IN THE MATTER OF YUKON ENERGY CORPORATION 2021 GENERAL RATE APPLICATION TO THE YUKON UTILITIES BOARD

FINAL ARGUMENT

YUKON ENERGY CORPORATION

October 12, 2021

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YUKON ENERGY 2021 GENERAL RATE APPLICATION ("APPLICATION") TO THE YUKON UTILITIES BOARD ("YUB" OR "BOARD")

YUKON ENERGY CORPORATION FINAL ARGUMENT

PREFACE

OVERVIEW OF YUKON ENERGY APPLICATION

The Application was submitted to the Board on November 20, 2020 (Exhibit B-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 2021 test year and to plan for future requirements thereafter.

In summary, the Application filed in November 2020 requests approvals (Exhibit B-1, pages 1-6):

- To recover forecast revenue requirement to supply customers in 2021, including provisions for adjusted fuel prices, updated depreciation rates, a defined benefit pension deferral account, and an allowed return on equity ("ROE") of 8.70% for 2021; and

- To implement interim refundable rate rider increase July 1, 2021 and a final total increase of YEC Rider J of 15.01 percentage points and any related true ups, starting no later than December 1, 2021; in order to provide minimal changes in customer bills, the timing for these rate increases was proposed to coordinate with setting to zero Rider F as at July 2021 and removal of the 2017-18 GRA true-up Rider J1 at the end of November 2021.

Subsequent to the Application filing, Yukon Energy filed:

- A limited scope application in March 2021 for a Rate Schedule 39 Interim Fixed Charge Adjustment (Exhibit B-10) effective April 1, 2021 applicable to VGC and Alexco; and

- An application in April 2021 for approvals of an updated Low Water Reserve Fund ("LWRF") Term Sheet and LWRF Annual Reports for 2019 and 2020 (Exhibit B-11).

The Board in Order 2021-07 ruled that final determinations regarding Rate Schedule 39 and the LWRF Term Sheet and the LWRF annual reports will be considered as part of YEC's 2021 GRA. The Board in Order 2021-08 approved an interim refundable rate rider increase of 10.08% (Rider J) for retail firm rates and industrial firm rates effective July 1, 2021 – this Rider J increase coincided as proposed in the Application with reduction of Rider F to zero.

On September 24, 2021 Yukon Energy filed an application (Exhibit B-34) for an additional refundable Rider J increase of 9.25 percentage points effective December 1, 2021 to match the expiry of the current Rider J1 true-up rider from the 2017-18 GRA approved compliance filing.

OUTLINE OF YUKON ENERGY FINAL ARGUMENT

Yukon Energy's Final Argument provides the support from the record for the requested Orders, focuses on the extensive evidence examined within the scope of the Board's review of the Application, and includes the following major sections:

- **Part 1 - Core Elements of Yukon Energy's Application** - Addresses core elements of the overall Application as submitted and reviewed during the hearing process to date, including matters addressed in the Application (pages 1 to 9) and Supporting Tab 1.

- **Part 2 - Response to Key Issues Raised** - Provides Yukon Energy's responses to key issues raised by the Board and intervenors in Intervenor Evidence, information requests (IRs) and the oral hearing, and provides transcript references containing more detailed information on these issues.

Total documentation and evidence in this hearing are substantial. There were two rounds of interrogatories with a total 1,120 information requests, 32 undertakings, and approximately 509 pages of transcript. To date, there have been over 80 exhibits, and 9 Board Orders flowing from the Application. There were 4 registered intervenors, with two intervenors filing evidence in the proceeding.

To the extent that the Board and intervenors examined specific issues with respect to specific parts of Yukon Energy's Application through interrogatories or cross-examination, Yukon Energy has attempted in this argument to address the apparent concerns raised. However, in the view of Yukon Energy, its filing, the answers to the many interrogatories, and other evidence submitted (including undertakings) fully address 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: CORE ELEMENTS OF YUKON ENERGY'S APPLICATION

Part 1 of Yukon Energy's Final Argument addresses the following core elements of the overall Application as submitted and reviewed during the hearing process to date:

A. Rate Strategy

B. Factors Driving 2021 Rate Increase Requirement

C. Treatment of Updates

A. RATE STRATEGY

Yukon Energy's last requested rate increase was for the 2017 and 2018 test years. Board Order 2018-10, approved 2018 forecast costs that were much lower than the actual costs incurred in that year. This resulted in an actual Return on Equity (ROE) of 6.25% for 2018 compared to the approved ROE of 8.70%. YEC's actual ROE continued to erode seriously in 2019 (3.81%) and 2020 (3.88% forecast).

Addressing this revenue shortfall in a GRA application was delayed by a number of factors, including delay in completion of the 2017/18 GRA to November 2019, the very large true up rider (and therefore customer bill increases) that resulted from that delay as well as due ot the COVID-19 pandemic in 2020.

Yukon Energy's approach for the 2021 GRA allows it to address this serious revenue shortfall while avoiding a material change in bills for Yukon ratepayers. Implementation of this rate strategy will result in a very small change to customer bills, i.e., less than 1% from November 2020 bills (see Exhibit B-1, Table 4.3 and related text at page 4-10). The key to this strategy is a one year GRA with rate increases timed to coincide with the reduction or expiration of rate riders scheduled in 2021.

1. Yukon Energy's application sought an interim rate increase for 2021 concurrent with the expected reduction of Rider F on July 1, 2021.[1]

2. Yukon Energy's application also noted that in order to minimize ratepayer bill impacts, and thereby reduce customer bill volatility, it was seeking approval for final 2021 test year rates to be effective on the same date as the removal of the existing Rider J1. This would enable coordination of final rates with removal of the 2017-18 YEC GRA true up Rider J1 of 9.25% which is in effect until November 30, 2021.

Any required "true up" between the utility and ratepayers for the 2021 test year will be part of the Board's final order setting out rates arising from this Application.

Interim Rate Application – For December 1, 2021

To address delays in the hearing process, on September 24, 2021, YEC filed for an additional interim rate increase effective December 1, 2021 to ensure no volatility or material impact on customer bills when the 2017/18 GRA Rider J1 comes off on that same date.

The interim rate application seeks approval of an additional interim refundable Rider J increase of 9.25 percentage points effective December 1, 2021, i.e., an increase that equals the expiry of the current Rider J1 true-up rider from the 2017-18 GRA approved compliance filing. The resulting total interim refundable Rider J of 19.33 percentage points (10.08% approved effective July 1, 2021 plus 9.25% proposed effective December 1, 2021) is slightly less than the GRA estimated Rider J plus Rider J1 (true-up) requirements of 19.85 percentage points.

The proposed December 1 rate approval is interim and refundable. This approach will prevent bill volatility while final 2021 rates are being determined by the Board. The Board retains the full authority to vary the rate increase and any differences between the interim rate approved and final rates will be "trued up" through the Rider J1 – GRA true-up rider.

B. FACTORS DRIVING 2021 REVENUE REQUIREMENT INCREASE

A rate increase is required for the 2021 test year to recover a forecast $10.971 million revenue shortfall. Without this GRA, YEC's ROE for 2021 is forecast at only 3.10%. (Application, Tables 1-1 and 1-2.)

YEC's 2021 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 (Table 1-2) and YEC's Opening Statement (Exhibit B-33). Increased capital rate base costs account for $4.148 million (37.8%) of the 2021 revenue shortfall through higher depreciation, interest and equity return costs [2] - this rate base increase reflects different drivers as noted below. Diesel rental costs to address peak load growth account for $3.834 million (34.9% of the 2021 revenue shortfall increase. Other non-fuel cost increases to address increasing requirements relate to labour O&M ($1.378 million, 12.6%) and other non-labour O&M ($1.737 million,15.8%).

The following key drivers for the above increased costs forecast in the Application are noted:

1. **Load growth and growth in peak demand:** Peak load growth, including the added peak load requirements revealed by the sustained cold spell in January 2020, has exacerbated the existing N-1 dependable capacity shortfall – and the need to ensure that YEC can continue to meet N-1 requirements has driven significant required investments and spending on dependable capacity. As outlined in the Application, responses to information requests, and oral testimony, given the seriousness of an N-1 event these expenditures are required and were prudently incurred.

   Yukon Energy has ensured temporary solutions are in place to meet the N-1 capacity requirement each winter until more permanent solutions can be put in place. The evidence has confirmed that the only feasible solution for 2021 is YEC's action to connect

[1] This was approved by the Board in Order 2021-08.
[2] Shows cost increase before considering changes to depreciation rates or other changes as noted in Table 1-2 of Application.

diesel rental units in Whitehorse and Faro for the 2021 test year to meet this requirement while longer term solutions are being developed. Although temporary diesel units were first rented in winter 2017-18, no diesel rental costs were forecast in the 2017-18 GRA or included in final 2018 approved revenue requirement. Diesel rental costs account for 34.9% ($3.8 million) of the forecast 2021 revenue shortfall (see section 2.3 of Part 2 of this Argument for review of these costs). Diesel rental infrastructure requirements at Whitehorse and Faro also affect added rate base capital costs in the Application.

Yukon Energy has also actively pursued more permanent solutions to the growing N-1 dependable capacity requirement. The 2021 GRA brings the LNG Third Turbine into rates as well as existing hydro uprates, diesel rental infrastructure and Demand Side Management (total $26.9 million net rate base addition forecast in Application). The Board has just concluded a Part 3 proceeding on the Battery Energy Storage System (BESS) project. YEC's recently completed 10-Year Renewable Electricity Plan (CW-YEC-1-36 Attachment 1) sets out other major resource developments on this matter that will affect future GRA requirements, including the Atlin Hydro EPA, diesel replacements, capacity-related Demand Side Management (DSM), and the Moon Lake Pumped Storage project.

Energy load growth above the 2018 GRA approved forecast has added revenues at existing rates, however, also increased long-term average (LTA) thermal generation costs and increased Mayo B Promissory Note interest expense, resulting in a $2.9 million net reduction in the forecast 2021 revenue shortfall. Higher forecast fuel prices in the Application compared to 2018 GRA approved prices reduce this net gain by $2.1 million .

2. **Aging Infrastructure requiring ongoing and material investments in sustaining capital**: Yukon Energy has been implementing a range of major investments in sustaining capital to address aging infrastructure.

   The 2021 GRA includes sustaining capital projects with about $1.4 million revenue requirement impact [including depreciation expense and return on rate base] for the 2021 test year for the following major projects that have $22.7 million net rate base increase: Mayo – McQuesten Transmission Line Project; Transmission Line Refurbishment Projects; the Breaker Replacement Program; and replacement of the P125 Headgate.

   To address these issues Yukon Energy has also been required to focus on development of a Physical Asset Management Managed System (PAMMS) to ensure YEC's asset management practices are aligned with industry best practice, and to ensure that expenditures on sustaining capital and maintenance are as efficient as possible. Implementation of PAMMS is supported by the purchase and implementation of the Enterprise Asset Management (EAM) software system in 2021 (net rate base increase of $4.9 million or annual revenue requirement impact of $0.5 million for the 2021 test year).

3. **Increased complexity of relationships with First Nations**: Federal and Territorial governments commitments to Reconciliation and First Nations increased involvement in regulatory processes relating to projects that have or will impact their traditional lands and activities have changed materially the landscape that utilities operate in across Canada.

a. In Yukon this has resulted in First Nations playing a more active role in project planning, assessment and regulatory approvals processes. Given these new realities, planning and relicensing projects have required more extensive engagement with and involvement by First Nations, which has increased the complexity, duration and costs of these projects.

b. Yukon Energy must also ensure that it has sufficient and capable dedicated resources on staff to address this requirement.

4. **Clean Energy Policy** - Yukon Energy's planning processes must also recognize the policy context being set by the Federal government and the Yukon government, including the Yukon government's climate change action plan (Our Clean Energy Future). The YIS is already reliant on renewable resources, and new renewable Independent Power Production (IPP) connections to the YIS will start to augment this reliance in the 2021 test year.

   The Yukon government plans to pass a Clean Energy Act requiring Yukon Energy to meet a Renewable Portfolio Standard of 93% long-term average renewable energy generation. In order to ensure alignment with understood government climate objectives, Yukon Energy updated its resource plan with the recent 10-Year Renewable Electricity Plan (costs of which are in 2021 GRA rate base) and is continuing to plan and pursue DSM and renewable energy projects to meet long term energy and capacity requirements for the YIS, including the WH2 and WH4 uprate projects being brought into service in the 2021 GRA test year to increase renewable generation.

In summary, the 2021 GRA revenue and rate requirements address specific growth in capital and operation components needed for cost-effective and reliable service.

YEC's challenges since the last GRA have been increased by delays in being able to file the next GRA plus the impacts of COVID-19. Costs have been constrained by available funds and resources – and at the same time YEC has responded as required to unexpected challenges arising from events such as the 2020 sustained cold spell or unexpected failures in hydro or thermal generation facilities.[3] The 2021 GRA revenue shortfall identifies the level of rate adjustment needed today to fund current requirements – and timely completion of the 2021 GRA will constrain regulatory costs for a one-year GRA and help reset to a framework for proceeding in future with a two test year GRA process that restores a more orderly regulatory process.

C. TREATMENT OF UPDATES

The Application filed in November 2020 provided an integrated forecast of 2021 test year costs based on the information then available. As in past GRA's, the utility accepts forecast risk.

During the GRA proceeding YEC has provided updates in response to IRs. In assessing treatment of updates for final approvals of the 2021 revenue requirement, it is important to distinguish the updates that can be easily accommodated from other updates that cannot properly be done without more evidence. Where adequate evidence is not available to address the

[3] The Application at page 3-20 notes the large RFID expense in 2020 regarding the Whitehorse hydro generating facility penstock and the Whitehorse LNG unit and LNG vapourizer.

integrated impacts of updates on test year costs the Board needs to rely on the Application forecasts.

Mr. Mollard elaborated on the relevant issues at Transcript pages 467- 468, noting that YEC's actual ROE being below approved ROE has demonstrated the extent to which the utility has accepted forecast risks. He highlighted the following at Transcript page 468:

> Q. So, you talked about Board directions and updates. If you were directed to do an update, in your mind would it be appropriate to just update certain matters?
>
> MR. MOLLARD: No, I wouldn't think so. I think if there's updates, we have to be careful about picking out just individual projects. I think it needs to be a fulsome update of all the projects, to be fair to both parties, to all parties.

In the context of ensuring fulsome treatment of changes to Application forecasts based on evidence in the current proceeding, updates for the 2021 test year can be easily accommodated in two areas:

1. IPP updates - In the Application Yukon Energy referenced updating Independent Power Production (IPP) generation forecasts in its compliance filing. This specific update was referenced in consideration of YEC's uncertainties and inability to control the timing of IPP in-service dates – and also with knowledge that a compliance filing can fully address the related changes in long-term average thermal generation forecast requirements and thereby provide a fair result to all parties. Evidence on IPP updates has also been filed in response to IRs.

