YUKON ENERGY CORPORATION

2021 GENERAL RATE APPLICATION

NOVEMBER 2020

2021 GENERAL RATE APPLICATION

TO THE YUKON UTILITIES BOARD (BOARD)

YUKON ENERGY CORPORATION

INTRODUCTION TO APPLICATION

Yukon Energy's 2021 General Rate Application (the GRA or Application) addresses adjustments to Yukon Energy's approved revenue requirement and other matters as required to implement overall rate adjustments through implementation of an adjusted Rider J (applicable to all firm retail customer class rates and to firm major industrial customer class rates) in order to recover the revenue shortfall in the test year.

Pursuant to the Order in Council (OIC) 1995/90 direction (as amended by OIC 2018/220), the Board must ensure that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers. Consequently, all proposed 2021 rate adjustments for retail customers and industrial customers apply equally, as percentages.

The Application includes the following:

- Overview;
- Summary of Requested Orders; and
- Overview of Supporting Documents.

OVERVIEW

Proposed Approach

Yukon Energy's last requested rate increase was for the 2017 and 2018 test years. The existing Yukon Energy Rider J was implemented in December 2019 based on the 2018 revenue requirement approved by the Yukon Utilities Board. Order 2018-10, issued in December 2018, approved 2018 forecast costs that were much lower than the actual costs incurred in that year.

As reviewed in Tab 1, this GRA addresses a difficult situation. Yukon Energy's actual ROE has continued to fall well short of the 2018 approved ROE, and a new GRA is required to address serious ongoing revenue shortfalls. Yukon ratepayers have also experienced large bill increases in late 2019 and many are now experiencing ongoing disruptions due to the COVID-19 pandemic.

In this context Yukon Energy has developed an approach to enable a rate adjustment for the 2021 test year to address YEC's financial requirements without any material change to Yukon ratepayer bills. The proposed approach in the 2021 GRA is to time rate increases to coincide with the reduction or expiration of existing rate riders:

- **Interim 2021 GRA Rates:** Interim rate increases are proposed to occur concurrent with expected reduction of Rider F as at July 1, 2021 in order to yield no material change in customer bills.

- **Final 2021 GRA Rates:** Yukon Energy proposes that this proceeding work to ensure that final 2021 GRA rates are effective no later than December 1, 2021 in order that final rate increases (including any true-up rider requirement) are timed concurrent with required removal of the 2017-18 GRA true-up rider J1 at the end of November 2021.

In summary, the proposed approach will enable the required rate increase to occur during 2021 while the residential customer bill for 1,000 kWh per month use would remain at $204.00 per month (before subsidies, rebates and taxes) from November 2020 through November 2021 and end at $204.72 in December 2021.

The 2021 GRA approach will also work to prevent rate and bill instability beyond 2021, and reduce rate increase requirements for a subsequent GRA.

In order to implement final rates by the end of November 2021, the Application includes only one test year (2021). Successful execution of this proceeding for 2021 will allow for a reset to a framework for proceeding in future with a two test year GRA that restores a more orderly regulatory process.

Factors Driving the 2021 Revenue Shortfall

A rate increase is required for the 2021 test year to recover a $10.971 million revenue shortfall driven by increased costs and changing load profiles. The Application documents the full range of load profile and cost changes. As reviewed in Tab 1, the following key factors are driving most of the 2021 rate increase:

- **Capital Costs (37.8% of revenue shortfall):** Aging infrastructure drives investments in sustaining capital and growth in peak and energy loads drive investments in new supply. These capital cost increases impact the 2021 GRA revenue shortfall through increases for depreciation/amortization, long term debt costs and equity return.

- **Energy & Peak Load Changes (8.4% of revenue shortfall):** Dependable capacity requirements caused by peak load growth for non-industrial sales drives diesel rental costs that account for $3.8 million (34.9%) of the 2021 GRA revenue shortfall. Higher overall loads provide increased revenues at existing rates ($14.4 million) that reduce the 2021 revenue shortfall by $2.9 million after considering load-related cost impacts of $10.8 million for increased long-term average thermal generation fuel cost requirements at 2018 GRA fuel prices (to address added energy generation) and $0.7 million for increased Mayo B Promissory Note interest due to higher loads.

- **Fuel Price Changes (19.4% of revenue shortfall):** Higher fuel prices account for $2.1 million of the 2021 GRA revenue shortfall.

- **Other Non-fuel O&M Factors (28.4% of revenue shortfall) –** Other non-fuel O&M cost increases relate to labour ($1.4 million) and non-labour ($1.7 million) factors.

- **Other Cost Changes (6.0% of revenue shortfall) –** Other cost changes include depreciation rate changes ($0.6 million increase), Reserve for Injuries and Damages (RFID) updates ($0.4 million increase), and new Independent Power Production (IPP) costs ($0.3 million). The 2021 GRA revenue shortfall is reduced by $0.7 million by amortization of VGC Group contributions of $11.5 million for McQuesten Substation and system improvement costs over the Eagle Gold 12 year mine life.

Proposed Rider J to Address 2021 Revenue Shortfall

The current level of firm rates result in a $10.971 million rate revenue shortfall in 2021 compared to revenue requirements set out in Tab 3. This shortfall, outlined in Table 1 below, forms the basis for the proposed rate increases in this Application.

Table 1:
Yukon Energy Revenue Required from Rates ($000s)

	2021
Revenue Requirement	$75,135
Less: Other Revenues	$369
Less: Secondary Sales	$0
Revenue Required from Firm Rates	$74,767
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$63,796
Additional Firm Rate Revenues Required	$10,971

In accordance with OIC 1995/90 direction, the Application proposes that the Yukon Energy revenue shortfall for the test year be recovered through a Rider J increase of 15.01 percentage points in 2021 applicable to all YEC and AEY retail firm rates and all major industrial firm rates. This Rider J increase results in an overall increase in existing rates (excluding existing Rider J1 true-up and Rider F) of 11.54% for 2021; as noted earlier, the proposed 2021 GRA approach will enable this rate increase to occur without a material change in customer bills. The proposed Rider J changes to recover the revenue shortfalls are reviewed in more detail below.

SUMMARY OF REQUESTED ORDERS

In summary, approval of the Board is requested for the following:

1. **2021 Revenue Requirement:** Approval of the forecast revenue requirement of $75.135 million for 2021, including approval, as required, of the following costs, revenues and other related provisions:

    a. **Fuel and Purchased Power Costs:** Fuel and purchase power costs forecast of $15.897 million in 2021, including approval for the following related matters:

        i. **Adjusted Fuel Prices:** Approval to adjust delivered diesel and LNG prices used in setting average fuel costs per kW.h to be $0.2051/kW.h for diesel and $0.1814/kW.h for LNG to reflect current market conditions.

        ii. **LNG/Diesel Generation:** Approval to assume that long-term average (LTA) thermal generation requirements (separate from thermal generation maintenance activity requirements) are supplied with a combination of 90% LNG and 10% diesel generation.

b. **Non-Fuel Operating and Maintenance Costs:** Non-fuel operating and maintenance costs forecast of $29.430 million in 2021, including approval of the following matters:

   i. **Reserve for Injuries and Damages (RFID):** Approval to increase the annual appropriation to the Reserve for Injuries and Damages to $0.411 million from the current $0.267 million level starting in 2021, and approval to amortize the remaining balance of $2.121 million over a five year period (as discussed in Section 3.3.7 of Tab 3).

c. **Depreciation and Amortization Expenses:** Approval of depreciation and amortization expenses forecast of $13.125 million for 2021, including approval of the following:

   i. **Updated Depreciation Rates:** Approval of updated depreciation rates as set out in Tab 7, with an overall increase to 2021 depreciation expense of approximately $0.636 million; and

   ii. **Defined Benefit Pension Deferral Account:** Approval of defined benefit pension plan deferral account as set out in Section 3.6.2 that captures variances in contributions to the defined benefit pension plan from the cost included in the test year revenue requirements as a result of the required annual actuarial evaluations.

d. **Mid-Year 2021 Forecast Rate Base:** Approval of mid-year forecast rate base costs of $322.777 million for 2021, including costs for capital works and deferred cost projects brought into service (or forecast to be brought into service) since the 2017/2018 General Rate Application.

e. **Return on Rate Base:** Approval of $16.682 million in 2021 including an allowed rate of return on equity of 8.70% for 2021.

2. **2021 Rates:** Approval of the following rates to recover the 2021 revenue shortfall:

   a. **2021 Retail and Industrial Rates:** Approval of an increase of the current YEC Rider J by 15.01 percentage points, starting no later than December 1, 2021, applicable to all YEC and AEY retail firm rates (all AEY recoveries from this rider would flow through to YEC), and to all major industrial firm rates, including the fixed Rider F charge of 0.211 cents/kWh.

   b. **Interim Refundable Rates effective July 1, 2021:** Approval to implement an interim refundable rate rider increase (Rider J) of 10.08% for retail firm rates and industrial firm rates effective on an interim refundable basis as at July 1, 2021 (see Tab 4, Appendix 4.1 for proposed interim Rider J rate schedule).

> Following receipt of final orders in this proceeding, including a final 2021 revenue requirement, any residual shortfall or surplus will be addressed pursuant to direction of the Board.

Yukon Energy acknowledges that it has been directed in Board Order 2019-08 to review and update the LWRF Term Sheet in this GRA, and to provide any further views on its risk and ratepayer risks that YEC considers relevant. Yukon Energy has been required, given COVID 19 conditions and other factors related to minimizing any bill impacts on ratepayers, to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application. Yukon Energy is working to complete and file an updated LWRF Term Sheet with the Board as soon as feasible.

OVERVIEW OF SUPPORTING DOCUMENTS

The following is an outline of the specific supporting documents included with the Application as Volume 1 of Yukon Energy's filed materials:

- **Tab 1 Introduction:** Provides an introduction to the supporting documents, addressing YUB review of Yukon Energy matters since the 2017/2018 GRA.

- **Tab 2 Yukon Energy System Sales and Generation:** Provides detail on the power system operated by Yukon Energy and its forecast sales and generation for 2021.

- **Tab 3 Revenue Requirement:** Provides detailed information on Yukon Energy's total forecast cost of providing service in 2021, including operating and maintenance expenses, rate base, depreciation and amortization, return on rate base (including a fair return on equity) and stabilization matters.

- **Tab 4 Rates:** Reviews Yukon Energy's rates and provides an explanation of Yukon Energy's proposed rate adjustments and Riders.

- **Tab 5 Capital Projects:** Provides an overview of Yukon Energy's capital spending for the period 2018 to 2019, as well as forecast capital spending for 2020 and for the 2021 test year.

- **Tab 6 Board Directives:** Provides a review of past Board Orders and responses to outstanding directives since the 2017/2018 General Rate Application.

- **Tab 7 Financial Schedules:** Provides detailed regulatory schedules for Yukon Energy supporting the Application.

- **Tab 8 Return on Equity:** Provides details with respect to Yukon Energy's fair rate of return for 2021.

- **Tab 9 Depreciation Study**: Provides a copy of the most recent Depreciation Study.

- **Tab 10 2019 Audited Financial Statements:** Provides a copy of Yukon Energy's audited financial statements.

- **Tab 11 Orders in Council:** Provides the relevant Order in Council documents which direct the Board regarding certain aspects of Yukon Energy's revenue requirement and rate design.

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INTRODUCTION

1.0 INTRODUCTION

Yukon Energy's 2021 General Rate Application (the "Application") includes 11 tabs of supporting documents reviewing information related to Yukon Energy's operations and the requested Board Orders. Tab 1 provides an introduction to the supporting documents under the following headings:

- Need, Context and Proposed Approach for 2021 GRA;
- Factors Driving the 2021 Rate Increase Requirement;
- Changes in Forecast Loads;
- Other Regulatory Concerns; and
- Yukon Energy Rates and Bills.

1.1 NEED, CONTEXT AND PROPOSED APPROACH FOR 2021 GRA

Existing Yukon Energy rates were established in December 2019 based on the 2018 revenue requirement approved by the Yukon Utilities Board (YUB) for YEC's 2017/18 General Rate Application (GRA). Order 2018-10, issued at the end of December 2018, approved 2018 forecast costs well below actual costs incurred in that year,[1] resulting in Yukon Energy's 2018 actual return on equity (ROE) of 6.25% being much lower than the approved ROE of 8.70%. Yukon Energy's actual ROE in 2019 and forecast for 2020 and 2021 has fallen to a range between 3.10% and 3.88%, underlining the inadequacy of existing rates relative to Yukon Energy's actual costs and revenues (see Table 1-1).

Table 1-1:
Return on Equity (%) Earned by Yukon Energy with Existing Rates[2]

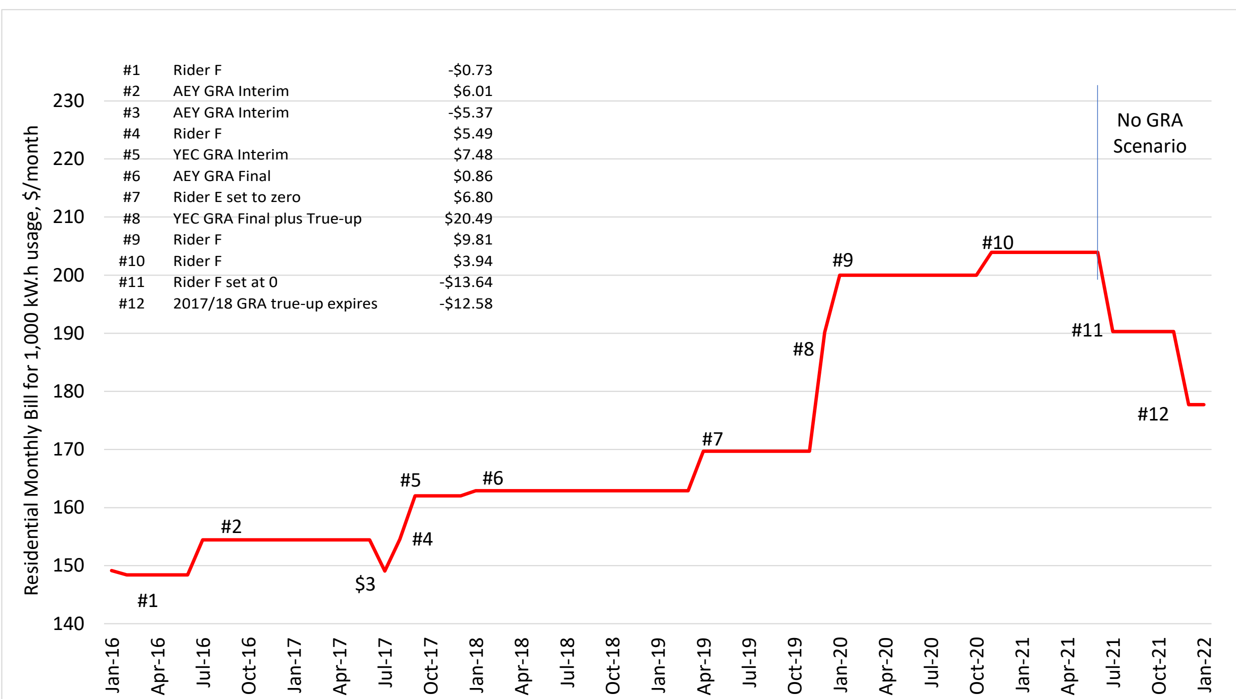
Year	ROE
2018 Approved	8.70%
2018 Actual	6.25%
2019 Actual	3.81%
2020 Forecast (no GRA)	3.88%
2021 Forecast (no GRA)	3.10%

[1] These impacts were highlighted in the response to Undertakings and in Yukon Energy's compliance filing.
[2] Source: Tab 7, Schedule 4.

In response to Board Order 2018-10 and its expected outcomes, Yukon Energy began to prepare a new 2019-20 GRA for filing after the final 2018-10 compliance filing was approved. However, a 2019 GRA filing to increase rates became unfeasible due to the 2017-18 GRA compliance proceedings extending well into November 2019 and the large bill increase impacts to customers resulting from the 2017/18 GRA delays causing a very large true-up rider (even when amortized over an extended 24 month period).

Figure 1-1 highlights the bill impact of the 2017/18 GRA approved rate changes effective December 1, 2019 with the true-up rider for a residential customer using 1,000 kWh/month, in the context of other rate changes since August 2016. Rate change #8 shows the $20.49 bill impact from the December 2019 rate increase, and rate change #12 shows the impact of removing (at the end of November 2021, after the prescribed 24 months) the $12.58 true-up rider bill impact required to collect 2017-2019 revenue shortfalls related to the extended proceeding. Figure 1-1 also shows the compounding impact of the Rider F increase (rate change #9) needed in January 2020 following finalization of the YEC rate approvals, and the impact in mid 2021 (rate change #11) of the expected reduction of Rider F.

Figure 1-1:
Change in Residential Monthly Bills, Aug. 2016 to Jan. 2022 with no 2021 GRA
(Whitehorse[1], 1000 kWh/month use)



Note: 1. Due to rate equalization, the same bill impacts occur for all Yukon residential ratepayers using 1,000 kW.h/month.

After having to cancel a 2019/20 GRA, Yukon Energy planned to adjust rates as soon as possible in 2020 with a new GRA for the 2020/21 test years. However, the effort to implement any rate change in 2020 had to be suspended in the spring in response to the disruptive impacts on all parties of the COVID-19 pandemic.

The situation today results in a clear dilemma regarding Yukon Energy rates and Yukon ratepayer bills:

- **Yukon Energy rates** –- A new GRA is overdue to enable Yukon Energy to address serious ongoing revenue shortfalls. The fact that this situation has occurred during the COVID-19 pandemic increases the risks of ongoing delays. However, further delay in adjusting rates will have material implications for the financial integrity of the corporation.

- **Yukon ratepayer bills** – Concurrent with Yukon Energy's dilemma, Yukon ratepayers now are experiencing ongoing disruptions from the impacts of COVID-19. Any material increases to ratepayer bills at this time (and in the near future) would raise concerns.

In this context, Yukon Energy has developed a proposed approach to enable a rate adjustment for the 2021 test year that can address YEC's financial requirements without any material change to Yukon ratepayer bills.

The key to Yukon Energy's proposed approach in the 2021 GRA is to time rate increases to coincide with the removal or expiration of existing riders:

- **Interim 2021 GRA rates** – Interim GRA rate increases would normally be introduced as soon as feasible in the test year; instead, YEC proposes to delay interim rate increases to be timed concurrent with planned reduction of Rider F as at July 1, 2021 in order to yield no material change in customer bills. Starting mid-year, the proposed interim rate based on the planned reduction of Rider F would recover approximately two-thirds of the proposed rate revenue increase.

- **Final 2021 GRA rates** – Yukon Energy proposes that this proceeding work to ensure that final 2021 GRA rates are effective no later than December 1, 2021 in order that final rate increases (including any true-up rider requirement) are timed concurrent with required removal of the 2017-18 GRA true-up rider at the end of November 2021. The end result is expected to avoid any material bill change for customers, e.g., the residential customer bill shown in Figure 1-1 would remain at $204.00 per month (before subsidies, rebates and taxes) from November 2020 through November 2021 and end at $204.72 in December 2021 (see Tab 4, Table 4.3 and Appendix 4.2,

Table 4.2A-3). Delay in rate adjustments until after December 1, 2021 would lead to bill instability (a sharp decline followed by a sharp increase when new rates are approved) and higher new true-up rate rider requirements.

In this way, adjusted rates to address serious revenue shortfall issues outstanding since 2019 can be implemented for 2021 in a manner that does not adversely impact customer bills. The 2021 GRA approach will also work to prevent rate and bill instability beyond 2021, and reduce rate increase requirements for a subsequent GRA.

The objective of this Application is to resolve outstanding revenue shortfall issues in 2021 without disrupting customer bills. In order to secure final rates by the end of November 2021 milestone critical to customer bill stability, the Application includes only one test year (2021). Successful execution of this proceeding for 2021 will allow for a reset to a framework for proceeding in future with a two test year GRA that restores a more orderly regulatory process.

1.2 FACTORS DRIVING THE 2021 RATE INCREASE REQUIREMENT

The 2021 GRA forecast revenues at existing rates are $10.971 million short of the 2021 GRA forecast revenue requirement. The 2021 rate increase is required to recover this revenue shortfall, and is driven by increased costs and changing load profiles as summarized below and in Table 1-2.

- **Capital Costs ($4.1 million impact, 37.8% of shortfall):** Aging infrastructure drives investments in sustaining capital, growth in peak and energy loads drive investments in new supply development, and the need for rigorous management of assets drives investment in asset management development. Related capital cost increases impact the 2021 GRA revenue shortfall through cost increases for depreciation, deferred cost amortization, long term debt costs and equity return. Major capital and deferred cost projects (i.e., rate base increases over $1 million) highlights include:

    - **Sustaining Capital Major Projects ($23.7 million net rate base impact):** Completion of Mayo McQuesten Transmission Line and McQuesten Substation ($8.9 million net); Transmission Line Refurbishment projects & Breaker Replacement program ($7.8 million); replace P125 headgate ($5.9 million); and Aishihik 3-Year Relicensing ($1.0 million).

    - **New Supply Major Projects ($26.9 million net rate base impact)**: WH2 and WH4 uprates ($13.6 million); completion of LNG Third Engine ($8.3 million); build N-1

Capacity Shortfall Thermal Rental Site Infrastructure ($3.3 million); and Demand Side Management ($1.7 million).

  - **Asset Management Major Project ($4.9 million net rate base impact):** Enterprise Asset Management System Purchase and Implementation ($4.9 million).

- **Energy & Peak Load Changes ($0.9 million impact, 8.4% of shortfall):** Peak load growth for non-industrial sales drives diesel rental costs that account for $3.8 million (34.9%) of the 2021 GRA revenue shortfall. Absent diesel rental costs, higher overall loads provide increased revenues at existing rates ($14.4 million) that reduce the 2021 revenue shortfall by $2.9 million after considering load-related cost impacts of $10.8 million for increased long-term average thermal generation fuel cost requirements at 2018 GRA fuel prices (to address added energy generation) and $0.7 million for increased Mayo B Promissory Note interest due to higher loads.

- **Fuel Price Changes ($2.1 million impact, 19.4% of shortfall):** Higher market fuel prices account for $2.1 million of the 2021 GRA revenue shortfall.

- **Other Non-fuel O&M Costs ($3.1 million impact, 28.4% of shortfall):** Other non-fuel O&M cost increases relate to labour ($1.4 million) and non-labour ($1.7 million) factors.

- **Other Cost Changes ($0.7 million impact, 6.0% of shortfall):** Other cost changes affecting the 2021 GRA revenue shortfall include depreciation rate changes ($0.6 million increase), Reserve for Injuries and Damages (RFID) updates ($0.4 million increase), and new Independent Power Production (IPP) costs ($0.3 million). The 2021 GRA revenue shortfall is reduced by $0.7 million by amortization of VGC Group contributions of $11.5 million for McQuesten Substation and system improvement costs over the Eagle Gold 12 year mine life (versus the 54 year asset life) in accordance with accounting requirements.

These cost drivers and other changes are addressed in detail in subsequent tabs of this supporting document. Changes in forecast loads are summarized in the next section below.

Table 1-2:

Summary of Revenue and Cost Changes - Approved 2018 vs 2021 GRA

2021 Revenue Shortfall Drivers	**2021 GRA over 2018 Approved ($000)**	**% of 2021 Revenue Shortfall (%)**
Capital Costs	**4,148**	**37.8%**
Depreciation (fixed asset increases) [1]	*1,154*	*10.5%*
Deferred costs amortization	*858*	*7.8%*
Long-term debt cost [2]	*907*	*8.3%*
ROE increase	*1,229*	*11.2%*
Energy & Peak Load Changes	**923**	**8.4%**
Added revenue impact at existing rates	*-14,371*	*-131.0%*
Long Term Average (LTA) thermal cost [3]	*10,763*	*98.1%*
Diesel Rental cost	*3,834*	*34.9%*
Mayo B Promissory Note	*696*	*6.3%*
Fuel Price Changes	**2,129**	**19.4%**
Non-Fuel O&M Costs	**3,115**	**28.4%**
Labour cost increase	*1,378*	*12.6%*
Non-labour O&M [4]	*1,737*	*15.8%*
Other Cost Changes	**656**	**6.0%**
Independent Power Production (IPP) costs	*314*	*2.9%*
Other Purchase Power cost	*14*	*0.1%*
Reserve for Injuries & Damages (RFID) update	*357*	*3.2%*
Depreciation rate changes	*636*	*5.8%*
Accelerated amortization VGC Group contributions	*-665*	*-6.1%*
Total 2021 Revenue Shortfall	**10,971**	

Notes:

1. Excludes depreciation rate changes & impact of accelerated amortization of VGC Group contributions.
2. Excludes Mayo B Note increase due to load growth.
3. Excludes fuel price change impacts.
4. Excludes diesel rental cost & RFID update.

1.3 CHANGES IN FORECAST LOADS

The 2021 load forecast is about 28% higher than the 2018 approved forecast.[3] As noted in Table 1-2, revenues from higher loads are largely offset by increases in fuel costs. Higher non-industrial loads also result in capacity shortfalls that must be addressed and that are driving both capital and O&M cost increases.

Test year forecasts for 2021 reflect the following:

- **Wholesale Load** – Actual 2018 (332.3 GWh) 17.6 GWh higher than approved forecast (314.7 GWh); firm wholesales for 2021 are forecast at 343.5 GW.h.
- **Industrial Load** – Actual 2018 industrial load exceeded approved forecast (36.9 GWh vs 32.2 GWh). Forecast firm Yukon Energy sales to industrial customers for the 2021 test year is 102.9 GW.h.
    - The **Minto mine** load in 2018 was 4.7 GW.h higher compared to the approved forecast. Minto load is forecast at 35.7 GW.h for 2021, reflecting return to partial production in late 2019.
    - The **Victoria Gold Group (VGC Group)** Eagle Gold mine connected to the YEC grid in May 2019, with a firm 2019 load of 9.8 GW.h. The Eagle Gold mine has provided a load forecast at 35.1 GW.h for 2020 and 43.1 GW.h for 2021.
    - **Alexco Resources** is forecast to resume industrial operations in late 2020; the customer has provided a forecast 2021 firm load of 24.1 GW.h.
- **No secondary sales in forecast** – The 2018 Compliance Filing included a forecast of 2.1 GW.h for secondary sales. Actual secondary sales were 0.258 GW.h in 2018; no secondary sales occurred in 2019, and none are forecast for 2020 or the 2021 test year.
- **Thermal Generation requirements are growing due to higher firm grid loads** – The 2018 Compliance Filings approved a forecast of 16.4 GW.h for long-term average (LTA) thermal generation requirements to supply the 2018 forecast grid load of 420 GWh. The 2021 LTA

[3] Forecast total firm generation load for the 2021 test year is 538.7 GW.h, compared to the 2018 approved load of 420.3 GWh.

thermal generation forecast is 84.3 GW.h for a forecast grid load 538.7 GW.h. The increased LTA thermal generation accounts for $10.8 million of the 2021 GRA cost increases from the approved 2018 GRA (based on 2018 GRA approved fuel prices). These added LTA thermal generation costs due to load growth are more than fully recovered by the increased revenues ($14.4 million) from the load growth.

- **Peak Capacity and N-1/ LOLE requirements in test years** - Winter peak load generation requirement continues to increase, with the 2018 actual peak reaching 93 MW and the forecast for 2021 of 112.7 MW. Yukon Energy N-1 peak capacity requirement for Yukon grid reliability is based on the non-industrial load winter peak. Non-industrial peak load has increased from 86.4 MW in the approved 2018 GRA forecast to 100.7 MW forecast for 2021 (14 MW increase), accounting for most of the 17 MW growth in the N-1 dependable capacity shortfall.[4] Diesel rental unit costs of approximately $3.8 million are forecast for the diesel rental units expected to be required for the 2021 GRA test year,[5] Yukon Energy's ongoing capital program costs include infrastructure to accommodate the rented diesels as well as work to address longer term solutions (e.g., battery energy storage system [BESS], diesel replacement at various grid locations, Atlin Hydro Expansion Project, and the potential development of pumped storage at Moon Lake).

1.4 OTHER REGULATORY CONCERNS

Aside from the need to address revenue requirement shortfalls at existing rates, the current Application identifies three other regulatory concerns that need to be addressed concurrently with the Application:

- **VGC Group and Alexco Fixed Charge:** Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group and for Alexco of $8,402/ month, subject to amendment from time to time, including provision for allocation of the Fixed Charge between VGC Group and Alexco in years when both customers are Major Industrial Customers of YEC.[6] As reviewed in Appendix 4.3 of this Application, YEC expects to file with the Board in late November/ early December 2020 for approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of $428,812,

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[4] The balance of the N-1 capacity shortfall growth reflects net changes in thermal unit capacities and net changes in hydro facility winter dependable capacities.
[5] 15 units at 1.8 MW for each unit to total 27 MW for 2021 plus two spare units to total of 17 units.
[6] Section 7.7 (c)(ii) of the VGC Group PPA provides that the Fixed Charge will initially be allocated between VGC Group and Alexco based on YEC's estimate of each mine's share of the Major Industrial Customer MWh load on the Transmission Facilities for the calendar year. Within 60 days of calendar year end, YEC will adjust the allocation based on each mine's actual share of the Major Industrial Customer MWh load on the Transmission Facilities.

resulting in an interim Fixed Charge (85% of the Transmission Facilities Fixed Cost) effective January 1, 2021 of $35,734 per month, with allocation of the interim Fixed Charge between VCG Group and Alexco [Table 4.3-2, Appendix 4.3 of this Application]. Aside from changes related to the 2021 GRA, a final Fixed Charge for 2021 would occur after 2021 year end as required to reflect final actual Transmission Facilities Fixed Cost and the actual MWh energy sales in 2021 that occurred to VGC Group and Alexco.

- **Defined Benefit Pension Deferral Account:** In this Application Yukon Energy is requesting approval of 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 revenue requirements as a result of the required annual actuarial evaluations. A similar deferral account was approved for AEY by Board Order 2014-06.

- **Low Water Reserve Fund (LWRF) and Related Matters:** The stabilization mechanism as represented by the LWRF Term Sheet as last approved in the 2017-18 GRA was provided to the Board in December 2019 along with the 2017-2018 LWRF Annual Report and Energy Reconciliation Adjustment ("ERA") filing, and acknowledged by the Board's letter of March 19, 2020. Yukon Energy acknowledges that it has been directed in Board Order 2019-08 to review and update the LWRF Term Sheet in this GRA, and to provide any further views on its risk and ratepayer risks that YEC considers relevant. Yukon Energy has been required, given COVID 19 conditions and other factors related to minimizing any bill impacts on ratepayers, to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application. Yukon Energy is working to complete and file an updated LWRF Term Sheet with the Board as soon as feasible.

1.5 YUKON ENERGY RATES AND BILLS

Since Yukon Energy was established in 1987, rate matters related to Yukon Energy and AEY have been typically dealt with on a joint basis. This arrangement reflected AEY management of Yukon Energy prior to 1998 and the rate policy directives to the YUB set out since 1987 in Orders in Council (OIC's) establishing equalized rates in Yukon (the most recent being OIC 1995/90), as well as directives amending OIC 1995/90.

Tab 11 provides copies of the current OIC's directing the Board on rate determinations. The current OIC 1995/90 is provided, integrating the impact of OIC directives amending it since 1995.

A separate OIC 2018-25 direction is included in Tab 11 to the general effect that in setting rates that an electrical utility is permitted to charge, so long as the electricity purchase agreement addresses the matters outlined in sections 3 to 6 of the OIC, the Board must allow the utility to recover the cost of purchasing electricity under an electricity purchase agreement; third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement; and the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

The Board directly determines rates (other than Rider F for diesel or natural gas fuel costs which is adjusted by the utilities in accordance with Board and OIC directives). The Yukon Government separately determines two other key factors directly affecting bills paid by most ratepayers (namely, the Income Tax Rebate related to AEY income taxes and the Interim Electrical Rebate).

The following are major changes affecting firm rates and bills generally paid by Yukon Energy's customers since the 2017/18 GRA and prior to the changes proposed in this Application:

1. **Rider F (Diesel or Natural Gas Fuel Price Changes and Rate Schedule 32 Changes)** – Per direction provided in Order 2009-8 quarterly updates are filed with the Board and provided on each Companies' website. Rider F adjusts all firm retail and industrial bills for changes in diesel or natural gas fuel prices and Rate Schedule 32 rates since the last YEC or AEY GRA. The current Rider F is 1.371 cents per kW.h and was last changed as at November 1, 2020.

2. **Interim Electrical Rebate (IER)** – The Government of Yukon provides for a 2.395 cents/kW.h rebate for up to the first 1,000 kW.h per month (first block) for residential non-government customers (since the termination of the RSF there is no longer similar rate relief for general service or municipal customers). This rebate was implemented in 2009 as an interim measure; it has continued to be extended with adjustments since that time.

TAB 2
SALES AND GENERATION

2.0 SALES AND GENERATION

The following items are reviewed in this tab:

- Overview;
- Sales Forecast;
- Power Generation; and
- Peak Demand Forecast and Dependable Capacity Requirement.

2.1 OVERVIEW

Yukon Energy is the main generator and transmitter of electrical energy for the Yukon Integrated System.

Yukon Energy directly serves about 2,300 customers at the distribution (retail) level, most of whom live in and around Dawson City, Mayo and Faro. Indirectly, Yukon Energy also provides power to Yukon retail customers served on the Integrated System (including those located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, Keno and Stewart Crossing) through its wholesale sales to ATCO Electric Yukon (AEY).

Actual firm sales to **non-industrial customers** (excluding secondary or interruptible customer load) supplied by Yukon Energy on the Integrated System in 2018 was 375.3 GW.h, which was 21.2 GW.h higher compared to the approved forecast load of 354.1 GW.h primarily due to an increase in firm wholesales to AEY. Actual firm sales to non-industrial customers in 2019 was 376.2 GW.h, an increase of 0.9 GW.h over 2018 actual. Full year forecast non-industrial sales in 2020 is 400.9 GW.h, reflecting January-June preliminary actuals and forecasts for July-December, which is an increase of 24.7 GW.h over 2019 actuals. Forecast firm Yukon Energy sales to non-industrial customers for the 2021 test year is 392.2 GW.h, a decline of 8.7 GW.h compared to 2020 forecast due almost entirely to reduced wholesales.

For 2018, **Industrial sales** under Primary Industrial Rate Schedule 39 included only sales to the Capstone Mining Corp (Minto mine), forecast at 32.2 GW.h with actual load at 36.9 GW.h. Actual firm industrial sales in 2019 was 27.3 GW.h, 9.6 GW.h lower than 2018 actuals. Full year forecast for 2020 at 64.9 GW.h reflects an increase of 37.6 GW.h over 2019 actuals. Forecast firm Yukon Energy sales to industrial customers for the 2021 test year is 102.9 GW.h, reflecting a further increase of 38.0 GW.h over 2020 forecast.

- The Minto mine load in 2018 of 36.9 GW.h was 4.7 GW.h higher compared to the approved forecast load of 32.2 GW.h. The approved forecast was amended during the 2017/18 GRA process and included actual results for January-June and an estimate of lower consumption for the last half of 2018 reflecting a shift from full production to care and maintenance. Higher overall actual results for 2018 were due to the Minto mine taking higher load while in care and maintenance despite the estimate provided by the customer. During 2019, ownership of the Minto mine changed to Pembridge Resources and firm load was 17.5 GW.h, a decline of 19.4 GW.h from 2018. Minto load is forecast at 29.7 GW.h for 2020 and 35.7 GW.h for 2021, reflecting return to partial production in late 2019.

- The Victoria Gold Corporation Group's[1] Eagle Gold project located north of Mayo connected to the YEC grid in May 2019, with a firm 2019 load of 9.8 GW.h. The Eagle Gold mine has provided a load forecast at 35.1 GW.h for 2020 and 43.1 GW.h for 2021.

- Alexco Resources is forecast to resume industrial operations in late 2020 in the Keno region north of Mayo and east of the Eagle Gold mine; the customer has provided a forecast 2021 firm load of 24.1 GW.h.

Overall, **total firm generation load** to be supplied by Yukon Energy on the Yukon Integrated System was forecast at 420.3 GW.h in the 2018 Compliance Filing. Actual total firm generation load was 450.1 GW.h in 2018 reflecting higher sales compared to the forecast. Actual total firm generation load in 2019 was 440.7 GW.h, and full year forecast for 2020 is 508.0 GW.h. Forecast total firm generation load for the 2021 test year is 538.7 GW.h.

Non-firm secondary sales ceased in September 2018 due to load growth and lack of water resources for hydro generation. The 2018 Compliance Filing included a forecast of 2.1 GW.h for secondary sales. Actual secondary sales were 0.258 GW.h in 2018 and zero in 2019, and no secondary sales were forecast for 2020 or for the 2021 test year when the 2021 GRA load forecast was prepared.[2] YEC will update 2021 test year forecasts in the compliance filing if any secondary sales are expected to occur in 2021 as a result of surplus water availability.

As per previous Board directives, Yukon Energy's revenue requirement annual thermal generation costs are based on long-term average (LTA) hydro generation (rather than forecasts of actual hydro generation

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[1] The Victoria Gold Corporation Group is the amalgamation of Victoria Gold Corporation and Stratagold Corporation as described in the Power Purchase Agreement for the Eagle Gold mine.
[2] Temporary secondary sales occurred during September 2020 due to high water conditions.

resulting from actual water conditions). Accordingly, for the purpose of the 2021 GRA test year, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information.

- The approved 2018 Compliance Filing, based on annual LTA hydro generation capability (rather than forecast actual 2018 hydro generation), forecast that over 96% of grid generation requirements in 2018 would be met with hydro generation and less than 4% with thermal generation. Based on higher-than-forecast actual load in 2018 (450 GW.h actual versus 420 GW.h forecast), hydro generation at LTA supply is calculated at 93% of 2018 grid generation and LTA supply thermal generation accounted for 7% of 2018 grid generation. Actual hydro generation in 2018 was 91.7% of grid generation, reflecting lower than LTA water availability.

- In 2019, reflecting lower firm generation at 440.7 GW.h, hydro generation at LTA is calculated at 94.3% of grid generation and related thermal generation accounted for 5.7% of 2019 grid generation. Actual hydro generation in 2019 was 84.1% of grid generation, reflecting lower than LTA water availability.

- For 2020 forecast and the 2021 test year, higher forecast firm generation (508.0 GW.h for 2020, 538.7 GW.h for 2021) results in forecast hydro generation at LTA supply accounting for 86.4% (2020) and 84.0% (2021) of grid generation and related forecast thermal generation accounting for 13.6% (2020) and 16.0% (2021) of grid generation.

- Independent Power Production (IPP) renewable generation is forecast to commence in November 2020 with less than 0.4% of forecast generation impact for 2021.

- Actual hydro generation in 2020 is forecast at 86.0% of grid generation, reflecting annual water availability at about LTA. Current forecast hydro generation for 2021 is 94.0% of grid generation, reflecting forecast water availability above LTA.

The 2012/13 and 2017/18 GRA's highlighted increasing relevance of LTA thermal generation on the Yukon hydro grid as the total generation requirement increases. As compared to the 0.95 GW.h LTA diesel generation forecast for 2009 in the approved 2009 Compliance Filing, the 2013 Compliance Filing approved a forecast of 11.0 GW.h for diesel generation requirements to supply the 2013 forecast grid load of 416.4 GW.h (excluding diesel requirements related to capital projects). The 2018 Compliance Filings approved a forecast of 16.4 GW.h for thermal generation requirements to supply the 2018 forecast grid load of 420 GWh. The 2021 thermal generation forecast is 84.3 GW.h for a forecast grid load 538.7

GW.h. This pattern highlights the increasing impact of LTA thermal generation as load increases on the grid. This impact is starting to be offset by new renewable generation planned as part of Yukon Energy's 10 Year Renewable Electricity Plan, commencing with the new IPP generation forecast to provide 0.06 GW.h of solar generation in 2020 and 2.0 GW.h of new renewable generation in 2021 based on information available at the time of filing. YEC will update 2021 test year forecasts for any change in forecast IPP generation for the compliance filing.

In addition to increases in firm energy generation requirements, winter peak generation on the Yukon Integrated System continues to increase, with the 2018 actual peak reaching 93 MW (see Table 2.2). Although the 2019 actual peak was 90.0 MW, peak generation load (including industrial load) is 103.8 MW for 2020 and forecast at 112.7 MW for 2021.

Excluding industrial load, the forecast peak in this Application is 100.6 MW in 2021. Based on existing dependable generation capacity available during winter on the Yukon Integrated System and the approved N-1 single contingency capacity planning criteria, a dependable capacity shortfall without rented diesel units is forecast at 25.8 MW for 2021 based on the non-industrial peak loads forecast in this Application. With rented diesel units as planned, there is no shortfall in dependable capacity under the N-1 criterion. Please see section 2.4 for details.

2.2 SALES FORECAST

Yukon Energy's actual sales for 2018 and 2019, full year forecast sales for 2020 and forecast sales for 2021 are summarized in Table 2.1 at the end of this tab.

Total forecast sales are 495.2 GW.h for the 2021 test year. Total firm forecast sales for 2021 include 343.5 GW.h of primary (firm) wholesale sales, 102.9 GW.h of primary major industrial sales, and 48.7 GW.h of firm retail sales (i.e., all firm sales other than wholesale or major industrial).

2.2.1 Wholesale Sales to ATCO Electric Yukon

Yukon Energy's firm sales are primarily made up of firm wholesale sales to AEY (69% in 2021).

Firm wholesales to AEY for 2018 had material changes since the last GRA, as summarized below:

- The 2018 approved forecast of firm wholesales at 314.7 GW.h included provision for AEY's Fish Lake hydro generation (which acts to reduce AEY wholesales) at 8.4 GW.h.

- Actual firm wholesales in 2018 of 332.3 GW.h were higher than the approved forecast. Given that actual Fish Lake hydro generation was approximately 5.5 GW.h, the actual wholesales excluding Fish Lake impact were about 14.7 GW.h higher than forecast in 2018.[3]

Actual firm wholesales in 2019 of 331.5 GW.h were 0.8 GW.h lower than 2018 actual. Given that actual Fish Lake hydro generation was approximately 5.0 GW.h, the actual wholesales excluding Fish Lake impact were about 1.3 GW.h lower than 2018 actual. The full year forecast wholesales in 2020 at 351.8 GW.h, reflecting January-June preliminary actuals and forecast for July-December, is higher compared to 2019 actual sales largely due to higher actual sales in the first six months of 2020.

Forecasts for 2021 test year firm wholesales focused on two key factors:

- AEY's forecast grid firm load (firm sales plus AEY losses), assuming normal weather temperature conditions.

- AEY's forecast Fish Lake hydro generation during the test year (which reduce wholesale purchase requirements).

Firm wholesales for 2021 are forecast in Table 2.1 at 343.5 GW.h, which is 12.0 GW.h higher than 2019 actual, but 8.2 GW.h lower than the 2020 full year forecast. This 2021 forecast reflects AEY Fish Lake generation at 3.6 GW.h as provided by AEY, which is the same as 2020 full year forecast. Higher wholesales in 2020 were primarily due to colder-than-normal weather (specifically January 2020 was colder than normal weather). Forecast 2021 is prepared based on multi-variate regression assessments of monthly wholesales changes at normal weather conditions. It also reflects incremental forecast Micro Generation for 2021 which reduces forecast wholesales.[4]

YUB Order 2018-10 directed YEC to refine its methodology of forecasting Wholesale Sales to ensure its forecasts align closely with the AEY forecasts in future applications. To develop YEC's Wholesale Sales forecasts for the test years, YEC worked closely with AEY. YEC reached out to the AEY Regulatory team and YEC and AEY staff worked closely to understand forecasting methodology and inputs into the respective forecasts. AEY cautioned YEC that AEY's forecast is for business plan purposes and it did not necessarily undergo the same rigor as a forecast that AEY would file in a GRA.

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[3] YEC's 2017-18 GRA Compliance Filing approved forecast firm wholesales for 2017 (based on actuals) was 328.4 GW.h or only 3.8 GW.h lower that the 2018 actual firm wholesales.

[4] YEC has forecast a micro-generation impact of about 1.5 GW.h for 2021. The micro-generation forecasts are based on information available from Energy Mines & Resources of the Yukon government.

AEY provided Yukon Energy with its forecast power purchase estimate at 345.9 GW.h for 2021. The AEY forecast for 2021 is 2.4 GW.h or 0.7% higher than YEC's forecast. Given AEY's forecast is only for business planning purposes, YEC is using YEC's forecast of 343.5 GW.h for 2021 test year.

2.2.2 Major Industrial

Minto Mine (Capstone Mining Corp.) continues to be forecast as a Major Industrial Customer[5] during the test year. The test year also includes VGC Group Eagle Gold project which was connected in 2019, and resumed operation of Alexco Resources as a major industrial customer. 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.

Sales to Minto Mine were 17.5 GW.h for 2019, well below the approved 2018 GRA forecast sales of 32.2 GW.h and actual 2018 sales of 36.9 GW.h. The decrease is a result of Minto Mine being in care and maintenance mode for the first three quarters of 2019, before switching to a production schedule of two weeks on and two weeks off for the remainder of the year. The full year forecast sales to Minto Mine for 2020 at 29.7 GW.h reflects January-June actuals and July-December forecast. The forecast for 2021 at 35.7 GW.h is close to the 2018 actual level.

Sales to Victoria Gold were 9.8 GW.h for 2019. The full year forecast for 2020 at 35.1 GW.h reflects actual sales for January-June and forecast for July-December. The forecast sales in 2021 is 43.1 GW.h. Victoria Gold has significantly reduced its forecast load for these years from what it forecast in its 2017 Power Purchase Agreement.[6] The reductions in forecast loads reflect experience to date after start of production; Current forecasts from the customer indicate gradual increase in loads over the next two years.

The forecast for 2021 also include Alexco as a Major Industrial Customer with sales forecast at 24.1 GW.h as provided by the customer.[7]

No sales are forecast under Rate Schedule 35 – Low Grade Ore Processing Secondary Energy Rate.

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[5] Per OIC 1995/90, an industrial customer is defined as "a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer."

[6] Section 5.1 of the Power Purchase Agreement forecast 51.8 GW.h for year 1 of operation (12 months) of operation (assumed connection March 2019, approximately four months before forecast first gold production) and 63.6 GW.h for year 2 of operation.

[7] The 2021 Alexco forecast reflects forecasts for Flame and Moth, Bermingham, Mill and Elsa, as well as small loads for Silver King and Galkeno. The information provided by Alexco shows that the mines could operate past 2024. Alexco has confirmed to YEC in October 2020 that it is commencing industrial operations in late 2020 – however, no forecast for Alexco 2020 load is included in Table 2.1.

The GRA forecast also does not include any potential reduction in revenues related to use of the peak shaving option included in Rate Schedule 39 Industrial Primary. Electing to take service under this provision requires at least six months advance notice from the customer, and to date, such notice has not been provided.

Yukon Energy continues to monitor the situation with respect to prospects for additional connected industrial mine loads within the next few years. Yukon Energy is not aware of any other potential near-term mine loads that could be connected to the grid.

2.2.3 Yukon Energy Firm Retail Sales

Yukon Energy firm retail sales are comprised of sales to residential, general service, street light and space light customer classes served directly by Yukon Energy [Dawson City, Mayo, North Klondike Highway, Faro, Champagne, Braeburn, Johnson Crossing]. Retail sales are forecast at 48.7 GW.h for the 2021 test year as compared with full year forecast at 49.2 GW.h for 2020, and actual sales of 43.0 GW.h and 44.7 GW.h for 2018 and 2019 years, respectively.

2.2.3.1 Residential Sales

Actual firm residential retail sales were 15.6 GW.h in 2018 and 15.4 GW.h in 2019; the full year forecast for 2020 is 16.7 GW.h and for the 2021 test year is 16.2 GW.h. The higher forecast sales in 2020 reflect colder than normal weather and modest growth in the number of customers. Residential sales forecasts are done on a community by community basis and are based on historical averages and input from YEC staff that is obtained through their work in the communities.

2.2.3.2 General Service Sales

Actual firm general service retail sales were 27.2 GW.h in 2018 and 29.1 GW.h in 2019; the full year forecast for 2020 is 32.3 GW.h and is forecast to remain at 32.3 GW.h in the 2021 test year. General Service sales forecasts are done on a community by community basis and are based on historical averages and input from YEC staff that is obtained through their work in the communities.

The largest General Service customer is Faro Mine remediation project. Actual sales to the Faro Mine remediation project were 7.8 GW.h in 2018 and 9.4 GW.h in 2019. Sales to Faro Mine remediation are forecast to grow to 14.4 GW.h in 2020 and 2021. 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.

For the 2018 and 2019 actual years and 2020 full year forecast Alexco Resources is also included as a commercial customer with actual sales at 2.4 GW.h in 2018 and 1.7 GW.h in 2019, and forecast sales at 1.6 GW.h in 2020.

