IN THE MATTER OF YUKON ENERGY CORPORATION 2023-2024 GENERAL RATE APPLICATION TO THE YUKON UTILITIES BOARD

FINAL ARGUMENT

YUKON ENERGY CORPORATION

March 22, 2024

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PREFACE

OVERVIEW OF YUKON ENERGY APPLICATION

The Application was submitted to the Board on August 31, 2023 (Exhibit 1) for adjustments to Yukon Energy's (YEC) revenue requirements, rates and other related matters as required to recover YEC's forecast costs to supply customers in 2023 and 2024 test years and to plan for future requirements thereafter.

Yukon Energy's 2023/24 Application filed in August 2023 seeks approval of the forecast revenue requirement of $81.440 million for 2023 and $90.425 million for 2024, including approval, as required, of costs, revenues and other related provisions as outlined in the Application. YEC's Application also includes requests for regulatory approvals for a new IPP Purchase Cost Deferral Account, and for a change in Rate Schedule 39 Fixed Charge assigned to industrial customers that use the Mayo-Keno transmission facilities.

Board Order 2023-23 approved an interim refundable rate adjustment rider increase of 10% (Rider J) effective January 1, 2024, to coincide with removal of the Rider F charge, as well as separate interim refundable Fixed Charge amounts for VCG Group and for Hecla Yukon (previously Alexco). To mitigate customer bill impacts, YEC seeks approval of final 2023/24 GRA rates effective August 1, 2024, to coincide with removal of YEC's 2021 GRA true-up rider.

OUTLINE OF YUKON ENERGY FINAL ARGUMENT

Yukon Energy's Final Argument outlines the record content that supports the requested Orders, focusing on the extensive evidence examined within the scope of the Board's review of the Application. It includes the following major sections:

- **Part 1 – Introduction:** Part 1 of the Final Argument restates the key factors driving YEC's 2023-24 revenue requirement, addressing, at a high level, the core elements of the overall Application as submitted, updated and reviewed during the hearing process. This includes matters addressed in the Application (pages 1 to 9) and Supporting Tab 1, information requests (IRs), the Opening Statement (Exhibit 10) and the undertakings. Part 1 also summarizes the updates that YEC has made to the Application; and it also provides preliminary comments on the appropriateness of YEC's requests for previously disallowed capital costs to be added to rate base commencing in the 2023 test year (as addressed in more detail in Part 2).
- **Part 2 - Response to Key Issues Raised:** Part 2 of the Final Argument responds to key issues raised by the Board and intervenors in Intervenor Evidence, information requests

(IRs) and the oral hearing, and provides transcript and undertaking references containing more detailed information on these issues. This includes three sections addressing the key issues relating to Tabs 2, 3 and 5 of the Application (Section 1.0: Tab 2 - Sales & Generation; Section 2.0: Tab 3 - Revenue Requirement; and Section 3.0: Tab 5 - Capital Projects), and a fourth section addressing other issues raised in the course of the proceeding (Section 4.0 – Other Matters).

In the above noted sections of Part 2, Yukon Energy aims to address the main concerns arising from the Board's interrogatories and/or from the cross-examination of YEC's panel by the Board, its counsel, and its technical consultant at the hearing, as well as concerns raised by intervenors to the extent that they are relevant to the matters properly in issue before the Board in this proceeding. Yukon Energy submits, however, that the commentary and supporting evidence it has already submitted in the proceeding, including its filed Application, the answers to the many interrogatories, and the other evidence submitted (including responses to undertakings) provide a complete answer to all such concerns, and fully support the reasonableness and necessity of the proposed revenue requirement. Further, no evidence-based contrary position has been tendered by any party.

Accordingly, Yukon Energy submits that all evidence necessary for the Board to address the Orders requested is in the record.

PART 1: INTRODUCTION

1.0 FACTORS DRIVING THE 2023-24 REVENUE REQUIREMENT INCREASE

The Application as filed in August 2023 forecast a cumulative required rate increase of 14.11% to recover forecast revenue shortfalls. Without this General Rate Application (GRA), YEC's return on equity (ROE) is forecast at 5.56% for 2023 and at only 0.18% for 2024 (Application, Table 1-2 and page 1-2, line 26).

YEC's forecast revenue shortfall is driven by material increased costs and growing load on the Yukon Integrated System (YIS) as described in Tab 1 of the Application (Section 1.2) and YEC's Opening Statement (Exhibit 10). For example, increased capital rate base costs account for $6.004 million (39.1%) of the 2024 revenue shortfall through higher depreciation, interest and equity return costs.[1] This rate base increase reflects different drivers as summarized below. Diesel rental costs to address peak load growth account for $3.269 million (21.3% of the 2024 revenue shortfall increase). Other non-fuel cost increases to address increasing requirements relate to labour O&M ($3.063 million, 20.0%) and other non-labour O&M ($2.577 million,16.8%).

Drivers of 2023 and 2024 Rate Increases

The key factors contributing to the increased costs forecast in the Application, and driving the need for YEC's proposed rates include: (i) steady growth in peak electricity demand, (ii) the need to upgrade or replace aging generation, transmission and distribution infrastructure, (iii) transition from reliance on fossil fuels in Yukon's heating and transportation sectors to clean energy alternatives, and (iv) the impact of rising costs and project complexity.

- **Growth in winter peak electricity demand:** Yukon is experiencing faster growth than any other province or territory in Canada, particularly with respect to winter peak electricity demand. This growth drives costs related to ensuring an adequate supply of dependable capacity resources to meet peak demands for power during normal operating conditions and emergencies, such as diesel rentals and capital cost rate base additions (e.g., Thermal Replacement (Faro diesels), Mayo-Faro Diesel Infrastructure, Whitehorse Interconnection, and DSM deferred cost programs related to reducing dependable capacity requirements).

- **Aging infrastructure**: Upgrading and replacing existing electricity assets, while at the same time renewing licences and permits for YEC's existing generation facilities, is critical to ensuring YEC's ability to continue to provide Yukoners with the electricity they need today while building and connecting the new sources of electricity needed in the future. This cost driver is reflected in capital cost rate base additions, costs for overhauls, and deferred cost rate base additions (e.g., relicensing projects), as well as intangible asset rate base additions (EAM and PAMMS).

- **Energy transition:** Yukon's electricity system is in a state of transformation with rapid changes to the way Yukoners both consume and produce electricity. Investments in

[1] Shows cost increase before considering changes to long-term debt cost (rate change) or return on equity (ROE) as noted in Table 1-2 of Application.

smart programs and technologies, including demand-side management (DSM) programs, are needed to better manage and shift system peaks when products like electric vehicle chargers, electric baseboards and water heaters, and heat pumps are used.[2] The transformation of Yukon's electricity system is also reflected in IPP cost changes, as well as capital cost rate base additions for previously disallowed costs for the WH2 Uprate and WH4 Servomotor Replacement projects.

- **Rising costs and project complexity:** More resources are required to direct, plan, execute and oversee the way Yukon Energy does business, to meet the needs of larger projects both in terms of project scope and expenditure, to pursue more projects to connect new customer extensions and distributed energy sources to the grid, and to meet greater stakeholder expectations and involvement in the way YEC's work is done. This includes consideration of inflation, rate changes for fuel prices, long term debt costs, diesel rental costs, and non-fuel O&M cost increase. The complex environment YEC operates in also requires additional staff to plan, deliver and oversee more complex projects with multiple groups of rightsholders and stakeholders; to address increased maintenance, environmental monitoring and compliance needs; and to strengthen strategic planning and communications with all levels of government through the energy transition. Accordingly, YEC's proposed rates also reflect an increase in 2024 staff positions compared with 2021 approved (19 FTEs) and forecast vacancies (9 FTEs), as well as rising labour costs (4.5% escalation in 2023 and 3% in 2024 labour rates in the Application).

In summary, the 2023/24 GRA revenue and rate requirements address specific growth in capital and operation components needed for cost-effective and reliable service.

2.0 UPDATES SINCE AUGUST 2023 APPLICATION FILING

YEC has provided updates to Application forecasts in the course of responding to information requests (IRs), in its Opening Statement, and in its responses to cross-examination during the oral hearing, with further details provided in the undertaking responses.

YEC's applied-for revenue requirement is based on forecasts for the 2023 and 2024 test years. No applied-for revenue requirement updates or changes have been provided regarding forecast sales or firm generation requirements, fuel prices, or non-fuel operating and maintenance expenses (e.g., forecast labour expenses are not adjusted for updates confirming hiring for positions and/or actual vacancy rates, and no revenue requirement updates are provided for forecast rented diesel expenses).

As reviewed in response to Undertaking #23, YEC proposes changes to the Application forecasts to address IPP project generation forecast updates, major capital project (i.e., over $1 million cost) updates affecting forecast in-service dates (i.e., deferral from 2023 to 2024, or deferral beyond 2024 and therefore remaining in WIP during the test years), a few specific major capital

[2] For example, during the oral hearing, Ms. Cunha provided the following evidence: "Yukon Government's Our Clean Futures strategy that was released, and the Yukon Government has set a target that by 2030, the Yukon will meet 50 percent of its heating needs with renewable energy. So that's an indication of where Yukon Government set its goals for renewable energy to be used for heat" (March 4, 2024 Transcript, page 111, line 23 - page 112, line 4).

project cost updates, and overhaul project updates. These updates are addressed as relevant in the corresponding sections of Part 2 of this Final Argument. YEC notes that capital spending forecast updates for test years will be affected by new project additions as well as project deferrals, that consideration of new project additions is typically not feasible during a GRA proceeding, and that these factors support focusing capital project updates only on major projects with costs exceeding $1 million.

The evidence also identifies the need for an update to the proposed return on equity (ROE) to reflect the BCUC update to its benchmark utility ROE (i.e., an increase from 8.75% assumed in YEC's Application to 9.65%). As reviewed below in section 2.4.1 of Part 2 (Return on Equity), final Board determination of the updated ROE for each Yukon electric utility will depend on the Board's determinations in the ATCO Electric Yukon (AEY) 2023-2024 GRA proceeding that was concluded in late 2023. YEC has reviewed the parameters relevant to determining the updated ROE for YEC, but is not able to propose a specific updated ROE number prior to Board determination of the AEY ROE. Accordingly, overall updating of the Application revenue requirement and rate increases beyond updates addressed in Undertaking #23 must by necessity be deferred to the compliance filing to be prepared after the Board's decision on the Application.

3.0 APPROPRIATENESS OF PREVIOUSLY DISALLOWED CAPITAL COSTS

In this GRA, YEC is seeking capital cost rate base additions for three projects that previously had some or all of their costs disallowed by the Board in the 2021 GRA: the WH2 Uprate Project, the WH4 Servomotor Replacement Project, and the EAM Project. The Board previously disallowed costs for these three projects because of the insufficiency of the business case evidence that YEC presented in the 2021 GRA proceeding.

As outlined previously in YEC's IR responses[3] and addressed further in section 3.0 of Part 2 below, seeking capital cost rate base additions for the previously disallowed costs of these three projects does not constitute retroactive ratemaking. YEC is not requesting recovery of depreciation or return for previously disallowed costs for any of these projects prior to December 31, 2022; it is only seeking recovery on a prospective basis, commencing January 1, 2023, at the start of the test years for this GRA.

Regardless of the findings made in the 2021 GRA decision, it is the Board's obligation in the this proceeding to evaluate whether the capital costs of these projects are prudent and reasonably incurred in light of the fuller and more comprehensive body of supporting evidence that YEC has now put forward. If the Board is satisfied that YEC has presented sufficient evidence to meet that test, then the previously disallowed costs for these three projects must be included in rate base effective January 1, 2023.[4]

[3] YUB-YEC-1-4(e) (Exhibit 2, PDF p. 229); YUB-YEC-1-80(e) (Exhibit 2, PDF p. 556).
[4] See also: YUB-YEC-1-4(a) (Exhibit 2, PDF pp. 227-228); YUB-YEC-1-80(a) (Exhibit 2, PDF pp. 554-555).

PART 2: RESPONSE TO KEY ISSUES RAISED

Part 2 provides Yukon Energy's responses to key issues raised by the Board and intervenors in Intervenor Evidence, IRs and at the oral hearing, and provides IR or transcript references containing more detailed information on these issues. This follows the outline of the Application's supporting information (tabs), focusing on Tabs 2, 3, and 5.

1.0 TAB 2 - SALES & GENERATION

Tab 2 reviews changes in YEC grid sales and generation for 2023 and 2024 compared to 2021 grid sales and generation forecasts approved by the Board for the 2021 GRA. Details for the load forecasts and generation forecasts in the Application were also summarized in the response to UCG-YEC-1-19, and YEC's Opening Statement (Exhibit 10) provided updates on forecast IPP generation (which have been included in YEC's review of updates in its response to Undertaking #23).

Overall, no key issues were raised during the hearing with regard to sales and generation forecasts for the 2023 and 2024 test years.

1.1 SALES FORECAST

The Application forecasts total firm retail and industrial sales of 482.8 GWh in 2023 and 488.2 GWh in 2024 (compared to 2021 approved of 495.2 GWh). Secondary sales are forecast at 2.9 GWh for each test year (see Exhibit 1, Tab 2, Table 2.1).

1.1.1 WHOLESALE SALES FORECAST

Wholesale Sales to AEY are reviewed in the Application (Exhibit 1) in Tab 2, Section 2.2.1, pages 2-4 to 2-5.

During the review of YEC's 2021 GRA,[5] the Board previously directed YEC to work with AEY "to provide details on discussions with AEY to align their wholesale sales forecasts." The Application and YEC's response to information requests confirm that this was done; the utilities worked together as directed prior to filing their respective GRAs. The Application (page 2-5) and UCG-YEC-1-21(c) provide details on YEC discussions with AEY to align forecasts and the ultimate decision that each company would proceed with its respective forecasts for the test years.

Differences in the AEY and YEC wholesale forecasts and methods[6] were reviewed in the Application, in IR responses, and at the oral hearing. As in past GRAs, YEC relied on a multi-variant regression assessment of monthly wholesale change at normal weather conditions using

[5] YUB Order 2022-03, Appendix A, paragraph 39.
[6] See YUB-YEC-1-9 for review of differences in forecast methods between YEC and AEY. UCG-YEC-1-21(b) provides details on YEC methods and components; UCG-YEC-1-21(d) provides firm wholesales and annual change percentage from 2012 to 2022 actual and YEC forecasts for the test years.

20-year historical averages (reduced by approved LTA Fish Lake generation, as required by OIC 2021/16).[7]

Variances between YEC and AEY GRA firm wholesale forecasts for 2023 and 2024 test years reflect differences in forecast methods and assumptions. In summary, AEY's firm wholesales forecast for 2023 is 1.6 GWh, or 0.5% lower than YEC's forecast of 351.3 GWh, while AEY's forecast for 2024 is 6.7 GWh, or 1.8% higher than YEC's forecast of 355.9 GWh.

- YEC's forecast annual increase in wholesales of 1.3-1.4% is in line with the historical averages [the average annual increase for the last five years is about 1.0%].

- As reviewed in response to YUB-YEC-1-9, the 2023 year-to-date actuals closely align with the 2023 forecasts [with preliminary actuals to October, the updated full-year forecast for 2023 was expected to be about 351.2 GWh versus the YEC GRA forecast of 351.3 GWh and the AEY GRA forecast of 349.7 GWh].

- YEC's 2024 forecast shows sustained growth at 1.3% (versus 1.4% the previous year). In contrast, AEY's 2024 forecast shows a major growth increase at 3.7%. During the oral hearing, Mr. Epp provided an explanation for key assumptions leading to this variance, specifically seven new large commercial customers AEY expected to be connected to the grid through the end of 2023 and into 2024.[8]

- Variances in Fish Lake hydro forecasts between the AEY and YEC GRAs contribute to differences in forecast primary wholesale purchases. The Application notes the need to use LTA hydro generation for Fish Lake hydro when setting revenue requirements. At the hearing, Mr. Epp also reviewed YEC's reliance on the LTA Fish Lake hydro generation last approved by the Board, in the absence of any available update to LTA Fish Lake hydro generation.[9]

In summary, YEC and AEY wholesale forecasts are both reasonable, they both rely on methods previously reviewed with the Board, and they both provide for forecast growth in line with past experience.[10] Subject to Board approval of an acceptable LTA Fish Lake hydro generation offset as required by OIC 2021/16, a common wholesales forecast for YEC and AEY can be approved as provided based on review of the evidence before the Board.

1.1.2 MAJOR INDUSTRIAL CUSTOMER LOADS

Tab 2, Section 2.2.2 of the Application includes a summary of forecast information provided to YEC by Hecla Yukon[11] and Victoria Gold.[12] Industrial sales are forecast at 75.0 GWh for 2023

[7] UCG-YEC-1-19 notes the wholesale forecasts for 2023 and 2024 are prepared based on multi-variate regression assessments of monthly wholesales changes, the same approach used in the 2021 GRA, at normal weather conditions using the 20-year historical averages.
[8] March 7, 2024 Transcript, page 483, line 13-22.
[9] March 7, 2024 Transcript, page 481, line 13 to page 482, line 11.
[10] See Mr. Epp review, March 7, 2024 Transcript, page 482, line 18 to page 484, line 6.
[11] YUB-YEC-1-11(b) notes that to date the forecast is aligned with actuals.
[12] YUB-YEC-1-11(a) REVISED notes that there are no minimum energy take or pay provisions in the PPA with Victoria Gold.

and 69.4 GWh for 2024, as compared with 2021 actual sales of 91.1 GWh and 2022 actual sales of 95.2 GWh. Details for the industrial load forecasts were also summarized in the response to UCG-YEC-1-19, with the industrial sales forecasts for Victoria Gold and Hecla Yukon (previously Alexco) being based on information provided by the customers.

The approximate 20 GWh decline from the 2021 GRA approved forecasts reflects the reduction in industrial sales due to the Minto mine closing in May 2023.

Minto mine was included as an industrial customer for January to May 2023 based on actual sales of 16.3 GWh; however, from June to December 2023 and for 2024, the load for Minto care and maintenance is included in the general service class (government).[13] The response to UCG-YEC-1-22 provides details on Minto consumption for the test years as an Industrial and General Service customer; outstanding amounts owed by Minto that were not collected; and how YEC is proposing to recover any outstanding amounts owed from Minto through the receivership process. As clarified further in YEC's response to Undertaking #37, YEC does not have contractual security for the outstanding amounts owed by Minto; however, YEC has filed miners lien claims for those amounts. YEC's Petition to enforce its miners liens is currently stayed pending the resolution of the Minto's receivership proceedings in the Yukon Supreme Court, which YEC is actively participating in. The recovery of the outstanding amounts owed from Minto is not included in this GRA revenue requirements.[14]

No material issues regarding the industrial sales forecast were raised in interrogatories or in cross examination at the oral hearing regarding industrial sales forecasts. YEC's forecasts are reasonable and should be accepted.

1.1.3 OTHER SALES [YEC RETAIL AND SECONDARY]

Retail and secondary sales forecasts are reviewed in Tab 2, Sections 2.2.3 and 2.2.4. Yukon Energy firm retail sales are comprised only of sales to residential, general service, streetlight and space light customer classes served directly by Yukon Energy in Dawson City, Mayo, Faro, and 12 small communities in southern Yukon (Mendenhall, Aishihik, Champagne, Braeburn, Johnson's Crossing, South Fox, Little Fox, Little Salmon, Drury Creek, Pine Lake, Canyon Creek, and McGundy). Retail firm sales are forecast at 56.1 GWh for 2023 and 63.0 GWh for 2024, as compared with 2021 actual sales of 47.2 GWh and 2022 actual sales of 46.2 GWh. The test years General Service sales forecast include sales to Minto as a General Service customer starting in June 2023.[15]

- Residential sales forecasts are based on historical trends and input from YEC staff that is obtained through their work in the communities. The forecast growth in 2023 and 2024 is also consistent with the population growth projections by the Yukon Government and the City of Whitehorse projections. (see UCG-YEC-1-19(a))

[13] The response to YUB-YEC-1-10(a) confirms that in May 2023, Minto ceased its mining operation and therefore no longer qualified as a major industrial customer defined under OIC 1995/90 and must be served under the retail customer class; and confirms that as Minto mine has ceased mining operations Rate Schedule 35 Low Grade Ore Processing rate schedule is no longer required. Minto's forecast consumption for the 2024 test year as a General Service customer is 13.1 GWh.

[14] March 5, 2024 Transcript, page 221, lines 13-16.

[15] UCG-YEC-1-6(a) provides test year GS sales to Minto of 8.0 GWh in 2023 and 13.1 GWh in 2024.

- General Service sales forecasts are based on historical trends and input from YEC staff that is obtained through their work in the communities plus separate forecasts for two large general service customers: Faro Mine remediation project and Minto Mine care and maintenance load (see UCG-YEC-1-19(a)).

- For the 2023/24 GRA, the secondary sales forecast is at 2.9 GWh for each test year. The forecasts for the test years were prepared based on actual secondary sales experienced in 2022 and expected water conditions for 2023 and 2024 at the time of preparation of the GRA. The response to UCG-YEC-1-18(b) notes that actual secondary sales to date for 2023 were lower than forecast for the test year due to reduced hydro output [Mayo A outage, reduced Whitehorse output due to WH4 outage and spinning reserve requirements, and drier Aishihik conditions].