2. Major capital project updates – Major projects over $1 million (including deferred cost and intangible projects) that are forecast to enter rate base in 2021 are a limited number of discrete cost elements within the Application where the Board conducts prudency reviews and where costs for each project can be updated with minimal likely impact on other test year forecast costs. Updates on costs for these major projects have also been filed in response to IRs.

In contrast, labour cost forecasts in the Application as well as other non-fuel O&M forecasts are subject to a wide range of interacting factors – and in this instance picking out individual update items ignores other potential offsetting updates not in evidence. Similarly, capital projects with costs under $1 million are also subject to a wide range of interacting factors – and focusing on cost updates for specific projects identified in the Application will not address consideration of other projects not in evidence where updates would now indicate 2021 costs under $1 million that will impact rate base.

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 supporting evidence follows the outline of the Application's supporting information (tabs), focusing on Tabs 2, 3, and 5 as regards 2021 test year revenue requirement issues and a concluding section on matters that do not impact the 2021 revenue requirement and rates.

1.0 TAB 2 - SALES & GENERATION

Tab 2 reviews changes in Yukon Energy grid sales and generation since 2018 relative to sales and generation forecasts for 2018 as approved by the Board for the 2017/2018 GRA, as well as the Application's forecast growth in sales and generation for the 2021 test year. Overall, no key issues were raised in the oral hearing with regard to sales and generation forecasts for the 2021 test year and no updates were sought or provided for the sales forecasts.

1.1 SALES FORECAST

The Application forecasts total 2021 test year sales of 495.1 GWh, representing a 27.5% increase (108.9 GWh) over the approved 2018 sales forecast with 70.7 GWh increase for industrial sales, 28.8 GWh increase for wholesales, and 6.9 GWh increase for YEC general service retail sales. No secondary sales were forecast for 2021.

1.1.1 WHOLESALE SALES FORECAST

Wholesale Sales to AEY are reviewed in the Application (Exhibit B-1) in Tab 2, Section 2.2.1, pages 2-4 to 2-7. During the review of YEC's 2017/18 GRA, Yukon Utilities Board directed (paragraph 39, Order 2018-10) YEC to refine its wholesale methodology "to ensure its forecasts align closely with AEY's forecasts in future GRA submissions". The Application and response to information requests confirm that this was done and that YEC worked closely with AEY to develop its Wholesale Sales forecast for the 2021 test year. [4]

AEY provided Yukon Energy with its forecast power purchase estimate at 345.9 GW.h for 2021. Yukon Energy's forecast is 2.4 GW.h, or 0.7% higher, than the AEY estimate provided. The 2021 wholesale forecast was prepared based on multi-variate regression assessments[5] of monthly wholesales changes at normal weather conditions.[6] It also reflects incremental forecast Micro Generation for 2021 which reduces forecast wholesales. Given that the forecasts are very close, and AEY's forecast is only for business planning purposes, YEC's wholesale sales forecast of 343.5 GW.h for 2021 test year is reasonable and should be approved.[7] No other issues regarding the forecast were raised by the Board or intervenors during the oral hearing.

[4] See CW-YEC-1-4 (a)... YEC reached out to the AEY regulatory team and worked closely with them to undertake the forecasting methodology and inputs for the respective forecast. A copy of the communication is provided in this response. See also CW-YEC-2-2.
[5] See response to CW-YEC-1-3 (c) for the model.
[6] See YUB-YEC-1-16 (a) and YUB-YEC-1-19 (a).
[7] CW-YEC-1-4 (b). If AEY forecast is used then the impact would be a 0.09% additional rate increase.

1.1.2 MAJOR INDUSTRIAL CUSTOMER LOADS

Tab 2, Section 2.2.2 of the Application provides a summary of forecast information provided to YEC by Minto Mine management, and by the management of Alexco and Victoria Gold. Industrial sales are forecast at 64.9 GW.h for 2020 and 102.9 GW.h for 2021, as compared with 2018 actual sales of 36.9 GW.h and 2019 actual sales of 27.3 GW.h.

Accordingly, given the approach to creating the forecast and further given that 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; GENERAL SERVICE; SECONDARY; LIGHTING]

Retail and general service sales forecasts are reviewed in Tab 2, at page 2-9. 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 seven communities [Dawson City, Mayo, North Klondike Highway, Faro, Champagne, Braeburn, Johnson Crossing].

As noted in the Application and in response to IRs, YEC residential sales and general service forecasts are made on a community by community basis, and based on three year historical averages. YEC staff in each community provide an update on activity in the area (for example, new residential construction projects and commercial activity).[8] For larger commercial customers, YEC receives power consumption forecasts from the commercial customer.[9]

- As illustrated in CW-YEC-1-6 Attachment 1 the annual sales and sales per customer are steady without any notable changes year over year, except for two instances: (1) annual changes for Mayo general service sales are impacted by Alexco sales,[10] and (2) increase in Faro general service sales that reflects changes for the largest General Service customer.[11]

- The response to YUB-YEC-1-16 (b) provides the average annual YEC residential customers for the last ten years, along with forecast counts for 2021; and YUB-YEC-1-16 (d) provides the actual and forecast (annual budgeted) residential sales generation for the past 10 years.

[8] YUB-YEC-1-15 (b). YEC has not incorporated the effect of increased numbers of people working from home. This is primarily due to uncertainty and, at the time of preparation of the residential and commercial sales forecasts, Yukon people working from home were starting to go back to working at work.

[9] YUB-YEC-1-15 (a). The largest General Service customer is Faro Mine remediation project. The Application's forecast sales for the Faro Mine load reflect information and forecasts provided to Yukon Energy by the customer, the Government of Canada.

[10] Application page 2-8 notes for the years 2018 through 2020 Alexco was a general service customer with 2.4 GW.h sales in 2018, 1.8 GW.h sales in 2019 and 1.6 GW.h sales forecast in 2020. Starting in 2021 Alexco was included as an industrial customer which resulted in a decrease in average sales per customer for general service in this community in 2021.

[11] Application page 2-7 notes the sales for this customer are forecast to grow to 14.4 GW.h in 2020 and 2021 resulting in an increase in average sales per customer. CW-YEC-1-8 (a) notes the customer provided YEC with forecasts for fiscal 2019 and 2020 (see Attachment 1 to this response). Subsequently by email, the customer provided an update that "our 2021 projection should be in line with what we projected for 2020." YEC reviewed the reasonableness of the forecast and compared it to actual historical results.

No material issues or concerns were raised in IRs or at the oral hearing regarding the residential, general service, secondary sales or the lighting sales forecasts included in the 2021 GRA sales and generation forecast. The only issues raised during the proceeding related to use of weather normalization for future forecasts (addressed separately below). As such, Yukon Energy's retail sales forecasts are reasonable and should be accepted.

Use of Weather Normalization for Retail Sales Forecasts

CW in evidence (Exhibit C3-6) recommended that YEC be directed to investigate the use of a simple linear regression to weather normalize retail sales and use per customer, and to forecast use per customer.

YEC uses multiple regression analyses to normalize sales where it makes sense to do so, i.e., for its wholesales forecast, based on the size and importance of these sales within the YIS (~70% of 2021 sales forecast). YEC does not prepare weather normalized level sales for retail and industrial sales forecasts for the following reasons:[12]

- The industrial sales class representing about 20% of 2021 sales forecast is primarily process loads that are driven by volumes of materials handled (i.e., ore) as opposed to weather.

- As reviewed in Tab 2 of the Application, YEC's remaining non-industrial retail sales (residential, commercial and streetlights) is divided into 7 different load centres or communities,[13] accounting for only 7% of 2021 forecast firm YEC energy sales (excluding Faro Mine reclamation as this is primarily process driven load). Separate weather normalized analysis for each community's retail sales by customer class is not considered to be a worthwhile exercise.[14] Historically, these sales categories are fairly close to budget forecasts, with year over year variances in the area of 3-5%.

Undertaking #2 also notes that "a simple linear regression analysis would only involve variation of a single variable (e.g. weather). However, weather is not the largest driver of load in these communities. The number of accounts for the YEC service areas, or step changes in the specific requirements for those accounts, is the largest driver of forecast load. Accordingly, a single variable weather-based regression analysis would not be useful for the purposes of deriving an accurate load forecast for these areas."

The recommendations made by CW's expert assume that linear regression to normalize retail sales and use per customer is worthwhile regardless of community size and importance within YEC's overall energy sales forecast on the YIS. YEC is aware of the extra work required to

[12] CW-YEC-1-6 (e) and (f). Yukon Energy uses the Environment Canada Canadian Climate Normal for Whitehorse Airport for the definition of normal weather as noted in response to YUB-YEC-1-16 (a). See also CW-YEC-1-3(d) which provides YEC's definition of normal weather. In CW-YEC-1-2 YEC noted that it does not prepare weather normalized version of its actual sales to retail and industrial customers; and in CW-YEC-1-6 (a) through (d) YEC provides retail sales for 2018 and 2019 actuals, 2020 and 2021 forecasts.

[13] Undertaking #1 notes there are weather stations in Dawson, Mayo, and Faro which could be used to estimate weather data for Dawson, Mayo, North Klondike Highway, and Faro. There are no weather stations in Champagne, Braeburn, or Johnson's Crossing.

[14] CW-YEC-1-2; Yukon Energy Rebuttal Evidence (Exhibit B-30), pages 4-5.

implement the recommendation, and has not seen evidence that it would provide any value or reduce regulatory burden of a rate application.[15]

1.2 PEAK DEMAND FORECAST & DEPENDABLE CAPACITY REQUIREMENT

The actual peak demand was 93.0 MW in 2018, 90.0 MW in 2019 and 103.8 MW in 2020[16]. The peak demand for the integrated system is forecast to be 112.7 MW in 2021. Excluding industrial load, the forecast peak in this Application is 100.6 MW in 2021.[17] The 2021 forecast peak at 112.7 MW is based on the updated peak forecast from YEC's 2020 10-Year Renewable Electricity Plan, consideration of the most recent peak including industrial of 103.8 MW in 2020, and forecast industrial peak load (12 MW). The major change driving an increase in the peak since 2018 is the increased use of electricity for space heating and commercial businesses.[18]

No material issues were raised in IRs or at the oral hearing regarding the 2021 test year peak demand forecast; and, consequently, the forecast is reasonable and should be accepted. Based on this forecast, no material issues were raised regarding the forecast single contingency (N-1) dependable capacity shortfall without rented diesels at 25.75 MW in 2021; consequently, this forecast is reasonable and should also be accepted.

1.3 GENERATION FORECAST

Forecast generation for the 2021 test year of 538.7 GWh is based on forecast firm sales plus system losses of 8.8%. The losses percentage is the same as the 2018 approved and also within the range of historical losses for the last three years, from 2017 (at 8.1%) through 2018 and 2019 (each at 9.2%). No material issues have been raised regarding the losses forecast and consequently the forecast generation for 2021 is reasonable and should be accepted.[19]

Forecast thermal generation of 84.3 GWh for the 2021 test year as determined in Appendix 2.1 of the Application consistent with the approved 2018 forecast is based on the firm generation requirement net of forecast long-term average (LTA) hydro generation (452.4 GWh including forecast WH uprate impacts) and the long-term forecast Independent Power Production (IPP) renewable generation (1.98 GWh). The LTA hydro generation forecast was updated from the 2018 approved to include 38 water years, updated reservoir and generation station water flow requirement changes, updated load curve reflecting changes to monthly sales related to material changes in the industrial sales forecast, and forecast IPP renewable generation. The IPP generation forecast assumed two solar projects connected through the Standing Offer Program (SOP).

[15] Undertaking #2 notes, "In order to develop a multivariate regression analysis (similar to that used for forecast wholesale load), which would incorporate regression of historical regional weather as well as the other relevant factors (namely, number of accounts and other minor variables) it is estimated an initial FTE effort of 3 to 4 weeks would be required. On an ongoing basis, an additional 3 to 5 FTE days per forecast would be required, to gather the necessary data and complete the regression analysis."

[16] NY-YEC-1-2 (a) notes the peak demand of 103.8 MW shown in Table 2.2 was realized in January 2020.

[17] CW-YEC-1-1(a) and (b) provide forecast and actual non-industrial and industrial peak demand for 2018/19 to 2021/22. CW-YEC-1-1(c) reviews the impact of peak demand on required capital investment. NY-YEC-1-2 (c) notes YEC peak forecast model only models a winter peak (maximum load expected in coldest period) – this data is not forecast by month. Peak loads are recorded as the maximum load experienced in each winter.

[18] UCG-YEC-1-20 (a).

[19] Review of losses forecast provided in YUB-YEC-1-18.

The LTA thermal generation forecast for the 2021 test year is consistent with OIC 2021/16, directives issued in February 2021, which require (Section 9(2) and (3)) that forecast thermal generation to be included in rates is determined based on long-term average annual renewable source availability. No material issues regarding the test year thermal generation forecast were raised in the oral hearing, IRs or other submissions.

Yukon Energy has highlighted considerable uncertainty regarding the timing of IPP project generation[20], and has provided an update indicating expected 2021 IPP production now at about 10% of the Application forecast.[21] YEC will update the IPP forecast in its compliance filing and adjust the LTA thermal forecast as required. However, given the small magnitude of the Application's forecast IPP generation, this change will not have a material impact on LTA thermal generation for 2021.

The Application (pages 2-11 and 2-12) assumed, as per past GRAs, a forecast LTA thermal fuel mix of 90% LNG generation and 10% diesel generation. Yukon Energy has reviewed in detail the rationale and statistical information that support retention of this fuel mix for LTA thermal generation forecast for the 2021 test year.[22] No material issues have been raised during the oral proceeding regarding the proposed thermal fuel mix and consequently the proposed thermal fuel mix for 2021 is reasonable and should be accepted.

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 2021 test year are $13.22 million higher than 2018 approved costs, with $10.76 million of this increase due to load growth and related LTA thermal generation requirements, $2.13 million due to higher fuel prices, $0.31 million due to the introduction of IPP power purchases, and $0.02 million due to an increase in purchases from AEY.

[20] YUB-YEC-2-12 is the latest IR on this uncertainty.

[21] YUB-YEC-2-2 provides an update on IPP production by project, with an updated forecast for three IPP projects now to be connected in October 2021 with forecast IPP generation in 2021 test year reduced to 0.2 GWh (versus 1.98 GWh forecast in the Application). YUB-YEC-1-11 Revised provided forecast of contract production by month for the two initial IPP projects included in the Application.