2.2.3.3 Lighting (Street Lights and Space Lights)

Actual firm retail sales for lighting were 235 MW.h in 2018, 178 MW.h in 2019 and forecast to remain at 178 MW.h for 2020 and for the 2021 test year. The decrease in lighting sales in 2019 was primarily due to conversion to LED street lights.

2.2.4 Secondary Sales

Due to the lack of surplus hydro generation available resulting from below average water conditions and growth of firm load, secondary sales ceased in September 2018. Secondary sales were 258 MW.h in 2018 (compared with 2,059 MW.h forecast in the 2018 Compliance Filing) and 0 MW.h in 2019. Secondary sales were forecast at 0 MW.h sales in 2020 and 2021 when the 2021 GRA load forecast was prepared.[8] YEC will update 2021 test year forecasts in the compliance filing if any secondary sales are expected to occur in 2021 as a result of surplus water availability.

2.3 POWER GENERATION

Hydro generation remains the predominant source of generation forecast for the test period, and is expected to be supplemented by natural gas (liquefied natural gas (LNG)) and diesel thermal generation as required. Table 2.2 provides a summary of forecast power generation by source, including forecast solar generation expected to be provided by Independent Power Production (IPP) through Standing Offer Program (SOP) offers under the Independent Power Production policy.

Total generation is based on the sum of total sales plus losses. The 2018 approved forecast losses were 8.8%. Actual losses were 9.2% in 2018 and 2019, and full year forecast for 2020 is 9.1%. The losses are forecast at 8.8% for the 2021 test year which is the same as the 2018 approved level in the 2017/18 GRA and also within the range of historical losses for last three years, from 2017 (at 8.1%) through 2018 and 2019 (each at 9.2%).

[8] Secondary sales were temporarily made available on September 1, 2020 due to high water inflows and full water reservoirs; secondary sales were again ceased by end of September, 2020 due to resumed need for thermal generation.

2.3.1 Integrated Grid Hydro Generation

The Yukon Integrated System (YIS) has 92.1 MW of installed YEC hydro generation, of which approximately 70.5 MW can be relied upon for the winter peak.

Previous Board approvals have resulted in Yukon Energy's revenue requirement and annual thermal generation costs being determined based on long-term average (LTA) forecast hydro and wind generation (rather than forecasts of actual hydro and wind generation resulting from actual water and wind conditions). Accordingly, for the purpose of the 2021 test year, thermal generation forecasts are based on LTA forecast hydro and other renewable generation as updated with the latest information. No YEC wind generation occurred in 2018 or 2019, and none is forecast for 2020 or for the 2021 test year.

Table 2.2 shows LTA YEC hydro generation for 2018 at 418.7 GW.h for the actual firm generation load 450 GW.h compared to the 2018 GRA forecast LTA hydro at 403.9 GW.h for the lower forecast generation load of 420 GW.h. LTA YEC hydro generation for 2019 was 415.4 GW.h and full year forecast for 2020 is 438.9 GW.h. The proposed forecast LTA YEC hydro generation in Table 2.2 for the 2021 test year, utilizing updates to the LTA forecast (see Section 2.3.2), is 452.4 GW.h. In addition, Table 2.2 shows forecast LTA IPP generation of 0.06 GW.h for 2020 and 2.0 GW.h for 2021.[9]

Table 2.2 also shows actual (as opposed to LTA) hydro generation for 2018 and 2019, and forecast actual hydro generation for 2020 and 2021. Actual hydro generation for 2018 and 2019 indicates the extent to which unfavourable water conditions in each of these years resulted in forecast actual hydro generation less than LTA. Actual hydro generation is currently forecast to reflect water availability at about LTA in 2020, and water availability above LTA in 2021.

In years with normal water conditions, the integrated system typically operates with Whitehorse Hydro as first-on generation (outside of Fish Lake) as a largely run-of-river plant. Mayo is also primarily a run-of-river plant and is therefore second on. Aishihik is used to supplement this run-of-river generation to achieve required output. Aishihik is a swing plant, meaning it follows the load profile until it reaches capacity then thermal is placed onto the grid. When thermal is generating on the system, Aishihik also provides the spinning reserve which is to provide coverage for the largest thermal unit on line.

[9] This IPP generation forecast assumes two solar projects coming into service through SOP offers – one in November 2020 and the second one in June 2021. YEC will update IPP generation for the compliance filing if more IPP projects are committed to connect to Yukon Grid during 2021.

The predominance of hydro generation on the Yukon system, combined with the fact that Yukon is isolated from other grids outside the territory, creates special seasonal and multi-year conditions that vary with YIS loads. For example, thermal generation sources are required to supplement available hydro to meet the system's winter/spring seasonal generation requirements, to provide reliable energy generation in drought years and to otherwise provide backup generation on the YIS when hydro is otherwise unavailable (e.g., breakdown/maintenance requirements). Conversely, on the isolated grid there is no opportunity to export surplus hydro (or other renewable generation) that typically occurs during summer, as well as when water conditions are higher than LTA and/or grid loads are low relative to existing hydro generation capability. The following are specifically noted:

- **Winter Constraints** – Seasonal water storage is typically needed for hydro facilities to be fully utilized in winter. In Yukon, seasonal storage exists at Aishihik and to a much lesser extent at Mayo, but is largely unavailable at Whitehorse. As grid load increases, there is an increasing need to rely on natural gas and/or diesel thermal generation to meet base load energy requirements in winter and early spring when the peak is high and/or hydro water flows are constrained.

- **Drought-Flood Year Constraints** – In addition to seasonal supply constraints, systems predominantly based on hydro generation resources such as the Yukon grid are vulnerable to drought (low water) conditions. In these circumstances, hydro generation on the YIS must be supplemented by thermal generation.

2.3.2 Diesel and LNG Thermal Generation

Yukon Energy's annual thermal generation costs for the 2021 test year are based on the forecast total firm generation requirement less LTA hydro and IPP generation (as updated with the latest information) for the forecast firm generation load.

Table 2.2 shows LTA thermal generation for 2018 as approved at 16.4 GW.h based on the forecast load of 420 GW.h, versus LTA thermal generation of 31.4 GW.h based on actual 2018 firm load of 450 GW.h. Table 2.2 also shows actual (as opposed to LTA) diesel and natural gas thermal generation for 2018, highlighting the extent to which unfavourable water conditions (and the related lower than LTA hydro generation) resulted in actual thermal generation at 37.3 GW.h being well above LTA thermal.

Table 2.2 shows 2019 LTA thermal generation of 25.3 GW.h based on the actual firm load, and full year LTA thermal generation forecast for 2020 at 69.0 GW.h. Like 2018, Table 2.2 also shows the extent to which unfavourable water conditions (and the related lower than LTA hydro generation) in 2019 resulted in actual thermal generation at 69.9 GW.h being well above LTA thermal; in contrast, the 2020 full year actual thermal generation forecast is expected to be at 71.2 GW.h, which is close to the LTA thermal at 69.0 GW.h.

The forecast 2021 LTA thermal generation for the Application is 84.3 GW.h. The forecast for the test year is based on proposed updates to the determination of LTA annual hydro availability for the current GRA as outlined in Appendix 2.1, including the following:[10]

- Yukon Energy now has more water year records compared to 2017/18 GRA [38 water years, from 1981 to 2018, compared to 35 water years, 1981 to 2015, used in 2017/18 GRA]. This added information has tended to increase LTA hydro estimates.

- Updated reservoir and generation station water flow requirements changes, including 10-year average for Aishihik Lake spring water levels to reflect water years as noted above, and Mayo GS winter outflow restrictions[11] as well as changes to the Whitehorse GS max winter flows.[12]

- Updated load curve reflecting changes to monthly sales related to material changes in industrial load shape and/or volumes, including added Victoria Gold, Minto and Alexco loads.

- Loads to reflect added IPPs as well as impact from Whitehorse unit #2 and unit #4 uprates.[13]

It is assumed in the Application that 90% of LTA thermal generation requirements as forecast for the test years will be met by liquified natural gas (LNG), with the balance (10%) supplied by diesel generation. This ratio was used in the 2017/18 GRA and confirmed to be reasonable ratio for the 2021 test year based on actual results for 2018 and 2019. As illustrated in Table 2.2, the actual LNG generation was about 81% of the total thermal generation in 2018 and 95% in 2019 (numbers slightly inflate diesel share due to inclusion of thermal generation for capital projects and RFID, i.e., LNG share was 83% of net thermal generation excluding capital and RFID loads in 2018 and 97% in 2019). Higher LNG generation numbers in 2019 reflect water conditions below LTA. For the 2020 full year forecast actual

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[10] See Appendix 2.1 for more detailed review of the updated LTA hydro determinations and related expected LTA thermal generation requirements at various grid loads with updates in Table 2.1-1 to reflect changes in industrial load shape/ volume as well as grid generation capabilities; information on additional water years was also included given the other updates required.

[11] Based on new Mayo Ice Protocol to address downstream flooding concerns, Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA].

[12] In 2019, Yukon Energy was able to increase Whitehorse GS winter max flows to 170 cms with better monitoring of the ice issues. Yukon Energy is planning to use 170 cms winter max flows for Whitehorse GS compared to 160 cms used in 2017/18 GRA.

[13] The determination of LTA thermal generation also reflects IPPs and expected incremental hydraulic generation from WH2 and WH4 uprate projects. Please see Appendix 2.1 for details on how these are reflected in determination of LTA thermal for the test year.

LNG is forecast to be about 74% of the total thermal due to colder-than-normal weather (specifically January 2020 was colder than normal weather) that resulted in high loads with diesel generation being required to supply baseload energy as LNG units were running at max output. For the 2021 test year actual LNG is currently expected to be about 90% of the total thermal due to increased load offset by favourable water conditions. YEC has no reason to believe there should be a change at this time to the 90% LNG/10% diesel for the thermal split purposes under LTA water conditions.

In addition to the thermal generation forecast to supply required firm loads, YEC is including in its forecast expenses in this Application (see Tab 3) forecast thermal unit operation for maintenance when there is no firm generation load that requires thermal generation. These requirements exist separate from the LTA thermal requirements as estimated above and in Table 2.2. To ensure proper maintenance and increase reliability, the diesel and LNG units need to be run at certain times solely for maintenance purposes, especially during summer months. In these circumstances the fuel requirements for electricity generated for maintenance will be part of the operating expense requirements (but not part of the LTA generation requirements to supply customers as shown in Table 2.2) included as part of the revenue requirement. See Section 3.2 for further details and forecasts of thermal consumption for maintenance activities.

2.4 PEAK DEMAND FORECAST AND DEPENDABLE CAPACITY REQUIREMENT

As indicated in Table 2.2, the peak demand for the integrated system is forecast to be 112.7 MW in 2021. The actual peak demand was 93.0 MW in 2018, 90.0 MW in 2019 and 103.8 MW in 2020.

At these forecast peak levels for the test year (which exceed reliable winter hydro dependable generating capacity of approximately 70.5 MW),[14] thermal generation will be required to supply firm energy demand.

Yukon Energy included an extensive review of its system capacity planning criteria in the 2006 Resource Plan. New criteria were adopted in 2006 for Yukon capacity planning purposes on the Whitehorse – Aishihik – Faro (WAF) and Mayo-Dawson (MD) grids which were not connected at that time. The new criteria required that dependable winter capacity on each hydro grid be sufficient to meet both of the following requirements:

[14] This reflects 37 MW at Aishihik, 6.5 MW at Mayo and 27 MW at Whitehorse. The Mayo GS dependable capacity has been reduced from 9 MW assumed in the 2017-18 GRA to reflect updated winter downstream flow restrictions and Whitehorse GS increased from 24.5 MW to 27 MW to reflect increased winter max flows.

- **Loss of Load Expectation (LOLE)** – In 2006, Yukon Energy incorporated into its capacity planning criteria a probability-based measure to evaluate the maximum loads that the WAF system can safely carry by identifying the potential interruption of service for any customer (forecast of the average number of system outages per year). The LOLE criterion also recognizes the role of transmission reliability, where relevant.[15] In 2006, the system-wide capacity planning criteria for WAF and MD provided that each system would be planned not to exceed a Loss of Load Expectation of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment.

- **Emergency (or "N-1") Standard** – The capacity planning review in 2006 also recognized that the LOLE function is an average that does not indicate how long any particular outage will last, or the potential severity of consequences for customers. To address the severity of a potential outage, Yukon Energy incorporated a second test – the N-1 standard which determines system capacity assuming the loss of the system's single largest generating or transmission-related generation resource. This standard does not include industrial loads as part of the assessment. It ensures there is sufficient grid generation installed to meet firm residential and commercial customers' loads when a failure occurs to the single largest system component.[16]

The 2006 Resource Plan noted that, absent industrial loads, the single contingency (N-1) criterion for the WAF grid was at that time setting a higher dependable capacity requirement than the LOLE criterion. It was also noted that the LOLE criterion could in future become determinative on WAF with sufficient added load (e.g., with sufficient industrial load connected to the WAF grid).

In 2011, as part of the five-year update to the 2006 Resource Plan, Yukon Energy reviewed the capability of the new system (including the integration of WAF and MD grids, and the completion of Mayo B), focusing on the question of whether the 2 hours/year loss of load expectation planning target, measured using the existing software and modeling approach,[17] continued to be appropriate for the updated and integrated grid system. This review confirmed that the previous approach used for WAF was reasonable

[15] The WAF system had substantial hydro generation availability that is directly affected by certain transmission; the WAF system also had been trending to an increasing probability of longer outages as it expanded (particularly with expansion of residential and commercial loads and major reductions in industrial load). Yukon Energy therefore incorporated the LOLE approach, with recognition of transmission reliability where relevant, into its system planning criteria to better protect all of its firm customers from generation-related outages.

[16] In 2006, it was noted that for WAF the single most critical system component is the Aishihik transmission line and the largest single potential loss of supply (at that time) would be 30 MW due to loss of transmission line from Aishihik to Whitehorse. Under this standard, each integrated system (WAF and MD) was planned in 2006 to be able to carry the forecast peak winter loads under the largest single contingency (known as the N-1), excluding major industrial loads which typically maintain sufficient on-site generation for their own emergency purposes.

[17] For example, the analysis included consideration of the Aishihik transmission line in overall generation adequacy assessment, but not other specific transmission lines.

for the integrated system, subject to the 25 km line L172 between Takhini and Whitehorse being appropriately reinforced within the next few years so as to provide no line constraint through this line segment. Yukon Energy subsequently proceeded to reinforce this segment as needed to address this concern.[18]

The 2016 Resource Plan and the subsequent 2017-18 GRA indicated that the existing hydro and diesel infrastructure did not meet the single contingency (N-1) capacity planning criterion in 2017 and 2018 test years at the forecast grid loads (at the forecast industrial load, the LOLE criterion was satisfied in each test year so long as the single contingency [N-1] criterion was met).[19]

The forecast dependable capacity based on the single contingency (N-1) criterion is forecast to be about 1.25 MW in excess of the forecast non-industrial winter peak for 2021, as outlined below:

- Installed YEC and AEY dependable grid capacity for the winter peak in 2021, based on existing capacity today and any planned additions/retirements and excluding Fish Lake hydro, is 139.1 MW in 2021 (70.5 MW of YEC hydro, 12.6 MW YEC LNG, 23.5 MW of YEC diesel, 5.6 MW of AEY diesel and plus 27 MW[20] diesel from rented diesel units in order to meet the N-1 criterion assessment).[21]

- For the single contingency (N-1) criterion assessment of the dependable capacity, excluding Fish Lake hydro, to meet the YEC load:

    - The dependable capacity is reduced to 100.6 MW for the N-1 event for 2021 (assumes 37.0 MW at Aishihik and 1.5 MW at Haines Junction are not available at Whitehorse because of an interruption to the Aishihik transmission line with the N-1 event).

    - This remaining dependable capacity is available to meet the projected non-industrial grid winter peak load (excluding an estimated 1.3 MW at Haines Junction that is not supplied

[18] As part of the Whistle Bend Subdivision Supply project, a new 25 kV power line was constructed between the Takhini Substation and the Whistle Bend subdivision. This addition has the effect of providing a redundant supply into Whitehorse if the L170 should become unavailable.
[19] The 2011 Resource Plan updated the LOLE assessment, concluding that an industrial winter peak in excess of approximately 12 MW would be needed before the LOLE criterion superseded the N-1 criterion. The 2011 Resource Plan updates included integration of WAF and MD grids, completion of Mayo B and Aishihik Third Turbine, the updated CEA unavailability rate for the Aishihik line, and ongoing changes in the overall grid load factor (updates of unit ratings, change in load distribution). The estimate excluded 1 MW for Haines Junction peak load as N-1 capacity planning requirements exclude this peak load.
[20] 15 units at 1.8 MW for each unit to total 27 MW for 2021.
[21] Yukon Energy's 2016 Resource Plan provides details on YEC's updated generation inventory and dependable winter capacity of 114,983 kW (see Chapter 4, Table 4.1). The updates since 2016 Resource Plan include reduced Mayo GS dependable capacity to 6.5 MW due to restricted winter outflows, increased WH GS dependable capacity to 27 MW, retired WH diesel #3, added LNG 3rd engine and other changes to the dependable capacity of the existing diesel units.

by the grid under N-1) of approximately 99.4 MW in 2021 (see Table 2.2; the industrial peak at 12.0 MW in 2021 including Minto, Victoria Gold and Alexco mine loads is removed for this assessment,[22] as well as the assumed 1.3 MW peak load at Haines Junction).

- In summary, under N-1, there is surplus of dependable capacity of approximately 1.25 MW in 2021. Without rented diesel units, the N-1 capacity shortfall would be 25.75 MW in 2021.

[22] The forecast industrial peak includes Minto peak load of 3.0 MW in 2021, Victoria Gold peak load of 5.2 MW in 2021 and 3.8 MW for Alexco in 2021.

Table 2.1:
Summary of Customers, Energy Sales and Revenues

Line No.	Description	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
1	**Residential**					
2	Customers	1,635	1,689	1,730	1,756	1,780
3	Sales in MWh	13,719	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.4	9.3	8.9	9.5	9.1
5	Revenue ($000s)	2,016	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.7	14.4	14.7
7	**General Service**					
8	Customers	489	506	517	516	514
9	Sales in MWh	25,436	27,171	29,148	32,250	32,323
10	MWh sales per customer	52.0	53.7	56.4	62.5	62.9
11	Revenue ($000s)	4,054	4,490	4,833	5,351	5,388
12	Cents per KWh	15.9	16.5	16.6	16.6	16.7
13	**Industrial**					
14	Sales in MWh	32,193	36,910	27,286	64,856	102,904
15	Revenue ($000s)	3,952	4,378	3,673	7,260	11,535
16	Cents per KWh	12.3	11.9	13.5	11.2	11.2
17	**Street lights**					
18	Sales in MWh	214	224	168	168	168
19	Revenue ($000s)	56	87	82	82	82
20	Cents per KWh	26.0	39.1	48.8	48.8	48.8
21	**Space lights**					
22	Sales in MWh	12	11	10	10	10
23	Revenue ($000s)	3	3	3	3	3
24	Cents per KWh	22.5	29.2	26.7	28.1	26.6
25	**Total Company - Firm Retail & Ind.**					
26	Customers	2,125	2,195	2,247	2,272	2,293
27	Sales in MWh	71,573	79,941	71,997	114,013	151,614
28	Revenue ($000s)	10,081	11,221	10,853	15,108	19,392
29	Cents per KWh	14.1	14.0	15.1	13.3	12.8
30	**Wholesale sales**					
31	Sales in MWh	314,700	332,270	331,495	351,775	343,537
32	Revenue ($000s)	26,114	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**					
35	Sales in MWh	386,273	412,212	403,491	465,788	495,151
36	Revenue ($000s)	36,194	38,792	38,360	44,298	47,899
37	Cents per KWh	9.4	9.4	9.5	9.5	9.7
38	**Secondary**					
39	Sales in MWh	2,059	258	0	0	0
40	Revenue ($000s)	115	20	0	0	0
41	Cents per KWh	5.6	7.6	0.0	0.0	0.0
42	**Total Company**					
43	Sales in MWh	**388,332**	**412,470**	**403,492**	**465,788**	**495,151**
44	Revenue ($000s)	**36,310**	**38,812**	**38,360**	**44,298**	**47,899**
45	Cents per KWh	**9.4**	**9.4**	**9.5**	**9.5**	**9.7**
46	Rider J ($000s)	13,231	13,329	13,842	15,289	15,897
47	**Total Sales Revenues[1]**	**49,541**	**52,141**	**52,203**	**59,588**	**63,796**
48	**Total Sales Revenues excluding secondary sales**	**49,425**	**52,121**	**52,203**	**59,588**	**63,796**

Note:
1. Excludes revenues from other revenues.

1 **Table 2.2:**
2 **Summary of Energy Balance, Losses, and Peak**

Line No.	Description	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
	Sales and Losses					
1	Total Energy Sales	388,332	412,470	403,492	465,788	495,151
2	Losses - MWh	34,173	37,898	37,185	42,193	43,575
3	Losses - %	8.8%	9.2%	9.2%	9.1%	8.8%
4	Total Generation	422,506	450,368	440,676	507,980	538,726
5	Secondary Sales Related Generation	2,241	282	0	0	0
6	Firm Load Generation	420,265	450,086	440,676	507,980	538,726
	Actual Generation - MWh					
	Hydro Generation					
7	Whitehorse	218,266	228,695	233,673	263,231	259,116
8	Aishihik	116,503	126,748	97,293	118,792	176,165
9	Mayo	76,628	57,610	39,853	54,703	71,201
10	Total Hydro	411,397	413,052	370,819	436,725	506,483
11	**Wind Turbine**	0	0	0	0	0
12	**IPPs**	0	0	0	56	1,983
	Diesel Generation[1]					
13	Whitehorse	1,000	5,518	2,188	13,848	1,870
14	Faro	234	302	802	889	237
15	Dawson	521	1,279	720	2,936	823
16	Mayo	18	87	84	748	21
17	Total Diesel	1,772	7,186	3,793	18,422	2,951
18	**LNG Generation**[1]	9,337	30,130	66,065	52,778	27,309
19	**Total Thermal**[1]	11,109	37,316	69,858	71,199	30,260
	Source - %					
20	**Hydro Generation**	97.4%	91.7%	84.1%	86.0%	94.0%
21	**LNG Generation**	2.2%	6.7%	15.0%	10.4%	5.1%
22	**Diesel Generation**	0.4%	1.6%	0.9%	3.6%	0.5%
23	**IPP Generation**	0.0%	0.0%	0.0%	0.0%	0.4%
	LTA Generation - MWh					
24	**LTA Hydro Generation**	403,910	418,695	415,377	438,905	452,437
25	**LTA Wind Generation**	0	0	0	0	0
26	**IPP Generation**	0	0	0	56	1,983
27	**LTA Thermal Generation**	16,355	31,391	25,300	69,019	84,306
28	**Total LTA Generation**	420,265	450,086	440,676	507,980	538,726
	Peak - MW[2]					
29	**Integrated System**	92.9	93.0	90.0	103.8	112.7

Notes:
1 Actual thermal generation reflects actual generation required for maintenance, capital, RFID and all other generation, e.g., peaking. Forecast Actual Generation includes peaking, maintenance (diesel of 0.198 GW.h in 2021, and LNG of 0 MW.h) and capital (0.234 GW.h diesel) requirements reflecting short-term hydro generation forecasts.
3 2 Peak load is one-hour maximum load on the grid (forecasts assume weather normalized temperature).

APPENDIX 2.1
LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS

APPENDIX 2.1: LONG-TERM AVERAGE THERMAL GENERATION CALCULATIONS

As per previous Board directives, Yukon Energy's GRA revenue requirement annual thermal generation costs for test years are based on long-term average (LTA) hydro generation (rather than forecasts of actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2021 GRA test year, hydro and thermal generation forecasts are based on LTA water supply for hydro generation as updated with the latest information.

The determination of LTA annual hydro availability is adjusted as required in each GRA to address material changes in LTA hydro system capability due to changes in loads, installed capacity, licensing/permits or other factors.

The forecast 2021 LTA thermal generation for the Application is 84.3 GW.h, based on the Table 2.1-1 developed to determine annual expected YEC thermal generation based on long-term average YEC hydro generation at YEC 2021 forecast grid loads (net of expected IPPs and expected Fish Lake generation) ranging from 475 to 585 GW.h/year. The forecast for the test year is based on the following proposed updates to the determination of LTA annual hydro availability for the current GRA:

a) Yukon Energy now has more water year records compared to 2017/18 GRA [38 water years, from 1981 to 2018, compared to 35 water years, 1981 to 2015, used in 2017/18 GRA]. This added information has tended to increase LTA hydro estimates.

b) Updated reservoir and generation station water flow requirements changes, including 10-year average for Aishihik Lake spring water levels to reflect water years as noted above, and Mayo GS winter outflow restrictions[1] as well as changes to the Whitehorse GS max winter flows.[2]

c) Updated load curve reflecting changes to monthly sales related to material changes in industrial load shape and/or volumes, including added Victoria Gold, Minto and Alexco industrial loads.

d) Loads to reflect added IPPs as well as impact from Whitehorse unit #2 and unit #4 uprates.[3]

[1] Based on new Mayo Ice Protocol to address downstream flooding concerns, Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which time restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA].
[2] In 2019, Yukon Energy was able to increase Whitehorse GS winter max flows to 170 cms with better monitoring of the ice issues. Yukon Energy is planning to use 170 cms winter max flows for Whitehorse GS compared to 160 cms used in 2017/18 GRA.
[3] The determination of LTA thermal generation also reflects IPPs [0.06 GW.h in 2020 and 2.0 GW.h in 2021] and expected incremental hydraulic generation from WH2 and WH4 uprate projects [half year impact for 2021 at 4.2 GW.h].

Table 2.1-1:
Expected Thermal Generation Based on Long-Term Average Hydro Generation (2021)

Line Number	YEC Grid Load Net of Wind (GWh)	YEC Hydro Generation (GWh)	YEC Thermal Generation (GWh)	Increase in Load (GWh)	Increase in Thermal Generation (GWh)	Thermal as % of Increased Load
	Column A	Column B	Column C	Column D	Column E	Column F = E/D
1	475.0	433.735	41.265			
2	480.0	435.293	44.707	5.0	3.441	69%
3	485.0	436.810	48.190	5.0	3.484	70%
4	490.0	438.277	51.723	5.0	3.532	71%
5	495.0	439.690	55.310	5.0	3.587	72%
6	500.0	441.043	58.957	5.0	3.647	73%
7	505.0	442.334	62.666	5.0	3.710	74%
8	510.0	443.557	66.443	5.0	3.776	76%
9	515.0	444.713	70.287	5.0	3.844	77%
10	520.0	445.800	74.200	5.0	3.913	78%
11	525.0	446.819	78.181	5.0	3.982	80%
12	530.0	447.769	82.231	5.0	4.049	81%
13	535.0	448.654	86.346	5.0	4.115	82%
14	540.0	449.477	90.523	5.0	4.177	84%
15	545.0	450.242	94.758	5.0	4.235	85%
16	550.0	450.954	99.046	5.0	4.288	86%
17	555.0	451.618	103.382	5.0	4.335	87%
18	560.0	452.243	107.757	5.0	4.375	88%
19	565.0	452.836	112.164	5.0	4.407	88%
20	570.0	453.406	116.594	5.0	4.430	89%
21	575.0	453.963	121.037	5.0	4.443	89%
22	580.0	454.519	125.481	5.0	4.444	89%
23	585.0	455.085	129.915	5.0	4.434	89%

Notes:
1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and Fish Lake hydro generation. The load will also be adjusted for WH2 and WH4 uprates as noted in #7 below.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from “YECSIM” - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 38 "water years" on record (1981-2018) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA]. The model aslo assumes Whitehorse GS winter max flows at 170 cms compared to 160 cms in 2017/18 GRA.
5. The simulation model results are based on 2021 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.
6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 585 GW.h and minimum YEC Grid Load at 475 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.
7. YEC is undertaking capital projects that will increase hydro generation output in Whitehorse GS [WH2 and WH4 uprates]. The preliminary estimates show that these capital projects will increase generation output by 7.1 GW.h/year [4.2 GW.h for 2021 considering expected in service date effective July 1, 2021 - monthly allocation based on Whitehorse GS monthly generation forecast]. Therefore, the YEC Grid Load is reduced to reflect increased output from these capital projects [not all incremental generation will directly displace LTA thermal].
8. Numbers are subject to rounding.

Example
Expected YEC Thermal Generation for the YEC generation at 536.743 GW.h (net of expected IPP & Fish Lake)
Remove Expected Generation for WH uprates [estimate for 2021 at 4.213 GW.h] to get net load at 532.530 GW.h

Step 1. Find the closest load from Column A that is less than 532.530 GW.h = 530 GW.h (Line 12).
Step 2. Find the thermal generation from Column C = 82.231 GW.h (Line 12).
Step 3. Find the difference between the given load (532.530 GW.h) and load from Step 1 (530 GW.h) = 2.530 GW.h
Step 4. Apply the percentage from Column F (Line 12, 82%) to the difference from Step 3 (2.530 GW.h) = 2.075 GW.h
Step 5. Add numbers from Step 2 (82.231 GW.h) and Step 4 (2.075 GW.h) = 84.306 GW.h

The expected thermal generation at 536.743 GW.h load [net of Fish Lake and IPPs] is 84.306 GW.h.

TAB 3
REVENUE REQUIREMENT

3.0 REVENUE REQUIREMENT

Yukon Energy's forecast revenue requirement is the total forecast cost of providing service in a given year, including a fair return on equity. As set out in Tab 4, this revenue requirement is recovered from the proposed firm rates charged to Yukon Energy's retail customers, industrial customers and wholesale customers, as well as other Yukon Energy revenues.

The following items are reviewed in this tab:

- Overview;
- Fuel and Purchased Power;
- Non-Fuel Operating and Maintenance Expenses;
- Rate Base, Depreciation and Amortization;
- Return on Rate Base (Interest Costs and ROE); and
- Stabilization Mechanisms.

3.1 OVERVIEW

This Tab summarizes the revenue requirement for Yukon Energy for the 2021 test year, as well as comparative figures for 2018 and 2019 actuals, and 2020 full year forecast [reflects January-June preliminary actuals and July-December forecasts].

There are three major components to Yukon Energy's 2021 revenue requirement:

- Operating and maintenance expenses which includes costs related to the production and delivery of energy and administrative costs of support functions (e.g. Finance, HR, IT, etc.);
- Depreciation and amortization of property plant and equipment and deferred costs included in rate base; and
- Return on rate base to cover the costs of the utility's sources of capital (long-term debt and equity) required to finance the rate base.

Table 3.1 compares Yukon Energy's forecast 2021 revenue requirement to the Yukon Utilities Board (YUB) approved (compliance) revenue requirement for 2018 ("2018 approved"), as well as the 2018 and 2019 actuals and 2020 full year forecast. Table 3.1 also shows Yukon Energy's forecast 2021 revenue requirements without this Application ("Existing 2021"), highlighting areas where the Application involves changes to previous approved costs (e.g., approved fuel prices, depreciation rates).

Actual revenue requirement for 2018 was $52.059 million or 4.6% higher than the approved compliance filing costs of $49.794 million. 2019 actual revenue requirement was $51.302 million and forecast to increase to $59.947 million in 2020. The forecast revenue requirements proposed for 2021 in the Application is $75.135 million, which is $25.342 million higher than the 2018 approved revenue requirement. In general, Yukon Energy's forecast 2021 revenue requirements primarily reflect proposed adjustments to thermal generation requirements and fuel prices, changes to labour and non-labour costs, changes to depreciation resulting from a depreciation study, and the impact of increases in rate base relative to 2018 approved numbers, the last test year reviewed by the Board during Yukon Energy's 2017/2018 GRA application.

Table 3.1:
Yukon Energy Revenue Requirement
($000)

					Forecast	
	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Existing 2021	Proposed 2021
Fuel and Purchased Power	$ 2,677	$ 5,348	$ 6,211	$ 11,874	$ 13,153	$ 15,897
Non-Fuel Operating and Maintenance	22,125	23,497	24,559	26,903	29,074	29,430
Depreciation and Amortization	11,141	11,104	11,053	11,007	12,489	13,125
Return on Rate Base	13,850	12,110	9,480	10,163	9,448	16,682
Revenue Requirement/Revenue	$ 49,794	$ 52,059	$ 51,302	$ 59,947	$ 64,164	$ 75,135

Fuel and Purchased Power consists of generation fuel cost forecasts based on long-term average hydro generation and forecast loads, cost of fuel required for maintenance purposes and power purchased from ATCO Electric Yukon (AEY) and from Independent Power Producers (IPPs). The forecast Fuel and Purchased Power cost increases by more than four times from 2018 approved to the 2021 forecast as proposed in the Application, with a $13.220 million increase from 2018 approved to the 2021 proposed forecast. This overall increase primarily reflects higher load (see Table 2.2) as well as higher fuel prices and costs for new IPP generation (see Section 3.2 for further description).

Non-Fuel Operating and Maintenance cost is forecast to increase by 33% ($7.306 million) from 2018 approved to the 2021 forecast as proposed in the Application. The increase from 2018 to 2021 reflects higher production and labour costs, including $3.834 million costs for diesel rentals required to meet the N-1 single contingency capacity planning criteria (no diesel rental costs were included in the 2018 approved costs).

Forecast Depreciation and Amortization costs increase by 18% ($1.984 million) from 2018 approved to the 2021 forecast as proposed in the Application. The increase reflects additions to net fixed asset depreciation ($1.126 million in 2021 over 2018 approved) and increase in deferred cost amortization ($0.858 million in 2021 over 2018 approved). The proposed forecasts include a $0.6 million increase as required resulting from the depreciation study that was mandated as per Board Order 2018-10 (see Section 3.4.1 and Tab 9 for further details on the depreciation study).

The forecast Return on Rate Base increases by 20% ($2.832 million) from 2018 approved to 2021 forecast as proposed in the Application. The increase primarily reflects about 12% increase in mid-year rate base in 2021 over 2018 approved. Yukon Energy's capital structure continues to be financed with 60% long-term debt and 40% equity. The forecast 2021 average cost of long-term debt at 2.81% is 58 basis points [or 26%] higher than the 2018 approved cost at 2.23%, primarily reflecting Mayo B related debt’s higher interest with higher loads. The forecast 2021 return on equity at 8.70% remains unchanged from the 2018 approved cost.

Each of the above categories of the 2021 revenue requirement is reviewed in detail below.

3.2 FUEL AND PURCHASED POWER

Fuel and Purchased Power costs as set out in Table 3.2 for the 2021 test year increase to $15.897 million (from $2.677 million in 2018 approved), reflecting primarily both increased load and higher fuel prices, as well as added purhased power cost [$0.314 million] for Independent Power Production (IPP).

As reviewed in Section 2.3.2, Yukon Energy's annual fuel costs are based on forecast hydro and thermal generation determined on a long-term average basis. This analysis applies only to firm load requirements. The test year long-term average forecasts for hydro generation have been updated to reflect new information, and forecast long-term average thermal requirements for the test years are assumed to be supplied with a combination of 90% LNG and 10% diesel generation, the same ratio as approved in the 2018 GRA (see Section 2.3.2). As reviewed in Section 3.6, the Low Water Reserve Fund (LWRF) is assumed to address any variance between actual thermal generation and long-term average requirements caused by variations in water supply for hydro generation facilities and Rider F is assumed to address any variance in diesel or LNG delivered fuel prices from the forecast prices assumed for the Application. The proposed test year fuel costs also include requirements for maintenance.

Table 3.2:
Fuel and Purchased Power
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Fuel	$ 2,638	$ 5,295	$ 6,153	$ 11,814	$ 12,787	$ 15,530
Purchased Power	39	53	57	60	367	367
Total Fuel and Purchased Power	$ 2,677	$ 5,348	$ 6,211	$ 11,874	$ 13,153	$ 15,897

Note:
1. Fuel costs reflect long-term average thermal generation fuel costs at forecast firm loads, maintenance requirements, and forecast fuel prices.

As reviewed in Section 2.3.2 and illustrated in Table 3.2.1, forecast long-term average thermal generation is 84.3 GW.h in 2021, as compared with 16.4 GW.h in 2018 approved. Test year fuel cost for forecast long-term average thermal generation is $15.490 million in 2021 before considering forecast fuel costs for thermal maintenance activities.

Table 3.2.1:
Fuel Cost Comparison: 2018 Approved and 2021 Proposed Forecast
($000)

	2018 Approved	2021 With GRA
Load net of Fish Lake and IPPs (MW.h)	420,265	536,743
LTA Thermal Generation (MW.h)	16,355	84,306
LNG	14,720	75,875
Diesel	1,636	8,431
Fuel Prices, $/kW.h		
LNG Price	$0.1467	$0.1814
Weighted Average Diesel price	$0.2633	$0.2051
LTA Fuel Cost, $000	**$2,590**	**$15,490**
Maintennace run-ups (MW.h)		
Diesel Run-Ups	146	198
LNG Run-Ups	67	-
Total Maintenance, $000	**$48**	**$41**
Total Fuel Cost, $000	**$2,638**	**$15,530**
Total fuel cost change, $000		$12,892
Fuel cost change due to LTA thermal volume		$10,763
Fuel cost change due to fuel price change		$2,129

Forecast thermal consumption for maintenance activities applies to both LNG and diesel generation units: maintenance activities (monthly run-ups) are required for LNG units when the engines have not run for a period of at least two months; diesel run-ups are required in any one month when the engines have not run. For maintenance activities, the forecast diesel unit operation required is 0.198 GW.h in 2021 ($0.041 million).

Forecast LNG delivered price to Yukon Energy's Whitehorse thermal facility for the 2021 test year is $0.4824 per litre, which reflects the expected average delivered LNG cost. This forecast for LNG cost is based on the results of a public competitive tender process completed in late 2019 for liquefaction and shipping costs and current market price for commodity value. Yukon Energy forecasts average efficiency for LNG generation of 2.66 kW.h/litre, which is the average efficiency based on actual results for 2019. The resulting forecast LNG cost is $0.1814/kW.h. The approved 2018 LNG price was $0.1467/kW.h.

Forecast diesel delivered prices for the 2021 test year are $0.7243 per litre for Whitehorse, $0.7615 per litre for Faro, $0.7898 per litre in Dawson and $0.7696 per litre in Mayo, and reflect the most recent diesel prices for YEC as of July 1, 2020. These diesel price forecasts are lower than the 2018 approved diesel prices of $0.9163 per litre, $0.9535 per litre, $0.9818 per litre and $0.9616 per litre respectively.

Yukon Energy forecast average efficiency for diesel fuel is 3.60 kW.h/litre in Whitehorse, 3.62 kW.h/litre in Faro, 3.71 kW.h/litre in Dawson and 4.01 kW.h/litre in Mayo, and is based on averages of 2018 and 2019 actuals. The overall grid efficiency of 3.64 kW.h/litre is an increase from the 2018 GRA, where the approved average efficiency was 3.58 kW.h/litre . The average cost per kW.h of diesel for the purposes of this Application is $0.2051/kW.h in 2021 compared to $0.2633/kW.h in 2018 aproved.

Purchased power costs include power purchased by Yukon Energy from AEY at Marsh Lake Control Structure and Johnson's Crossing. Forecast cost for purchases from AEY is $0.053 million in 2021 compared to $0.039 million in 2018 approved. Purchased power costs also include forecast purchases in 2021 under the Yukon government Independent Power Production (IPP) Policy of 1.983 GW.h[1] as provided in Table 2.2. The purchase cost for the IPPs in 2021 is assumed at $0.1583/kW.h based on the latest approved thermal fuel cost for YEC in its 2017/18 GRA.[2] Total IPP purchase cost is forecast at $0.314 million for 2021.

3.3 NON-FUEL OPERATING AND MAINTENANCE EXPENSES

The total non-fuel operating and maintenance expense approved in the 2018 GRA was $22.125 million, accounting for approximately 44% of the total revenue requirement. Table 3.3 indicates a higher actual expense for 2018 at $23.497 million. Total operating and maintenance costs are forecast in the Application to increase to $29.430 million for 2021. This is a $7.306 million increase in 2021 over 2018 approved (33% increase). Table 3.3 reports labour expense as a company total; subsequently in this Tab, the labour expenses are broken out by function. In addition to the details below, more labour information is provided in Schedule 10A of Tab 7 as directed by YUB.

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[1] The forecast IPP purchases reflect two solar projects which are expected to be connected to the grid: one in November 2020 and the other one in June 2021. YEC will update IPP generation for the compliance filing if more IPP projects are committed to connect to Yukon Grid during 2021 (see Section 2.3.1).

[2] Standing Offer Program Rules, Section 4.2 (a) state that "the Base Fuel Price is to be equal to the YEC's average blended fuel price per kWh for thermal generation most recently approved by the YUB before the date on which the EPA takes effect".

Table 3.3:
Non-Fuel Operating and Maintenance Expenses
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 11,932	$ 12,083	$ 11,863	$ 12,727	$ 13,310	$ 13,310
Production	1,799	3,300	3,935	4,876	5,978	5,978
Transmission	1,419	1,058	1,304	1,403	1,394	1,394
Distribution	535	449	293	536	491	491
General O&M	1,219	1,395	1,530	1,352	1,391	1,391
Administration	3,001	3,016	3,365	3,491	3,858	3,858
Insurance and Reserve for Injuries/Damages	1,510	1,525	1,596	1,778	1,902	2,259
Property Taxes	708	671	673	739	750	750
Total OM&A (Tab 7, Schedule 10)	$ 22,125	$ 23,497	$ 24,559	$ 26,903	$ 29,074	$ 29,430

Non-labour costs are forecast to increase by $5.928 million in 2021 over 2018 approved costs. The average annual compound increase in non-labour expenses is approximately 16.51% (2021 expenses over 2018 approved) primarily due to $3.834 million costs for diesel rentals required to meet the N-1 single contingency capacity planning criteria (no diesel rental costs were included in the 2018 aprpoved costs).

An increase in labour expense makes up $1.378 million, or 19%, of the total $7.306 million increase in operating and maintenance expense forecast for 2021 over 2018 approved costs. The average annual compound increase in labour expenses is approximately 3.71% (2021 expenses over 2018 approved).

3.3.1 Labour

Total labour expenditure is made up of labour expense for maintenance and administration and capitalized labour. Capitalized labour is charged to capital projects and becomes part of revenue requirement through annual depreciation charges incurred after in service. Maintenance and administarion labour expense is charged directly to revenue requirement. Total maintenance and administration labour expense is forecast to be $13.310 million in 2021 as compared to 2018 approved costs of $11.932 million, reflecting an increase of $1.378 million.

Labour expense is generally a function of the following factors:

- **Labour Rates** – This includes factors such as base pay, benefit cost, annual increments (performance increments, cost of living adjustments), etc. This is heavily influenced by collective bargaining agreements (CBA). The last settled CBA covered fiscal periods 2017 to 2019 inclusive; the actual annual negotiated increase in base pay from 2018 to 2019 was 2.0%. To date, the CBA has not been settled for fiscal periods 2020 and 2021; an arbitration hearing is scheduled for April 2021. Forecast 2020 and 2021 labour rates include estimated economic increments of 2%; these estimates were developed by YEC management based on prior settlements.

- **Head Count** – This relates to the number of full time equivalent positions. The Yukon Energy employee complement is shown in Table 3.4.

Of the total labour expense increase from 2018 approved, approximately $0.882 million relates to additional headcount and $0.740 million relates to labour rate increases. The balance is made up of other factors impacting labour costs such as changes in overtime, vacancies and capital allocation.

Table 3.4:
Employee Complement History

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
President	4.16	5.14	4.82	4.01	4.16
First Nation Relations	-	-	-	-	1.00
Communications, Cust. Acctg.	1.00	1.00	1.00	3.10	4.60
Human Resources & Info. Mgmt.	5.25	5.27	5.34	5.32	5.25
Resource Planning and Environment	5.00	5.00	5.75	5.51	7.05
Finance, Cust. Acctg. & Purchasing	16.79	16.89	17.24	13.54	14.79
Operations	44.50	46.58	47.12	48.75	49.25
Engineering Services	15.00	13.03	15.16	15.63	15.50
Health, Safety & Environment	2.00	2.00	2.00	2.00	2.00
Total	93.70	94.91	98.44	97.86	103.60

Note:
1. The employee complement numbers are net of allocation to YDC.
2. Customer Accounting was transferred from Finance to Communications in 2020.

Table 3.4 shows that the total position count is forecast to increase by 9.90 positions since 2018 approved to 2021 test year.

At the historic staff level, employees were finding it difficult to keep pace with increased demands, more so as additional assets are added and increasing burden for planning and executing capital works. In recent years overtime hours have increased creating additional workload and adverse effect for the existing employees which in turn resulted in an increase in employee turnover. The increase in employee turnover has increased the recruiting and relocation costs for the forecast years.

There are a number of corporate factors that directly affect employee complement:

- Increasing assets;
- Strategic importance of improving First Nation and public engagement, realtionships and communications;
- Steady growth in customer accounts;
- Increased planning requriements for projects recommended through the 2020 Ten Year Renewable Electricity Plan; and
- Continuing high capital demands to maintain existing aging assets.

To combat the above issues, YEC is forecasting an increased employee complement. The increase in employee complement has resulted in a significant decrease in forecast overtime costs for 2021. Also, the increased employee complement in 2019 through 2021 is due to an effort, where possible, to do more work internally as opposed to hiring outside consultants and contractors. YEC has made a conscience effort to limit increases to only those areas where required as reviewed below.

A detailed description of the increases from 2018 approved to the forecast for 2021 is provided below.

- **First Nation Relations**: Yukon Energy operates electricity generation, transmission and distribution systems across the Yukon on the Traditional Territories of multiple Yukon First Nations. Building and maintaining strong, respectful and productive relationships with Yukon First Nations is critical to the Corporation's ongoing success. Yukon Energy's 5-Year Strategic Plan, published in 2019, confirmed the Corporation's commitment to establishing mutually beneficial and strategic partnerships with Yukon First Nations governments, through respectful and thoughtful collaboration. Specific actions were included in the 5-Year Strategic Plan to develop a framework of partnership options with First Nations, share opportunities for First Nations-owned businesses in Yukon Energy's procurement and project development activities, and create opportunities for Yukon First Nations candidates to join their team. To facilitate this process, YEC has added the following positions:

  - There is a 1.00 position increase in 2021 due to the addition of a Vice President, First Nation Relations.

- **Communications, Customer Billing/Accounting**: From 2018 approved to 2021 forecast the employee complement increases by 3.60 positions. The increase is in part due to increase in number of customers served by YEC [for example, the number of residential customers has increased by about 9% from 2018 approved]. The changes in FTE are as follows:

  - There is a 2.10 position increase in 2020 due to the transfer of the Customer Billing/Accounting division from the Finance Department (no net FTE change). This includes the Senior Office Administrator, Customer Service Representative and Meter Reader positions.

  - There is a 1.00 position increase in 2021 due to the addition of a new full-time position, Senior Communications Advisor. This position is considered necessary as the roles and responsibilities of Yukon Energy's Manager of Communications have significantly changed in the last two years; some of the key changes include increased strategic focus on public communications, the necessity of comprehensive public engagement on generation supply projects and increased demands of social media monitoring and reporting.

  - There is a 0.50 position increase in 2021 due to the change of a 0.50 FTE Meter Reader to a 1.00 FTE Meter Reader / Office Administrator. The last adjustment to the Customer Service department happened in 2017 when the role of the 0.5 FTE Customer Service Representative was changed to a 0.6 FTE Customer Service Representative. Since then, demands of the Customer Service department have increased, causing both the 0.6 FTE Customer Service Representative and 0.5 Meter Reader to work more than their allotted hours.

- **Resource Planning and Environment**: From 2018 approved to 2021 forecast the employee complement increases by 2.05 positions due to the following:

  - There is a 2.00 position increase in 2021 due to the addition of 2 new full-time positions, Senior Project Manager and Resource Planning Engineer. The Resource Planning

Engineer position is a two year term created in 2020 to assist with the backlog of planning work designated for completion. The Senior Project Manager is created in 2021 specifically to address priority initiatives recommended in the 2020 10 Year Renewable Electricity Plan.

- **Finance, Customer Billing/Accounting and Purchasing**: From 2018 approved to 2021 forecast the employee complement decreases by 2.00 positions due to the following:
  - There is a 2.10 position decrease in 2020 due to the transfer of the Customer Billing/Accounting division to the Communications Department (no net FTE change). This includes the Senior Office Administrator, Customer Service Representative and Meter Reader positions.
  - There is a 1.00 position decrease in 2020 due to the transfer of the Manager, Property and Projects to Operations (no net FTE change).
  - There is a 1.00 position increase due to the addition of a new full-time position, Procurement Administrator. There is 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, which 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 for client managers new to YEC.
- **Operations:** From 2018 approved to 2021 forecast the employee complement increases by 4.75 positions due to the following:
  - There was a 1.00 position increase in 2018 as a Distribution Technician was moved from Engineering (no net FTE change).
  - There was a 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).
  - There is a 1.00 position decrease in 2020 due to the transfer of the Manager, Property and Projects to Operations (no net FTE change).