No material issues or concerns were raised in IRs or at the oral hearing regarding the residential, general service, lighting sales or secondary sales forecasts included in the 2023 and 2024 GRA sales and generation forecasts. As such, Yukon Energy's retail and secondary sales forecasts are reasonable and should be accepted.

1.2 PEAK DEMAND FORECAST & DEPENDABLE CAPACITY REQUIREMENT

The basis for the peak demand forecast is reviewed in detail in the Application at Section 2.4 and in response to IRs (including YUB-YEC-1-17, YUB-YEC-1-18, UCG-YEC-1-20 and UCG-YEC-1-27). Peak demand for the integrated system was forecast at 119.5 MW in 2023 and 123.2 MW in 2024 (see Application, Table 2.2). Excluding industrial load, the forecast peak load in the Application for the purpose of determining the N-1 dependable capacity requirement is 110.9 MW in 2023 (based on winter 2023/24) and 114.6 MW in 2024 (based on winter 2024/25).

UCG-YEC-1-27 reviews the method used by YEC to prepare the peak demand forecast since 2018 (i.e., Itron econometric model and related inputs), and provides the actual peak for the period 2013-22; and forecast total peak included in the 2012/13, 2017/18 and 2021 GRAs. In sum, forecast peak loads that impact dependable capacity requirements for the test years reflect updated econometric model results for a one-hour maximum load on the grid assuming a temperature of -39 C based on the new coldest day record from January 2022.

The dependable capacity shortfall and related rental diesel requirements and costs for the 2023 and 2024 test years were determined based on the N-1 criterion which excludes the industrial peak.[16] YUB-YEC-1-18(c) and (d) notes that YEC did not adjust the forecast non-industrial N-1 peak demand in the test years for Minto load to reflect the recent closure of mine operations and the resulting shift to service under the general service class; however, the mine continues to have on-site thermal generation sources in case of a power outage from the grid.

[16] UCG-YEC-1-20 notes The N-1 standard does not include industrial loads as part of the assessment as major industrial customers typically maintain sufficient on-site generation for their own emergency purposes; and although the N-1 standard does not include industrial peak, industrial customers currently share the diesel rental costs as part of the overall rate increase, as well as any fuel used for the rental units [for rate setting purposes, YEC does not distinguish the diesel fuel cost between own units and rental units].

The peak demand forecast for the test years as required for dependable capacity determinations is reasonable and should be accepted.

1.3 GENERATION FORECAST

The Application's forecast firm generation of 525.5 GWh and 531.2 GWh, for 2023 and 2024 respectively, is based on forecast firm sales plus system losses of 8.8%. The 8.8% line losses forecast is the same as the 2021 GRA approved level and also within the range of historical losses for the last three years [9.1% in 2020, 8.4% in 2021 and 9.0% in 2022].[17] No material issues were raised regarding the firm sales forecasts or system losses forecast, and consequently the forecast generation for 2023 and 2024 is reasonable and should be accepted.

Reduced LTA thermal generation for the test years compared to 2021 approved LTA thermal generation reflects lower forecast grid generation and forecast growth in IPP renewable generation in the test years (see Appendix 2.1 for details). The LTA thermal generation forecast for the test years is consistent with OIC 2021/16 directives (section 9(2) and (3)), which require that the forecast thermal generation to be included in rates must be determined based on long-term average annual renewable source availability. Subject to updates for IPP generation forecasts, no material issues regarding test year thermal generation forecast were raised in the oral hearing, IRs or other submissions.

The Application assumes, as per past GRAs, a forecast LTA thermal fuel mix of 90% LNG generation and 10% diesel generation. The fuel mix ratio was adopted based on the expectation that LNG would be heavily used during drought or low water conditions, and that in years with higher-than-average water conditions, LNG use would be lower and diesel use would exceed 10% of the thermal mix as it would be used for peaking, emergencies and other specific uses. Yukon Energy has reviewed the rationale and information that support retention of the fuel mix for LTA thermal generation for the test years. No material issues were raised during the hearing regarding the proposed thermal fuel mix, and consequently the proposed thermal fuel mix for the test years is reasonable and should be accepted.

The Application's IPP generation forecasts and purchase power costs were updated in YEC's Opening Statement (Exhibit 10) and in Undertaking #23 to reflect the latest available information on expected LTA IPP renewable generation for the YIS during the test years. In summary, forecast LTA IPP generation was reduced by 4.1 GWh for 2023 (from 6.1 GWh to about 2.0 GWh) and by 2.5 GWh for 2024 (from 16.8 GWh to about 14.3 GWh). At the hearing, YEC witnesses reviewed how LTA forecasts for IPP generation are based on information provided by each IPP as part of the development of each electricity purchase agreement.[18]

IPP generation is beyond the control of YEC, and the updated forecasts should be considered reasonable and accepted for test year generation forecasts.

Further, as reviewed in YEC's response to Undertaking #23, the updated and lower LTA IPP generation forecasts result in updated and higher LTA thermal generation forecasts for each test

[17] See UCG-YEC-1-19(a).
[18] March 7, 2024 Transcript, evidence from Mr. Epp, Ms. Cunha and Mr. Osler, page 487, line 20 to page 490, line 20.

year.[19] The updated LTA thermal generation forecasts should be considered reasonable and accepted for test year generation forecasts.

2.0 TAB 3 – REVENUE REQUIREMENT

Tab 3 of the Application reviews Yukon Energy's revenue requirement for the test years, including an overview, followed by more detailed consideration of key components: fuel and purchased power; non-fuel operating and maintenance expenses; rate base, depreciation and amortization; and return on rate base (interest and ROE).

Responses to key issues raised are addressed below for each of the components. Details on capital costs that impact rate base are addressed in Tab 5.

2.1 FUEL AND PURCHASED POWER

As reviewed in section 3.2 of the Application, fuel and purchased power costs forecast for the 2024 test year are $1.085 million higher than 2021 approved costs. The total increase by the end of the 2024 test year reflect primarily higher fuel prices, as well as increased purchased power cost for IPPs. The manner in which forecast fuel prices for the Application were determined was reviewed in Section 3.2.

Forecast fuel costs (see Table 3.2-1 in the Application) include: (1) forecast thermal generation fuel costs for the forecast LTA thermal generation (as determined in Tab 2) at forecast fuel prices; and (2) forecast maintenance fuel costs for LNG and diesel units in each test year (see Application, pages 3-4 and 3-5).

- Forecast long-term average thermal generation in the Application is 74.5 GWh in 2023 and 68.1 GWh in 2024, as compared with 85.9 GWh in 2021 approved. The fuel cost for forecast long-term average thermal generation is $15.061 million in 2023 and $13.770 million in 2024 before considering forecast fuel costs for thermal maintenance activities (see Section 2.3.2 and Table 3.2.1).

- For maintenance activities, the forecast diesel unit operation required is 0.198 GWh/year for both test years ($0.061 million, an increase from $0.041 million reflecting higher fuel prices).

Proposed GRA fuel prices for approval by the Board reflect the following [see Application, pages 3-4 and 3-5 and YUB-YEC-1-20 for details]:

- This forecast for LNG cost reflects contracted liquefaction and shipping costs for 2023, as well as the most recent market price for commodity value prior to completion of the Application [i.e., the actual price for May 1, 2023]. Yukon Energy forecasts average efficiency for LNG generation of 2.58 kW.h/litre, which is the average efficiency for the last three years [2020-2022].

[19] Undertaking #23 indicates forecast LTA thermal generation increase of 3.1 GWh for 2023 and 1.9 GWh for 2024 as a result of the updated LTA IPP generation forecasts.

- Forecast diesel prices for the test years reflect prices as of May 1, 2023, the most recent prices prior to completion of the Application. Diesel fuel efficiency is based on averages for the last three years [2020-2022].

Purchased power costs in the Application include forecast IPP purchases (see Table 2.2) of 6.102 GWh in 2023 and 16.811 GWh in 2024 under the Yukon government's IPP Policy and OIC 2019/25. As reviewed above (section 1.3 on Generation Forecasts), forecast IPP purchases have been updated in Exhibit 10 and Undertaking #23, and these updates include related impacts on forecast Fuel and Purchased Power Costs.[20]

The forecast costs for 2023 and 2024 test years, with the updates for IPP purchases and LTA thermal generation as per Undertaking #23, are reasonable and should be accepted.

2.2 NON-FUEL OPERATING AND MAINTENANCE EXPENSE

The Application provides details on each component of the non-fuel operating and maintenance expense $8.909 million increase forecast for the 2024 test year compared with 2021 approved. Labour and production expense (mostly diesel rental) together account for approximately 78% of the increase, and each is reviewed separately in the discussion that follows.

Transmission and Distribution brushing expenses, which is also reviewed below, are forecast to decrease by $0.020 million in 2023 and 2024 from 2021 approved. Brushing activities are based on YEC's brushing policy and plans.

With respect to the Reserve for Injuries and Damages (RFID), the Application does not change the annual appropriation. However, YEC also noted in the Application that there was a need for higher annual appropriation, and, in the event that other Application 2024 test year costs are reduced by updates or Board decisions, YEC proposes that the RFID annual appropriation starting in 2023 be increased from $0.616 million/year up to the lesser of (a) a level consistent with the Application's 2024 required rate increase of 14.11% and (b) $1.016 million/year (the level consistent with a normal GRA adjustment to reflect the 10-year average RFID charge plus amortization over 10 years of the opening RFID balance at the start of the first test year).[21]

Major issues were not raised during interrogatories or the oral hearing with regard to General O&M,[22] Administration,[23] Insurance and RFID,[24] or property taxes, which together account for the balance of the increase. These forecasts are therefore not reviewed below. YEC will respond in reply argument to any specific issues or questions raised by intervenors regarding any of the forecasts.

[20] As reviewed in Undertaking #23, these updates to Fuel and Purchased Power Costs reduced forecast costs by $0.144 million for 2023 and increased forecast costs by $0.002 million for 2024.
[21] Exhibit 1, PDF p. 73.
[22] See YUB-YEC-1-51 (a-e) for specific details regarding variance between years, reasons for decreased costs between years.
[23] See YUB-YEC-1-52 (a-d) for specific details on environmental management cost variances between years, recruitment cost variances from 2021 to 2022 and the increase in forecast contracting costs in 2023 compared to 2021 and 2024.
[24] See YUB-YEC-1-53(a-c) for details on market rate increases, reduced insurer participation rate and dollar value change in the deductible; and YUB-YEC-1-53(d-e) for details on actual annual changes in Table 3.11 and 3.11.1.

2.2.1 LABOUR EXPENSE

The total labour expense increase in 2024 from 2021 approved ($3.063 million) relates to additional headcount ($1.859 million or 61% of increase) and labour rate increases (the remaining $1.024 million, 39% of increase).[25] Test year forecast labour expenses are reasonable and required for YEC to address the full range of its responsibilities and challenges, and to reduce overtime costs. Each of these matters is explained in further detail below. In summary, the evidence confirms that the forecast labour expense for the test years are reasonable and should be accepted.

Labour Rates Increase

The Application notes that 2023 labour rates escalated by 4.5% and 2024 labour rates escalated by 3%, consistent with approved increases for Yukon government employees.[26]

Forecast 2023 and 2024 labour rates are estimated to reflect a negotiated increase in the Yukon Government collective bargaining agreement.[27] The Application and IR responses note that while YEC employees are not considered Yukon government employees, the Yukon government collective agreement heavily influences the results in negotiations between YEC and its union as the Yukon government is considered the greatest market comparator.[28] In all recent YEC collective agreements, arbitration/mediation resulted in YEC wage rate adjustments exactly equal to Yukon government wage rate adjustments.[29]

Mr. Epp noted in his testimony at the hearing[30] that a 3-year collective agreement has been negotiated covering the period from 2023 to 2025:

> For revenue requirement, when we prepared this application, it was done before we had an agreement with the union, and we thought it reasonable to base our estimate on history that said this is where we've always ended up in the past, so we thought that would be a reasonable justification for using that in the current forecast. Now, subsequent to us submitting the application, we have signed a collective agreement with the union, and it did equal what we put into our application.

[25] Application, Section 3.1.1, pages 3-7 and 8.
[26] YUB-YEC-1-5(a-b), corrects Application page 1-8 reference to 4% escalation in 2023.
[27] Application, page 3-8.
[28] See March 6, 2024 Transcript pg 326-27 where Mr. Epp notes: "when we go to collective bargaining with the union, it's historically been YEC management's opinion that the comparator is the local market, and the best indicator of that is the Yukon Government. We also look at the hospital, the City of Whitehorse, as well. But for all of the past agreements we've had with the union, whether it be resolved by arbitration or mediation or agreement with the union, the ending rate increases have been determined to be exactly equal to what has been decided in the Yukon Government contracts."
[29] YUB-YEC-1-5(a)
[30] March 6, 2024 Transcript, p. 328.

FTE Complement Increase

The Application outlines at pages 3-8 to 3-15 the required increase in employee complement; and the justification and rationale for added positions. There was a 19.21 cumulative FTE increase from 2021 approved to 2024 forecast. Factors driving the increase in employee complement were noted in the Application (pages 3-9 to 3-10) and include:

- Increasing assets;
- Increased planning and regulatory requirements for environmental monitoring and compliance;
- Strategic importance of improving First Nation and public engagement, relationships and communications;
- Steady growth in customer accounts; and
- Continuing high capital demands to maintain existing aging assets.

The forecast increase in employee complement is required to address the issues identified above and to decrease overtime costs. YEC has made a conscious effort to limit increases only to those areas where required.

- The additional positions outlined in Tab 3 are required to plan, permit, execute and deliver YEC's $85 million/year capital budget forecasted in the 2023 and 2024 test years, and anticipated future capital requirements related to increased demands for electricity and the energy transition (described in the Application and Tab 1). The Application notes that YEC's forecast 2023 and 2024 annual capital programs are nearly double the size they were prior to 2021. Additional staff positions are needed with training and knowledge to build and connect new projects to meet growing demands for electricity; to replace and upgrade assets that are nearing or at end-of-life; and to plan, deliver and oversee more complex projects with multiple groups of rightsholders and stakeholders, both in terms of scope and expenditures.[31]
- Maintenance requirements for plant operations, and environmental monitoring and compliance requirements for YEC's entire electricity system, have increased. This is due to the growing number of generation assets that are now connected to the Yukon grid, the additional maintenance needed to continue to operate them safely and reliably, and the monitoring programs required to monitor and adapt to changing climate conditions and to comply with regulatory direction.
- The remaining added FTEs address the needs of a growing number of customers and stakeholders, managing demand-side management programs, higher vendor and employee expense payment volumes, additional reporting needs, including Key Performance Indicators (KPI) and Environment, Social and Governance (ESG) reporting,

[31] Application, Page 1-8.

etc., and a need to strengthen strategic planning and communications with all levels of government on major capital works, operations and planning for the energy transition. Please see full details in Tab 3, Section 3.3.1.

In the Opening Statement (Exhibit 10), YEC confirmed that all of the positions to be filled for 2023 and 2024 (excluding the summer students who won't be hired until approximately May 2024), as described in the Application, were filled, with the exception of one position currently in the active recruitment stage. See also responses to YUB-YEC-1-23(a) to (d) which updates positions filled for Finance, Procurement & Information Technology; Planning, Environment, Health and Safety; and Engineering Services.

With regard to the one vacant position, Ms. Cunha noted during the oral hearing that YEC had posted for the unfilled position in the previous week and anticipated the position could be filled by April 2024.[32] Mr Epp clarified that "while we weren't able to hire the manager of community relations last year, the work was still there. Ms. Cunha was able to get support of two six-month full-time term positions to backfill that role while we have been waiting for this position to become permanent".[33]

A vacancy factor of 9 FTEs was applied to labour expenses for the 2023-2024 test years based on a 5-year historical average. The vacancy factor for the 2021 GRA was 5 FTEs (excluding 3 new FTEs the YUB directed to remove from the revenue requirements in its Order 2022-03, Appendix A). Although YEC forecast an increase of approximately 19 FTEs in 2024 over the approved 2021 FTEs, the increased vacancy factor reduces the impact on the net labour cost.[34] There is no direct formulaic reconciliation between FTE additions and increases in vacancy rate, but there is the general reasonableness test that as the FTE count increases, so will the vacancy rate. The vacancy rate is equal to the average of the actual vacancy rates in the previous five years.[35] This approach is consistent with prior applications.

Vacancies were also discussed at the oral hearing (see March 6, 2024 Transcript page 340, line 15 - page 342, line 16) with further information provided in response to Undertaking #22 where the Board requested actual vacancies for 2023 and 2024 to date. The expanded version of Table 3.4 in response to Undertaking #22 shows 12.21 vacant positions in 2023 and only 5.25 for 2024 as of March 6, 2024. The undertaking response also noted that YEC incurred more overtime hours in 2023 than forecast in the GRA due to higher vacant positions in 2023 compared to the forecast. The information included in Table 3.4 of the Application regarding total positions and net of vacancies was also clarified (see March 6, 2024 Transcript, pages 331-334)[36] with added lines in the version of Table 3.4 included in Undertaking #22.

[32] See March 6, 2024 Transcript pages 335-36.
[33] March 6, 2024 Transcript page 336. Further details were also provided by Ms. Cunha at pages 336-37.
[34] Application, page 1-8 – also page 3-8, 3-9.
[35] YUB-YEC-1-5(d & f).
[36] In discussion it was clarified that the complement noted in Tabel 3.4 were gross numbers, "So if we're looking at Table 3.4 where it says we had a FTE complement of 107 employees, that's the gross number of employees that we – gross number of positions we have. Then when we look at the YUB-YEC-1-5 response which says we have vacancy rate of 12 -- and you said percentages earlier. It's not percentages. It's rate -- of 12 FTEs. What that basically means is we had positions of 107, of which 12 or so were vacant or unfilled throughout the year, which, in other words, means we had about 95 employees paid for."

Overtime

The increase in employee complement has resulted in a significant decrease in forecast overtime costs as a percentage of total labour costs for 2023 and 2024 compared to the overtime for 2021 and 2022 actual years.[37] The percentage of gross salary decreased from 6.14% in 2021 to 3.93% (forecast) in 2024 (YUB-YEC-1-21(a)). YEC cannot provide a useful estimate of forecast overtime reduction for each test year resulting from YEC's increase in employee complement. Based on the premise that the work needs to get done, if YEC did not add FTEs or hire outside consultants or contractors, there would be a significant increase in overtime hours and costs (YUB-YEC-21(c)).

Positions Replacing Outside Consultant or Contractor

YEC reviewed specific examples where an FTE position was filled and thereby replaced the use of an outside consultant or contractor.[38]

1. In 2022, YEC created a Regulatory Planner position. This position is responsible for research and analysis services in support of regulatory filings. This position has greatly reduced the use of outside consultants with all regulatory filings, including this Application.

2. Since YEC's 2021 GRA, there has been a focus within YEC to increase the capacity of the Engineering department to enable itself to deliver growth in workload due to an unprecedented capital program resulting from demands driven by adaptation for climate change, expanding infrastructure to meet increased electricity demand driven by population growth, electrification and transition to a net zero carbon economy, and revitalization of aging infrastructure. Specifically, YEC added a Director of Capital Projects, a Director of Engineering and a Junior Project Manager. Without these positions being filled internally, YEC would have had to hire outside consultants or contractors to fulfill the workload.

3. Adding FTE positions is not always the best option as compared to hiring an outside consultant or contractor. The decision depends on many factors, including but not limited to market conditions (i.e., can a qualified employee be found?) and workload (i.e., are the position's duties required throughout the entire year?). There are many situations where hiring an outside consultant or contractor is the better option.

Capital/Maintenance Allocation

The 2021 approved revenue requirement forecasts included an allocation set at 17.2% capital and 82.8% maintenance. For the 2023 test year the forecast allocation is 17.9% capital and 82.1% maintenance and for the 2024 test year the forecast allocation is 18.4% capital and 78.6% maintenance. The ratio is based on YEC's best estimates of each employee's time to perform

[37] Application, Page 3-10.
[38] YUB-YEC-1-21(b).

their job based on corporate goals and expectations and an overall increase in capital projects volumes.[39]

YEC's forecast allocation between capital and maintenance costs changed only minimally in the test years compared to 2021 Actuals (despite the increase in forecast capital costs) as the majority of capital project costs are materials and contractor costs.[40] The Thermal Replacement and Battery projects make up a large portion of the capital program, but much of the costs are for the equipment (diesel engines and the batteries).

Labour Requirements and YEC capital forecasts

Approvals or rejections by the Board of YEC capital forecasts during a GRA proceeding are unlikely to significantly impact what projects YEC executes or the related staffing requirements.[41] The timing and nature of Board GRA reviews does not typically create opportunities for YEC to adjust its capital spending during the test years based on a final Board decision. The Board's GRA review is typically dealing with projects already fully committed and, in many cases, already implemented – and staffing for these committed projects will accordingly also have been fully committed for the GRA test years.

2.2.2 PRODUCTION

Total non-labour production costs for 2024, excluding fuel and purchased power costs, are forecast to be $3.855 million higher than approved 2021 costs. Diesel generation related expenses account for approximately 86% of this cost increase, with almost all this being accounted for by diesel rental costs. No material issues were raised during interrogatories or the oral hearing with regard to the balance of the non-labour production cost increases which were related to hydro, LNG and diesel generation [excluding diesel rental costs discussed below], and operation supervision.