[22] YUB-YEC-2-4 provides an extensive review, elaborating on the response to YUB-YEC-1-32(b) that shows how available statistics confirm that the LNG share of fuel mix has been below 90% when hydro power was similar to or in excess of LTA, and above 90% in 2019 when hydro generation was well below LTA. As reviewed in this response, LTA thermal generation determinations are driven by thermal generation requirements during a small percentage of years (e.g., 20%) with drought conditions. The higher overall grid load for 2021 test year is also shown to provide further support for the 90/10 LNG/diesel fuel mix in the 2021 test year. Finally, OIC 2021/16 requirement for LTA renewable generation forecast use for revenue requirement determinations also supports retention of the 90/10 LNG/ diesel fuel mix relevant to LTA hydro generation conditions.

Forecast fuel costs include the following two items (see Table 3.2-1 in Application):

- Forecast thermal generation fuel costs for the forecast LTA thermal generation as determined in Tab 2 (see section 1.3 of this Argument – 84.3 GWh with 90% liquefied natural gas (LNG) generation and 10% diesel generation) at forecast fuel prices of $0.1814/ kW.h and $0.2051/ kW.h respectively (compared with approved 2018 prices of $0.1467/kW.h for LNG and $0.2633/kW.h for diesel); and

- Forecast maintenance fuel costs for LNG and diesel units in each test year (these costs forecast for 2021 show a slight reduction from approved 2018).

The proposed 2021 GRA fuel prices for approval by the Board reflect the following:

- The forecast LNG price of $0.4824 per litre is based on a public competitive tender process completed in 2019 for liquefaction and shipping costs and current market price (mid 2020) for the commodity; the forecast price of $0.1814/kW.h is based on average 2019 efficiency for LNG generation of 2.66 kW.h/litre. The response to YUB-YEC-1-33 provides additional details, including: the competitive tender was for four years supply starting in 2020; the increase in fuel price is mostly due to increase in transportation costs, which under the contract will reduce in 2023; fuel efficiency for 2019, which was the last full year before filing the GRA, showed improvement over 2018 approved.

- Forecast diesel prices for 2021 reflect prices as of July 1, 2020, i.e., the most recent prices prior to completion of the Application. Diesel fuel efficiency reflects an average of 2018 and 2019 actuals for each diesel plant.

Forecast IPP purchase power costs for 2021 are based on IPP generation as determined in Tab 2 (see section 1.3 of this Argument), and a purchase price (as required by Standing Offer Program Rules and section 3(2) of OIC 2019/25) of $0.1583/kW.h based on the last approved average blended fuel price per kW.h for YEC in its 2017/18 GRA. As reviewed in section 1.3 of this Argument, the compliance filing will reflect updates to 2021 IPP generation – however, given the small magnitude of the Application's forecast IPP generation, this change will not have a material impact on overall forecast fuel and purchased power costs for 2021.

No material issues have been raised regarding forecast fuel and purchased power costs for 2021 and consequently the forecast costs for 2021 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 $7.3 million increase forecast for the 2021 test year compared with 2018 approved. Labour and production expenses together account for approximately 76% of this increase, and each is reviewed separately below. Major issues have not been raised during interrogatories or the oral hearing with regard to other components:

- Transmission and Distribution expenses each reduced slightly for 2021 versus 2018 approved;[23] and
- General O&M, administration,[24] insurance and Reserve for Injuries and Damages (RFID), and property taxes together account for the balance of the increase.

2.2.1 LABOUR EXPENSE

Labour costs in the 2021 revenue requirement forecast increases of $1.378 million over 2018 approved. This increase in total labour expense relates mainly to added positions ($0.882 million) and labour rate increases ($0.740 million). Other factors impacting forecast labour costs include changes in overtime, vacancies and the capital allocation:

- **Overtime**: Overtime costs for 2021 are forecast at $0.76 million, compared to actual costs of $0.9 to $0.99 million in each of the previous three years. YUB-YEC-1-38(e) provides actual overtime costs from 2018 to 2020 and forecast overtime costs for 2020 and 2021, and notes higher actual than forecast overtime costs in 2020.[25] CW-YEC-1-14(b) notes none of the new positions were created solely to reduce overtime – however, for the Operations department (Maintenance Mechanic and Plant Operators), as well as in the Engineering department (Electrical Engineer) the increases were also in an effort to reduce overtime per employee.

- **Vacancies**: Vacancy rate for 2021 is forecast at 5, compared to actual vacancy rates of 6.50 to 9.99 in each of the previous three years. YUB-YEC-1-38(c) provides the actual (2018-2020) and forecast (2020 and 2021) vacancies. See also CW-YEC-1-3(b).

- **Capital/ Maintenance Allocation:** Labour O&M expense reflects the allocation of total labour costs to maintenance versus capital. Maintenance allocation for 2021 is forecast at 82.4% (17.6% allocated to capital), compared to 83% forecast for 2018 approved and actual maintenance allocations of 81.8% to 85.3% in each of the past three years. The response to YUB-YEC-1-39(s) provides historical results for the years 2018 through 2020 that were used to determine the 2021 forecast capital to maintenance ratio allocation. CW-YEC-1-13(b) provides the actual (2018-2020) and forecast (2020 and 2021) capital allocation. See also discussion at transcript page 249.[26]

[23] CW Evidence (Exhibit C3-6) raised concerns about reduction in distribution brushing costs in 2019. YEC addressed this concern in rebuttal evidence (Exhibit B-30) and in Mr. Mollard's testimony, Transcript pages 57-64. In summary, YEC staff in the communities with YEC distribution service retain the ability to identify and address brushing as needed to prevent the concerns raised by CW, and the identified adjustments to brushing costs only reflect external resource use and the overall priority use of external resources for transmission brushing. YUB-YEC-1-41 also addressed allocations of brushing costs between transmission and distribution.

[24] YUB-YEC-1-43 responds to Board questions on administration costs.

[25] Mr. Mollard notes at transcript page 248-49, "Well, I think it's important to understand the nature of some of our overtime costs. We will frequently incur overtime when we are in a thermal run scenario. So engines have to run when they need to run. So we typically are running them at peak times in the early mornings and afternoons. We have to pay people to be on staff to look after those units. So if there's thermal runs, you're going to have overtime. That's pretty much unavoidable. And we can't cut that. That's keeping the lights on. So I offer that as one example where we don't necessarily have discretion to cut overtime, particularly when service delivery is at risk."

[26] MR. MOLLARD: Mr. Chair, if I could intervene here. We describe in Tab 3 Revenue Requirement with respect to labour that, when we set the labour component of revenue requirement, we first divide up what we believe to be the split of labour between capital and O&M, or admin, so it's not double dipping. The number that's in Tab 3 Revenue Requirement is only that component of the labour that is charged to O&M. The capital costs run through the projects and are included in revenue requirement when the project is put in service through Tab 5. So there is no double dipping.

The justification for labour cost increases in the test years was extensively reviewed in interrogatories and in cross examination at the oral hearing. Detailed information is provided in Tab 3, pages 3-7 to 3-13, and in Tables 3.3, 3.4, 3.5, 3.6, 3.7, 3.8 and 3.9. Labour rates, new positions, and the interaction between different labour cost components were addressed during the oral proceeding, and are reviewed in more detail below.

Labour Rates

Labour rates[27] include factors such as base pay, benefit costs, annual increments (performance increments, cost of living adjustments), etc., and is heavily influenced by collective bargaining agreements (CBA).

The actual annual negotiated increase in base pay from 2018 to 2019 was 2%. Forecast 2020 and 2021 labour rates include estimated economic increments of 2%. These estimates were developed by YEC management based on prior settlements. Additional details were provided in CW-YEC-1-16; CW-YEC-2-5; UCG-YEC-2-24; and UCG-YEC-1-26 revised.

During the oral proceeding Mr. Epp confirmed that the agreed upon negotiated increase to union employee base pay for each of 2020 and 2021 was 1.75% per year, and that this same increase had been applied to all other employees.[28] Mr**.** Epp clarified at transcript pages 339-40[29]:

> Ms. Graham, when you were questioning me yesterday on labour rates, when I looked at the transcript, you were specifically asking about base pay. And my response was that the collective bargaining process resulted in a 1.75 percent increase in base pay, which is what did happen in the collective bargaining agreement. But as our application detailed, our labour rates don't just include base pay but they include other benefits in our 2 percent forecast in the application. So these other benefits that are part of the collective bargaining agreement are such things as vacation leave, special leave, and there was also a shift premium. So all those costs added together result in an additional cost of 0.25 percent that was agreed to in the collective bargaining process. So the total economic increment as per our application of 2 percent is actually what did result in the collective bargaining agreement. So I just wanted to clarify that, that there wasn't a difference between the 1.75 and the 2 percent.

Additional detail regarding labour inflation rates is provided in YUB-YEC-1-37.

Additional FTE Positions

The Application includes a 9.9 FTE increase for 2021 over 2018 approved. The Application at pages 3-8 to 3-13 provides a summary of changes from 2018 approved to 2021 forecast. Table 3.4 (in Tab 3, page 3-8 of the Application) reviews the Employee Complement History (net of allocation to YDC). CW-YEC-1-14(a) provides employee complement with total labour by department. Additional details were provided in response to information requests, the opening statement, in discussion at the oral hearing[30] and in Undertakings #13 and #14.

[27] See Application, Section 3.3.1, page 3-8.
[28] Transcript pages 290-291.
[29] This clarification was provided in response to discussion at transcript pages 289-91.
[30] See transcript pages 291 to 295 which reviewed each of the added positions and whether or not the position had been filled.

Page 3-9 of the Application notes the factors affecting employee complement including: asset growth; strategic importance of improving First Nations and public engagement, relationships and communications, steady growth in customer accounts, increasing planning requirements and continuing high capital demands to maintain existing assets.

While the addition of positions during the prior GRA proceeding was premised on reducing consulting costs – the requirement for increases to YEC's complement levels in 2021 is very different. YUB-YEC-1-38(f) provides costs related to outside consultants and contractors (2018-2020 actual and 2020 and 2021 forecast). The 2021 addition of positions reflect critical requirements beyond reducing consulting costs:

- As noted in Tab 3 and Undertaking #14, of the GRA, at historic staff levels, employees were finding it difficult to keep pace due to the addition of assets and the increased burden related to planning and executing capital works, e.g., Table 5.1 in Application highlights material growth in annual capital spending, and planning is having to deal with material increase in relicensing and new resource projects

- Further details on employee turnover are provided in response to YUB-YEC-1-38(b) and (c) (number of employees resigned or retired on an actual basis from 2018-2020), and YUB-YEC-1-38(d) provides recruitment and relocation costs (2018-2020 actual and 2020 and 2021 forecast).

- Other factors that lead to increased complement related to the strategic importance of improving First Nations and public engagement relationships and communication, and steady growth in customer accounts.

Undertaking #14 noted that a number of positions were not filled in 2021 (or have yet to be filled), despite YEC's requirements. While some positions would reduce consultant costs, others relate to work not previously performed by consultants (First Nation Relations) or otherwise will not reduce consultant costs (Meter Reader, Plant Operator and Job Planner). Where positions were filled and will reduce consultant costs these were noted in the response to Undertaking #14 (e.g., Resource Planning Engineer, and Electrical Engineer). Further discussion on use of internal resource and how consulting costs are cost-effectively used was provided on the transcript pages 142-144 where Mr. Hall noted in cross examination:

> So these relicensings are big projects, they're complicated, and our expenditures, overall, are not out of line with what was spent last time. Now as to the question could we have brought that in-house, I would argue we run a very tight ship here. We do not have spare people available to take on this kind of work. Our staff are running at full capacity, and when you bring a project such as a relicensing project forward, we don't have the staff internally to take that on completely. We have a project manager in Ms. Milojevic's group, one person, at max one and a half, assigned to that project. And if you look at the complexity, there's no way you could get that done with one to one and a half people. So the business model of relying on consultants, I believe, is efficient because once the relicensing is done, you know, there's no need to incur those costs anymore."

Mr Mollard also noted:

> "Yeah, Mr. Chair, I guess I can comment on the General Rate Application. Again, that's -- they vary in their timing, so we don't do them every year. They're an extremely tight deadline, and it's an extremely high volume of work. And as we sit today, the company has Jason and I to do these things. So I'm not sure how anybody could expect that the two of us could produce 3300 pages of evidence I think was the Round 1 IR responses in about two months. It's just not realistic. But that being said, I don't need to have a regulatory consultant underfoot all the time, so using consultants allows me to use them when I need them and send them home when I'm not working actively on a GRA."

The following are specifically noted regarding justification for the added positions:

- **First Nation Relations (1.00 position)[31]:** The new Vice President, First Nations Relations is a critical addition to YEC's employee complement to help build and maintain strong, respectful and productive relationships with Yukon First Nations so crucial to the Corporation's ongoing success. As reflected in the justification for this position, this role has also resulted from an increased focus on First Nation engagement requirements compared to prior years. The importance of this new role was emphasized in YEC 5 year strategic plan published in 2019. This position was filled in 2021.

- **Communications, Customer Billing and Accounting[32]:** The Application notes the increased in employee complement is due in part to the increase in number of customers served by YEC (e.g., 9% increase in residential customers in Application from 2018 approved).

    - **Senior Communications Advisor (1.00 position)** – Application page 3-10 notes, the position is required as the roles and responsibilities of the Manager of Communications have significantly changed, including increased strategic focus on public communications, necessity of comprehensive public engagement on generation supply projects and increased demands of social media monitoring and reporting. The response to YUB-YEC-1-39(h) notes, "as a one-position department with critical responsibilities during unplanned events. the Manager Communications is effectively on call 24/7, 365 days a year. The added position will provide an additional resource for this important function."

    - **Meter Reader/ Office Administrator (0.5 position increase)-** Application page 3-10 notes that the increase is required due to the increased demands of the Customer service department which have caused the 0.6 FTE Customer Service Representative and 0.5 FTE meter reader to work more than their allotted hours.

- **Resource Planning and Environment**: The Application notes a forecast increase related to the following added positions (see pages 3-10 and 3-11):

    - **Senior Project Manager:** Created in 2021 specifically to address priority initiatives recommended in the 2020 10-Year Renewable Electricity Plan. The response to YUB-YEC-1-39(i) notes that the Senior Project Manager will lead

[31] For further details, see Tab 3, page 3-9 to 3-10; Response to YUB-YEC-1-39(a) to (d), Yukon Energy's Opening Statement and response to Undertaking #14.
[32] See Tab 3, page 3-10; Response to YUB-YEC-1-39(e) to (h), and response to Undertaking #14.

completion of the Southern Lake Transmission Line and Pumped Storage projects.