- There is a 1.00 position increase in 2021 due to the addition of a new full-time position, Plant Operator. The plant operator compliment has not changed in over 15 years and has not kept up with the additional assets [including new hydro generation assets such as Mayo B and Aishihik 3rd Turbine, and the three LNG generation units].

- There is a 0.75 position increase due to the addition of casual and temporary, Plant Operators.

These positions are considered necessary due to increasing generation requirements (load growth), additional generation assets,[3] an effort to reduce overtime per employee and an effort to do more work internally as opposed to hiring outside consultants and contractors.

- **Engineering Services:** From 2018 approved to 2020 forecast the employee complement increases by 0.50 positions due to the following:

  - There is a 1.00 position decrease as a Distribution Technician was moved to Operations (no net FTE change).

  - There is a 1.00 position increase due to the addition of a new full-time position, Job Planner, effective July 1, 2019. This position is considered necessary to assist with increased operational responsibilities for planning resulting from implementation of new asset management processes.

  - There is a 1.00 position increase in 2020 due to the addition of a new full-time position, Electrical Engineer. This position is considered necessary 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.

  - There is a 0.50 position decrease due to the leave of an Electrical Engineer, effective July 1, 2020.

[3] Since 2011 YEC has installed an additional hydro unit at the Aishihik facility, two natural gas engines and related storage and vaporization equipment in Whitehorse and a new hydro plant in Mayo consisting of a substation and two hydro units. In 2019, a new substation was built at McQuesten and a third natural gas unit was placed into service at the Whitehorse plant.

In addition to the factors affecting labour listed above, the capital/maintenance forecast allocation also impacts the forecast labour expenses. YEC estimates the percentage of time each position will spend on capital and non-capital works. This assessment is based on past experience as well as expectations for the coming year. This allocation directly impacts the revenue requirement in any given year as maintenance charges are directly expensed while capital labour is reflected in expenses such as depreciation after the project is completed and placed into service. The 2018 approved revenue requirement forecasts included an allocation set at 17.1% capital and 82.9% maintenance. For the 2021 test year the forecast allocation is 17.6% capital and 82.4% maintenance. The ratio is based on YEC's best estimates for each employee's time to perform their job based on corporate goals and expectations.

3.3.2 Production

Costs for production consist of labour and non-labour components, excluding fuel and purchased power costs. As set out in Table 3.5, actual total production costs in 2018 at $7.755 million were higher than 2018 approved costs by $1.825 million. The actual costs for 2019 was $8.402 million and the forecast for 2020 is $9.871 million. Total production cost in 2021 is forecast at $10.909 million, an increase of $4.979 million over 2018 approved.

Table 3.5:
Production Costs
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 4,131	$ 4,455	$ 4,467	$ 4,995	$ 4,931	$ 4,931
Diesel	425	1,617	1,723	3,055	4,370	4,370
LNG	196	357	550	500	410	410
Hydro	1,093	1,229	1,435	1,210	1,082	1,082
Wind	6	-35	0	0	0	0
Operation Supervision	79	132	226	112	116	116
Total Production	$ 5,930	$ 7,755	$ 8,402	$ 9,871	$ 10,909	$ 10,909

Approximately 16% of the forecast increase in 2021 over 2018 approved for production costs is due to higher labour cost ($0.800 million increase in 2021 forecast over 2018 approved).

Non-labour production expenses are forecast to increase by $4.179 million (232%) in 2021 over 2018 approved. About $4.158 million or 99.5% of the total $4.179 million increases in non-labour expenses are due to thermal generation related expenses:

- **Diesel rentals [cost increase of $3.834 million over 2018 approved GRA]:** Costs of mobile diesels to address dependable capacity shortfalls (see Tab 2, section 2.4) is forecast to increase to $3.834 million in 2021 as compared to actual 2018 costs of $1.048 million and no costs included as part of 2018 Approved costs. Forecast mobile diesel costs are based on negotiated contracts with the vendor.

- **Consumables [production costs for LNG and Diesel, excluding diesel rentals, increase by $0.324 million]:** Increased consumables such as oil, filters and spark plugs relating to increased thermal generation resulting from low water and increased load leading to increased thermal operation.

3.3.3 Transmission

As set out in Table 3.6, total transmission costs in the 2021 test year with the Application are forecast to be $0.014 million above the approved 2018 costs of $2.054 million.

Table 3.6:
Transmission Costs
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 635	$ 526	$ 545	$ 659	$ 674	$ 674
Brushing Cost	1,161	922	1,149	1,179	1,175	1,175
Other Non-Labour	258	136	156	224	219	219
Total Transmission	$ 2,054	$ 1,585	$ 1,849	$ 2,062	$ 2,068	$ 2,068

Forecast labour costs are expected to increase $0.039 million in 2021 over 2018 approved.

Forecast non-labour costs are expected to decrease by $0.025 million in 2021 from 2018 approved mostly due to reduction in other non-labour costs. The major portion of the transmission cost variance relates to changes in the annual brushing cost requirements and changes in the allocation of brushing budgets between transmission and distribution lines. Table 3.6.1 provides further details on the brushing allocations.

Table 3.6.1:
Brushing Costs
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Transmission Brushing	$ 1,161	$ 922	$ 1,149	$ 1,179	1,175	1,175
Distribution Brushing	331	212	28	249	212	212
% Transmission	78%	81%	98%	83%	85%	85%
% Distribution	22%	19%	2%	17%	15%	15%
Net Brushing Expense	$ 1,492	$ 1,134	$ 1,176	$ 1,429	$ 1,388	$ 1,388

Total brushing costs are forecast to decrease by $0.104 million in 2021 from 2018 approved. Brushing activities are based on Yukon Energy's brushing policy and 10 year plan. Yukon Energy has had success since establishing a regular cycle as per the policy, with an overall decrease in the number of tree caused outages and an increasingly competitive bid process. Tender packages offer much higher quality information and, along with an increase in contractor familiarity with the geography and conditions of YEC lines, has resulted in positive tender results. Significant work has also been done in developing brushing specifications to be followed by contractors as well as a guideline for brushing tender evaluation. There has already been a noticeable reduction in resources required to respond to vegetation management "hot spots", a trend that is expected to continue.[4]

3.3.4 Distribution

Costs of operating and maintaining the distribution system are set out in Table 3.7.

[4] See Key Performance Indicators (KPIs) provided as Appendix 3.1.

**Table 3.7:
Distribution Costs
($000)**

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 856	$ 801	$ 625	$ 617	$ 629	$ 629
Brushing Cost	331	212	212	249	212	212
Other Non-Labour	204	236	80	287	279	279
Total Distribution	$ 1,391	$ 1,250	$ 918	$ 1,154	$ 1,120	$ 1,120

Forecast labour costs are expected to decrease by $0.227 million in 2021 from 2018 approved reflecting labour cost changes as well as functional changes noted in section 3.3.1.

Forecast non-labour costs are expected to decrease $0.044 million in 2021 from 2018 approved. The fluctuation results from changes in brushing allocations between transmission and distribution lines. Table 3.6.1 provides further details on the brushing allocations.

3.3.5 General Operation and Maintenance

Yukon Energy incurs expenses categorized as "General" with respect to transportation, communications, SCADA communications, and maintenance of company owned properties, as set out in Table 3.8.

**Table 3.8:
General Operating and Maintenance
($000)**

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 395	$ 351	$ 391	$ 343	$ 378	$ 378
Transportation	504	553	614	485	555	555
Maintenance of Company Owned Properties	508	667	762	633	598	598
SCADA Communication	207	176	154	235	238	238
Total General O&M	$ 1,615	$ 1,746	$ 1,921	$ 1,695	$ 1,770	$ 1,770

Labour costs are forecast to decrease by $0.017 million in 2020 from 2018 approved.

Total forecast costs in the non-labour General O&M categories in 2021 are $0.172 million higher than approved 2018 costs of $1.219 million. Transportation expenses are forecast to increase $0.051 million (10%) in 2021 over 2018 approved. Maintenance of Company Owned Properties is expected to increase $0.090 million (18%) in 2021 over 2018 approved. SCADA Communication expenses are forecast to increase by $0.031 million (15%) in 2021 under 2018 approved.

3.3.6 Administration

As shown in Table 3.9, Administration expense is forecast to increase $1.640 million (18%) in 2021 over 2018 approved primarily due to increase in labour costs by $0.783 million (13%) in 2021 over 2018 approved reflecting labour cost changes as well as functional changes noted in section 3.3.1. Non-labour costs are forecast to increase $0.856 million (29%) in 2021 over 2018 approved.

Table 3.9:
Administration
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 5,916	$ 5,949	$ 5,835	$ 6,113	$ 6,699	$ 6,699
Resource Planning	48	48	29	174	84	84
Communications	130	126	129	125	155	155
Customer Accounting	225	208	244	206	240	240
Environmental Mgmt	238	184	197	259	535	535
General	662	688	742	620	790	790
Information Systems	645	555	771	803	741	741
Fish Hatchery	168	158	169	200	210	210
Safety	182	210	168	168	226	226
Training	175	173	131	124	200	200
Recruitment	229	245	379	323	255	255
Board of Directors	182	246	280	274	252	252
Union	20	119	60	148	90	90
Regulatory Affairs	33	26	11	15	20	20
Material Management	37	9	31	32	32	32
Contracting	12	5	7	12	12	12
Professional Development	15	15	17	7	15	15
Total Administration	$ 8,917	$ 8,966	$ 9,201	$ 9,603	$ 10,557	$ 10,557

- The increase in Administration costs reflect ongoing cost pressusre related to recruitment, training, safety and other cost categories, including: Environmental Management expenses are forecast to increase by $0.297 million (124%) in 2021 over 2018 approved due to increased environmental monitoring activities associated with the new 3 year water license of the Aishihik Generating Station.

- General administration expenses are forecast to increase by $0.129 million (19%) in 2021 over 2018 approved primarily due to new licenses required for the new asset management software.

- Information Systems expenses are forecast to increase by $0.096 million (15%) in 2021 over 2018 approved due to increased costs for data circuits.

- Union expenses are forecast to increase by $0.070 million (350%) in 2021 over 2018 approved but is $0.029 less than 2018 actual. Fluctuations in Union expenses are due to cyclical renegotiation of the Collective Bargaining Agreement, which expired December 31, 2019.

- Board of Directors expenses are forecast to increase by $0.069 million (38%) in 2021 over 2018 approved due to additional training and increased meeting costs, as reflected in 2018 actuals.

3.3.7 Insurance and Reserve for Injuries and Damages

Yukon Energy's costs related to insurance and Reserve for Injuries and Damages (RFID) are set out in Table 3.10.

Table 3.10:
Insurance and Reserve for Injuries and Damages
($000)

					Forecast	
	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Existing 2021	Proposed 2021
Insurance	$ 1,031	$ 1,046	$ 1,117	$ 1,299	$ 1,423	$ 1,423
Reserve Appropriation (RFID)	479	479	479	479	479	835
Total	$ 1,510	$ 1,525	$ 1,596	$ 1,778	$ 1,902	$ 2,259

Note:

1. As per Board Order 2018-10, the Existing RFID amount reflects annual appropriation of $0.267 million plus amortization of the 2016 balance over a five year period [$0.212 million/year] to total $0.479 million.

2. The Proposed 2021 RFID amount reflects annual appropriation of $0.411 million (the ten-year average) plus amortization of the 2020 balance over a five year period [$0.424 million/year] to total $0.835 million.

Yukon Energy's costs for insurance in 2021 are forecast to increase by $0.392 million (38%) above approved 2018 costs of $1.031 million, and are based on the completed 2020 annual renewal process. Costs in 2020 increased due to mid-year market rate adjustments (overall rate increase of 25% on commercial package) and increased insured asset value. Costs in 2021 increase primarily due to a full year impact of the 2020 rate increase [most of the costs for the 2021 fiscal year are already locked by the insurance policy renewables in 2020 due to insurance year cycle differences from YEC's fiscal year]. The market rate increases experienced by YEC as part of 2020 renewals are consistent with peer utilities in Canada.

The RFID is an account maintained as approved by the Board, in order to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The reserve serves two purposes: (1) it allows for a balance to be struck between purchasing additional insurance vs. using a self-insurance type approach via the RFID; and (2) it allows the costs of unforeseen events to be smoothed out over a number of years to avoid rate instability for ratepayers.

As part of the 2017/18 GRA, the Board approved amortization of the 2016 negative balance of $1.059 million over a 5-year period ($0.212 million per year from 2017 through 2021) and an annual appropriation of $0.267 million per year to total annual appropriation of $0.479 million.

As shown in Table 3.11 the 10-year average of charges to the RFID increased to $0.411 million. As reviewed in Table 3.11.1 the balance of RFID by end of 2020 forecast to be $2.121 million [owing from customers]. Consistent with 2017/18 GRA approach, YEC is proposing to amortize the outstanding balance over five years [$0.424 million/year over five years] and increase annual appropriation to $0.411 million based on average for the last 10 years to total annual appropriation at $0.835 million as shown in Table 3.11.1

The ten-year history and average of actual expenses is shown in Table 3.11 below.

Table 3.11:
RFID Annual Charges Ten Year History
($000)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	10 Year Average
Annual Charges	$415	$302	$204	$404	$196	$193	$1,018	$666	$651	$62	$411

Table 3.11.1 below shows the RFID continuity schedule.

**Table 3.11.1:
RFID Continuity Schedule
($000)**

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Opening Balance	-$906	-$1,247	-$1,419	-$1,002	-$2,121	-$2,121
Annual Appropriation	479	479	479	479	479	835
Annual Costs	-267	-651	-62	-1,598	-411	-411
Closing Balance	-$694	-$1,419	-$1,002	-$2,121	-$2,053	-$1,697

The large expense in 2020 reflect works required in Whitehorse hydro generation facility penstock [about $0.730 million], Whitehorse LNG Unit #2 [$0.4 million], LNG Vapourizer [$0.3 million] and other small projects. In 2021 test year, YEC is forecasting annual costs of $0.411 million.

3.3.8 Property Taxes

Yukon Energy's property tax costs reflect payments in lieu made to the municipalities where it operates, and are shown in Table 3.12.

**Table 3.12:
Property Taxes
($000)**

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Property Taxes	$ 708	$ 671	$ 673	$ 739	$ 750	$ 750

Property taxes are forecast to increase $0.042 million in 2021 over 2018 approved, due to rate increases and valuation updates. Property taxes for 2021 remain unchanged from 2020 forecast with the exception of the City of Whitehorse, which increases 2.30% each year as per the City of Whitehorse 2019-2021 Operating Budget.

3.4 RATE BASE, DEPRECIATION AND AMORTIZATION

Yukon Energy's rate base includes investment in assets necessary to provide service to ratepayers, as well as provision for working capital necessary for day-to-day financing of the company operations. It comprises property, plant and equipment (net of depreciation), deferred study and other costs, reserves set aside for various regulatory purposes and working capital as indicated in Schedule 1 of Tab 7 of this submission. A detailed summary of the capital spending undertaken by Yukon Energy since the 2018

GRA, as well as forecast spending for 2021, is provided in Tab 5 of this Application. Table 3.13 provides Net Rate Base at mid-year as approved in 2018, actuals for 2018 and 2019, forecasts for 2020 and forecast for the 2021 test year.

Table 3.13:
Mid-Year Net Rate Base
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Year-End:						
Net plant in service[1]	$ 278,702	$ 287,713	$ 293,199	$ 303,158	$ 323,642	$ 322,649
Mid-Year:						
Net plant in service						
Before contributions	$ 445,367	$ 449,441	$ 458,678	$ 475,781	$ 498,719	$ 498,223
Less contributions	167,112	166,677	168,222	177,603	185,319	185,319
Net plant in service	278,255	282,764	290,456	298,178	313,400	312,904
Mid-year regulatory deferral[2]	3,879	3,805	3,009	2,484	2,732	2,732
Working capital	5,344	5,617	5,935	6,592	6,985	7,141
Net Rate Base	$ 287,478	$ 292,186	$ 299,399	$ 307,255	$ 323,117	$ 322,777

Notes:
[1] Net plant in service at year end is gross property, plant and equipment plus deferred study and relicensing costs, less work in progress, depreciation, amortization, customer contributions, reserve for future removal and site restoration, deferred fire gain, and disallowed assets.
[2] This reflects the regulatory deferred costs, excluding DSM and the balance of the hearing reserve account.

Yukon Energy's 2021 mid-year forecast rate base in this Application is $322.777 million (an increase of $35.3 million or 12% from 2018 approved mid-year rate base of $287.5 million).

Mid-year net plant in service before contributions, which includes unamortized deferred costs, as well as physical plant net of depreciation, is forecast to increase to $498.2 million in 2021 (a $52.9 million increase over 2018 approved mid-year balance of $445.4 million). The major increases over the 2018 approved reflects sustaining capital investments such as Mayo to McQuesten Transmission Line Upgrade, Transmission Line Refurbishment, WH2 headgate replacement, EAM purchase and implementation, Breaker Replacement Program as well as new supply options to address the capacity gap and future growth such as WH2 Uprate, WH4 Uprate and other projects as provided in Table 5.2.

Increases in net plant in service since the 2017/2018 GRA were offset partly by mid-year contributions for extensions ($185.3 million in 2021 and $167.1 million approved in 2018). New contributions since 2018 include $11.5 million from VGC Group to fund McQuesten Substation and system improvement capital costs, which contributions are being amortized over the expected 12 year life of the Eagle Gold mine.

The balance of the change in net rate base from mid-year 2018 approved to mid-year 2020 reflects increased working capital ($1.8 million increase in 2021 forecast over 2018 approved of $5.3 million).

As directed in Board Order 2018-10, Yukon Energy undertook a depreciation study in 2019. Depreciation cost changes reflect changes in the balance of assets in service as well as adjustments to depreciation arising from the depreciation study, addressed below in Section 3.4.1 and in Tab 9 of this filing. Yukon Energy's forecast proposed 2021 expense related to depreciation of capital assets and amortization of deferred charges is $13.125 million as shown in Table 3.14. Accelerated amortization of VGC Group contributions related to McQuesten Substation and system improvement costs result in these assets reducing total depreciation and amortization costs by $0.665 million in the 2021 test year.

Table 3.14:
Depreciation and Amortization
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Fixed Asset Depreciation	$ 12,196	$ 12,185	$ 12,677	$ 12,963	$ 12,945	$ 13,581
Less: Customer contribution	-5,652	-5,635	-6,237	-6,482	-5,911	-5,911
Less: Amortization of fire insurance recoveries	-262	-262	-262	-262	-262	-262
Less: Disallowed Depreciation	-204	-204	-204	-204	-204	-204
Plus: Amortization of deferred charges	5,063	5,020	5,079	4,992	5,921	5,921
Total Depreciation & Amortization	$ 11,141	$ 11,104	$ 11,053	$ 11,007	$ 12,489	$ 13,125

Notes:
1. Disallowed depreciation reflects fixed asset depreciation amounts for disallowed assets per YUB Orders: $0.004 million (YUB 1992-1), $0.012 million (YUB 2013-01) and $0.188 million (YUB 2018-10).

Forecast "Existing" fixed asset depreciation expense in 2021 of $12.945 million (as compared to $12.196 million in 2018 approved), reflects changes in the assets in service. Forecast "Proposed" fixed asset depreciation expense in 2021 of $13.581 million also reflects changes resulting from the depreciation study.

As a component of net depreciation costs, the revenue requirement includes substantial credits related to amortization of contributions (customer contributions, and other no-cost capital such as grants from

Yukon Development Corporation, Yukon Government and Federal Government). This offset has increased from $5.652 million in 2018 approved to $5.911 million forecast in 2021.[5]

Deferred charges include planning and study costs, regulatory hearing costs and licensing costs related to maintaining licenses of YEC's hydro facilities and air emission permits. The amortization of planning costs is the largest component of deferred costs, which is primarily studies of the existing system and options for expanding the quantity of renewable generation, as well as studies related to the safety and reliability of the system, and other small projects.

Forecast amortization of deferred costs is $5.921 million in 2021 [before contributions]. This includes amortization of feasibility studies ($3.568 million) amortization of regulatory costs ($0.922 million), licensing costs ($0.368 million), intangibles ($0.749 million), dam safety costs ($0.093 million) and amortization of vegetation management deferral costs ($0.222 million).

As per Order 2013-01, Yukon Energy established a hearing cost reserve account. As part of the 2017/18 GRA, the Board approved amortization of the 2016 negative balance of $0.973 million over a 5-year period ($0.195 million per year from 2017 through 2021) and an annual provision of $0.250 million per year to net annual appropriation of $0.055 million. YEC is not proposing any changes for the test year.

Table 3.14.1 shows the hearing cost reserve account continuity schedule.

Table 3.14.1:
Hearing Cost Reserve Account Continuity Schedule
($000)

					Forecast	
	2018 Approved	**Actual 2018**	**Actual 2019**	**Forecast 2020**	**Existing 2021**	**Proposed 2021**
Opening Balance	-$1,026	-$1,026	-$926	-$99	-$61	-$61
Annual Appropriation	-55	-55	-55	-55	-55	-55
Annual Costs	155	155	883	93	0	0
Closing Balance	-$926	-$926	-$99	-$61	-$116	-$116

Note:
1. As per Board Order 2018-10, the Hearing Cost Reserve Account reflects annual appropriation of $0.250 million plus amortization of the 2016 credit balance over a five year period [$0.195 million/year] to total $0.055 million.
2. The Proposed 2021 column does not include 2021 GRA hearing related costs as the costs are included in the hearing reserve after approval by the YUB and YEC does not expect the 2021 GRA hearing costs will be approved by end of 2021.

[5] This includes $1.450 million related to deferred costs.

In addition to the hearing cost reserve account, Order 2013-01 required Yukon Energy to create a vegetation management deferral account to defer brushing costs in excess of 2011 actual brushing costs. As part of the 2017/18 GRA, the Board approved amortization of the 2016 balance of $2.215 million over a 10-year period ($0.222 million per year from 2017 through 2026) and directed that deferral of these costs is no longer required. YEC is not proposing any changes for the test years. Brushing costs are detailed in Table 3.6.1. Table 3.14.2 shows the deferred vegetation management continuity schedule.

Table 3.14.2:
Deferred Vegetation Management Continuity Schedule
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Opening Balance	$1,994	$1,994	$1,772	$1,551	$1,329	$1,329
Annual Deferred Costs	0	0	0	0	0	0
Annual Amortization	-222	-222	-222	-222	-222	-222
Closing Balance	$ 1,772	$ 1,772	$ 1,551	$ 1,329	$ 1,108	$ 1,108

Yukon Energy maintains a provision for future removal and site restoration costs related to property, plant and equipment. As a result of Order 2005-12, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5.757 million. It also directs Yukon Energy to notify intervenors and interested parties when the balance of the provision reaches $2.000 million. Table 3.14.3 provides the continuity schedule of the reserve for site restoration. The costs in 2019 are for decommissioning of three Whitehorse diesel engines as well as retirement of portions of certain transmission lines.

Table 3.14.3:
Reserve for Site Restoration Continuity Schedule
($000)

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Existing 2021	Proposed 2021
Opening Balance	$4,304	$4,303	$3,963	$2,790	$2,790	$2,790
Annual Appropriation	0	0	0	0	0	0
Annual Costs	-165	-340	-1,173	0	0	0
Closing Balance	$ 4,139	$ 3,963	$ 2,790	$ 2,790	$ 2,790	$ 2,790

3.4.1 Depreciation Study

Yukon Energy has undertaken a review of its depreciation rates and provisions, using an external expert (Alliance Consulting Group). The result of this review is a significant change in the Corporation’s service lives for certain major assets. The updated Yukon Energy depreciation study is provided in Tab 9 of this filing.

Given the various factors and data available for the analysis, Yukon Energy has determined it appropriate to update its depreciation rates based on the results of the Alliance study. As set out in Schedule 3A of Tab 7, the impact of the change was an overall increase to 2021 depreciation expense by $0.6 million.[6]

3.5 RETURN ON RATE BASE (INTEREST COSTS AND ROE)

The total forecast return on Yukon Energy's mid-year net rate base for 2021 is $16.682 million as shown in Table 3.1 (see Section 3.1). This is comprised of average interest costs related to the Corporation's debt, and a fair return on shareholder equity (as discussed more fully in Tab 8).

As set out in Table 3.15, Yukon Energy seeks approval of a forecast average cost of capital of 5.17% for 2021. This reflects changes to the average interest rate on debt. Yukon Energy is not proposing a change to capital structure (60% debt and 40% equity) or return on equity (8.70%) from the approved levels in YEC's 2017/2018 GRA proceeding.

Table 3.15:
Cost of Capital

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Existing 2021	Proposed 2021
Average Cost of Debt	2.23%	2.58%	2.71%	2.92%	2.81%	2.81%
Return on Equity	8.70%	6.25%	3.81%	3.88%	3.10%	8.70%
Average Cost of Capital	4.82%	4.14%	3.17%	3.31%	2.92%	5.17%

Yukon Energy's forecast mid-year capital structure for 2021 with the Application (Proposed 2021) is comprised of $193.7 million in long-term debt and $129.1 million in common equity (see Schedule 4 of Tab 7).

3.5.1 Costs of Debt

Yukon Energy's long-term debt at the end of 2020 consists of the following components (see Schedule 11 of Tab 7):

[6] The increase largely reflect changes to some hydraulic and transmission facilities.

- Yukon Development Corporation Term Note ($66.672 million): $92.458 million original debt bearing interest at 2.40%, payable monthly with annual principal payments.

- TD Bank Interest Rate Swap ($21.554 million): bearing interest at 3.67%, payable monthly with monthly principal payments.

- Yukon Development Corporation Mayo B Promissory Note ($18.531 million): bearing interest at the maximum face interest of 5.46%, payable annually with annual principal payments, which forgives the interest expense if the Integrated Grid load is lower than Minimum Grid Load as set in Schedule 1 of the Mayo B Promissory Note; if the calculated interest expense is negative then YDC pays that amount in order to reduce the impact to ratepayers.

  If the load is in the range between Maximum Grid Load and Minimum Grid Load then interest expense is calculated as follows:

  - 5.46% * (Actual Load – Minimum Grid Load) / Range for the year.

  The increase in Grid Load from 2018 to the 2021 forecast results in increased interest for the Mayo B Promissry Note (2021 Proposed interest at $1.030 million reflects the full 5.46% interest rate, compared with 2018 Approved interest at $0.334 million which reflected interest reduced to 1.7%).

- Yukon Development Corporation Term Note ($15.948 million): $20.984 million original debt bearing interest at 2.21%, payable annually with annual principal payments.

- Yukon Development Corporation Term Note ($12.136 million): $12.136 million original debt bearing interest at 2.10%, payable monthly with no annual principal payments.

- TD Bank Interest Rate Swap ($7.858 million): $11.0 million original debt bearing interest at 2.69%, payable monthly with monthly principal payments.

- Yukon Development Corporation Term Note ($5.505 million): $5.505 million original debt bearing interest at 2.40%, payable monthly with no annual principal payments.

- TD Bank Interest Rate Swap ($6.303 million): $6.688 million original debt bearing interest at 2.899%, payable monthly with monthly principal payments.

- Yukon Development Corporation Term Note ($2.871 million): $2.871 million original debt bearing interest at 2.899%, payable monthly with no annual principal payments.

In order to maintain the 60% debt component of the capital structure as well as finance capital projects, Yukon Energy forecasts additional long-term debt of $21.210 million in 2020 and $18.135 million in 2021, at a rate of 2.19%. As per Board Order 2018-10, the interest rate is a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 0.99% as of June 30, 2020).

3.5.2 Return on Common Equity

As reviewed in Tab 8, Yukon Energy has reviewed its forecast Return on Equity (ROE) based on the methods and approach approved by the Board in Order 2018-10 following the 2017/18 GRA. As reviewed in Tab 8, Yukon Enregy's forecast return on equity for the 2021 test year is 8.70%.

The following are specifically noted regarding the basis for Yukon Energy's return on equity:

- **Low Risk Utility Benchmark:** Per Order 2018-10, the Board continues to approve use of the British Columbia Utilities Commission (BCUC) benchmark utility ROE as the base for determining the ROE for Yukon utilities. The current BCUC benchmark ROE continues to be 8.75%.

- **Risk Premium Adder for YEC:** Order 2018-10 established a 45 basis point risk premium for YEC over the BCUC benchmark ROE. A 45 basis point risk premium for YEC was considered to be fair and reasonable based on: (1) recognition of small size and principles established for AEY in Order 2017-01;[7] and (2) recognition of YEC risk related to generation, isolated grid, and customer diversity.[8] As noted in Tab 8, there are no new issues or material changes in circumstance at this time that would alter the basis for approving a risk premium of 45 basis points for Yukon Energy.

[7] 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.
[8] 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.

To reflect OIC 1995/90, Section 2, for each test year, Yukon Energy's allowed ROE is required to be set equal to the Yukon Energy fair return on common equity less 50 basis points (0.5%). Accordingly, the Yukon Energy proposed ROE in this Application for each test year is 8.70% (8.75% +0.45% - 0.50%).

3.6 STABILIZATION MECHANISMS

Yukon Energy maintains two mechanisms or deferral accounts designed to stabilize rates and revenues. These are:

- Rider F; and
- Low Water Reserve Fund (LWRF).

Yukon Energy is also proposing a new deferral account, defined benefit pension deferral account, that captures variances in forecast costs for the test year and actual costs between test years as reviewed in Section 3.6.2.

3.6.1 Rider F

The Deferred Fuel Price Variance Account (DFPVA) and Rider F are established and maintained pursuant to Order in Council 1995/90, Section 8. This account captures all variations in fuel price per litre for each actual litre consumed, compared to the most recent GRA approved fuel prices. Pursuant to Order 2005-12, Yukon Energy also credits this account with all variantions (positive and negative) in the ongoing quarterly adjustment to the prices of secondary sales, compared to the most recent GRA-approved price.

OIC 2018-220 has also amended Section 8 of Yukon Rate Policy OIC 1995/90 to replace the expression "diesel fuel" with "diesel fuel and natural gas". In Order 2018/10 the Board approved YEC's 2017/18 GRA request to incorporate references to LNG pricing in the Rider F policy, noting that it was reasonable for YEC to defer variances with respect to LNG prices to the DFPVA and to include deferred LNG price variances in the amounts collected (or refunded) to customers through Rider F. The Board also noted that the addition of a different thermal fuel was not contrary to the purpose of this deferral account, and consistent with the reasons for establishing such a deferral account.

As with the typical situation where final rates are put in place following the start of the test year, once final approvals are received for new test year fuel prices, Yukon Energy recalculates the balances in these accounts to ensure that all charges to the accounts are precisely equal to what would have occurred had the ultimate YUB approvals been know at the start of the first test year.

3.6.2 Defined Benefit Pension Deferral Account

In this Application Yukon Energy is proposing a new deferral account, defined benefit pension deferral account, that captures variances in forecast costs for the test year and actual costs between test years.

Yukon Energy sponsors an employee defined benefit pension plan for employees joining YEC before January 1, 2002.[9] The plan was inherited from AEY when YEC was under YECL management. The defined benefit pension plan for employess is regulated by the Office of the Superintendent of Financial Institutions through the *Pension Benefits Standards Act* and regulations.

Yukon Energy is required to file updated actuarial valuation reports on an annual basis with valuation reports determining the required funding for the next year. The actual contributions for the year can vary from the forecast depending on market conditions and the performance of the pension plan assets. The proposed deferral account protects both the utility and ratepayers from variances in required contributions over the amounts included in test year revenue requirement. For the 2021 test year, the defined benefits pension plan cost is $0.720 million.

Similar deferral account was approved for AEY by YUB Order 2014-06 where the YUB stated the following:[10]

> "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."

Considering the above, YEC is requesting approval of defined benefit pension plan deferral account that captures variances in contributions to the defined benefit pension plan from the the cost included in the test year revenue requirements as a result of the required annual actuarial evaluations.

3.6.3 Low Water Reserve Fund (LWRF)

The Low Water Reserve Fund (LWRF), previously called the Diesel Contingency Fund (DCF), is a long established deferral account that operates to smooth customer rate changes from thermal (diesel, LNG and other thermal) generation cost impacts caused by fluctuation of hydro or wind generation due to changes in water conditions or changes in wind conditions. The LWRF is only to be used for variations from long-term average (LTA) water and wind availability.[11] Thermal generation costs not related to changes in water or wind conditions are not included in LWRF determinations, including thermal generation costs due to equipment failure, force majeure, capital projects, or planned maintenance events. Yukon Energy manages the LWRF as a ratepayer "trust fund". The LWRF, and the prior DCF, ensures that the Fund (and utility ratepayers), rather than YEC earnings, pays for or benefits from changes to grid thermal generation due to fluctuations in grid hydro generation due to water condition changes that are beyond utility control.

LWRF determinations are made after the end of a fiscal year to address actual thermal generation cost variations from LTA water and wind availability. There are essentially two aspects to the LWRF determinations:

- **Long-Term Average (LTA) Generation Forecast** – Based on the forecast test year load, the utility needs to determine in each GRA the cost of thermal generation to include in the forecast test year revenue requirement. As approved by the Board in prior proceedings, this forecast volume of thermal generation is determined through the application of a forecast model to determine, based on long-term average (LTA) water and wind availability, how much thermal generation is required for a given load. This output is then costed using approved forecast fuel prices and efficiencies as provided in each GRA application (e.g., see section 3.2 for the current Application). After the completion of each fiscal year, when actual load is known, this same procedure is repeated for the LWRF determination of LTA thermal generation required at the actual load.

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[9] YEC makes contributions to the employees joining YEC after January 1, 2002 and employess who belonged to the defined benefit plan, but elected to opt out of that plan.
[10] YUB Order 2014-06 on AEY 2013-2015 GRA, Appendix A, pages 34 and 35.
[11] Appendix A to Board Order 2015-01, section 2.1.1.4, page 14. The Board directed as follows: "…the Board directs that the DCF fund is to be used only for variations from LTA water availability. Any application to utilize the fund in some other fashion will require the closing of the fund, the refunding of any balances to customers, and the direction for YEC to use short-term forecasts for its hydro generation in future GRAs."

- **LWRF Stabilization Mechanism** – The LWRF is a deferral account mechanism that captures variations in actual thermal generation fuel costs (at GRA approved fuel prices and efficiencies) from the thermal generation fuel costs required at LTA water and wind availability. It establishes how thermal generation costs are allocated between the utility's fuel expense on the profit and loss statement and the LWRF (as represented by the trust account on the utility's balance sheet). The stabilization mechanism does not affect determination of a GRA forecast revenue requirement; it only pertains to the allocation of thermal generation costs after the year is complete. In Yukon, the stabilization mechanism rules are contained in the LWRF Term Sheet.

For this 2021 GRA, the current Application addresses the LTA generation forecast as part of Tab 2 sales and generation forecasts (see Appendix 2.1).

The stabilization mechanism as represented by the LWRF Term Sheet as last approved in the 2017-18 GRA was provided to the Board in December 2019 along with the 2017-2018 LWRF Annual Report and Energy Reconciliation Adjustment ("ERA") filing, and acknowledged by the Board's letter of March 19, 2020. Yukon Energy acknowledges that it has been directed in Board Order 2019-08 to review and update the LWRF Term Sheet in this GRA, and to provide any further views on its risk and ratepayer risks that YEC considers relevant. Yukon Energy has been required, given COVID 19 conditions and other factors related to minimizing any bill impacts on ratepayers, to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application. Yukon Energy is working to complete and file an updated LWRF Term Sheet with the Board as soon as feasible.

APPENDIX 3.1
2017-19 KPI ANNUAL REPORT

KEY PERFORMANCE INDICATORS

YUKON ENERGY COPORATION

2017-2019

Customers, Sales, and Generation

Description	2017	2018	2019
Residential			
Customers	1,653	1,689	1,730
Sales in MWh	14,965	15,626	15,384
MWh sales per customer	9.1	9.3	8.9
General Service			
Customers	499	506	517
Sales in MWh	26,132	27,171	29,148
MWh sales per customer	52.3	52.7	56.4
Industrial			
Sales in MWh	43,419	36,910	27,286
Street lights			
Sales in MWh	228	224	168
Space lights			
Sales in MWh	12	11	10
Total Firm Retail & Ind.			
Customers	2,152	2,195	2,247
Sales in MWh	84,756	79,941	71,997
Wholesale sales			
Sales in MWh	328,427	332,270	331,495
Total Company - Firm			
Sales in MWh	413,182	412,211	403,492
Secondary			
Sales in MWh	8,385	258	0
Total Company			
Sales in MWh	421,564	412,470	403,492
Losses - MWh	33,991	38,470	37,185
Losses - %	8.1%	9.3%	9.2%
Total Generation in MWh	455,554	450,368	440,676
Generation Source			
Hydro	441,048	413,052	370,819
% of Total	96.8%	91.7%	84.1%
Diesel	4,618	7,186	3,793
% of Total	1.0%	1.6%	0.9%
LNG	9,856	30,130	66,065
% of Total	2.2%	6.7%	15.0%
Wind	32.582	0	0
% of Total	0.0%	0.0%	0.0%

Generation

Year	Capacity Factor	Unit Availability	Operating Factor	Forced Outage Rate	Planned Outage Rate
Hydro					
2017	54.4%	89.9%	66.3%	2.1%	8.0%
2018	50.9%	91.9%	61.9%	.2%	7.9%
2019	45.7%	96.2%	56.8%	0.1%	3.7%
Thermal					
2017	4.1%	95.1%	3.4%	0.6%	4.3%
2018	10.7%	87.3%	7.2%	3.4%	4.4%
2019	20.0%	65.2%	7.4%	1.4%	2.3%

Capacity Factor – Defined as the actual energy produced by the generators, divided by the maximum possible energy production in a year. This indicator ignores the fact that there may not be sufficient fuel (e.g., water or wind) to run the generation unit at its maximum for 365 days. It is useful as an indication of the utilization of the generators as useful assets, especially in terms of providing energy (kWh's). The higher the percentage the more the units are being run at closer to their maximum capacity.

Unit Availability – Defined as the actual number of hours the generators were available for use in the year, divided by the total number of hours in the years (8,760 except in a leap year). This number, expressed as a percentage, is useful in monitoring the overall reliability of the generators but does not consider whether the units were available when they were needed the most, (i.e., hydro in the summer and diesel in the winter).

Operating Factor – Defined as the hours that the generators were on-line and generating power, divided by the total number of hours in the year. It is useful in assessing the value of the generation required on the grid.

Forced Outage – Defined as the occurrence of a component failure or other condition which requires that the generation unit be removed from service immediately or up to and including the very next weekend. It represents the percentage of time that a unit is not available for operation due to an unscheduled removal from service.

Planned Outage – Defined as the removal of a generating unit from service for inspection and/or general overhaul usually scheduled well in advance. It is the overall percentage of hours less Unit Availability and Forced Outages rates.

Distribution

Reliability Performance Indicators

Year	SAIFI	SAIDI	CAIDI
2017	13.82	5.74	0.42
2018	7.59	8.37	1.10
2019	12.39	6.88	0.56

System Average Interruption Frequency Index (SAIFI) - SAIFI is the average number of interruptions per customer for the period (a year in this case). It is a measure of how many outages an "average" customer experienced throughout the year. SAIFI is calculated by taking the total number of customer interruptions divided by the total number of customers served.

System Average Interruption Duration Index (SAIDI) - SAIDI is the system average interruption duration for customers served for the period (a year in this case). It is a measure of how long all customers were affected (i.e., the last customer to be restored power). SAIDI is calculated by totalling the customer hour interruptions and dividing by the total number of customers served.

Customer Average Interruption Duration Index (CAIDI) - CAIDI is the average customer interruption duration for customers interrupted. It is a measure of how long the "average" outage lasted for the customers affected. CAIDI is the total number of customer hour interruptions divided by the total number of customer interruptions.

Cause of Interruption

Cause	2017	2018	2019
Unknown	7	0	1
Scheduled	19	12	16
Loss of Supply	4	1	3
Tree Contact	3	4	5
Lightning	3	2	9
Defective Equipment	9	10	6
Weather	10	5	24
Environment	4	0	0
Human Element	5	2	4
Foreign Interference	11	6	13
Total	**75**	**42**	**81**

Yukon Energy classifies the primary cause of its customer interruptions to match the following CEA classification codes and descriptions:

0 – Unknown/Other - Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - Scheduled Outage - Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 – Loss of Supply - Customer interruptions due to problems in the bulk electricity supply system such as under frequency load shedding, transmission system transients, or system frequency excursions.

3 – Tree Contacts - Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 – Lightning - Customer interruptions due to lightning striking the Electrical System, resulting in an insulation breakdown and/or flashover.

5 – Defective Equipment - Customer interruptions resulting from equipment failure due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 – Adverse Weather - Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 – Adverse Environment - Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 – Human Element - Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage.

9 – Foreign Interference - Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage (by others) and foreign objects.

Environmental Performance

Number of Spill Incidents

Type	**2017**	**2018**	**2019**
Petroleum Hydrocarbon Materials	2	1	1
Natural Gas	0	0	0

Health & Safety Performance

Category	**2017**	**2018**	**2019**
All Injury Frequency Rate	5.1	2.5	7.6
Lost Time Injury Frequency Rate	2.5	1.2	1.3
Lost Time Injury Severity Rate	12.7	8.7	3.8
Motor Vehicle Frequency Rate	1.1	0	0

TAB 4
RATES

4.0 RATES

This tab reviews Yukon Energy's existing rates and sets out the changes to those rates proposed in this Application. This tab consists of the following items:

- Summary of Proposed Rate Changes;
- Overview;
- Secondary Energy Rate Design;
- Major Industrial Firm Rates;
- Non-Industrial Firm Retail Rates; and
- Wholesale Rates.

4.1 SUMMARY OF PROPOSED RATE CHANGES

The key rate changes sought in this Application are:

- **Rider J – Yukon Energy Revenue Shortfall Rider** – Applicable to all YEC and ATCO Electric Yukon (AEY) firm retail rates (all AEY recoveries from this rider would flow through to YEC) and industrial rates. The existing Rider J is 22.32% for non-industrial rates and 18.67% for industrial rates. The Rider J increase to each existing Rider J to recover the Application revenue shortfalls is 15.01% for the 2021 test year. As noted below, interim refundable rates at the Rider J rate levels for retail and industrial customers are sought effective July 1, 2021.

- **Rider J – 2021 Yukon Energy Interim Revenue Shortfall Rider** – An interim refundable increase to Rider J of 10.08% starting July 1, 2021 and applicable to all YEC and AEY firm retail sales (all AEY recoveries from this rider would flow through to YEC) and industrial rates. Yukon Energy is proposing July 1, 2021 effective date for the interim rates to reduce customer bill volatility [the current Rider F rider is forecast to be reduced effective July 1, 2021, and the Rider J 10.08% is set only to offset the Rider F reduction based on estimate for a 1,000 kW.h/month residential customer consumption]. These interim rates will be replaced with final approved rates as described above. Appendix 4.1 provides the proposed interim refundable Rider J as adjusted for this increase.

The rates arising from the final order in this GRA will not be in place until late 2021, given the current timing estimates. As outlined in Section 4.5, interim refundable rates at the Rider J rate level are sought effective July 1, 2021. This approach will mean that any required "true up" for 2021 will be part of the YUB's final order setting rates arising from the Application. In order to reduce customer bill volatility, Yukon Energy is seeking approval for final 2021 test year rates to be effective by no later than December 1, 2021, i.e., this will enable coordination of these 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, or such earlier month end when the $12.557 million 2017-18 GRA shortfall has been recovered.

The Application also addresses adjustments to the Industrial Fixed Charge rate expected to be applicable to VGC Group and Alexco effective January 1, 2021 due to completion of the Mayo-McQuesten Substation transmission before the end of 2020 (see Section 4.4.2 and Appendix 4.3).

4.2 OVERVIEW

Yukon Energy's revenue earned from rates is collected from charges for firm power and for secondary (interruptible or surplus) sales when applicable. All revenues from secondary power, as an opportunity use of hydro power that would otherwise be wasted, go to lower the required level of retail rates for firm power.

The rates charged to Yukon Energy's customers for firm sales are designed to yield the revenue requirements set out in Tab 3, net of $0.369 million forecast non-rate revenues.[1] No secondary sales are forecast for 2021 due to higher loads as discussed in Tab 2.

In 2021, the revenue required from firm rates is $74.767 million compared to Yukon Energy's forecast revenues from existing firm electrical rates (including the existing Rider J) at $63.796 million.

As set out in Table 4.1, assuming the sales forecasts set out in Tab 2, the current level of existing firm rates would result in a $10.971 million rate revenue shortfall in 2021 compared to revenue requirements set out in Tab 3. This shortfall forms the basis for the proposed rate increases in this Application.

[1] Including items such as pole rentals, connection charges, and other facility rentals.

Table 4.1:
Yukon Energy Revenue Required from Rates
($000s)

	2021
Revenue Requirement	$75,135
Less: Other Revenues	$369
Less: Secondary Sales	$0
Revenue Required from Firm Rates	$74,767
Less: Revenues from Firm Sales at Existing Rates [includes Rider J]	$63,796
Additional Firm Rate Revenues Required	$10,971

4.3 SECONDARY ENERGY RATE DESIGN

No secondary sales are forecast for the 2021 test year.

When available, Yukon Energy's secondary rate offering provides interruptible power to customers of Yukon Energy or AEY who qualify under Rate Schedule 32. In order to qualify, the power must be "in excess of normal consumption and represent incremental electric usage displacing an alternative fuel source in order to provide space or process heating." The customer must have a viable alternative fuel source available to provide backup in the event of power interruptions.

The bulk of previous secondary sales in Yukon were made by AEY as retailer, with Yukon Energy selling the equivalent quantity of power on a wholesale secondary basis to AEY at the then current retail secondary power rate less 1.1 cents/kWh (per approved Wholesale Secondary Rate Schedule 32). Yukon Energy does not propose to change this relationship between wholesale and retail secondary energy rates.

4.3.1 Retail Secondary Sales Rates (Rate Schedule 32)

In 2005, the Yukon Utilities Board (YUB or the Board) approved an increase in the secondary sales rate and established an ongoing adjustment mechanism to maintain a reasonable correlation between the secondary sales rate and fuel oil prices. The secondary sales rate was set effective January 1, 2005 at 66.7% of the equivalent costs of heating with oil.[2] Yukon Energy also proposed, and the Board approved in Order 2005-12, an automatic adjustment mechanism that would adjust the rate on a quarterly basis, based on the lowest of the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for Whitehorse. In order to address fuel price related variance in income, the Rider F Deferred Fuel Price mechanism was used to normalize the secondary sales revenues and act as a natural hedge to the Rider F account, reducing variability that would otherwise be charged through the joint Yukon Energy/Yukon Electrical rate rider.

Based on the existing mechanism, the latest secondary rates are 6.1 cents per kW.h for secondary wholesale and 7.2 cents per kW.h for secondary retail.[3] The existing Rider F adjustment mechanism will continue to be applied on a quarterly basis to adjust the rate based on the lowest of the three most recent Yukon Bureau of Statistics bi-weekly furnace oil prices for Whitehorse. As reviewed in Section 2.2.4, due to higher loads no secondary sales are forecast for the 2021 test year.

4.3.2 Low Grade Ore Processing Secondary Energy (Rate Schedule 35)

The Power Purchase Agreement (PPA) with Minto Explorations included as Schedule D, Rate Schedule 35, Low Grade Ore Processing Secondary Energy Rate. As discussed during the PPA hearing process, this was a negotiated rate specific to the circumstances of the Minto mine (i.e., it may only be used for processing low grade copper ore as defined under Rate Schedule 35), interruptible and available only from surplus hydroelectricity not otherwise required by Rate Schedule 32 customers.

This rate was reviewed by the Board and intervenors during the Minto PPA hearing process, and was approved by the Board on an interim basis. The Board also noted that audit and control measures and reporting requirements must be developed between YEC and Minto, and once developed these are to be filed with the Board for approval.[4] This requirement was included in the PPA as amended May 14, 2007, which was approved by Board Order 2007-6. Accordingly, YEC cannot implement this rate until such audit and control measures and reporting requirements have been proposed by Minto, reviewed and agreed upon by Yukon Energy, and approved by the Board.

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[2] For measuring the costs of heating with oil, the calculation uses the price for oil based on the lowest of the three values cited in the biweekly Yukon bureau of Statistics measurement for Furnace Oil in Whitehorse. The efficiency assumed for the alternate heating source was 90%.
[3] The rate are effective October 1, 2020 as filed with YUB on August 31, 2020 http://yukonutilitiesboard.yk.ca/pdf/Reports/2020-10-01_SS_Rate_Advisory_Letter_to_YUB.pdf.
[4] See Board Order 2007-5.

To date, the Yukon Utilities Board prerequisites for Rate Schedule 35 have not been met.

