated under the laws of Canada,
with offices in Yellowknife, Northwest Territories

(hereinafter referred to as "**North of 60 Companies**")

- and -

ATCO GAS, an operating name of
ATCO Gas and Pipelines Limited,
with offices in Edmonton and Calgary, Alberta

(hereinafter referred to as "**ATCO Gas**")

WHEREAS North of 60 Companies desires to engage ATCO Gas to provide services as described in this Services Contract (the "Contract"), in accordance with the terms and conditions described in this Contract; and

WHEREAS ATCO Gas has the expertise and is capable of providing the services to and for North of 60 Companies as described in this Contract, in accordance with the terms and conditions described in this Contract;

THIS CONTRACT WITNESSES that in consideration of the respective covenants and agreements of North of 60 Companies and ATCO Gas (individually each a "Party" and collectively, the "Parties") contained herein, and for other good and valuable

consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties covenant and agree as follows:

1. SCHEDULES

1.1 The following Schedules are attached hereto and made a part of this Contract:

- (a) Schedule A - Scope of Services - detailing the services to be provided by ATCO Gas to North of 60 Companies pursuant to this Contract (the "Services");
- (b) Schedule B - Scope of Terms – detailing, if applicable:
 - (i) the date, if any, set for commencement of the Services by ATCO Gas (the "Commencement Date");
 - (ii) the schedule, if any, set for performance of the Services by ATCO Gas;
 - (iii) the date, if any, set for completion of the Services by ATCO Gas (the "Completion Date");
 - (iv) the term, if any, of the duration for which the Services will be provided by ATCO Gas (the "Term");
 - (v) the compensation to be paid by North of 60 Companies to ATCO Gas;
 - (vi) any categories of out-of-pocket expenses for which reimbursement will be payable from North of 60 Companies to ATCO Gas in accordance with Section 5.1 herein;
 - (vii) any invoice requirements or provisions desired by the Parties in supplement to Article 6 herein; and
 - (viii) any other supplemental provisions or agreements desired by the Parties to form part of this Contract.
- (c) Schedule C - North of 60 Companies' Representative
- (d) Schedule D - ATCO Gas' Representative

1.2 In case of a conflict between this main body of this Contract and the Schedules, this main body of this Contract shall govern.

2. THE SERVICES

- 2.1** North of 60 Companies hereby engages ATCO Gas, and ATCO Gas hereby agrees to provide the Services on the terms and conditions set forth herein.
- 2.2** ATCO Gas shall furnish all personnel, materials, and supervision necessary for successful performance of the Services, at ATCO Gas' own expense, subject to Section 5.1 herein providing for reimbursement for certain identified categories of expenses.
- 2.3** Any material amendments to the Services shall be made in accordance with Section 22.3 of this Contract.
- 2.4** ATCO Gas shall periodically, but no more frequently than monthly, furnish to North of 60 Companies written progress reports, when and as requested by North of 60 Companies.

3. TIME OF PERFORMANCE

- 3.1** ATCO Gas shall commence the Services on the Commencement Date if any such date is set forth in Schedule B. ATCO Gas shall perform the Services with due diligence and dispatch or as otherwise expressly provided in Schedule B.
- 3.2** ATCO Gas shall complete the Services by the Completion Date, or by the end of the Term, if any such date or time period is set forth in Schedule B. If ATCO Gas determines that it will be unable to complete the Services within any such time schedule, it will promptly so notify North of 60 Companies in writing.
- 3.3** Should ATCO Gas, with the prior written authorization of North of 60 Companies, continue to provide services beyond the end of the stated Completion Date or Term of this Contract in order to complete a project, then the Completion Date or Term shall be automatically extended by an additional one month, extendable month to month thereafter.

4. COMPENSATION

- 4.1** As full consideration for performance of the Services, North of 60 Companies will pay ATCO Gas in accordance with the terms detailed in Schedule B.
- 4.2** In accordance with Articles 8 and 9 herein, compensation from North of 60 Companies shall be payable without deduction, including, without limitation, no deductions for federal income taxes, employment insurance, Canada pension plan, or provincial income taxes, all of which shall be the responsibility of ATCO Gas.