Diesel Rentals

As detailed in Table 1 of YEC's response to YUB-YEC-1-1,[42] YEC forecast a need for 20 diesel rental units (excluding 2 spares) during the 2023 and 2024 test years, to provide a total of 36 MW of additional dependable generation capacity that is required to meet YEC's forecast 2023/24 and 2024/25 winter N-1 dependable capacity shortfall. This represents an increase of 5 diesel rental units over the 15 units (excluding 2 spares) that were required to meet N-1 dependable capacity criteria during the winter of 2021/22, the costs of which were previously approved by the Board in the 2021 GRA proceeding.[43]

As reported in Tab 1 of YEC's Application,[44] the cost of the 20 diesel rental units claimed in the current GRA constitutes 21% of YEC's total 2024 revenue shortfall ($3.3 million), with $1.2 million due to the need for more rental diesels and $2.1 million due to higher rental prices.

[39] Application Page 3-15.
[40] YUB-YEC-1-60(a-b).
[41] YUB-YEC-1-5(e)]
[42] Exhibit 2, PDF p. 216.
[43] YUB Order 2022-03, Appendix A, paragraph 114.
[44] Exhibit 1, PDF p. 20.

The Board accepted the necessity of YEC's diesel rental units in its 2021 GRA decision. However, the Board also cautioned YEC that this did not mean it was making any finding that YEC's use of diesel rental units would continue to be prudent in the future, noting concerns that were previously identified in YUB Order 2018-10.[45] The Board expressed the view that YEC should explore other planning options to mitigate the use of diesel rental units,[46] and, accordingly, it directed YEC to provide a business case in its next GRA to support its continued reliance on diesel rental units to meet the N-1 dependable capacity requirement.[47]

In accordance with the Board's direction, YEC provided a specific business case in Appendix 3.1 of its 2023/24 GRA Application to support the short-term need to retain diesel rentals to meet N-1 dependable capacity requirements in the 2023 and 2024 test years, in the context of YEC's ongoing, long-term dependable capacity planning options. YEC also supplemented this business case analysis with additional evidence provided in response to Information Requests, including detailed information provided in YUB-YEC-1-35 REVISED, and in response to eight additional follow-up questions posed by the Board in YUB Order 2023-25.[48]

The need for 20 diesel rentals (36 MW) or other equivalent new dependable capacity to meet the forecast N-1 dependable capacity shortfall during the 2023 and 2024 test years has not been disputed during the current GRA proceeding. Further, as reviewed in response to Follow-Up Question #3 in YUB-YEC-1-35 REVISED, the Board in Order 2022-03 approved diesel rental costs to meet the 2021 forecast N-1 dependable capacity shortfall after accepting YEC's evidence that it would be able to operate the units as required during N-1 emergency conditions. YEC in its response to Follow-up Question #3, has again detailed how it would be able to respond during the test years to an emergency event notwithstanding the need to use installed back-up diesel rental capacity that exceeds permitted capacity for normal operations.[49]

In evaluating the reasonableness of the diesel rental costs claimed by YEC in this GRA, it is critical for the Board to distinguish between the continued short-term need for diesel rental units to satisfy N-1 dependable capacity criteria during the 2023 and 2024 test years, versus YEC's ongoing planning to address future dependable capacity requirements in the longer term. YEC has provided evidence to the Board of its long-term objective to reduce or eliminate the continued need for mobile diesel rental units through its planned development of new permanent dependable capacity, which would be one of the key focus areas in the Electricity Supply Plan and Resource Plan that YEC is currently working on. However, the development of new permanent capacity takes time. In particular, any large new projects require prudent planning, and such projects are typically dependent on securing permitting and local First Nation support, as well as any necessary funding commitments from government, when applicable.[50]

YEC has provided evidence to the Board concerning its long-term resource planning, and concerning the emergence of the diesel rental "option" in that context. Diesel rentals were initially identified as the only feasible way to address forecast dependable capacity shortfalls on a short-

[45] YUB Order 2022-03, Appendix A, paragraph 111.
[46] YUB Order 2022-03, Appendix A, paragraph 113.
[47] YUB Order 2022-03, Appendix A, paragraph 115.
[48] Exhibit 5, PDF pp. 3-92.
[49] YUB-YEC-1-35 REVISED, Exhibit 5, PDF pp. 21-24.
[50] Exhibit 1, PDF p. 94

term basis for the winter of 2017/18 (with 4 units initially rented in that year), pending the prudent development and commissioning of new permanent dependable capacity and/or related DSM measures to meet N-1 dependable capacity requirements. As such, since the winter of 2017/18, YEC has always considered diesel rental as a residual option, to be relied on only to the extent that the combination of other feasible generation options that YEC can implement each year are forecast to be insufficient to meet dependable capacity shortfalls without being supplemented by diesel rentals.[51]

Following the 2017/18 GRA, YEC dependable capacity planning was focused on its initial planning and feasibility assessment for the 20 MW thermal plant project that had been contemplated by the 2016 Resource Plan, as well as the proposed Battery (BESS) Project. However, as outlined in YUB-YEC-1-35 REVISED, YEC's board of directors prudently decided not to proceed with the 20MW thermal plant because of a lack of social licence, and to proceed instead with YEC's updated resource plan that would subsequently be detailed in the 10-Year Renewable Electricity Plan presented in January 2020. That plan included 12.5 MW diesel replacement, the BESS and Atlin Hydro Expansion projects, capacity DSM, and the Moon Lake Pump Storage project.[52]

In the context of those longer term resource development plans, YEC still needed to address dependable capacity shortfalls on an ongoing basis, and diesel rentals continued to be the only feasible way to achieve this in the short term pending the implementation of YEC's planned projects, with the number of diesel rental units increased to 6 for the winter of 2018/19, 9 for the winter of 2019/20, and 15 (plus 2 spares) for the winter of 2020/21.[53]

When YEC filed its 2021 GRA in November 2020, its BESS application in January 2021, and its initial Atlin EPA application in January 2022, each of those applications included a review of then available information and analysis on dependable capacity non-industrial peak MW requirements, committed and planned resources, and forecast diesel rental use to address forecast N-1 dependable capacity shortfalls prior to the then planned installation of the phase 1 Moon Lake Storage Project's 35 MW of dependable capacity by the winter of 2028/29, followed by phase 2's additional 10 MW in the winter of 2031/32.[54]

Needless to say, the planned installation of the Moon Lake Pump Storage Project continued to be a critical component of YEC's long-term capacity planning, until YEC's recent determination that it would not be feasible to move forward with that project within the foreseeable timeframe as a result of a lack of sufficient local First Nation support at this time. As such, until that determination was made, YEC's evaluation of short-term generation options – including its continued use of rental diesels to close the N-1 dependable capacity gap on a year-by-year basis – necessarily had to take into account the very significant additional permanent capacity that the Moon Lake project was expected to add to the system, alongside planned development of the BESS and Atlin Hydro Expansion projects, diesel replacements, and DSM.[55] As outlined in response to

[51] YUB-YEC-1-35 REVISED, Exhibit 5, PDF pp. 9-12, and Attachment 1, PDF pp. 40-55.
[52] YUB-YEC-1-35 REVISED, Exhibit 5, PDF p. 12.
[53] YUB-YEC-1-35 REVISED, Exhibit 5, PDF p. 12, and Attachment 2, PDF pp. 56-62.
[54] YUB-YEC-1-35 REVISED, Exhibit 5, PDF p. 13.
[55] JM-YEC-1-7(d), Exhibit 2, PDF p. 15; NY-YEC-1-7, Exhibit 2, PDF pp. 28-29; NY-YEC-1-21, Exhibit 2, PDF pp. 89-90; YUB-YEC-1-44, Exhibit 2, PDF p. 353; YUB-YEC-1-47, Exhibit 2, PDF pp. 371-372; YUB-YEC-1-35 REVISED, Follow-up Question #1, PDF p. 18.

YUB-YEC-1-35 REVISED, Follow-up Question #4, under the 10-Year Renewable Electricity Plan, it was expected that the continued use of rented diesels prior to commissioning of Moon Lake Pump Storage would avoid the need for YEC to incur capital costs to develop additional generation capacity that would cease to be used and useful and would thereby become stranded assets following the Moon Lake project's commissioning.[56]

It was in that context that YEC continued to rent 15 diesel units (excluding 2 spares) to meet its N-1 dependable capacity shortfall for the winters of 2021/22 and 2022/23,[57] and that YEC reasonably determined, when forecasting its generation needs for the 2023 and 2024 test years, that the 20 mobile diesel rentals units (excluding 2 spares) whose costs are claimed in this proceeding would provide the only feasible short-term option to ensure sufficient dependable capacity to meet the N-1 dependable capacity requirement for the winters of 2023/24 and 2024/25.[58]

In particular, for the 2023 and 2024 test years, practical constraints related to timing and planning for commitment of major new capital expenditures made it impracticable for YEC to plan adding new permanent diesel generation facilities that could be commissioned in the test years beyond the diesel replacement facilities in Whitehorse, Faro and Dawson that were specified in the 10-Year Renewable Electricity Plan and planned for in-service during winter 2023/24.[59]

Of course, in light of YEC's recent determination that the Moon Lake project cannot proceed within the foreseeable timeframe – as well as the delays now anticipated in development of the Atlin Hydro Expansion Project – YEC is now re-evaluating its capacity options.[60] In particular, as outlined in response to YUB-YEC-1-35 REVISED, Follow-up Question #6, YEC is developing an Electricity Supply Plan to identify the resource options that can be implemented in the next 5-10 years to increase the supply of dependable capacity and energy during the winters months and to reduce the use of diesels. Additionally, a longer-term Resource Plan is also being developed to determine Yukon's long-term electricity needs and to identify the resource options that are best suited to meet those needs.[61]

In the meantime, in response to the Board's specific direction in the 2021 GRA decision, the business case provided by YEC in this proceeding specifically elaborates on YEC's current consideration of the possible alternative options of purchasing and reselling diesel units, or the longer-term lease of such units. At this time, it is YEC's evidence that neither of those alternative options are viable or prudent in comparison to YEC continuing to rent mobile diesel units for the test year winter months.

In particular, the purchase/resale option would not have been feasible for the 2023 and 2024 test years because of the key factors outlined in YEC's business case,[62] including the following:

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[56] YUB-YEC-1-35 REVISED, Follow-up Question #4, Exhibit 5, PDF p. 26.
[57] YUB-YEC-1-1 Attachment 1, Exhibit 2, PDF p. 219.
[58] Exhibit 1, PDF p. 90; YUB-YEC-1-35 REVISED, Exhibit 5, PDF p. 15.
[59] YUB-YEC-1-35(a)-(c), Exhibit 2, PDF p. 320.
[60] YUB-YEC-1-35 REVISED, Follow-up Question #7, Exhibit 5, PDF p. 38.
[61] YUB-YEC-1-35 REVISED, Follow-up Question #6, Exhibit 5, PDF p. 35.
[62] Exhibit 1, PDF pp. 91-92.

- The diesel rental equipment that YEC is currently renting is the only known rental option available to YEC, and that equipment would not be considered prudent for capital spending by YEC.

- YEC would need sufficient time to complete prudent planning and implementation activities (including design, procurement and installation) before purchasing additional new diesel units beyond those included in the 10-Year Renewable Electricity Plan. This could not have been done in time to displace the need for rental diesels in the test years.

- Delays in commissioning the BESS Project, replacing permanent end-of-life diesel capacity in Dawson and Whitehorse, adding new permanent capacity in Dawson, and the Atlin Hydro Expansion Project have materially increased the 2024 diesel rental requirement beyond what was forecast in the 10-Year Renewable Electricity Plan and recent updates to that plan.[63]

- If YEC had planned to purchase new diesel units based on an expectation that they would be resold when Moon Lake Pump Storage is commissioned, there would have been no apparent feasible option at the time of purchase to lock down a time and acceptable price for future sale of those units.

- Due to fast-changing environmental regulations, diesel units purchased today based on an assumed future unconfirmed sale may be very difficult to market in future at any acceptable price.

It is also YEC's evidence that, to date, short-term diesel rentals have resulted in lower GRA revenue requirements in the near term than would have been feasible with new capital facility options. For example, the Levelized Cost of Capacity (LCOC) for Faro rented diesels over a 10-year period with 4% annual price inflation is $239/kW-yr. In contrast, using new purchase costs for the 5 MW of Faro units in service in 2024 at $3.66 million/MW, the LCOC for new units sold in the 11th year after commissioning could not come close to competing with the rental option without assuming unrealistically high resale prices. For example, even with an unrealistic 10-year resale price equal to 75% of original cost, YEC's updated estimate of the LCOC for the purchase/resale option would be $281/kW-year – much higher than the LCOC for the rental option.[64]

As for the possible alternative option of a longer-term lease of diesel units, it is YEC's evidence, based on the information available to date, that such a longer-term lease would neither have been viable nor prudent compared to the continued short-term rental of diesel units during the winter months of the test years. The rental diesels are only needed to close the N-1 dependable capacity shortfall for about four and a half months of the year, from the start of December until

[63] In contrast, the forecast dependable capacity shortfall for winter 2025/26, with committed new diesel and BESS in service, is reduced to 19.7 MW (11 diesel rentals, excluding spares). Completion of the Atlin Hydro Expansion Project as included in the 10-Year Renewable Electricity Plan would enable further near-term reduction of diesel rentals. See YUB-YEC-1-1, Table 1.
[64] Exhibit 1, PDF p. 95; YUB-YEC-1-48(d), Exhibit 2, PDF p. 375; YUB-YEC-1-35 REVISED, Follow-up Question #4, Exhibit 5, PDF p. 28.

mid-April. YEC has no interest and to date has seen no value in paying for a lease of those units year-round.[65]

In all of the circumstances, it is apparent that YEC's decision to rent 20 diesel units (excluding the 2 spares) in the test years to close the N-1 dependable capacity gap for the winters of 2023/24 and 2024/25 was both prudent and necessary. YEC submits that it must be permitted to recover the costs of those units in this GRA.

2.2.3 TRANSMISSION AND DISTRIBUTION

Total brushing costs are forecast to decrease by $0.020 million in 2023 and 2024 ($1.368 million each year) from 2021 approved ($1.388 million). The overall transmission and distribution budget is relatively constant, with the majority of the transmission and distribution expense focused on brushing.[66] Brushing activities are based on Yukon Energy's brushing policy and brushing plans. The IRs and oral testimony have highlighted YEC's success since establishing a regular cycle as per the policy.[67]

During the IR process and oral hearing, differences in actual and approved brushing costs were reviewed:

- During the oral hearing, Yukon Energy noted in response to undertakings that 2018 actual brushing costs were lower than 2018 approved brushing costs as "in 2018, our transmission and distribution department had to focus its attention on the major transmission line replacement project. Our T&D department did not have capacity to complete that project as well as provide support on the full brushing program."[68]

- The actual brushing cost in 2019 was $1.176 million, and the 2020 brushing cost was $1.365 million. [69]

- The decrease in spending during 2022 ($1.180 million) was due to challenges in completing the work. Wildfires, contractor availability, and mechanical breakdowns all negatively impacted the completion of the planned scope of brushing work. These issues were not experienced to the same extent during 2023.[70] As a result, less brushing work

[65] Exhibit 1, PDF p. 92. YEC will continue to re-assess all options, including lease, for addressing future dependable capacity shortfalls.
[66] YUB-YEC-1-50 (c-d). The transmission and distribution department annually incur administrative costs primarily consisting of helicopter rentals to scan the lines for the purpose of identifying issue areas. The T&D Department is also responsible for other costs, including: Pole straightening; Planned repairs/maintenance; Unplanned repairs; System operations; and Outage response. Distribution also includes: Street light maintenance; and Pole inspections and audits. Administrative costs are not a factor contributing to the increase in other non-labour costs in 2022 as compared to 2021 actual costs.
[67] Application, Pg 3-19 notes an overall decrease in the number of tree caused outages and an increasingly competitive bid process. Tender packages offer much higher quality information and, along with an increase in contractor familiarity with the geography and conditions of YEC lines, have resulted in positive tender results. Significant work has also been done in developing brushing specifications to be followed by contractors as well as a guideline for brushing tender evaluation.
[68] March 7, 2024 Transcript page 462.
[69] March 7, 2024 Transcript page 462.
[70] YUB-YEC-1-50 (a-b). The preliminary actual brushing costs for 2023 are $1.339 million [March 7, 2024 Transcript, page 462 lines 1-2].

was completed in 2022, which allowed more budget to be allocated to other non-brushing activities.

- During the oral hearing, the importance of the brushing to reduce outages was also highlighted.[71]

In summary, the transmission and distribution expense forecasts for the test years are reasonable and should be accepted.

2.3 RATE BASE, DEPRECIATION AND AMORTIZATION

Mid-year net rate base in the 2024 test year is forecast in section 3.4 of the Application at $376.004 million, an increase of $66.538 million (21.5%) over 2021 approved. This 2024 increase reflects growth in mid-year rate base for net plant in service of $65.054 million from 2021 approved (Table 3.13 in section 3.4 of Application); that growth is mainly due to capital cost increases in rate base that are addressed in section 3 below. Changes in treatment of the Low Water Reserve Fund (LWRF) as an offset to rate base also impact the forecast test year mid-year net rate base (see section 2.3.1 below for review of this change).[72] Updates to forecast rate base additions have reduced forecast mid-year net rate base to $327.9 million in 2023 ($4.5 million reduction) and $372.8 million in 2024 ($3.2 million reduction).[73]

Depreciation and amortization costs net of contributions are forecast in section 3.4 of the Application at $15.161 million in the 2024 test year; an increase of $2.530 million over 2021 approved, reflecting changes in plant in service.[74] Updates to forecast rate base additions, including deferrals of forecast 2023 project in-service to 2024 for projects, have reduced forecast depreciation and amortization costs net of contributions for 2024 by approximately $0.3 million.[75]

Subject to addressing issues related to capital costs (see section 3 below) and removal of LWRF as an offset to rate base (see section 2.3.1 below), no issues have been identified during the proceeding regarding rate base or depreciation and amortization expenses. Accordingly, the rate base, depreciation and amortization rate changes proposed in the Application are reasonable and should be accepted, subject to the review of capital costs added to rate base and the removal of the LWRF offset to rate base.

2.3.1 LOW WATER RESERVE FUND (LWRF) AS OFFSET TO RATE BASE

Board Order 2022-03 (Appendix A, para 368) directed YEC, on a go forward basis, to treat the balance in the LWRF as an offset to rate base. The net impact of this change increased YEC's

[71] March 6, 2024 Transcript page 348, lines 18-24.
[72] The approved 2021 net mid-year rate base was increased by $1.5 million due to the required LWRF mid-year balance offset to rate base as directed in Board Order 2022-03 (Appendix A, para 368). The Application forecast for 2023 and 2024 mid-year rate base did not include any LWRF offset.
[73] Undertaking #23, Attachment 1, Table 3.13 compared with Application, Table 3.13.
[74] Section 3.4 of the Application also reviews continuity schedules for the Hearing Cost Reserve Account, Deferred Vegetation Management, the Reserve for Site Restoration, Defined Pension Deferral Account, and Proposed IPP Purchase Cost Deferral Account. These regulatory deferral accounts do not include any annual changes affecting test year revenue requirements.
[75] Undertaking #23, Attachment 1, Table 3.1 compared with Application, Table 3.1.

2021 mid-year rate base by $1.5 million (due to LWRF negative balance), and reduced YEC's 2022 mid-year rate base by $6.3 million (due to LWRF positive balance).[76]

In Section 3.4 of the 2023/24 GRA Application, YEC is applying for a change to this Board direction, and for removal of this LWRF offset to rate base for the test years based on considerations that are reviewed below.

The Application's forecast rate base reflects this proposed change. If the LWRF continued to be an offset to rate base for the test years, increasing LWRF due to water availability forecast to be above long-term average (LTA) would have the following effects on mid-year rate base and revenue requirement for the test years:[77]

- Reduction in mid-year net rate base of $12.004 million in 2023, and $15.057 million in 2024; and

- Reduction in forecast revenue shortfall of $0.455 million in 2023, and $0.910 million in 2024.

The need to remove the LWRF offset to rate base, on an ongoing basis, is reviewed below.

In summary, the LWRF exists during the test years solely to minimize the effect on ratepayers "that would otherwise be caused by variation in actual renewable source variability, including the variation caused by drought conditions" as required by OIC 2021/16. It was not established to provide any role in financing, or providing offsetting contributions to, YEC's rate base. Use of the LWRF to offset YEC rate base introduces new effects on ratepayers caused by variation in actual renewable source availability, and is therefore contrary to the purpose of the LWRF and the directions of OIC 2021/16. Treating the LWRF as an offset to rate base is also contrary to the requirements of section 32 of the *Public Utilities Act*, and is not appropriate or consistent with normal principles established in Canada for utilities as directed by section 3 of OIC 1995/90.[78]

Specific considerations supporting removal of the LWRF as an offset to rate base are reviewed in more detail below:

1. Notwithstanding the Board's initial determination in Order 1992-1 to treat low water reserve funds as financing rate base through a deduction from rate base, in YEC's 1996/97 GRA (Board Order 1996-7) and all subsequent YEC GRAs until Order 2022-03 and the passage of OIC 2021/16, the Board has removed any use of the LWRF (or its equivalent, i.e., the DCF) as an offset to YEC rate base. In summary, prior to OIC 2021/16, the Board for over 25 years has consistently treated the LWRF as a deferral account to address thermal generation cost impacts from water variability and not as source of funding for YEC rate base.