4.4 MAJOR INDUSTRIAL FIRM RATES

Major industrial customers are defined in Order in Council (OIC) 1995/90 as being those customers "engaged in manufacturing, processing, or mining and whose peak demand for electricity exceeds 1 MW". This classification applies to the Minto, Victoria Gold and Alexco mines for 2021. No other major industrial customers are forecast to require service under Rate Schedule 39 in the test year.

Interim rate adjustments to the Fixed Charge for service to the Alexco Resource Corp. (Alexco) and the Victoria Gold Corp. and StrataGold Corporation (collectively, the VGC Group) effective January 1, 2021 will be part of a separate application as reviewed in Section 4.4.2 below.

4.4.1 Rider J Applicable to Industrial Customers

Rates for major industrial customers have been set in recent GRAs pursuant to Section 6 of OIC 1995/90, as amended by subsequent OICs (see Tab 11 for copies of OICs).

Section 6.1 of OIC 1995/90 requires the Board to ensure that rates charged to major industrial customers are sufficient to recover the cost of service to that customer class (with those costs treating all of Yukon as a single rate zone and the same rates being charged by both utilities). However, rate policy OICs since 2012 (namely, OICs 2012/68, 2014/23 and 2018/220) have required that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.[5] Section 2.1 of OICs 2012/68 and 2014/23 included provisions that outlined when this requirement would expire. OIC 2018/220 has repealed the prior expiry provisions, i.e., the provisions of Section 2.1 as currently apply require rate adjustments to apply equally, when measured as percentages, to all classes of retail and major industrial customers and this provision now does not have an expiration date.[6]

The existing Rider J rate applicable for major industrial customer rates (Rate Schedule 39) is 18.67%. In conformance with OIC 2018/220 and the Rider J increases reviewed in Table 4.2, the existing

[5] OIC 2008/149 included this direction for all classes of retail customers. OIC 2007/94 also added subsection 6(3) to OIC 1995/90 directing that the Board ensure that rates charged to major industrial customers conform the Rate Schedule 39 attached as Schedule A to the OIC. Board Orders 2011-04 and 2011-14 approved increases in Rate Schedule 39 demand and energy rates as provided for in OIC 2007/94. This OIC 2007/94 requirement (as well as the attached Schedule A) was deleted in OIC 2018/220.
[6] OIC 2018/220 replaced subsection 6(3) with the following: "Despite subsection (1), the Board must ensure that the rates charged to major industrial customers conform to Section 2.1."

Rider J applicable to Rate Schedule 39 is to be increased by 15.01% for 2021 (applicable total Rider J rate for major industrial customers rates of 33.68%). The interim refundable Rider J increase of 10.08% effective July 1, 2021 would apply to Rate Schedule 39.

4.4.2 VGC Group and Alexco Fixed Charge

Pursuant to Rate Schedule 39, a Fixed Charge is assigned to industrial customers that use the Mayo-Keno transmission facilities;[7] the Fixed Charge assigns to these customers an 85% share of annual depreciation and return cost related to these transmission facilities. The basis and premise for the Fixed Charge was initially reviewed as part of the Alexco Resource Corp Power Purchase Agreement (PPA) approved in 2011 by Order 2011-01, and confirmed in the VGC Group PPA[8] approved in 2018 by Board Order 2018-04.

Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group and for Alexco of $8,402/ month for transmission connection to the mine site,[9] subject to amendment from time to time as provided for in Section 7.7 of the VGC Group PPA, including provision for allocation of the Fixed Charge between VGC Group and Alexco in years when both customers are Major Industrial Customers of YEC.[10]

The VGC Group PPA provides for YEC to complete various facilities related to providing service to the VGC Group mine, including the McQuesten Substation, the Transmission Facilities Development to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing, and the SVC/Statcom at Stewart Crossing. Section 7.7 (b) notes that after the Transmission Facilities Development Operation Date,[11] 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. Board Order 2018-04 also directs 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).

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[7] This was established in the 2010 Alexco PPA to ensure that Alexco mine paid its share of costs for transmission facilities maintained in service to serve future industrial customers after the closure of the UKHM mine.

[8] The Power Purchase Agreement (PPA) dated November 9, 2017 between YEC, Victoria Gold Corp., and StrataGold Corporation (Victoria Gold Corp. and StrataGold Corporation are collectively, the VCG Group) for transmission connection to the mine site.

[9] The VGC Group initial Fixed Charge as determined pursuant to Section 7.7.(c)(i) of the VGC Group PPA is $100,828 per annum ($8,402/month), equal to 85% of the specified Transmission Facilities Fixed Cost of $118,621.

[10] Section 7.7 (c)(ii) of the VGC Group PPA provides that the Fixed Charge will initially be allocated between VGC Group and Alexco based on YEC's estimate of each mine's share of the Major Industrial Customer MWh load on the Transmission Facilities for the calendar year. Within 60 days of calendar year end, YEC will adjust the allocation based on each mine's actual share of the Major Industrial Customer MWh load on the Transmission Facilities.

[11] Defined as the date provided by YEC to VGC Group to confirm that the Transmission Facilities Development has been completed and is in service to deliver Grid Electricity to the Mine Facilities through the Mine Facilities Spur. The Transmission Facilities Development means any future transmission facilities developed by YEC to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing.

The Transmission Facilities Development Operation Date is forecast to occur in late November 2020/ early December 2020 when the Transmission Facilities Development comes into service, connecting the McQuesten Substation with a substation at Mayo. Yukon Energy's limited scope application to the Board to be filed when this development comes into service is described in Appendix 4.3 based on forecast costs and YEC's approved 2018 GRA cost of capital. In summary, as reviewed in Appendix 4.3, YEC expects to seek approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of $428,812, resulting in an interim Fixed Charge (85% of the Transmission Facilities Fixed Cost) effective January 1, 2021 of $35,734 per month, with allocation of the interim Fixed Charge between VCG Group and Alexco as shown in Table 4.3-2. Aside from changes related to the 2021 GRA, a final Fixed Charge for 2021 would occur after 2021 year end as required to reflect final actual Transmission Facilities Fixed Cost and the actual MWh energy sales in 2021 that occurred to VGC Group and Alexco.

The interim Fixed Charge for 2021 will also be subject to adjustment and Board review and approval as part of YEC's 2021 GRA. YEC understands that the final Transmission Facilities Fixed Cost and an adjusted Fixed Charge for VGC Group and Alexco for 2021 will be determined subsequently based on YEC's final compliance filing as approved for the 2021 GRA (including actual costs as then known for the relevant new facilities) and also based on adjustments as required after 2021 year end to reflect actual MWh loads of VGC Group and Alexco and any adjustments as needed for actual costs as then known for the relevant new facilities.

4.5 NON-INDUSTRIAL FIRM RETAIL RATES

Firm retail non-industrial rates within each non-government retail customer class (i.e., rates for residential, general service and lighting customer classes) are required by OIC 1995/90 to be equal throughout Yukon for both Yukon Energy and AEY customers, subject to allowed variation for run-off rates to reflect incremental costs that differ for different rate zones.

On October 3, 2008, the Yukon Government enacted OIC 2008/149 amending OIC 1995/90 to add immediately after Section 2 the following direction to be in effect until December 31, 2012:

> 2.1(1) the Board must ensure that rate adjustments for all retail customers apply equally, when measured as percentages, to all classes of retail customers.

Section 2.1 provided in OIC 2008/149 was replaced in April 2012 with OIC 2012/68. Insofar as it affects all classes of retail customers, this direction in effect extended the earlier Section 2.1(1) direction until December 31, 2013, and ensured that the same percentage rate adjustments will also apply to the class of major industrial customers (subject to provisions noted in Section 4.4 of this Application). OIC 2014/23 subsequently extended this OIC direction to December 31, 2018. OIC 2018/220 removed subsection 2.1(3) which established an expiry date for Section 2.1. With this change, the provisions of Section 2.1(1) currently remain in effect without any expiry date.

In accordance with OIC 2018/220, the Application proposes that the Yukon Energy revenue shortfall for 2021 as shown in Table 4.1 be recovered through increases to Revenue Shortfall Riders applied across the board to all firm retail and industrial rates of YEC and AEY in 2021. Ignoring timing for actual rate implementation (i.e., the proposed Interim Revenue Shortfall Rider and subsequent final rate riders when the proceeding is concluded), the proposed Revenue Shortfall Riders are as follows (see Section 4.4 of this Application for details regarding how these riders also apply to industrial rates):

- An across the board increase is required of 11.54% applied, on an ongoing basis, to all firm retail and industrial customer rates, including YEC Rider J and AEY Rider R (i.e., excludes customers served under Rate Schedule 32 and Rate Schedule 35, as well as Rider J1, Rider F and Rider E), assumed to have started as of January 1, 2021 as provided in Table 4.2.

- Considering that the current YEC Rider J is applied only to base rates, the required new Rider J as of January 1, 2021 would increase from the current 22.32% for non-industrial to 37.33%, and from the current 18.67% for industrial to 33.68%. The calculation of Rider J is provided in Table 4.2.

Table 4.2:
Calculation of Required 2021 Rate Increases and Rider J

Line #			Forecast 2021
1a	Consolidated Firm Retail Sales Revenues - Base Rates[1]	$000	61,574
1b	Consolidated Firm Industrial Sales Revenues - Base Rates	$000	11,535
2a	Consolidated Rider J Revenues[2]	$000	15,897
2b	AEY Rider R Revenues[3]	$000	6,068
3=1+2	**Total Consolidated Firm Sales Revenues at existing rates**	$000	95,074
4=Table 1	Retail Revenue increase required in 2021	$000	10,971
5a=4/3	Required Rate Increase on total Consolidated Revenues	%	11.54%
5b=4/(1a+1b)	Rider J Increase Required	%	15.01%
6=3+4	**Total Consolidated Firm Sales Revenues with 2021 Increase**	$000	106,045
7	Total Cumulative 2021 Rate Increase		11.54%
	Rider J Required		
8=5b	Rider J Increase Required	%	15.01%
9	Existing Rider J - non-industrial	%	22.32%
10	Existing Rider J - industrial	%	18.67%
11=8+9	Total Rider J with increases - non-industrial	%	37.33%
12=8+10	Total Rider J with increases - industrial	%	33.68%

Notes:
1. Total Consolidated Retail Revenues at existing Base Rates include revenues from YEC and AEY's residential, general service and streetlight sales.

2. Consolidated Rider J revenues at existing rates include YEC's Rider J at 22.32% for firm YEC and AEY retail sales and at 18.67% for firm industrial sales based on YUB 2019-08 Order. YEC's Rider J1 2017-18 GRA true-up rider revenues are not included (Rider J1 at 9.25% is in effect until the earlier of November 30, 2021, or at such earlier month end when the $12.557 million shortfall has been recovered).

3. AEY Rider R Revenues at existing rates include AEY's Rider R at 8.30% for firm retail and industrial base rate sales of YEC and AEY.

In order to implement rate changes, it is proposed that Rider J for 2021 of 32.40% for all firm non-industrial, and 28.75% for all firm industrial, be applied initially as of July 1, 2021 as an interim refundable rate rider, equal to a 10.08 percentage point increase in the existing Rider J rates for non-industrial and industrial rates [reflects about 67% of the total Rider J rate increase for 2021 in the current GRA]. Yukon Energy is proposing July 1, 2021 effective date for the interim rates to reduce customer bill volatility. The current Rider F rider is forecast to be reduced effective July 1, 2021, and the Rider J 10.08% is set only to offset the Rider F reduction based on estimate for a 1,000 kW.h/month residential customer consumption with Rider F assumed to approximate zero as at July 1, 2021.

This interim refundable rate rider proposal recognizes that rates arising from the final order in this GRA will not be in place until sometime in late 2021 given current timing estimates, and that any required "true-up" for 2021 will be part of the YUB's final order setting rates arising from this Application. In order to reduce customer bill volatility, Yukon Energy is seeking approval for final 2021 test year rates to be effective by no later than December 1, 2021, i.e., this will enable coordination of these 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, or such earlier month end when the $12.557 million 2017-18 GRA shortfall has been recovered.

Appendix 4.2 includes bill comparisons related to non-government residential and commercial customers, indicating how Yukon rates compare with those in other jurisdictions and impacts of the Application on monthly rate charges and bills for a residential customer using 1,000 kW.h/month and a general service customer using 2,000 kW.h/month.

Table 4.3 summarizes residential and commercial non-government bill impacts with the rate changes proposed in the Application, assuming that Rider F approximates zero effective July 1, 2021 and that the true-up Rider J1 is adjusted at December 1, 2021 from 9.25% to an estimated 4.84%.[12] In addition to the customer use levels assumed in Appendix 4.2 (1,000 kW.h/month for residential and 2,000 kW.h/month for commercial), Table 4.3 presents estimated bill impacts for average annual Yukon customer use assumed at 850 kW.h/month for residential and 3,500 kW.h per month with 15 kW demand for commercial.[13]

In summary, bill changes in Table 4.3 as at December 2021 due to the Application equal less than 0.75% of November 2020 bills for each case examined. By way of example, the bill for a residential customer using 1,000 kWh/month would remain at $204.00 per month (before subsidies, rebates and taxes) from November 2020 through November 2021 and end at $204.72 in December 2021 (the $0.72 increase in December 2021 equal a 0.35% increase over the pre-GRA November 2020 bill of $204.00).

[12] The 2017/18 true-up rider (Rider J1) of 9.25% expires after 24 months (as at November 30, 2021). The 2021 GRA true-up rider (Rider J1) that would be applied starting December 1, 2021 is estimated at 4.84% assuming a similar 24 month period for implementation. The 2021 GRA true up rider will be determined in the YEC Compliance Filing after the Board's decision on the Application.

[13] Average Yukon use levels per month (AEY and YEC combined) over the year are estimated for each customer class based on AEY and YEC filings for the most recent Phase 2 GRA proceedings in 2009.

Table 4.3:
Application Bill Impacts for Residential & Commercial Non-Government Customers

	Nov-20	Jul-21	Dec-21
Residential Non-Government, Whitehorse			
850 kWh/month consumption	$176.48	$176.70	$177.31
change from Nov 2020		*$0.22*	*$0.84*
1,000 kWh/month consumption	$204.00	$204.00	$204.72
change from Nov 2020		*-$0.00*	*$0.71*
Commercial Non-Government, Whitehorse			
2,000 kWh/month consumption [5 kW demand]	$358.84	$355.30	$356.54
change from Nov 2020		*-$3.54*	*-$2.30*
3,500 kWh/month consumption [15 kW demand]	$753.00	$755.81	$758.45
change from Nov 2020		*$2.81*	*$5.45*

Note: See Appendix 4.2 for detailed calculation for 1,000 kWh/ month residential and 2,000 kWh/month commercial bill calculations; same assumptions used for 850 kWh/ month residential and 3,500 kWh commercial bill impacts. December 31, 2021 bills include Rider F at zero and true-up Rider J1 reduced from 9.25% to 4.84%.

4.6 WHOLESALE RATES

Yukon Energy's firm rate revenues today primarily arise from the wholesale rate charged to AEY (Rate Schedule 42) plus the provision for all AEY recoveries from YEC's rate riders to flow through to YEC. Rate Schedule 42 includes a fixed Energy Charge of 8.298 cents per kW.h that applies to all wholesale primary supply to AEY by YEC, and an Energy Reconciliation Adjustment provision which is intended to adjust charges to AEY that are attributable to AEY's wholesale purchases that vary from the wholesale forecast approved for YEC's last GRA in years.

On December 6, 2017, in response to directions stemming from Board Order 2017-08, YEC filed a two-part application regarding ERA matters. The two-part application was directed in order to comply with the direction from the Yukon Court of Appeal[14] and further directions from the Board.[15] Part 1 of the two-part application requested the approval of the ERA amounts for 2013 to 2016, inclusive. Following a written process, Order 2018-05 approved the ERA amounts as submitted by YEC for 2012 to 2016 as final; and approved the amended Rate Schedule 42 attached as Appendix B to the Order.

No change in the Energy Charge or the ERA is proposed as a result of this Application.

[14] On September 12, 2017 the Court of Appeal of Yukon released a judgement on an appeal by Yukon Energy Corporation related to certain aspects of Board Order 2015-06. That judgement set aside the order of the Yukon Utilities Board (Board) related to the issues of the Diesel Contingency Fund (DCF) and the wholesale rates provision in Section 7 of Rate Policy Directive, OIC 1995/090. The Court remitted the matter back to the Board with directions "to set a wholesale rate that enables Yukon Energy to recover all of its diesel generation costs, which costs include any net payment made by Yukon Energy attributable to Yukon Electricals' above-forecast wholesale purchases of electricity."

[15] In that order, YEC was directed to file a separate two-part application. The first part of the application was to address ERA issues for the year 2012.

APPENDIX 4.1
INTERIM RIDER J

Effective: 2021/07/01
Supersedes: 2019/12/01

RIDER J

NEW INTERIM RIDER J TO INCLUDE RECOVERY OF PORTION OF 2021 YUKON ENERGY REVENUE SHORTFALL

AVAILABLE: To all electric service throughout the Yukon Territory.

APPLICABLE: To all electric service retail rates except Rate Schedule 32, Rate Schedule 35, Rate Schedule 42 and Rate Schedule 43.

RATE: Rider J at 32.40% applicable to the base rates of the following rate classes to recover the 2021 revenue shortfall. All ATCO Electric Yukon recoveries from this rider to flow through to the Yukon Energy Corporation.

Residential Non Gov.
Residential Gov
General Service Non Gov.
General Service Municipal Gov.
General Service Gov. Fed. and Terr.
Street and Sentinel Lighting

Rider J for Industrial customers at 28.75% applicable all firm sales revenues, including fixed Rider F revenues.

NOTE: Rider J does not apply to Rate Schedule 32, Rate Schedule 35, Rate Schedule 42 and Rate Schedule 43.

APPENDIX 4.2
BILL IMPACTS FOR YUKON RESIDENTIAL NON-GOVERNMENT AND GENERAL SERVICE NON-GOVERNMENT CUSTOMERS

APPENDIX 4.2: BILL IMPACTS FOR YUKON RESIDENTIAL NON-GOVERNMENT AND GENERAL SERVICE NON-GOVERNMENT CUSTOMERS

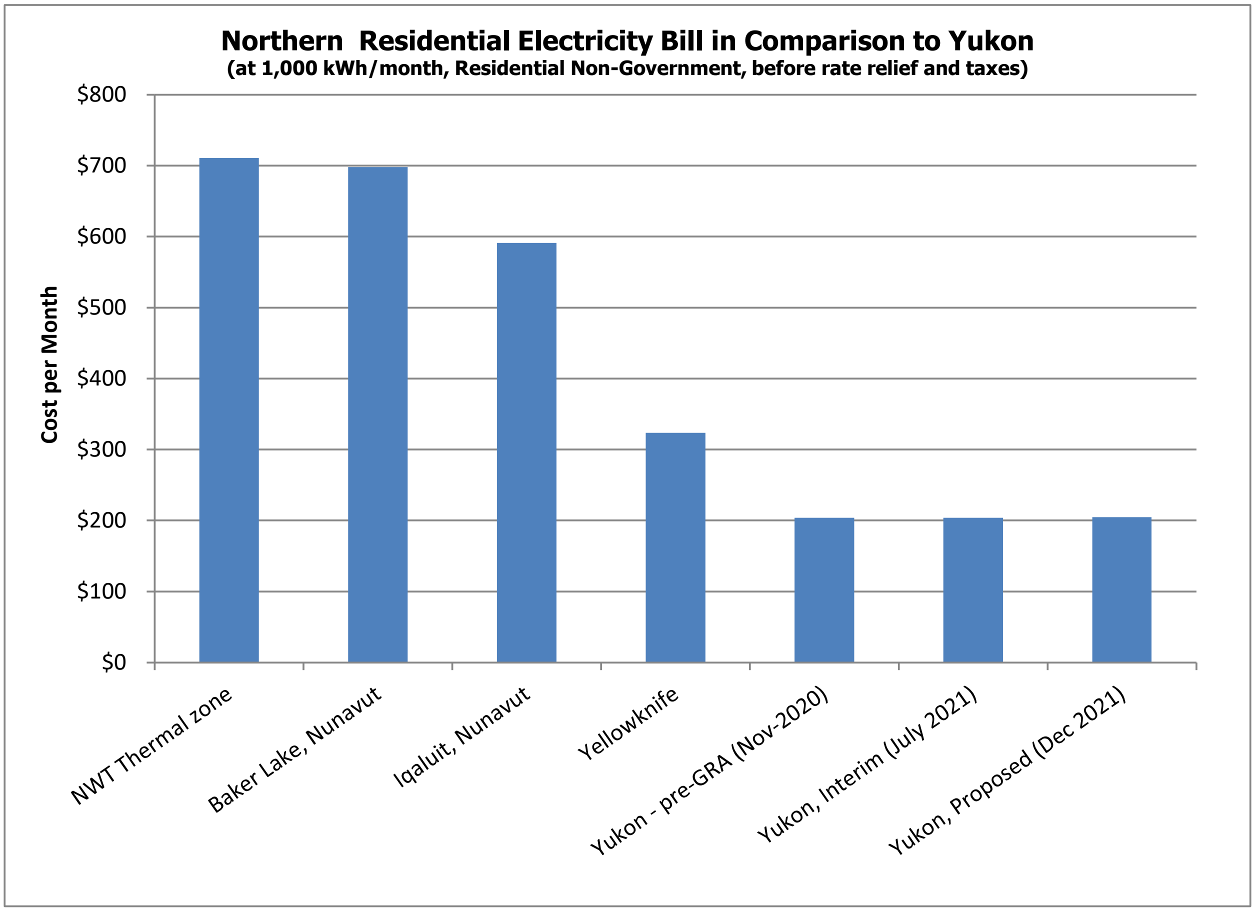
Table 4.2A-1:
Residential Electricity Bills in Comparison to Yukon
(1000 kWh/month consumption, Residential Non-Government, $)

		Monthly Bills before rate relief and taxes
1	NWT Thermal zone	$710.70
2	Baker Lake, Nunavut	$698.00
3	Iqaluit, Nunavut	$591.10
4	Yellowknife	$323.67
5	Yukon - pre-GRA (Nov-2020)	$204.00
6	Yukon, Interim (July 2021)	$204.00
7	Yukon, Proposed (Dec 2021)	$204.72
8	Toronto, ON	$188.42
9	Ottawa, ON	$173.77
10	Halifax, NS	$168.88
11	Charlottetown, PEI	$168.27
12	Regina, SK	$165.07
13	Calgary, AB	$148.31
14	Edmonton, AB	$142.93
15	St. John's, NL	$135.99
16	Moncton, NB	$134.19
17	Vancouver, BC	$115.13
18	Winnipeg, MB	$96.02
19	Montreal, QB	$72.99

Notes:

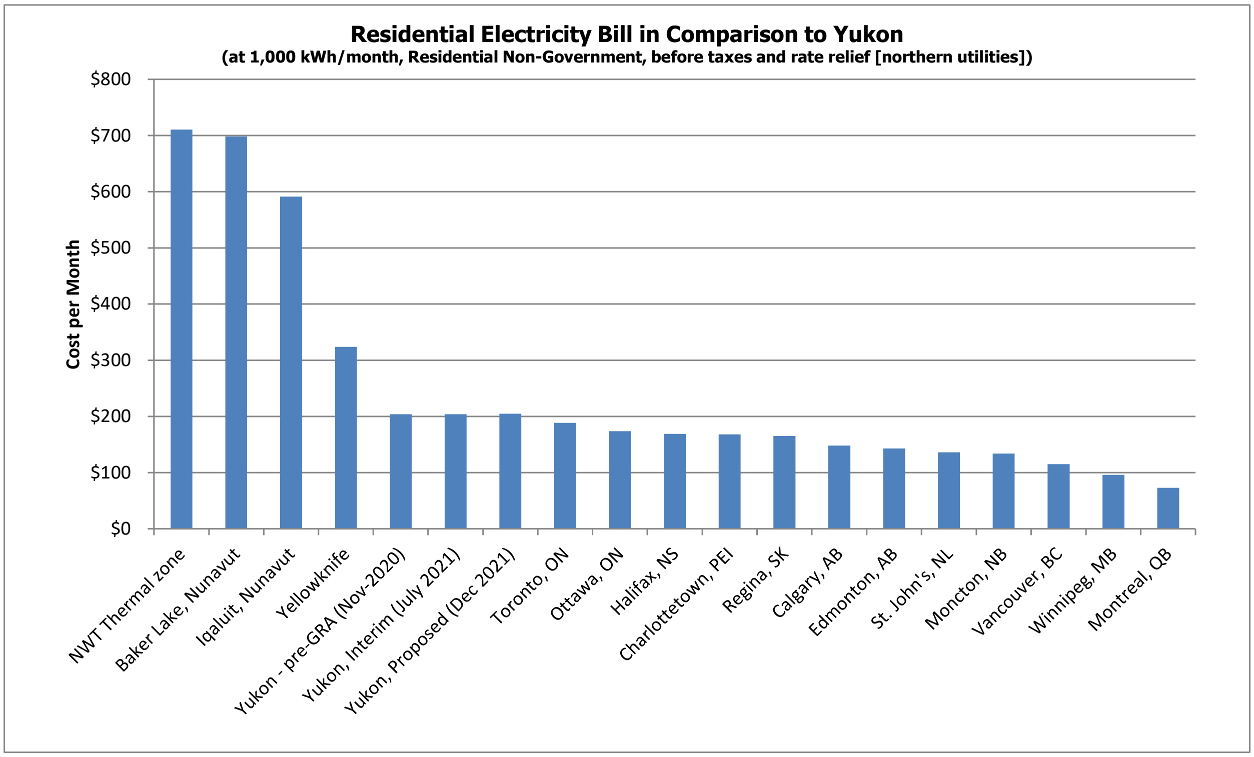
1. Monthly Bills are before taxes and rate relief [Hydro Quebec does not specify if the rate comparison includes rate relief].
2. Yukon existing bills include YEC Rider J [22.32%] and Rider J1 [9.25%], AEY Rider R [8.30%] and Rider F.
3. Yukon proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.
4. The monthly bills for Yellowknife are calculated using the rates in place in June 2019. Available at https://www.northlandutilities.com/en-ca/customer-billing-rates/bill-calculator/northland-utilities-limited-yellowknife.html [accessed on September 25, 2020].
5. The monthly bills for NWT Thermal Zone are calculated using the rates in place effective September 1, 2020. Available at https://www.ntpc.com/customer-service/residential-service/what-is-my-power-rate [accessed on September 25, 2020].
6. The monthly bills for Iqaluit and Baker Lake are calculated using the rates approved effective April 1, 2019, but also includes fuel rider refund effective October 1, 2020. Available at https://www.qec.nu.ca/customer-care/accounts-and-billing/customer-rates [accessed on September 25, 2020].
7. Bills for Toronto and Ottawa are based on Ontario Energy Board Bill Calculator. Toronto average monthly bill for 1,000 kW.h at $188.42 before taxes and rebates - calculation for Toronto Hydro-Electric System Limited tiered rate that include 12.6 c/kW.h energy rate, $58.15/month delivery charge and $4.27/month Regulatory charges; Ontario Electricity Rebate at $62.56/month is not included. Ottawa average monthly bill for 1,000 kW.h at $173.77 before taxes and rebates - calculation for Ottawa River Power Corporation tiered rate that include 12.6 c/kW.h energy rate, $43.44/month delivery charge and $4.33/month Regulatory charges; Ontario Electricity Rebate at $57.59/month is not included. https://www.oeb.ca/rates-and-your-bill/bill-calculator [accessed on October 21, 2020].
8. The monthly bills for the other cities are from Hydro Quebec's Comparison of Electricity Prices in Major North American Cities, Rates in effect April 1, 2020. Available at http://www.hydroquebec.com/data/documents-donnees/pdf/comparison-electricity-prices.pdf [accessed on October 21, 2020].

Figure 4.2A-1:[1]
Northern Residential Electricity Bill in Comparison to Yukon



[1] Please see notes to Table 4.2A-1.

Figure 4.2A-2:[2]
Residential Electricity Bill in Comparison to Yukon



[2] Please see notes to Table 4.2A-1.

Table 4.2A-2:
Small Commercial Electricity Bills in Comparison to Yukon
(2000 kWh/month consumption, Commercial Non-Government, $)

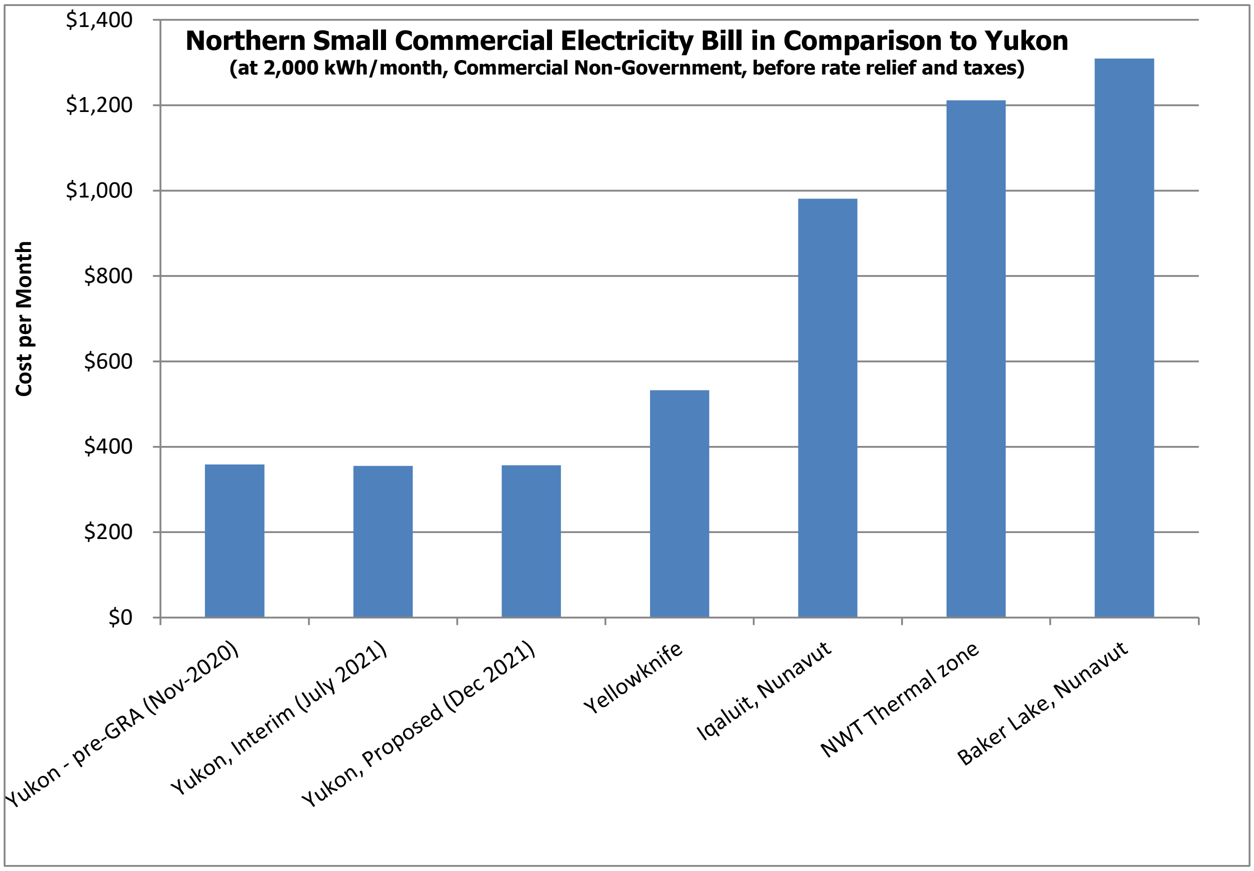
		Monthly Bills before rate relief and taxes
1	Yukon - pre-GRA (Nov-2020)	$358.84
2	Yukon, Interim (July 2021)	$355.30
3	Yukon, Proposed (Dec 2021)	$356.54
4	Yellowknife	$532.26
5	Iqaluit, Nunavut	$981.20
6	NWT Thermal zone	$1,212.00
7	Baker Lake, Nunavut	$1,310.00

Notes:

1. Monthly Bills are before Rate Relief and taxes.
2. Yukon existing bills include YEC Rider J [22.32%] and Rider J1 [9.25%], AEY Rider R [8.30%] and Rider F.
3. Yukon proposed bills assume interim Rider J increase of 10.08% effective July 1, 2021 and 4.93% Rider J increase effective December 1, 2021.
4. The monthly bills for Yellowknife are calculated using the rates in place in June 2019. Available at https://www.northlandutilities.com/en-ca/customer-billing-rates/bill-calculator/northland-utilities-limited-yellowknife.html [accessed on September 25, 2020].
5. The monthly bills for NWT Thermal Zone are calculated using the rates in place effective April 1, 2019. Available at https://www.ntpc.com/customer-service/business-service/business-rates [accessed on September 25, 2020].
6. The monthly bills for Iqaluit and Baker Lake are calculated using the rates approved effective April 1, 2019, but also includes fuel rider refund effective October 1, 2020. Available at https://www.qec.nu.ca/customer-care/accounts-and-billing/customer-rates [accessed on September 25, 2020].

Figure 4.2A-3[3]

Northern Small Commercial Electricity Bill in Comparison to Yukon



[3] Please see notes to Table 4.2A-2.

Table 4.2A-3
Yukon Bills– Existing vs. Proposed - Non-Government Residential
(prior to consideration of subsidies, rebates and taxes)

Line #	Customer Use per month: 1,000 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		YEC's 2021 GRA Jul-21		YEC's 2021 GRA Dec-21	
		Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates														
1	Customer Charge (per month)	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65	$14.65
2=KWh*Base rate	First Block Energy (kWh)	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40	$0.1214	$121.40
3=KWh*Base rate	Second Block Energy (kWh)														
4=KWh*Rider F rate	Rider F (kW.h)[Fuel Price Rider]	-$0.000110	-$0.11	-$0.000110	-$0.11	-$0.000110	-$0.11	$0.009700	$9.70	$0.013710	$13.71	$0.0	$0.00	$0.0	$0.00
5=(1+2+3)*Rider J rate	YEC Rider J (%)	16.51%	$22.46	16.51%	$22.46	22.32%	$30.37	22.32%	$30.37	22.32%	$30.37	32.40%	$44.08	37.33%	$50.78
6=(1+2+3)*Rider J1 rate	YEC Rider J1 (%)		$0.00		$0.00	9.25%	$12.58	9.25%	$12.58	9.25%	$12.58	9.25%	$12.58	4.84%	$6.59
7=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]	-$0.006800	-$6.80	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00	$0.0	$0.00
8=(1+2+3)*Rider J rate	AEY Rider J (%)		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
9=(1+2+3)*Rider R rate	AEY Rider R (%)	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29	8.30%	$11.29
10=Sum(1:9)	Total Before Tax Rebate, IER, GST		$162.89		$169.69		$190.18		$199.99		$204.00		$204.00		$204.72

Table 4.2A-4
Yukon Bills– Existing vs. Proposed - Non-Government General Service
(prior to consideration of subsidies, rebates and taxes)

Line #	First Block Energy Use - Customer Use per month:												YEC's 2021 GRA			
		2,000 kWh	Jan-18		Apr-19		Dec-19		Jan-20		Nov-20		Jul-21		Dec-21	
		5 kW														
			Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill	Rates	Bill
	Base Rates															
1	Demand Charge (per kW per month)		$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95	$7.39	$36.95
2=KWh*Base rate	First Block Energy (kWh)		$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00	$0.1000	$200.00
3=KWh*Rider F rate	Rider F (kW.h)		-$0.00011	-$0.22	-$0.00011	-$0.22	-$0.00011	-$0.22	$0.00970	$19.40	$0.01371	$27.42	$0.00000	$0.00	$0.00000	$0.00
4=(1+2)*Rider J rate	YEC Rider J (%)		16.51%	$39.12	16.51%	$39.12	22.32%	$52.89	22.32%	$52.89	22.32%	$52.89	32.40%	$76.76	37.33%	$88.44
5=(1+2)*Rider J1 rate	YEC Rider J1 (%)						9.25%	$21.92	9.25%	$21.92	9.25%	$21.92	9.25%	$21.92	4.84%	$11.48
6=KWh*Rider E rate	Rider E (kW.h) [LWRF Rider]		-$0.00680	-$13.60	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00	$0.00000	$0.00
7=(1+2)*Rider J rate	AEY Rider J (%)			$0.00		$0.00		$0.00		$0.00		$0.00		$0.00		$0.00
8=(1+2)*Rider R rate	AEY Rider R (%)		8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67	8.30%	$19.67
9=Sum(1:8)	Total Before Tax Rebate, GST			$281.92		$295.52		$331.20		$350.82		$358.84		$355.30		$356.54

APPENDIX 4.3
VGC GROUP AND ALEXCO FIXED CHARGE ADJUSTMENTS

APPENDIX 4.3: VGC GROUP AND ALEXCO FIXED CHARGE ADJUSTMENTS

Background

Pursuant to Rate Schedule 39, a Fixed Charge is assigned to industrial customers that use the Mayo-Keno transmission facilities; the Fixed Charge assigns to these customers an 85% share of annual depreciation and return cost related to these transmission facilities. The basis and premise for the Fixed Charge was initially reviewed as part of the Alexco Resource Corp (Alexco) Power Purchase Agreement (PPA) approved in 2011, and confirmed in the VGC Group PPA[1] approved in 2018 by Board Order 2018-04.

Rate Schedule 39 as currently approved includes a Fixed Charge for VGC Group and for Alexco of $8,402/month.[2] The approved VGC Group PPA includes provision for amendment of the Fixed Charge by the Yukon Utilities Board ("YUB" or "Board") and for allocation of the Fixed Charge between VGC Group and Alexco in years when both customers are Major Industrial Customers of YEC.[3]

The VGC Group PPA provides for YEC to complete various facilities related to providing service to the VGC Group mine and also other customers served by the Mayo-Keno transmission facilities, including the McQuesten Substation, the Transmission Facilities Development to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing, and the SVC/Statcom at Stewart Crossing.

Section 7.7 (b) of the VGC Group PPA notes that after the Transmission Facilities Development Operation Date,[4] 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. Board Order 2018-04 also directs 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).

[1] The Power Purchase Agreement (PPA) dated November 9, 2017 between YEC, Victoria Gold Corp., and StrataGold Corporation (Victoria Gold Corp. and StrataGold Corporation are collectively, the VCG Group) for transmission connection to the mine site.
[2] The VGC Group initial Fixed Charge as determined pursuant to Section 7.7.(c)(i) of the VGC Group PPA is $100,828 per annum ($8,402/month), equal to 85% of the specified Transmission Facilities Fixed Cost of $118,621. The Transmission Facilities Fixed Cost includes $37,222 for depreciation and $81,399 for return of 4.92% (as then forecast) on mid-year rate base forecast for 2019 of $1,654,454.
[3] Section 7.7 (c)(ii) of the VGC Group PPA provides that the Fixed Charge will initially be allocated between VGC Group and Alexco based on YEC's estimate of each mine's share of the Major Industrial Customer MWh load on the Transmission Facilities for the calendar year. Within 60 days of calendar year end, YEC will adjust the allocation based on each mine's actual share of the Major Industrial Customer MWh load on the Transmission Facilities.
[4] Defined as the date provided by YEC to VGC Group to confirm that the Transmission Facilities Development has been completed and is in service to deliver Grid Electricity to the Mine Facilities through the Mine Facilities Spur. The Transmission Facilities Development is defined as any future transmission facilities developed by YEC to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing.

Transmission Facilities Fixed Cost and Fixed Cost Charge Adjustments

The Transmission Facilities Development Operation Date is forecast to occur in late November 2020 when the Transmission Facilities Development comes into service, connecting the McQuesten Substation with a substation at Mayo. Separate from review of the 2021 GRA application, Yukon Energy is expecting to file before the end of November, 2020 a limited scope application as outlined below to establish an adjusted Fixed Charge for VGC Group and Alexco effective January 1, 2021 based on current forecast costs for the relevant facilities.[5]

Yukon Energy's limited scope application to the Board is expected to adjust, effective January 1, 2021, the Transmission Facilities Fixed Cost and the Fixed Charge based on the 2020 forecast costs for the relevant new facilities (see Table 4.3-1) and YEC's approved 2018 GRA cost of capital at 4.82%, i.e., these initial adjustments do not include any changes related to YEC's 2021 GRA proposed cost of capital. YEC understands that the final Transmission Facilities Fixed Cost and the Fixed Charge for VGC Group and Alexco for 2021 will be determined subsequently based on YEC's final compliance filing as approved for the 2021 GRA (including actual costs as then known for the relevant new facilities) and also based on adjustments as required after 2021 year end to reflect actual MWh loads of VGC Group and Alexco and any adjustments as needed for actual costs as then known for the relevant new facilities.

Table 4.3-1 provides YEC forecast year-end Transmission Facilities Fixed Costs in rate base (net costs after contributions and amortization) for 2020 to 2022. Table 4.3-1 breaks out these year end rate base costs and annual amortization costs as follows:

- **Existing Transmission Costs** (these costs are reflected in the current Fixed Cost Charge, with amortization as previously reported);
- **YEC's McQuesten Substation Costs** (these are costs that VCG Group recovered from YEC, related to YEC upgrades to accommodate 138 kV transmission if developed in the future; this work was completed in 2019, and costs are assumed to be amortized over 54 years); and
- **Transmission Facilities Development Costs and SVC/Statcom Costs** (forecast YEC net costs after federal government contributions [75% of costs] for the new transmission between Mayo and McQuesten Substation [Transmission Facilities Development Costs] that is forecast to be completed in November 2020 [added into rate base in December 2020], and forecast YEC net costs

[5] Final costs for relevant facilities are not expected to be determined for some months after the facilities are in service. Subsequent adjustments to the Fixed Charge will be required to address other factors as outlined in this Appendix 4.3, and any changes to facility costs will be addressed when relevant when other adjustments are required.

after federal government contributions [75% of costs] for the SVC/Statcom at Stewart Crossing that is forecast to be completed in November 2021 [added into rate base in December 2021]; costs for these facilities are assumed to be amortized over 65 years).

As summarized in Table 4.3-2, YEC's limited scope application that is expected to be filed in late November/early December 2020 will seek approval of an amended Transmission Facilities Fixed Cost effective January 1, 2021 of $428,812 resulting in an interim Fixed Charge (85% of the forecast Transmission Facilities Fixed Cost) effective January 1, 2021 of $35,734 per month, with allocation of the interim Fixed Charge between VCG Group and Alexco as shown in Table 4.3-2. Aside from changes related to the 2021 GRA, a final Fixed Charge for 2021 would occur after 2021 year end as required to reflect final actual Transmission Facilities Fixed Cost and the actual MWh energy sales in 2021 that occurred to VGC Group and Alexco.

This interim Fixed Cost Charge for 2021 will also be subject to adjustment and Board review and approval as part of YEC's 2021 GRA. Table 4.3-3 provides the forecast final Transmission Facilities Fixed Cost for 2021 based on the 2021 GRA proposed cost of capital (5.17%), resulting in a forecast Fixed Charge of $37,638 for 2021 with forecast allocation between VGC Group and Alexco as shown in Table 4.3-3.

Table 4.3-3 also shows the adjustment required in 2022 based on the current forecasts, assuming that the SVC/Statcom is completed in November 2021, at which time YEC will file a limited scope application to adjust the Fixed Charge effective January 1, 2022 to include the SVC/Stacom costs as shown.

Table 4.3-1:
YEC Year-End Transmission Facilities Fixed Costs in Rate Base: 2020-2022

		2020 forecast	2021 forecast	2022 forecast
	Existing Transmission net costs - based on Attachment B from VG PPA proceeding			
1	Year End Net Cost	2,244,721	2,244,721	2,244,721
2	Annual Amortization	37,222	37,222	37,222
3	Accumulated Amortization	646,100	683,322	720,544
4=1-3	Year End Net Book Value	1,598,621	1,561,399	1,524,177
5	Mid-Year Rate Base		**1,580,010**	**1,542,788**
	Total New Transmission Facilities Fixed Costs (net YEC new costs for transmission & SVC/Statcom)			
	YEC's McQuesten Substation Costs			
6	Year End Net Cost	930,563	930,563	930,563
7	Annual Amortization	17,233	17,233	17,233
8	Accumulated Amortization	17,233	34,465	51,698
9=8-6	Year End Net Book Value	913,330	896,098	878,865
10	Mid-Year Rate Base		**904,714**	**887,481**
	Transmission Facilities Development in 2020*			
11	Year End Cost	20,501,134	20,501,134	20,501,134
12	Year End Contributions	15,274,110	15,274,110	15,274,110
13=11-12	Year End Net Cost	5,227,024	5,227,024	5,227,024
14	Annual Amortization		80,416	80,416
15	Accumulated Amortization		80,416	160,832
16=13-15	Year End Net Book Value	5,227,024	5,146,608	5,066,193
17	Mid-Year Rate Base		**5,186,816**	**5,106,400**
	SVC/Statcom Costs in 2021*			
18	Year End Cost		11,200,000	11,200,000
19	Year End Contributions		8,400,000	8,400,000
20=18-19	Year End Net Cost		2,800,000	2,800,000
21	Annual Amortization			43,077
22	Accumulated Amortization			43,077
23=20-22	Year End Net Book Value		2,800,000	2,756,923
24	Mid-Year Rate Base			**2,778,462**
	Total New Transmission Facilities Fixed Costs (net YEC new costs for transmission & SVC/Statcom)			
25=10+17+24	**Mid-Year Rate Base**		**6,091,530**	**8,772,343**
26=7+14+21	**Annual Amortization**		**97,648**	**140,725**

*Transmission Facilities added to rate base in December 2020; SVC/Statcom in December 2021.

Table 4.3-2:
Adjusted YEC Annual Transmission Facilities Fixed Charge Calculation: Interim January 2021

	2021	
Existing Transmission Facilities		
Mid-year rate base	$1,580,010	Table 4.3-1, Line 5
Average Cost of Capital (approved 2018 GRA)	4.82%	
Return on Rate Base	$76,125	
Annual depreciation	$37,222	Table 4.3-1, Line 2
Subtotal existing facilities	**$113,347**	
New Transmission Facilities [net of contributions]		
Mid-year rate base	$6,091,530	Table 4.3-1, Line 25
Average Cost of Capital (approved 2018 GRA)	4.82%	
Return on Rate Base	**$293,490**	
Annual depreciation	$97,648	Table 4.3-1, Line 26
Subtotal new facilities	**$391,138**	
Total Transmission Facilities Fixed Cost (annual)	**$504,485**	
Fixed Charge at 85% of annual costs	$428,812	
Fixed Charge per month	$35,734	
Major Industrial Use of Transmission Facilities	Sales, MW.h	
Victoria Gold	43,143	
Alexco	24,061	
Monthly Fixed Charges, $/month	**2021**	
Victoria Gold	$22,940.5	
Alexco	$12,793.9	
Total	$35,734.4	

Notes:

1. See Table 4.3-1 for forecast year end net rate base and annual depreciation (amortization) for 2020 and 2021, as assumed to determine mid-year net rate base for each cost component.
2. Average Cost of Capital as approved (Board Order 2019-08) regarding final YEC Compliance Filing for 2017/18 GRA.
3. Forecast Victoria Gold and Alexco MWh loads as per YEC's 2021 GRA, Tab 2, Table 2-1.

Table 4.3-3: Adjusted YEC Annual Transmission Facilities Fixed Charge Calculation: 2021 & 2022 with YEC 2021 GRA

	2021	2022	
Existing Transmission Facilities			
Mid-year rate base	$1,580,010	$1,542,788	Table 4.3-1, Line 5
Average Cost of Capital (per 2021 GRA)	5.17%	5.17%	
Return on Rate Base	$81,660	$79,736	
Annual depreciation	$37,222	$37,222	Table 4.3-1, Line 2
Subtotal existing facilities	**$118,882**	**$116,958**	
New Transmission Facilities [net of contributions]*			
Mid-year rate base	$6,091,530	$8,772,343	Table 4.3-1, Line 25
Average Cost of Capital (per 2021 GRA)	5.17%	5.17%	
Return on Rate Base	**$314,830**	**$453,383**	
Annual depreciation	$97,648	$140,725	Table 4.3-1, Line 26
Subtotal new facilities	**$412,479**	**$594,109**	

* *Transmission Facilities added to rate base in December 2020; SVC/Statcom completed in December 2021.*

	2021	2022
Total Transmission Facilities Fixed Cost (annual)	**$531,361**	**$711,067**
Fixed Charge at 85% of annual costs	$451,657	$604,407
Fixed Charge per month	$37,638	$50,367
Major Industrial Use of Transmission Facilities	Sales, MW.h	% share
Victoria Gold	43,143	64.2%
Alexco	24,061	35.8%
Monthly Fixed Charges, $/month	**2021**	**2022**
Victoria Gold	$24,162.6	$32,334.4
Alexco	$13,475.4	$18,032.8
Total	$37,638.0	$50,367.2

Notes:

1. See Table 4.3-1 for forecast year end net rate base and annual depreciation (amortization) for 2020 and 2021, as assumed to determine mid-year net rate base for each cost component.
2. Average Cost of Capital as forecast in YEC 2021 GRA.
3. Forecast Victoria Gold and Alexco MWh loads as per YEC's 2021 GRA, Tab 2, Table 2-1.