5. EXPENSES

- 5.1** In accordance with Schedule B, ATCO Gas may also be entitled to be reimbursed by North of 60 Companies for reasonable out-of-pocket expenses incurred by ATCO Gas in the performance of the Services and recognized in Schedule B as belonging to certain identified categories of reimbursable expenses. In accordance with Section 6.2 herein, ATCO Gas is required to submit itemized requests for reimbursement of such expenditures supported by sufficient documentation of the expenditures and explanation of their purpose.
- 5.2** Any Goods and Services Tax ("G.S.T.") which is applicable to ATCO Gas' reimbursable expenses shall be identified separately as a part of all invoices submitted by ATCO Gas.

6. INVOICING AND PAYMENT

- 6.1** ATCO Gas shall present on or before the 5th day of each calendar month, or at such other times and for such other periods as may be determined in Schedule B, an original invoice(s) for any monies owed by North of 60 Companies for the immediately prior month for Services provided pursuant to this Contract.
- 6.2** For reimbursement for reasonable pre-approved out-of-pocket expenses as described in Section 5.1 herein, invoices must be submitted with a complete statement of costs actually incurred during the preceding calendar month, and with back-up documents necessary to support the expenditures listed in ATCO Gas' statement.
- 6.3** All invoices shall provide a G.S.T. registration number, and identify the total amount of G.S.T. included in the invoice. In the event that ATCO Gas does not invoice North of 60 Companies for G.S.T., ATCO Gas shall indicate on the invoice the basis upon which ATCO Gas claims exemption from the statutory obligation to collect G.S.T.
- 6.4** All invoices shall be provided in accordance with Section 21.2 herein.
- 6.5** All payments are due and payable by North of 60 Companies **twenty-five (25)** days after receipt in North of 60 Companies' offices of the invoice and any substantiating documentation required by this Contract. If North of 60 Companies has any objection to the invoice or substantiating documentation, it shall notify ATCO Gas within 15 days of receipt of the invoice. Interest on overdue amounts shall be due and payable by North of 60 Companies to ATCO Gas at a rate of Prime plus 2 % percent per annum from the date on which payment was due until the date of payment, inclusive. "Prime" means the Bank of Montreal prime lending rate for demand loans made in Canadian funds to Canadian customers. North of 60 Companies shall be entitled to set off any mutually agreed upon amount owed by ATCO Gas to North of 60 Companies against any amount owing

to ATCO Gas. Notwithstanding any such set-off, separate invoices of each transaction shall be provided to the other Party.

7. AUDIT

- 7.1** This Article 7 shall only apply in the event compensation paid by North of 60 Companies under this Contract is based on ATCO Gas' costs.
- 7.2** ATCO Gas shall keep and maintain complete and accurate records of costs incurred for the subject Services, and maintain books and accounts in accordance with generally accepted accounting principles and practices respecting all matters pertinent to this Contract or to the Services for the longer of (a) 2 years following the date of termination of this Contract; or (b) such time period required by statute.
- 7.3** North of 60 Companies, upon providing written notice to ATCO Gas, shall have access to and the right to audit, during business hours and for a maximum of a two (2) year period following total completion of the Services, all files, data, correspondence, books, and accounting records relating in any way to the Services. ATCO Gas shall preserve all of its relevant documents during the aforementioned period, and shall make them readily available to North of 60 Companies and its authorized representatives, and shall also make available those employees or sub-contractors of ATCO Gas reasonably required to supply desired information during the audit.
- 7.4** North of 60 Companies will notify ATCO Gas in writing of any erroneous statements made by, or payments made to, ATCO Gas. Subject to ATCO Gas' right to have the matter determined in accordance with Article 27 herein, ATCO Gas will promptly make appropriate adjustments and ATCO Gas shall reimburse North of 60 Companies for any amounts of overpayments still outstanding as reflected by said adjustments, notwithstanding that a temporary withholding may have been effected pursuant to this Contract.
- 7.5** ATCO Gas shall use reasonable efforts to cause any of its sub-contractors to allow North of 60 Companies to carry out audits of the books, records, and accounts of such sub-contractors relating to the Services in accordance with the forgoing provisions of this Article 7 herein.