2. There is no provision of OIC 2021/16 that allows the LWRF to be used for any purpose inconsistent with minimizing the effect on rates that would otherwise be caused by

[76] Application, page 3-28. Footnote 6.
[77] YUB-YEC-1-26(b) – Attachment provides details.
[78] YUB-YEC-1-27(d).

variation in actual renewable source availability. Board direction to use the LWRF to offset rate base will create effects on rates that are inconsistent with the LWRF's required purpose under OIC 2021/16.[79] In summary, OIC 2021/16 confirms the role of the LWRF as evidenced in prior Board decisions since the 1996/97 GRA, it provides no basis for now using the LWRF as an offset to YEC's rate base, and it provides clear additional reasons for ensuring that the LWRF is not used to finance rate base.[80]

3. The net impact of the change in 2021 to using the LWRF as an offset to rate base can result (contrary to OIC 2021/16) in rate base (and therefore rates) increasing when water availability is below long-term average and declining when water availability is above long-term average.[81]

    a. This change increased YEC's 2021 rate base when the LWRF was negative (LWRF in mid-2021 was negative $1.5 million due to lower water availability causing a LWRF balance of negative $4.272 million at the end of 2020); in contrast, improved water conditions in 2021 resulted in positive mid 2022 LWRF balance of $6.3 million, reducing the mid-year 2022 rate base by this amount due to the new requirement for LWRF to offset rate base.

    b. Under drought conditions the LWRF rate base offset as currently approved by the Board is likely to swing (due to changes in water availability) from positive effect on ratepayers due to a reduction in rate base and rates (when above average water availability and high LWRF reduces rate base) to negative effect on ratepayers due to an addition to rate base and rates (when drought reduces LWRF and increases the rate base). This swing could be from $16 million positive to $16 million negative or net $32 million rate base increase based on the current maximum and minimum balances approved by the YUB, and thereby during a drought cause an increase in revenue requirement related to return on rate base (equal to an annual return increase of $1.77 million based on 2024 GRA Application average cost of capital of 5.54%).[82]

    c. As the LWRF deals with the variance between long-term average and actual thermal generation, there should not be any LWRF transfer forecasts for the 2023 and 2024 test years as part of the GRA rate setting process. The inclusion of any LWRF transfers for the 2023 and 2024 GRA test years would directly contradict OIC 2021/16 requirements [i.e., the revenue requirements would not be set based on long-term averages].[83]

    d. Further, the inclusion of forecast estimated 2023 and 2024 LWRF transfers as an offset to rate base for the 2023 and 2024 test years would again result in a reduction of the revenue requirements and therefore be in direct contravention of OIC 2021/16 requirements (as the rates would be lower than the rates that are set based on long-term averages, everything else being equal).[84]

[79] YUB-YEC-1-28(a-b).
[80] Application, pages 3-28 and 3-29.
[81] Application, page 3-28.
[82] YUB-YEC-1-27(b).
[83] YUB-YEC-1-26(a).
[84] YUB-YEC-1-26(a).

4. Treating the LWRF as an offset to rate base is also contrary to the requirements of section 32 of the *Public Utilities Act*. In particular, the balance of the LWRF is irrelevant to the Board's determination of what costs must be included in YEC's rate base in accordance with the statutory requirements set out in section 32(1) and (3), and there is nothing else in section 32 of the Act that could authorize the Board to apply the LWRF balance as an offset to rate base. As such, the effect of an offset would be to deny YEC the fair return (less 0.5%) that it is entitled to earn under section 2 of OIC 1995/90 on a rate base that is properly determined in accordance with section 32 of the Act.[85]

5. LWRF use to fund rate base is not appropriate or consistent with requirements applicable to long-term financing of YEC rate base:

    a. Use of the LWRF to finance YEC rate base places new risks on YEC financing to the extent that LWRF funds are not YEC funds, and will vary due to factors beyond YEC's control, thereby placing YEC's overall long-term financing as required for its rate base at risk and without precedent to any comparator utility's business risks. Determining the actual amount of hydro power generation likely to be available cannot reasonably be forecasted beyond about six to 18 months. In particular, there is always a risk of drought conditions arising that could result in material LWRF reductions within a period of a few years.

        - Mr. Epp explained at the hearing that using the LWRF to fund part of rate base "would not be a prudent way for me to finance a business, something that is out of my control".[86]

        - Mr. Osler also reviewed how the LWRF is not designed to finance rate base, and can be materially reduced very quickly and without ability to forecast in advance during a drought.[87]

    b. The extent to which the LWRF is likely to be positive – or at its maximum allowed level – over multiple years has no relevance to supporting any use of the LWRF use to finance rate base.[88] Prior LWRF or DCF balances show material fluctuations on several occasions relating to water availability, mine load

[85] YUB-YEC-1-27(a).
[86] March 7, 2024 Transcript, page 510, lines 5-10.
[87] March 7, 2024 Transcript, pages 508-509, page 530 line 10 to page 531, line 11.
[88] Appendix A to Board Order 2022-03 at par. 368 noted, as potential basis for LWRF use as offset to rate base, YEC testimony in the 2021 GRA proceeding "that YEC expects the LWRF to maintain a positive balance (i.e., collecting funds for future low water events) and that a positive balance is expected to exist in most years." Exhibit 19 has clarified the YEC testimony of Mr. Mollard at page 185 of the 2021 GRA hearing transcript that the Board relied upon – Mr. Mollard on this page emphasized that the LWRF is a smoothing mechanism to reduce volatility of rates to ratepayers, and only confirmed that positive balances were maintained when feasible so that there will be funds to address the impact of a drought, i.e., no evidence was provided on fluctuation in the fund balance, or the number of years that it would remain positive before it became negative as allowed under the Term Sheet approved by the Board. Review of Volume 2 of the 2021 GRA hearing transcript indicates some further discussion with Mr. Mollard at pages 182 to 190 where opinion was provided, based on models rather than historic actual experience, on a positive LWRF balance likely to be retained over many years – however, Mr. Mollard also made clear that the LWRF was not YEC money, that YEC viewed it as a trust fund for ratepayers, and that YEC did not consider it as an offset to rate base or as an amount to be capitalized. Mr. Epp and Mr. Osler also reviewed the fluctuation in LWRF balances and why it is not eligible for funding rate base (see two prior footnote references).

changes, changes in fund caps and other factors, and included years when the fund was negative.[89]

6. The LWRF positive fund balances, when they occur, are augmented by interest payment provisions in the approved LWRF Term Sheet. In response to Undertaking #38, YEC provided details of how interest was applied to the LWRF balance prior to the issuance of YUB Order 2022-03:[90]

    a. The fund balance attracted interest based on the short/intermediate term bond rates in which the utility may invest the fund, with any negative balances only attracting interest at the lowest short-term borrowing rate available to the utility through a line of credit.

    b. When the fund balance was positive (indicating a benefit to ratepayers), that positive balance attracted interest that was added to the fund balance [i.e., increasing the balance]. Conversely, when the fund balance was negative, the calculated interest further reduced the fund balance. This interest calculation had no impact on YEC earnings as the calculated interest either reduced or increased the fund balance.

    c. These interest provisions addressed any short-term use of these funds by YEC. There is no evidence that YEC has used positive LWRF fund balances for long-term rate base financing, except when directed by the Board to use the LWRF as an offset to rate base.

2.4 RETURN ON RATE BASE

Return on rate base expenses are forecast in Tab 3 of the Application at $20.814 million for 2024, an increase of $4.653 million over 2021 approved that is accounted for by the following (capital structure for rate base financing remained at 60% long-term debt and 40% equity).[91]

- Increase in interest expense on long-term debt of $2.276 million, averaging 3.43% (compared with 2.94% in 2021 approved), of which $1.172 million reflected increase in mid-year rate base and $1.104 million reflected increase in long-term average debt cost rate; and

- Increase in return on equity (ROE) of $2.377 million, of which $2.302 million reflected increase in mid-year rate base and $0.075 million reflected increase in the ROE percentage to 8.70% compared with 2021 approved at 8.65% [prior to the need to reflect the new BCUC benchmark as reviewed in section 2.4.1 below].

[89] Review of DCF-LWRF year end balances from 2012 to 2021 shows six of 10 years when the actual balance was not stable at the then maximum allowed level. The fund balance was negative at the end of 2019 and 2020.
[90] See Exhibit 17, Undertaking #38 and response to YUB-YEC-3-2. Mr. Epp reviewed LWRF interest March 7, 2024 Transcript, page 502 line 3 to page 504, line 16.
[91] Exhibit 1, Table 1-2 in Tab 1 and Schedule 4 in Tab 7 provide the referenced details.

Updates to forecast rate base additions have reduced forecast rate base return by approximately $0.3 million for 2023 and approximately $0.2 million for 2024.[92]

No major issues were raised in IRs at the oral hearing on the Application's capital structure for rate base financing or on the forecast interest rates. The 2023-2024 test year ROE determination is reviewed in detail below to address updates required due to the BCUC determination of an updated benchmark ROE that is to be applied for the YEC GRA 2023-2024 GRA test years.

2.4.1 RETURN ON EQUITY (ROE)

YEC's comments below regarding the ROE focus on addressing the following:

1. Continuing need for simplified approach to determine fair ROE;
2. YEC Application ROE at 8.70% based on prior BCUC benchmark of 8.75%.
3. BCUC GCOC Stage 1 Decision & Order G-236-23 and Stage 2 Order G-6-24; and
4. Retain deemed equity at 40%.

Continuing Need for Simplified Approach to Determine Fair ROE

Since at least the YEC 2005 revenue requirement proceeding, the Board has consistently approved a simplified approach using a BCUC benchmark and evidence on BCUC approved risk premiums for other BC utilities to determine a fair ROE as required by OIC 1995/90 for Yukon utilities. The Board noted in Order 2009-08, that it "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," and that it "strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon."[93] This simplified approach avoids the need for expert evidence to determine the risk premium adder.

Throughout these ROE determinations, the Board has also consistently determined that the applicable business risk premium was higher for YEC than for AEY. In this regard, Order 2009-02 also noted YECL's acknowledgement that "relative to YECL, YEC has more risk".[94]

It is YEC's position that this simplified approach should be continued, with reliance on available BCUC ROE determinations and acknowledgement that the business risk premium for YEC should be higher than AEY.

[92] Undertaking #23, Attachment 1, Table 3.1 compared with Application, Table 3.1. The reductions in Return are due to the reduced mid-year rate base for each test year and, in for 2023, a slight reduction in average cost of debt from 3.315 to 3.27% (see Table 3.15 in Undertaking #23 and the Application).

[93] Order 2009-8, page 53-54. Order 2005-12 had previously used BCUC benchmark and risk premium information to determine YEC approved ROE. This approach was re-affirmed for YEC in Order 2009-08, adopted for AEY in Order 2009-02, and re-affirmed for AEY in Order 2017-01 and for YEC in Orders 2018-10 and 2023-01.

[94] Order 2009-2, page 29.

YEC Application ROE at 8.70% Based on Prior BCUC Benchmark of 8.75%

Pending update of the BCUC benchmark that was then currently being completed, Tab 8 of YEC's Application proposed an ROE of 8.70% based on the then existing BCUC benchmark utility ROE of 8.75% for FortisBC Energy (FEI).

The proposed 8.70% ROE for the YEC GRA test years assumed a risk premium adder (to the benchmark ROE of 8.75%) of 45 basis points as per YUB Order 2018-10, and further reflected the 50 basis point reduction required by section 2 of OIC 1995/90.[95] The following considerations are noted in support of the proposed 45 basis point risk premium:

- Board Order 2018-10 provided a 25 basis point risk premium in recognition of YEC's small size relative to FEI and principles supporting an AEY risk premium of 25 basis point adder in Order 2018-10, plus a further 20 basis point risk premium for YEC in recognition of YEC's added risks related to generation, isolated grid and customer diversity (which includes material industrial loads for YEC). Board Order 2018-10 acknowledged that the YEC's overall risk is greater than FBC's (5 basis point higher YEC risk premium) as well as being greater than AEY's (20 basis point higher YEC risk premium).

- Tables 8.1 and 8.2 in Exhibit 1 document the basis for retaining for the 2023-24 GRA at least the same risk premiums for YEC relative to FBC and AEY, i.e.:

    - YEC continues to be considerably smaller than FBC (comparator revenues, rate base, employees and customer numbers are each 20% of less of FBC);

    - YEC has similar 60/40% debt/ equity ratio capital structure;

    - YEC has materially higher own generation versus purchased generation (100% for YEC versus 45% for FBC and 9% for AEY); and

    - YEC has higher revenue share from industrial customers (21.2% for YEC versus 9.6% for FBC and 0% for AEY).

- Board Order 2023-01 for the 2021 GRA R&V decision used a YEC risk premium of 45 basis points over the FEI benchmark, and then reduced this by 5 basis points "due to changes in risks since Decision 2018-10."[96] The only potential change since Decision 2018-10 noted by the Board was OIC 2021/16, which did not modify YEC's risks relative to FBC or AEY. For the 2023-2024 GRA, there is no reasonable basis, given the data reviewed above, for concluding that YEC's risk premium is not greater than FBC's risk premium, as the Board in Order 2018-10 has already found that "the additional 20 basis points acknowledges the overall risk of YEC as being greater than that of FortisBC (Electric) and greater than that of AEY".

[95] See Exhibit 1, Tab 8, sections 8.2 and 8.3; also see Exhibit 2, YUB-YEC-1-84, YUB-YEC-1-85 and YUB-YEC-1-86.
[96] Order 2023-01, Appendix A, page 13 (footnote 34).

BCUC GCOC Stage 1 Decision & Order G-236-23 and Stage 2 Order G-6-24

Since the YEC GRA filing in August 2023, the Board has had the opportunity during the AEY GRA proceeding to receive evidence and submissions regarding the recent fall 2023 BCUC decision approving an ROE of 9.65% for both FEI and FBC.[97] This is higher than the prior FEI benchmark of 8.75% that was referenced in YEC's Application. A YUB decision on basic ROE determinations for Yukon is therefore expected in the AEY GRA decision. In this context, it continues to be YEC's position that its ROE should be higher than the ROE approved by the Board for AEY, to reflect the long-acknowledged higher risks for YEC relative to AEY.

As reviewed in Exhibit 10, on January 4, 2024, the BCUC issued another decision (Order G-6-24) determining that FEI will be the benchmark for ROE-setting for other BC utilities (excluding FBC). The BCUC also ruled that there could be risk discounts as well as risk premiums relative to the FEI benchmark ROE when determining ROEs for other BC utilities (excluding FBC). No further BCUC decisions on this Stage 2 GCOC are expected until much later in 2024 based on the BCUC's proceeding schedule.

The recent BCUC decision changed the relationship between ROEs for FEI and FBC. Prior to Order G-236-23, FBC's approved ROE of 9.15% was based on the FEI benchmark ROE of 8.75% plus a risk premium of 40 basis points, with FEI's approved deemed equity of 38.5% being lower than FBC's deemed equity of 40.0%. In contrast, Order G-236-23 approved the same ROE (9.65%) for both FBC and FEI, but with FBC's approved deemed equity of 41% being lower than FEI's deemed equity of 45%. The effect of this is that FEI's effective equity return (ROE times deemed equity) for revenue requirement purposes now exceeds FBC's effective equity return, i.e., FEI is now assessed to have a higher business risk than FBC.

In light of this change in approach, FBC (as the electric utility) is now likely to be the appropriate reference BC utility ROE to assist the Board in determining an allowed AEY and YEC ROE in the 2023-24 AEY and YEC GRA proceedings, i.e., FEI (the gas utility) is no longer relevant as a reference or benchmark ROE for Yukon electric utilities, given the BCUC determination that the Fortis gas utility has a higher risk than the Fortis electric utility.

Using FBC instead of FEI as the reference ROE for the current AEY and YEC GRA ROE determinations requires the Board to consider what if any risk premium should be added to the FBC ROE for the purposes of setting AEY's and YEC's ROE. YEC submits that this issue must be considered in light of past Board assessments of AEY's and YEC's risk relative to FBC, and in light of the relevant evidence presented by AEY at the hearing, including confirmation of BCUC's determination that FBC's business risk has not changed substantially since its previous decision on this matter.

In summary, BCUC update decisions have confirmed ongoing use of the benchmark ROE setting process for utilities in British Columbia, and therefore they also confirm the YUB's ability to continue to apply a simplified ROE determination approach for Yukon utilities that relies on available BCUC ROE determinations. Further, given the BCUC determination of the FBC updated ROE at 9.65%, the Board now has the opportunity to use the electric utility ROE to assist in determining 2023-2024 YEC and AEY GRA ROEs. As noted above, YEC's position is that

[97] See Exhibit 2, YUB-YEC-1-84, YUB-YEC-1-85, and JM-YEC-1-1.

whatever final determination is made by the Board on the AEY risk premium relative to the 9.65% updated ROE benchmark, YEC's risk premium should continue to be higher than AEY's based on the current evidence and factors acknowledged to be determinative in setting comparative risk premiums.

Retain Deemed Equity at 40%

YEC proposes to retain deemed equity at 40% for regulatory efficiency, rather than adjust deemed equity to reflect business risk differences, because this is generally what the Board has accepted in the past and its continued use avoids adding unnecessary complexities.

3.0 TAB 5 - CAPITAL PROJECTS

Tab 5 of the Application reviews capital project investments forecast to be added to rate base in the 2023 and 2024 test years compared to 2021 approved rate base, as well as capital spending forecast to remain as work in progress at the end of 2024. Increased capital rate base costs account for $6.004 million (39.1%) of the Application's 2024 revenue shortfall through higher depreciation, interest and equity return costs[98] due to growth of $65.054 million in net mid-year rate base (before working capital costs) from 2021 approved.[99]

Tab 5 reviews forecast capital spending before and after contributions, and prior to any depreciation or amortization expenses, for three categories:

- Capital works (property, plant and equipment), addressed in Tab 5, section 5.2;
- Deferred costs (planning and study costs, regulatory and licensing activities, and dam safety reviews), addressed in Tab 5, section 5.3; and
- Intangible assets, addressed in Tab 5, section 5.4.

The majority of capital expenditure forecast to be added to rate base by the end of the 2024 test year as provided in the August 2023 Application relate to major projects over $1 million which account (before any updates reviewed below) for $110.9 million net addition to rate base for the years 2021-2024 (before depreciation/amortization) while projects with costs between $0.1 million and $1.0 million add approximately $16.0 million.[100]

Key issues are reviewed separately below for major and other capital projects impacting rate base and projects remaining in WIP. Updates to the August 2023 Application provided in IR responses, in the Opening Statement (Exhibit 10), or during the oral hearing, and as reviewed in Undertaking #23, are addressed where relevant for capital projects. Overall, the updates increase

[98] Shows cost increase before considering changes to long-term debt interest rates or ROE percent of rate base as noted in Table 1-2 of Application.

[99] Table 3.13 in Application. Table 3.13 in Application also shows $1.484 million increase in working capital cost contribution to mid-year rate base in 2024 test year compared with approved 2021. In addition, Tab 5 appendices 5.1, 5.3 and 5.5 review capital and deferred projects remaining in work in progress (WIP) at the end of 2024.

[100] Exhibit 1, Table 5.6. Tab 5 provides separate review for each major project forecast to be added to rate base by 2024 with details in Appendices 5.1A, 5.2A and 5.3A; Appendices 5.1B, 5.2B and 5.3B provide separate forecast reviews for all other projects with costs over $100,000.

total net rate base additions by end of 2024 (excluding depreciation/amortization) by approximately $2.2 million, due to a $0.4 million increase for major projects and a $1.8 million increase for overhauls;[101] however, the updates reduce net rate base additions as at the end of 2023 by approximately $8.9 million, reflecting delays of forecast in-service until 2024 for several projects.

Preliminary Issue: Appropriateness of Previously Disallowed Capital Costs

In this GRA, as noted in Section 3.0 of Part 1 above, YEC is seeking capital cost rate base additions for three projects that previously had some or all of their costs disallowed by the Board in the 2021 GRA: the WH2 Uprate Project, the WH4 Servomotor Replacement Project, and the Enterprise Asset Management (EAM) Project. All three of these projects are already in service and providing benefits to ratepayers. In particular, the two WH hydro unit projects provide clear net economic benefits through reduced net costs and extended hydro unit lives, while the EAM is a critical element of YEC's overall required asset management improvements. The preliminary issue addressed below is the appropriateness of the Board's review of previously disallowed capital costs for these projects in the context of the current GRA proceeding.

As outlined previously in YEC's IR responses,[102] YEC's requested rate base additions for previously disallowed costs for these three projects do not constitute retroactive ratemaking. YEC is not requesting recovery of depreciation or return for previously disallowed costs for any of these projects prior to January 1, 2023; it is only seeking recovery on a prospective basis, commencing January 1, 2023, at the start of the test years for this GRA. Mr. Epp confirmed specifically at the hearing that YEC is not seeking to add any of these previously disallowed costs into rate base in 2021, and that it is only seeking to add these previously disallowed costs into rate base in 2023.[103] As such, if the Board grants this request, it will not result in any retroactive change to its revenue requirements or rates for 2021 or 2022 or for any other earlier time period that would constitute a request for retroactive ratemaking that is not provided for under the *Public Utilities Act*.