TAB 5

CAPITAL PROJECTS

5.0 CAPITAL PROJECTS

Capital project investments in rate base are generally grouped in one of three categories: capital works on property, plant and equipment; deferred cost studies (including new supply and other feasibility studies, studies required by regulation or relicensing and dam safety works); and intangible assets. This section provides an overview of Yukon Energy's actual capital spending since the 2017/18 General Rate Application, as well as forecast capital spending for 2021.

- **Overview of Capital Spending:** Provides a summary of Yukon Energy capital spending from 2018 through 2021.

- **Capital Works:** Reviews capital spending on property, plant and equipment (PP&E). This includes a detailed discussion of the major projects over $1 million that are completed, in service and included in rate base in the test year (see Section 5.2.1). Descriptions for projects in excess of $100,000 and up to $1 million that are forecast to be completed and included in rate base from 2019 to 2021 are also provided (see Section 5.2.2). Capital projects with spending over the period from 2019 to 2021 exceeding $1 million that remain in WIP at the end of 2021 (and therefore do not affect the 2021 GRA revenue requirement) are summarized in Appendix 5.1.

- **Spending on Deferred Costs:** Reviews the capital spending on deferred cost projects (i.e., planning and study costs, regulatory and licensing activities, and dam safety reviews) for major initiatives from 2018 to 2021. Descriptions of deferred cost projects greater than $1 million that are completed and included in rate base are provided in Section 5.3.1. Descriptions of studies between $100,000 and up to $1 million that have been completed and are to be included in rate base in 2021 are provided in Section 5.3.2 and Appendix 5.4. Deferred cost projects greater than $1 million that are retained in WIP at the end of 2021 are summarized in Appendix 5.3. Deferred Studies between $100,000 and up to $1 million that remain in WIP at the end of 2021 are summarized in Appendix 5.5.

- **Spending on Intangible Assets:** Intangible asset cost projects from 2019 to 2021 that are forecast to be completed and in rate base in 2021 that are greater than $1 million are provided in Section 5.4.1, and that are between $100,000 and up to $1 million are provided in Section 5.4.2 and Appendix 5.6.

Tables 5.1 to 5.7 at the end of Tab 5 provide details of capital projects constructed since 2018 and forecasts for the 2021 test year. More specifically, Tables 5.1 and 5.2 describe investment in property, plant and equipment; Tables 5.3-5.6 describe various deferred capital projects (i.e., feasibilities studies, regulatory, relicensing, dam safety), and Table 5.7 provides the continuity schedule of intangible assets.

5.1 OVERVIEW OF CAPITAL SPENDING

Yukon Energy's capital spending from 2018 through 2021 reflects spending on sustaining capital requirements, investments specifically to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements.

- **Focus on Sustaining Capital Requirements:** Since 2017/18 GRA spending has focused on projects planned to sustain or maintain the capability of the existing grid system ("sustaining capital projects"), including a number of enhancements, repairs or improvements to existing infrastructure and intangible assets.

- **Investment to Address Capacity Planning Requirements:** The 2017/18 GRA identified the continuing need for investments to address capacity planning requirements and the 2016 Resource Plan identified a near-term dependable capacity shortfall that needs to be addressed.

- **Investment for New Supply Options or to Maximize Renewable Energy Generation from existing facilities:** The 2016 Resource Plan identified options to reduce thermal energy generation. The 2017/18 GRA identified deferred capital expenditures for planning and feasibility, relicensing and regulatory costs, including near term generation projects (such as Demand Side Management [DSM] and hydro storage enhancement projects at Mayo Lake and Marsh Lake [Southern Lakes]) and longer term renewable generation projects (e.g., hydro and wind).

Total spending on PP&E projects in the 2021 test year as shown in Table 5.1 totals $61.767 million, with 91% of this spending in major projects over $1 million ($56.266 million) and 48% ($29.801 million, Table 5.2-1) included in 2021 rate base. Total PP&E spending was $21.300 million in 2018, $31.154 million in 2019, and is forecast at $36.171 million in 2020. Overall, PP&E transfers to rate base since the end of 2018 approximate $92 million. Contributions transferred to rate base to offset some of these expenditures since the end of 2018 approximate $37 million (Table 5.1).

Deferred cost capital spending (including Work in Progress [WIP] and after contributions) was $4.3 million in 2018 (Table 5.3), $3.7 million in 2019 (Table 5.4), and is forecast at $5.4 million in 2020 (Table 5.5) and $10.5 million in 2021 (Table 5.6). The current GRA results in approximately $7.4 million of

Deferred costs being brought into rate base in the current GRA (including relevant test year spending and before transfers to the Hearing Reserve Account), with approximately $1.5 million for 2019, $4.0 million for 2020, and $1.9 million for 2021.

Actual and forecast intangible asset spending (including WIP) over 2018 to 2021 is $6.062 million, all of which is forecast to be brought into rate base by 2021, as illustrated in Table 5.7.

5.2 CAPITAL WORKS

This section reviews (a) major capital works projects (projects with total cost over $1.0 million) undertaken by YEC since the 2017/18 GRA hearing and planned for 2021; and (b) ongoing capital projects costing between $100,000 and $1 million forecast.

5.2.1 Major Projects > $1 Million – Rate Base Additions

Test year spending on major capital works projects focuses on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments on new supply options and expenditures to ensure sufficient dependable capacity for the integrated grid.

Total forecast to be added to year-end net rate base, net of contributions, for major capital works projects by the end of 2021 is approximately $47.846 million, including projects reviewed in 2017/18 GRA and closed in 2018. Each major project added to rate base is reviewed separately below (see also Tables 5.1 and 5.2 at the end of Tab 5):

- **Spending to address Capacity Planning Requirements** – Net rate base impact of approximately $11.596 million:
  - **LNG Third Engine/ Critical Spares** – actual cost of approximately $8.261 million, completed and in service in 2018, but not included in rate base approved in 2017/18 GRA.
  - **N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure** – actual cost of approximately $1.298 million, completed in 2019.
  - **N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure** – actual cost of approximately $2.037 million, completed in 2020.

- **Spending on Sustaining Capital -** Net rate base impact of approximately $22.683 million:

  - **Mayo to McQuesten Transmission Line** (MMTL) – forecast cost of approximately $31.701 million, with total contributions of $23.674 million and net rate base impact of $8.027 million; transmission line component of project will enter service in late 2020 while Stewart Crossing substation enhancements will be completed and in service in 2021.

  - **McQuesten Substation** – actual cost of approximately $11.619 million, with total contribution from VGC Group of $10.688 million; and net ratebase impact of $0.931 million. The project was completed and in service in 2019.

  - **Transmission Line Refurbishment** – actual cost of approximately $4.272 million, for work completed in 2019.

  - **WAF Line 178 Refurbishment** – forecast cost of approximately $1.300 million, for work forecast to be completed in 2021.

  - **Breaker Replacement Program** – actual cost of approximately $2.260 million with work completed and project in service 2019.

  - **Replace P125 Headgate** – forecast cost of approximately $5.893 million with work forecast to be completed and in service in 2021.

- **Capital investments on New Supply options to maximize renewable energy generation** – Net rate base impact of approximately $13.568 million:

  - **WH2 Uprate** – forecast cost of approximately $12.038 million, with work forecast to be completed and in service in 2021.

  - **WH4 Uprate (Servomotor Replacement)** – forecast cost of approximately $1.531 million, with work forecast to be completed and in service in 2021.

Business case summaries for major capital projects added to rate base in this GRA are reviewed below. Major capital projects retained in WIP at the end of 2021 with forecast costs to end of 2021 of approximately $36.7 million are reviewed in Appendix 5.1 and Table 5.2-2.

5.2.1.1 LNG Third Engine/ Critical Spares – ($3.156 million to end of 2017; $5.008 million in 2018; and $0.097 million in 2019)

The LNG Third Engine Project provides a third natural gas-fired generation unit of approximately 4.4 MW at the Whitehorse thermal plant to help address the existing dependable capacity shortfall in a cost effective manner.[1] Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service, and permanent solutions (rather than relying on temporary options such as mobile diesel) are needed to address an ongoing and growing dependable capacity shortfall.

The project was reviewed during 2017/18 GRA, with updated capital cost forecasts reviewed as part of the interrogatory process (in September 2017) and at the oral hearing (in June 2018).[2] At the time, Yukon Energy noted that a number of regulatory reviews for the project had been concluded[3] and that the design, procurement and installation of the third engine would be completed in 2017 and 2018, with in service planned for Q1 2019.

In Order 2018-10, the Board noted that the cost per MW of the third LNG engine project was favourable when compared to alternative projects and found that it was reasonable for YEC to continue with the project.[4] The Board accepted YEC's submission with respect to the N-1 capacity reliability criterion in support of the project.[5] As the project was not forecast to be in service in the 2017-2018 GRA test years and not part of rate base additions any determination on the prudency of the costs for the project was deferred until YEC applied for the project to be put into rate base.

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[1] The 2016 Resource Plan identified a dependable capacity shortfall for the YIS under its single contingency (N-1) capacity reliability criterion that approximated 6 MW in 2017, increasing to 10-11 MW by 2019. Tab 2 of the 2017/18 GRA included a forecast dependable capacity shortfall on the same basis at 5.6 MW in 2017 and 6.9 MW in 2018.

[2] In the response to YUB-YEC-1-71, YEC noted updated project costs of $8.9 million (compared to the original $6.2 million forecast costs). A $1.669 million cost increase resulted from the omission of key cost items from the original cost estimate including installation, engineering and project management and commissioning, which the owner's engineer had assumed were included in the scope of the supplier's preliminary proposal. Balance of plant costs increased by $1.372 million due to an increase in electrical installation costs and inclusion of a "General Contractor premium management of Balance of Plant contract that was omitted from the Stage gate 3 estimate". YEC owner costs increased by $0.113 million due to an increase of forecast labour and the addition of construction support costs. Contingency increased by $0.240 million due to development of a comprehensive risk-based contingency for the updated project cost estimate.

[3] The 2013/14 regulatory review (YESAB and YUB Part 3 hearing) of the LNG Plant project addressed development of up to 13.1 MW of additional thermal capacity as required to remove capacity shortfalls, with the first two LNG units (approximately 8.8 MW) installed in 2014-15 and the third LNG engine (4.4 MW) to be installed when new grid capacity was next required.

[4] Order 2018-10, paragraph 411 notes: "Mr. Maissan submitted that this project amounts to a per-MW cost of approximately $2.02 million, compared to $3.11 million per MW for a new 20 MW diesel plant, $5 million per MW for a new 20 MW LNG plant and $3.425 to 5.425 million per MW for the battery storage project. Accordingly Mr. Maissan recommended that the Board approve the third LNG engine project." Paragraph 412 notes "the Board agrees with Mr. Maissan that the cost per MW of the third LNG engine project is favourable when compared to alternative projects. Therefore, the Board finds that it is reasonable for YEC to continue with this project."

[5] Paragraph 412 of Order 2018-10.

Project Update

As noted in Table 5.2.1-1 below, the project was completed on schedule with total actual project costs for the LNG Third Engine of $8.261 million. This was below the 2017/18 forecast budget of $8.9 million.

Table 5.2.1-1: Summary of Spending by Year

	Pre-2018	Actual 2018	Actual 2019	Total
LNG Third Engine / Critical Spares	3,156	5,008	97	**8,261**

The following activities were completed in 2018:

- Most construction was completed in Q2 and Q3 2018, with the exception of minor deficiencies in Balance of Plant (BOP) works, which were completed in November 2018;
- Receipt of approval to operate the LNG engine was obtained from Yukon Government Oil and Gas Branch in November 2018;
- Testing and commissioning was completed on December 10, 2018, with engine in service on November 23, 2018;
- Performance tests were completed December 10, 2018; the tests demonstrated the LNG Engine exceeded all performance guarantees provided by the manufacturer.

The LNG engine was officially transferred to operations and has been commercially in operation since November 23, 2018.

5.2.1.2 N-1 Capacity Shortage Thermal Rental Site Infrastructure

N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure[6] ($0.227 million in WIP at end of 2018 and $1.070 million in 2019)

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximated 6 MW in 2017, increasing to 10-11 MW by 2019. Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service and to address an ongoing and growing dependable capacity shortfall.

The project involved the design of infrastructure to accommodate temporary rented thermal generators at Whitehorse substation to address the capacity shortfall projected under the N-1 for 2018/19 and 2019/20 winters.

In winter 2018/19 six temporarily rented 1.8 MW units were installed in the proximity of S150 Whitehorse Rapids Substation. The 2019 project included installation of two additional temporarily rented 1.8 MW units in the area between P126 Whitehorse Diesel and S150 Whitehorse Substation. The project scope included planning support, limited engineering design assistance, protection settings and installation support temporary seasonal diesel power generators to meet seasonal N-1 load requirements and assist with meeting winter system peaks. Total project cost was approximately $1.298 million.

N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure[7] ($2.037 million forecast in 2020)

The project involves the design and installation of temporary rental site electrical infrastructure at Faro (870S) to ensure Yukon Energy can continue to meet its N-1 capacity planning requirements.

The project scope includes engineering and design, procurement of materials, installation and construction and other internal and project management costs. Specifically, the major scopes of work include:

- Preliminary design and feasibility studies (system impact study and grounding studies); and

[6] Table 5.2-1 references this project as "N-1 Capacity Shortage Mobile Genset."
[7] Table 5.2-1 references this project as "N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure".

- Faro 870S temporary diesel generator infrastructure – design, procurement, construction and commissioning, including: civil/ structural work; 138 kV line tap and substation work; 4160V collection system; fuel system; stations service power; protection, control, communication and SCADA integration.

The project is expected to be completed in 2020 at an estimated budget of $2.037 million. The project is on track for a mid-November 2020 in service date.

5.2.1.3 Mayo – McQuesten Transmission Line Upgrade – ($0.501 million in 2019; $20.000 million forecast in 2020, offset by contribution of $15.274 million; and $11.200 million forecast in 2021, offset by contribution of $8.4 million)

The Mayo – McQuesten Transmission Line (MMTL) project involves the construction of a new 138 kW framed transmission line from the Mayo to McQuesten substations as well as the installation of electronic voltage support equipment (Statcom[8]) at Stewart Crossing South substation that will improve overall reliability and power quality in the system. The MMTP transmission will initially be operated at 69 kV.

The existing 69 kV transmission line from Mayo to Keno constructed by the Northern Canada Power Commission (NCPC) in 1951 is at end of life and in need of replacement. The transmission line has experienced both reliability and power quality issues with an increasing number of outages on the line affecting customers on a system wide basis. Key requirements under the VGC Group PPA include development of the McQuesten Substation plus new transmission to replace the existing 69 kV facilities between at least Mayo and McQuesten by approximately summer of 2020.

The initial project concept involved installation of a new 138 kW transmission line from Stewart Crossing South to Keno City.[9] The project was subsequently divided into stages – with the MMTL[10] being the first

[8] Statcom is a set of electrical devices for providing fast-acting reactive power on high voltage electricity transmission networks. They are used in two main situations: (1) connected to the power system, to regulate the transmission voltage; and (2) connected near large industrial loads, to improve power quality.
[9] This was reviewed in Section 5.3.1.1 of the 2017/18 GRA. It was noted that a decision to advance the project would be undertaken once Yukon Energy confirmed project costs and potential funding availability; and that Yukon Energy was considering options for a staged project development, with the initial stage to remove and replace deteriorated and 'end of life' transmission infrastructure between Mayo and Keno City in the event that third party funding was not available.
[10] Stage 1: design and construction of a 32 km 138 kW transmission line from Mayo to McQuesten and the design, purchase, delivery and installation of a new Statcom device at Stewart Crossing South substation.

stage of development. Later stages will proceed only when loads in the area justify increasing the operating voltage to 138 kW, and when additional federal funding becomes available.[11]

The planned project construction standard is expected to reduce outages and improve the quality of service. Design features expected to reduce outages include: increase in lightning protection with overhead shield wire; increased strength of structures and phase spacing; and increase in structural stability with use of H-frame structures in difficult terrain. Fewer line failures will also reduce reactive maintenance costs. Asset health improvements are also expected due to reduced conductor overheating. Increased power transfer/ capacity will also support economic development in central Yukon, as well as connection of renewable energy sources such as hydro, wind and solar.

The project has previously been reviewed as part of the 2017 VGC Group Power Purchase Agreement proceeding; and as part of the 2017/18 General Rate Application.

Update on Project Planning and Implementation

Effects assessment and stakeholder engagement development activities for all project stages were undertaken in 2015 and 2016. As reported during the 2017-18 GRA, all project permits were in place, including the land use permit, access permits and highway permits. No additional permitting was anticipated to be required.

Chimax was contracted in 2015 and 2016 to complete preliminary design and detailed design of the Stewart to Keno 138kV transmission line (SKTL), which included the Mayo to McQuesten Transmission line (L180). Preliminary designs were finalized in 2017. Valard completed the civil design and the electrical design. The contract for the statcom installation and substation at Stewart Crossing has been tendered and is awarded.

Project activities related to construction of the transmission line, substations and statcom were expected to commence in April 2019, but were delayed until September 2019. The project has also experienced delays related to the tendering process and related to impacts of the COVID-19 pandemic.

Transmission line survey and brushing were completed in Q2 2020 with the exception of bird nest areas. Access road and transmission line construction have proceeded. Transmission line construction and

[11] Stage 2 included construction of a 138 kV transmission line from Stewart Crossing South to Mayo and energizing the Mayo to McQuesten line to 138 kV; and Stage 3 included construction of a new 138 kV transmission line from McQuesten to Keno.

commissioning is expected to be completed by the end of November 2020; the 138 kV facility will initially be operated at 69 kV. Decommissioning of the old 69 kV line is expected to occur between November 2020 and December 2020. Substation construction at Stewart Crossing commenced in August 2020 and is expected to be completed by June 2021. An order has been placed for the Statcom and it is in manufacturing. Statcom delivery is expected to occur by August 2021, with installation in September 2021 and commissioning completed by October 2021.

Project Costs

The three largest project contracts (transmission line, substation and statcom) are competitively tendered fixed price contracts and comprise 86% of the project budget. Project costs and contributions are summarized in Table 5.2.1-2.

Table 5.2.1-2: Project Cost and Contributions

	Actual 2018	Actual 2019	Forecast 2020	Forecast 2021
MMTL Upgrade ($000)	0	501	20,000	11,200
MMTL Contribution ($000)	0	274	15,000	8,400
Net Expense	**0**	**227**	**5,000**	**2,800**

The total spending of $20.501 million for 2019 and 2020 is offset by $15.274 million in contributions [net $5.227 million] and is forecast to be closed and included in rate base in December 2020; the spending of $11.200 million in 2021 is offset by $8.400 million in contributions [net $2.800 million] and is forecast to be closed and included in rate base in December 2021.

Project and ratepayer risks have been addressed as follows:

1. **Yukon Government Funding for initial stages to advance project to shovel ready stage by Q4 2016:** An initial $5.3 million tranche of funding was provided by the Yukon Government for costs required to advance the project to a shovel ready stage by Q4 2016.[12] This funded costs required to advance the project through the effects assessment in order to obtain Decision

[12] This included undertaking initial engineering, planning and assessment activities required to prepare and submit a Yukon Environmental and Socio-economic Assessment Act (YESAA) project proposal to YESAB before the end of 2015. YESAB screening was completed in May 2016. A Land Use application was submitted and government authorizations required to proceed with geotechnical and survey work to completed detailed engineering was completed in September 2016.

Documents; and preliminary design work oriented to confirming technical ability to construct the project, and timing and configuration of major project components.

2. **Power Purchase Agreement with VGC Group:** Over 2017, Yukon Energy negotiated a Power Purchase Agreement (PPA) with Victoria Gold Corp. (VGC) and StrataGold Corp (StrataGold) (collectively referred to as VGC Group), and submitted an Application to the YUB for approval of the VGC Group PPA on November 10, 2017. Following its review, the Board issued Order 2018-04 approving the VGC Group PPA. The PPA sets out rights and obligations of VGC Group to YEC under Section 6.1 of the PPA for YEC capital costs, including payments by VGC Group to YEC for negotiation and conclusion of the PPA; capital costs for Initial YEC System Improvements[13]; YEC Owners Costs for McQuesten Substation development;[14] and YEC Costs reasonably required for design, engineering, procurement, construction and commissioning of the step-down transformer at the McQuesten Substation should one be determined to be required. The PPA also includes Fixed Charge provisions[15] which have come into effect in 2019;[16] and provisions to amend the transmission facilities fixed cost after the Transmission Facilities Development Operation Date.[17]

3. **Federal Funding through Investing in Canada Infrastructure Program (ICIP)**: The Federal Government's Investing in Canada Infrastructure Program (ICIP) provides funding towards strategic electricity projects which support Canada's Greenhouse Gas emission reduction targets where federal funding is available for projects that meet required criteria. An ICIP application was submitted for the MMTP and on July 30, 2019 Yukon Energy received funding approval from the Federal and Yukon Governments to proceed. In total, the Federal Government contribution of $23.674 million covers 75% of eligible project budget.

5.2.1.4 McQuesten Substation (including Asset Contribution) – ($0.123 million in 2018 and $11.496 million in 2019; with $10.688 million contribution)

The Mayo-McQuesten portion of the Mayo to Keno City transmission line was at end of life and needed to be replaced. Yukon Energy had an 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

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[13] As set out in Schedule C of the VGC Group PPA.
[14] As set out in Table B-1 of the VGC Group PPA.
[15] As set out in Section 7.7 of the VGC Group PPA.
[16] The initial transmission facilities fixed costs of $118,621 per year as documented in Attachment B of the VGC Group PPA.
[17] Adjustments would be based on YEC's adjusted annual costs as approved by the Board for depreciation and return on rate base related to the Transmission Facilities (which includes the Transmission Facilities Development), plus SVC/ Statcom and YEC's McQuesten Substation costs ($930,563 under Section 6.1(d) and Schedule B of the PPA).

McQuesten, and potentially also facilitate proceeding with additional necessary upgrades that would provide long term enhancement benefits to infrastructure on the northern grid.

The project has previously been reviewed as part of the 2017 VGC Group Power Purchase Agreement proceeding; and as part of the 2017/18 General Rate Application.

Completion of the McQuesten Substation was required for the Victoria Gold mine to receive Grid Electricity from YEC.[18] The facility was built with capability to accommodate future connection of 138 kV transmission from Stewart Crossing or from Mayo.

Pursuant to the VGC Group PPA, the McQuesten Substation[19] was developed by VGC Group and YEC, with the intention that it would be owned and operated by YEC.[20] Except as otherwise specified in the PPA,[21] VGC Group was responsible for all capital costs related to the McQuesten Substation development.

As outlined in the PPA Application, Yukon Energy and VGC Group worked together to design, engineer, procure, construct and commission the McQuesten Substation.[22] Yukon Energy and VGC Group also entered into a Memorandum of Understanding (MOU)[23] to establish the formal relationship between the Parties and commitments to enable the Parties to work together on tendering, procurement, construction, commissioning and eventual turnover of the McQuesten Substation to YEC. Pursuant to the MOU: (a) the McQuesten Substation design was directed and reviewed by YEC, (b) the VGC Group ordered long lead equipment and would undertake other steps as required to protect the schedule for the McQuesten Substation development, and (c) thereafter VGC Group would undertake construction management and pre-commissioning activities. The target date for McQuesten Substation operation was February 28, 2019 in order to accommodate Commencement of Delivery of power to the Mine in March 2019.[24]

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[18] Pursuant to the VGC Group PPA application initial commencement of delivery to the Mine also required completion of Initial YEC System Improvements, the VGC Group Power Facilities, and the Mine Facilities Spur. YEC completed environmental review and permitting for the McQuesten Substation, as an element of the Stewart Keno City Transmission Line Project ("SKTP") environmental review and permitting.

[19] The McQuesten Substation is located along YEC's existing 69 kV transmission line between Mayo and Keno City at approximately the junction of the South McQuesten Road and the Silver Trail Highway.

[20] In accordance with the provisions of Schedule B of the VGC Group PPA.

[21] The PPA provides for VGC Group to recover from YEC the incremental fees, costs and expenses associated with the McQuesten Substation, as initially developed, being able to operate at 138 kV voltage ("YEC McQuesten Substation Costs" as specified in Schedule B of the PPA).

[22] As set out in Schedule B of the VGC Group PPA.

[23] The McQuesten Substation MOU provided in Schedule B to the PPA.

[24] See Section 4.2 and Section 4.3 of the VGC Group PPA.

Total cost estimated for the McQuesten Substation during the VGC PPA proceeding were $8.529 million (assuming no need for a Step Down transformer[25]); $7.598 of this cost was to be funded by VGC Group, and the balance funded by YEC as outlined in the VGC Group PPA. Specifically, section 6.1(d) of the PPA identified YEC McQuesten Substation Costs of $930,563, as set out under Section B.4 of Schedule B, associated with the McQuesten Substation as initially developed being able to operate in future (if and when so required) at 138 kV. YEC funding of VGC Group costs for these added facilities for 138 kV service recognized that these facilities were not required at the outset for delivery of Grid Electricity to the 69 kV Mine Facilities Spur line, but are required as part of any planned Transmission Facilities Development option.

The McQuesten Substation was completed and commenced operation in 2019 with final VGC Group costs of $11.619 million. YEC has received an asset contribution from 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).

5.2.1.5 Transmission Line Refurbishment - L70, L171 and L172 in 2018 and 2019 ($4.272 million in 2019)

Yukon Energy's 138 kV Whitehorse-Aishihik-Faro (WAF) transmission system was constructed in the late 1960's and early 1970's, and plays a critical role linking key hydro generation sources to load centres in Whitehorse and on the northern grid. Recent studies as well as a detailed line assessment in 2017 indicated that key components of the WAF system were at end of life, in poor condition, and required replacement.

This project was initiated to address replacement of key components of the following YEC transmission lines which are approaching the end of their economic life (refurbishment of L178 is being addressed as a separate project as discussed further in Section 5.2.1.6):

Line #	Route	Install Date
L170	Takhini Substation to Carmacks	1968
L171	Aishihik plant to Takhini Substation	1975
L172	Whitehorse plant to Takhini Substation	1968

[25] At the time future Step Down transformer costs were estimated at $1.34 million.

Specifically, certain components of these lines had begun to exhibit higher failure rates. Based on these events, YEC commissioned external asset assessments of the key backbone lines on the integrated system as noted above.[26] These assessments indicated that a large number of cross arms and insulators are at end of life with a high risk of failure.

Initial testing and lifecycle assessments undertaken in 2016 indicated as follows for the components tested:

- **Insulators**: A high percentage of mechanical failure due to a deterioration of the insulation materials caused by age, mechanical stress and adverse field conditions; it was noted that the vintage of insulators would experience increased frequency of failure and recommended that the insulators be replaced with polymeric or hardened glass insulators.

- **Cross-arms**: Full replacement of all original cross-arms with priority on crossarms on structures adjacent to road crossing and long spans was recommended based on the failure modes of the samples of wood crossarms tested.

- **Snowshed Crossarms**: Replacement of all original snowshed crossarms with steel crossarms was recommended as testing determined that snowshed crossarms do not meet industry standards and identified weaknesses attributable to cracks along the wood grain which could result in failure.

Given the number of end of life insulators, cross-arms and snowshed crossarms identified for replacement, this work could not be effectively completed within a reasonable timeframe through the annual Transmission Maintenance program (which only replaces approximately 34 structures per year). It was determined that a standalone project was required to complete the full scope of the refurbishment.

The alternative to proceeding with this project is to respond to structure and component failures as they occur. This may lead to significant reliability impacts as well as higher overall costs. In addition, employee health and safety risk is reduced by planned maintenance activities that remove the likely need for emergency work.

[26] Samples of the original 1970's vintage insulators, cross-arms and snowshed crossarms were sent to PowerTech Labs (PowerTech) a BC Hydro testing facility for testing and life cycle assessment in 2016. A detailed line assessment was completed on L170, L171 and L172 in 2017 to validate the findings of the PowerTech studies and develop a condition-based assessment and refurbishment plan.

Project Update

The Transmission and Distribution Line replacement 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 included in ratebase.

All remaining components requiring replacement on lines L170, L171 and L172 were completed by the end of 2019. This included replacement of full structures, cross arms or insulators for the Takhini to Carmacks Transmission Line (L170), the Aishihik to Takhini Transmission Line (L171) and the Whitehorse to Takhini Transmission Line (L172). Remaining work in 2019 was completed at a total cost of $4.272 million and included refurbishment of 255 structures (58 full structures, 80 crossarms, and 117 insulators).

5.2.1.6 Transmission Line Refurbishment – L178 (forecast $1.3 million in 2021)

The final phase of the Transmission Line Refurbishment Project will commence in 2021 for the Carmacks to Faro Transmission Line (L178), as refurbishment has been completed for L170, L171 and L172 (see Section 5.2.1.5).

Outages on the L178 currently trip at S164 (Takhini Substation) and can result in an outage on the Takhini-Carmacks L170 transmission line. Failure to complete this element of the refurbishment project would increase the risk of component failure on L178 resulting in a split in the North-South grid and significant thermal generation costs in the northern gird to maintain supply to all customers.

Maintenance on 95% of the structures that make up L178 will be completed as part of the project scope. The scope of the project involves like for like replacements on an authorized right of way using approved accesses and no additional permits or approvals are required (see Table 5.2.1-3).

Table 5.2.1-3: Summary of Scope of Transmission Line Refurbishment Work (L178)

Work Description	Number of Structures	Percent
Full structure replacement	141	17%
Cross arm replacement	96	12%
Insulator replacement	556	67%
No maintenance required	41	5%
Total structures	834	100%

The $1.3 million budget will cover the work done in 2021, which is only a portion of the full L178 transmission line refurbishment forecast to cost $8.3 million (costs to be brought into rate base each year as each year's work is completed).

5.2.1.7 Breaker Replacement Program ($0.479 million in WIP in 2018, and $1.781 million in 2019)

The project involves replacement of twelve aging circuit breakers in various substations throughout the Yukon, including the replacement of five 34.5 kV Medium Voltage (MV) and five 138 kW High Voltage (HV) breakers. Many of the breakers are 40 years old, replacement parts are not available[27] and any damage to aging components could result in lengthy outages to implement repairs or eventual replacement of a breaker, impacting system reliability. Restricted operation of some breakers and non-routine maintenance are becoming increasingly frequent.

This project commenced in 2017 and was reviewed as part of the 2017/18 GRA. At the time it was noted that project costs would be capitalized as breakers were replaced and put into service. As described in the 2017/18 GRA, the project included two elements. The following shows the costs for each element:

1. Replacement of 5 medium voltage (34.5kV) breakers in YEC substations S150(4) and S176(1): replacement of medium voltage breakers was initiated in 2017 with procurement of breakers with installation following in 2018. The project was added into rate base in 2018 with total cost of $0.798 million [including $0.110 million WIP by end of 2017 and $0.688 million spending in 2018].

2. Replacement of 7 high voltage (138kV) breakers in YEC substations at Aishihik Faro, Riverside and Takhini: this was initiated in 2018 and was to be completed in 2019. The high voltage breaker replacement program was completed in 2019 with a total cost of $2.26 million.

In total five MV breakers were replaced in 2018 and seven HV breakers were replaced in 2019. Costs for replacement of the five MV breakers were reviewed as part of the 2017/18 GRA and included in ratebase at that time. The installation and commissioning of all seven HV breakers was completed in 2019. Final documentation, drawings, and minor deficiencies were finalized before the end of 2019.

[27] As per the equipment manufacturer both models of breaker are at end of life and have been phased out, making it difficult to find replacement parts.

In the 2017/18 GRA it was noted that replacement of these assets was expected to result in O&M savings estimated of about $30,000 every three to five years. New breakers have similar maintenance cycles but generally only require testing along with some minor lubrication and tightening of components. This is within the capabilities of YEC staff and is expected to only take a few hours per breaker.

Total project costs incurred over 2018 and 2019 are $2.260 million. The project is now complete and in service.

5.2.1.8 Replacement of P125 Head Gate ($0.093 million in 2019, $2.300 million forecast in 2020, and $3.500 million forecast in 2021)

The P125 Hydro Plant, originally commissioned in 1958, is located at Whitehorse Rapids Generating Station and houses three of the four hydro power units at Whitehorse Rapids (Whitehorse Hydro units 1, 2 and 3). The headgates at the P125 plant are located above the plant at the water intake structure and serve as the single isolation point for the hydro units. The headgates are critical for operating and maintaining the P125 Plant, and play a critical role in ensuring worker safety when isolation is required to inspect the runner and draft tube as well as protecting the hydro units and water conveyance system. Specifically, during upset conditions, the headgates drop to protect the hydro units and the water conveyance system. To date, the headgates have never been overhauled.

An external engineering firm (SNC Lavalin) performed tests and structural assessments of the P125 headgates in 2019 that indicate that the headgates can no longer be relied upon for emergency closure or for single device isolation. The gates were tested, in a controlled situation, to determine if they would close during emergency conditions and two out of the three gates did not close. This failure could result in a unit runaway / over-speed that could potentially cause severe damage to the unit as well as the plant.

YEC currently installs stop logs in front of the existing headgates to ensure worker safety when dewatering the units; however, this requires additional man hours as well as crane rental, and in the winter months becomes more problematic due to icing.

The scope of the project includes the removal of existing headgates, design and installation of new headgates and control systems, and refurbishment of the headgate hoist mechanism. Yukon Energy tendered and proceeded with work on the WH2 headgate in 2020, and is assessing team capacity to complete replacement and refurbishment of the gates and related infrastructure for units WH1 and WH3 in 2021.

Initial inspection of WH2 indicates the headgate embedded parts to be in relatively good condition and that they can be repaired as expected. Fabrication of the replacement headgate has commenced with delivery expected in Q4 2020. The headgate hoist has also been removed and shipped to Surrey, BC for overhaul and refurbishment. The condition of the hoist was worse than expected and additional components not considered in the original cost estimates will be required.

It is expected that the WH2 headgate will be completed in 2020 at a forecast cost of $2.3 million; and that the WH1 and WH3 headgates will be completed in 2021 at a forecast cost of $3.5 million.

5.2.1.9 WH2 Uprate ($3.044 million in 2019, $1.693 million forecast in 2020, and $7.300 million forecast in 2021)

Whitehorse Hydro #2 (WH2) was commissioned in 1958 and is one of the three units installed at P125. It is a Kaplan Turbine unit with nominal rating of a 5.8 MW and is currently operating with the original runner, rotor, stator and windings from 1958. WH2 asset health has been declining due to its age, and there is an increased risk of failure and related unplanned outages and costs. Specifically, the generator has exceeded a typical winding life of 40 years; and issues have been identified with oil leaks at the runner blade to hub seals and with possible voids in the concrete behind the draft tube liner. In the circumstances, it was considered prudent to rewind the generator in order to mitigate these risks and their potential reliability and cost implications. External studies also determined that unit efficiency would be improved with a new runner of modern design.

The 2016 Resource Plan identified the uprating of WH2 as a cost effective project that could be implemented in the near-term to help address the existing capacity shortfall. The project would also provide an incremental source of renewable energy to offset thermal generation as load grows on the YEC system.

In 2017, Hatch completed an economic assessment of various uprate options at the Whitehorse Rapids Generating Station (WRGS). The report concluded that the uprating of the WH1 or WH2 units would be the most cost-effective option and provide the best payback of the WRGS hydro units. Management selected the uprating of WH2 over WH1 since there are existing known issues with the WH2 governor, and the uprating project would resolve these issues.

The project is planned to be implemented over a three year period (2019-21), and is expected to add 6.4 GWh/yr additional hydraulic generation to the grid [starting in the third quarter of 2021]. The project is also expected to increase dependable capacity of WH2 by 0.94 MW.

The WH2 uprate scope of work will include unit rehabilitation, runner replacement, generator stator and rotor re-winding, governor replacement, exciter replacement and upgrading of the control and condition monitoring systems.

Yukon Energy contracted Litostroj Power to undertake the runner fabrication with the following concurrent activities planned for 2020: governor fabrication, balance of plant civil construction; balance of plant P&C design completion, relace of balance of plant request for proposal, and delivery of materials to Whitehorse. The balance of plant civil scope work included rehabilitation of the tailrace crane superstructure and concrete piers. Due to significant new damage to the WH1 and WH2 penstocks discovered in 2020, the planned penstock work was cancelled and will be completed as part of the penstock repairs.

The WH2 uprate project is currently expected to be delivered on time with total project cost of $12.038 million.[28]

5.2.1.10 WH4 Uprate - Servomotor Replacement ($0.052 million in 2018; $0.079 million in 2019; $0.400 million forecast in 2020; and $1.000 million forecast in 2021)

The project involves detailed design, procurement and installation of two new Servomotors for Whitehorse Hydro Unit 4 (WH4) wicket gate operation. Implementation will increase the output of the WH4 unit by allowing full range of operation of the wicket gates; this enhancement adds additional hydraulic generation of 0.9 GWh/year.

Contracts with Andritz (OEM), L&S Electric (to review documentation and develop a governor commissioning plan) and Hatch (owners engineer) have been finalized. Procurement has not yet been undertaken for testing services and installation of a lifting device.

Yukon Energy entered into a contract with ANDRITZ Hydro for the design and supply of two new servo motors. Final design is nearing completion and manufacturing is expected to commence in Q3 2020. Other work is proceeding in parallel including planning for changes to the governor, signature testing and characteristic testing with assistance from Hatch and L&S Electric. Delivery of the Servos is expected by January 2021. Contractor mobilization and installation, testing and commissioning is expected to occur in June 2021. The project is expected to be in service in June 2021.

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[28] In addition to the capital spending, the engineering related costs shown in Appendix 5.4 of $0.259 million will be added to project which increases the total cost to $12.297 million.

The total project budget is $1.531 million and includes work from 2018 through to project completion (expected in Q3 2021).

5.2.2 Projects $100,000 to $1 Million

Growth in rate base reflects ongoing need to refurbish old assets and improve grid reliability. Ongoing reinvestment in existing infrastructure ensures that the Yukon integrated grid can continue to meet loads on the system in a safe and reliable manner. PP&E spending for projects less than $1 million was $7.591 million in 2019, and forecast spending to be added to net rate base in 2021 is $6.881 million in 2020 and $5.501 million in 2021 (see Table 5.2-1). Forecast customer contributions related to these capital works over these three years is approximately $1.9 million.

Appendix 5.2 provides, for capital works projects with costs between $100,000 and $1 million from 2019 to 2021 that are included in 2021 rate base, summary business case reviews for generation, transmission, distribution, general plant and equipment and overhaul/ decommissioning projects.

5.3 DEFERRED COSTS

This section reviews (a) major deferred cost projects (projects over $1 million) and (b) other deferred cost projects between $100,000 and $1 million, undertaken by Yukon Energy since the 2017/2018 General Rate Application.

Deferred costs include feasibility studies for a wide range of projects (focused mainly on potential new generation or transmission options), continued relicensing work (for this Application, this grouping includes water licence renewal activities as well as water licence amendment projects, e.g., Mayo Lake Storage Enhancement Project), regulatory work (includes DSM), and dam safety review work.

Deferred costs additions to rate base net of contributions approximated $1.5 million at the end of 2019 and are forecast at approximately $4.0 million at the end of 2020 and $1.9 million at the end of 2021. Deferred costs in rate base are forecast at approximately $10.3 million at the end of 2021, compared to approximately $11.8 million at the end of 2018.

Deferred expenditures in WIP at the end of 2019 were approximately $19.9 million and are forecast at the end of 2020 and 2021 at approximately $21.3 million and $30.0 million respectively.

5.3.1 Major Projects >$1 Million – Rate Base Additions

Test year spending on major deferred cost projects focuses on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other future potential generation and transmission requirements.

Total forecast to be added to net rate base for major deferred cost projects by the end of 2021 is approximately $2.741 million. Each major project added to rate base is reviewed separately below (see also Tables 5.3 to 5.6 at the end of Tab 5):

- **Spending on Sustaining Capital** – Net rate base impact of approximately $1.004 million, excluding reductions due to amortization:
  - **Aishihik Relicensing (Three Year Licence Renewal)** - ($1.004 million net increase in rate base by the end of 2021, excluding reductions due to amortization).
- **Spending on planning to meet other future Generation and Transmission Requirements** – Net rate base impact of approximately $1.737 million, excluding reductions due to amortizations:
  - **Demand Side Management (DSM)** – ($1.737 million net increase in rate base by the end of 2021, excluding reductions due to amortization).

Business case summaries for major deferred cost projects added to rate base in this GRA are reviewed below. Major deferred cost projects retained in WIP at the end of 2021 with forecast costs to end of 2021 of approximately $28.6 million are reviewed in Appendix 5.3.

5.3.1.1 Aishihik Generating Station Three Year Licence Renewal – ($0.805 million to end of 2019; and $0.200 million in 2020)

The Aishihik Generating Station (AGS) facility licence was renewed in 2002 for a 17 year period and was to expire at the end of 2019. A water use licence renewal was required for the continued operation of the 37 MW hydro facility, which provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System. Yukon Energy began a process in 2016, working with Champagne and Aishihik First Nations (CAFN), to prepare a long-term licence renewal application for review and approval before the end of 2019.

In late 2018, Yukon Energy still planned to proceed with a long-term licence renewal and prepared its YESAA Project Proposal assuming a 25 year renewal term (the maximum allowed term under the *Waters Act*). However, due to delays in filing the YESAA Project Proposal to accommodate Yukon Government discussions with CAFN, Yukon Energy had to address material risks that the regulatory review timelines could extend beyond 2019. In order to avoid a lapse in Yukon Energy's water use licence for the AGS, Yukon Energy brought forward the AGS Relicensing Project Proposal in February 2019 for a renewal term of three-years. It was expected that this would allow the necessary time for the regulatory review process for the 25-year licence renewal to occur without a lapse in Yukon Energy's AGS water use licence.

Over the course of 2019 and early 2020, Yukon Energy completed the regulatory review process for the three year renewal including: the YESAA Designated Office review and issuance of Decision Documents by Decision Bodies[29]; 3-Year extension of the existing Fisheries Act Authorization;[30] and three year water use licence renewal.[31]

Costs for the 3-year AGS licence renewal were incurred from January 2019 through to end of February 2020 (when the 3-year licence renewal was obtained). Costs over this period include regulatory costs for the Designated Office review; costs related to the preparation of the Yukon Water Board Application for the 3-year renewal and for the 60-day renewal and for the related review processes; and costs related to preparation of an application to extend the DFO *Fisheries Act* Authorization and related review processes; and costs related to negotiations with CAFN and for negotiation of compensation with claimants pursuant to the *Waters Act*.

Spending in WIP in 2019 was \$0.805 million in 2019 with \$0.200 forecast in 2020. Costs for the three-year renewal will be amortized over the 3-year licence period.

[29] The DO evaluation concluded in August 2019 with the issuance of an Evaluation Report. Decision Documents were issued in September 2019.
[30] Issued December 24, 2019.
[31] A 60-day renewal was issued in December 2019 extending the licence to February 29, 2020, and a 3-Year renewal was issued on February 19, 2020.

5.3.1.2 Demand Side Management – ($0.833 million to the end of 2019; $0.375 million forecast in 2020 and $0.894 million forecast in 2021, with contributions of $0.365 million).

The context within which Yukon Energy has approached Demand Side Management (DSM) has materially changed since the Board made the following DSM related determination in Board Order 2018-10 (paragraph 482):

> "The Board is not persuaded that YEC should continue to operate DSM projects. YEC has indicated the benefits of expanding the program and submitted that its programs have met or exceeded key performance indicators. However, the Board notes that the Yukon government has DSM incentive programs in place, and the Board is of the view that it is better to leave DSM projects to government, rather than having ratepayers fund these projects. For these reasons, the Board is of the view that continuation of DSM programs by YEC is not necessary."

Since that determination the Yukon Government has put in place a Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy"[32] which emphasizes the importance of DSM as a valuable resource to reduce the Yukon's energy and capacity requirements. As part of that policy the government fully expects Yukon Energy to pursue a cost-effective DSM program.

Pursuant to this policy initiative and the Government's expectations, and further given DSM remains a cost-effective means of reducing energy and capacity requirements, Yukon Energy has included in the proposed 2021 rate base the expenditures for the programs and activities as reviewed below.

DSM Program Development

The 2016 Resource Plan determined that DSM programs are a cost-effective way to meet energy and capacity demand that should be included in the proposed future portfolio of energy supply projects. In the 2017/18 General Rate Application, Yukon Energy noted plans to use end-use survey data,[33] the

[32] "Our Clean Future: A Yukon strategy for climate change, energy and a green economy", (last updated, September 2020) at page 45.

[33] Sufficient Yukon-specific data is required for program design. This requires that residential and commercial customer end use survey be developed and undertaken to gather information on how Yukon homes and businesses currently use energy.

results of a Capacity DSM Feasibility Study,[34] and an updated CPR model,[35] to design a suite of new DSM programs to complement the existing inCharge program. This work was completed in early 2019. Yukon Energy will be targeting programs that deliver a capacity benefit to address the dependable capacity shortfall. Minimal costs to provide brand and education continuity have also been incurred since early 2019 to maintain the inCharge program in the local market. Project expenditures to be included in rate base of $1.279 million ($0.385 in 2019 and $0.894 million in 2021) are amortized over 10 years.

DSM Residential Demand Response Pilot

The 2017/18 GRA noted that based on 2016 Resource Plan recommendations, that new program development would include consideration of capacity focused DSM programs such as demand response.

The Yukon Government's recent Climate Change policy initiative called "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy" also provides the following policy directions regarding utility pursuit of capacity DSM:[36]

- EMR and YEC establish a partnership between the Government of Yukon, Yukon Energy Corporation and ATCO Electric Yukon by 2021 that will collaborate on the delivery of energy and capacity demand-side management programs.

- YEC complete the Peak Smart pilot project by 2022 to evaluate the use of smart devices to shift energy demand to off-peak hours.

Yukon Energy faces a capacity shortage under the single contingency (N-1) planning criterion. With this capacity planning context, and mindful of the policy context outlined in the Yukon Government's Climate change strategy, Yukon Energy has pursued a pilot program testing internet connected, wifi enabled demand response technology designed to control residential baseboard and hot water heating during winter peak periods to help reduce system peak and reduce reliance on thermal generation such as diesel or natural gas.

[34] Yukon Energy also noted plans to undertake a Capacity DSM Feasibility Study to quantify the potential cost and achievable uptake of capacity-focused DSM programs such as demand response, behaviour change and other demand-focused measures.
[35] At the time Yukon Energy also noted plans to update the Conservation Potential Review (CPR) model used to inform DSM program design, to better match the inputs needed for resource planning; and to develop in house capacity to use the CPR model to extract data for resource planning and program design purposes.
[36] Our Clean Future: A Yukon strategy for climate change, energy and a green economy, page 45 (last updated September 2020).

The objective of the program is to: evaluate the technical feasibility of the demand response technology; model and test the peak shifting effect of the pilot; test the reliability of the peak shifting effects of the pilot; and evaluate customer acceptance of the demand response events.

The project is managed by Yukon Energy with funding support from Atco Electric Yukon (AEY), Yukon Development Corporation (YDC) and Natural Resources Canada (NRCan). Project expenditures of $0.809 million ($0.434 million in 2019 and $0.375 million in 2020) are to be included in rate base, offset by contributions of $0.365 million in 2019, are amortized over 10 years.

LED Streetlight Retrofit Program

In addition to the program's specifically developed in response to the Yukon Governments Climate Change initiative, the Board also noted in Order 2018-10 (Para 481) that it "considers that retrofitting streetlights at end of life with LED lights were prudent expenditures. Any LED installations that are not end-of-life conversions must not be included in YEC's rate base." The 2017/18 GRA outlined the basis for the LED Streetlight Replacement program noting that Yukon Energy decided to move forward with the retrofit of streetlight assets with LEDs.[37] Streetlights in downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit the remaining streetlights in Faro, Mendenhall and Champagne in 2018. As illustrated in Table 5.3, $0.273 million was added to rate base in 2018.

5.3.2 Projects between $100,000 and $1 Million

The projected total 2021 spending in deferred cost activities excluding major projects over $1 million (as described in Section 5.3.1) totals approximately $1.7 million in 2021 ($1.0 million in closed projects going to rate base), as set out in detail in Table 5.6. Total increase to rate base since 2018 from deferred cost activities excluding major projects over $1 million, but including transfers from WIP spending prior to 2021, is $4.7 million in 2021 (excluding reductions due to amortizations).