8. INDEPENDENT CONTRACTOR

- 8.1** In the performance of the Services, ATCO Gas is an independent contractor and not an employee, in particular, but without limitation, for the purposes of the Income Tax Act, the Workers' Compensation Act and other applicable labour legislation. Nothing contained in this Contract shall be regarded or construed as creating any further relationship (such as employer and employee, joint venture, association, or partnership) between the Parties.

- 8.2** All persons employed by ATCO Gas in connection with the Services shall be ATCO Gas' employees and not employees of North of 60 Companies in any respect.
- 8.3** Neither Party shall enter into any contract or commitment in the name of or on behalf of the other Party and nothing in this Contract shall constitute or deem one Party as the agent of the other Party.

9. WORKERS' COMPENSATION AND OTHER CONTRIBUTIONS

- 9.1** ATCO Gas shall promptly pay or cause to be paid, and North of 60 Companies shall not be responsible for, any assessment or contribution required to be paid in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed.
- 9.2** Before commencement of the Services, ATCO Gas will, if requested by North of 60 Companies deliver to North of 60 Companies certificates from the relevant Workers' Compensation Boards or Commissions, as the case may be, that all required assessments and contributions have been paid by ATCO Gas and its sub-contractors. Before the final payment owed under this Contract is made by North of 60 Companies, North of 60 Companies may request that ATCO Gas deliver to North of 60 Companies similar certificates with ATCO Gas' application for final payment from North of 60 Companies.
- 9.3** North of 60 Companies may, in addition to any other rights reserved to it under this Contract, withhold from compensation to be paid to ATCO Gas the amount, if any, of ATCO Gas' required assessment or contribution in connection with the Services pursuant to the Workers' Compensation Act (or equivalent) in each province or jurisdiction in which the Services are performed, where North of 60 Companies, in its sole discretion, determines that such amounts may be assessed against North of 60 Companies. Any such withholding or deduction shall not be construed as an admission by North of 60 Companies that ATCO Gas in performing the Services is an employee of North of 60 Companies. North of 60 Companies will assist ATCO Gas in defending any claims against ATCO Gas in the event that ATCO Gas disputes such claims.
- 9.4** In the event that North of 60 Companies does not deduct and maintain an amount sufficient to provide for ATCO Gas' required assessments or contributions as specified in Section 9.3 herein, ATCO Gas shall indemnify and save harmless North of 60 Companies for any amounts assessed against and paid by North of 60 Companies as a result of failure by ATCO Gas to comply with the provisions of this part of the Contract or any such Workers' Compensation legislation.
- 9.5** ATCO Gas shall pay or cause to be paid, and North of 60 Companies shall not be responsible for, any required or assessed contributions or payments to or for the Canada Pension Plan, employment insurance, federal or provincial withholding

taxes, or any other contributions or benefits that might be expected in an employer-employee relationship, for ATCO Gas' employees and ATCO Gas.

10. LIABILITY AND INDEMNIFICATION

10.1 ATCO Gas shall:

- (a) be liable to North of 60 Companies for all losses, costs, damages, and expenses whatsoever which North of 60 Companies and North of 60 Companies' directors, officers, agents, and employees, (collectively, the "Indemnified Parties") may suffer, sustain, pay, or incur; and
- (b) indemnify and save harmless the Indemnified Parties against and from all actions, proceedings, claims, demands, losses, costs, damages, and expenses whatsoever which may be brought or made against or suffered by the Indemnified Parties, or which the Indemnified Parties may sustain, pay, or incur;

as a result of ATCO Gas' negligence or wilful acts or omissions but excluding such actions, proceedings, claims, demands, losses, costs, damages and expenses to the extent that they are sustained, paid, or incurred by reason of or are otherwise attributable to

- (c) the negligence or wilful acts or omissions of the Indemnified Parties while not acting under the direction or control of ATCO Gas or its employees or sub-contractors; or
- (d) ATCO Gas while under the direction of the Indemnified Parties.