- **Resource Planning Engineer:** Two year term created to assist with the backlog of planning work designated for completion. The response to YUB-YEC-39(i) notes the general challenge that YEC is unable to advance concurrently, as required, all of its project give limited internal planning resources. The concern looking forward is that the upcoming work requirement is expected to be even more challenging than that experienced to date. [33]

- **Finance:** The Application at page 3-11 notes 1.00 position increase related to new full-time position for a procurement administrator. The position is required due to the increased workload in the department due to greater volume of high dollar projects, increasingly complex contracting strategies for some capital projects, including the additional requirements of the First Nation procurement policy. All of this has increased the complexity and administrative support required for large project procurement as well as the need to allow departmental management to concentrate on policy renewal and development and education or client mangers new to YEC.

  The response to YUB-YEC-1-39(l) notes that the addition of the Procurement administrator will not result in less work for other staff. The volume of purchasing is exceeding the capacity of the department to the point where some projects were delayed due to backlogs in procurement.[34]

- **Operations:** The Application at page 3-11 to 3-12 notes added positions are required due to increasing generation requirements (load growth), additional generation assets, an effort to reduce overtime per employee and an effort to do more work internally as opposed to hiring outside consultants and contractors.

  - Maintenance Mechanic (1.00 position): Required to address additional responsibilities (e.g., LNG assets).[35]

  - Plant Operator (1.75 position): The Application notes that the plant operator complement has not changed in over 15 years and has not kept up with the

[33] Transcript page 293 notes re the position, "So it actually is the resource planning engineer position. When we looked closely at the position requirements, we determined, due to the nature of the work, that a project manager, and not necessarily an engineer, would be appropriate to fill the role. So the title is resource planning project manager that is the equivalent to the resource planning engineer in the application. And a small correction for me, I stated yesterday that we filled the position in October 2020. That was just my memory failing me. In fact, it was in December 2020, just for the record.

[34] Further details regarding the department are outlined in the response to YUB-YEC-1-39(m) to (o).

[35] See response to Response to YUB-YEC-1-39(p) which notes: the "1.00 position increase in 2018 due to the addition of a new full-time position, Maintenance Mechanic to address additional responsibilities (e.g., LNG assets)" was not specifically contemplated in YEC's original LNG project business case. The position was required to address the workload of all generation assets based on the workload at that time, which changed from the time when the LNG business case was prepared. The process to justify the additional position was done using a spreadsheet that assigned annual tasks at each facility. This process determined the staff complement against the work. The latest iteration of the work indicated a deficit in mechanical trades staff. With the addition of the LNG facility there was an obvious lack of person hours to complete the suggested maintenance.

additional assets (including new hydro generation assets such as Mayo B and Aishihik 3rd Turbine, and the three LNG units).[36]

- **Engineering services:**

  - **Job Planner:** 1.00 position increase due to addition of a new full-time position considered necessary to assist with increased operational responsibilities for planning resulting from implementation of new asset management processes.

  - **Electrical Engineer:** 1.00 position increase required due to increasing generation requirements (load growth), additional generation assets, an effort to reduce overtime per employee and an effort to do more work internally as opposed to hiring outside consultants and contractors.

Interaction Between Labour Cost Components

At transcript page 465, Mr. Landry asked how the vacancy rate interplays with unfulfilled positions in terms of a forecast. Mr Epp in response noted at transcript page 465-66:

> So, Mr. Landry, when we are calculating the costs for labour and revenue requirement, we do add up all the costs for the 103 positions that we are asking for. From that cost we deduct a vacancy factor, which in this case was a vacancy rate of five employees that we assumed would be unfilled for calculating the costs of revenue requirement.
>
> Now, we don't go into specifics on that number of five vacancy factor because we just don't know which -- at the time of preparing this we just don't know which positions will be filled and which won't be, and the reasons for that can vary from year to year.
>
> So the fact that positions are unfilled is expected. Yes, there might be differences between actuals and forecast, but it's not a surprise that some positions are unfilled at a certain point in time.

Mr. Epp also noted at transcript page 149-50 with regard to overtime in relation to vacancies:

> And, Mr. Chair, if I could on that same IR just refer you to Table 3 rather than Table 5. So you also have to look at, when you're looking at overtime, your employee complement. And this Table 3 is talking about vacancy rate. And as you can see in these three years it's increasing. So what that means is we have more open positions, unfilled positions. So considering the work still needs to get done by less positions, people actually working, they're going to have to work overtime. And in the end the overtime costs basically offset the vacancy rate cost savings.

In summary, the evidence confirms the 2021 test year forecast labour rates and the requirements for the specified new FTE positions to enable Yukon Energy to meet its evolving responsibilities and challenges. The 2021 test year overall forecast labour costs reflect these requirements as

[36] The response to YUB-YEC-1-39(q) notes “The 1.75 position increase represents a 16% increase in plant operators.”

well as forecast vacancy rates and overtime costs and the allocation of labour costs to maintenance and capital. Given interactions between the various labour cost components, delays in filling some of the new positions are likely to be reflected in added other costs not included in the forecast (e.g., added overtime costs would offset cost reductions due to having a vacant position). In this regard see also Section C, Part 1.

Accordingly, the overall labour operating and maintenance cost forecast is therefore reasonable and should be accepted.

2.2.2 PRODUCTION EXPENSE

As reviewed at page 3-14 of the Application, about 99.5% of the $4.179 million non-labour production expense increase in 2021 compared with 2018 approved is due to thermal generation expenses related to diesel rental costs ($3.834 million) and non-fuel consumables ($0.324 million).

Rental diesel expense increases have been a major issue of review during interrogatories and the oral hearing, and the need and prudency of these expenses is therefore summarized below under the following headings:

- 2021 N-1 Dependable Capacity Shortfall
- Rented Diesels only Feasible Option to address 2021 Capacity Shortfall
- Renting Option for 2021 is Preferable to Possible Ownership
- 2021 Feasibility to Operate Rented Diesels if required for N-1 Event

2021 N-1 Dependable Capacity Shortfall

Mobile diesels are being rented for the 2021 peak winter period in response to a dependable capacity shortfall relative to the YIS N-1 single contingency capacity planning criterion as reviewed in Tab 2 of the Application, in Part 1 of this Argument, and in YEC evidence at the oral hearing.[37]

The N-1 capacity planning criterion requires sufficient dependable capacity during winter to meet forecast non-industrial peak load under an extended cold weather period (i.e., up to two weeks at temperatures experienced in the January 2020 extended cold spell) without access to the Aishihik generation station's 37 MW of dependable capacity.

The need to address a growing dependable capacity shortfall with rented diesels was recently confirmed by the Board in its Part 3 Report on the BESS Project where the Board found "…that a large capacity shortfall will exist until YEC connects additional supply options" and that "Currently and into the future, unless a permanent thermal option is pursued, YEC will need to continue relying on rented diesel units to address the capacity shortfall."[38]

[37] Mr. Hall, Transcript, pages 35, 442-444. See also YUB-YEC-1-1(a), YUB-YEC-1-50(a), (b), (c) and (d).
[38] Exhibit B-30, reference to YUB Report to Yukon Minister of Justice on YEC Application for Energy Project Certificate and Energy Operation Certificate Regarding the Proposed Battery Energy Storage System (BESS) Project, June 30, 2021.

Intervenors did not challenge the need in the 2021 test year to provide the required thermal generating capacity of 27 MW that is being provided by diesel rentals (15 units, plus two spares, at 1.8 MW per unit) as set out in the 2021 GRA.[39] In fact, the CW Evidence (Exhibit C3-6) describes YEC's obligation to provide safe and reliable service by ensuring that this capacity is connected and available as required, even though it argues that YUB should disallow the diesel rental generation costs required to provide that service.

The issues raised by Exhibit C3-6 regarding rented diesels relate to assessment of options. These issues are addressed below.

Rented Diesels only Feasible Option to address 2021 Capacity Shortfall

YEC has conducted several detailed assessments of more permanent options for addressing the dependable capacity shortfall since diesel rentals were first installed for the 2017/18 winter – including YEC's recent 10 Year Renewable Electricity Plan completed in 2020 and its earlier more detailed assessment of a 20 MW new diesel plant and other options in YEC's 2016 Resource Plan.

In summary, the evidence confirms that Yukon Energy has diligently assessed permanent options to address the capacity shortfall:[40]

- YEC's 2016 Resource Plan issued in spring of 2017 was the first time the magnitude of the current dependable capacity shortfall was identified as a major issue; the 2016 Resource Plan reviewed extensively the possible permanent options. As a result of that extensive review the Plan recommended a number of possible permanent options including a new 20 MW diesel plant (with provision for future expansion to 30 MW), a BESS project, a third LNG unit, dependable capacity DSM, and potential new dependable hydro capacity options.

- YEC first rented diesels for the following winter of 2017/18. It was without question the only feasible option for that winter to address the then identified N-1 dependable capacity shortfall. YEC has continued to pursue diesel rental thereafter as required each winter to address the forecast N-1 dependable capacity shortfall until permanent solutions can be brought into service. In this context, rented diesels have become the default option used to assess the cost effectiveness of proposed permanent solution options such as the BESS project and permanent diesel replacement options.

- Following the 2016 Resource Plan, YEC diligently pursued permanent solution options, including the 20 MW new diesel plant, the third LNG unit, the BESS project, dependable capacity DSM, and potential new dependable hydro capacity options. Given these actions there is no basis for suggesting that YEC was imprudent or irresponsible in its planning to address the dependable capacity gap.

- As a result of detailed planning assessments (including consultation and engagement on the 20MW new diesel plant site options), YEC's Board in 2019 rejected that alternative

[39] The evidence reviews the basis and costs for the 17 rental units, including the two spare units to enhance reliability at each rental unit site (Whitehorse and Faro), as well as YEC operation of the units when diesel is required on the grid – see YUB-YEC-2-1; YUB-YEC-2-3; Mr. Mollard, Mr. Epp and Ms. Milojevic, Transcript pages 298-304.
[40] See Mr. Hall, Transcript pages 450 to 454; CW-YEC-2-6(a) and (b).

for further consideration and directed that new permanent thermal options focus on diesel replacement at existing plants.

- Yukon Energy is currently diligently acting to implement the 10 Year Renewable Electricity Plan that includes diesel replacement options at existing diesel plants, renewable capacity alternatives including BESS, dependable capacity DSM, and dependable hydro capacity provided by the Atlin Hydro Expansion project and the Tutshi-Moon Lake Pumped Storage project.[41]

- Yukon Energy has confirmed that as at 2019, when the decision was made to not pursue the 20 MW new diesel plant option after completion of detailed planning work, it would have taken at least four years to plan, permit and construct a new 20 MW or 12.5 MW diesel plant, i.e., such a new diesel plant could only have been available in 2023 at the earliest.[42] In other words that option -- even if it was pursued -- could not have been in service during the 2021 test year.

In summary, the evidence confirms that rented diesels are the only feasible option for Yukon Energy to address the dependable capacity gap for the 2021 test year. Further, the evidence confirms that this situation exists notwithstanding YEC's ongoing diligent pursuit of new permanent solution options to address the dependable capacity gap.

Further, the evidence also clearly demonstrates the challenges that Yukon Energy faced in successfully securing sufficient additional rental diesels (including moving to place sufficient units at Faro) by winter 2020/21 following the lessons learned from the extended cold spell in January 2020.[43]

Renting Option for 2021 is Preferable to Possible Ownership

Questions have been raised in Exhibit C-6 and in cross examination by the Board[44] relating to the possibility of purchasing rather than renting required diesel units.

YEC has provided business case Levelized Cost of Capacity (LCOC) cost comparisons for new permanent dependable capacity project options (including permanent YEC owned diesels) versus rented diesels. These LCOC cost assessments confirm that diesel rental costs are reasonable in comparison with permanent diesel costs when these can be installed.[45]

Further the evidence also demonstrates that rented diesels is a flexible year-by-year option that avoids capital cost commitments and related risks associated with asset ownership options. As such the LCOC comparison is directed at simply confirming the cost effectiveness of permanent solutions (when these are feasible to implement) relative to the rented diesel option, i.e., the

[41] CW-YEC-2-6(a) and (b). These investigations were detailed in the response, with reference to CW-YEC-1-36(a) Attachment 1 copy of the YEC 10-Year Renewable Electricity Plan completed during 2020. Ms. Milojevic also reviewed the extensive work done by YEC to identify and cost options for the 2016 Resource Plan and the current 10-Year Renewable Electricity Plan, Transcript pages 458-460.
[42] Mr. Hall, Ms. Milojevic, Transcript pages 454-456
[43] Mr. Gazankas, Transcript pages 445-446.
[44] Mr. Fortin, Transcript pages 430-433.
[45] CW-YEC-2-6(a) and (b). Diesel rental costs are indicated at $162.4/kW for winter 2021/22 for 27 MW (15 units for N-1 requirements), versus an LCOC (2022$) of $211/kW for 20 year life and $243/kW for a 40 year life. A 12.5MW YEC owned diesel plant option LCOC (2022$) with a 40 year life is estimated at $186/kW without property tax (Takhini site) and $212/kW with property tax (Whitehorse site).

LCOC assessment alone is not a useful indicator for assessing rented diesel costs for the 2021 test year.

As evidenced by the 10-Year Renewable Electricity Plan, YEC is actively pursuing a range of permanent dependable capacity options to remove the need for reliance on rented diesels as soon as this can reasonably be achieved within an effective long-term resource development plan – but as noted none of these options can displace the need for rented diesels in the 2021 test year.

Focusing then only on rented diesels, YEC has confirmed that purchase rather than rental of these units is not a prudent or practical option for the Corporation even when subsequent sale of the units is considered as a way to retain a degree of flexibility relative to "permanent ownership" options:

- First, the current rental units are not the type of unit that YEC would ever seek to secure as permanent units. Further and in any event – Finning (who is renting the units to YEC) has not made any proposals for YEC ownership and in some cases does not even own the units that it is renting to YEC.[46]

- Second, Mr. Hall reviewed in some detail why a purchase/ sale alternative would not be a realistic or practical option that YEC could quantify adequately at the front end. He explained why he would not be comfortable getting into the business of trading diesel units pretty much on an annual basis, and why renting diesel units is an appropriate way to address relevant ongoing uncertainties as to the need for additional diesel units.[47]

> Briefly, I don't believe it's a realistic option that we would have been able to quantify economically in an adequate fashion at the front….
>
> Well, you can imagine that, you know, a strategy to rent, the rental costs are known at the front end. If we were to look at an option to purchase and then sell again in the future, we have to look at, firstly, you know, what certainty we have around those overall economics. Then the practicality of buying and selling units potentially on an annual basis.
>
> So I'll deal with each of those in turn.
>
> So the first thing about cost certainty, I know of no way that we could have confirmed the sale price of the units four, five, eight years down the track to an adequate level of certainty that our board would have been comfortable that we had a handle on the economics. So that's the first point.
>
> In terms of practicality, you know, I'll draw folks attention to Figure 20 again in the 10-year renewable plan….