Spending from 2019 to 2021 on each deferred cost activity totalling between $100,000 and $1 million that impacts 2021 rate base is summarized below (total rate base impact in 2021 test year of $4.046 million, excluding reductions due to amortization). Key areas of spending include feasibility studies,

[37] Yukon Energy began piloting LED streetlights in 2011 to determine if the technology was suitable for the Yukon climate, gather customer feedback and analyze the business case for retrofitting existing high pressure sodium streetlights. The piloting of LED streetlights showed that they were effective in the Yukon climate and positive feedback was received from customers in the areas where the LED streetlight were tested.

relicensing, dam safety and regulatory. Appendix 5.4 provides a description (including need for and justification) for each project.

- **Studies undertaken to determine feasibility of potential supply options**: Rate base additions of $1.267 million for the following projects:
  - IPP Standing Offer Program Implementation ($0.232 million in 2020 for expenditures in 2018 and 2019);
  - Mt Sumanik Wind Feasibility Study ($0.776 million for expenditures from before 2018 until 2020); and
  - WH2 Uprate Engineering ($0.259 million in 2021 for expenditures from 2018 to 2020).
- **Studies undertaken to ensure continued reliability or to determine requirement for business improvements for existing assets**. Rate base additions of $1.551 million for the following projects:
  - Building Condition Reports 2021-2024 ($0.175 million in 2021);
  - Business Continuity Plan ($0.080 million in 2020 and $0.075 million in 2021)
  - Mayo and Aishihik Hydro Climate Change Study ($0.638 million in 2020 for expenditures from 2017 to 2020);
  - PMF Flood Study ($0.150 million in 2021);
  - Transmission Access Road Program Study ($0.133 million in 2020 and $0.200 million in 2021); and
  - Whitehorse Diesel Rental Substation Improvements ($0.100 million in 2021).
- **Regulatory** and **Dam Safety Review**: Rate base additions of $1.228 million for the following projects:
  - 10 Year Renewable Energy Plan ($0.713 million in 2020 for expenditures in 2019 and 2020);

- o Atlin Hydro EPA Preparation ($0.200 million in 2020); and
- o Dam Safety Review ($0.315 million in 2020).

Deferred cost projects with total spending since 2018 greater than $100,000 million and less than $1 million that remain in WIP in 2021, excluding General Rate Application costs in WIP, have total expenditures of $0.400 million and are described in Appendix 5.5.

5.4 INTANGIBLE ASSETS

An intangible asset is a non-monetary asset without physical substance and that is identifiable (either being separable or arising from contractual or other legal rights). It is a resource that is controlled by an entity as a result of past events (for example, purchase or self-creation) and from which future economic benefits (inflows of cash or other assets) are expected. Examples include patented technology, computer software, databases and trade secrets.

Intangible assets are reviewed in Table 5.7 and include financial software, customer service costs and costs related to development of an asset management framework (i.e., Enterprise Asset Management Purchase and Implementation). The one major project (i.e., costs exceeding $1 million) intangible asset impacting rate base is reviewed in Section 5.4.1 below. Intangible assets with costs greater than $100,000 (but less than $1 million) that remain in WIP in 2021 are summarized in Appendix 5.6.

5.4.1 Major Projects > $1 Million – Rate Base Additions

Test year spending on Intangible Assets over $1 million relate to implementation of the Enterprise Management System purchase and implementation (see Section 5.4.1.1. for description). As summarized in Table 5.7, total forecast spending included in rate base by the end of 2021 is approximately $4.938 million.

5.4.1.1 Enterprise Asset Management (EAM) System Purchase and Implementation – ($0.809 million in 2019, $3.854 million forecast in 2020, and $0.275 million forecast in 2021)[38]

The 2017/18 GRA included feasibility costs for development of an Asset Management Program that would document plans to systematically assess major asset groups (hydro, substations and transmission and distribution) and manage the planning of investments to meet overall corporate goals.[39] It was noted at the time that there was no asset management methodology for managing critical hydro and transmission assets which could result in unplanned ad hoc repairs and replacement projects. A permanent solution was required with health indices and reporting tools to allow for investment planning based on consideration of empirical data and risk.

Yukon Energy is undertaking a multi-year process to develop and implement a formal Physical Asset Management Managed System (PAMMS) that will align its practices with the ISO 55000 standard[40] for physical asset management (see Appendix 5.1 for further details on the Asset Management Framework). A key part of the PAMMS initiative is the selection and implementation of an Enterprise Asset Management (EAM) solution suited to the needs of the company.

The existing Computerized Maintenance Management System (CMMS) does not meet Yukon Energy's current or future asset management needs. An EAM system is an enterprise level software application that enables an organization – particularly an asset intensive organization – to manage and optimize its assets throughout the entire asset lifecycle including asset needs identification, asset investment planning and prioritization, advanced asset maintenance management and asset performance tracking.

EAM project activities since 2018 relate to the selection, purchase, planning and implementation of an EAM system. A procurement process to evaluate and select a replacement system was initiated in 2018; and selection of a replacement EAM system was completed in 2019. The tool will be integrated with the Microsoft Dynamics GP, YEC's financial management solution, and other legacy applications to provide an integrated solution that ties to YEC's financial and inventory management systems.

The following project activities have been completed:

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[38] $0.276 million was spent in 2018 under PP&E and transferred to Intangibles in 2019. The 2019 spending was $0.533 million to total 2019 cost to rate base at $0.809 million.

[39] 2017/18 GRA, Appendix 5.4, page 5.4-2 provides a summary of this project, with forecast spending of $0.200 million in 2017 and $0.150 million in 2018. In Order 2018-10, the Board found the project reasonable and the associated costs prudent and approved the deferred costs as filed.

[40] The ISO 55000 standard is an international standard covering management of assets of any kind.

- **Procurement of Project Management Services:** In 2019, YEC issued a Request for Proposals (RFP) for project management of the EAM implementation, and KPMG was selected as the proponent for this work. The KPMG team is well qualified and experienced and its team members successfully implemented a similar EAM system at NTPC (demonstrating knowledge and competence to deal with issues faced by small, northern Crown utilities).

- **Procurement of Software Solution:** A multi-stage competitive procurement was administered in 2018. A total of 27 potential suppliers were invited to participate in a request for information process. From this, 8 vendors were invited to a full request for proposal (RFP) process. As a final step, three vendors were invited to participate in vendor presentations and site visits and full cost work up. Based on this extensive process, YEC awarded a time and materials contract to Infor ERP Software.

Over 2020, YEC has worked towards implementation of the software solution provided by Infor. This has included the following:

- **Inception (completed in 2020):** Undertaking activities related to project kickoff; training workshops by vendor (Infor) with YEC team members; workshops conducted by Infor to define as-is process models, technical strategy and architecture and KPIs as a basis for the EAM solution; workshop conducted by KPMG (OCM lead) to gather YEC executive input on expected organizational challenges and ensure alignment project objectives; and prioritization requirements for next phase.

- **Elaboration (commenced in 2020 and ongoing):** Involves detailed scoping and finalization of business requirements and integration design, advanced training for core team members, development of a testing strategy, scope and defining data structures and plan integration strategy and requirements.

- **Construction (commenced in Q2 2020 and Completed in Q4 2020):** Development of user acceptance testing plan, initial testing and final data conversion preparation by vendor. This includes development of training curriculum and methodology and approach; assessment of impact of EAM project on YEC; test all modules of AEM solution, going through business processes and verifying functionality; determine if designed and configured solution meets YEC's requirements and specifications; build EAM integrations with YEC legacy systems; local testing of integrations developed; and end to end system testing of AEM system and integrations.

- **Transition (commenced in Q4 2020 and ongoing):** Finalization of EAM solution and preparation to launch into production; including preparing for training for broader YEC users; outline and convert data from non-EAM systems to EAM systems and checking redundancies involved while going live; change impact assessment based on enhanced understanding of project; assessment of readiness for launch and finalize EAM for users and convert to production 'live' environment.

- **Optimize (commence late Q4 2020 and complete early 2021):** After launch into production review of project successes and lessons learned, including limited support work from vendor as required.

Total costs to complete the project are currently estimated at $4.938 million. The project is expected to be fully implemented in early 2021.

YUKON ENERGY CORPORATION
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT - SUMMARY
($000S)

Table 5.1
November 2020

Description	Actual 2018	Actual 2019	Forecast 2020	Forecast 2021
SUMMARY - RECONCILIATION OF PROPERTY, PLANT AND EQUIPMENT				
Work in Progress (WIP), Beginning of Year	4,759	4,491	8,088	10,796
Total Major Projects	15,230	23,563	29,290	56,266
Ongoing Capital				
Total Transmission	1,234	1,335	1,038	550
Total Distribution	1,245	1,399	774	625
Total Generation	1,040	1,737	1,205	1,110
Total General Plant & Equipment	1,734	1,740	2,066	2,045
Total Overhaul	0	145	198	760
Total RFSR	165	1,173	0	0
Total RFID	651	62	1,598	411
Subtotal Ongoing Capital	6,069	7,591	6,880	5,501
Total Expenditures	21,300	31,154	36,171	61,767
Transfer to RFSR	-165	-1,173	0	0
Transfer to RFID	-651	-62	-1,598	-411
Transfers (Income Statement, Feasibility and Other)	-295	-660	-2	-2
Total WIP Adjustments and Transfers	-1,111	-1,895	-1,600	-413
Transfer to Ratebase	-20,457	-25,662	-31,863	-34,761
WIP end of year	**4,491**	**8,088**	**10,796**	**37,389**
Opening PPE in-service	593,997	610,895	634,650	666,513
Net transfer from WIP	20,457	25,662	31,863	34,761
Retirements and other adjustments	-3,559	-1,908	0	0
Closing PPE in-service	**610,895**	**634,650**	**666,513**	**701,274**
Opening Total PPE (in-service plus WIP)	598,756	615,387	642,738	677,309
Change to total PPE	16,631	27,351	34,571	61,354
Closing total PPE	**615,387**	**642,738**	**677,309**	**738,663**
RECONCILIATION OF CUSTOMER CONTRIBUTIONS				
Opening Customer Contributions WIP	**21**	**603**	**385**	**776**
Customer Contributions Received	776	12,192	16,513	28,800
Adjustments				
less: transfer to Rate Base	-193	-12,409	-16,122	-8,800
Customer Contributions WIP end of year	**603**	**385**	**776**	**20,776**
Opening Gross Customer Contributions in Service	**200,811**	**198,924**	**211,333**	**227,455**
Transfers from WIP	193	12,409	16,122	8,800
Retirements, Disposals and Adjustments	-2,080			
Closing Gross Customer Contributions in Service	**198,924**	**211,333**	**227,455**	**236,255**
Opening Total Contribution (in-service plus WIP)	200,832	199,527	199,527	211,719
Change to total Contribution	-1,305	12,192	28,704	45,313
Closing total Contribution	**199,527**	**211,719**	**228,231**	**257,031**

Notes:
1. Based on IFRS requirements, the financial statement accumulated depreciation at January 1, 2014 was rebased to $0 and total costs adjusted accordingly. Therefore, the total gross plant in Table 5.1 is not the same as gross plant in the financial statements.

YUKON ENERGY CORPORATION
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT [2,3]
Projects Included in 2021 Rate Base
($000S)

Table 5.2-1
November 2020

Description	Actual 2018 [4]	Actual 2019	Forecast 2020	Forecast 2021
Major Projects				
Major Projects not in 2017-18 GRA Rate Base				
Breaker Replacement Program	479	1,781	0	0
Mayo to McQuesten Transmission Line Upgrade[1]	0	501	20,000	11,200
McQuesten Substation[1]	123	11,496	0	0
N-1 Capacity Shortage Mobile Genset	227	1,070	0	0
Replace P125 WH2 Head Gate	0	93	2,300	3,500
N-1 Capacity Shortage Thermal Rental Site Electrical Infrastructure	0	0	2,037	0
Transmission Line Refurbishment	0	4,272	0	0
WAF L178	0	0	0	1,300
WH2 Uprate	0	3,044	1,693	7,300
WH4 Uprate [Servomotor]	52	79	400	1,000
Major Projects Reviewed in 2017/18 GRA [forecast not included in 2018 GRA rate base]				
LNG Third Engine / Critical Spares	5,008	97		
Major Projects Reviewed in 2017/18 GRA [forecast included in 2018 GRA rate base]				
MH2 Ten Year Overhaul	1,645			
Breaker Replacement Program - 2018	688			
Transmission Line Refurbishment - 2018	6,280			
Total Major Projects	**14,503**	**22,433**	**26,430**	**24,300**
Generation				
Dam Safety Program	0	0	0	300
Dam Safety Recommendations 2017/18	110	272	300	0
P126 LNG Boil-off-gas Heat Exchanger	0	194	0	0
Wareham Gate Heater	0	574	100	0
Wareham Gate Refurbishment	0	0	250	0
Whitehorse Diesel System Grounding for Generators	39	218	10	0
WH1 and WH2 Design and Install Dewatering System	0	137	0	0
WH4 Ventilation	0	0	0	750
Other projects under $100K	891	342	545	60
Total Generation	**1,040**	**1,737**	**1,205**	**1,110**
Transmission				
Alexco Mobile Substation Connection[1]	0	0	178	0
L177 Re Route	0	0	105	250
Minto Mine Substation - Neutral Ground Resistor [1]	58	105	0	0
Protection and Control Program	0	0	0	300
Transmission Line Access	215	324	300	0
Van Gorda Substation [1]	0	54	199	0
WAF Transmission Upgrades	870	793	0	0
Other projects under $100K	91	59	256	0
Total Transmission	**1,234**	**1,335**	**1,038**	**550**

YUKON ENERGY CORPORATION **Table 5.2-1**
EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT [2,3] **November 2020**
Projects Included in 2021 Rate Base
($000S)

Description	Actual 2018 [4]	Actual 2019	Forecast 2020	Forecast 2021
Distribution				
Customer Extensions[1]	663	626	600	600
L355 Voltage Regulator	0	144	35	0
System Improvements for Eagle Gold Mine	352	487	0	0
Other projects under $100K	230	143	139	25
Total Distribution	**1,245**	**1,399**	**774**	**625**
General Plant & Equipment				
Communications Upgrade	255	801	0	0
Building Upgrades	77	370	275	0
Crane Replacement/Refurbishment	0	0	165	400
Mayo Earthworks	0	0	300	0
New Mobile Office Unit - IT	0	0	0	230
Vehicle Purchases	209	258	476	580
Compact Digger Truck	0	0	0	185
Water Improvement Upgrades	0	0	150	0
Other projects under $100K	1,194	311	700	650
Total General PPE	**1,734**	**1,740**	**2,066**	**2,045**
Overhauls				
FD7 Overhaul	0	0	0	580
Other projects under $100K	0	145	198	180
Total Overhaul	**0**	**145**	**198**	**760**
Reserve for Site Restoration				
Decommission WD3	0	999	0	0
Decommission WW1	165	0	0	0
Site Restoration Transmission Lines	0	174	0	0
Total Reserve for Site Restoration	**165**	**1,173**	**0**	**0**
Reserve for Injuries and Damages				
Injuries and Damages Costs	651	62	1,598	411
Total Reserve for Injuries and Damages	**651**	**62**	**1,598**	**411**
TOTAL	**20,572**	**30,024**	**33,310**	**29,801**

Notes:
1. The costs before expected contributions for the project. Please see section of Tab 5 document for details of the contributions.
2. Numbers include AFUDC where applicable.
3. Numbers incude transfers from planning and study cost and transfers from other projects where the capital expenditures may not be in the year shown.
4. Projects included in 2018 GRA rate base except as otherwise noted in table.

YUKON ENERGY CORPORATION **Table 5.2-2**

EXPENDITURES ON PROPERTY, PLANT AND EQUIPMENT [2,3] **November 2020**

Major Projects Forecast to Remain in WIP by end of 2021 [5]

($000S)

Description	**Actual 2018**	**Actual 2019**	**Forecast 2020**	**Forecast 2021**
AH3 Contract Dispute[1]	13	-318	0	0
Dawson Voltage Conversion	0	60	50	300
Energy Storage System (transfer from Feasibility) [4]	0	38	1,000	25,000
MH0 (Mayo A) Generating Station Slope Stability	0	0	0	1,500
Pumped Storage	0	0	250	395
Replacement of Mayo A Surge Chamber	0	0	0	200
Southern Lakes Transmission Line	0	0	0	175
Stop Log Crane WH Main Spillway	0	0	0	200
Asset Management Framework	715	1,349	1,560	1,196
Whitehorse Interconnection	0	0	0	3,000
Total Major Projects	**728**	**1,129**	**2,860**	**31,966**

1. This does not include legal costs required to be expensed for accounting purposes. Upon final settlement of the lawsuit (under appeal as of 2021 GRA filing), total project costs (including legal expensed) will be presented to the board for review.
2. Numbers include AFUDC where applicable.
3. Numbers incude transfers from planning and study cost and transfers from other projects where the capital expenditures may not be in the year shown.
4. The costs before expected contributions for the project. Please see section of Tab 5 document for details of the contributions.
5. All project listed above will have capital expenditures after 2021. AH3 Contract Dispute cost will depend on final settlement of the lawsuit.

YUKON ENERGY CORPORATION **Table 5.3**
Continuity Schedule of Deferred Costs (2018) **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2018 Actual		Dec 31	Amortization	Dec 31	2018 Actual		Dec 31
	2017	Additions	Transfers /Retired	2018	Rate and Method	2017	Expenses	Retired	2018
Feasibility Study									
Completed Projects:									
Aishihik Turbine Re-Runnering	115,894			115,894	SL-5 years	23,179	23,179		46,358
Assessment of Fuel Tank Whitehorse	30,528		(30,528)	-	SL-5 years	25,440	5,088	(30,528)	-
Asset Condition Assessment	127,545			127,545	SL-5 years	25,509	25,509		51,018
Asset Management Plan	417,641			417,641	SL-5 years	-	83,528		83,528
Atlin Storage	2,230,652			2,230,652	SL-10 years	1,338,393	223,065		1,561,458
Biogas Preliminary Design 2 Contribution	(16,500)			(16,500)	SL-5 years	(6,325)	(3,300)		(9,625)
Biogas Study	95,288			95,288	SL-5 years	41,612	19,058		60,670
Biogas Study Contribution	(7,000)			(7,000)	SL-5 years	(4,200)	(1,400)		(5,600)
Building Condition Reports	104,405			104,405	SL-5 years	20,881	20,881		41,762
Carmacks Airport Substation	50,627			50,627	SL-5 years	21,066	10,125		31,191
Climate Change Study	604,377			604,377	SL-5 years	90,656	120,875		211,532
Condition Assessment of Selected YEC Assets	230,631			230,631	SL-5 years	46,126	46,126		92,252
Condition Assessment of WH & WD Assets	227,969			227,969	SL-5 years	45,594	45,594		91,188
Cross Arm Replacements Evaluation	189,614			189,614	SL-5 years	37,923	37,923		75,846
Dawson Downtown Distribution Fusing	4,122			4,122	SL-5 years	824	824		1,649
Detailed Line Inspection L169-L172	231,146			231,146	SL-5 years	-	46,229		46,229
Diesel Generator Protection	34,476			34,476	SL-5 years	575	6,895		7,470
Disaster Recovery / Business Continuity Plan	-	3,756		3,756	SL-5 years	-	723		723
Disaster Recovery Plan	21,162		(21,162)	-	SL-5 years	16,930	4,232	(21,162)	-
Electric Vehicle Technical Study	67,919			67,919	SL-5 years	22,640	13,584		36,224
Electric Vehicle Technical Study - Contributions	(3,500)			(3,500)	SL-5 years	(1,167)	(700)		(1,867)
Enterprise Risk Management	169,398			169,398	SL-5 years	33,880	33,880		67,759
Enterprise Risk Management Report	43,767		(43,767)	-	SL-5 years	35,014	8,753	(43,767)	-
Evaluation of CIS Options	26,113			26,113	SL-5 years	-	5,223		5,223
Faro Mine Pumped Storage Project	21,634			21,634	SL-5 years	8,654	4,327		12,981
Geothermal	1,947,735		(324)	1,947,411	SL-10 years	1,168,706	194,806	(324)	1,363,188
Geothermal 2013 Contribution	(3,414)		3,414	-	SL-5 years	(2,731)	(683)	3,414	-
Gladstone	4,521,265			4,521,265	SL-10 years	452,127	452,127		904,253
Home Heating Retrofit Options	9,684			9,684	SL-5 years	3,067	1,936.80		5,003
Hoole Canyon and Slate Rapids	40,845			40,845	SL-5 years	16,338	8,169		24,507
Hydraulic Wood Removal System	18,556		(18,556)	-	SL-5 years	15,464	3,093	(18,556)	-
IFRS Upgrades	72,592			72,592	SL-5 years	-	14,518		14,518
L170 Cross Arm Testing & Change	50,824			50,824	SL-5 years	30,494	10,165		40,659
Large Hydro	291,237			291,237	SL-5 years	58,247	58,247		116,495
Life Cycle Analysis of LNG/Diesel	118,036			118,036	SL-5 years	23,607	23,607		47,214
LNG Boil Off Gas Options	46,317			46,317	SL-5 years	9,263	9,263		18,527
LNG Feasibility Study	(150,000)			(150,000)	SL-5 years	(30,000)	(30,000)		(60,000)
LNG Supply Option	273,095			273,095	SL-5 years	54,619	54,619		109,238
LNG Third Engine Assessment	47,081			47,081	SL-5 years	-	9,416		9,416
LNG Transportation Options	277,700			277,700	SL-5 years	55,540	55,540		111,080
LNG Transportation Options Contribution	(15,000)			(15,000)	SL-5 years	(3,000)	(3,000)		(6,000)
Load Forecasting	17,148			17,148	SL-5 years	6,859	3,429		10,288
Mayo A Hydro Assessment	95,038			95,038	SL-5 years	25,344	19,008		44,351
Mayo Hydro Bridge Icing Upgrade	15,603			15,603	SL-5 years	9,362	3,121		12,482
Moon Lake Hydro Project	170,667			170,667	SL-5 years	-	34,133		34,133
N-1 Event Risk Assessment	-	128,911		128,911	SL-5 years	-			-
Power Canal Leak Investigation	61,525		(61,525)	-	SL-5 years	49,220	12,305	(61,525)	-
Resource Plan Update - 2016	2,015,083			2,015,083	SL-5 years	167,924	403,017		570,940
SKTP Planning 2015-2017	3,389,993			3,389,993	SL-5 years	508,499	677,999		1,186,497
SKTP-YG Funding	(3,389,993)			(3,389,993)	SL-5 years	(508,499)	(677,999)		(1,186,497)
Solar PV Installation-WH	48,901			48,901	SL-5 years	19,560	9,780		29,341
System Stability Review	88,544			88,544	SL-5 years	53,126	17,709		70,835
Transformer T9 Assessment	105,341			105,341	SL-5 years	21,068	21,068		42,136
Unit 4 Weir Assessment	87,336			87,336	SL-5 years	-	17,467		17,467
Vegetation Management on Powerline Rights of Way	47,421			47,421	SL-5 years	2,371	9,484		11,855
Waste To Energy	1,667,372			1,667,372	SL-10 years	826,477	166,737		993,214
Waste To Energy Contribution	(782,591)			(782,591)	SL-10 years	(384,606)	(78,259)		(462,865)
Whitehorse Diesel Plant Conversion	318,814			318,814	SL-5 years	63,763	63,763		127,526
Whitehorse Turbine Re-runnering	164,134			164,134	SL-5 years	13,760	32,827		46,587
Wind Feasibility - Ferry Hill	118,743			118,743	SL-5 years	23,749	23,749		47,497
WRGS Contamination Assessment	35,307			35,307	SL-5 years	21,184	7,061		28,245
YDC Feasibility Asset Contribution	(3,574,464)		103,686	(3,470,777)	SL-5 years	(1,238,441)	(617,580)	103,686	(1,752,335)
Total Feasibility Study Closed	13,264,383	132,667	(68,761)	13,328,289		3,355,662	1,790,866	(68,761)	5,077,767
Work in Progress:									
Dawson Downtown Voltage Upgrade Assessment	-	76,552		76,552					
Disaster Recovery / Business Continuity Plan	3,464	292	(3,756)	-					
Dyke Heating Pipe Assessment	-	8,416		8,416					
Emergency Preparedness Improvement	-	48,130		48,130					
Energy Storage System	15,113	8,207		23,320					
GIS Assessment	-	44,613		44,613					
IPP Standing Offer Program Implementation	-	48,127		48,127					
Mayo & Aishihik Climate Change	304,757	169,556		474,313					
Mayo Lake Outlet Channel	435,876	69,051		504,927					
Mt Sumanik Wind Feasibility Study	618,184	76,242		694,426					
N-1 Event Risk Assessment	39,142	89,769	(128,911)	-					
Southern Lakes Storage	7,168,290	150,789		7,319,079					
Diesel Retirement Replacement	5,011	35,996		41,007					
Wareham Spillgate Leakage Reduction Study	-	49,579		49,579					
Water Study Main Building	-	7,451		7,451					
WH2 Uprate Assessment	-	207,944		207,944					
Total Feasibility Study WIP	8,589,838	1,090,716	(132,667)	9,547,887					
Total Feasibility	21,854,221	1,223,384	(201,429)	22,876,176	-	3,355,662	1,790,866	(68,761)	5,077,767

YUKON ENERGY CORPORATION **Table 5.3**
Continuity Schedule of Deferred Costs (2018) **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2018 Actual		Dec 31	Amortization	Dec 31	2018 Actual		Dec 31
	2017	Additions	Transfers /Retired	2018	Rate and Method	2017	Expenses	Retired	2018
Regulatory									
Completed Projects:									
Arc Flash Study	178,986			178,986	SL-5 years	35,797	35,797		71,594
Asset Appraisal - Replacment Cost	-	46,631		46,631	SL-5 years	-	6,217		6,217
DSM	3,490,061	272,928	(12,378)	3,750,611	SL-10 years	328,576	349,006		677,582
DSM Contribution	(974,549)			(974,549)	SL-10 years	(97,455)	(97,455)		(194,910)
IFRS Transition	181,080			181,080	SL-5 years	36,216	36,216		72,432
Resource Plan Update - 2016	244,223			244,223	SL-5 years	48,845	48,845		97,689
Resource Plan Update - 2016 Contribution	(6,000)			(6,000)	SL-5 years	(1,200)	(1,200)		(2,400)
Victoria Gold PPA Process	-	226,100	(84,500)	141,600	SL-5 years	-	11,800		11,800
Victoria Gold PPA Process Contribution	-	(100,000)		(100,000)	SL-5 years	-	(8,384)		(8,384)
YUB 2007-7 & 9 - PPA Review	243,045			243,045	SL-12 years	202,537	20,254		222,791
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	41,113	4,111		45,225
Total Regulatory Closed	3,541,857	445,659	(96,877)	3,890,639		594,430	405,208	-	999,638
Work in Progress:									
2012 ERA and Long-Term Hydro YUB Application	56,843	13,796	(70,639)	-					
Asset Appraisal - Replacement Cost	-	46,631	(46,631)	-					
DSM	180,415	92,513	(272,928)	-					
DSM Program Development	-	257,478		257,478					
General Rate Application - 2017/18	550,771	374,268		925,038					
Victoria Gold PPA Process	196,959	29,141	(226,100)	-					
Victoria Gold PPA Process Contributions	(100,000)	-	100,000	-					
Total Regulatory WIP	884,988	813,827	(516,299)	1,182,517					
Total Regulatory	4,426,845	1,259,486	(613,176)	5,073,156		594,430	405,208	-	999,638
Relicensing									
Completed Projects:									
Aishihik Relicensing	8,779,230		(1,399,869)	7,379,361		7,901,847	483,319	(1,399,869)	6,985,297
Whitehorse Relicensing	285,867			285,867		137,075	20,604		157,678
Mayo Relicensing	139,006			139,006		50,637	11,347		61,983
Total Relicensing Closed	9,204,103	-	(1,399,869)	7,804,234		8,089,559	515,269	(1,399,869)	7,204,959
Work in Progress:									
Mayo Lake Storage Assessment	2,515,013	353,434		2,868,447					
Aishihik Relicensing	2,974,250	1,982,949		4,957,199					
Whitehorse Hatchery Water Relicensing	-	22,203		22,203					
Total Relicensing WIP	5,489,264	2,358,586	-	7,847,849	-	-	-		-
Total Relicensing	14,693,367	2,358,586	(1,399,869)	15,652,083	-	8,089,559	515,269	(1,399,869)	7,204,959
Dam Safety Review									
Completed projects	147,712			147,712	SL-5 years	29,542	29,542		59,085
Work in Progress	-			-					
Total Dam Safety Review	147,712	-	-	147,712		29,542	29,542	-	59,085
Total Deferred Costs	**41,122,145**	**4,841,456**	**-2,214,474**	**43,749,127**		**12,069,193**	**2,740,885**	**-1,468,631**	**13,341,448**
Closed				**25,170,874**					
WIP				**18,578,253**					
Net Deferred Costs (excluding WIP)									**11,829,426**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION **Table 5.4**
Continuity Schedule of Deferred Costs (2019) **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2019 Actual		Dec 31	Amortization	Dec 31	2019 Actual		Dec 31
	2018	Additions	Transfers /Retired	2019	Rate and Method	2018	Expenses	Retired	2019
Feasibility Study									
Completed Projects:									
Aishihik Turbine Re-Runnering	115,894			115,894	SL-5 years	46,358	23,179		69,536
Asset Condition Assessment	127,545			127,545	SL-5 years	51,018	25,509		76,527
Asset Management Plan	417,641			417,641	SL-5 years	83,528	83,528		167,057
Atlin Storage	2,230,652			2,230,652	SL-10 years	1,561,458	223,065		1,784,523
Biogas Preliminary Design 2 Contribution	(16,500)			(16,500)	SL-5 years	(9,625)	(3,300)		(12,925)
Biogas Study	95,288		(23,469)	71,819	SL-5 years	60,670	19,058	(23,469)	56,258
Biogas Study Contribution	(7,000)		7,000	-	SL-5 years	(5,600)	(1,400)	7,000	(0)
Building Condition Reports	104,405			104,405	SL-5 years	41,762	20,881		62,643
Carmacks Airport Substation	50,627			50,627	SL-5 years	31,191	10,125		41,316
Climate Change Study	604,377			604,377	SL-5 years	211,532	120,875		332,407
Condition Assessment of Selected YEC Assets	230,631			230,631	SL-5 years	92,252	46,126		138,379
Condition Assessment of WH & WD Assets	227,969			227,969	SL-5 years	91,188	45,594		136,782
Cross Arm Replacements Evaluation	189,614			189,614	SL-5 years	75,846	37,923		113,768
Dawson Downtown Distribution Fusing	4,122			4,122	SL-5 years	1,649	824		2,473
Dawson Downtown Voltage Upgrade Assessment	-	78,648		78,648	SL-5 years	-	-		-
Detailed Line Inspection L169-L172	231,146			231,146	SL-5 years	46,229	46,229		92,459
Diesel Generator Protection	34,476			34,476	SL-5 years	7,470	6,895		14,365
Disaster Recovery / Business Continuity Plan	3,756			3,756	SL-5 years	723	751		1,474
Dyke Heating Pipe Assessment	-	68,263		68,263	SL-5 years	-	3,413		3,413
Electric Vehicle Technical Study	67,919			67,919	SL-5 years	36,224	13,584		49,808
Electric Vehicle Technical Study - Contributions	(3,500)			(3,500)	SL-5 years	(1,867)	(700)		(2,567)
Emergency Preparedness Improvement	-	75,011		75,011	SL-5 years	-	-		-
Enterprise Risk Management	169,398			169,398	SL-5 years	67,759	33,880		101,639
Evaluation of CIS Options	26,113			26,113	SL-5 years	5,223	5,223		10,445
Faro Mine Pumped Storage Project	21,634			21,634	SL-5 years	12,981	4,327		17,307
Geothermal	1,947,411			1,947,411	SL-10 years	1,363,188	194,741		1,557,929
Gladstone	4,521,265			4,521,265	SL-10 years	904,253	452,126		1,356,380
Home Heating Retrofit Options	9,684			9,684	SL-5 years	5,003	1,937		6,940
Hoole Canyon and Slate Rapids	40,845			40,845	SL-5 years	24,507	8,169		32,676
IFRS Upgrades	72,592			72,592	SL-5 years	14,518	14,518		29,037
L170 Cross Arm Testing & Change	50,824		(50,824)	-	SL-5 years	40,659	10,165	(50,824)	0
Large Hydro	291,237			291,237	SL-5 years	116,495	58,247		174,742
Life Cycle Analysis of LNG/Diesel	118,036			118,036	SL-5 years	47,214	23,607		70,822
LNG Boil Off Gas Options	46,317			46,317	SL-5 years	18,527	9,263		27,790
LNG Feasibility Study	(150,000)			(150,000)	SL-5 years	(60,000)	(30,000)		(90,000)
LNG Supply Option	273,095			273,095	SL-5 years	109,238	54,619		163,857
LNG Third Engine Assessment	47,081			47,081	SL-5 years	9,416	9,416		18,833
LNG Transportation Options	277,700			277,700	SL-5 years	111,080	55,540		166,620
LNG Transportation Options Contribution	(15,000)			(15,000)	SL-5 years	(6,000)	(3,000)		(9,000)
Load Forecasting	17,148			17,148	SL-5 years	10,288	3,430		13,718
Mayo A Hydro Assessment	95,038			95,038	SL-5 years	44,351	19,008		63,359
Mayo A&B Road Infrastructure Study	-	14,510		14,510	SL-5 years	-	1,451		1,451
Mayo Hydro Bridge Icing Upgrade	15,603		(15,603)	-	SL-5 years	12,482	3,121	(15,603)	0
Moon Lake Hydro Project	170,667			170,667	SL-5 years	34,133	34,133		68,267
N-1 Event Risk Assessment	128,911			128,911	SL-5 years	-	25,782		25,782
Resource Plan Update - 2016	2,015,083			2,015,083	SL-5 years	570,940	403,017		973,957
SKTP Planning 2015-2017	3,389,993			3,389,993	SL-5 years	1,186,497	677,999		1,864,496
SKTP-YG Funding	(3,389,993)			(3,389,993)	SL-5 years	(1,186,497)	(677,999)		(1,864,496)
Solar PV Installation-WH	48,901			48,901	SL-5 years	29,341	9,780		39,121
System Stability Review	88,544		(88,544)	-	SL-5 years	70,835	17,709	(88,544)	0
Transformer T9 Assessment	105,341			105,341	SL-5 years	42,136	21,068		63,205
Unit 4 Weir Assessment	87,336			87,336	SL-5 years	17,467	17,467		34,934
Vegetation Management on Powerline Rights of Way	47,421			47,421	SL-5 years	11,855	9,484		21,340
Waste To Energy	1,667,372			1,667,372	SL-10 years	993,214	166,737		1,159,952
Waste To Energy Contribution	(782,591)			(782,591)	SL-10 years	(462,865)	(78,259)		(541,124)
Water Study Main Building	-	13,409		13,409	SL-5 years	-	1,341		1,341
Whitehorse Diesel Plant Conversion	318,814			318,814	SL-5 years	127,526	63,763		191,288
Whitehorse Turbine Re-runnering	164,134			164,134	SL-5 years	46,587	32,827		79,414
Wind Feasibility - Ferry Hill	118,743			118,743	SL-5 years	47,497	23,749		71,246
WRGS Contamination Assessment	35,307		(35,307)	-	SL-5 years	28,245	7,061	(35,307)	(0)
YDC Feasibility Asset Contribution	(3,470,777)		170,996	(3,299,781)	SL-5 years	(1,752,335)	(584,111)	170,996	(2,165,450)
Total Feasibility Study Closed	13,328,289	249,842	(35,749)	13,542,382		5,077,767	1,823,496	(35,749)	6,865,514
Work in Progress:									
Dawson Downtown Voltage Upgrade Assessment	76,552	2,096	(78,648)	-					
Dyke Heating Pipe Assessment	8,416	59,847	(68,263)	-					
Emergency Preparedness Improvement	48,130	26,881	(75,011)	-					
Energy Storage System	23,320		(23,320)	-					
GIS Assessment	44,613	1,137	(45,750)	-					
IPP Standing Offer Program Implementation	48,127	183,912		232,039					
Mayo & Aishihik Climate Change	474,313	124,249		598,562					
Mayo A & B Road Infrastructure Study	-	-		-					
Mayo Lake Outlet Channel	504,927	11,872	(516,800)	-					
Mt Sumanik Wind Feasibility Study	694,426	31,155		725,581					
Small Hydro	-	16,028		16,028					
Southern Lakes Storage	7,319,079	374,889		7,693,968					
Diesel Retirement Replacement	41,007	554,224		595,231					
Wareham Spillgate Leakage Reduction Study	49,579	303		49,882					
Water Study Main Building	7,451	5,957	(13,409)	-					
WH2 Uprate Assessment	207,944	44,448		252,393					
Total Feasibility Study WIP	9,547,887	1,436,998	(821,201)	10,163,683					
Total Feasibility	22,876,176	1,686,840	(856,951)	23,706,066	-	5,077,767	1,823,496	(35,749)	6,865,514

YUKON ENERGY CORPORATION **Table 5.4**
Continuity Schedule of Deferred Costs (2019) **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2019 Actual		Dec 31	Amortization	Dec 31	2019 Actual		Dec 31
	2018	Additions	Transfers /Retired	2019	Rate and Method	2018	Expenses	Retired	2019
Regulatory									
Completed Projects:									
Arc Flash Study	178,986			178,986	SL-5 years	71,594	35,797		107,392
Asset Appraisal - Replacment Cost	46,631			46,631	SL-5 years	6,217	9,326		15,544
DSM	3,750,611	14,285		3,764,896	SL-10 years	677,582	401,116		1,078,699
DSM Contribution	(974,549)			(974,549)	SL-10 years	(194,910)	(97,455)		(292,365)
DSM Program Development	-	385,009		385,009	SL-10 years	-	-		-
IFRS Transition	181,080			181,080	SL-5 years	72,432	36,216		108,648
Resource Plan Update - 2016	244,223			244,223	SL-5 years	97,689	48,845		146,534
Resource Plan Update - 2016 Contribution	(6,000)			(6,000)	SL-5 years	(2,400)	(1,200)		(3,600)
Victoria Gold PPA Process	141,600			141,600	SL-5 years	11,800	28,320		40,120
Victoria Gold PPA Process Contribution	(100,000)			(100,000)	SL-5 years	(8,384)	(20,000)		(28,384)
YUB 2007-7 & 9 - PPA Review	243,045		(243,045)	-	SL-12 years	222,791	20,254	(243,045)	(0)
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	45,225	4,111		49,336
Total Regulatory Closed	3,890,639	399,294	(243,045)	4,046,888		999,638	465,331	(243,045)	1,221,924
Work in Progress:									
10 Year Renewable Energy Plan	-	310,842		310,842					
DSM	-	14,285	(14,285)	-					
DSM Program Development	257,478	127,531	(385,009)	-					
DSM Residential Demand Response Pilot	-	433,612		433,612					
DSM Residential Demand Response Pilot Contributions	-	(365,315)		(365,315)					
General Rate Application - 2017/18	925,038	43,549	(834,879)	133,708					
General Rate Application - 2021	-	154,875		154,875					
Total Regulatory WIP	1,182,517	719,379	(1,234,173)	667,722					
Total Regulatory	5,073,156	1,118,673	(1,477,218)	4,714,611		999,638	465,331	(243,045)	1,221,924
Relicensing									
Completed Projects:									
Aishihik Relicensing	7,379,361		(7,379,361)	-		6,985,297	394,064	(7,379,361)	0
Aishihik 2020 3 Year Relicensing	-	804,593		804,593		-	-		-
Whitehorse Hatchery Water Relicensing	-	39,987		39,987		-	800		800
Whitehorse Relicensing	285,867			285,867		157,678	20,604		178,282
Mayo Relicensing	139,006		(10,204)	128,802		61,983	11,077	(10,204)	62,856
Total Relicensing Closed	7,804,234	844,579	(7,389,565)	1,259,248		7,204,959	426,544	(7,389,565)	241,938
Work in Progress:									
Mayo Lake Outlet Channel	-	-	516,800	516,800					
Mayo Lake Storage Assessment	2,868,447	250,507		3,118,954					
Aishihik 2020 25 Year Relicensing	4,957,199	512,755		5,469,954					
Aishihik 2020 3 Year Relicensing	-	804,593	(804,593)	-					
Whitehorse Hatchery Water Relicensing	22,203	17,784	(39,987)	-					
Total Relicensing WIP	7,847,849	1,585,638	(327,780)	9,105,708	-	-	-	-	-
Total Relicensing	15,652,083	2,430,218	(7,717,345)	10,364,956	-	7,204,959	426,544	(7,389,565)	241,938
Dam Safety Review									
Completed projects	147,712			147,712	SL-5 years	59,085	29,542	-	88,627
Work in Progress	-			-					
Total Dam Safety Review	147,712	-	-	147,712		59,085	29,542	-	88,627
Total Deferred Costs	**43,749,127**	**5,235,730**	**-10,051,513**	**38,933,344**		**13,341,448**	**2,744,914**	**-7,668,359**	**8,418,003**
Closed				**18,996,231**					
WIP				**19,937,114**					
Net Deferred Costs (excluding WIP)									**10,578,228**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION **Table 5.5**
Continuity Schedule of Deferred Costs (2020) **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2020 Forecast		Dec 31	Amortization	Dec 31	2020 Forecast		Dec 31
	2019	Additions	Transfers /Retired	2020	Rate and Method	2019	Expenses	Retired	2020
Feasibility Study									
Completed Projects:									
Aishihik Elevator Study	-	15,000		15,000	SL-5 years	-	-		-
Aishihik Turbine Re-Runnering	115,894			115,894	SL-5 years	69,536	23,179		92,715
Asset Condition Assessment	127,545			127,545	SL-5 years	76,527	25,509		102,036
Asset Management Plan	417,641			417,641	SL-5 years	167,057	83,528		250,585
Atlin Storage	2,230,652			2,230,652	SL-10 years	1,784,523	223,065		2,007,589
Biogas Preliminary Design 2 Contribution	(16,500)			(16,500)	SL-5 years	(12,925)	(3,300)		(16,225)
Biogas Study	71,819			71,819	SL-5 years	56,258	14,364		70,622
Building Condition Reports	104,405			104,405	SL-5 years	62,643	20,881		83,524
Business Continuity Plan	-	80,000		80,000	SL-5 years	-	-		-
Carmacks Airport Substation	50,627		(50,627)	-	SL-5 years	41,316	9,310	(50,627)	0
Climate Change Study	604,377			604,377	SL-5 years	332,407	120,875		453,282
Condition Assessment of Selected YEC Assets	230,631			230,631	SL-5 years	138,379	46,126		184,505
Condition Assessment of WH & WD Assets	227,969			227,969	SL-5 years	136,782	45,594		182,375
Cross Arm Replacements Evaluation	189,614			189,614	SL-5 years	113,768	37,923		151,691
Dawson Downtown Distribution Fusing	4,122			4,122	SL-5 years	2,473	824		3,297
Dawson Downtown Voltage Upgrade Assessment	78,648			78,648	SL-5 years	-	15,730		15,730
Detailed Line Inspection L169-L172	231,146			231,146	SL-5 years	92,459	46,229		138,688
Diesel Generator Protection	34,476			34,476	SL-5 years	14,365	6,895		21,260
Disaster Recovery / Business Continuity Plan	3,756			3,756	SL-5 years	1,474	751		2,225
Dyke Heating Pipe Assessment	68,263			68,263	SL-5 years	3,413	13,653		17,066
Electric Vehicle Technical Study	67,919			67,919	SL-5 years	49,808	13,584		63,391
Electric Vehicle Technical Study - Contributions	(3,500)			(3,500)	SL-5 years	(2,567)	(700)		(3,267)
Emergency Preparedness Improvement	75,011			75,011	SL-5 years	-	15,002		15,002
Enterprise Risk Management	169,398			169,398	SL-5 years	101,639	33,880		135,518
Evaluation of CIS Options	26,113			26,113	SL-5 years	10,445	5,223		15,668
Faro Mine Pumped Storage Project	21,634		(21,634)	-	SL-5 years	17,307	4,327	(21,634)	(0)
Geothermal	1,947,411			1,947,411	SL-10 years	1,557,929	194,741		1,752,670
Gladstone	4,521,265			4,521,265	SL-10 years	1,356,380	452,126		1,808,506
Home Heating Retrofit Options	9,684			9,684	SL-5 years	6,940	1,937		8,877
Hoole Canyon and Slate Rapids	40,845		(40,845)	-	SL-5 years	32,676	8,169	(40,845)	0
IFRS Upgrades	72,592			72,592	SL-5 years	29,037	14,518		43,555
IPP Standing Offer Program Implementation	-	232,039		232,039	SL-5 years	-	-		-
Large Hydro	291,237			291,237	SL-5 years	174,742	58,247		232,990
Life Cycle Analysis of LNG/Diesel	118,036			118,036	SL-5 years	70,822	23,607		94,429
LNG Boil Off Gas Options	46,317			46,317	SL-5 years	27,790	9,263		37,054
LNG Feasibility Study	(150,000)			(150,000)	SL-5 years	(90,000)	(30,000)		(120,000)
LNG Supply Option	273,095			273,095	SL-5 years	163,857	54,619		218,476
LNG Third Engine Assessment	47,081			47,081	SL-5 years	18,833	9,416		28,249
LNG Transportation Options	277,700			277,700	SL-5 years	166,620	55,540		222,160
LNG Transportation Options Contribution	(15,000)			(15,000)	SL-5 years	(9,000)	(3,000)		(12,000)
Load Forecasting	17,148		(17,148)	-	SL-5 years	13,718	3,430	(17,148)	(0)
Mayo A Hydro Assessment	95,038			95,038	SL-5 years	63,359	19,008		82,366
Mayo A&B Road Infrastructure Study	14,510			14,510	SL-5 years	1,451	2,902		4,353
Mayo & Aishihik Climate Change	-	638,562		638,562	SL-5 years	-	-		-
Moon Lake Hydro Project	170,667			170,667	SL-5 years	68,267	34,133		102,400
Mt Sumanik Wind Feasibility Study		775,581		775,581	SL-5 years	-	-		-
N-1 Event Risk Assessment	128,911			128,911	SL-5 years	25,782	25,782		51,564
Repeater Network Upgrade Assessment	-	50,000		50,000	SL-5 years	-	-		-
Resource Plan Update - 2016	2,015,083			2,015,083	SL-5 years	973,957	403,017		1,376,974
SKTP Planning 2015-2017	3,389,993			3,389,993	SL-5 years	1,864,496	677,999		2,542,495
SKTP-YG Funding	(3,389,993)			(3,389,993)	SL-5 years	(1,864,496)	(677,999)		(2,542,495)
Small Hydro	-	16,028		16,028	SL-5 years	-	-		-
Solar PV Installation-WH	48,901		(48,901)	-	SL-5 years	39,121	9,780	(48,901)	(0)
Transformer T9 Assessment	105,341			105,341	SL-5 years	63,205	21,068		84,273
Transmission Access Road Program Study	-	132,787		132,787	SL-5 years	-	-	-	-
Trash Rack Cleaning Study	-	90,000		90,000	SL-5 years	-	-	-	-
Unit 4 Weir Assessment	87,336			87,336	SL-5 years	34,934	17,467		52,402
Vegetation Management on Powerline Rights of Way	47,421			47,421	SL-5 years	21,340	9,484		30,824
Wareham Spillgate Leakage Reduction Study	-	49,882		49,882	SL-5 years	-	-		-
Waste To Energy	1,667,372			1,667,372	SL-10 years	1,159,952	166,737		1,326,689
Waste To Energy Contribution	(782,591)			(782,591)	SL-10 years	(541,124)	(78,259)		(619,383)
Water Study Main Building	13,409			13,409	SL-5 years	1,341	2,682		4,023
Whitehorse Diesel Plant Conversion	318,814			318,814	SL-5 years	191,288	63,763		255,051
Whitehorse Turbine Re-runnering	164,134			164,134	SL-5 years	79,414	32,827		112,240
WH4 Turbine Floor Cooling Upgrade Assessment	-	70,000		70,000	SL-5 years	-	-		-
Wind Feasibility - Ferry Hill	118,743			118,743	SL-5 years	71,246	23,749		94,994
YDC Feasibility Asset Contribution	(3,299,781)			(3,299,781)	SL-5 years	(2,165,450)	(540,559)		(2,706,008)
Total Feasibility Study Closed	13,542,382	2,149,879	(179,155)	15,513,106		6,865,514	1,868,648	(179,155)	8,555,007
Work in Progress:									
Aishihik Elevator Study	-	15,000	(15,000)	-					
Business Continuity Plan	-	80,000	(80,000)	-					
Diesel Retirement Replacement	595,231	800,000		1,395,231					
IPP Standing Offer Program Implementation	232,039		(232,039)	-					
Mayo & Aishihik Climate Change	598,562	40,000	(638,562)	-					
Mt Sumanik Wind Feasibility Study	725,581	50,000	(775,581)	-					
Repeater Network Upgrade Assessment	-	50,000	(50,000)	-					
Small Hydro	16,028		(16,028)	-					
Southern Lakes Storage	7,693,968	485,000		8,178,968					
Transmission Access Road Program Study	-	132,787	(132,787)	-					
Trash Rack Cleaning Study	-	90,000	(90,000)	-					
Wareham Spillgate Leakage Reduction Study	49,882		(49,882)	-					
WH2 Uprate Assessment	252,393	6,679		259,072					
WH4 Turbine Floor Cooling Upgrade Assessment	-	70,000	(70,000)	-					
Total Feasibility Study WIP	10,163,683	1,819,466	(2,149,879)	9,833,270					
Total Feasibility	23,706,066	3,969,345	(2,329,034)	25,346,377		6,865,514	1,868,648		8,555,007

YUKON ENERGY CORPORATION — **Table 5.5**
Continuity Schedule of Deferred Costs (2020) — **November 2020**
($)

	Total Expenditures				Amortization	Accumulated Amortization			
	Dec 31	2020 Forecast		Dec 31	Rate and	Dec 31	2020 Forecast		Dec 31
	2019	Additions	Transfers /Retired	2020	Method	2019	Expenses	Retired	2020
Regulatory									
Completed Projects:									
10 Year Renewable Energy Plan	-	712,967		712,967	SL-5 years	-	-		-
Arc Flash Study	178,986			178,986	SL-5 years	107,392	35,797		143,189
Asset Appraisal - Replacment Cost	46,631			46,631	SL-5 years	15,544	9,326		24,870
Atlin Hydro EPA Preparation	-	200,000		200,000	SL-5 years	-	-		-
DSM	3,764,896			3,764,896	SL-10 years	1,078,699	402,545		1,481,244
DSM Contribution	(974,549)			(974,549)	SL-10 years	(292,365)	(97,455)		(389,819)
DSM Program Development	385,009			385,009	SL-10 years	-	38,501		38,501
DSM Residential Demand Response Pilot	-	808,612		808,612	SL-10 years	-	-		-
DSM Residential Demand Response Pilot Contributions	-	(365,315)		(365,315)	SL-10 years	-	-		-
IFRS Transition	181,080			181,080	SL-5 years	108,648	36,216		144,864
Resource Plan Update - 2016	244,223			244,223	SL-5 years	146,534	48,845		195,379
Resource Plan Update - 2016 Contribution	(6,000)			(6,000)	SL-5 years	(3,600)	(1,200)		(4,800)
Victoria Gold PPA Process	141,600			141,600	SL-5 years	40,120	28,320		68,440
Victoria Gold PPA Process Contribution	(100,000)			(100,000)	SL-5 years	(28,384)	(20,000)		(48,384)
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	49,336	4,111		53,447
Total Regulatory Closed	4,046,888	1,356,264	-	5,403,152		1,221,924	485,007		1,706,930
Work in Progress:									
10 Year Renewable Energy Plan	310,842	402,125	(712,967)	-					
10 Year Renewable Energy Plan Contributions	-			-					
Atlin Hydro EPA Preparation	-	200,000	(200,000)	-					
DSM Residential Demand Response Pilot	433,612	375,000	(808,612)	-					
DSM Residential Demand Response Pilot Contributions	(365,315)		365,315	-					
General Rate Application - 2017/18	133,708	(88,979)	-	44,729					
General Rate Application - 2021	154,875	250,000		404,875					
Total Regulatory WIP	667,722	1,138,146	(1,356,264)	449,604					
Total Regulatory	4,714,611	2,494,410	(1,356,264)	5,852,757		1,221,924	485,007		1,706,930
Relicensing									
Completed Projects:									
Aishihik 2020 3 Year Relicensing	804,593	200,000		1,004,593		-	268,198		268,198
Whitehorse Hatchery Water Relicensing	39,987			39,987		800	1,599		2,399
Whitehorse Relicensing	285,867			285,867		178,282	20,604		198,886
Mayo Relicensing	128,802			128,802		62,856	10,938		73,795
Total Relicensing Closed	1,259,248	200,000	-	1,459,248		241,938	301,339		543,277
Work in Progress:									
Mayo Lake Outlet Channel	516,800			516,800					
Mayo Lake Storage Assessment	3,118,954	460,000		3,578,954					
Aishihik 2020 25 Year Relicensing	5,469,954	1,488,000		6,957,954					
Aishihik 2020 3 Year Relicensing	-	200,000	(200,000)	-					
Total Relicensing WIP	9,105,708	2,148,000	(200,000)	11,053,708	-	-	-		-
Total Relicensing	10,364,956	2,348,000	(200,000)	12,512,956	-	241,938	301,339		543,277
Dam Safety Review									
Completed projects	147,712	315,000		462,712	SL-5 years	88,627	29,542.39		118,170
Work in Progress	-	315,000	(315,000)	-					
Total Dam Safety Review	147,712	630,000	(315,000)	462,712		88,627	29,542		118,170
Total Deferred Costs	**38,933,344**	**9,441,755**	**-4,200,298**	**44,174,801**		**8,418,003**	**2,684,536**		**10,923,383**
Closed				**22,838,219**					
WIP				**21,336,582**					
Net Deferred Costs (excluding WIP)									**11,914,836**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.