10.2 ATCO Gas shall not be liable for any of the Indemnified Parties' indirect or consequential damages, except to the extent that such damages are recoverable under any applicable insurance coverage.

11. INSURANCE

11.1 Without in any way limiting the liability of ATCO Gas under this Contract, it shall be the responsibility of ATCO Gas while this Contract is in effect to maintain and keep in force and good standing the following insurance coverage:

- (a) **Automobile Liability Insurance** - covering all vehicles used for operations in any way connected with the Services, including owned, non-owned, and hired vehicles. The limits of such coverage shall not be less than, for bodily injury (including passenger hazard) and property damage, \$2,000,000 inclusive, any one accident, or equivalent limits.
- (b) **Comprehensive General Liability Insurance** - covering all operations in any way connected with the Services, including employers' liability,

owners' and contractors' protective liability, contractual liability assumed by ATCO Gas under this Contract, and products/completed operations liability. The limits of such coverage shall not be less than, for bodily injury and property damage, \$5,000,000 inclusive, any one occurrence, or equivalent limits.

- (c) Such other insurance as may from time to time be required by law or reasonably required by North of 60 Companies.

- 11.2 ATCO Gas, or contractors engaged in the provision of the Services, shall provide North of 60 Companies with 30 days prior written notice of any material changes, proposed cancellation or reduction in coverage, or proposed lapse of their respective insurance policies.
- 11.3 ATCO Gas shall require all of its sub-contractors to obtain, maintain, and keep in force and good standing, during the time in which they are engaging in performing the Services, all required insurance coverage
- 11.4 Upon request by North of 60 Companies, ATCO Gas shall, before commencement of the Services, deposit with North of 60 Companies information satisfactory to North of 60 Companies as evidence of the insurance required in Sections 11.1 and 11.2 herein.

12. COMPLIANCE WITH LAW AND POLICY

- 12.1 The Parties hereto and their employees and sub-contractors shall observe and comply with all applicable laws, ordinances, codes, and regulations of governmental agencies, including federal, provincial, municipal, and local governing bodies having or asserting jurisdiction in respect of this Contract, the Services, or any part thereof. All Services performed by ATCO Gas must be in accordance with such laws, ordinances, codes, and regulations.
- 12.2 ATCO Gas and its employees and sub-contractors shall observe and comply with all rules, regulations, policies, advice, and directives of North of 60 Companies from time to time in force which are brought to ATCO Gas' notice and which are not contrary to law or the provisions of this Contract.
- 12.3 ATCO Gas shall promptly notify North of 60 Companies in writing upon discovery of any failure to comply with such laws, ordinances, codes, regulations, policies, advice, or directives.
- 12.4 Unless otherwise specified in this Contract and subject to Section 5.1 herein, ATCO Gas shall obtain and pay for all permits, licenses, and approvals required for the provision of the Services.

13. PUBLICITY RELEASE

- 13.1** ATCO Gas shall not, without the prior written consent of North of 60 Companies, use North of 60 Companies', name in advertising, publicity releases, or any other form of promotional material relating to this Contract, the Services to be performed, or the results thereof, except to the extent that such information is in the public domain.

14. CONFIDENTIAL INFORMATION

- 14.1** The term "Confidential Information" shall mean all confidential information of or relating to North of 60 Companies or its business or its customers and shall include without limitation all information which ATCO Gas or its employees or sub-contractors, directly or indirectly, receives or acquires from North of 60 Companies either in writing, orally, or through observation, or which ATCO Gas or its employees or sub-contractors develops in connection with this Contract or the Services, and shall include, but shall not be limited to, all business plans and information, customer information, software, source code, inventions (whether patentable or not), technical information, process and apparatus designs, design calculation, drawings, engineering appraisals and studies, data reports, flow sheets, plans, sketches, surveys, field notes, and design concepts, but shall not include information falling into any one of the following categories:

- (a) information which was in the possession of ATCO Gas or its employees or sub-contractors, reasonable proof of which lies on ATCO Gas, prior to receipt or acquisition thereof from North of 60 Companies and which was not acquired by ATCO Gas or its employees or sub-contractors under any obligation of confidentiality;
- (b) information which, at the time of the receipt or acquisition thereof by ATCO Gas or its employees or sub-contractors from ATCO Gas was or thereafter became a part of the public domain through no act or failure on the part of ATCO Gas or its employees or sub-contractors nor on the part of any third party under an obligation of confidentiality with respect to such information; and
- (c) information which is disclosed to ATCO Gas or its employees or sub-contractors by a third party without a covenant of confidentiality, provided such third party is under no obligation of confidentiality to North of 60 Companies with respect to such information.

- 14.2** ATCO Gas and its employees and sub-contractors shall, unless expressly otherwise permitted or requested by North of 60 Companies in writing, hold all Confidential Information in the strictest of confidence at all times and shall take all necessary precautions necessary to maintain such confidence, and shall not use (except in ATCO Gas' performance of the Services) or disclose to any third party

(except as required to be disclosed by operation of law) such Confidential Information, provided that ATCO Gas may disclose such Confidential Information to those of ATCO Gas' employees or sub-contractors to whom disclosure is required for ATCO Gas' performance of the Services, but only after such employee or sub-contractor has agreed to assume obligations identical in principle with those which ATCO Gas has assumed in this Article 14, and ATCO Gas shall ensure that all employees and sub-contractors at all times comply with such obligations.

14.3 North of 60 Companies shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 14 without the requirement of posting a bond or proof of actual damage.

14.4 The terms of this Article 14 shall apply, mutatis mutandis, to North of 60 Companies' treatment of Confidential Information of or relating to ATCO Gas.

15. INTELLECTUAL PROPERTY

15.1 For the purposes of this Contract, "Intellectual Property" means

- (a) all inventions, whether or not patentable,
- (b) all applications for patent, registration, inventor certificate or like protection now existing, or filed in the future for inventions,
- (c) all patents, registrations, inventor certificates or like protection presently issued, issued in the future, re-issued or extended in any way, for inventions, including, but not limited to, divisions or divisionals, continuations, continuations-in-part, supplemental disclosures, re-issues and re-examinations, and
- (d) all other intellectual property rights anywhere in the world, including without limitation, all copyrights, trademarks, service marks, trade secrets, industrial designs, integrated circuit topographies and all rights in any matured cause of action related thereto in Canada and throughout the World.

15.2 All Intellectual Property made or conceived by ATCO Gas, its employees or sub-contractors:

- (a) in the course of providing the Services;
- (b) during the Term and which relates in any manner to the business of North of 60 Companies;
- (c) made with or which arises with the use of the materials, equipment or resources of North of 60 Companies; and

- (d) which are improvements or enhancements on or relating in any way to the Confidential Information or the intellectual property defined in this Article 15;

shall be the exclusive property of ATCO Gas.

- 15.3 ATCO Gas shall have the right to obtain injunctive relief to prevent any violation or further violation of the terms of this Article 15 without the requirement of posting a bond or proof of actual damage.

16. ASSIGNMENT

- 16.1 With the exception of the subcontracting of Services in the normal course of business, neither Party shall sell, assign or transfer this Contract or subcontract any part this Contract (except for the delivery of materials) without the prior written consent of the other Party, such consent not to be unreasonably withheld. Such consent shall not release or relieve either Party from any of its obligations or liabilities under this Contract. Any such assignment or delegation by a Party without such consent from the other Party will be void.