[46] Mr. Mollard and Mr. Hall, Transcript pages 305-306; Mr. Mollard, Transcript page 431. Also Mr. Hall and Mr. Mollard, Transcript pages 432-433 (Mr. Mollard also references here looking continuously for potential other rental suppliers than only Finning, who to date was the least cost rental supplier offering this service to YEC).
[47] Mr. Hall, Transcript, pages 461-463.

> So you can see that the height of the hatched grey bars, the temporary diesel rental, varies over time. So you can see as additional resources are brought online through to 2024, so that would be the battery for example, plus the Atlin project, the number of rentals would drop. So we would be buying diesels, then selling them and then lo and behold after 2024 the height of that bar starts growing again. So we'd have to be buying again.
>
> So this whole idea of getting into the business of trading pretty much on an annual basis diesel engines, I mean, that's not our business, and I wouldn't be comfortable with us getting into that line of work.
>
> So given that profile of how many rentals we need, I think the idea -- renting gives you a lot more flexibility in terms of being able to determine the number of rentals on an annual basis and not having to buy and sell and trade those units.
>
> Also, as we've seen, there's some uncertainty to all of this, of course. So how quickly load grows, it has some uncertainty associated with it. And renting is an appropriate way of accommodating that uncertainty. If we were buying, we would be locking ourselves in, and then having to respond in a much more inflexible way to changes in circumstance.
>
> So I think if I look at those two factors together, the idea of buying rental units and then selling them again we just viewed as not being a practical solution for the company.

In summary, the evidence confirms that any suggestion that a potential diesel ownership option simply has no merit.

2021 Feasibility to Operate Rented Diesels if required for N-1 Event

Mr. Yee's evidence (Exhibit C4-6) has raised questions regarding the ability of YEC to operate all of its rented diesels as required to deal with an N-1 event in the winters of 2020/21 and 2021/22.

During cross examination, Ms. Milojevic confirmed that YEC does not need a permit to install diesel capacity (including diesel rentals), that an air emissions permit simply sets the production capacity at the site, i.e., the production capacity permitted for normal operation – it is not tied to specific units. She also testified that as a result of s. 49 of YESAA YEC also has ability under an N-1 emergency event to operate any available diesel generating capacity connected to the system.[48]

Mr. Hall also explained that YEC's primary responsibility to make sure that Yukoners are safe if an N-1 event is encountered, and YEC made the decision to install the diesel rental units based on this fundamental responsibility.[49]

Yukon Energy has confirmed (Exhibit B-30) that four points need emphasizing in this regard:

[48] See, for example, Ms. Milojevic at Transcript, pages 86 to 91, pages 96 to 104.

[49] Mr. Hall, Transcript page 105. Ms. Milojevic reviewed additional considerations at Transcript page 106 regarding why it was considered prudent to proceed with installing the rental units.

1. For the additional N-1 dependable capacity requirements arising from the January 2020 peak – YEC needed to have connected (i.e., ready to operate) by winter 2020/21 the rental diesels located at Faro.

2. The permitted production capacity for Faro for normal operations was 10.6 MW. YEC has applied to amend the existing permit to increase this to 15.5 MW.

3. Until the amendment is granted YEC had and continues to have the capability to operate diesels in Faro beyond 10.6 MW (in the unlikely event that YEC required more capacity from Faro beyond 10.6 MW to meet an N-1 peak load in the coldest part of winter because of an unexpected loss of the Aishihik facility) using the emergency exception set out in section 49 of YESAA. That section states that no assessment is required in "*response to an emergency when it is in the interest of public welfare, health or safety or of protecting property or the environment that the activity be undertaken immediately*").[50]

4. If required to deal with an N-1 emergency event in winter 2021/22, the 17 rented diesels installed at Whitehorse and Faro will ensure that YEC has full capability to respond to the emergency as required. [51,52]

In summary, based on above review of the four issue components, the rental diesel expense forecast for 2021 test year is reasonable and should be accepted.

2.3 RATE BASE DEPRECIATION AND AMORTIZATION

Rate base depreciation and amortization costs net of contributions are forecast in section 3.4 of the Application at $13.125 million in the 2021 test year, an increase of $1.984 million over 2018 approved that is accounted for in the Application by three factors[53]:

- $2.012 million increase due to growth in net mid-year rate base for plant in service of $34.64 million from 2018 approved (Table 3.13 in Application – increases in rate base due to capital costs are addressed in section 3 below);

- $0.636 million increase due to depreciation rate changes resulting from the depreciation study that YEC completed per Board directions in Order 2018-10 (Tab 9 of the Application provided the study); and

- $0.665 million reduction estimated in the Application due to accelerated amortization of VGC Group contributions relative to the depreciation required on the YEC assets (McQuesten Substation and system improvements) funded by these contributions.

[50] Although diesels were installed and available to meet such a potential emergency in winter 2020/21, no such event occurred, and the Faro facility operated within its currently permitted production capacity limit of 10.6 MW.
[51] YEC has permits today that authorize normal diesel unit operation of 14.0 MW at Whitehorse (see Undertaking #29 for information on the 14 MW capacity related to the permitted production from five generating units) and 10.6 MW at Faro; YEC also has an explicit permit authorization for an added 12 MW diesel capacity operation at Whitehorse under emergency conditions. NY-YEC-1-6 REVISED provides the stacking order for the existing YEC thermal unit operation in conformance with existing permit requirements and emergency condition operation.
[52] Although the rental units were acquired to meet the N-1 requirement – YEC has also explained that it does operate the rental units (within the permit limits) as a cost effective operating option. Mr. Hall, Transcript, page 108.
[53] Section 3.4 of the Application also reviews continuity schedules for the Hearing Cost Reserve Account, Deferred Vegetation Management, and the Reserve for Site Restoration.

Interrogatories and undertakings reviewed details related to the depreciation and amortization rate changes resulting from the depreciation study; however, no major issues were identified on these matters in the oral proceeding. Accordingly, the depreciation and amortization rate changes proposed in the Application are reasonable and should be accepted.

Interrogatories of the Board and cross examination in the oral hearing reviewed issues regarding the hearing cost reserve account and reduction due to accelerated amortization of VGC Group contributions. These issues are reviewed in more detail below.

Hearing Cost Reserve Account

The hearing cost reserve account is addressed in the Application at page 3-23; and details on charges to the hearing cost reserve account were provided in response to Undertaking #15; and Undertakings #30 and #31; and during the oral hearing (see transcript pages 314-17 and transcript pages 386-392).

Discussion at the oral hearing clarified that when YEC incurred legal costs in connection with appeal of the Board decision regarding the DSM appeal these costs were included in the hearing cost reserve account. At page 316, Mr. Mollard notes that costs related to the DSM appeal are considered part of the regulatory process and subject to being paid on the same basis[54]:

> Q. Okay. Why are YEC's legal costs in relation to appeals of Board decisions properly in revenue requirement?
>
> A. MR. MOLLARD: Well, it is -- in my mind, it is part of the regulatory process and, therefore, it should be paid for the same as the costs of the application and defence of the application.

Board counsel and the Board Chair questioned whether costs incurred related to the appeal of board decisions should be included in rates where the appeal by the utility was unsuccessful. YEC's view is that costs incurred by the utility to ensure that decisions that materially impact its revenue requirement are reasonable should be considered prudently incurred costs.

Accordingly, the costs for the Appeal of the Board's decision related to DSM were prudently incurred and should be included in rates at this time.

[54] At page 391 Mr. Mollard notes further that the costs for review or appeal of board decisions can be reviewed by the Board similar to other YEC costs included in the revenue requirement application at the time of the GRA hearing:

> THE CHAIR: Okay. Now, given that the appeal was unsuccessful and the Board's decision on the order was essentially vindicated by the Court of Appeal, do you have a rationale as to why the ratepayers should have those costs imposed on them?
>
> A. MR. MOLLARD: Well, I could offer a parallel, if I could, Mr. Chair. We put an application in front of the Board for a rate increase that touches on all aspects of our business. And while I'm pretty proud of all of our success on these applications, we're very rarely completely successful. So I would say that -- but I still ask for the full costs of preparing and defending that application. So even though I don't win everything within the application, I still get paid to prepare and defend it. So I would suggest that the appeals could be considered -- appeal costs could be considered in the same light.
>
> Q. Regardless of whether or not the appeal itself or the -- or for that matter the legal opinion on which it was presumably based was accepted or rejected by the Court of Appeal?
>
> A. MR. MOLLARD: Yes, that would be my position.

Accelerated Amortization of VGC Group Contributions

The Application notes (page 3-22) that accelerated amortization (over the expected 12 year life of the Eagle Gold Mine) of the VGC Group contributions relating to the YEC's McQuesten Substation and system improvements reduced total YEC depreciation and amortization costs by $0.665 million in the 2021 test year.

The response to YUB-YEC-110 (d) and (e) notes that these contributions are being amortized over the expected 12 year life of the mine "as required by YEC's auditors (the Auditor General of Canada) in accordance with International Financial Reporting Standards (IFRS) for customer contributions. YEC has not had any prior Board approval for the 12-year amortization of these contributions, nor any direction from the Board not to follow IFRS with regard to these contributions.[55] The expected life of the related assets is as shown for the amortization of the costs, i.e., approximately 54 years." Undertaking #17 advises that the Office of the Auditor General referenced in this regard IFRS 15 – Revenue from Contracts with Customers in directing this accounting treatment; guidance on recognition commences at paragraph 9 of the standard.

Undertaking #18 and #19 combined notes that the intent of the PPA with VGC Group was to ensure that customer rates would not be impacted today or in the future by McQuesten Substation costs and specified System Improvement costs that are fully funded up front by VGC Group. The undertaking confirms, with table examples, that this outcome requires matching of amortization rates for asset costs and related VGC Group contributions.[56] The undertaking also notes that YEC's stated intent is to maintain the McQuesten Substation (as well as the System Improvements) for the life of the assets, i.e., the cost incurred to enable 138 kV capability at this substation was to retain this capability for the life of the asset [54 years based on existing and 45 years based on new depreciation study] in the event that 138kV transmission is adopted in future connecting McQuesten Substation to YEC's 138 kV grid.

Undertaking #18 and #19 combined notes that, absent YUB direction to depart from Generally Accepted Accounting Principles, assets fully funded by VGC Group will have cost amortization over a longer life than the amortization of the VGC Group funding contribution. As a result, all ratepayers will be subsidized during the expected mine life and remaining customers will be required to pay residual capital costs for these assets as soon as the mines have closed. It is also noted in this undertaking that this accelerated amortization has no impact on Rate Schedule 39 Fixed Charge applied to the VGC Group and Alexco mines.

2.4 RETURN ON RATE BASE

Return on rate base expenses are forecast in the Tab 3 of the Application at $16.682 million, an increase of $2.832 million over 2018 approved that is accounted for by the following:

[55] Yukon Energy was also directed by its auditors to use this accounting approach with respect to the contributions to transmission system capital improvements received from the Minto Mine customer for YEC's spur line to the mine. However, in that case and in accordance with the approved PPA, the Minto spur line is intended to be decommissioned when the mine ceases operation unlike the circumstances with the VGC Group contribution for the McQuesten substation. In the Minto Mine case, the amortization of the spur line costs and the related contribution are both based on the estimated life of the mine.

[56] The undertaking uses updated costs and analysis. Appendix 1 indicates, with updated information, that the impact on 2021 revenue shortfall due to the accelerated amortization of VGC Group contributions is a reduction of $0.656 million.

- Increase in interest expense on long-term debt of $1.603 million, averaging 2.81% (compared with 2.23% in 2018 approved), of which;

    - $0.907 million reflects interest expense increases due to increased mid-year rate base (with new debt interest set as per Board direction in Order 2018-10 using a formulaic approach based on long-term Canada Bonds benchmark rate of 0.99% as of June 30, 2020, plus 120 basis points); and

    - $0.696 million reflects increased interest on the Mayo B Promissory Note to the full allowed rate of 5.46% (compared with 1.7% in 2018 approved), due to load growth increases in YEC total firm generation; and

- Increase in return on equity (ROE) of $1.229 million due to increased mid-year rate base (the ROE percentage remained unchanged from 2018 approved at 8.70%).

No major issues were raised in IRs or the oral hearing on the Application's determination of forecast interest rates or the 8.70% ROE, other than Board cross examination related to possible changes in YEC ROE risk due to the proposed defined benefit pension deferral account and from OIC 2021/16 directions related to the LWRF deferral account. The 2021 test year ROE determination is reviewed in detail below to address the issues raised.

Return on Equity

The basis for determining the ROE for Yukon Energy in 2021 is reviewed in Tab 8 of the Application. This provides background regarding how ROE has historically been determined for YEC in this jurisdiction [section 8.1]; and a summary of the rationale for determining fair ROE for YEC of 8.70% in the test year.

Yukon Energy's Application has relied on the simplified approach for determining the appropriate risk premium for Yukon utilities that has been approved by the Board in 2005 (Order 2005-12) and in 2008 (Order 2009-2 and Order 2009-8). The approach and determination of a risk premium for YEC was extensively reviewed and tested during the 2017/18 GRA. There is nothing in evidence in the current proceeding that would change the basis for relying on the risk premium last approved by the Board for YEC in Order 2018-10.

The risk premium of 45 basis points was established by the Board in Order 2018-10 based on the following factors:

1. **Recognition of Small Size and Principles Established for AEY in Order 2017/01**: The risk premium is based on principles developed in Decision 2017-01, which established a 25 basis point risk premium for AEY relative to the BCUC benchmark utility. The 25 basis point risk premium was awarded to recognize AEY's small size. This is also applicable to Yukon Energy.

2. **Recognition of risk related to generation, isolated grid and customer diversity**: The Board awarded Yukon Energy an additional 20 basis point risk premium (for a total risk premium of 45 basis points above the BCUC benchmark utility) in recognition of YEC specific risks related to generation, isolated grid and customer diversity. The Board

indicated that the additional 20 basis points acknowledges the overall risk of YEC as being greater than that of FortisBC (Electric) as well as AEY.

3. **Appropriate comparator utilities**: The Board recognized FortisBC (Electric) and AEY as appropriate comparators for determining YEC's risk premium (i.e., YEC has more risk than FortisBC Electric and AEY) but did not accept PNG-West as an appropriate comparator utility for YEC. The Board noted that "PNG-West had experienced negative customer growth for nine consecutive years covering the 2003 to 2012 period" and "PNG-West's total system throughput declined by 87 percent over the 2003-2012 time frame".