YUKON ENERGY CORPORATION **Table 5.6**
Continuity Schedule of Deferred Costs (2021) **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2021 Forecast		Dec 31	Amortization Rate and Method	Dec 31	2021 Forecast		Dec 31
	2020	Additions	Transfers /Retired	2021		2020	Expenses	Retired	2021
Feasibility Study									
Completed Projects:									
Aishihik Elevator Study	15,000			15,000	SL-5 years	-	3,000		3,000
Aishihik Turbine Re-Runnering	115,894		(115,894)	-	SL-5 years	92,715	23,179	(115,894)	0
Asset Condition Assessment	127,545		(127,545)	-	SL-5 years	102,036	25,509	(127,545)	(0)
Asset Management Plan	417,641			417,641	SL-5 years	250,585	83,528		334,113
Atlin Storage	2,230,652		(2,230,652)	-	SL-10 years	2,007,589	223,065	(2,230,654)	-
Biogas Preliminary Design 2 Contribution	(16,500)		(16,500)	(33,000)	SL-5 years	(16,225)	(275)	(16,500)	(33,000)
Biogas Study	71,819		(71,819)	-	SL-5 years	70,622	1,197	(71,819)	-
Building Condition Reports	104,405		(104,405)	(0)	SL-5 years	83,524	20,881	(104,405)	-
Building Condition Reports 2021-2024	-	175,000		175,000	SL-5 years	-	-		-
Business Continuity Plan	80,000	75,000		155,000	SL-5 years	-	16,000		16,000
Climate Change Study	604,377			604,377	SL-5 years	453,282	120,875		574,158
Condition Assessment of Selected YEC Assets	230,631		(230,631)	0	SL-5 years	184,505	46,126	(230,631)	-
Condition Assessment of WH & WD Assets	227,969		(227,969)	(0)	SL-5 years	182,375	45,594	(227,969)	-
Cross Arm Replacements Evaluation	189,614		(189,614)	(0)	SL-5 years	151,691	37,923	(189,614)	-
Dawson Downtown Distribution Fusing	4,122		(4,122)	(0)	SL-5 years	3,297	824	(4,122)	-
Dawson Downtown Voltage Upgrade Assessment	78,648			78,648	SL-5 years	15,730	15,730		31,459
Detailed Line Inspection L169-L172	231,146			231,146	SL-5 years	138,688	46,229		184,917
Diesel Generator Protection	34,476			34,476	SL-5 years	21,260	6,895		28,155
Disaster Recovery / Business Continuity Plan	3,756			3,756	SL-5 years	2,225	751		2,977
Dyke Heating Pipe Assessment	68,263			68,263	SL-5 years	17,066	13,653		30,719
Electric Vehicle Technical Study	67,919		(67,919)	-	SL-5 years	63,391	4,528	(67,919)	-
Electric Vehicle Technical Study - Contributions	(3,500)		3,500	-	SL-5 years	(3,267)	(233)	3,500	-
Emergency Preparedness Improvement	75,011			75,011	SL-5 years	15,002	15,002		30,004
Enterprise Risk Management	169,398		(169,398)	-	SL-5 years	135,518	33,880	(169,398)	(0)
Evaluation of CIS Options	26,113			26,113	SL-5 years	15,668	5,223		20,890
Geothermal	1,947,411		(1,947,411)	-	SL-10 years	1,752,670	194,741	(1,947,411)	0
Gladstone	4,521,265			4,521,265	SL-10 years	1,808,506	452,126		2,260,633
Home Heating Retrofit Options	9,684		(9,684)	-	SL-5 years	8,877	807	(9,684)	-
IFRS Upgrades	72,592			72,592	SL-5 years	43,555	14,518		58,074
IPP Standing Offer Program Implementation	232,039			232,039	SL-5 years	-	46,408		46,408
Large Hydro	291,237		(291,237)	-	SL-5 years	232,990	58,247	(291,237)	0
Life Cycle Analysis of LNG/Diesel	118,036		(118,036)	-	SL-5 years	94,429	23,607	(118,036)	0
LNG Boil Off Gas Options	46,317		(46,317)	-	SL-5 years	37,054	9,263	(46,317)	0
LNG Feasibility Study	(150,000)		150,000	-	SL-5 years	(120,000)	(30,000)	150,000	-
LNG Supply Option	273,095		(273,095)	-	SL-5 years	218,476	54,619	(273,095)	0
LNG Third Engine Assessment	47,081			47,081	SL-5 years	28,249	9,416		37,665
LNG Transportation Options	277,700		(277,700)	-	SL-5 years	222,160	55,540	(277,700)	(0)
LNG Transportation Options Contribution	(15,000)		15,000	-	SL-5 years	(12,000)	(3,000)	15,000	-
Mayo A Hydro Assessment	95,038		(95,038)	-	SL-5 years	82,366	12,672	(95,038)	-
Mayo A&B Road Infrastructure Study	14,510			14,510	SL-5 years	4,353	2,902		7,255
Mayo & Aishihik Climate Change	638,562			638,562	SL-5 years	-	127,712		127,712
Moon Lake Hydro Project	170,667			170,667	SL-5 years	102,400	34,133		136,534
Mt Sumanik Wind Feasibility Study	775,581			775,581	SL-5 years	-	155,116		155,116
N-1 Event Risk Assessment	128,911			128,911	SL-5 years	51,564	25,782		77,347
PMF Flood Study	-	150,000		150,000	SL-5 years	-	-		-
Repeater Network Upgrade Assessment	50,000			50,000	SL-5 years	-	10,000		10,000
Resource Plan Update - 2016	2,015,083			2,015,083	SL-5 years	1,376,974	403,017		1,779,990
SKTP Planning 2015-2017	3,389,993			3,389,993	SL-5 years	2,542,495	677,999		3,220,493
SKTP-YG Funding	(3,389,993)			(3,389,993)	SL-5 years	(2,542,495)	(677,999)		(3,220,493)
Small Hydro	16,028			16,028	SL-5 years	-	3,206		3,206
Transformer T9 Assessment	105,341		(105,341)	-	SL-5 years	84,273	21,068	(105,341)	(0)
Transmission Access Road Program Study	132,787	200,000		332,787	SL-5 years	-	26,557		26,557
Trash Rack Cleaning Study	90,000			90,000	SL-5 years	-	18,000		18,000
Unit 4 Weir Assessment	87,336			87,336	SL-5 years	52,402	17,467		69,869
Vegetation Management on Powerline Rights of Way	47,421			47,421	SL-5 years	30,824	9,484		40,308
Wareham Spillgate Leakage Reduction Study	49,882			49,882	SL-5 years	-	9,976		9,976
Waste To Energy	1,667,372			1,667,372	SL-10 years	1,326,689	166,737		1,493,426
Waste To Energy Contribution	(782,591)			(782,591)	SL-10 years	(619,383)	(78,259)		(697,642)
Water Study Main Building	13,409			13,409	SL-5 years	4,023	2,682		6,704
Whitehorse Diesel Plant Conversion	318,814		(318,814)	-	SL-5 years	255,051	63,763	(318,814)	0
Whitehorse Turbine Re-runnering	164,134			164,134	SL-5 years	112,240	32,827		145,067
WH2 Uprate Assessment	-	259,072		259,072	Note 2	-	-		-
WH4 Turbine Floor Cooling Upgrade Assessment	70,000			70,000	SL-5 years	-	14,000		14,000
Whitehorse Diesel Rental Substation Improvements	-	100,000		100,000	SL-5 years	-	-		-
Whitehorse Fire System Investigation	-	20,000		20,000	SL-5 years	-	-		-
Wind Feasibility - Ferry Hill	118,743		(118,743)	-	SL-5 years	94,994	23,749	(118,743)	(0)
YDC Feasibility Asset Contribution	(3,299,781)			(3,299,781)	SL-5 years	(2,706,008)	(505,534)		(3,211,542)
Total Feasibility Study Closed	15,513,106	979,072	(6,989,385)	9,502,793		8,555,007	2,272,436	(6,989,387)	3,838,056
Work in Progress:									
Aishihik Elevator Study	-			-					
Building Condition Reports 2021-2024	-	175,000	(175,000)	-					
Business Continuity Plan	-	75,000	(75,000)	-					
Callison S250-T1 Replacement Assessment	-	50,000		50,000					
Diesel Retirement Replacement	1,395,231	5,000,000		6,395,231					
EV Infrastructure Strategy	-	200,000		200,000					
P125 Trashrack Study	-	200,000		200,000					
PMF Flood Study	-	150,000	(150,000)	-					
Southern Lakes Storage	8,178,968	1,200,000		9,378,968					
Transmission Access Road Program Study	-	200,000	(200,000)	-					
WH2 Uprate Assessment	259,072		(259,072)	-					
WH4 Turbine Floor Cooling Upgrade Assessment	-			-					
Whitehorse Diesel Rental Substation Improvements	-	100,000	(100,000)	-					
Whitehorse Fire System Investigation	-	20,000	(20,000)	-					
Total Feasibility Study WIP	9,833,270	7,370,000	(979,072)	16,224,199					
Total Feasibility	25,346,377	8,349,072	(7,968,456)	25,726,992		8,555,007	2,272,436		3,838,056

YUKON ENERGY CORPORATION — **Table 5.6**
Continuity Schedule of Deferred Costs (2021) — **November 2020**
($)

	Total Expenditures					Accumulated Amortization			
	Dec 31	2021 Forecast		Dec 31	Amortization Rate and Method	Dec 31	2021 Forecast		Dec 31
	2020	Additions	Transfers /Retired	2021		2020	Expenses	Retired	2021
Regulatory									
Completed Projects:									
10 Year Renewable Energy Plan	712,967			712,967	SL-5 years	-	142,593		142,593
Arc Flash Study	178,986			178,986	SL-5 years	143,189	35,797		178,986
Asset Appraisal - Replacment Cost	46,631			46,631	SL-5 years	24,870	9,326		34,196
Atlin Hydro EPA Preparation	200,000			200,000	SL-5 years	-	40,000		40,000
DSM	3,764,896			3,764,896	SL-10 years	1,481,244	402,545		1,883,788
DSM Contribution	(974,549)			(974,549)	SL-10 years	(389,819)	(97,455)		(487,274)
DSM Program Development	385,009	894,000		1,279,009	SL-10 years	38,501	38,501		77,002
DSM Residential Demand Response Pilot	808,612			808,612	SL-10 years	-	80,861		80,861
DSM Residential Demand Response Pilot Contributions	(365,315)			(365,315)	SL-10 years	-	(36,532)		(36,532)
IFRS Transition	181,080			181,080	SL-5 years	144,864	36,216		181,080
Resource Plan Update - 2016	244,223			244,223	SL-5 years	195,379	48,845		244,223
Resource Plan Update - 2016 Contribution	(6,000)			(6,000)	SL-5 years	(4,800)	(1,200)		(6,000)
Victoria Gold PPA Process	141,600			141,600	SL-5 years	68,440	28,320		96,760
Victoria Gold PPA Process Contribution	(100,000)			(100,000)	SL-5 years	(48,384)	(20,000)		(68,384)
YUB 2007-8 - Part 3 Hearing	185,011			185,011	SL-45 years	53,447	4,111		57,559
Total Regulatory Closed	5,403,152	894,000	-	6,297,152		1,706,930	711,929		2,418,860
Work in Progress:									
DSM Program Development	-	894,000	(894,000)	-					
General Rate Application - 2017/18	44,729			44,729					
General Rate Application - 2021	404,875	500,000		904,875					
Total Regulatory WIP	449,604	1,394,000	(894,000)	949,604					
Total Regulatory	5,852,757	2,288,000	(894,000)	7,246,757		1,706,930	711,929		2,418,860
Relicensing									
Completed Projects:									
Aishihik 2020 3 Year Relicensing	1,004,593			1,004,593		268,198	334,864		603,062
Whitehorse Hatchery Water Relicensing	39,987			39,987		2,399	1,599		3,999
Whitehorse Relicensing	285,867			285,867		198,886	20,604		219,489
Mayo Relicensing	128,802			128,802		73,795	10,938		84,733
Total Relicensing Closed	1,459,248	-	-	1,459,248		543,277	368,006		911,282
Work in Progress:									
Mayo Lake Outlet Channel	516,800			516,800					
Mayo Lake Storage Assessment	3,578,954	525,000		4,103,954					
Aishihik 2020 25 Year Relicensing	6,957,954	960,000		7,917,954					
Whitehorse Relicensing	-	260,000		260,000					
Total Relicensing WIP	11,053,708	1,745,000	-	12,798,708	-	-	-		-
Total Relicensing	12,512,956	1,745,000	-	14,257,956	-	543,277	368,006		911,282
Dam Safety Review									
Completed projects	462,712			462,712	SL-5 years	118,170	92,542		210,712
Work in Progress	-			-					
Total Dam Safety Review	147,712	-	-	462,712		88,627	92,542		210,712
Total Deferred Costs	**43,859,801**	**12,382,072**	**-8,862,456**	**47,694,416**		**10,893,841**	**3,444,914**		**7,378,911**
Closed				**17,721,906**					
WIP				**29,972,511**					
Net Deferred Costs (excluding WIP)									**10,342,995**

Notes:
1. This table does not include projects with zero net book value in the beginning of the year.
2. By end of 2021 WH2 Uprate Assessment will be transferred to Property, Plant and Equipment and added to WH2 Uprate total cost [amortized over 72 years starting in 2022].

YUKON ENERGY CORPORATION
Continuity Schedule of Intangible Assets
($000S)

Table 5.7
November 2020

Description	Actual 2018	Actual 2019	Forecast 2020	Forecast 2021
Work in Progress (WIP), Beginning of Year	**0**	**77**	**944**	**4,728**
Expenditures				
EAM Purchase and Implementation	0	809	3,854	275
ERP System Upgrades			200	
Projects under $100K	308	212	185	220
Total Expenditures	308	1,021	4,239	495
Close to Ratebase	-231	-153	-454	-5,223
WIP end of year	**77**	**944**	**4,728**	**0**
Opening Intangibles in-service	**4,282**	**4,512**	**4,993**	**4,678**
Net transfer from WIP	231	153	454	5,223
Retirements and other adjustments	0	327	-769	0
Closing Intangibles in-service	**4,512**	**4,993**	**4,678**	**9,902**
Opening Accumulated Amortization of Intangibles	**2,423**	**2,905**	**3,598**	**3,407**
Amortization	482	693	578	749
Retirements and other adjustments	0	0	-769	0
Closing Accumulated Amortization of Intangibles	**2,905**	**3,598**	**3,407**	**4,156**
Opening NBV of Intangibles in-service	**1,859**	**1,607**	**1,395**	**1,271**
Annual Change	-251	-212	-124	4,475
Closing NBV of Intangibles in-service	**1,607**	**1,395**	**1,271**	**5,746**

APPENDIX 5.1
CAPITAL PROJECTS > $1 MILLION
NOT IMPACTING RATE BASE

APPENDIX 5.1: CAPITAL PROJECTS > $1 MILLION NOT IMPACTING RATE BASE

Appendix 5.1 provides project summaries for capital projects with spending over the period from 2019 to 2021 exceeding $1 million that remain in WIP at the end of 2021 (and therefore do not affect the 2021 GRA revenue requirement). Total forecast spending on these projects is forecast to grow from $1.129 million in 2019, to $2.860 million in 2020 to $31.966 in 2021. The forecast material increase in 2021 spending relates largely to the Battery Energy Storage System project which has $25 million forecast spending in 2021. However, it is noted that spending for this project will be offset by a $16.5 million contribution. Further details on annual spending are summarized in Table 5.2-2.

As outlined below, spending for these projects is largely focused on: (1) capital works to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance); (2) investments to ensure sufficient dependable capacity for the integrated grid; and other projects.

- **Capital Works to Address Sustaining Capital Requirements:**

    1. Dawson Voltage Conversion
    2. MH0 (Mayo A) Generating Station Slope Stability
    3. Replacement of Mayo A Surge Chamber
    4. Stop Log Crane WH Main Spillway
    5. Asset Management Framework

- **Investments to Ensure Dependable Capacity**:

    6. Battery Energy Storage System (transfer from Feasibility)
    7. Pumped Storage
    8. Southern Lakes Transmission Line
    9. Whitehorse Interconnection

- **Other:**

    10. Aishihik Contract Dispute

Summary descriptions for each of these projects are provided in the discussion that follows. It is noted that five of these projects each have total spending less than $1 million by the end of 2021, i.e., Dawson Voltage Conversion ($0.410 million by 2021), Pumped Storage ($0.645 million by 2021), Replacement of Mayo A Surge Chamber ($0.200 million in 2021), Southern Lakes Transmission Line ($0.175 million in 2021), and Stop Log Crane WH Main Spillway ($0.200 million in 2021). In each case, expenditures on additional project activities are anticipated to occur after the test year and expected to exceed $1 million.

5.1-1: CAPITAL WORKS TO ADDRESS SUSTAINING CAPITAL REQUIREMENTS

Summaries for each of the major capital projects being undertaken to address sustaining capital requirements that remain in WIP in 2021 are provided below. Total spending on these major capital works to address sustaining capital requirements to the end of 2021 is approximately $7.130 million.

1. Dawson Voltage Conversion	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
		$60,000	$50,000	$300,000

Dawson City's two 4.16 kV distribution feeders have reached their practical operating limits, resulting in frequent power outages, constant voltage flicker, and longer fault clearing times. Teshmont Consultants LP conducted a site visit to assess the entire 4.16 kV distribution system to identify protection issues, potential voltage levels, transformer utilization and power flow. The primary issues facing the Dawson distribution system were noted as follows:

- Inadequate protection settings resulting from load growth have increased outage frequency and fault clearing times;
- Long feeders result in low available fault currents at the end of the feeders, with high fault currents at the beginning of the feeder, resulting in potential safety concerns if protective devices fail to operate; and
- Poor voltage at the end of each feeder limiting secondary conductor lengths and forcing underutilization of the transformer capacity.

Teshmont recommended converting the operating voltage of the Dawson City distribution system from 4.16 kV to 12.47 kV in a single stage. Increasing the voltage immediately improves the capacity on the existing conductors, reduces fault current at the primary, reduces voltage drops and decreases energy losses. Not addressing the issue will result in reliability safety concerns if protective devices fail to operate; damage to customer equipment; and minor fines related to not meeting CEA voltage requirements.

The project is currently forecast to be completed in 2022.

2. MH0 (Mayo A) Generation Station Slope Stability	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
				$1,500,000

Two key safety and reliability issues related to slope stability have been identified that affect the area in and around the Mayo Generating Station (MH0 or Mayo A) and that are required to be addressed:

1. The access road to the generating station has started to slough down the hill on the downstream side. The upstream side has started to slough onto the road and has caused issues with the ditching and drainage. The rock and soil slides are forcing drivers to avoid these hazards and drive closer to the downstream edge, where the barrier is failing. This results in unsafe driving conditions (with a high potential for injury), as the guiderail is no longer providing an effective barrier as the top of the guiderail is below the top of the road. As this is a road with sufficient grade, snowfall in the area could create a slippery and sliding condition for a vehicle, where the barriers are not there to mitigate the issues.
2. The second issue is the soil/rock slope around the surge chamber. In 2016, a rock fence was provided, and some slope stabilization was undertaken (on the west side of the surge chamber). The east side of the surge chamber is failing and rock slides have damaged the access platform to the surge chamber. Mitigation put in place in 2016 does not prevent finer material from eroding and building up against the MH0 building. The rock and soil have plugged the drainage in the area causing flooding within the building and on the roadway.

The work for this project will include a rock fence, regrading, earthworks, guiderail installation, and erosion control measures. Road alignment will be assessed and modified for safe access. The road will be regraded, the guiderail will be relocated to provide a safe barrier, the upslope will be shaped to minimize erosion, move the alignment of the road, provide erosion control measures, ditching, and culverts. The slope at surge chamber will be stabilized with rock fencing, erosion control measures, and rock anchors to eliminate rocks causing damage, impeding access and causing silt to build up next to the MH0 building resulting in flooding issues. If nothing is done, the road will continue to be blocked and access will be limited and create hazard for operators; slope failure at surge chamber will also progressively get worse and potentially damage infrastructure.

The project is currently forecast to be completed in 2022.

3. Replacement of Mayo A Surge Chamber	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
				$200,000

The Mayo A surge chamber is at end life and must be replaced before there is a catastrophic failure. An engineering study is being undertaken in 2021 to determine solutions and further work is forecast in 2022.

4. Stop Log Crane WH Main Spill Way	2018 WIP	2019 Additions	2020 Additions	2021 Additions
				$200,000

The stop log crane at the Whitehorse hydro main spill way is critical infrastructure that is required for installing stop logs, including in emergency situations. Furthermore, cranes are subject to annual inspection by regulation. The stop log crane is aging and is experiencing a number of issues. Several structural fasteners are showing signs of rusting and possible fatigue. A section of rail on the trolley beam is damaged. The hoist traveling up and down has excessive vibration – and a thorough inspection of the complete open gear transmission has been recommended to determine issues with gear alignment, condition of geared components and proper repair procedures. Due to the age and design of this unit, any parts required to facilitate this repair will have to be independently sourced and/or manufactured.

If the stop log crane is not replaced or refurbished it is likely to fail certification in the future, and this would result in it being declared out of service by inspectors. Given that it is critical infrastructure for the facility, identified issues must be addressed at this time. The project is currently forecast to be completed in 2022.

5. Asset Management Framework	2018 WIP	2019 Additions	2020 Additions	2021 Additions
	$715,000	$1,349,000	$1,560,000	$1,196,000

The 2017/18 GRA included feasibility costs for development of an Asset Management Program that would document plans to systematically assess major asset groups (hydro, substations and transmission and distribution) and manage the planning of investments to meet overall corporate goals.[1] It was noted at the time that there was no asset management methodology for managing critical hydro and transmission assets which could result in unplanned ad hoc repairs and replacement projects. A permanent solution was required with health indices and reporting tools to allow for investment planning based on consideration of empirical data and risk.

Yukon Energy is undertaking a 5-year project to develop and implement a formal Physical Asset Management Managed System (PAMMS) that will align its practices with the ISO 55000 standard.[2] The project will develop and implement systems (including Enterprise Asset Management as discussed in Section 5.4.1) that will improve investment decisions over asset life cycles. This includes development of health indices and reporting tools and providing an integrated solution that also addresses associated support systems such as document management, equipment records and history. The 5-year plan includes completion of Maintenance Plans/ Instructions; Asset Management Plans (AMPs); Asset Health Indices (AHIs); and Governance model framework and procedures.

Yukon Energy is proceeding in a staged manner. Asset Management Framework costs to the end of 2019 were $2.064 million, with $1.560 million of forecast expenditures in 2020 and $1.196 million of forecast expenditures in 2021. Project costs will remain in WIP at the end of 2021 as activities for the 5-year program remain ongoing in 2022. Costs for EAM system purchase and implementation are addressed separately (see Section 5.4.1).

[1] 2017/18 GRA, Appendix 5.4, page 5.4-2 provides a summary of this project, with forecast spending of $0.200 million in 2017 and $0.150 million in 2018. In Order 2018-10 [paragraph 530], the Board found the project reasonable and the associated costs prudent and approved the deferred costs as filed.
[2] The ISO 55000 standard is an international standard covering management of assets of any kind.

5.1-2: INVESTMENTS TO ENSURE DEPENDABLE CAPACITY

Summaries for each of the major capital projects being undertaken to ensure dependable capacity requirements that remain in WIP in 2021 are provided below. Total spending to the end of 2021 on these major investments to ensure dependable capacity is approximately $29.858 million (with a $16.5 million contribution to be applied to the Battery Energy Storage System final costs as noted below).

	2018 WIP	2019 Additions	2020 Additions	2021 Additions
6. Battery Energy Storage System (transfer from feasibility)		$38,000	$1,000,000	$25,000,000 ($16,500,000 contribution)

Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service and to address an ongoing and growing dependable capacity shortfall. Permanent solutions are needed rather than relying upon temporary options such as mobile diesel generators. The 2016 Resource Plan identified a grid scale Battery Energy Storage System (BESS) as a medium-term solution to partially address the capacity shortfall.[3] A number of potential operational benefits were also identified for grid-connected BESS on Yukon's isolated grid. The technical and economic feasibility of these additional benefits will be confirmed and assessed as part of the specification and design of the BESS system.

The 2017/18 GRA forecast costs for the battery between $21.7 million and $27.4 million for an initial 15-20 year life (depending on the type of battery selected), after which battery replacement was estimated to cost between $17.4 and $22.1 million. Yukon Energy indicated at the time that government funding would be required in order to move forward with the development of a BESS.

In Order 2018-10 regarding the 2017/18 GRA the Board noted its view that the estimated costs for 4 MW of battery storage did not compare favourably on a dollar per MW basis with the LNG third engine or the 20 MW thermal plant.[4] Further, concern was noted that the technology was not tested, and shown demonstrated benefits, in northern climates. Given the costs and unproven nature of the technology in a northern environment, the Board determined the project was not viable and absent NRCan funding it was risky to undertake the project.

Project Update

Updated sizing for the BESS is 7 MW/40 MWh. While the budget estimate remains uncertain prior to completing feasibility engineering, the estimated budget at this time is about $29.4 million (less contributions of $16.5 million as noted below). The following factors will affect the project budget: selection of the BESS design specification and use cases; degree of system customization; site selection and infrastructure requirements; and design requirements for cold weather operation.

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[3] The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to about 13 MW by 2020.

[4] Battery costs noted of $21.7 million and $27.4 million; compared to $6.2 million cost for 4.4 MW for LNG third engine and $60 million cost for 20 MW thermal plant.

In 2019, a funding application was submitted in collaboration with Yukon Development Corporation (YDC) and the Department of Community Services to the Federal Government's Investing in Canada Infrastructure Program (ICIP). On September 3, 2019, the Government of Canada committed $16.5 million towards development of the BESS project.

Final selection of the BESS design and project location will be made following completion of feasibility engineering (completed in July 2020) and site assessment activities (planned to be completed before end of 2020), including engagement with First Nations on whose Traditional Territories potential sites are located, as well as public engagement. During the feasibility engineering phase trade-offs between system functionality and costs will be identified and considered in the selection of the final BESS specification and use cases.

The project is currently forecast to be completed in 2022.

7. Pumped Storage	2018 WIP	2019 Additions	2020 Additions	2021 Additions
			$250,000	$395,000

Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service and to address an ongoing and growing dependable capacity shortfall. Permanent solutions are needed rather than relying upon temporary options such as mobile diesel generators. Yukon Energy's 10-Year Renewable Electricity Plan identified the development of a pump storage hydro project as a key priority that would provide renewable capacity to address the existing and forecast capacity shortfall under N-1 planning criterion. The project would also allow for spilled summer energy from Independent Power Producer (IPP) Standing Offer Projects (SOP) and YEC's surplus summer hydro to be captured and stored for use during the winter months. Federal funding was identified as a critical requirement for this project to keep the project affordable for customers and to minimize risks.

The project involves planning and construction of a new pump storage facility. Yukon Energy completed an updated evaluation of Pumped Storage sites as part of the 10 Year renewable Electricity Plan and the Moon-Tutshi project was identified as preferred.

This is a multi-year project forecast to be completed by 2028. Project planning and development will be managed through a stagegate process. The scope of work to be completed in 2020 and 2021 includes: stream monitoring at Moon Lake; initiation of environmental monitoring; initiation of the First Nation Engagement and consultation; and feasibility engineering on Moon Lake-Tutshi and/or other preferred sites (if selected).

8. Southern Lakes Transmission Line	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
				$175,000

An upgrade and expansion of the Southern Lakes transmission network is required to allow interconnection of large projects currently being planned as part of the 10 Year Renewable Electricity Plan to provide the energy and N-1 capacity to the grid. This project may also include an additional substation, if required. This requirement will be assessed as part of the feasibility engineering. This is a multi-year project forecast to be completed by 2028.

9. Whitehorse Interconnection	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
				$3,000,000

The 10-Year Renewable Electricity Plan outlines a number of potential new projects being planned over the next decade to meet Yukon's growing electricity needs. Many of these projects are located at or near the Whitehorse Rapids facility. Design and engineering is required to change the interconnection of YEC's existing and incoming generation assets at Whitehorse, since the diesel replacement and new battery projects will be adding dependable capacity to the system. An alternative interconnection scheme must be developed and constructed to enable interconnection of these new capacity projects and to avoid creation of a new N-1 contingency. The first stage of the project is to examine the transmission requirements of all new projects collectively to examine the options for interconnection and determine the most cost-effective solution for connecting to the grid. Engineering of an alternative connection will facilitate the BESS project in 2022.

5.1-3: OTHER PROJECTS

A summary for the other major capital project in WIP and not included in rate base in the test year is provided below. Total spending to the end of 2021 on this project is approximately -$0.305 million.

10. Aishihik (AH3) Contract Dispute	2018 WIP	2019 Additions	2020 Additions	2021 Additions
	$13,000	($318,000)		

The Aishihik hydro facility 7 MW third turbine (AH3) came into service in December 2011. Subsequently, the installation contractor advised Yukon Energy of a dispute under the contract.[5] After several rounds of negotiation without success, the contractor filed a claim with the Yukon Supreme Court.[6] YEC filed its defense and a counter claim.[7] The case went to trial in early Q2 2016 with judgement issued August 1, 2016. The judgement awarded some amounts to both parties, with the net result in favour of the contractor.[8] YEC management reviewed the reasons for decision produced by the court and, in consultation with legal counsel, concluded that several legal errors existed in the judgement. Based on this conclusion, the decision was made to appeal. Yukon Energy brought forward its appeal in 2016 and ultimately was successful on appeal. The Court of Appeal ordered the matter to be retried. The second trial occurred in November 2019. The judgement has not been received to the date of this filing.

Under GAAP, YEC is required to expense legal costs incurred for the matter.[9] During the 2017/18 GRA, Yukon Energy noted that legal costs expensed in 2016 per audit direction were $0.962 million. It remains YEC's position that these are prudently incurred costs that were required to be incurred to defend the company against legal action resulting from the project; and that it is appropriate to recover these costs from ratepayers. As the matter is ongoing, YEC is not at this time seeking to add any amount to rate base in this Application related to this issue. These costs will be applied for at the next proceeding following resolution of the appeal. Yukon Energy will carry related costs until such time as the legal process has run its course at which time the utility will bring forward amounts for review by the YUB.

[5] See 2017/18 GRA Section 5.2.1.1 which notes that Yukon Energy at that time had incurred $2.715 million of costs after 2012 wrap up activities related to the project, including $2.574 million of costs from a dispute with a contractor on the project. Total spending in 2016 was $2.117 million, the majority being legal costs required to be expensed during the year for accounting purposes.

[6] See response to YUB-YEC-1-61 provided during the 2017/18 GRA which provides a chronology of the project; and detailed cost breakdown. Response to YUB-YEC-1-61(b) from the 2017/18 GRA notes, "From the beginning of this dispute, both parties were motivated to find a settlement outside of a court process. Several negotiation sessions were held, including a court-sponsored mediation. Although some progress was made on some of the issues, overall settlement was not achieved."

[7] Total claims as filed were: Contractor claim $3,674,000; and YEC counter claim $2,442,045.

[8] The Yukon Supreme Court awarded the contractor a net amount of $1,623,565 plus interest and costs (the amount awarded included $1,308,462 that consisted of holdbacks and extra works done where the price had been agreed upon, but not yet paid due to YEC's claims for set-off rights. The final cost of the claim dispute included YEC legal fees of $0.962 million.

[9] This assessment was based on the previous disallowance of costs by the YUB with respect to the Mayo-Dawson transmission project contract settlement from the 2005 Required Revenues and Related Matters proceeding.

APPENDIX 5.2
CAPITAL PROJECTS >$100,000 AND < $1 MILLION
ADDED TO RATE BASE

APPENDIX 5.2: CAPITAL PROJECTS >$100,000 AND < $1 MILLION ADDED TO RATE BASE

Appendix 5.2 summarizes PP&E capital projects over $100,000 but less than $1 million that will be added to rate base in the test years. Details on project costs are summarized in Table 5.2-1. Summaries for each of the projects included in Table 5.2-1, and project spending by year by cost category (i.e., generation, transmission, distribution, general plant and equipment and overhauls and reserve for site restoration), are provided in tables that follow.

5.2-1: GENERATION PROJECTS

Spending on generation projects includes projects to address prior and recent dam safety review recommendations, as well as spending on capital works to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance). There was approximately $1.395 million in actual spending in 2019 on generation projects $100,000 to $1 million; $0.660 million forecast for 2020; and $1.050 million forecast for the 2021 test year. Total 2021 rate base increase from these generation projects approximates $3.105 million, excluding any depreciation or amortization deductions.

Dam Safety Program	2019 Actual	2020 Forecast	2021 Forecast
			$300,000

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on outcomes of this review is also required by each Yukon Energy generating facility water use licence. The DSR includes a comprehensive review of all of Yukon Energy's dam structures, and includes consideration of all civil, structural, geotechnical, electrical, mechanical and safety issues that may affect YEC personnel and the general public. The review identifies hazards and potential problems of high risk that require immediate attention (within one year) as well as lower risk items that can be performed over time.

A DSR was completed in 2020 and included an extensive inspection of all water control facilities, underwater inspection of structural elements by divers, geotechnical investigation of the Whitehorse power canal, and research into historical records of YEC assets. The 2020 DSR resulted in a detailed report that prioritized recommendations for work to be completed in future years. Spending in 2021 is required to address 2020 DSR outcomes and priorities identified for 2021. Some of the high priority items that will be addressed include:

- Wareham dam spillway design
- Warning and danger signage around the six dams
- Public safety around Marsh Lake

Dam Safety Recommendations 2017/18	2019 Actual	2020 Forecast	2021 Forecast
	$272,000	$300,000	

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the CDA. Reporting on the results of each review is also required by each Yukon Energy generating facility water use licence. The 2015 DSR resulted in a detailed report that outlined a list of observed deficiencies and corresponding recommended actions to address identified deficiencies and eliminate hazardous conditions which could adversely affect the safety of the public and YEC staff. 2019 spending included required maintenance around the Marsh Lake control structure, and replacement of Whitehorse piezometers; while planned 2020 activities include replacement of the Mayo Lake Dam wood planking, Wareham Dam seismic upgrades, and the implementation of a public safety plan at the Marsh Lake control structure.

P126 LNG Boil-Off Gas Heat Exchanger	2019 Actual	2020 Forecast	2021 Forecast
	$194,000		

Prior to decommissioning of the Mirrlees diesel generators, LNG boil off gas was piped to P126 and burned in the P126 plant boiler and/or dissipated through the WD1 jacket water heat exchanger. With retirement and removal of the three Mirrlees gensets at the Whitehorse Diesel Plant (P126) there was a requirement to replace this heat dissipation function and to design, supply and install a new heat exchanger at the plant to dissipate extra heat from the combustion of LNG boil off gas. Work related to the installation of the heat exchanger included hiring an owners engineer to prepare design, drawings and specifications for the new heat exchanger, piping, a new pump with VFD, and a temperature sensing device, and provide mechanical and electrical drawings and technical specifications for equipment and piping installation for tendering the construction work.

Wareham Gate Heater	2019 Actual	2020 Forecast	2021 Forecast
	$574,000	$100,000	

The Wareham Gate Heating project replaced an old and ineffective heating system on both Wareham Spillway Gates. The new system is designed to keep both spillway gates operational through the winter. Passing flows during outages and times of high inflows is a critical function of the spillway.

Wareham Gate Refurbishment	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
		$250,000	

The Wareham Dam impounds Wareham Lake and is classified as an extreme hazard Dam.[1] The Wareham Spillway Gates have been in service since 1953 and are critical infrastructure for the Wareham Dam. The spillway gates at Wareham Dam have had significant leakage problems over a number of years, primarily due to age-related wear and corrosion. Recent observations, including an external engineering assessment, indicated that the gates were deteriorating in several ways. Specifically, the skinplates were experiencing pitting corrosion[2] and needed to be repaired by sandblasting, adding additional plates and plug welding and seal welding the plates in an array to add strength. During testing of the hoist following repairs in 2019, extremely high friction forces were also observed acting on the gate; the wheel bushing was worn; and there was evidence of fretting wear on the wheel paths. Side seals were also leaking at a high rate at times; and copper staunching rod links and retaining clips required refurbishment with new self lubricated bushings to allow them to seal smoothly. Spending in 2020 was focused on undertaking work as identified above to address each of these issues.

As operation of the spillway is a critical part of Mayo Generating Station dam safety, issues with the gates raised reliability and safety concerns. YEC is required to maintain critical infrastructure at the Wareham Dam in accordance with CDA standards; and the existing EPP requires the gates to function at all times.

Whitehorse Diesel System Grounding for Generators	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$218,000	**$10,000**	

This project prepared grounding calculations and installed acceptable grounding equipment for all Whitehorse diesel generators in order to address the following issues: (1) WD4 and WD5 generators were ungrounded and in the case of a ground fault there was risk of significant damage to this equipment; and (2) the grounding for WD6 and WD7 generators was not identical, and this was an inadequate configuration when several generators were running in parallel.

WH1 and WH2 Design and Install Dewatering System	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$137,000		

A suitable system was not in place to automatically control the water levels in the WH1 and WH2 draft tube during dewatering activities. This project installed a redundant and automatic dewatering system integrated with the station PLC to provide visibility and status alarms to increase safety and reduce the risk of a flood in the P125 plant. Prior to implementation of the project, the existing system was oversized, and required large volumes of makeup water to be

[1] The spillway gates are required to stand up to seismic and flood loading and be operational after adverse seismic and flood events. These events are specified in the Canadian Dam Association Guidelines and place a considerable structural demand on the gates.
[2] The skinplates of the Wareham spillway gates have experienced pitting corrosion which is common for old steel structures submerged in water. The problem may be accelerating because of the additional air introduced to the water by the bubbler system.

added in order to keep the pumps primed and running. This was a serious safety issue that Yukon Energy needed to address as a pump failure could have resulted a rapid rise in water levels potentially causing serious injury or death and potentially flooding the P125 plant turbine floor.

WH4 Ventilation	2019 Actual	2020 Forecast	2021 Forecast
			$750,000

The WH4 plant is overheating during the summer. Given that YEC is adding additional capacity to the WH4 hydro unit with new servo motors in 2021, removing the restriction placed on output by the overheating issue will enable the extra capacity to be used reliably throughout the year.

5.2-2: TRANSMISSION PROJECTS

Spending on transmission projects is focused on upgrading transmission lines and substations. A number of projects also included customer contributions (e.g., Alexco Mobile substation connection; Minto mine substation neutral ground resistor; and Van Gorda substation). Other projects are driven by safety and reliability and/or regulatory requirements. There was approximately $1.276 million in actual spending in 2019 on transmission projects $100,000 to $1 million; $0.782 million forecast for 2020; and $0.550 million forecast for the 2021 test year. Total 2021 rate base increase from these transmission projects approximates $2.608 million, excluding any depreciation or amortization deductions and before contributions (total of $0.550 million).

Alexco Mobile Substation Connection	2019 Actual	2020 Forecast	2021 Forecast
		$178,000 ($178,000 contribution)	

Alexco plans to use a 3 MVA, 69 kV/4.16 kV mobile self-contained substation to feed their Birmingham site at Keno. The substation must be connected to the McQuesten-Keno 69 kV line. The project includes supply, installation and commissioning of the new line tap including connection to existing 69 KV line, engineering and commissioning support for the new mobile substation. YEC has engaged Chimax to complete a 69 kV line tap design to connect the Alexco mobile substation to the McQuesten-Keno 69 kV line. The actual project costs will be fully recovered from the customer.

Line 177 Re Route	2019 Actual	2020 Forecast	2021 Forecast
		$105,000	$250,000

Some areas of L177 are on the border, or within, the highway right of way (ROW). The Yukon Highways Department is undertaking road construction upgrades; and the design will have cuts for a new ditch starting where some YEC poles are currently located. Three poles fall within a highway cut and at least one will be within 2 m of a highway cut. As a condition of our permit with YG, YEC is required to move the affected poles, and poles adjacent, in order to meet Yukon Government's construction requirements.

Minto Mine Substation – Neutral Ground Resistor	2019 Actual	2020 Forecast	2021 Forecast
	$105,000 ($184,000 contribution[3])		

The Minto mine requires that the following equipment be installed at the S254 Minto mine substation to be in compliance with regulatory direction: 25 kV recloser c/w bypass switch, instrument transformers, protection and controls; and 5 kV NGR c/w instrument transformers, protection and control. As this equipment is being installed at the customer's request, the full cost of the work will be recovered from the customer.

Protection and Control Program	2019 Actual	2020 Forecast	2021 Forecast
			$300,000

The protection and control program is a capital replacement program under development as part of the Asset Management Framework. YEC has engaged SNC to conduct an asset condition assessment for all protection and control equipment in all generating plants and substations throughout the YEC system. The protection and control review will develop a 20-year capital plan to prioritize the replacement of aging protection and control assets throughout the YEC grid. The program is being undertaken to improve system reliability, protect generating and transmission assets, and reduce outage frequency.

Transmission Line Access	2019 Actual	2020 Forecast	2021 Forecast
	$324,000	$300,000	

YEC requires access to transmission lines for maintenance, inspection, and brushing activities. A number of temporary access points lacked the necessary permitting and were potentially not constructed to an acceptable standard. The Yukon government authority has indicated this situation is no longer acceptable and must be rectified.

[3] Contribution amount greater than cost incurred in 2019 is due to the contribution also addressing a cost incurred in a prior year.

The project included the completion of a management plan for transmission access points including current condition, work and permits required, and estimated costs, specifically for accesses required to complete the Transmission Line Refurbishment project (see Section 5.2.1.5). It also included construction of new accesses and upgrades to existing accesses. Completion is expected to result in faster response times for emergency line work, avoidance of potential YG penalties and reliable access to key YEC assets.

Van Gorda Substation	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$54,000	$199,000 ($188,000 contribution)	

Crown Indigenous Relations and Northern Affairs Canada (CIRNAC) is responsible for the Faro Mine Site; they are working to design, supply, install and commission a substation at the Van Gorda mine which is part of the Faro mine complex. CIRNAC has also expressed interest in transferring ownership of an existing stepdown transformer (138kV: 4.16 kV / 12 MVA) at the Faro substation which is currently out of service. CIRNAC has requested that Yukon Energy support their project. Yukon Energy's role in the project would be to support CIRNAC and its technical consultants with respect to technical and operational matters, support transfer of ownership of the T1 Transformer, supply YEC approved meters, complete SCADA works for YEC monitoring, and monitor commissioning activities. YEC will witness all commissioning and start up activities.

WAF Transmission Upgrades	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$793,000		

The WAF transmission system allows low cost hydro generation supplied from Aishihik, Whitehorse, or Faro to be transmitted to other locations on the grid. Failure of a transmission line structure would interrupt this supply, potentially resulting in a wider grid collapse. The structures on this transmission line were built in the 1960s through 1970s and were in various stages of deterioration. 2019 project work focused on L178 (Carmacks to Faro). The remainder of the WAF line was addressed as part of the Transmission Line Refurbishment (TLR) project (see Tab 5, Section 5.2.1.5); and the remainder of the deficient L178 structures will be replaced as part of the L178 portion of the TLR project (see Tab 5, Section 5.2.1.6).

5.2-3: DISTRIBUTION PROJECTS

Spending on distribution projects is focused on customer extensions, addressing voltage issues at Haines Junction substation and system improvements for the Eagle Gold mine. Both customer extensions and System Improvements for the Eagle Gold mine include customer contributions. There was approximately $1.256 million in actual spending in 2019 on distribution projects $100,000 to $1 million; $0.635 million forecast for 2020; and $0.600 million forecast for the 2021 test year. Total 2021 rate base increase from these distribution projects approximates $2.491 million, excluding any depreciation or amortization deductions and before contributions (total of $1.524 million).

Customer Extensions	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$626,000 ($698,000 contribution)	$600,000 ($426,000 contribution)	$600,000 ($400,000 contribution)

Yukon Energy is required to provide service to new customers connecting to the grid system. Customer extensions are forecast and budgeted as capital items without identifying specific projects. Most costs of customer extensions are covered by customer contributions pursuant to the Terms and Conditions of Service.