In the 2021 GRA, the Board previously disallowed some or all of the costs for these three projects because of the insufficiency of the business case evidence that YEC had presented in that proceeding to support their inclusion in rate base in 2021.[104] However, as detailed in YEC's response to YUB-YEC-2-1 (Exhibit 7) and outlined further below, YEC has fully addressed that deficiency in the current proceeding by providing additional evidence that very clearly justifies the costs of all three of these projects and demonstrates their benefit to ratepayers. Regardless of any finding made in the 2021 GRA, it is the Board's obligation in the current proceeding to evaluate whether these costs are prudent and reasonably incurred in light of the fuller and more comprehensive body of supporting evidence that YEC has now put forward. If the Board is satisfied that YEC has presented sufficient evidence to meet that test, then the previously

[101] Undertaking #23, Table 5.6 and Application, Table 5.6. Major project updates by end of 2024 occurred for 2023 Mayo-Faro Diesel Infrastructure Project (+$1.4 million), Lewes River Boat Lock Road Access Rebuild (-$1.2 million), and Aishihik 5 Year Licence Renewal (+$0.2 million); the overhaul cost increase was $1.8 million (AH3 Overhaul +$2.2 million, DD4 Overhaul -$0.45 million).
[102] YUB-YEC-1-4(e) (Exhibit 2, PDF p. 229); YUB-YEC-1-80(e) (Exhibit 2, PDF p. 556).
[103] March 7, 2024 Transcript, page 473, lines 12-16; page 475, lines 2-13; page 602, line 14 - page 603, line 7.
[104] YUB Order 2022-03, Appendix A, paragraphs 277-278, 281-282, 332-333.

disallowed costs for these three projects must be included in rate base effective January 1, 2023.[105]

Preliminary Issue: YEC Financial Policy and AFUDC

YEC financial policy regarding capitalization versus expensing of costs, and relating to Allowance for Funds Used During Construction (AFUDC), was examined during Board IRs and cross examination during the oral hearing. For clarity as regards YEC forecast capital costs in the Application, YEC emphasizes the following key points regarding its financial policy, the policy's application to capitalization, and AFUDC related to capitalized costs:

- YEC's current financial policy remains Finance Policy FA-016 (Exhibit 14) as previously approved by the Board in Board Order 2018-10, Appendix A, paragraph 540, which defines accounting policy for costs incurred in relation to deferred cost planning activities. The following YEC accounting guidelines provide additional support and guidance for YEC staff in implementing this policy:[106]
    - Finance Accounting Practice FX-005 provides guidelines for capitalization and amortization of study costs [this document was provided as Attachment 1 to YUB-YEC-1-63(f)]; and
    - Finance Accounting Practice FX-008 provides guidelines for intangible assets [this document was provided as Attachment 2 to YUB-YEC-1-63(f)].[107]
- The following additional YEC accounting guidelines were filed during the proceeding:
    - Finance Accounting Practice FX-Appendix provides detailed definitions for various Property, Plant and Equipment (PP&E) terminologies [this document was provided as Attachment 1 to Undertaking #27 – and was also provided in the 2021 GRA]; and
    - Finance Accounting Practice FX-004, which is referenced in the Finance Accounting Practice, provides guidance on the application of AFUDC to capital projects during construction to cover the cost of financing projects during construction using the Weighted Average Cost of Debt [this document was provided as Attachment 2 to Undertaking #27].
- The Board has previously approved capitalization of deferred cost projects (e.g., planning and study costs, regulatory and licensing activities, and dam safety reviews) for rate regulation purposes in the 2017-2018 and 2021 GRAs consistent with the approved YEC Finance Policy FX-016, referencing the fact that these costs relate to long-term services rather than test year services.

[105] See also: YUB-YEC-1-4(a) (Exhibit 2, PDF pp. 227-228); YUB-YEC-1-80(a) (Exhibit 2, PDF pp. 554-555).
[106] Mr. Epp, March 6, 2024, Transcript, page 367, line 5 to page 374, line 8. Mr. Epp clarified that accounting practices FX-005 and FX-008 are consistent with the Finance Policy FA-016 and work as guidelines "to assist our financial team in just clarifying items at the higher level in the policy itself" [March 6, 2024 Transcript, page 372].
[107] YUB-YEC-1-63(e) and (f).

  - YEC is not aware of the Board raising questions in past YEC decisions regarding any option of expensing these costs in the year the expenses are incurred.

  - Capitalization provides the benefits of smoothing rate impacts. Without capitalization, the impacts on costs and rate requirements would be bumpy.[108]

- Capitalized projects (i.e., PP&E projects, deferred cost projects, and intangible asset projects) are charged AFUDC on costs incurred until project completion in order to cover the cost of debt financing (i.e., no ROE is included) for projects during planning and construction.[109] Throughout past YEC revenue requirement proceedings, the Board has recognized and approved Orders providing for recovery of this cost as an integral part of rate base costs for completed and/or terminated projects. The inclusion of AFUDC costs in capitalized project costs when the Board reviews and approves rates is also consistent with principles established in Canada for utilities, as required by section 3 of OIC 1995/90.

In light of the foregoing, in the absence of any question as to the prudency of the timing of YEC's capital expenditures (i.e., if there is no basis conclude that expenditures were made prematurely, in the sense that YEC incurred capital costs before there was a need for them, as in *Alberta Power Limited v. Alberta Public Utilities Board*, 1990 ABCA 33), YEC is presumptively entitled to recovery of AFUDC on its prudently incurred capital costs while those costs remained in WIP.

In the case of a terminated project such as the Southern Lakes Enhanced Storage Project (SLESP) (as discussed further in Section 3.1.2 below), there is no reasonable basis to question YEC's entitlement to WIP for costs incurred (including AFUDC) up to the time when the Board previously concluded (in YUB Order 2013-01) that SLESP was a viable project with costs that should remain in WIP until the project was completed. Nor is there any evidentiary basis to question the reasonableness of the timing of the costs that YEC continued to incur after that date, up to the time the project was cancelled in November 2022. As outlined in Section 3.1.2 of this Argument, all of the expenditures made by YEC on the SLESP project (including provision for debt financing costs as provided for by AFUDC) were reasonable and prudent at the time those expenditures were made.

Nor is there any reasonable basis to question YEC's entitlement to WIP for any costs (including AFUDC) incurred on the 5-year relicensing of the Aishihik Generating Station (AGS) (as also discussed further in Section 3.1.2 below). Any questions about the timing of YEC's expenditures on the long-term relicensing of the AGS are outside the scope of this GRA, to the extent that those costs remain in WIP, since YEC is not seeking to add those costs to rate base for the current GRA test years. The reasonableness of the timing of those expenditures will properly be dealt with in a future GRA proceeding after the long-term licence renewal process has been completed.

With respect to the other capital cost rate base additions that YEC is seeking in this GRA, YEC has not been put on notice in this proceeding of any issue as to the reasonableness of the timing

[108] Mr. Epp, March 7, 2024 Transcript, page 601, lines 3 to 18 (reviews capitalization of the transmission line test and treat program over its five year period, and notes that same principle applies to any program that has been capitalized).
[109] YUB-YEC-1-63(a) and (b). See also Finance Accounting Practice FX-004 (Undertaking #27, Attachment 2).

of any of the relevant expenditures. It would be unreasonable – and procedurally unfair – to deny the AFUDC that YEC is presumptively entitled to recover for those capital expenditures without putting YEC on notice of any potential concerns the Board might have about the timing of those expenditures, in order to give YEC a fair and reasonable opportunity to respond to those concerns.

In the circumstances, there is no reasonable basis for the Board to deny any of the AFUDC included in any of the capital cost rate base additions that YEC is seeking in this GRA.

3.1 MAJOR PROJECTS IMPACTING RATE BASE

The Application forecasts $110.846 million net capital additions for the 2021-2024 years before depreciation for major capital, deferred and intangible projects with costs exceeding $1 million, as follows:

1. Fifteen capital projects >$1 million with total capital additions to rate base in the test year forecast in Tab 5 at $70.240 million (excluding updates in Undertaking #23 as well as changes for two projects approved in the 2021 GRA):[110]

    a. **Investment to Address Load Growth Capacity Planning Requirements ($33.825 million Tab 5 net rate base impact):** Thermal Replacement; 2023 Mayo-Faro Diesel Infrastructure (before $1.4 million added cost update provided in Undertaking #23); and Whitehorse Interconnection.

    b. **Spending on Aging Infrastructure and Sustaining Capital Requirements ($28.547 million Tab 5 net rate base impact):** Transmission Line Replacement L178; WH1 Head Gate Replacement; P&C: S250 Callison Protection, Control and Scada Upgrade; MHO Road and Road Slope Stability; Wareham Spillway Concrete Repair; Whitehorse Stoplog Crane Replacement; Schwatka Lake Safety/Debris Boom; Dawson Voltage Conversion; Whitehorse Spillway Stoplog Refurbishment; and Lewes River Boat Lock Road Access Rebuild (before $1.2 million reduced cost update provided in Undertaking #23 for deferral of project in-service beyond 2024 for Lewes River Boat Lock Road Access Rebuild).

    c. **Investment on New Supply Options or to Maximize Renewable Energy Generation from Existing Facilities ($7.867 Million)**: WH2 Uprate Construction and Engineering [Disallowed project cost component from 2021 GRA decision]; and WH4 Servomotor Replacement [Disallowed project cost component from 2021 GRA decision].

2. Three deferred cost projects >$1 million (Aishihik 5-year Water Use Licence Renewal, Demand Side Management (DSM) and Southern Lakes Enhanced Storage Project) with total net rate base impact in Tab 5 of $16.037 million (before $0.2 million addition

[110] As reviewed in Application, page 5-5: Mayo-McQuesten Transmission Line Upgrade final net costs are $0.507 million lower than approved in Board Order 2022-03, Appendix A, para 258. Replace P125 WH2 Head Gate cost of $2.072 million was approved in Board Order 2022-03, Appendix A, para 270, but adding this cost to rate base was deferred to the next GRA ($1.923 million of this final cost was closed in 2020 and the balance of $0.149 million was closed in 2021 as noted in Table 5.2 of the Application).

correction provided re: Aishihik 5-Year Water Use Licence Renewal [see Undertaking #23]).

3. Two intangible projects >$1 million (Enterprise Asset Management and PAMMS) – net rate base impact in Tab 5 of $10.016 million.

Key issues identified for specific major projects are reviewed in more detail below.

3.1.1 MAJOR CAPITAL PROJECTS

Investment to Address Load Growth Capacity Planning Requirements

Thermal Replacement

The 16.5 MW thermal replacement project is required to provide dependable capacity to address the existing and forecast Yukon Integrated System (YIS) dependable capacity shortfall under the N-1 planning criterion. The installation of additional thermal capacity in Dawson City (above the amount required to replace existing thermal assets) also retains an adequate amount of dependable capacity for retail customers in Dawson during emergency situations as demand for electricity continues to grow in the community.[111] Expected in service that impacts test revenue requirement is 5 MW at Faro in Q3 2024.[112]

The 16.5 MW thermal replacement includes: 5 MW diesel replacement in Faro (in-service in 2024 and included in base rate for 2024),[113] 5 MW diesel replacement in Whitehorse (forecast in-service in 2025); and 6.5 MW diesel in Dawson (consisting of 2.5 MW for replacement of the existing diesel units to be retired, and a 4 MW expansion to meet growing demand). The 5 MW of new dependable thermal capacity being provided in 2024 at the Faro diesel plant helps to address the existing and forecast YIS dependable capacity shortfall under the N-1 planning criterion. The portions of the Thermal Replacement project at Whitehorse and Dawson will provide further displacement of diesel rental requirements for winter 2025/26 (these project component costs are forecast to remain in WIP at the end of 2024 and therefore do not affect 2023/24 GRA revenue requirements).[114]

No material issues were raised in IRs or at the oral hearing regarding this project.

2023 Mayo-Faro Diesel Infrastructure

Mayo-Faro Diesel Infrastructure Project will provide infrastructure for mobile and modular diesel units at a new Mayo site further away from the community to assist in meeting the Yukon Integrated System (YIS) dependable capacity needs for the winter of 2023/24 and beyond under the N-1 dependable capacity planning criteria. The Project will also provide diesel infrastructure

[111] Additional information is provided in response to YUB-YEC-1-65; NY-YEC-1-15 (d) and (e) and NY-YEC-1-18.
[112] YUB-YEC-1-65(c) and (d).
[113] This replaces 2023 retirement of Faro Diesel 1 (5.1 MW) and will displace the need to rent three additional 1.8 MW diesel units for winter 2024/25.
[114] YUB-YEC-1-65(a) confirms that $29.771 million in Table 5.5, $32.329 million as corrected in the IR response, for this project refers to the 2024 closing WIP balance on costs incurred to that point for the Dawson and Whitehorse portions of the Thermal Replacement Project. None of these costs impact rate base during the test years. The total forecast cost for Dawson and Whitehorse portions is at $42.4 million as noted in response to YUB-YEC-1-65(a).

modifications at the Faro site to accommodate new diesel installations at this site (see Application, Section 5.1A-2, page 5.1A-13; and NY-YEC-1-17 for further details). The project is in service.[115]

During the oral hearing, YEC reported that as of December 2023 the budget for this project was increased by $1.4 million, from $4.3 million in the Application to $5.7 million (Mr. Murchison, March 6, 2024 Transcript, volume 3, page 318, lines 3-19). The cost for 2023 as reviewed in Undertaking #23 was updated from $4.3 million to $5.290 million based on 2023 actuals [the 2023 cost is closed] with forecast spending of $0.410 million in 2024.

No material issues were raised in IRs or at the oral hearing regarding this project.

Whitehorse Interconnection

The Whitehorse Interconnection project involves the modification and expansion of the S171 substation, including the purchase and installation of a new higher capacity transformer, and construction of transmission lines to connect the BESS project and the Whitehorse LNG to the S171 substation (see Application, Section 5.1A-3, pg 5.1A-15 for further details regarding the need for the project).[116] The Project is required to avoid the BESS and new thermal generation at Whitehorse creating a new N-1 contingency risk at S150, which, in the absence of this Project, would have required YEC to invest in additional dependable capacity to satisfy increased N-1 dependable capacity requirements.[117] The Whitehorse Interconnection project supports both new sustainable and renewable projects.[118] The project is expected to be completed in Q1 2024.[119]

During the oral hearing, it was confirmed that this project was not part of the BESS project [March 7, 2024 Transcript, page 538 line 23 - page 539, line 4].

No material issues were raised in IRs or at the oral hearing regarding this project.

3.1.1.1 Capital Spending on Aging Infrastructure and Sustaining Capital Requirements

Transmission Line Replacement L178

The Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late 1960s and early 1970s and plays a critical role linking key hydro generation sources to load centres in Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in

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[115] YUB-YEC-1-65(c) and (d).

[116] As noted in the Application, without this reconfiguration, the BESS and new thermal and hydro generation (e.g., rental diesels, hydro uprates), in combination with other existing dependable capacity at Whitehorse would trigger a new N-1 scenario and would result in additional dependable capacity being required on the YEC system.

[117] The development of the BESS and the planned addition of 5MW of replacement thermal generation at the WRGS site triggered the need for a reconfiguration of the substations serving the WRGS and the expansion of the S171 Riverside substation (S171). Without the Whitehorse Interconnection project, a new higher N-1 dependable capacity requirement would have been created with the Whitehorse substation.

[118] NY-YEC-1-1 - A summary of the more significant spending to address capacity planning requirements is provided on page 5-3 of the Application, which shows the net rate base impact of approximately $33.825 million. This includes the Whitehorse Interconnection project of $11.199 million that supports both new sustainable and renewable projects.

[119] Updated provided per YUB-YEC-1-65(c) and (d).

2017 indicated that key components of the WAF system were at end of life, in poor condition, and required replacement.

The need for this project, alternatives considered, and risk of not proceeding with it at this time were reviewed in the Application (Section 5.1A-4, Exhibit 1, PDF p. 170).[120] In particular, failure to complete this project will lead to significant reliability impacts as well as higher overall costs. Additionally, risks to employee health and safety are reduced by planned maintenance activities that remove the likely need for emergency work.

The total project cost has increased substantially from the 2021 GRA estimate of $8.3 million for a number of reasons:

- L178 is the only line in the WAF system that required significant rock blasting in order to replace certain structures; the terrain in the area is much less accessible, requiring specialized equipment and increased installation time for each structure.

- Inflationary pressures have driven both contractor rates and material costs higher than anticipated over the last few years; and

- The cost to permit and build access roads to the structure locations has been included in the cost of this project (this was planned to be done separately as of the last GRA, similar to the other transmission lines).

Additional information was provided in YUB-YEC-1-72. This includes a summary in (a) and (b) of structures replaced to date or planned to be replaced by year (2024-27),[121] as well as detailed plans for 2022-2024; an explanation in (c) regarding conditions increasing costs and why they were not factored into the original estimate; and a further explanation in (d) that this work is being done primarily by contractors with YEC powerline technicians supporting the project as required (typically during isolation of the transmission line).

No material issues were raised in IRs or at the oral hearing regarding this project.

P&C: S250 Callison Protection, Control and Scada Upgrade

This upgrade project[122] is urgently required because the S250 Callison Substation has been identified as at critical risk of failure due to several factors including protection and control assets like protection relays being at end of life. Details on the need, justification and risk for not proceeding with the project are provided in Application, Section 5.1A-6, pg 5.1A-20 and 5.1A-21

[120] Failure to complete this final element of the WAF refurbishment project would increase the risk of component failure on L178 resulting in a split in the North-South grid and significant thermal generation costs in the northern gird to maintain supply to all customers.

[121] Estimates for 2025-27 will be updated based on the results of the 2024 tendering process.

[122] This project is to upgrade the Protection, Control, and SCADA communications in the Callison substation, install new S250-52-R2 breakers for reactors R2 and R3 and install a new tap changer control for the Dawson distribution regulating transformer. The SCADA network equipment will also be upgraded with the Thermal Replacement project, the Synchronous Condenser Protection and Controls Upgrade projects in mind.

and YUB-YEC-1-73.[123] The completion of this project supports other projects in Dawson such as the Thermal Replacement Project (connecting the Callison 12.5kV switchgear), and the Dawson Voltage Conversion Project, as well as the Synchronous Condenser Overhaul project. The project is expected to be completed in Q2 2024.[124]

No material issues were raised in IRs or at the oral hearing regarding this project.

MHO Road and Road Slope Stability

This project is required to address two key safety and reliability issues identified relating to slope stability that affects the area in and around the Mayo Generating Station (MH0 or Mayo A). Details on the need, justification and risk for not proceeding with the project are provided in Application, Section 5.1A-7, pg 5.1A-22. The project is expected to be completed in Q3 2024.[125]

No material issues were raised in IRs or at the oral hearing regarding this project.

Wareham Spillway Concrete Repair

This project is required to address interim concrete repairs of the Wareham spillway at the Mayo Generating Station (see Application, Section 5.1A-8, pg 5.1A-24 for details on the need, justification and risks of not proceeding with the project).[126]

Interim repairs will be continually required until the spillway can be either permanently repaired or replaced. This will be completed under a separate project – Mayo Civil/Structural Infrastructure Program – to be started in 2023. Permanent replacement of the spillway is estimated to be completed between 2027 and 2030.

The decision to capitalize the project is based on the original engineering assessments that the fixes would last at least five years; and accounting treatment to capitalize is beneficial to ratepayers as the entire expense is not all recorded in one year. During the 2021 year-end accounting procedures and audit, YEC wrote off all previous Wareham Spillway costs as that asset was not considered to have any useful service life left at that time. All previous Wareham Spillway costs have been removed from rate base and are not being recovered from ratepayers.[127]

No material issues were raised in IRs or at the oral hearing regarding this project.

[123] Protection relays have failed at the substation, leaving equipment exposed to a higher risk of damage and personnel exposed to increased safety risk. The potential risk of not completing the S250 Callison upgrade includes failure of the protection relays and SCADA remote terminal units which are currently at end of life. Should this equipment fail, there is the potential for an extended outage in Dawson with the possibility of extended diesel usage. This substation is critical to the city of Dawson as it supplies the city with clean renewable energy from the grid as well as backup diesel power to customers on the Hunker Feeder.
[124] YUB-YEC-1-65(c) and (d) - project delayed due to design flaw resulting increased scope and cost required to address.
[125] YUB-YEC-1-65(c) and (d) - contractor did not complete the hydroseed in 2023; no change in scope; and increased cost due to quantity variance.
[126] Wareham spillway provides the Inflow Design Flood (IDF) capacity to the Wareham Lake system. There is no other spilling structure at Wareham Lake which can pass IDF or spring freshet; and inoperability of the spillway during flood increases the risk profile of the Wareham dam significantly.
[127] YUB-YEC-1-74.

Whitehorse Stoplog Crane Replacement

This project is required to address numerous safety and reliability issues that have been identified in recent inspections. The Application provides details on the need and justification for the project and the risk of not proceeding with it, as well as options considered (Section 5.1A-9, pg 5.1A-25 and 5.1A-26). The project is expected to be completed in Q4 2024.[128]

No material issues were raised in IRs or at the oral hearing regarding this project.

Schwatka Lake Safety/ Debris Boom

This project replaces the damaged safety/debris boom at the Whitehorse main dam at Schwatka Lake. A functioning boom is required to ensure public safety and to prevent debris from accumulating at the intakes. It is also critical to Yukon Energy meeting the requirements of the Canadian Dam Association. Design, procurement and installation were publicly tendered (see pg 5.1A-27). Details on the need and justification for the project and the risk of not proceeding with it are provided in Application (Section 5.1A-10, pg 5.1A-27). The project is expected to be completed in Q2 2024.[129]

No material issues were raised in IRs or at the oral hearing regarding this project.