Reference to a benchmark ROE for a low-risk utility, with adjustments to reflect any specific added risks related to Yukon Energy, provides for continuity with prior Yukon proceedings and practice, and offers a simple, transparent and cost effective method to determine a consistent and fair return for Yukon utilities. Over the past decade the Board has confirmed its strong preference for using a simplified approach for determining ROE for Yukon utilities in order to ensure regulatory efficiency and reduce costs in a jurisdiction with a relatively small customer base. There is no basis for changing the approach used, and no intervenor in IRs, cross-examination or evidence raised an issue with the use of the BCUC low risk utility benchmark or risk premium methodology.[57] The Board in Order 2021-10, Appendix A in its ruling on UCG's motion regarding UCG-YEC-1-32(a-f), agreed with YEC that the parameters for the YEC benchmark against FortisBC(Electric) have been established.[58]

Further, at this time there are no new issues or material changes in circumstance that would alter the basis for awarding Yukon Energy a risk premium of 45 basis points, as established by the Board in Order 2018-10. Specifically, Yukon Energy and AEY both continue to be small utilities relative to the benchmark utility; and Yukon Energy continues to be subject to material risks related to generation, being on an isolated grid, and customer diversity.

During cross-examination Board council questioned whether the OIC 2021/16 direction provided regarding the LWRF or the approval of the defined benefits pension deferral account would alter YEC's risk and consequently the risk premium applied for determining fair ROE for YEC.

<u>OIC 2021/16 issues</u>

Mr. Mollard confirmed at transcript page 175 that OIC 2021/16 does not change the risk profile applicable to YEC's ROE determination:

> Q. It's a general question, but if you want to look at specifically 9 -- Section 9(4), please pull that up? So our understanding of the OIC generally is that, you know, it sets out, you know, the forecasts to be addressed under the OIC and then there's the true-up or a

[57] UCG-YEC-1-32 notes the comparative risks of YEC and Fortis BC (Electric) (FBC) were extensively reviewed during the 2017-18 YEC GRA proceedings, with follow up questions on YEC Undertakings [YUB-YEC-3-5] providing additional detail related to FBC's power supply context and arrangements with BC Hydro and information showing that the context for FBC is very different and less risky than YEC. The power supply context for FBC was also reviewed in the 2017-18 GRA Undertaking #38 and Undertaking #39 as well as the following follow-up questions on YEC Undertakings: YUB-YEC-3-3, YUB-YEC-3-4, and YUB-YEC-3-6. In summary, it has been well documented in YEC proceedings that FBC is not on an isolated grid, and is not exposed to the same thermal cost risks that YEC is exposed to given that FBC has access to renewable generation resource options available on BC's integrated grid system.

[58] In UCG-YEC-1-32(d-f) Revised (Exhibit B-25) provided added information that further highlighted that YEC has greater risks than FortisBC(Electric).

> deferral mechanism. So from your perspective, you can agree or disagree with that, but our main question we're asking you here is, does the OIC itself remove uncertainty regarding your forecast risk -- forecast or risk of incremental load in the low water reserve fund?
>
> A. MR. MOLLARD: Okay, I think I have that now. Thank you. Yes. I would like to remind the Board that the low water reserve fund in various forms has been in place in Yukon since the early '90s, and excluding recent decisions, the amount of forecast risk YEC had under those previous iterations is the same as what this OIC does. So, yes, we have less forecast risk, but we never had that forecast risk since '91 when this fund was created.
>
> Q. So I guess, Mr. Mollard, your position would be that this OIC maintains a status quo on how the fund operates?
>
> A. MR. MOLLARD: That would be an accurate summary. Yes, thank you.

Mr. Mollard elaborated on the related LWRF issues, and the relevance in this regard of rate volatility protection for customers rather than load risk protection for YEC, in response to further questions at Transcript page 224:

> Going back to when this was created in 1991, it actually wasn't -- didn't have anything to do with the drought. It actually was a situation where the utility had more water than it needed and the Board recognized that that was creating volatility in rates.
>
> So, again, it wasn't about the load; it was about what is the cost impact doing to rates because of this variability in hydro supply. So that was where it started, and it was always about how much water we had, not how much load we had.

The combined response to undertaking #8 and #20 provided further documentation on the record regarding past Board decisions related to the LWRF or DCF, including the following summary comments:

> Prior to 2015 (as well as in Decision 2015-01) the Board did not address any variation in application of the LWRF or DCF as regards portions of the actual load (including load above versus up to the last approved forecast load), i.e., during this period the Board approved LWRF/ DCF mechanisms to cover the variability of hydrogeneration from long-term forecasts for the actual load during a fiscal year regardless as to whether this actual load was above or below the last approved forecast.
>
> Appendix 1 [to this undertaking] provides a summary from Board decisions prior to and including 2015 that addressed the issues noted in the undertaking regarding the Low Water Reserve Fund (LWRF) or the Diesel Contingency Fund (DCF) [which replaced the LWRF for several years during this period], starting in 1991 with the Board's first reference to the LWRF relevant to this undertaking.
>
> Board decisions in the 1990s established the LWRF mechanism for the Whitehorse-Aishihik-Faro (WAF) system to stabilize rates related to changes in water availability, and led to the long-term average (LTA) being fully adopted for this mechanism. However, LWRF/DCF activity was sidelined for many years during the 1990's by shutdowns of the

> Faro Mine (which tended to result in diesel not being "on the margin" and the LWRF not being active for its original purposes) and other related issues. The issue of applying the LWRF above or below the forecast load was not discussed as such, i.e., LWRF determinations were made after year end based on actual load (regardless of the forecast load).
>
> ….
>
> Board Order 2015-01 approved resumed operation of the DCF without addressing any variation in application of the DCF as regards portions of the actual load (including load above versus up to the last approved forecast load). Order 2015-01 confirmed the understanding that year-end DCF determinations will define expected diesel costs for the actual load based on long-term average (LTA) hydro availability, and that any deviation between the expected diesel costs at LTA availability and actual diesel costs are then attributed to the DCF.

Board Order 2018-10 approved the last YEC GRA ROE based on the same principles and understandings regarding the LWRF as had applied in prior rulings, i.e., during the 2017-18 proceedings prior to this decision there had been no evidence suggesting that the LWRF should apply only to the forecast rather than the actual load, and the decision did not reference any such consideration in its ruling on the ROE. The following related points are also noted:

- Board directions after Order 2018-10 during the extended 2017-18 GRA proceeding required the LWRF to apply only up to forecast load. These directions did materially increase YEC's risk related to low water conditions as documented in Undertaking 11 Revised in the current proceeding, i.e., Board Order 2019-08 directions would result in YEC incurring in 2019 an added $0.738 million of thermal generation fuel costs due to water conditions below LTA and load above the last approved GRA forecast.

- Requiring YEC to bear any water-related risk, including risk for load above approved load forecasts, is not consistent with prior Board decisions; further, the evidence reviewed in the 2017-18 proceeding confirmed that no such water-related risk applied to FortisBC(Electric), and that any such added risk being applicable to YEC would require adding to the ROE risk premium for YEC as approved by the Board in Order 2018-10.

In summary – as noted during the 2017/18 GRA, the regulatory principles that resulted in the development of the LWRF/DCF, DFPVA and Rider F have been in place since the early 1990's, with ratepayers bearing (through Rider F and LWRF/DCF deferral accounts) the thermal generation cost risks related to fuel price and water availability as regards actual YEC loads, i.e., without any distinction between actual load and last approved forecast load. The ROE for Yukon Energy has been established since that time with consideration of these factors, and the fact that other comparator utilities also do not bear any thermal generation cost risks related to fuel price or water availability. Yukon Energy's risk profile would be increased and the ROE would need to be increased accordingly if the mechanisms in Board Order 2019-08 were to apply. In contrast, OIC 2021/16 directives on the LWRF are consistent with past LWRF/ DCF principles prior to Board Order 2019-08 – and therefore OIC 2021/16 does not change the YEC risk profile relevant to ROE determination for the 2021 GRA.

Defined Benefits Pension Deferral Account Issues

Mr. Mollard reviewed the purpose of the Defined Benefits Pension Deferral Account at Transcript pages 312-313, noting that this had been approved for AEY in its last GRA proceeding and that it was viewed as a fairness matter that this should also be approved for YEC. At Transcript pages 313-314, Mr. Mollard confirmed that approval of this deferral account would not reduce YEC's risk to the extent that a risk reduction should be extended to YEC's ROE – he noted that it's a risk YEC cannot control, but that YEC has never assessed the risk of a benefit plan for an employee as being relevant for consideration as regards YEC's ROE level risk.

The similar deferral account was approved for AEY by the Board Order 2014-06, where the Board noted that a deferral account for both the current service payments and special payments would meet the criterion that "costs are not under the control of the company and are not reasonably forecastable."

In the same Order, the Board stated the following regarding the impact of the deferral account to the AEY's risk:

> Although the Board recognizes YEC's argument that approval of the deferral account reduces YECL's risk, the Board disagrees with YEC that this is detrimental to ratepayers. Defined benefit funding requirements will be inherently volatile since they are based on actuarial assumptions partial to swings in the financial markets. The market factors that drove the pension into a deficit could just as easily reverse and put the pension into a surplus position. If market forces move in the right direction, ratepayers will benefit from lower contributions. If market forces move in the wrong direction, ratepayers will be adversely affected through higher contributions. Whether future market events will be beneficial or detrimental to the pension plan are not known to the Board, or in the Board's opinion, anyone else. By requesting the defined benefit pension requirement deferral account, YECL has signaled that it does not want to speculate on the financial markets. In the Board's view, neither does the ratepayer.

In addition to the above, the following is noted:

- The amount of defined benefits for YEC is much lower compared to the amount for AEY.[59]

- The response to YUB-YEC-1-35 (d) confirms[60] that the swing in the actual amount could be in both directions, i.e., protecting both the utility and the ratepayers from the changes in market conditions as the Board highlighted in Order 2014-06 noted above.

In conclusion, OIC 2021/16 and the proposed Defined Benefits Pension Deferral Account do not provide any reasonable basis to adjust YEC risk profile as regards retention of the 8.70% ROE as approved in Board Order 2018-10.

[59] The amount for AEY for the 2013 test year noted in the YUB Order 2014-06 was $1.041 million. The forecast cost for YEC for 2021 is $0.720 million.

[60] The 2018 actuals were about $21k higher than the forecast, while 2019 actuals were $52k lower than 2018 forecast included in rates.

3.0 TAB 5 - CAPITAL PROJECTS

Tab 5 of the Application reviews capital project investments forecast to be added to rate base in the 2021 test year compared to 2018 approved rate base, as well as capital spending forecast to remain as work in progress at the end of 2021. Increased capital rate base costs account for $4.148 million (37.8%) of the Application's 2021 revenue shortfall through higher depreciation, interest and equity return costs[61] due to growth of $34.649 million in net mid-year rate base (before regulatory deferral and working capital costs) from 2018 approved.[62]

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 in the 2021 test year relates to major projects over $1 million which account for $55.5 million net addition to rate base while projects with costs between $0.1 million and $1.0 million add approximately $15.8 million[63].

Updates to Application forecast capital costs have been provided in response to YUB-YEC-2-17. As reviewed in Section C of Part 1 of this Argument, appropriate treatment of these updates is required when finalizing overall test year approved forecasts.

- Updates can be considered for major projects over $1 million (including deferred cost and intangible projects) that are forecast to enter rate base in 2021, as these projects are a limited number of discrete cost elements within the Application where the Board conducts prudency reviews and where costs for each project can be updated with minimal likely impact on other test year forecast costs.
- In contrast, capital projects with costs under $1 million are subject to a wide range of interacting factors – and focusing on cost updates for specific projects identified in the Application in this group will not address consideration of other projects not in evidence where updates would now indicate 2021 costs under $1 million that will impact rate base

[61] Shows cost increase before considering changes to depreciation rates or other changes as noted in Table 1-2 of Application.

[62] Table 3.13 in Application. Net rate base is after deduction of work in progress, depreciation, amortization, contributions and disallowed assets. In addition to plant in service (including deferred study and relicensing costs), Table 3.13 in Application also shows $1.147 million reduction in mid-year regulatory deferral net rate base (regulatory deferral costs, excluding DSM and the balance of the hearing reserve account) and $1.797 million increase in working capital cost contribution to mid-year rate base in 2021 test year compared with approved 2018. 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 2021.

[63] Tab 5 provides separate review for each major project forecast to be added to rate base by 2021, and Appendices 5.2, 5.4 and 5.6 provide separate forecast reviews for all other projects with costs over $100,000. Further cost breakdowns as well as cost and timing updates for these projects were provided in YUB-YEC-1-49 and YUB-YEC-2-17[63], as well as in many other IRs on individual projects or groups of projects. Additional information was provided during cross examination during the oral hearing.

and therefore updating without full information would not only be unfair it cannot be done in the circumstances.

Key issues are reviewed separately below for major and other capital projects impacting rate base and projects remaining in WIP.

3.1 MAJOR PROJECTS IMPACTING RATE BASE

The Application forecasts $55.526 million net rate base impact for major capital, deferred and intangible projects as follows (updates to costs as provided in YUB-YEC-2-17 would reduce this by approximately $2.04 million):

1. Eleven capital projects >$1 million with total net rate base impact in the test year forecast in Tab 5 of $47.846 million (updates provided in YUB-YEC-2-17 would reduce this by about $0.6 million):

    a. **Investment to Address Load Growth Capacity Planning Requirements ($11.596 million Tab 5 net rate base impact)**: (LNG Third Turbine, Thermal Rental Site Infrastructure at Whitehorse and Faro).

    b. **Spending on Aging Infrastructure and Sustaining Capital Requirements ($22.683 million Tab 5 net rate base impact –** Updates provided in YUB-YEC-2-17 would reduce this by $4.2 million): Projects planned to sustain or maintain the capability of the existing grid system, including Mayo to McQuesten Transmission Line (MMTL); McQuesten Substation; Transmission Line Refurbishment; WAF Line 178 Refurbishment; Breaker Replacement Program; and Replace P125 Headgate.

    c. **Investment for New Supply options or to maximize renewable energy generation from existing facilities ($13.568 million Tab 5 net rate base impact –** updates provided in YUB-YEC-2-17 would increase this by $3.61): projects identified in the 2017/18 GRA to reduce thermal energy generation (including WH2 Uprate and WH4 Uprate (Servomotor replacement).

2. Two deferred cost projects >$1 million (Aishihik 3-year licence renewal and DSM) with total net rate base impact in Tab 5 of $4.478 million (updates provided in YUB-YEC-2-17 and at the oral hearing would reduce this by about $1.1 million).

3. One intangible project >$1 million (Enterprise Asset Management) –net rate base impact in Tab 5 of $4.938 million (updates provided in YUB-YEC-2-17 would reduce this by about $0.3 million).