17. FORCE MAJEURE

- 17.1 For the purposes of this Contract "Force Majeure" means any acts of God, including therein, but without restricting the generality thereof, lightning, earthquakes and storms, and, in addition, shall mean any strikes, lockouts or other industrial disturbances, acts of the Queen's enemy, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, floods, fires, washouts, arrests and restraints, civil disturbances, explosions, breakages of or accidents to machinery, the orders of any court or governmental authority, or any other causes, excepting financial, whether of the character or kind herein enumerated or otherwise, and not within the control of the Party claiming suspension and whether or not arising out of or resulting from an event, cause or occurrence under this Contract or otherwise, which, by the exercise of due diligence, such Party could not have prevented or is unable to overcome.
- 17.2 Delay in or failure of performance by either of the Parties under this Contract shall not constitute default under this Contract, or give rise to any claim for damages, if and to the extent that such delays or failure are caused by an event of Force Majeure.
- 17.3 In the event that performance of the Service or this Contract is in the reasonable opinion of either of the Parties made impossible by Force Majeure, then such Party shall if at all possible so notify the other in writing, and North of 60 Companies shall either:
 - (a) terminate this Contract, or

- (b) authorize ATCO Gas to complete the performance of the Services with such adjustments as are required by the existence of the force majeure and are agreed upon by the Parties.

18. TERMINATION

- 18.1 In the event that either Party violates, or is in breach of, their obligations under this Contract or the terms herein or otherwise fails to perform the Services in accordance with the terms herein, the other Party shall provide written notice of said violation, breach or non-performance. If, within five (5) days of receipt of written notice, such Party fails to correct the deficiency, the other Party shall have the right to immediately terminate this Contract.
- 18.2 In the event of termination pursuant to this Article 18, ATCO Gas shall only be entitled to receive such remuneration as is owing up to the date of termination, including any obligations to third parties made in order to permit ATCO Gas to carry out its duties under this Contract. North of 60 Companies shall not be liable for damages or loss of anticipated profits on account of such termination.

19. REMEDIAL WORK

- 19.1 ATCO Gas shall after receipt of notice from North of 60 Companies, at North of 60 Companies' option and at no cost to North of 60 Companies, without prejudice to any other right that North of 60 Companies might have, provide such services as may be necessary to remedy any defect caused by the performance, purported performance, or non-performance by ATCO Gas in carrying out the Services pursuant to this Contract (the "Remedial Work") in accordance with the service standards and specifications agreed upon by the Parties. North of 60 Companies reserves the right to complete such remedial work or have such remedial work completed by other parties but at ATCO Gas' expense, in the event ATCO Gas fails to complete the Remedial Work as soon as reasonably possible after receiving written notice from North of 60 Companies.

20. WAIVER

- 20.1 Failure of either of the Parties to insist upon strict compliance with any of the terms, covenants, and conditions in this Contract shall not be deemed a waiver or relinquishment of any similar right or power hereunder at any subsequent time or of any other provision herein.

21. REPRESENTATIVES AND NOTICES

- 21.1 North of 60 Companies' representative, who has full authority to represent North of 60 Companies in administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "C", attached hereto.

ATCO Gas' representative, who has full authority to represent ATCO Gas in

administering this Contract and agreeing to any amendments thereto, is as indicated in Schedule "D", attached hereto.

- 21.2** Unless otherwise specified in this Contract, any notice required or permitted to be given under this Contract shall be sufficient and effective if in writing and if sent by facsimile, mail, or personally delivered to the Party to whom notice should be given at that Party's respective address as follows:

North of 60 Companies: See **ATCO Gas:** See Schedule "D"
Schedule "C"

- 21.3** Unless otherwise specified in this Contract, notice shall be deemed effective upon receipt if made by personal delivery; three (3) days following deposit with Canada Post if sent by mail, and, upon receipt of a facsimile confirmation if sent by facsimile.

22. ENTIRETY OF AGREEMENT

- 22.1** This Contract contains the entire understanding and agreement between the Parties. All previous proposals and communications relative to the services to be provided under this Contract, oral or written, are hereby superceded, except to the extent that they have been expressly incorporated into this Contract.
- 22.2** There is no representation, warranty, collateral term, or condition affecting this Contract for which either Party can be held responsible in any way, whether they be contained in any material or alleged against and director, officer, agent, or employee of either Party, other than as expressed in this Contract in writing. The representations, warranties, terms, and conditions expressed in writing in this Contract shall be paramount, and no action in tort, under any statute or in equity, relating to any other representation, warranty, collateral term, or condition affecting this Contract, or made prior to the execution of this Contract, but not expressed in writing in this Contract, shall be brought by either Party against the other Party. The Parties confirm that their rights, obligations, remedies, rights of indemnity, and measure of damages in the event of a breach, are limited to those conferred by or arising out of this Contract.
- 22.3** No amendment to this Contract shall be binding unless made in writing and signed by both Parties.