Dawson Voltage Conversion

Dawson City's two 4.16 kV distribution feeders have reached their practical operating limits, resulting in voltage flicker and longer fault clearing times. Teshmont provided its report in 2021, a copy of which was filed during YEC's 2021 GRA proceeding (YUB-YEC-1-66). If this issue is not addressed, that failure will result in reliability safety concerns if protective devices fail to operate; as well as damage to customer equipment; and YEC exposure to the risk of minor fines related to not meeting CEA voltage requirements. Details on the need and justification for this project, and the risk of not proceeding with it, are provided in Application (Section 5.1A-11, pg 5.1A-28). The project is expected to be completed in Q4 2024.[130]

No material issues were raised in IRs or at the oral hearing regarding this project.

Whitehorse Spillway Stoplog Refurbishment

This project replaces the stoplog crane at the Whitehorse spillway gates. The need, justification and options considered for the project were reviewed in the Application, Section 5.1A-9, pg 5.1A-25 and response to YUB-YEC-1-75.[131] Recent inspections by Kone Cranes identified major issues resulting in the crane being condemned. The crane could be authorized for a one-time

[128] YUB-YEC-1-65(c) and (d) - project delayed due to design flaw resulting increased scope and cost required to address.
[129] YUB-YEC-1-65(c) and (d) - project delayed due to design flaw resulting increased scope and cost required to address.
[130] YUB-YEC-1-65(c) and (d) - project delayed due to design flaw resulting increased scope and cost required to address.
[131] answers questions relating to the tendering process, vendors solicited, number of quotes received, price range of quotes and whether YEC administered the public tender process.

emergency use but is otherwise out of service due to multiple significant issues.[132] The project is expected to be completed in Q4 2024.[133]

No material issues were raised in IRs or at the oral hearing regarding this project.

Lewes River Boat Lock Road Access Rebuild

The road access to the boat lock side of the Lewes River control structure upstream of the Whitehorse Generating Station needs to be rebuilt. The Application reviews the need and justification for this project and options considered (Section 51A-13, pg 5.1A-30).[134] YUB-YEC-1-77 clarified that YEC was proposing to capitalize costs to repair boat lock access road in 2024, as the work was expected to be completed in 2024. Later, however, in Attachment 1 to the Opening Statement [Exhibit 10, PDF page 12] and Undertaking #23, YEC noted that this project is now expected to be delayed beyond 2024 and that it will therefore remain in WIP.

No material issues were raised in IRs or at the oral hearing regarding this project.

3.1.1.2 Investment for New Supply

WH2 Uprate and WH4 Uprate (Servomotor Replacement) – Previously Disallowed Costs

As set out in Tab 5 of YEC's Application,[135] YEC is seeking capital cost rate base additions in the total amount $7.867 million in respect of the portions of its costs for the WH2 Uprate Project and WH4 Servomotor Replacement Project that were previously disallowed by the Board in its 2021 GRA decision in YUB Order 2022-03. This total is comprised of the following amounts:

- The $7.078 million difference between the total in-service cost of $12.814 million for the WH2 Uprate Project and the $5.736 million in costs previously approved by the Board in YUB Order 2022-03; and

- The $0.789 million difference between the total in-service cost of $1.337 million for the WH4 Servomotor Replacement Project and the $0.548 million in costs previously approved by the Board in YUB Order 2022-03.

As outlined in Section 3.0 of Part 1 above, YEC is only seeking recovery of these previously disallowed amounts on a prospective basis, commencing January 1, 2023. As such, these requests do not constitute retroactive ratemaking, and it is proper and appropriate for the Board to consider adding these previously disallowed costs to rate base prospectively, having regard to the fuller and more comprehensive body of supporting evidence that YEC has put forward in the present GRA. That evidence includes:

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[132] The option to refurbish the existing crane and related equipment was initially explored however the owner's engineer subsequently hired for the project (Klohn Crippen Berger) provided a detailed assessment report recommending full replacement for several reasons. These include significant known issues, additional issues that could be found during disassembly, timeframes for construction, and the obsolescence of many of the components.
[133] YUB-YEC-1-65(c) and (d).
[134] An assessment performed by a 3rd party geotechnical engineer (Tetra Tech) determined that it was in an unsafe condition for vehicle use; after reviewing options, it was concluded that leaving the damaged road in its current condition was not an option as proper access is required for rebuilding the damaged boat lock and long-term inspection work.
[135] Exhibit 1, PDF pp. 131-132.

- The business case evidence in support of these two projects set out in Sections 5.1A-14 and 5.1A-15 of the Application;[136]

- The additional evidence provided about these two projects in YEC's responses to YUB-YEC-1-4 and YUB-YEC-1-19;[137] and

- The further, more detailed evidence provided about both of these projects in YEC's response to YUB-YEC-2-1, including:

    - The detailed tables that YEC has provided at the Board's request for each of these projects, comparing the information that was provided in the 2021 GRA and the current GRA, and explaining how that information addresses the concerns the Board previously expressed in YUB Order 2022-03;[138]

    - The summaries that YEC has provided in the prefaces to both of those tables of the key points of relevance to the Board's evaluation of each project's current GRA business case;[139] and

    - The additional information provided in Appendix A to that IR response outlining the evolution of the WH2 Uprate Project, and the extensive work that was done on project scoping from the time of issuance of the initial, high-level study completed by Hatch in 2017 (which the Board relied on as the basis for the $5.736 million in costs that were approved in Order 2022-03) up to the time YEC's board of directors approved a $12.3 million budget for this project in June 2019.[140]

The key points arising from all of this additional evidence can be briefly summarized as follows:

<u>WH2 Uprate Project</u>

The $5.736 million in costs previously approved by the Board for the WH2 Uprate Project in YUB Order 2022-03 were based on a preliminary, high-level cost estimate of $4.782 million that was provided by Hatch in 2017 for uprating a unit with increased turbine flow, plus a 20% allowance for cost overruns. However, the Board made that decision without the benefit of the substantial additional information that YEC has now provided in the current proceeding to demonstrate the prudency of the full $12.814 million in costs ultimately incurred on this project.[141]

As outlined in the preface to Part 1 of YUB-YEC-2-1,[142] the scope of the WH2 Uprate Project that YEC's board of directors ultimately approved in June 2019 was much greater than the scope of work that was included in the initial high-level cost estimate that Hatch provided in 2017. The

[136] Exhibit 1, PDF pp. 184-197.
[137] Exhibit 2, PDF pp. 227-229 and 257-258
[138] Exhibit 7, PDF pp. 11-24 and 26-34.
[139] Exhibit 7, PDF pp. 7-10 and 25.
[140] Exhibit 7, PDF pp. 41-46.
[141] Undertaking #34 indicates AFUDC of $317.15k included in total project cost of $12,814.33k, and estimates AFUDC of $175.18k related to the disallowed cost of $7.08 million.
[142] Exhibit 7, PDF pp. 7-10.

WH2 uprate itself was only one component of the full project that was ultimately approved by the board of directors and implemented by YEC, which also included very significant additional refurbishment work that was outside the scope of Hatch's original $4.782 million cost estimate, but which was determined to be necessary and prudent to carry out concurrently with the uprate work in order to extend the life of an aging facility commissioned in 1958. Indeed, some of this refurbishment work was needed to address WH2 deficiencies that it was not possible to identify until after the project was already underway and the WH2 unit was disassembled.

Hatch's 2017 report specifically contemplated that it would be prudent for YEC to consider carrying out this additional refurbishment work concurrently with the uprate, even though the additional refurbishment work was not included in Hatch's original cost estimate.

Hatch's preliminary, high-level cost estimate also did not include the Owner's Cost component of the WH2 Uprate Project (owner's engineer, AFUDC, internal cost and project management), beyond a 10% allowance for "administration and engineering" on the original cost estimate. In the final project scope, YEC had to incur Owner's Cost on all components of the project, including the additional refurbishment work that went significantly beyond the scope of Hatch's original cost estimate.

In addition to the limited scope of work that was included in Hatch's preliminary high-level cost estimate, it is important for the Board to recognize the other limitations on Hatch's estimate, which was in 2017$, and was based on information gathered from different suppliers without any specifics related to the WH2 runners and assumptions in Hatch's study. Hatch's study also included an assumption that the new turbine runners could be purchased at discounted prices by purchasing that equipment for both WH1 and WH2 in as a single contract; however, that assumption became inapplicable in light of YEC's subsequent decision to uprate WH2 only. The Hatch report also substantially understated the benefit of the project that was ultimately approved by YEC's board of directors, estimating that the project as originally scoped would yield avoided thermal generation of only 1.879 GWh/year, in contract to YEC's current projection of approximately 5 GWh/year thermal displacement on a long-term average basis, taking into account the additional refurbishment work that was added to the scope of the project.

As outlined in Appendix A to YUB-YEC-2-1,[143] YEC has now provided the Board with additional, detailed information about the evolution of this project after YEC's receipt of Hatch's initial report in 2017, including the further project scoping and extensive budget process (including RFPs and fixing of prices and guarantees) that YEC undertook for the project leading up to the Board's approval of a $12.3 million budget in June 2019. That final project budget reflected the extensive work done after Hatch's initial report was completed, and the higher budgeted cost was largely attributable to adding further life extension work and other refinements to the final project scope.

As such, it is the final project budget of $12.3 million, rather than Hatch's preliminary, high-level cost estimate, that provides the relevant base for the Board to assess the final project costs, and it is now apparent, based on the additional evidence that YEC has presented in this proceeding, that there is no reasonable basis to cap YEC's cost recovery (prospectively) based on Hatch's original cost estimate plus 20%. The actual final project cost of $12.814 million was only 4.5%

[143] Exhibit 7, PDF pp. 41-46.

higher than the 2019 budgeted estimate, and reflected additional requirements revealed when the unit was opened up for the needed work.

As summarized further in the preface to Part 1 of YUB-YEC-2-1,[144] YEC's evidence before the Board in the current proceeding demonstrates that the overall benefits of this project, including both the uprate itself and the additional refurbishment components of the work completed, are much higher than its costs to ratepayers, with incremental annual test year benefits of $1.105 million compared to the annual test year revenue requirement cost of no more than $0.885 million with total cost included in YEC's rate basis. This indicates that the project reduces costs to ratepayers even before considering the additional life extension and environmental benefits of the project. Moreover, the annual benefits over the project life would be even higher as the annual cost of capital reduces over the years as the cost is depreciated.

Overall, based on all of the evidence that is now before the Board in this proceeding, it is apparent that the full cost of the more broadly scoped WH2 Uprate Project ultimately approved by YEC's board of directors was prudently incurred, for the net benefit of ratepayers. The costs for this project that were previously disallowed in the 2021 GRA should be added to rate base in 2023.

WH4 Servomotor Replacement Project

The $0.548 million in costs previously approved by the Board for the WH4 Servomotor Replacement Project in YUB Order 2022-03 were based on another preliminary cost estimate by Hatch of $0.457 million, plus a 20% allowance cost overruns (total $0.548 million). However, as with the WH2 Uprate Project, the Board again made that decision without the benefit of the substantial additional information that YEC has now provided in the current proceeding to demonstrate the prudency of the full $1.337 million in costs ultimately incurred on this project.[145]

As outlined in the preface to Part 2 of the YUB-YEC-2-1,[146] similar to the WH2 Uprate Project, it is important for the Board to recognize that Hatch's 2017 Capacity Increase Desktop Study provided only a high-level initial cost estimate for the WH Servomotor Replacement Project; that the original cost estimate was in 2017$; and that it did not include YEC costs (owner's engineer, AFUDC, internal cost and project management) or any allowances for installation and commissioning or balance of plant.

During the oral hearing, Mr. Murchison explained that, after the Hatch 2017 estimate, YEC did additional work on the WH4 Servomotor Replacement and then the YEC board approved a budget based on the additional work, in the same way that YEC's board had approved a budget for WH2 Uprate based on additional work done after the Hatch study. The final approved WH4 Servomotor Replacement budget included work beyond the servomotor replacement; Mr. Murchison's recollection was that the work was completed within the approved budget, and that

[144] Exhibit 7, PDF p. 9.
[145] Undertaking #35 indicates AFUDC of $33.90k included in total project cost of $1,337.14k, and estimates AFUDC of $19.41k related to the disallowed cost of $0.789 million.
[146] Exhibit 7, PDF p. 25.

the expanded budget and final costs reflected additional work that YEC had concluded to be prudent and reasonable for this project.[147]

YEC has separately explained that the $0.293 million increase in the servomotor supplier cost, from Hatch's initial estimate of $0.457 million to actual cost of $0.750 million, reflected cost escalations after the 2017 cost estimates plus final design requirements and supplier costs for this work. Replacing the original servomotors with custom spring assisted servomotors was a significant change to the WH4 unit, which required extensive analysis and testing to verify that the unit was capable of handling the added flow and that servomotors could be relied on for safe unit operation. Other additional costs not in the Hatch estimate of $0.587 million have been identified as being for owner's engineer ($0.049 million), internal costs and project management ($0.346 million), and balance of plant ($0.192 million) that consists of a monorail lifting beam to remove/install the servomotors, the piping modifications, and the new governor parts and tuning.[148]

YEC's evidence before the Board in this proceeding demonstrates that the full costs incurred by YEC on the WH4 Servomotor Replacement Project were prudently incurred for the net benefit of ratepayers, with incremental annual benefits of $0.112 million compared to the annual revenue requirement cost of no more than $0.089 million with total cost included in YEC's rate base. This indicates that the project reduces costs to ratepayers even before considering the project's additional environmental benefits. Moreover, the annual benefits over the project life would be even higher as the annual cost of capital reduces over the years as the cost is depreciate.

The costs for this project that were previously disallowed in the 2021 GRA should be added to rate base in 2023.

3.1.2 MAJOR DEFERRED COST PROJECTS

Aishihik Relicensing – Five-Year Licence Renewal

As detailed both in the Application[149] and in Appendix A to YEC's response to YUB-YEC-1-90 in the 2021 GRA,[150] the Aishihik Generating Station (AGS) is a critically important generation asset for the Yukon Integrated System (YIS). It provides the only multi-year hydro storage and the largest winter peak hydro generation capacity on the system, with 37 MW of dependable capacity – more than one-quarter of YEC's maximum dependable generation capacity. Under long-term average conditions, it supplies approximately 25% of the annual YIS generation – and about 40% of annual YIS winter generation concentrated in the months from November through May when peak YIS loads occur and run-of-river hydro supplies are constrained. Cessation or reduction of AGS's operation would require YEC to replace its current generation capacity with some other source or sources of energy that could be relied on during the winter months. No such renewable alternative is in place today.

[147] March 6, 2024 Transcript, page 237 line 23 - page 238 line 23.
[148] Exhibit 1, PDF p. 195; Exhibit 7, PDF p.p. 27-28.
[149] Exhibit 1, PDF pp. 231-232.
[150] YUB-YEC-1-61 Attachment 1, Exhibit 2, PDF pp. 498-499.

The Application also noted that a significantly higher capital cost than $100 million and approximately $12 million/year in annual operating and maintenance costs would be required to replace the AGS with similar new dependable renewable capacity, even if such an alternative were available in the near to medium term (which it is not).[151]

As the Board recognized previously in its 2021 GRA decision, it is critically important for YEC to maintain AGS's licensure – and this continues to be the case going forward.[152]

When YEC first acquired the AGS from the Northern Canada Power Commission (NCPC) in 1987, the facility held a 25-year water licence covering the period from 1977 to 2002.[153] Along with that 25-year licence, YEC also acquired significant unresolved issues with the Champagne and Aishihik First Nations (CAFN), on whose traditional territory the project is situated, concerning their historical grievances with the facility's original construction by NCPC and its ongoing impacts.[154] CAFN's ongoing concerns about the facility have continued to be front and center in every relicensing process since that time, including:

- The 2002 renewal process that led to issuance of a 17-year water licence that expired on December 31, 2019;[155]
- The subsequent renewal process that led to the issuance of a shorter 3-year water licence from 2020 to 2022, to ensure that the facility's authorizations would not expire and to allow time to complete a long-term renewal process; [156] and
- The most recently completed renewal process, leading to the facility's current 5-year water licence.[157]

In that most recently completed renewal process, YEC initially submitted a proposal to the Haines Junction Designated Office Yukon Environmental and Socio-economic Assessment Board (YESAB) under the *Yukon Environmental and Socio-economic Assessment Act* for a long-term 25-year licence renewal (the longest renewal term available under section 16 of the *Waters Act*). However, the Designated Office declined to assess the licence renewal for the 25-year period proposed by YEC in light of concerns raised by the CAFN in the YESAB assessment, and decided instead to confine the temporal scope of the assessment to five years. As a result, the Government of Yukon and Fisheries and Oceans Canada issued a Decision Document for a 5-year renewal term only, and, due to those regulatory decisions, YEC had no feasible option but to revise its water licence renewal application to be limited to that 5-year period.[158]

In this GRA proceeding, as set out in Section 5.2A-1 at Tab 5 of YEC's Application,[159] updated in

[151] Exhibit 1, PDF p. 234, Footnote #4.
[152] YUB Order 2022-03, Appendix A, paragraph 294.
[153] March 7, 2024 Transcript, page 602, lines 7-10.
[154] Exhibit 1, PDF p. 232; YUB-YEC-1-61(j) and Attachment 1, Exhibit 2, PDF pp. 486, 493 and 495.
[155] Exhibit 1, PDF p. 231; YUB-YEC-1-61 Attachment 1, Exhibit 2, PDF p. 495.
[156] Exhibit 1, PDF p. 231; YUB-YEC-1-61 Attachment 1, Exhibit 2, PDF pp. 495-497.
[157] Exhibit 1, PDF pp. 232-233; YUB-YEC-1-61(h) and (j), Exhibit 2, PDF pp. 485-487.
[158] Exhibit 1, PDF pp. 231-232; YUB-YEC-1-61(j), Exhibit 2, PDF p. 487.
[159] Exhibit 1, PDF pp. 231-235.

YUB-YEC-1-16(f),[160] and further updated in YEC's response to Undertaking #31,[161] YEC now seeks additions to rate base totaling $4.708 million for forecast costs attributable to the 5-year renewal of the AGS water licence and for the costs of obtaining a *Fisheries Act* Authorization for that 5-year period, including associated costs in respect of the project's YESAB assessment that have been allocated to the 5-year licence.[162] This $4.708 million total is comprised of $3.903 million for actual costs closed in 2022, and additional costs of $0.615 million[163] in 2023 and $0.189 million in 2024.

As noted in YUB-YEC-1-61(d)[164] and further detailed in the table in YEC's response to Undertaking #31, these figures reflect YEC's allocation of AGS relicensing costs as between:

- Costs of $0.917 million attributable to the previous 3-year renewal for the period from 2020 to 2022, which were accepted by the Board as reasonable and approved to be added to the 2021 rate base in the 2021 GRA;[165]

- Projected total costs of $4.708 million attributable to the 5-year renewal for the period from 2023 to 2027, which YEC seeks to add to rate base in this Application; and

- Projected further costs of $7.974 million by end of 2024 in support of YEC's planned application for a longer-term 25-year licence renewal following the expiry of the current 5-year licence, which costs remain in WIP and are not being sought in this Application.[166]

Those costs include the specific costs outlined in the table on page 5.2A-3 of the Application for Stakeholder Engagement ($0.449 million), Permitting ($1.189 million), Monitoring ($0.513 million), Compensation ($0.619 million), Impact Assessment ($1.303 million) and Project Management ($0.406 million), plus the $0.230 million in additional costs referenced in note 3 to the table in YEC's response to Undertaking #31 included in further costs incurred for community and individual compensation and for the *Fisheries Act* Authorization renewal.

The Application further details the need for YEC's expenditures in each of these areas as follows:

- **Stakeholder Engagement** costs relate to funding the Champagne and Aishihik Community Advisory Committee (CACAC); negotiation costs to reach an agreement with the CAFN and Yukon Government relating to the AGS; capacity funding to CAFN to support participation in the project technical review and development of the Monitoring and Adaptive Management Plan; and public engagement activities.

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[160] Exhibit 2, PDF p. 484; Exhibit 10, PDF p. 12.
[161] YEC 2023-24 GRA Undertaking Responses, March 12, 2024, PDF pp. 81-82.
[162] The $4.708 million updated cost for the AGS 5-year licence renewal adjusts the August 2023 Application project cost of $4.479 million.
[163] This $0.615 total consists of the $0.575 million in forecast 2023 costs specified in the Application plus an additional cost of $0.040 million referenced in note 3 to the table in YEC's response to Undertaking #31.
[164] Exhibit 2, PDF p. 483.
[165] YUB Order 2022-03, Appendix A, paragraph 294.
[166] Exhibit 1, PDF p. 232, footnote 2; YUB-YEC-1-61(d), (h) and (i), Exhibit 2, PDF pp. 483 and 485-486; March 6, 2024 Transcript, page 449, lines 12-15. As noted in response to Undertaking #31, this $7.974 million in costs are forecast costs to 2024 and not total costs, as the table does not include forecast costs beyond 2024.