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

3.1.1 Investment to Address Load Growth Capacity Planning Requirements

LNG Third Engine/ Critical Spares

No material issues were raised in IRs or at the oral hearing regarding this project. The project was extensively reviewed during the 2017/18 GRA. Order 2018-10, noted that the cost per MW

was favourable when compared to alternative projects and that it was reasonable for YEC to continue with the project. The project was completed on schedule and below the budget estimated during the 2017/18 GRA.. For further details see Application Section 5.2.1.1 and YUB-YEC-1-50 and UCG-YEC-1-35.

N-1 Capacity Shortage Rental Site Infrastructure (Faro and Whitehorse)

The justification for this project is reviewed in detail in section 2.2.2 of this Argument (Production Costs). Further details are provided in Application Section 5.2.1.2, and in YEC's Rebuttal Evidence as well as in response to information requests.[64]

3.1.2 Capital Spending on Aging Infrastructure and Sustaining Capital Requirements

Mayo to McQuesten Transmission Line (MMTL) and McQuesten Substation

The MMTL project involves the construction of a new 138 kV transmission line from the Mayo to McQuesten substation, as well as the installation of electronic voltage support equipment (Statcom) at Stewart Crossing South substation that will improve overall reliability and power quality of the system.

These projects were reviewed extensively during the 2017 VGC Group PPA proceeding, the 2017/18 GRA and during the current proceeding.

As outlined in those prior proceedings and in the Application and in response to information requests, the existing 69 kV transmission line from Mayo to McQuesten was at end of life and in need of replacement, having experienced both reliability and power quality issues over a number of years. The project improves the overall reliability and power quality of the grid.

Accordingly, Yukon Energy had a unique opportunity to interconnect a new industrial load in a manner that would facilitate timely replacement of the end of life transmission infrastructure between Mayo and McQuesten, and potentially also facilitate proceeding with additional necessary upgrades that would provide – at a very reasonable cost --long term enhancement benefits to infrastructure on the northern grid.

Ratepayer risks were addressed as follows: [65]

1. Yukon Government's $5.3 million funding to advance project to shovel ready stage;
2. Power Purchase Agreement with VGC Group which includes payments by VGC Group to YEC for:
    a. YEC's costs relating to the negotiation and conclusion of the PPA;
    b. Capital costs for Initial YEC System Improvements;

[64] See for example: CW-YEC-1-17; CW-YEC-1-26; CW-YEC-2-6; YUB-YEC-1-31; YUB-YEC-1-50; YUB-YEC-2-1 and YUB-YEC-2-3; NY-YEC-1-3; NY-YEC-1-4; NY-YEC-1-5; NY-YEC-1-6 revised; NY-YEC-1-7 revised; NY-YEC-1-8; NY-YEC-1-9; NY-YEC-1-10; NY-YEC-1-11; NY-YEC-1-12; NY-YEC-1-13; NY-YEC-2-1 revised; NY-YEC-2-2 revised; NY-YEC-2-3 revised; NY-YEC-2-4 revised; NY-YEC-2-5; NY-YEC-2-6 revised; UCG-YEC-1-13 and UCG-YEC-2-13.
[65] See Application pages 5-10 and 5-11.

c. YEC Owners Costs for the McQuesten Substation development; and

d. YEC Costs reasonably required for design, engineering, procurement, construction and commissioning of the step down transformer at the McQuesten Substation should one be required.

The PPA also includes Fixed Charge provisions which provide for industrial customers located along the MMTL to pay 85% of the fixed costs for the line over the period when the customers are connected to the line.

3. Federal funding through Investing in Canada Infrastructure Program (ICIP) – Yukon Energy received a contribution towards the project of $23.674 million which covers 75% of the eligible project costs.

The McQuesten Substation was completed and commenced operation in 2019 with final VGC Group costs of $11.619 million; YEC received an asset contribution form VGC Group valued at $10.688 million, and has incurred a net cost of $0.931 million (related to added facilities to enable future 138 kV service operation if required).[66]

Transmission Line Refurbishment (TLR) & WAF Line 178 Refurbishment Projects

No material issues were raised in IRs or at the oral hearing regarding these projects. The 138 KV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late 1960s and early 1970's, and plays a critical role linking key hydro generation sources to load centres in Whitehorse and on the northern grid.

Yukon Energy has outlined on the record of prior proceedings (the 2017/18 GRA) as well as the current proceeding that key components of the WAF system are at end of life, and in poor condition and required replacement:

- The TLR project was initially reviewed as part of the 2017/18 GRA; and project components were capitalized as completed and placed into service with approved costs forecast to the end of 2018. Remaining components requiring replacement on lines L170, L171 and L172 were completed by the end of 2018[67].

- The Application also notes that the WAF Line 178 Refurbishment Project is the final phase of the TLR project. Failure to complete this element 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 grid to maintain supply to all customers. YUB-YEC-2-17 notes the WAF Line 178 Refurbishment Project did not proceed in 2021 as forecast in the GRA application. During the procurement process the market price came back much higher than YEC expected. YEC has reduced the project scope for 2021 to

[66] For further details see Application Section 5.2.1.3 and Section 5.2.1.4, as well as responses provided to YUB-YEC-1-51 Revised; YUB-YEC-1-52; YUB-YEC-2-18; UCG-YEC-1-38; UCG-YEC-1-39.
[67] For further details see Application Sections 5.2.1.5 and responses to the following information requests: YUB-YEC-1-53; YUB-YEC-2-19; CW-YEC-1-28; CW-YEC-2-10 and UCG-YEC-1-40.

$0.3 million to reflect work completed by YEC power line crews, and this cost will be closed in 2021.[68]

Breaker replacement Program

No material issues were raised in IRs or at the oral hearing regarding this project.[69]

Replace P125 Headgate

No material issues were raised in IRs or at the oral hearing regarding this project.[70]

YUB-YEC-2-17 notes that Yukon Energy completed the replacement of the WH2 headgate in 2020. As part of YEC's annual business planning process, team capacity was assessed and upon completion of the assessment it was determined that the replacement and refurbishment of the gates and related infrastructure for units WH1 and WH3 will be deferred to 2022 and 2023 respectively. Planning is currently underway for the replacement of the WH1 headgate which includes revision of the technical specifications based on learnings from the WH2 headgate replacement, as well as preparation and release of an RFP in advance of the 2022 project.

3.1.3 Investment for New Supply

WH2 Uprate

No material issues were raised in IRs or at the oral hearing regarding this project.[71]

WH4 Uprate (Servomotor Replacement)

No material issues were raised in IRs or at the oral hearing regarding this project.[72]

3.1.4 Deferred Cost Projects >$1 million in Rate Base

Aishihik Relicensing – 3 Year Licence Renewal

No material issues were raised in IRs or at the oral hearing regarding this project.[73] The costs for this project were required to ensure that a renewed licence for the facility was in place while the long term renewal licence is being pursued.

[68] For further details see Application section 5.2.1.6; and responses to the following information requests: YUB-YEC-1-54; YUB-YEC-2-20; CW-YEC-1-28 and UCG-YEC-1-41

[69] The basis for proceeding with the project is reviewed in detail in the Application at section 5.2.1.7. Further detail regarding the project is provided in the following information requests: YUB-YEC-1-55 and CW-YEC-1-30.

[70] The basis for proceeding with the project is reviewed in detail in the Application at section 5.2.1.8. Further detail regarding the project is provided in the following information requests: YUB-YEC-1-56; YUB-YEC-2-21; CW-YEC-1-31; CW-YEC-2-11; and UCG-YEC-1-42 revised.

[71] The basis for proceeding with the project is reviewed in detail in the Application at section 5.2.1.9. Further detail regarding the project is provided in the following information requests: YUB-YEC-1-57; YUB-YEC-2-22; UCG-YEC-1-52; UCG-YE-1-53; UCG-YEC-2-15; CW-YEC-1-32 and CW-YEC-1-33.

[72] The basis for proceeding with the project is reviewed in detail in the Application at section 5.2.1.10. Further detail regarding the project is provided in the following information requests: YUB-YEC-1-58; YUB-YEC-2-23; UCG-YEC-1-43 revised and UCG-YEC-1-54.

[73] Project costs are reviewed in Section 5.3.1.1 of the Application as well as in response to YUB-YEC-1-59(a) and UCG-YEC-1-44 which provide cost breakdowns. YUB-YEC-2-17 notes no change in project cost details from the information provided in response to YUB-YEC-1-59(a). The actual costs for project management and assessment and review process activities were lower than the initial GRA forecast resulting in lower than forecast actual costs for 2020.

Demand Side Management (DSM)

By OIC 2021-16 Yukon government has provided direction for Yukon's utilities to pursue cost effective demand-side management measures.[74] That OIC also provides direction to the Board to include in rates provision to recover costs that a public utility reasonably incurs to provide or participate in a demand side management program.[75]

DSM is considered a legitimate, cost-effective energy and capacity resource for electric utilities. This is supported by numerous resource planning reports where DSM compares favorably when evaluated against other supply options, as well as by utility experience and practice in other Canadian jurisdictions.[76]

The Order in Council specifically references consideration of "the extent of any duplication between the program for which costs are incurred and a demand-side management program provided by the Government of Yukon or in which the Government of Yukon is a participant."

To address this, YEC has engaged with Yukon government to ensure the existing demand-side management programs offered or planned by the Energy Branch are considered in YEC's program design, to avoid duplication.[77] In addition, the Application reflects the DSM Court of Appeal decision, in that historical costs that were covered by the appeal are not included in this Application.[78] YUB-YEC-2-32 clarifies that YEC's 2021 GRA was filed in the first instance after November 1, 2020, and no order was issued by the Board under section 27 of the Act before February 11, 2021 (when the OIC section came into effect) on the 2021 GRA filings with regard to DSM costs to be recovered in the 2021 test year.

It is important to note that the proposed treatment of DSM costs incurred prior to 2021 and after 2018 for inclusion in the 2021 test year rate base is no different than the treatment of any other project that is put into service between GRAs – the YUB is frequently asked to approve projects in rates that have been built or otherwise brought into rate base in prior years.

See also the clarification Ms. Milojevic provided at transcript page 270:

> Q. So we've spent taking off the pilot program. We've spent at least half a million dollars on developing some programs with nothing at hand. Is that how I read this?
>
> A. MS. MILOJEVIC: Well, to be clear, I think Mr. Mollard had referenced earlier the decision in the Court of Appeal regarding the DSM historical costs. So accordingly, in this table, the $385,000 -- I'm sorry, pardon me, $385,009 for DSM program design in 2019

[74] See discussion of "Our Clean Future: A Yukon strategy for climate change, energy and a green economy" and its implications for DSM as discussed in YUB-YEC-1-46 revised; YUB-YEC-2-31, YUB-YEC-2-32, YUB-YEC-2-33 and YUB-YEC-2-35.
[75] See YUB-YEC-1-46 revised: YG has clearly stated that DSM is a valid supply option for Yukon utilities and that they expect YEC to actively consider and implement prudent DSM programs. They also indicated their intention to direct the YUB to support cost-effective programs administered by YEC and AEY.
[76] See YUB-YEC-1-46 revised, part (e).
[77] SeeYUB-YEC-2-31(d). A subgroup of the Advisory Group on Energy Demand and Supply (AGEDS) has been formed to act as a DSM working group (the DSM Action Group or DSMAG). Through this advisory group YEC will continue to engage with YG as it initiates the Company's updated DSM program design and implements the plan. This will allow for avoidance of duplication, and assessment of potential collaboration or efficiencies. Coordination with Yukon government regarding DSM programs to ensure there is no duplication was also reviewed at Transcript pages 195 to 202.
[78] YUB-YEC-1-46(g); and UCG-YEC2-16-2(a).

> will be written off, as in not charged to ratepayers. So, no, the total net costs for program design that we're talking about here is somewhere in the range of 100,000 or less.

Prudence of DSM program costs were extensively reviewed in the Application (see Section 5.3.1.2) and in response to information requests.[79]

Project cost updates were provided in response to YUB-YEC-2-17.[80] The GRA forecast 2021 budget was based on implementation of a full suite of DSM programming in 2021, assuming program design was completed in 2020. The lower actual spending in 2020 due in large part to delay in issuing OIC 2021/16 has shifted the program design to being completed in 2021, with program implementation costs not being forecast until 2022 and later. The updates in YUB-YEC-2-17 do not address the 2019 cost write offs noted by Ms. Milojevic at page 270 of the transcript, i.e., the 2019 expenditure of $385,000 for DSM Program Design and $14,285 for InCharge maintenance have been written off. The updated DSM net cost for 2019 is therefore $68,307, and the overall updated DSM net cost for 2019, 2020 and 2021 is $279,852.

Yukon Energy DSM programs have been carried out in accordance with Yukon Government policy directives and OIC 2021-16, and as such the programs should be assessed based on standard cost effectiveness tests applied to the energy and capacity expected to be provided by each potential program.[81].

3.1.5 Intangible Assets Included in Rate Base

Test year spending for projects over $1 million relates to implementation of the Enterprise Management System purchase and implementation, with total spending in rate base by the end of 2021 forecast at $4.938 million.

Enterprise Asset Management (EAM)

YEC is completing a major update and modernization of its asset management practices and supporting software systems, bringing these practices in line with industry best practice and ensuring that YEC is spending money on both maintenance and sustaining capital in an appropriate manner.[82] The Asset Management Framework project will implement a formal Physical Asset Management Managed System (PAMMS)[83] that aligns YEC's practices with the ISO 55000 standard for physical asset management. A key part of this initiative is the selection and implementation of an Enterprise Asset Management (EAM) solution suited to the needs of the company.

[79] YUB-YEC-1-46 revised; YUB-YEC-1-47; YUB-YEC-1-59(b); YUB-YEC-1-60; YUB-YEC-1-61;YUB-YEC-1-62;YUB-YEC-2-31, YUB-YEC-2-32, YUB-YEC-2-33, YUB-YEC-2-34, YUB-YEC-2-35; YUB-YEC-2-36 and YUB-YEC-2-37; UCG-YEC-1-48; and CW-YEC-1-34 See also extensive discussion of the DSM program at transcript pages 191 to 217. Costs included in the 2021 forecast were also reviewed at Transcript, pages 192-94.

[80] YUB-YEC-2-17 notes, OIC 2021/16 providing direction to the YUB was not issued until February 2021 and YEC therefore did not undertake the planned DSM program design work in 2020, resulting in a lower actual spending on DSM in 2020 compared to forecast (the only DSM costs in 2020 were related to the demand response pilot and a small amount for administering the inCharge rebate).

[81] YUB-YEC-1-46 revised (d).

[82] Transcript page 21. See also transcript pages 280-81; and pages 284-86.

[83] Information regarding the Asset Management Framework (PAMMS) project is provided in the Application at Appendix 5.1, page 5.1-4, and in response to the following information requests: YUB-YEC-1-70; and YUB-YEC-2-27. YUB-YEC-2-25 also clarifies that the EAM is a separate project from PAMMS to source, configure and install asset management software. In short, the EAM system is used to operationalize the framework that was developed under PAMMS.