23. SEVERABILITY

- 23.1** Any invalid or unenforceable provision of this Contract, whether prohibited by any applicable law, by-law, or regulation of any appropriate or relevant governmental authority, or held to be unenforceable, invalid, or illegal by any court of competent jurisdiction, or invalid or unenforceable for any other reason, shall be ineffective to the extent of such invalidity or unenforceability without

affecting any other provisions of this Contract, and this Contract shall be construed as though such invalid or unenforceable provision were omitted.

24. SURVIVAL OF TERMS

24.1 The provisions of this Contract respecting audit (Article 7 herein), indemnity for Workers' Compensation and other contributions (Article 9 herein), liability and indemnification (Article 10 herein), publicity release (Article 13 herein), confidential information (Article 14 herein), Intellectual Property (Article 15 herein), remedial work (Article 19 herein), and all obligations which have accrued hereunder prior to the termination of this Contract, shall survive the Completion Date, the date of actual completion of the Services if different from the Completion Date, the end of the Term of this Contract, and any termination of this Contract.

25. GOVERNING LAW

25.1 The validity and interpretation of this Contract, the legal relations of the Parties, and the conflict of laws rules to determine the system of law governing this Contract shall be governed by and construed in accordance with the laws in force from time to time in the Province of Alberta and the federal laws of Canada applicable therein.

25.2 The Courts of the Province of Alberta and any Court of Appeal therefrom shall have exclusive jurisdiction to determine all matters in dispute hereunder, and the Parties hereby attorn to the jurisdiction of such Courts.

26. INTERPRETATION

26.1 Title headings contained in this Contract are for convenience and reference only, and are not to be construed as limiting or extending the meaning of any of the provisions herein.

26.2 In this Contract, words importing the singular number shall include the plural and vice versa, words importing masculine gender shall include the feminine and neuter and vice versa, and words importing a person or Party shall include individuals, partnerships, firms, associations, corporations, joint ventures, trusts, or other entities, as the context or reference to the Parties requires.

26.3 Where reference is made in this Contract to "North of 60 Companies' affiliates", such reference shall be meant to include:

- (a) an Affiliate, within the meaning of the *Business Corporations Act*, of North of 60 Companies; and

- (b) a partnership, joint venture, or person in which North of 60 Companies has a controlling interest or that is otherwise subject to the control of North of 60 Companies.

27. DISPUTE RESOLUTION

27.1 The Parties shall resolve any dispute between them concerning the Contract or its interpretation firstly by negotiation between the respective Presidents of North of 60 Companies and ATCO Gas.

27.2 If such dispute is not resolved pursuant to Section 27.1 above, then upon mutual agreement, the Parties may submit the dispute to arbitration pursuant to the *Arbitration Act* of Alberta.

27.3 In the event that:

- (a) such dispute is not resolved pursuant to Section 27.2 above; or
- (b) the Parties do not agree to submit the dispute to arbitration;

then either Party may pursue any other remedy available at law to resolve such dispute.

28. GENERAL PROVISIONS

28.1 The Parties agree to perform any further acts and to execute and deliver any further documents which may be necessary or appropriate to carry out the purposes of this Contract.

28.2 All amounts quoted in this Contract shall be payable in Canadian funds, unless expressly stated otherwise.

28.3 This Contract shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

28.4 Time is of the essence in the performance of every obligation of this Contract.

28.5 This Contract may be executed in any number of counterparts, each of which when so executed shall be deemed an original, and all of which together shall constitute one and the same contract.

IN WITNESS WHEREOF the Parties have duly executed this Contract with effect from the date and year first above written.

North of 60 Companies

ATCO Gas

Per: RH Whithell

Name: RH Whithell

Per: [Signature]

Name: Paul Goggin

Per: [Signature]

Name: James Enyik

Per: [Signature]

Name: Marcel Boen