YEC deemed it prudent to engage CAFN at the beginning of the current water use licence renewal process, given that the facility is located within CAFN's traditional territory and the First Nation has significant historic grievances related to construction of the facility and ongoing interests in how the facility is operated. The objective of engagement was to increase participation by the CAFN in the water use relicensing regulatory process, and to increase collaboration between YEC and CAFN, with a view to reducing the risk of conflict and/or adversarial legal action during the formal regulatory proceedings, and to finding mutually agreeable resolutions to matters of interest to each party that would satisfy the requirements of the YESAA Decision Document and avoid the risk of the AGS water licence renewal potentially being delayed or denied by the Yukon Water Board (YWB).

- **Permitting** process costs are required to complete the regulatory activities that are mandatory to achieve the primary objective of the project (i.e., obtaining a renewed water use license for the facility). They include: 1) the project proposal to YESAB's Haines Junction Designated Office; 2) regulatory application to the DFO; and 3) regulatory application to the YWB. Each of these permitting activities involved more than preparing the filing documents. In each case, YEC had to respond to questions from the respective regulator and other participants, and to actively participate in separate public regulatory processes.

- **Monitoring costs** are related to early monitoring carried out to address issues relevant to CAFN, YESAB and regulators (including requirements from 3-year licence).

- **Compensation** costs relate to compensation to the CAFN and affected water users for the water use licence renewal, in accordance with the requirements of the Yukon *Waters Act*.

- **Impact Assessment** studies costs are related to the planning and execution of the environmental and social impact assessment studies in preparation for and response to information requests related to the YESAB and YWB applications. These costs are required to be able to prepare the Project Proposal for the YESAB Designated Office and develop a Monitoring & Adaptive Management Plan for the YWB application, as well as costs associated with data collection and analysis during the assessment and permitting phases.

- **Project management** costs are primarily YEC internal costs related to work on planning and executing the project. These costs are required to move the project forward and coordinate the various working groups and deliverables.

None of the foregoing costs were reasonably avoidable in the current regulatory environment affecting large-scale hydro projects such as the AGS, having regard, in particular, to CAFN's long-standing concerns with this facility's origins, its history, and its ongoing impacts, the Yukon Government's decision by early 2019 to engage in negotiation of an agreement with CAFN to address issues of concern including reconciliation, the impact of relevant regulatory decisions by YESAB, the Yukon Government and Fisheries and Oceans Canada, and the practical need to continue to pursue a collaborative process with CAFN to ensure YEC's ability to secure the required licence in order to avoid any interruption in the AGS's authorizations, and provision of reliable and affordable electricity service to Yukoners.[167] Not only was YEC's ongoing collaborative engagement with CAFN critically important to assuring YEC's ability to obtain a renewed AGS water licence without interruption upon expiry of the previous 3-year licence; that ongoing collaborative engagement and the monitoring and adaptive management and environmental programs that have resulted from it will also be critical to the viability of obtaining a long-term licence renewal upon expiry of the current 5-year licence.[168]

In the circumstances, YEC submits that all of its applied-for costs for the AGS 5-year relicensing are reasonable, and that the Board should approve their addition to rate base.

With respect to the costs allocated to the 25-year relicensing process, that process will not be completed until after the test years, and the full justification for those costs will be provided at the next GRA after the long-term licence renewal process has been completed.[169] A review of those long-term relicensing costs is outside the scope of the current GRA proceeding. At this time, however, YEC emphasizes the evidence given by Ms. Cunha and Mr. Milner at the hearing concerning the rationale for YEC's efforts in continuing to seek a longer-term licence for the AGS, and YEC's confidence in its ability to work collaboratively with CAFN and the Yukon Government on a 25-year relicensing project.[170] Therefore, it is appropriate to record these costs as work-in-progress at the end of 2024.

Demand Side Management (DSM)

The DSM program included in the test years is reviewed in detail in the Application, Section 5.2A-2 and Attachment 5.2A-2.1 (Demand Side Management Program Design for YEC) and Attachment 5.2A-2.2 (Yukon DSM Program Comparison) and in YEC's responses to information requests YUB-YEC-1-81, YUB-YEC-1-82, UCG-YEC-1-31, and NY-YEC-1-26. DSM Program Development cost additions to test year rate base consist of costs to refine and update DSM program design, to carry out a DSM Residential Demand Response Pilot, and depending on the success of the pilot, to expand the Residential Demand Respond Program more broadly. YUB-YEC-1-81 provides a breakdown of DSM actual and forecast costs by the various DSM programs (from 2021 to 2024). All costs to date have been attributed to the Residential Demand Response program.

The Application and information provided in IR responses demonstrate that Yukon Energy's current and planned DSM programs that affect rate base costs in 2023 and 2024 meet all three requirements stipulated by OIC 2021-16:

1. **Meet the definition of "demand-side management program":** Yukon Energy's DSM programs will reliably reduce the peak demand on the Yukon Integrated System, reducing the need for additional dependable generation capacity by improving alignment

[167] YUB-YEC-1-61(j), Exhibit 2, PDF p. 486.
[168] YUB-YEC-1-61(h) and (j), Exhibit 2, PDF pp. 486 and 487; March 6, 2024 Transcript, page 443, line 17 - page 444, line 11.
[169] YUB-YEC-1-61(d), Exhibit 2, PDF p. 483; March 7, 2024 Transcript, page 468, line 14 - page 469, line 5.
[170] March 6, 2024 Transcript, page 443, line 4 - page 444, line 11; page 445, line 15 - page 446, line 10; March 7, 2024 Transcript, page 446, line 21 - page 468, line 5.

between electricity supply and demand. This aligns with the definition of DSM provided in OIC2021-16.[171] See Appendix 5.2A, Section 5.2A-2, pp 5.2-12 to 5.2-14.

2. **Costs must be "reasonably incurred":** All DSM programs that will be planned and implemented by Yukon Energy pass both the Ratepayers Impact Measures (RIM) test and Utility Cost Test (UCT), with additional cost-effective measures to address previously expressed program equity concerns regarding low-income households. See Appendix 5.2A, Section 5.2A-2, pp 5.2-15 and 5.2-24. The business case assessment provided has demonstrates the following key points:

    a. All of Yukon Energy's current and planned DSM programs meet both the RIM and UCT cost effectiveness tests, with additional steps taken to support program equity.

    b. Equity-based considerations previously identified by the YUB, including participation barriers that low-income households may otherwise face, are being actively addressed in a manner that does not negatively impact program cost-effectiveness.

    c. The UCT Test is the most suitable cost-effectiveness test for utility-led DSM initiatives in the Yukon, evaluated at the program level for regulatory approval, presented as a cost-benefit ratio and/or levelized cost of capacity,

    d. The RIM Test is only suitable for identifying the need for participation equity considerations; a RIM Test result below 1.0 indicates a need to prioritize participation equity but does not indicate a particular program should not proceed.

3. **Not be in duplication of DSM programs participated in or provided by another Yukon public utility or the Yukon Government:** A thorough comparison of DSM and related programs by a variety of territorial government departments, crown corporations, and utilities. As demonstrated by this comparison, there is no duplication of DSM programs between Yukon Energy's DSM programs and DSM programs participated in or provided by another Yukon public utility or the Yukon Government. See Appendix 5.2A, Section 5.2A-2, pp 5.2-24 and 5.2-25.

Based on the above assessment, Yukon Energy's actual and forecast costs incurred in the planning and execution of the described Yukon Energy's DSM programs are prudent, reasonable and eligible to be recovered through rates.

[171] A "demand-side management program" is defined in OIC 2021-16 as the following:

> "a measure, action, or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity generation or transmission by a public utility, including through the promotion of customer use of electricity that (a) is more efficient, or (b) better aligns electricity supply and demand." (OIC 2021-16, Section 10(1))

Southern Lakes Enhanced Storage Project (SLESP)

As set out in Section 5.2A-3 at Tab of YEC's Application,[172] YEC is seeking a capital cost base rate addition of $8.784 million in 2023 in respect of the now cancelled Southern Lakes Enhanced Storage Project (SLESP), to be amortized over 10 years starting in 2023.

This project was envisioned as a means of enhancing the amount of renewable winter energy generated each year at the Whitehorse Rapids Generating Station (WRGS) to displace higher cost thermal generation that would otherwise be required. As reported in the 2012/13, 2017/18 and 2021 GRAs, the project would have required an amendment to the WRGS water licence to increase the full supply level by 0.3 meters and to reduce the low supply level by 0.1 meters. It would have also included capital additions to shorelines affected by the project to mitigate the effects of higher water levels during the fall. This additional water storage would have been available to YEC for hydro generation over the winter period.[173]

YEC decided to cancel the project in November 2022 after the Carcross/Tagish First Nation (C/TFN) notified YEC that it would not support any portion of the SLESP. Given that C/TFN was a Decision Body for the SLESP,[174] YEC concluded that there was no longer a reasonable probability that the project would proceed, and work ceased on the project.

Had it proceeded to completion, the SLESP would been beneficial for ratepayers. While the SLESP remained at a prefeasibility stage at the time of the 2012/13 GRA,[175] the Board found in that proceeding that it was a viable project, and directed that related projects costs were to be held in WIP until the project was completed.[176] The Board also directed at that time that YEC was to cease work on the project if and when it concluded that the project would have no net economic benefit for ratepayers (as ultimately occurred in November 2022).[177]

At the time of the 2012/13 GRA, SLESP project costs included $3.231 million in planning and feasibility costs incurred to the end of 2011, with further forecast spending of $1.6 million over the 2012 and 2013 test years.[178] The vast majority of project costs incurred to that point were for third-party engineering, environmental assessment and project management (approximately $2.9 million of the costs incurred to the end of 2011).[179]

The estimated total project capital cost at that time (in 2010$) was $10.5 million, about one-half which was expected to be incurred on mitigation design (shoreline erosion and surface water) required to proceed with the project licensing and development.[180]

Following the 2012/13 GRA, the SLESP project could not proceed as had been planned in the 2012/13 GRA due to a need for further studies and engagement activities. Accordingly, YEC

[172] Exhibit 1, PDF pp. 256-261.
[173] Exhibit 1, PDF p. 256.
[174] Exhibit 1, PDF p. 259.
[175] Exhibit 1, PDF p. 257.
[176] YUB Order 2013-01, Appendix A, paragraph 337; Exhibit 1, PDF p. 258.
[177] YUB Order 2013-01, Appendix A, paragraph 337; Exhibit 1, PDF p. 258.
[178] YUB Order 2013-01, Appendix A, paragraph 331, Table 18; Exhibit 1, PDF pp. 257-258.
[179] Exhibit 1, PDF p. 258.
[180] Exhibit 1, PDF p. 257.

proceeded with required work on technical studies and assessment, engagement and consultation with various stakeholders, and extensive meetings with property owners who would be directly impacted by the project. The project also remained dependent on obtaining First Nations support. It was expected that a decision to proceed with submitting a YESAB proposal would be made at a Stagegate 3 project review.[181]

By the time of the 2017/18 GRA, YEC estimated that it had spent almost $6.8 million to that point, and that it was forecasting an additional $8.578 million for a total estimated project cost of $15.377 million. This was almost 50% higher than the 2012/13 GRA forecast, and included $7.950 million forecast for effects assessment, $0.300 million forecast for YESAA assessment and permitting, and $7.127 million forecast for mitigation implementation. The principal drivers for the cost increase were the unanticipated level of effort and time that was required for stakeholder engagement in the planning process (accounting for over $1 million of added costs), approximately $2 million of added effects assessment costs related to added baseline studies and engineering, and added forecast implementation/mitigation costs of approximately $1.9 million as a result of increased predictions of the extent of sensitive shorelines that would need protection as well as the extent of required engineering concepts and inflation over the 8-year planning period.[182]

During the oral hearing of the 2017/18 GRA in June 2018, YEC confirmed that it had received conditional support at that time from C/TFN to proceed with a YESAB proposal for the SLESP project; however, that support was conditional on completing a benefits agreement for the project. The project would also need to be brought back to YEC's board of directors to reassess public, First Nation and government support for it.[183]

In its final decision on the 2017/18 GRA, the Board expressed some concern about the project's delay and increased cost estimate. The Board nevertheless accepted that the project may still be viable, while cautioning YEC that if it chose to continue developing the project the onus would be on YEC to demonstrate the prudence of all project expenditures.[184]

Following the 2017/18 GRA, YEC completed an additional round of engagement in 2019 to confirm the level of support for the project. This included engagement with local residents in the Southern Lakes area and Yukoners generally, as well as a further round of engagement with affected First Nations, including Kwanlin Dün First Nation (KDFN) and Ta'an Kwäch'än Council (TKC) as well as C/TFN.[185]

The costs forecast in YEC's 2021 GRA assumed that the project continued, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in-service for the project was 2023.[186]

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[181] Exhibit 1, PDF p. 258.
[182] Exhibit 1, PDF pp. 258-259.
[183] YUB Order 2018-10, Appendix A, paragraph 503; Exhibit 1, PDF p. 259.
[184] YUB Order 2018-10, Appendix A, paragraph 507; Exhibit 1, PDF p. 259.
[185] Exhibit 1, PDF p. 259.
[186] Exhibit 1, PDF p. 259.

In June 2020, YEC's board of directors approved a budget of $1.314 million to advance the SLESP to the submission of a YESAB project proposal (Stagegate 3).[187] Based on the information that was available at that time, the board of directors concluded that the project still provided a net economic benefit to ratepayers, that it still had a reasonable possibility of proceeding, and that there was not a reasonable basis to justify terminating the project.[188]

In December 2021, as part of the approval of Stagegate 1 activities on the WRGS relicensing project, the board of directors approved a further resolution for YEC to work with the Yukon Government and the affected First Nations to pursue the SLESP water licence amendments as part of the YESAB assessment for the WRGS relicensing, instead of as a separate YESAB submission.[189] This was done because the overlapping work on SLESP and WRGS relicensing was leading to confusion, resulting in duplication of work, and straining First Nation resource capacity for engagement.[190] If YEC had continued to pursue a separate YESAB proposal for the SLESP at that time, the feedback received from the affected First Nations was that they did not have sufficient internal capacity to participate in two separate YESAB assessment processes simultaneously, and that the two separate processes would have caused confusion for their citizens and the public.[191] There was also a risk that the YESAB Designated Office would identify the two separate SLESP and WRGS relicensing assessments as related activities and combine the two assessments anyways.

At the October 31, 2022, meeting of the WRGS Relicensing Senior Officials Group (SOG), made up of representatives of YEC, Yukon Government, C/TFN, KDFN and TKC, the group reviewed the project scope for WRGS relicensing, including the option to include potential enhanced storage elements of the SLESP in the WRGS relicensing project. At the SOG meeting, C/TFN representatives stated that they did not support changes to the full or low supply limits (i.e., elements of the SLESP project), and they requested that those elements be removed from the scope of the WRGS relicensing project description and proposal.[192]

In follow-up to the SOG meeting, on November 6, 2022, C/TFN issued a formal letter stating their lack of support for the enhanced top and bottom storage elements of the proposed WRGS relicensing scope (i.e., the SLESP project requirements).[193]

At the time, YEC considered the implications of C/TFN's stated non-support for those essential features of SLESP, and concluded that there were no options remaining to pursue completion of the project. Consequently, YEC concluded that the project no longer offered a net economic benefit to ratepayers as there was no reasonable probability it would proceed, and YEC ceased work on the project as directed by the Board in YUB Order 2013-01.[194]

As a result of the cessation of work on the project, the work that YEC had commenced for the purpose of including the SLESP water licence amendments in the WRGS relicensing YESAB

[187] Exhibit 1, PDF p. 259; March 6, 2024 Transcript, page 427, line 16 - page 428, line 3.
[188] YUB-YEC-1-83(a), Exhibit 2, PDF p. 569.
[189] Exhibit 1, PDF p. 259.
[190] YUB-YEC-1-83(f), Exhibit 2, PDF p. 571.
[191] March 6, 2024 Transcript, page 422, line 18 - page 425, line 9.
[192] Exhibit 1, PDF pp. 259-260.
[193] Exhibit 1, PDR p. 260.
[194] Exhibit 1, PDF p. 260.

submission was not completed, and no submission for the SLESP was made to the YESAB Designated Office.[195]

From the time of the project's inception in 2009 to the cessation of work on the project in November 2022, total feasibility costs incurred on the project were approximately $8.784 million.[196] YEC has provided a detailed breakdown of this total cost in UCG-YEC-1-31(h),[197] showing the costs incurred by category (environmental assessment, project management, public consultation, third-party engineering, YEC costs, and AFUDC) for the period up to the end of 2012, and for each year thereafter from 2013 to 2022.

As noted in YEC's Application, approximately $7.3 million, representing approximately 83% of total project costs, were incurred between inception and the end of 2018 (when YUB Order 2018-10 was issued),[198] and those costs related mostly (87%) to environmental assessment studies, engineering, and public consultation activities plus related AFUDC interest costs. Those costs were reviewed at a high level in the 2012/13 and 2017/18 GRAs.[199]

The following further observations can also be made from the detailed cost breakdown in UCG-YEC-1-31(h):

- Nearly one-half of all expenses incurred on the SLESP project were incurred up to the end of 2012, over a time period when the Board has specifically determined (in YUB Order 2013-01, issued in March 2013) that the project was viable.

- After the end of 2012, over the entire period from 2013 to 2022, the vast majority of non-AFUDC related costs that YEC continued to incur were for environmental assessment ($2.117 million) and public consultation ($0.518 million), comprising approximately 91.5% of the total non-AFUDC costs of $2.879 million incurred over that period.

- Of the $1.465 million in remaining project costs that YEC continued to incur after the issuance of YUB Order 2018-10, approximately 25% of those remaining costs were for environmental assessment ($0.368 million), approximately 24% were for public consultation ($0.349 million), approximately 4% were for project management ($0.058 million), and approximately 47% were for AFUDC ($0.688 million).

- Of the $0.777 million in non-AFUDC related costs that YEC continued to incur after issuance of YUB Order 2018-10, approximately 47% were for environmental assessment, approximately 45% were for public consultation, and approximately 7% were for project management.

YEC also notes Mr. Milner's evidence at the hearing that it did not become apparent that the SLESP project would be unable to proceed until after the licensing process was underway for the WRGS relicensing project, the timing of which also occurred after two high-water years. As a result, YEC continued to see SLESP as a good project, and retained a level of optimism that it

[195] YUB-YEC-1-83(c), Exhibit 2, PDF p. 570; March 6, 2024 Transcript, page 425, lines 17-20.
[196] Exhibit 1, PDF p. 260.
[197] Exhibit 2, PDF p. 197.
[198] YUB Order 2018-10 was issued on December 27, 2018.
[199] Exhibit 1, PDF p. 260.

could be completed, until late in 2022 when it became apparent that the C/TFN support needed to move the project forward to completion was not there.[200]

Ms. Cunha also testified at the hearing that, over the course of the project's life, decisions were made to continue to proceed with it because of the economics of the project and the avoidance of thermal generation costs that would have resulted from it. As Ms. Cunha testified, it did not become clear that YEC would be unable to proceed with the project until it received C/TFN's letter of non-support in November 2022.[201]

Mr. Epp also confirmed at the hearing that after YEC received C/TFN's letter of non-support and work ceased on the project, no further costs were incurred on the project.[202]

Ms. Cunha also provided further evidence at the hearing about the October 31, 2022, SOG meeting and its significance. That meeting involved collaboration between YEC, the Yukon Government, and the three affected First Nations (C/TFN, KDFN and TKC) who were having discussions about the WRGS relicensing project. The purpose of the meeting was to confirm the scope of the WRGS relicensing project. At that meeting, C/TFN expressed their lack of support for including required elements of SLESP (the changes in maximum and minimum supply levels) as part of the WRGS relicensing project. C/TFN's letter of non-support was delivered one week later.[203]

Ms. Cunha also testified about the context of the ongoing discussions that YEC was pursuing with the First Nations in the project area, including C/TFN, at the time YEC's board of directors made its decision in June 2020 to advance the SLESP project to Stagegate 3. At that time, YEC was actively consulting with First Nations officials about how the SLESP could be advanced from a technical environmental perspective, about assessing its effects, and about potential project benefit agreements with the First Nations specific to SLESP and other matters on their traditional territories related to energy planning. So work was advancing at the time on the SLESP through consultation, through technical work, and through agreements, until technicians from the First Nations asked YEC in 2021 to contemplate SLESP as part of the YESAB submission for the WRGS relicensing instead of as a separate project.[204]

Ms. Cunha testified further that the request to consider SLESP as part of the WRGS relicensing proposal occurred coincidentally around the time that Marsh Lake and the Southern Lakes experienced a flood, which influenced the technical discussions about increasing lake levels, and gave rise to renewed interest in exploring potential flood mitigation measures, including the use of drawing down Marsh Lake to a potentially lower low supply level as one potential flood mitigation measure.[205]

Mr. Milner also testified further about how during 2021 and 2022, technicians from YEC, YG and the First Nations involved in the WRGS relicensing process spent considerable time doing an

[200] March 5, 2024 Transcript, page 224, line 13 - page 225, line 21.
[201] March 5, 2024 Transcript, page 226, line 23 - page 227, line 17.
[202] March 6, 2024 Transcript, page 437, lines 11-16.
[203] March 6, 2024 Transcript, page 426, line 2 - page 427, line 1.
[204] March 6, 2024 Transcript, page 428, lines 3-21.
[205] March 6, 2024 Transcript, page 428, line 22 - page 429, line 21.

extensive review and analysis of past studies and work completed as part of SLESP to inform the WRGS relicensing project and the project description that would be later defined in late 2022.[206]

In summary, notwithstanding the concerns expressed by the Board in Order 2018-10, the evidence shows that YEC continued to be actively and constructively engaged with the affected First Nations through until late 2022, and that there was a reasonable basis through that time period for YEC's continued optimism that the SLESP project could proceed.