The EAM system is required to operationalize the framework that was developed as part of the Asset Management Framework (PAMMS project). It is required to implement the PAMMS project.

The EAM Project is required as the existing Computerized Maintenance Management System no longer meets YEC's current or future asset management needs and required replacement.[84] Alternatives were explored as part of the extensive tender process followed by YEC and the most suitable alternative was selected (see Application page 5-29 and response to YUB-YEC-1-64 and YUB-YEC-1-24 for review of the tender process implemented by YEC and the results).[85],[86] The successful bidder (Infor) was the second lowest bidder on the project however they scored higher on technical merits and overall were the highest ranked bid. The evaluated price difference between Infor and the lowest price was $12,718.00 (0.5% difference).[87]

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

The Application forecasts approximately $15.8 million net rate base impact in the 2021 test year over 2018 approved for projects with costs exceeding $100,000 (updates to costs are provided in YUB-YEC-2-17 as follows:

1. Appendix 5.2 reviews 29 capital projects <$1 million and >$100,000 with total net rate base impact of $11.586 million:

    a. Generation Projects – 8 projects with net rate base impact of $3.105 million

    b. Transmission Projects – 7 projects with net rate base impact of $2.608 million less $0.55 million contributions.

    c. Distribution Projects – 3 projects with net rate base impact of $2.491 million less $2.011 million contributions.

    d. General Plant & Equipment Projects – 8 projects with net rate base impact of $4.190 million.

    e. Overhauls & Reserve for Site Restoration Projects – 3 projects with net rate base impact of $1.753 million.

2. Appendix 5.4 reviews 12 deferred projects <$1 million and >$100,000 with total net rate base impact in the test year forecast of $4.046 million:

    a. Feasibility Studies – Potential Renewable Generation Options – 3 projects with net rate base impact of $1.267 million.

[84] YUB-YEC-1-64(b) notes preliminary market study and RFI were carried out by YEC and Hatch to assess suitability of Key2Act's (YECs existing CMMS) to support YEC's long term strategic needs. The assessment and the interviews with YEC staff indicate that the Key2Act solution was incapable of supporting YEC's long term strategic objectives and was not meeting their current operational needs.
[85] These are described in YUB-YEC-1-64(d).
[86] Further detail regarding the EAM project is provided in Application Section 5.4.1.1, and responses to YUB-YEC-1-64, YUB-YEC-2-24 and YUB-YEC-2-25. See also UCG-YEC-2-16-1.
[87] YUB-YEC-2-24.

b. Feasibility Studies – Continued Reliability & Asset Improvements – 6 projects with net rate base impact of $1.551 million.

c. Regulatory and Dam Safety Review – 3 projects with net rate base impact of $1.228 million.

3. Appendix 5.6 reviews one intangible project <$1 million and >$100,000 (ERP System Upgrades) with total net rate base impact in the test year forecast of $0.2 million:

Yukon Energy will respond to any specific issues or questions raised by intervenors regarding any of these projects in reply argument.

3.3 PROJECTS THAT REMAIN IN WIP

The GRA Appendices 5.1 and 5.3 review major capital projects (Appendix 5.1) and major deferred projects (Appendix 5.3) not affecting rate base.

- Major Capital projects not impacting rate base include capital works to address sustaining capital requirements (Dawson Voltage Conversion;[88] MH0(Mayo A) Generating Station Slope Stability;[89] Replacement of Mayo A Surge Chamber;[90] Stop Log Crane MH Main Spillway;[91] and Asset Management Framework);[92] and investments to ensure dependable capacity (Battery Energy Storage System;[93] Pumped Storage;[94] Southern Lakes Transmission Line and Whitehorse Interconnection).[95]

- Major deferred projects retained in WIP are reviewed in Appendix 5.3 and relate to spending on sustaining capital (Aishihik and Whitehorse relicensing projects);[96] and spending to address capacity planning requirements (Diesel Retirement Replacement);[97] or spending to maximize renewable energy generation from existing facilities (SLESP and MLESP).[98]

Appendix 5.5 reviews deferred studies >$100,000 and less than $1 million not added to rate base in the test year (EV Infrastructure Project;[99] and P125 Trashrack study).[100]

These projects are forecast to remain in WIP in the 2021 test year and do not affect forecast test year rate base or revenue requirement.[101] The purpose of these appendices is to clearly identify projects with costs through to the end of 2021 (i.e., costs beyond 2021 are not addressed) that will not affect forecast test year rate base and therefore do not require detailed review at this time

[88] See YUB-YEC-1-66.
[89] See YUB-YEC-1-67.
[90] See YUB-YEC-1-68 and YUB-YEC-2-26.
[91] See YUB-YEC 1-69.
[92] See YUB-YEC-1-70 and YUB-YEC-2-27.
[93] See YUB-YEC-1-71 and CW-YEC-1-41.
[94] See YUB-YEC-1-72.
[95] See YUB-YEC-1-73
[96] See YUB-YEC-1-90; YUB-YEC-1-91; UCG-YEC-1-83; UCG-YEC-1-84; and UCG-YEC-1-102.
[97] For further details see YUB-YEC-1-92; and UCG-YEC-1-85.
[98]For further details see YUB-YEC-1-93; and YUB-YEC-1-94. See also UCG-YEC-1-86; and UCG-YEC-1-87; and UCG-YEC-1-102.
[99] For further details provided in YUB-YEC_1-101 Revised; CW-YEC_1-39 and UCG-YEC-1-98.
[100] For further details see responses to YUB-YEC-1-102 and UCG-YEC-1-99.
[101] For further details see YUB-YEC-1-89; UCG-YEC-1-103.

for the purpose of the 2021 GRA Application. Projects included in these appendices are currently in WIP and will remain in WIP at the end of 2021.

Costs for these projects will be fully reviewed at a subsequent proceeding when YEC applies to have the costs included in rates.

4.0 MATTERS THAT DO NOT IMPACT 2021 REVENUE REQUIREMENT AND RATES

Yukon Energy's Application also addresses three other regulatory issues not directly related to the revenue shortfall or proposed rates: the Rate Schedule 39 fixed charge for the industrial customers served by the Mayo McQuesten Transmission Line (MMTL); the Defined Benefit Pension Deferral Account; and the Low Water Reserve Fund (LWRF) and the related OIC 2021/ 16 directions.

4.1 RATE SCHEDULE 39 FIXED CHARGE

A Fixed Charge is assigned to industrial customers that use the Mayo-Keno transmission facilities [see Tab 4, Section 4.2.2, Appendix 4.3, YUB-YEC-4-45]. The Fixed Charge assigns to these customers an 85% share of annual depreciation and return cost related to these facilities. The basis for the Fixed Charge was reviewed as part of the Alexco PPA proceeding in 2011 (Order 2011-01), and confirmed in the VGC Group PPA proceeding in 2017 (Order 2018-04).

The basis for the 85% share is also reviewed in UCG-YEC-2-10.

The Fixed Charge is subject to amendment from time to time (see Section 7.7 of the VGC Group PPA).[102] Board Order 2018-04 [approving the VGC Group PPA] directed YEC to submit a limited scope application to amend the firm mine rate within 60 days of the Transmission Facilities Development Operation Date (Paragraph 57).[103]

YEC filed the Transmission Fixed Cost application in March 2021 (Exhibit B-10) for an interim Fixed Charge adjustment effective May 1, 2021. Board Order 2021-09 approved an interim Fixed Charge for the VCG Group mine and the Alexco mine and mill to reflect YEC's McQuesten Substation Fixed and Transmission Facilities Development Costs for the new transmission facilities between Mayo and McQuesten.

Outstanding determinations to approve a final Fixed Charge for the specified facilities have been identified as follows: [104]

1. Any adjustments to final Transmission Facilities Development Costs for the new transmission facilities between Mayo and McQuesten Substation are to be reflected in

[102] See also Tab 4, Section 4.2.2, Appendix 4.3, YUB-YEC-1-45. The VGC Group PPA provides for YEC to complete various facilities related to providing service to the Victoria Gold. Section 7.7 (b) of the VGC Group PPA notes after the Transmission Facilities Development Operation Date, YEC will apply to the YUB to amend the Transmission Facilities Fixed Charge based on YEC's adjusted annual costs for depreciation and return on rate base related to the Transmission Facilities plus the SVC/Statcom and YEC's McQuesten Substation Costs.

[103] At time of filing the 2021 GRA, the Transmission Facilities Development Operation Date was forecast to occur in late November 2020/ early December 2020. The Transmission Facilities Development Operation Date was delayed to March 2021.

[104] See Exhibit B-10, YUB-YEC-2-5, and YUB-YEC-2-8.

the required year end reconciliation for the Fixed Charge or in the compliance filing for the 2021 GRA (whichever occurs sooner);

2. As part of the 2021 GRA, the Fixed Charge needs to be updated to reflect the Weighted Average Cost of Capital (WACC) as approved for the 2021 GRA (the interim Fixed Charge effective April 1, 2021 is based on the approved WACC for 2018 at 4.82%), and any required true-up provision to the applicable Fixed Charge since April 1, 2021;
3. The VGC PPA requires the Fixed Charge to be re-calculated when the SVC/Statcom is added later this year and costs are finalized; YEC will file a limited scope application, within 60 days of completion date, to update the Rate Schedule 39 Fixed Charge as required for this facility; and
4. The allocation of the annual fixed charge between the mines will be finalized at the end of each fiscal year once actual mine loads are known for that year.

4.2 DEFINED BENEFIT PENSION PLAN DEFERRAL ACCOUNT

The Application (Page 1-9 and Section 3.6.2) outlline Yukon Energy's request for approval of a defined benefit pension plan deferral account that captures variances in contributions to the defined benefit pension plan from the cost included in the test year renven requiremetns as a result of required annual actuarial evaluations.

4.3 LOW WATER RESERVE FUND (LWRF)

Yukon Energy filed Exhibit B-11 on April 8, 2021 seeking approval of an updated LWRF Term Sheet, and Yukon Energy's LWRF 2019-2020 Annual Reports and Energy Reconciliation Adjustment (ERA) Filings. Yukon Energy noted that this filing can be addressed independent of any issues in the 2021 GRA related to determining 2021 revenue requirement and rates.

OIC 2021-16 establishes the Board's mandate in relation to the LWRF.[105] The LWRF must now comply with the directions as outlined in OIC 2021/16.

The 2019-2020 LWRF Annual Report schedules filed with Exhibit B-11 comply with directions under Section 9 of OIC 2021/16, given that YEC's application was made in the first instance to the Board after November 1, 2020 and that no order has been issued under section 27 of the Act prior to February 11, 2021 with regard to this filing.[106]

Because Board Order 2019-08 directions to remove from the LWRF calculations the incremental generation due to incremental load are not consistent with OIC 2021/16 directions the 2019-2020 LWRF Annual Report schedules do not comply with those directions.[107]

Fund Cap

The LWRF Term Sheet in Exhibit B-11 includes provision to increase the LWRF cap from +/-$8 million to +/-$16 million.

[105] See UCG-YEC-2-2; UCG-YEC-2-4; UCG-YEC-2-5; UCG-YEC-2-6.
[106] UCG-YEC-2-1; UCG-YEC-2-2; UCG-YEC-2-4; UCG-YEC-2-6
[107] OIC 2021/16 does not apply to LWRF annual reports, or related deferral account determinations, for 2018 or prior years. See YUB-YEC-2-6.

OIC 2021/16 sets out basic principles to be followed by the Board in setting the cap level for the LWRF, without dictating specific maximum or minimum cap levels. Subsection 9(6) provides the basic principles to be followed in setting LWRF cap levels, i.e., to operate the LWRF for the purpose of minimizing the effect on rates that would otherwise be caused by the actual variability in renewable source availability.

The $8 million cap increase is required to minimize the effect on rates that would otherwise be caused by the variation in actual renewable source availability.

As outlined in the response to YUB-YEC-2-7, there has been a material increase in YEC's forecast generation load for the 2021 test year compared to the last GRA 2018 test year forecast. More specifically, the forecast firm grid load for the 2021 test year at 532.5 GWh is well above any of the grid loads previously considered in the 2017/18 GRA.[108] At that load the thermal generation required during the drought years could be more than 155 GWh costing about $29 million based on 90% LNG/10% diesel generation assumption.[109] This is well above the thermal costs assumed in Appendix 1 analysis and supports the proposed increase in LWRF cap limit.

A LWRF cap of $16 million would have the following key positive impacts:[110]

- It will reduce the number of years with rate rider changes (for charges as well as rebates).[111] No rate riders are forecast to be needed in 26 out of 35 years (compared to 20 years with existing cap).

- This will also result in a reduction in drought 1 year rate rider charges, i.e., reduces the peak drought year charge from $14.0 million to $8.2 million; and reduces the average charge year amount (for years with rate rider charges) from $4.8 million to $3.5 million.

A cap increase to +/-$16 million is appropriate at this time to ensure that the Fund (which was negative $4.272 million as at the end of 2020) has sufficient ability to address possible near term additions. The cap will be reviewed in each future GRA to assess if further changes are warranted.

Fuel Mix

The methodology for calculating the cost impact to the LWRF is documented in the LWRF Term Sheet in Exhibit B-11. As previously approved, this methodology ensures that YEC income statement fuel expense for the year reflects the last GRA-approved fuel mix (i.e., 90% LNG: 10% Diesel) , subject to the same constraints as applied in the last approved LWRF.

The use of an "average" fuel mix is consistent with the fact that forecast thermal generation for the test year is based on LTA annual renewable resource availability (and therefore LTA thermal generation) rather than on forecast actual thermal generation fuel mix. In contrast, actual fuel mix in any year reflects actual water availability and hydro generation, and can therefore vary

[108] See YUB-YEC-2-7 Appendix 1 which copies Table 3.4-5 from the Appendix 3.4 of the 2017/18 GRA). The 450 GW.h load peak drought year thermal requirement is 117.0 GW.h (vs. LTA thermal of 28.6 GW.h), costing $18.5 million for 90% LNG/10% diesel generation.
[109] As per YUB-YEC-2-7 Appendix 1, assessed based on YECSIM model simulation of available water years on YIS (per Appendix 2.1 of Application, current analysis uses 38 water years ofrecord).
[110] See YUB-YEC-2-7, Appendix 1.
[111] See response to YUB-YEC-2-7

materially from the LTA fuel mix. This volatility is exactly the risk the LWRF is designed to mitigate against; use of actual thermal generation fuel mix is not consistent with the objective of this mechanism.

See also section 1.3 of this Argument for review of the fuel mix ratio for the 2021 GRA forecast, and YUB-YEC-2-4.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

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