The foregoing evidence also demonstrates that it was reasonable and prudent for YEC to continue to pursue the SLESP project after the issuance of YUB Order 2018-10, until YEC received C/TFN's letter of non-support in November 2022.

Indeed, given that the vast majority of project costs claimed by YEC for SLESP had already been incurred by the time YUB Order 2018-10 was issued, and given that the further costs YEC continued to incur after that time (mostly on environmental assessment and public consultation, apart from AFUDC) were relatively low in comparison, it would have been imprudent – and wasteful of the investment that YEC had already made in this project – for YEC to have cancelled the project prematurely, earlier than November 2022.

Accordingly, YEC submits that all of its applied-for costs for the SLESP project are reasonable, and that the Board should approve YEC's request to add them to rate base, amortized over 10 years starting in 2023.

YEC notes further that this is consistent with the Board's previous approvals of costs related to cancelled new generation projects [e.g., Board Order 2018-10 approved inclusion to rate base in the 2017/18 GRA and amortization over 10 years of costs of the Gladstone diversion project, which was cancelled due to opposition from the First Nations]. It is also consistent with the Planning Cost Accounting Policy FA-016 approved by Board Order 2018-10 [per section 2.5(b) of the Policy if a project does not proceed: "Where accumulated planning and studies costs have exceeded $1 million – the planning and studies costs will be amortized over ten years"].

3.1.3 MAJOR INTANGIBLE ASSETS INCLUDED IN RATE BASE

As set out in Appendix 5.3A of YEC's Application,[207] YEC is seeking capital cost rate base additions totaling approximately $10.016 million by the end of 2023[208] in respect of two closely interrelated asset management projects:

- The Physical Asset Management Managed System Asset Management Framework project (PAMMS); and
- The Enterprise Management System Purchase and Implementation project (EAM).

PAMMS is a multi-year project that was started in 2018, which involves the formal documentation of all governance, roles and responsibilities, processes and procedures required for the

[206] March 6, 2024 Transcript, page 430, line 23 - page 432, line 7.
[207] Exhibit 1, PDF pp. 390-406.
[208] Exhibit 1, PDF p. 391. The correct total figure is $10.016 million, as shown in Table 5.6 of the Application (Exhibit 1, PDF p. 150).

establishment and ongoing operation of YEC's asset management system. PAMMS is forecast to be used and useful as of December 31, 2023, and YEC seeks to bring its capital costs into rate base in 2023.[209]

EAM is an enterprise-level software application that was brought into operation in 2021, which enables YEC, as a key part of its asset management program, to manage and optimize its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management, and asset performance tracking.[210] Although the EAM had been identified as a distinct project, it is an essential and fundamental part of YEC's multi-year PAMMS project.[211]

Together, these two projects are necessary to align YEC's asset management practices with the ISO 55000 standard[212] for physical asset management and to address the insufficiency of YEC's pre-existing Computerized Maintenance Management System (CMMS).[213]

In the 2021 GRA, YEC previously sought the Board's approval to bring EAM's then-forecast capital cost of $4.657 million into rate base in 2021.[214] However, the Board disallowed those costs for inclusion in 2021 rate base based on concerns about the adequacy of the evidence that YEC presented in the 2021 GRA proceeding to support them.[215]

In the current GRA, as outlined in Part 1, section 3.0 above, YEC is seeking recovery of its previously disallowed costs for the EAM on a prospective basis only, commencing January 1, 2023. As such, that request does not constitute retroactive ratemaking, and it is proper and appropriate for the Board to consider adding EAM's previously disallowed costs to rate base prospectively, having regard to the fuller and more comprehensive body of supporting evidence that YEC has put forward in the present GRA (as outlined further below).

YEC has recalculated the total rate base addition that it is now seeking for the EAM project at $4.550 million, reflecting the actual expenditures incurred on that project from 2018 to 2021.[216]

YEC is also seeking a rate base addition of $5.466 million in 2023 for total expenditures incurred on the PAMMS project from 2018 to 2023.[217] YEC has not previously sought to include any of those costs in rate base, so this GRA is the first time the Board is considering them.[218]

The evidence that YEC has provided to the Board in this proceeding to support adding the costs of both of these interrelated projects to rate base in 2023 includes the following:

[209] Exhibit 1, PDF p. 395; YUB-YEC-1-80(b) and (c), Exhibit 2, PDF p. 555.
[210] Exhibit 1, PDF p. 399.
[211] Exhibit 7, PDF p. 35.
[212] The Board in Order 2022-03 stated that it "accepts that there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000."
[213] Exhibit 7, PDF p. 35.
[214] YUB Order 2022-03, Appendix A, paragraph 331.
[215] YUB Order 2022-03, Appendix A, paragraphs 332-333.
[216] Exhibit 1, PDF p. 399; YUB-YEC-1-80(d), Exhibit 2, PDF pp. 555-556.
[217] Exhibit 1, PDF p. 395.
[218] YUB-YEC-1-80(a), Exhibit 2, PDF p. 555; March 7, 2024 Transcript, page 474, lines 7-12.

- The business case evidence that YEC has provided in support of both projects in Appendix 5.3A of the Application,[219] which also includes:
  - the detailed business cases analysis completed by METSCO in May 2023 that is included as Attachment 5.3A-1;[220] and
  - the further detailed review of YEC's initial work in 2018-19 in support of both projects (Attachment 5.3A-1.1)[221] and the further work completed on PAMMS in 2020-23 (Attachment 5.3A-1.2);[222]
- The additional evidence provided about these projects in YEC's responses to UCG-YEC-1-33, UCG-YEC-1-34, UCG-YEC-1-35 and YUB-YEC-1-80;[223] and
- The further evidence provided about the EAM in YEC's response to YUB-YEC-2-1, including the detailed table that YEC has provided at the Board's request comparing the information that was provided about the EAM in the 2021 GRA and the current GRA, and explaining how that information addresses the concerns the Board previously expressed in YUB Order 2022-03.[224]

METSCO's May 2023 report is especially important, because it provides detailed expert analysis of the available evidence relevant to assessing the expected benefits of these projects, including the expected benefits if YEC were to implement PAMMS on its own without EAM (Option 2 in the METSCO report) and the expected benefits from implementing PAMMS in conjunction with EAM (Option 3 in the METSCO report). The evidence relied on in this analysis includes project-specific findings from METSCO's comparison with YEC's peer utilities.[225] As Mr. Osler emphasized in his testimony at the hearing, that peer group analysis demonstrates the need for these kinds of investments in asset management to meet a modern standard.[226]

METSCO's analysis confirms the expected NPV benefit of the EAM project as a key component of PAMMS, with PAMMS having an estimate NPV of $7.4 million in quantifiable benefits if it were to be implemented without EAM, and a significantly greater estimated NPV of $11.1 million in quantifiable benefits if implemented with EAM.[227] As shown in Table 4 of METSCO's report,[228] those quantifiable benefits relate to the impacts described in Sections 3.3.2.1 to 3.3.2.7 of the report that were included in METSCO's economic/financial analysis.[229] Therefore, based on its quantifiable benefits alone, the EAM project is forecast to be economical to ratepayers over its life.

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[219] Exhibit 1, PDF pp. 390-406.
[220] Exhibit 1, PDF pp. 407-462.
[221] Exhibit 1, PDF pp. 463-469.
[222] Exhibit 1, PDF pp. 470-474.
[223] Exhibit 2, PDF pp. 201-205 and 552-556.
[224] Exhibit 7, PDF pp. 36-40.
[225] Exhibit 7, PDF p. 35.
[226] March 7, 2024 Transcript, page 547, line 13 - page 548, line 3; page 550, lines 8-9.
[227] Exhibit 7, PDF p. 35.
[228] Exhibit 1, PDF pp. 419-420.
[229] Exhibit 1, PDF pp. 441-450.

In addition to the quantifiable benefits of these projects, METSCO's report also includes a separate analysis of the multiple qualitative benefits of PAMMS and EAM that are described in Sections 3.3.1.1 to 3.3.1.6 of the report and summarized in Table 12.[230]

MESTCO's analysis also confirms that the status quo CMMS is not an acceptable software alternative to the EAM.[231]

YEC's panel also testified at the hearing about the benefits of PAMMS and EAM, both qualitative and quantitative.[232] This included Mr. Murchison's enthusiastic testimony about the critical value of YEC's asset management system as a whole – including both PAMMS and EAM – to YEC's capital planning and O&M.[233] Under questioning by Mr. Ward, Mr. Murchison acknowledged that some of the benefits of these projects involve the reduction of "soft" costs,[234] but he emphasized the significance of the efficiencies YEC expects to derive from these asset management projects,[235] their importance to YEC's ability to maintain system reliability through its capital planning process in light of the growth that YEC is experiencing,[236] and their anticipated enhancement of YEC's ability to efficiently collect and access asset condition data, including the data required for regulatory proceedings such as this GRA, and the data required to optimize YEC's investments in capital assets and to maintain YEC's existing assets.[237]

Ms. Cunha similarly emphasized the value of these asset management projects to future ratepayer savings and to maintaining reliability of service, given the importance of asset management to identifying the current health of YEC's assets, to making informed, prudent and timely decisions about future capital investments, and to ensuring that O&M expenditures are made prudently and at the right time.[238]

Mr. Milner also emphasized the particular value of these asset management tools for an organization like YEC with a relatively small staff complement and limited resources, operating over a huge geographical area,[239] with a huge range of assets to manage, including aging assets with original parts dating back to the 1950s or 1970s.[240]

Appendix 5.3A also includes a detailed review of the selection process that YEC followed, with expert support, to select a final EAM software supplier to achieve an optimal combination of functionality/performance and price, including the specific scoring and basis for the final Infor EAM selection. This information is provided to further assist the Board in evaluating the prudency of the costs incurred on the EAM project.[241]

[230] Exhibit 1, PDF pp. 433-441.
[231] Exhibit 7, PDF p. 38.
[232] March 7, 2024 Transcript, pages 540-562.
[233] March 7, 2024 Transcript, page 554, line 11 - page 555, line 15.
[234] March 7, 2024 Transcript, page 557, lines 17-19.
[235] March 7, 2024 Transcript, page 557, lines 21-22.
[236] March 7, 2024 Transcript, page 558, lines 5-17.
[237] March 7, 2024 Transcript, page 554, line 11 - page 556, line 16; page 558, line 18 - page 561, line 16.
[238] March 7, 2024 Transcript, page 550, line 17 - page 552, line 15.
[239] March 7, 2024 Transcript, page 552, lines 16-25.
[240] March 7, 2024 Transcript, page 545, line 24 - page 546, line 10.
[241] Exhibit 1, PDF pp. 401-406; Exhibit 7, PDF pp. 35 and 38.

The peer organization descriptions provided in the METSCO report show that asset management processes continue to develop and improve over time, and that this is normal. Ongoing operational costs were fully considered in METSCO's assessments of the net economic benefits of PAMMS/EAM, as growing the asset data within EAM will enhance EAM's effectiveness .

Based on all of the evidence that is now before the Board, it is apparent that the costs of both PAMMS and EAM were prudently incurred for the net benefit of ratepayers, and that both are in service, used and useful, and should be added to rate base in 2023.

3.2 OTHER PROJECTS <$1MILLION AND >$ 100,000 IN RATE BASE

The Application forecasts approximately $22.4 million net rate base impact in the 2024 test year over 2021 approved for projects with costs under $1 million and exceeding $100,000:

1. Appendix 5.1B of the Application reviews 37 capital projects <$1 million and >$100,000 with 2024 total net rate base impact of $17.9 million excluding subsequent updates for overhauls:

    a. Generation Projects – 9 projects with total 2024 rate base increase of $3.620 million in 2024, excluding any depreciation or amortization deductions.

    b. Transmission Projects – 7 projects with total 2024 rate base increase of $3.009 million, excluding any depreciation or amortization deductions and before contributions of approximately $0.627 million.

    c. Distribution Projects – 4 projects with total 2024 rate base increase of $9.642 million, excluding any depreciation or amortization deductions and before total contributions of approximately $9.031 million.

    d. General Plant & Equipment Projects – 11 projects with total 2024 rate base increase of $4.865 million, excluding any depreciation or amortization deductions.

    e. Overhauls & Reserve for Site Restoration Projects – 6 projects with total 2024 rate base impact of $6.452 million, excluding any depreciation or amortization; the subsequent update increased this rate base impact to $8.202 million.[242]

2. Appendix 5.2B of the Application reviews 18 deferred projects <$1 million and >$100,000 with forecast total net rate base impact in in 2024 of $3.716 million (excluding reductions due to amortization, reflecting $0.581 million additions in 2021, $0.115 million additions in 2022, $1.692 million additions in 2023, and $1.328 million additions in 2024).

    a. Feasibility Studies – Reliability and Asset Improvements – 13 projects with net rate base impact of $2.229 million.

[242] Undertaking #23, Table 5.6 and Application, Table 5.6. The overhaul cost increase was $1.8 million (AH3 Overhaul +$2.2 million, DD4 Overhaul -$0.45 million).

b. Regulatory and Dam Safety Review – 5 projects with net rate base impact of $1.486 million.

3. Appendix 5.3B of the Application reviews 5 intangible projects <$1 million and >$100,000 with total rate base impact in 2024 test year of approximately $0.766 million, excluding reductions due to amortization, reflecting $0.147 million additions in 2022, $0.368 million additions in 2023, and $0.250 million additions in 2024).

No material issues were raised in IRs or at the oral hearing regarding specific projects in this cost category, and experience shows that delays or cancellations of smaller projects tend to be replaced with new projects such that total in-service impact spending is not materially affected. Evidence also confirmed that projects were being capitalized in accordance with approved financial policy. Yukon Energy will respond in reply argument to any specific issues or questions raised by intervenors regarding any of these projects.

3.3 PROJECTS THAT REMAIN IN WIP

Projects that are forecast to remain in WIP at the end of the 2024 test year do not affect forecast test year rate base or revenue requirement. Detailed information was not included in the 2023/24 Application for these projects, as they are not considered to require detailed review at this time. Costs for these projects will be fully reviewed at a subsequent GRA proceeding when YEC applies to have the costs included in rates.

4.0 OTHER MATTERS

4.1 MATTERS NOT IMPACTING REVENUE REQUIREMENT (DEFERRAL ACCOUNTS)

4.1.1 DEFINED BENEFIT PENSION DEFERRAL ACCOUNT

Board Order 2022-03 approved the Defined Pension Deferral Account to defer any variances between approved defined benefit pension plan expenses in the test year and actuals. Table 3.14.4 provides a continuity schedule for this deferral account. YEC is not proposing amortization of the deferral account balance at this time as the balance is not significant.

4.1.2 IPP DEFERRAL ACCOUNT

YEC has applied for a new deferral account for costs related to Independent Power Producers' (IPP) projects under the IPP program directed by the Yukon Government. YEC requires an IPP deferral account to recover variances from forecast IPP-related costs that occur due to factors beyond each utility's control. The expectation for IPP deferral accounts is that accounting will be trued-up in the next GRA, with all costs still subject to review by the Board as to reasonableness.

1. The Deferral account is required to implement OIC requirements – and each GRA will provide ample opportunity for review as to the accuracy of the IPP forecasts for GRA test years.[243]

[243] UCG-YEC-1-15.

2. LTA thermal calculations are needed for the proposed IPP purchase cost deferral account to address YEC's overall net cost effects related to variances in IPP purchase volumes from approved GRA forecasts.[244]

3. IPP LTA thermal displacement benefits related to the IPP purchase volume variances is proposed to be included in the deferral account as an offset to the power purchase cost variance:[245]

    a. Without consideration of LTA thermal displacement benefits, the deferral account would address variances in YEC's costs for IPP purchases simply by reference to variance in IPP volumes and the applicable IPP pricing. The net effect of including LTA thermal displacement benefits in the deferral account calculations is to reduce YEC deferral costs when IPP volumes exceed approved forecasts and increase YEC deferral costs when IPP volumes fall below approved forecasts.

    b. The LTA thermal generation reduction benefits related to forecast hydro and IPP renewable sources are prepared based on YECSIM model runs consistent with the LTA hydro and thermal generation determinations provided in Appendix 2.1. As such, given that these are forecasts, there is no actual tool to "prove" the LTA thermal generation reduction or displacement benefits from IPPs or other renewable generation sources.[246]

    c. The reference YEC previously made to the "accumulation of benefits from drought years" was intended to recognize that LTA thermal displacement benefits are determined based on long-term averages [over 41 years of water conditions]. Although the IPP generation in the test years are predominantly in summer months when no thermal displacement benefits are expected, on a long-term average basis the benefits from IPPs to reduce thermal generation during drought years will be recognized. Without long-term average calculations, material thermal displacement benefits would not occur in most years as the IPP generations mostly displace hydro generation during normal and high-water years [i.e., the benefits from IPPs will be notably lower than 59% thermal displacement]. During lower water/drought conditions, the IPP deliveries will be used to supply the firm load and normally do not displace hydro, but help to reduce the use of thermal generation. Therefore, on a long-term average basis the IPPs that are expected to be connected to the grid by end of 2024 test year displace about 59% of thermal generation. This is consistent with the LTA hydro and thermal generation determinations provided in Appendix 2.1.

    d. As reviewed in response to YUB-YEC-1-32(b), LTA thermal calculations are needed for the proposed IPP purchase cost deferral account only to address YEC overall net cost effects related to variances in IPP purchase volumes from approved GRA forecasts. The net effect of including LTA thermal displacement

[244] YUB-YEC-1-30.
[245] YUB-YEC-1-32(b).
[246] YUB-YEC-1-33(b).

benefits in the deferral account calculations is to reduce YEC deferral costs when IPP volumes exceed approved forecasts and increase YEC deferral costs when IPP volumes fall below approved forecasts.

4.2 ISSUES RAISED BY THE YUKON UTILITIES BOARD

The Board in IRs and during the oral hearing asked questions related to energy policy and YEC's plans to meet electricity requirements over the near term and longer term.

YEC noted in response to IRs (YUB-YEC-1-1) and in its Opening statement that it is developing an Electricity Supply Plan to identify the resource options that can be implemented in the next 5-10 years to increase the supply of dependable capacity and energy during the winter months and reduce the use of rental diesels.

The Electricity Supply Plan is expected to be released by mid-2024. It will consider the status of projects proposed in the 10-Year Renewable Electricity Plan and outline a workplan to meet Yukon's electricity needs in the next 10 years. Yukon Energy is also working on a Resource Plan in 2024 and 2025. The Resource Plan is a long-term plan (beyond 10 years) that will determine Yukon's long-term electricity needs and identify resource options that are best suited to meet those needs.

4.3 ISSUES RAISED BY NATHANIEL YEE

Mr. Yee's submissions in this proceeding have largely consisted of argument, including various allegations of fraud against Yukon Energy. As outlined in YEC's rebuttal evidence (Exhibit 9), YEC disputes all of the allegations included in Mr. Yee's submissions. Mr. Yee's attempt to use this regulatory proceeding to pursue allegation of fraud against YEC is inappropriate, it is entirely without merit, and it is a distraction from the real issues before the Board in this GRA.

As noted in YEC's rebuttal evidence and Opening Statement, it is particularly inappropriate and unacceptable that Mr. Yee has levelled unsupported allegations against reputable and hard-working YEC employees.

Providing safe and reliable service is YEC's overriding concern. This drives all of YEC's decision making. With regard to the diesel rentals, the evidence before the Board consistently shows that YEC can and will operate any of its diesel rental units if and when it may become necessary to do so to protect the welfare, health and safety of Yukoners during an emergency. YEC has been clear and transparent about this to the Board and to regulators and has acted accordingly.

The issues raised by Mr. Yee are generally irrelevant to the questions properly before the Board in this proceeding, they are concerned with matters involving other regulatory processes outside the Board's jurisdiction, and they represent and attempt to revisit matters that the Board has already ruled on conclusively in the 2021 GRA concerning the appropriateness of including diesel rentals that are required for meeting N-1 capacity requirements in YEC's rate base.

In particular, there is nothing new about the fact that there is a difference between YEC's permitted diesel capacity for normal operations and the additional diesel capacity that YEC needs to rent to meet N-1 dependable capacity requirements. This distinction was very well understood in the previous 2021 GRA proceeding, and the YUB dealt directly with Mr. Yee's arguments on this issue in its final decision in that proceeding. In the final 2021 GRA decision,[247] the YUB dismissed the very same arguments that it appears Mr. Yee is seeking to make again in this proceeding, and rejected his recommendation to disallow YEC's costs for diesel rentals that are needed to close the N-1 dependable capacity gap, even if those rentals are not covered by YEC's existing air emissions permits. YEC has been very transparent about all of this. Nothing has changed in this regard since 2021.

YEC will not comment further on these issues here, beyond what it is has already stated in its rebuttal evidence (Exhibit 9), given the lack of relevance of these issues to the matters that are properly before the Board in this proceeding. However, YEC reserves its right to make further submissions in its Reply Argument in response to any points that Mr. Yee continues to pursue in his Final Argument.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Jason Herbert & P.John Landry, K.C.
Counsel for Yukon Energy Corporation

March 22, 2024

[247] YUB Order 2022-03, Appendix A, paragraph 108.