L355 Voltage Regulator	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$144,000	$35,000	

Atco Electric Yukon (AEY) has reported low voltage levels (below CSA standards) at the AEY Haines Junction substation, which is supplied from Aishihik via distribution line L355. The project identified the voltage profile of L355, determined the appropriate location and settings of voltage regulators, and completed all installation and commissioning work.

System Improvements for Eagle Gold Mine	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$487,000 ($487,000 Contribution)		

The VGC Group PPA provides for development on the Yukon grid of the McQuesten Substation plus the Initial YEC Facilities Improvements, as described in Schedule C of the VGC Group PPA, prior to Commencement of Delivery to the Eagle Gold Mine. These Yukon grid enhancements and facilities are required to connect the Mine to the existing transmission grid, to maintain acceptable system voltages while supplying this new load, and to address potential contingent operating conditions such as loss of generation at Mayo or loss of the transmission connection between Mayo and Whitehorse. The VGC Group PPA provides in Section 6.1 for YEC to recover from the mine the reasonably incurred capital costs for the Initial YEC System Improvements as set out in Schedule C of the PPA.

5.2-4: GENERAL PLANT AND EQUIPMENT PROJECTS

Spending on General Plant and Equipment projects is focused on completing required communications and building upgrades, as well as spending on capital works to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance). There was approximately $1.429 million in actual spending in 2019 on General Plant and Equipment projects $100,000 to $1 million; $1.366 million forecast for 2020; and $1.395 million forecast for the 2021 test year. Total 2021 rate base increase from these general plant and equipment projects approximates $4.190 million, excluding any depreciation or amortization deductions.

Communications Upgrades	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$801,000		

Communication systems allow YEC to monitor and control generation and substation equipment from the System Control Centre (SCC) in Whitehorse. Loss of communication with YEC operating facilities increases risk to the overall operation of these assets and to the electrical system. The project completed a number of recommendations that resulted from a Communications Needs Assessment undertaken by an independent consultant that were required to achieve necessary improvements in security, integration, performance and redundancy. The project was reviewed in detail in the 2017/18 GRA.[4] YEC noted at the time that the project was planned to be executed over multiple years – and each specific upgrade would come into service and into ratebase when completed. In Order 2018-10 the Board noted that it "accepts that communications upgrades to ensure the continued operation of the electrical system in the event of an incident significantly affecting YEC's head office in Whitehorse are warranted."[5] The 2017/18 review noted that satellite installations for SCADA and fibre communications upgrades were required to create redundancy for disaster planning; network access controls were needed due to changes resulting from the satellite installations, and that the SCADA communications upgrades would facilitate satellite communication at YEC's various sites. Key projects completed in 2019 included: fibre communication upgrades; SCADA upgrades, the Takhini Redundant Datacentre; Satellite installations for SCADA.

Building Upgrades	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$370,000	$275,000	

In 2016, an external consultant was hired to perform an asset assessment on YEC-owned buildings and facilities, mainly consisting of staff houses and administration buildings.[6] A number of building components were identified at each location as being at end of life or not in compliance with applicable code regulations. This project addressed the

[4] Section 5.2.1.4 of the 2017/18 General Rate Application; and paragraphs 394 and 395 of Order 2018-10.
[5] In its Reasons for Decision at paragraph 395 the Board notes, "YEC clearly linked the satellite installations for SCADA and fibre communications upgrades to creating redundancy for disaster planning. YEC's application also states that the network access controls are needed due to changes resulting from the satellite installations and that the SCADA communications upgrades will facilitate satellite communication at YEC's various sites. Therefore, the Board finds that the satellite installations for SCADA, fibre communications upgrades and network access controls are necessary as part of YEC's disaster recovery planning and approves these projects."
[6] Detail regarding the need and justification for building upgrades was provided during the 2017/18 GRA proceeding. Specifically, a copy of the Building Condition Report was provided in response to John Maissan-YEC-1-37(a).

concerns identified by the report and bring YEC buildings up to an acceptable condition.

Work in 2019 and 2020 was undertaken to address end of life and/or health and safety concerns. 2019 work included: exterior works,[7] HVAC retrofits,[8] flooring replacement,[9] electrical panel replacements,[10] and equipment replacement.[11] 2020 costs relate to replacement of the WH4 hydro plant (P127 roof). During 2019 the roof membrane failed, and an interim patch was installed to address a leak. If the roof was not repaired additional leaks would develop and need to be addressed at a much higher cost.

Compact Digger Truck	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
			$185,000

The purchase of a 4 to 5 ton chassis compact digger truck for use in Dawson will substantially decrease risks for workers and ensure greater efficiency in day to day work; including providing improvements in outage response times. Servicemen currently use an attachable bucket that goes on the side of the digger boom for many types of work from street light maintenance, service work, trouble call response, and new construction. The bucket is heavy and difficult to attach/detach. In a trouble call scenario this can also be time consuming and increase trouble call response time leading to frustration and potential unsafe working conditions.

Crane Replacement/ Refurbishment	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
		$165,000	$400,000

During an annual crane inspection, three YEC cranes (Aishihik service building, P127 powerhouse, & P127 stop log hoist) were identified as needing significant structural, electrical, and mechanical repairs in order remain in acceptable working condition. 2020 spending will provide for a detailed assessment of each crane to determine an engineered plan for replacement or refurbishment as required. Actual construction activities are planned for 2021.

Mayo Earthworks	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
		$300,000	

A number of issues at and around the Mayo Hydro facilities have been identified. These include slope instability and erosion issues near access roads (Mayo A, Mayo B, and Wareham dam), both powerhouse buildings, surge tank, and both substations. During 2019 a complete site inventory of civil issues was undertaken to identify and prioritize

[7] There are many exterior works, including roofing, heat trace, metal or wood cladding, structural or building envelope work or windows and doors. A variety of work is required to be done on staff housing, offices and plants.
[8] Numerous Heating Ventilation and Air Conditioning (HVAC) issues have been identified. The intent is to group the HVAC work requirements into annual tenders seeking contractor to do works within the communities required.
[9] Flooring issues identified relate to removal of warn carpeting or sealing of foundation flooring to alleviate any potential radon into the workplace.
[10] A majority of electrical panels are at end of life or currently overloaded and need to be replaced.
[11] A stepdown transformer is required for the Aishihik office plant as the existing one has exceeded its life expectancy.

issues. The inspection highlighted several required projects to improve roads, make culvert installations and secure embankments. 2020 spending developed a detailed work plan for identified issues including a geotechnical assessment, topographic survey, detailed engineering design (including drawings and specifications), construction methodology, and project scope, schedule & budget development.

New Mobile Office Unit – IT	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
			$230,000

The existing IT trailer houses five offices and a closed storage space. It is aging and requires additional O&M support each year. The project involves replacement of the aging, undersized IT trailer with a larger unit able to accommodate eight office spaces and storage. Additional office spacing would allow for staff expansion as a less costly solution than building onto the main building.

Vehicle Purchases	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
	$258,000	$476,000	$580,000

Fleet vehicles were historically replaced at regular intervals based simply on age and mileage. YEC has recently adopted a replacement policy that considers more comprehensive criteria when assessing specific vehicles to be replaced each year. The forecast amounts for 2019 include the purchase of pickup trucks with service bodies, including a 2 tonne mechanical operator’s vehicle (the current 1 tonne vehicles did not have sufficient chassis to do the work safely), and forecast 2020 acquisitions focused on vehicles based in Dawson and Mayo due to the higher cost of local repair services. 2021 costs are to replace aging/ high mileage vehicles that are incurring greater O&M costs to maintain.

Water Improvement Upgrades	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
		$150,000	

The cooling water and potable water systems in the YEC main corporate office have experienced pre-mature piping failure and select cooling coil leaks for at least the past 10 years. An external engineering firm was engaged to assess the current systems and provide recommendations to address the issues. The project will implement those recommendations including the installation of a particulate filter, a VFD drive for the existing pump, a heat exchanger, new cooling water piping and valves, and fan coil drip pans with leak detection.

5.2-5: OVERHAULS & RESERVE FOR SITE RESTORATION PROJECTS

PP&E spending also includes spending on overhauls, decommissioning and site restoration projects as noted below. There was approximately $1.173 million in actual spending in 2019 on overhauls and decommissioning projects $100,000 to $1 million; no expenditures forecast for 2020; and $0.580 million forecast for the 2021 test year. Total 2021 rate base increase from these projects approximates $1.753 million, excluding any depreciation or amortization deductions.

FD7 Overhaul	2019 Actual	2020 Forecast	2021 Forecast
			$580,000

Faro Diesel #7 (FD7) is located at the Faro Diesel Plant and uses as 12-cylinder Caterpillar Model 3612 diesel engine as its prime mover (vintage 1992). The unit was used when purchased by YEC from a mining operation; however, the complete service history for the unit is not known (YEC has registered 28,624 operating hours). A conditional assessment for the engine was undertaken in 2016 by MPR Associates and a follow-up inspection was undertaken by Finning in May 2016. The inspection focused on items identified in the MPR report and included a more fulsome mechanical inspection that included: removal, measurement and inspection of piston/ rings; inspection of camshaft segments and filter assemblies; measurement of heads and valves and connect rod bearings. One cylinder lining was found cracked and replaced during the inspection. Due to the significant wear found on the inspected parts, it was recommended that a complete overhaul of the unit be undertaken.

Decommissioning on WD3	2019 Actual	2020 Forecast	2021 Forecast
	$999,000		

After removing the third Mirrlees engines from service, all three units were fully decommissioned. Decommissioning included disassembly and removal of all ancillary equipment and piping, asbestos abatement as required, separation and hoisting of major engine components, and backfill and compaction of the engine pits. All decommissioned equipment was removed from site and appropriately disposed of.

Site Restoration Transmission Lines	2019 Actual	2020 Forecast	2021 Forecast
	$174,000		

The Utility maintains a regulatory provision for future removal and site restoration related to property, plant and equipment. Costs of dismantling capital assets, including site remediation, are applied to this account. In 2019, YEC spent $0.174 million on site remediation relating to the L178 and L355 Transmission Lines.

APPENDIX 5.3
DEFERRED PROJECTS >$1 MILLION
NOT ADDED TO RATE BASE

APPENDIX 5.3: DEFERRED PROJECTS >$1 MILLION NOT ADDED TO RATE BASE

Deferred expenditure test year spending on major projects (i.e., expenditures over $1 million) retained in WIP is focused on projects required to address sustaining capital requirements (i.e., required to replace, repair or enhance/ improve components of the existing system to ensure continued reliability, safety and environmental or regulatory compliance), investments to ensure sufficient dependable capacity for the integrated grid, and continued planning expenditures to meet other potential future generation and transmission requirements.

Approximately $28.573 million of deferred costs are forecast to be incurred in WIP for major projects by the end of 2021. Details on actual and forecast expenditures by year are reviewed in Tables 5.2 to 5.6.

- **Spending on Sustaining Capital:** Net deferred costs in WIP by end of 2021 of approximately $8.178 million:

  1. **Aishihik Generating Station Water Use 25 Year Licence Renewal** – (forecast WIP cost of approximately $7.918 million by end of 2021 - project planned for completion in 2022).

  2. **Whitehorse Rapids Generating Station Water Use Licence Renewal -** (forecast WIP cost of approximately $0.260 million by end of 2021 - project planned for completion in 2025).

- **Spending to address Capacity Planning Requirements:** Net deferred costs in WIP by end of 2021 of approximately $6.395 million:

  3. **Diesel Retirement Replacement (12.5 MW)** – (forecast WIP cost of approximately $6.395 million by end of 2021 planning, engineering, permitting, long-lead equipment procurement – total project planned for completion by 2024, with certain portions completed and in service starting in 2022).

- **Spending on planning to maximize renewable energy generation from existing facilities**: Net deferred costs in WIP by end of 2018 of approximately $14.000 million:

4. **Southern Lakes Storage (Marsh Lake Storage Enhancement Project)** – (forecast WIP cost of approximately $9.379 million by end of 2021 - project subject to ongoing review, potential in-service by 2023).

5. **Mayo Lake Storage Enhancement Project (including Mayo Lake Outlet Channel)** – (forecast WIP cost of approximately $4.621 million by end of 2021 - project subject to ongoing review, potential in-service by 2023).

5.3-1: SPENDING ON SUSTAINING CAPITAL

Deferred expenditure spending on sustaining capital is focused on planning and regulatory activities for long term licence renewals for the Aishihik and Whitehorse generating facilities.

	2018 WIP	2019 Additions	2020 Additions	2021 Additions
1. Aishihik Generating Station (AGS) Long Term Year Water Use Licence Renewal	$4,957,199	$512,755	$1,488,000	$960,000

A long term licence renewal of the Aishihik Generating Station (AGS) water use licence (WUL) is required for the continued operation of the AGS hydro facility after the recent 3-year renewal expires at the end of 2022. The water use licence renewal is required for the continued operation of the 37 MW hydro facility, which provides the only multi-year hydro storage and the largest winter peak hydro generation capability on the Yukon Integrated System.

The planned long term AGS Water Use Licence renewal project and related costs were initially reviewed as part of the 2017/18 GRA. At that time, it was noted that the total forecast budget for the project was $3.569 million spread over five years (2015-2019). Project expenditures to support the long term licence renewal were reviewed in detail in the 2017/18 GRA (See Section 5.3.1.2 and response to YUB-YEC-1-77 in that GRA). Total deferred costs to the end of 2018 were forecast at $2.899 million.

In 2018, Yukon Energy prepared a long-term Project Proposal application for filing with YESAA Designated Office in December 2018, prior to Yukon Energy's decision in early 2019 to secure a three-year licence renewal.[1] The long-term Project Proposal document was updated over Q1 and Q2 2020 and filed with the Haines Junction Designated Office in July 2020. It is expected that the Designated Office review process will be completed in Q2 2021. Yukon Energy expects to prepare and file its long term water use licence renewal application with the Yukon Water Board in early 2021, and that a hearing regarding the licence renewal would occur sometime in 2022.

The deferred costs forecast in the Application include spending in WIP increasing from $4.957 million at the end of 2018 to $7.918 million by the end of 2021. The project is forecast to be complete by the end of 2022.

[1] Due to delays in filing the YESAA Project Proposal to accommodate Yukon Government discussions with Champagne and Aishihik First Nations (CAFN), Yukon Energy had to address material risks that the regulatory review timelines could extend beyond 2019. In order to avoid a lapse in Yukon Energy's water use licence for the AGS, Yukon Energy brought forward the AGS Relicensing Project Proposal in February 2019 for a three-year renewal term. It was expected that this would allow the necessary time for the regulatory review process for the 25 year licence renewal to occur without a lapse in Yukon Energy's AGS water use licence. A three-year licence renewal was secured in February 2020, extending the licence to December 31, 2022.

2. Whitehorse Generating Station Water Use Licence Renewal	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
				$260,000

The existing water use licence for the Whitehorse Rapids Generating Station (WRGS) expires at end of 2025 and must be renewed in order to ensure ongoing, lawful operation of the WRGS hydro facilities. This is a multi-year project to renew the existing long-term project authorizations for the WRGS Hydro Plants and associated infrastructure. Project activities include conducting required baseline studies (e.g., environmental, socio-economic, engineering), and undertaking environmental and socio-economic effects assessment, First Nation engagement and consultation, other stakeholder engagement as required to submit a YESAA project proposal to the Whitehorse Designated Office. Project activities will also include completing the YESAA review process, the water use renewal process with the Yukon Water Board, and *Fisheries Act* Authorization (DFO) regulatory process.

5.3-2: SPENDING TO ADDRESS CAPACITY PLANNING REQUIREMENTS

Deferred expenditure spending on capacity planning requirements is focused on the diesel retirement replacement project; as well as ongoing work on the Mayo Hydro Enhancement Project and the Southern Lakes Enhanced Storage Project. The basis for pursuing the Mayo Hydro Enhancement Project and Southern Lakes Enhancement Project have each been reviewed in past General Rate Applications. Brief updates are provided in this appendix.

3. Diesel Retirement Replacement (12.5 MW)	**2018 WIP**	**2019 Additions**	**2020 Additions**	**2021 Additions**
	$41,007	$554,224	$800,000	$5,000,000

The 2016 Resource Plan identified a dependable capacity shortfall for the Yukon Integrated System under its single contingency (N-1) capacity reliability criterion that approximates 6 MW in 2017, increasing to 10-11 MW by 2019. Yukon Energy is required to provide sufficient dependable winter capacity to meet the single contingency capacity reliability criterion, i.e., there is no acceptable "do nothing" option given the need to maintain reliable service and to address an ongoing and growing dependable capacity shortfall.

The 2016 Resource Plan identified a new 20 MW greenfield diesel plant as one of the preferred options for addressing the dependable capacity shortfall gap in a cost effective manner in the near term.[2] The YUB reviewed planning for the project during the 2017/18 GRA, and noted it was not persuaded that the project was the only way to address the predicted capacity shortfall, and that YEC should not proceed with the project without a detailed business case that considers the alternatives to the project.

Following the Board's direction in Order 2018-10, Yukon Energy proceeded with the additional work as required to evaluate project alternatives. This included identifying and evaluating a number of options for a new 20 MW thermal plant. In October 2019, it was determined that considering the results of the technical, environmental and socio-

[2] The 2016 Resource Plan identified a dependable capacity shortfall for the YIS under its single contingency (N-1) capacity reliability criterion that approximate 6 MW in 2017, increasing to about 13 MW by 2020.

economic research, as well as public feedback, YEC would focus potential options to add or replace capacity at existing generation facilities on an incremental basis as diesel engines are retired.

This includes consideration of the following near term activities:

- Installation of 5 MW of thermal capacity at the Whitehorse Diesel Plant (P126);
- Replacement of 5.1 MW of diesel to be retired at the Faro Diesel Plant with a 5 MW diesel unit;
- Retirement of the existing 2.5 MW of diesel capacity in Dawson City with installation of 2.5 MW of diesel capacity at the Callison Substation.

Efforts in 2020 have focused on preliminary engineering and finalizing a procurement strategy, defining vendor contracts and milestones, and updating the overall project schedule.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $0.041 million at the end of 2018 to $6.395 million by the end of 2021. Dependable capacity from these projects is expected to be available by winter 2023/24. In the interim, Yukon Energy will continue to rent diesel generators each winter to ensure an adequate supply of back-up power in case of an emergency.

5.2-3: SPENDING TO MAXIMIZE RENEWABLE GENERATION FROM EXISTING FACILITIES

4. Southern Lakes Enhanced Storage (Marsh Lake Storage Project)	2018 WIP	2019 Additions	2020 Additions	2021 Additions
	$7,319,000	$374,899	$485,000	$1,200,000

The Southern Lakes Enhanced Storage Project ("SLESP") (formerly "Marsh Lake Storage Project") is a means of enhancing winter energy at the Whitehorse Rapids generating station to displace higher cost thermal generation that would otherwise be required. The SLESP project includes capital improvements to the Lewes Lake control structure, shoreline mitigation, First Nation consultation and an amendment to YEC's water licence to increase the full supply level by 0.3 metres and reduce the low supply level by 0.1 meters. This additional water storage would be available to YEC for hydro generation over the winter period.

Forecast MLSEP project costs and actual expenditures were reviewed in detail in the 2012/13 and the 2017/18 GRAs. The 2012/13 GRA, identified the project as a relatively small project, with earliest in-service assumed in 2014 (first full year 2015) at a capital cost (2010$) of $10.5 million, with mitigation design (shoreline erosion and surface water) expected to comprise about one-half of this total cost (actual costs for mitigation were stated in the 2012/13 GRA as an item that at that time could not be known with any certainty). In the 2017/18 GRA, forecast total project costs increased to $15.377 million ($9.795 million forecast for effects assessment; $0.300 million forecast for YESAA assessment and permitting; and $7.127 million forecast for mitigation implementation).[3]

Annual incremental hydro generation was estimated at 6.4 GW.h on average, focused in winter months at the current Whitehorse plant. Annual operating cost (2010$) was estimated at $8/MW.h. Full Utilization LCOE (2010$) was

[3] Response to 2017/18 GRA IR YUB-YEC-1-84. Costs to date for the project have included technical studies and assessments (including baseline environmental and socio-economic studies necessary to support an effects assessment and the development of mitigation), engagement and consultation with various stakeholders and extensive meetings with property owners that will be directly impacted by the project.

estimated at 8.5 cents/ kW.h. Marsh Lake Storage was also assumed in the 2012/13 GRA to provide 1 MW of added reliable peak winter capacity.

Project Update

During the 2017/18 GRA, Yukon Energy indicated that the next major milestone was obtaining First Nation support for the project in order to progress to the YESAB assessments stage. It was noted that the project would be cancelled without such support, as there would be no reasonable possibility of successful implementation and further costs would have no economic benefits to ratepayers. Once the above milestone was achieved, all project authorizations would be formally sought following the conclusion of a project assessment pursuant to the Yukon Environmental and Socio-economic Assessment Act and the subsequent issuance of Decision Documents from the assessment Decision Bodies.[4]

Yukon Energy completed an additional round of engagement in 2019 to confirm the level of support for the project. This included engagement with local residents in the Southern Lakes area, and Yukoners generally; as well as a further round of First Nations engagement to confirm the position of the affected First Nations (Carcross/Tagish First Nation, Kwanlin Dun First Nation and Ta'an Kwach'an Council).[5] Prior to the end of 2020, Yukon Energy will make a determination regarding whether to advance the project to the YESAA assessment phase.

The deferred costs forecast in the Application assumes that the project continues, with spending in WIP increasing from $7.319 million at the end of 2018 to $9.379 million by the end of 2021. Potential in service for the Project is 2023.

5. Mayo Lake Storage Enhancement Project – including Mayo Lake Outlet Dredging	2018 WIP	2019 Additions	2020 Additions	2021 Additions
	$3,373,374	$262,379	$460,000	$525,000

The Mayo Lake Enhanced Storage Project (MLSEP) will amend the Mayo Generation Station Water Use Licence to provide for up to one metre of additional draw down of Mayo Lake that would enhance the long-term average renewable power generation capability of the Mayo hydro facility and displace diesel generation that would otherwise be required. MLSEP project planning includes activities related to the Mayo Lake Outlet Channel Dredging project and related costs, reflecting the need to remove sediment and remnant coffer dam remains from the outlet channel in order to be able to utilize the MLES added storage.

The MLSEP was previously reviewed in the 2012/13 GRA[6] and the 2017/18 GRA.[7] The 2012/13 GRA estimated total project costs over the life of the project of $5.4 million (2012$) (including mitigation and monitoring costs) with an LCOE (2010$) of 6.3 centres/kWh for approximately 4 GWh/year of added long term average hydro grid energy with

[4] Response to 2017/18 GRA IR YUB-YEC-1-84(b &c).
[5] Response to 2017/18 GRA IR YUB-YEC-1-84.
[6] Section 5.3.1.4 of the 2012/13 GRA Application reviewed the project concept, work completed to date (including environmental and socio-economic fieldwork activities, analysis and assessment, project proposal preparation, engineering support, and public consultation), and project risks, costs and benefits. The project was included in the 2012/13 GRA under Relicensing rather than Feasibility Study deferred cost projects, reflecting the central objective to modify the current water licence affecting water storage at Mayo Lake.
[7] Section 5.3.1.9 of the 2017/18 GRA provided an update on the project progress, costs, and potential in service. Further detail was provided in response to YUB-YEC-1-85 in the 2017/18 GRA. In Order 2018-10, the Board noted that it had approved the Mayo Lake storage enhancement in Order 2013-01, and that given that sediment removal was necessary to realize any benefits from this project it was prudent to expand the scope of work for this project accordingly.

1 metre of added storage at Mayo Lake.

The Project was initially forecast to be completed by the end of 2013, however, Yukon Energy subsequently determined that sediment in the Mayo outlet channel was constraining water flow through the channel at the low end of the licensed storage range, reducing long term average hydro generation from existing Mayo Hydro facilities and preventing any benefit from being realized by the MLESP reducing the Low Supply Level at Mayo Lake. It was determined that removal of the sediment deposits in the Mayo Lake outlet channel was required to utilize additional storage at Mayo Lake as provided for the proposed MLSEP.

In Order 2018-10 the Board noted that it approved the Mayo Lake storage enhancement in Order 2013-01. Given that the sediment removal is necessary to realize any benefits from the project, the Board also considered it prudent to expand the scope of work for the project accordingly, and approved the Mayo Lake storage enhancement project as applied for, noting the costs are to remain in WIP, and the prudence of the costs will be assessed at the time the project is complete and YEC applies to add the costs to rate base.[8]

Project Update

In 2018, Northwest Hydraulic Consultants (NHC) was retained to provide a technical assessment regarding whether sediment remediation steps in the Mayo Outlet Channel were feasible and cost effective. This assessment determined that removal of a coffer dam remnant in the outlet channel would improve flow in the near term and, through scouring activity, could potentially also remove the sediment from the channel; if required, as a next step, dredging the channel upstream of the coffer dam could improve hydraulic benefit for power generation. Yukon Energy has subsequently proceeded with preparing a YESAA assessment for the project (including the two-phase outlet channel work) which is targeted to be filed with the Mayo Designated Office before the end of 2020.

The deferred costs forecast in the Application assume that the project continues, with spending in WIP increasing from $3.373 million at the end of 2018 to $4.621 million by the end of 2021. Provided licencing processes commence in late 2020/early 2021, potential in service of the amended licence would be in 2023. Work to remove the coffer dam remnant would then proceed as a separate project.

[8] Board Order 2018-10, paragraph 513.

APPENDIX 5.4
DEFERRED STUDIES >$100,000 AND <$1 MILLION
ADDED TO RATE BASE

APPENDIX 5.4: DEFERRED STUDIES >$100,000 AND <$1 MILLION ADDED TO RATE BASE

Appendix 5.4 summarizes deferred cost projects over $100,000 but less than $1 million that will be added to rate base in the test years. Details on project costs are summarized in Tables 5.3 to 5.6.

Spending from 2019 to 2021 on each deferred cost activity totalling between $100,000 and $1 million that impacts 2021 rate base is summarized below (total rate base impact in 2021 test year of $4.046 million, excluding reductions due to amortization). More detailed review of each project is provided in subsequent sections of Appendix 5.4.

- **Studies undertaken for potential renewable generation options**: Rate base additions of $1.267 million for the following projects:
  - IPP Standing Offer Program Implementation ($0.232 million in 2020 for expenditures in 2018 and 2019);
  - Mt Sumanik Wind Feasibility Study ($0.776 million for expenditures from before 2018 until 2020); and
  - WH2 Uprate Engineering ($0.259 million in 2021 for expenditures from 2018 to 2020).
- **Studies undertaken to ensure continued reliability or to determine requirement for business improvements for existing assets**. Rate base additions of $1.551 million for the following projects:
  - Building Condition Reports 2021-2024 ($0.175 million in 2021);
  - Business Continuity Plan ($0.080 million in 2020 and $0.075 million in 2021)
  - Mayo and Aishihik Hydro Climate Change Study ($0.638 million in 2020 for expenditures from 2017 to 2020);
  - PMF Flood Study ($0.150 million in 2021);
  - Transmission Access Road Program Study ($0.133 million in 2020 and $0.200 million in 2021); and

- Whitehorse Diesel Rental Substation Improvements ($0.100 million in 2021).

- **Regulatory** and **Dam Safety Review**: Rate base additions of $1.228 million for the following projects:

  - 10 Year Renewable Energy Plan ($0.713 million in 2020 for expenditures in 2019 and 2020);

  - Atlin Hydro EPA Preparation ($0.200 million in 2020); and

  - Dam Safety Review ($0.315 million in 2020).

5.4-1: FEASIBILITY STUDIES – POTENTIAL RENEWABLE GENERATION OPTIONS

IPP Standing Offer Program Implementation	**2018 WIP**	**2019 Addition**	**2020 Addition**	**2021 Addition**
	$48,127	$183,912		

Yukon Energy and ATCO Electric Yukon (AEY) are responsible for implementing the Yukon Government's Independent Power Producers (IPP) Policy. The Standing Offer Program (SOP) was developed based on the model used in British Columbia and required development of the following key documents: (1) SOP Program Guide; (2) SOP Program Rules); (3) SOP Application Process; (4) SOP Application Form; (5) Interconnection Standards; and (6) Electricity Purchase Agreement Template.

The utilities were directed to implement the policy by the Yukon Government and are required to execute the policy. OIC 2019-25 requires that utility costs be recovered in rates. Yukon Energy costs related to its share of legal costs for implementation of the IPP policy.

The project is to be closed in 2020 with total expenditures of $232,039 to be amortized over five years.

Mt Sumanik Wind Feasibility Studies	**2018 WIP**	**2019 Addition**	**2020 Addition**	**2021 Addition**
	$694,427	$31,155	$50,000	

Yukon Energy's 2011 Resource Plan recognized that wind generation had the potential to be an energy supply option of interest given emerging government policy regarding greenhouse gas emission reduction. Without the addition of renewable generation, increasing loads would need to be met with thermal generation.

In 2014, Yukon Energy initiated a multi-year project to complete early feasibility studies for potential wind farm sites throughout the Yukon. The purpose of this project was: 1) to assess of wind's viability as a resource option for Yukon Energy for resource planning purposes, and 2) evaluate the potential for a wind farm on Mt Sumanik. Mt Sumanik was identified as a particular site of interest for wind development given the advantages of its proximity to Whitehorse. From 2014 to 2015, work on this project focused on the siting, engineering, environmental assessment, permitting and installation of wind monitoring equipment at Mt Sumanik. This included completion of applicable studies such as a grid impact study and wind integration study. A Lidar unit and power supply system was installed on Mt Sumanik to track wind data.

From 2016 to 2017, the project work consisted mostly of data collection and management, as well as evaluating upgrades to the power system for the monitoring equipment which experienced difficulties. In 2018 work was conducted to repair the laser of the Lidar unit as the equipment was malfunctioning. Yukon Energy's 2016 Resource Plan identified a potential energy gap under the High Industrial Activity scenario. The Action Plan identified one wind supply option under this scenario. Accordingly, as wind was still a resource of interest, Yukon Energy considered whether further data monitoring should be conducted given missing data from the malfunctioning equipment.

The need for Yukon Energy to directly conduct resource wind monitoring and site assessments has since been eliminated due to the high likelihood that future wind resources will be developed by Independent Power Producers. As such, the project was decommissioned in 2020 with total expenditures of $775,581 to be amortized over five years.

WH2 Uprate Engineering[1]	**2018 WIP**	**2019 Addition**	**2020 Addition**	**2021 Addition**
	$207,944	$44,448	$6,679	

The Whitehorse Rapids Generating Station (WRGS) is a critical hydro generating asset to Yukon Energy. Whitehorse Hydro Unit #2 (WH2) is over 60 years old, and the generator has exceeded a typical winding life of 40 years. WH2 performance was declining and due to its age there was an increased risk of failure and related unplanned outages and costs. Issues were identified with oil leaks at the runner blade to hub seals and with possible voids in the concrete behind the draft tube liner. In the circumstances, it was considered prudent to rewind the generator in order to mitigate these risks and their potential reliability and cost implications. External studies also determined that unit performance would be improved with a new runner of modern design.

In 2016, Hatch assessed the uprate options at the WRGS. Uprate of the WH2 was considered the most economically attractive option. The WH2 Uprate project would include completion of the WH2 unit's rehabilitation, replacement of the turbine runner and stator rewind and rotor refurbishment. Proceeding with the project was recommended as it would improve reliability and availability of WH2 by replacing/ refurbishing the necessary electrical and mechanical components; and would also increase the unit's maximum efficiency from 88.1% to 94%.[2]

The WH2 uprate engineering study was the first stage of a multi-year, phased project. The initial stage involved selection of an Owners Engineer to conduct preliminary design work (commenced in 2018 and completed in 2020). An external engineer was required to undertake this work as uprate studies are a specialized skillset that YEC does not employ internally. Phase 1 work was required to develop the business case required to proceed with later stages of the project. See Section 5.2.1.10 for a full description and business case for completing the WH2 Uprate Project

[1] By end of 2021 WH2 Uprate Engineering costs will be transferred to Property, Plant and Equipment and added to WH2 Uprate total cost [amortized over 72 years starting in 2022].
[2] The Hatch report noted that a modern Kaplan turbine operating under the similar head and flow conditions would have a peak efficiency of approximately 94%. As per the Hatch report, the WH2 generator should be able to generate 10% more power than its nameplate capacity. However, this requires replacement of the existing stator winding and refurbishment of the rotor field poles and windings.

before the end of 2021. This is a near term project that if implemented would extend the life of an existing asset, increase unit reliability, help meet generation demand, and reduce both energy and capacity shortfalls.

The project is to be closed in 2021 with total expenditures of $259,072 to be amortized over 72 years.

5.4-2: FEASIBILITY STUDIES – CONTINUED RELIABILITY & ASSET IMPROVEMENTS

Building Condition Reports 2020-2024	2018 WIP	2019 Addition	2020 Addition	2021 Addition
				$175,000

Yukon Energy is moving from a crisis management model (e.g., waiting for a furnace to fail in the middle of winter), towards a preventive maintenance schedule (identifying life cost cycling of a furnace) for all YEC-owned buildings. This change in approach can provide material cost savings. Building condition reports are required to formally document the structure and fabric of a property, describe the construction of the building and its current condition, and outline work required, timing and costs for completion.

An external engineering firm will undertake site visits for all owned YEC properties and provide an assessment of the condition of each site that outlines requirements for immediate maintenance and repairs; maintenance and repairs required over the next five years; code violations; and cost estimates for required work. The building condition report will be used to forecast O&M projects building condition assessment capital works over 2020-2024.

The project is to be closed in 2021 with total expenditures of $175,000 to be amortized over five years.

Business Continuity Plan	2018 WIP	2019 Addition	2020 Addition	2021 Addition
			80,000	$75,000

A gap analysis was undertaken by a third party consultant regarding Yukon Energy's current Business Continuity Plan (BCP). This identified substantial work required to address the identified gaps in order to meet current industry standards. This includes development of technical recovery procedures, based on identified Recovery Time Objectives (RTO) for the various business processes related to IT applications and infrastructure components; developing a defined methodology for evaluating the criticality of vendors, establishing vendor Business Continuity/Disaster Recovery (BC/DR) requirements, and monitoring vendor BC/DR compliance; and developing a formal BC/DRP/Emergency Response Planning training program or exercise and testing program. If the current BC/DR program deficiencies are not addressed, YEC will face a number of risks in the event of an actual emergency. This includes delays in poorly defined Incident Command System, unclear priorities for returning critical support systems to service, lack of adequate employee training or potential communication breakdowns.

The project is to be closed in 2020 and 2021 with total expenditures of $155,000 to be amortized over five years.

Mayo and Aishihik Hydro Climate Change	2018 WIP	2019 Addition	2020 Addition	2021 Addition
	$474,313	$124,249	$40,000	

Operations and planning require a better understanding of climate change and its ongoing effects on flow volume, timing and extreme events in the Mayo, Aishihik and Whitehorse basins; and short and long term changes in hydroelectric generation due to climate variability. YEC must be able to incorporate information regarding climate change impacts into resource planning and water relicensing activities.

The project involves research and modelling to better understand how climate change will affect flow volume and timing of water at both Mayo and Aishihik hydro dams; and will provide data on the potential for climate change to cause extreme events that would directly affect hydro power production at the Mayo and Aishihik hydro dams. Installation of meteorological data collection equipment in the Mayo and Aishihik drainage will also greatly improve monitoring systems in those basins. The study included four interrelated research objectives/ deliverables: (1) scale down regional climate change analysis and model data for regional constraints; (2) improve understanding of the factors contributing to flow volume and timing (temperature, snow melt, precipitation, groundwater, interflow, surface flows); (3) identify potential impacts of climate change on timing and volume of flow and potential extreme events as well as a range of the event severity (minimum and maximum flood flows) and their predicted frequency; and (4) develop and test a long term and short term forecasting tool using the hydrologic model. Forecasting tools developed through the study will help YEC better anticipate changes in flow, volume and timing into the Mayo, Aishihik reservoirs to enhance reliability of electrical generation throughout the Yukon grid.

A partnership was developed in 2016 between Yukon College and INRS, a university institution which developed a successful joint ARD/CRD proposal to leverage funding from NSERC.

The project is to be closed in 2020 with total expenditures of $638,562 to be amortized over five years.

PMF Flood Study	2018 WIP	2019 Addition	2020 Addition	2021 Addition
				$150,000

A Probable Maximum Flood (PMF) study is required for Aishihik Lake and Canyon Lake. The PMF study will determine high water levels up to and including the PMF event; then an inundation study will be performed and potential upgrades to the Canyon Lake and Aishihik Lake control structures will be determined. The study is required under the water licence for the Aishihik Generating Station; and will help to determine if and where upgrades are required.

The PMF study will provide updated hydrographs of 100-year, 1,000-year and probable maximum flood events. These hydrographs were last updated in 1992, and there is more than 30 years of data to considered along with the effects of climate change. The hydrographs will be used, along with the Canadian Dam Association (CDA) risk rating of the dam: to establish high water levels; to update the stage-discharge of the Aishihik and Canyon lake dams used for a dam breach study; and to determine inundation of a flood and/or breach event. Once the PMF and stage-discharge relationships of the dams are performed, the requirement for any upgrades to the Aishihik Control structure will be determined.

The project is to be closed in 2021 with total expenditures of $150,000 to be amortized over five years.

Transmission Access Road Program Study

2018 WIP	2019 Addition	2020 Addition	2021 Addition
		$132,787	$200,000

Yukon Energy does not have a proper inventory of all the road accesses for transmission line access; and does not know the status of all the accesses that are required to maintain approximately 1,110 km of transmission line. The objective of the study is to engage an external consultant to provide a GIS database outlining access locations; the current status of accesses; and to prepare a GIS data base and report that includes a gap analysis of what needs to be addressed to complete the GIS database.

The project is to be closed in 2020 and 2021 with total expenditures of $332,787 to be amortized over five years.

Whitehorse Diesel Rental Substation Improvements

2018 WIP	2019 Addition	2020 Addition	2021 Addition
			$100,000

The temporary substation behind the diesel plant is the grid connection point for the rental diesel fleet, was built using repurposed/ savaged equipment, and has temporary fencing. The cables for the temporary substation were re-used from the WD1 and WD2 units and are aged.

Cabling from this substation to S150 is a direct connection, and a cable fault will result in the shutdown of S150, which is the primary generating and distribution station on the grid. In order to prevent risk of such a failure, the cables, breakers, and enclosures must be replaced and a permanent fence must be installed. The natural gas pipe and regulator must also be relocated and cable protection at S150 must be installed. Spending in 2021 relates to developing an engineered solution, including a budget and risk analysis.

The project is to be closed in 2021 with total expenditures of $100,000 to be amortized over 45 years.

5.4-3: REGULATORY AND DAM SAFETY REVIEW

10 Year Renewable Energy Plan

2018 WIP	2019 Addition	2020 Addition	2021 Addition
	$310,842	$402,125	

Yukon Energy developed a 10-Year Renewable Energy Plan in response to the Yukon government's "Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy". The plan was expected to expand on the work completed for Yukon Energy's 2016 Resource Plan, with a specific focus on advancing renewable energy projects to meet renewable portfolio standards articulated in 'Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy', and updating load forecasts to anticipate additional load growth arising from electrification initiatives supported in 'Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy'. The 10-Year Renewable Electricity Plan that was developed followed the same methodology as the 2016 Resource Plan with a focus on advancing renewable energy projects. A desktop update of the 2016 Resource Plan was completed with additional renewable energy project considerations. The update consisted of a new long term load forecast, expansion of existing hydro inventory, update of financial resource attributes, portfolio analysis and an action plan charting the path for resource development and implementation over the next 10 years. The outcome of this project and its acceptance will allow YEC to establish and follow a plan to ensure that reliability criteria are met.

The project is to be closed in 2020 with total expenditures of $712,967 to be amortized over five years.

Atlin Hydro EPA Preparation	**2018 WIP**	**2019 Addition**	**2020 Addition**	**2021 Addition**
			$200,000	

The Atlin (Pine Creek) Hydro Expansion project was selected as a key project in the 10 Year Renewable Electricity Plan, given its relatively advanced stage of development as a brown-field expansion project, when compared to other potential greenfield hydro developments. The project also has a lower Levelized Cost of Energy (LCOE) than the Drury Lake project. In 2020, YEC engaged in discussions with Xeitl Limited Partnership (Xeitl LP) (Taku River Tlingit development corporation) regarding the Atlin project being planned by Xeitl LP, and key principles and terms for an Agreement-in-Principle (AIP), as well as potential IPP contract provisions. An AIP has been signed, and discussions towards an EPA are underway.

The project is to be closed in 2020 with total expenditures of $200,000 to be amortized over five years.

Dam Safety Review	**2018 WIP**	**2019 Addition**	**2020 Addition**	**2021 Addition**
			$315,000	

A full dam safety review (DSR) is performed every 5 years by an external consultant as recommended by the Canadian Dam Association (CDA). Reporting on outcomes of this review is also required by each Yukon Energy generating facility water use licence. The DSR includes a comprehensive review of all of Yukon Energy's dam structures, and includes consideration of all civil, structural, geotechnical, electrical, mechanical and safety issues that may affect YEC personnel and the general public. The review identifies hazards and potential problems of high risk that require immediate attention (within one year) as well as lower risk items that can be performed over time.

The project is to be closed in 2020 with total expenditures of $315,000 to be amortized over five years.

APPENDIX 5.5
DEFERRED STUDIES >$100,000 AND <$1 MILLION
NOT IMPACTING RATE BASE

APPENDIX 5.5: DEFERRED STUDIES >$100,000 AND <$1 MILLION NOT IMPACTING RATE BASE

Deferred cost projects with total spending since 2018 greater than $100,000 million and less than $1 million that remain in WIP in 2021, excluding General Rate Application costs in WIP, have total expenditures of $0.400 million and are described below.

EV Infrastructure Project	2018 WIP	2019 Addition	2020 Addition	2021 Addition
				$200,000

The Yukon government 'Our Clean Future: A Yukon Strategy for Climate Change, Energy and a Green Economy' includes a number of actions to encourage the adoption of electric vehicles in Yukon, and the construction of public electric vehicle charging stations. The Yukon Government is forecasting 5,000 electric vehicles in the Yukon by 2030. YEC must be proactive in undertaking infrastructure upgrades and improvements to accommodate the anticipated increased demand on the electrical grid due to this planned growth. Strategy development will assess the potential impact of electric vehicles on the Yukon electrical system and identify a path forward for YEC to meet these challenges. Not addressing this could result in unforeseen costs and reactionary programs.

P125 Trashrack Study	2018 WIP	2019 Addition	2020 Addition	2021 Addition
				$200,000

The P125 intake is becoming blocked with debris and frazil ice. These blockages are currently being removed manually by divers and plant operators. This results in multiple outages each year to address blockages. Not addressing this issue will mean continued outages and requirement for divers to address the issue manually. A track rack must be installed that can permanently address the variety of debris encountered at the intake. The study will confirm the deck structural capacity and other details such as power supply and trash rack geometry.

APPENDIX 5.6
INTANGIBLE ASSETS >$100,000 AND <$1 MILLION
ADDED TO RATE BASE

APPENDIX 5.6: INTANGIBLE ASSETS >$100,000 AND<$1 MILLION ADDED TO RATE BASE

ERP System Upgrades	2019 Actual	2020 Forecast	2021 Forecast
		$200,000	

Given Yukon Energy's role as the primary generator of electricity for an isolated grid, it is critical to maintain a modern and robust Enterprise Resource Planning (ERP) system. ERP system refers to a type of software that organizations use to manage day-to-day business activities such as accounting, procurement, project management, maintenance management and supply chain operations. Best practice is to update systems regularly to ensure that the systems are up to date. The project involves upgrades to the ERP system components to the recommended latest stable versions. System experts are contracted to help with individual components as these are critical systems and Yukon Energy has no inhouse expertise.

TAB 6
BOARD DIRECTIVES

6.0 BOARD DIRECTIVES

This Tab reviews outstanding directives contained in prior Yukon Utilities Board (YUB) Decisions and, where relevant, Yukon Energy's response.

Order 2010-13 provided the Board's decision following the 2009 Phase II Rate Application and resulted in a number of directives related to cost of service and rate design issues that were not addressed in the compliance filing following that proceeding.

Tab 6 of the 2012/13 GRA outlined Yukon Energy's response to directives related to these cost of service (COS) and rate design issues as follows:

- In Order 2010-13 the Board "[did] not accept the COS study as filed by the Companies", "an updated COS study approved by the Board is essential to establishing a future rate restructuring process" and directed the Companies to "file a joint COS study within six months of the expiry of OIC 2008/149" that "incorporate[s] all findings and directions of the decision."

- The Board directives regarding Cost of Service and Rate Design consequently cannot be addressed until the next joint cost of service study is filed by the Companies.

- The latest Order in Council (OIC) direction provided in December 2018 (OIC 2018/220) provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken at this time. The remaining outstanding directives in Order 2010-13 will be addressed in the next joint cost of service and rate design application. This includes directives #1 to #12 and #19 (as summarized in Tab 6 of the 2012/13 GRA filing).

The balance of the information reviewed in Tab 6 relates to outstanding directives since the submission of the 2017/18 General Rate Application (GRA).

6.1 BOARD ORDER 2018-10, 2019-01, 2019-04 AND 2019-06 – YUKON ENERGY 2017-2018 GENERAL RATE APPLICATION & RELATED COMPLIANCE FILINGS

On June 22, 2017, Yukon Energy filed with the YUB an Application pursuant to the *Public Utilities Act* (*PUA*) and OIC 1995/90 for approval of its forecast revenue requirements for the 2017 and 2018 test years. The 2017 and 2018 test year revenue requirements were approved subject to Board ordered adjustments pursuant to directions provided in Order 2018-10. Yukon Energy filed its Compliance Filing with the Board regarding Order 2018-10 on February 25, 2019. The Board then issued Order 2019-01 outlining a process and schedule for review of Yukon Energy's compliance filing which included Information Requests to Yukon Energy (responded to April 9, 2019), written Intervenor Argument (April 19, 2019) and written YEC Reply Argument (May 1, 2019).

Order 2019-04 regarding Yukon Energy's 1st Compliance Filing was provided on September 12, 2019 noting that the Board considered YEC's February 25, 2019 Compliance Filing (the 1st Compliance Filing) to have complied with the directions provided in Board Order 2018-10, other than with regard to four specific issues. The 2nd Compliance Filing was provided on September 23, 2019 and copied the 1st Compliance Filing to Board Order 2018-10 with only a few specific changes as required to comply with the findings and direction in Appendix A of Board Order 2019-04.

Order 2019-06 outlined a process for review of YEC's 2nd Compliance filing that included a Technical Session (October 8, 2019), Interrogatories to YEC (October 15, 2019) and YEC responses (October 21, 2019), Intervenor Argument (October 28, 2019) and YEC Reply (November 4, 2019).[1]

Order 2018-10 resulted in a number of specific Board directions. Most of these directives related to 2017 and 2018 revenue requirements, and accordingly were incorporated into the 1st Compliance Filing which was addressed in Order 2019-04 and the 2nd Compliance Filing addressed by Order 2019-08. Yukon Energy's response to the each of the remaining directives is outlined below where applicable to the 2021 Application (unless stated otherwise, referenced directives are from Board Order 2018-10).[2]

6.1.1 Directives related to Sales and Generation

Directive #2 (paragraph 39) – Wholesale Forecast

- ***"The Board directs YEC to refine its methodology to ensure its forecasts align closely with AEY's forecasts in future GRA submissions".***

During the preparation of the Application YEC contacted AEY regarding the load forecast for 2021 test year. As reviewed in Section 2.2.1, YEC and AEY staff reviewed the forecasting methodology and inputs into the respective forecasts. AEY has cautioned that its forecast is for business plan purposes and has not been subject to the level of rigor that would be applied to a GRA forecast. AEY's forecasting methodology has two key inputs: net customer additions and forecast use per customer (UPC).

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[1] Due to a motion for further disclosure by UCG the original dates for Intervenor Argument and YEC Reply were subsequently adjusted from October 28 to November 1 (for Intervenor Argument) and November 4 to November 5 (for YEC Reply).

[2] Note the numbering provided in Section 6.1 relates to the numbering in the Board directions provided in Appendix A to Board Order 2018-10.

Peak Demand Forecast (para 66)

- ***The Board is of the view that peak loads are likely to grow in coming years. As a result, the Board encourages YEC to communicate closely with all parties (for example, customers, developers, mining operations) to forecast as accurately as possible to meet increased peak loads and new mining energy requirements.***

At paragraph 66 the Board noted its view that peak loads are likely to grow in coming years, and encouraged YEC to communicate closely with all parties to forecast as accurately as possible to meet peak loads and new mining energy requirements. YEC continues to communicate with relevant stakeholders in order to ensure forecasts are as accurate as possible. Tab 2 documents discussions undertaken with AEY as well as major industrial customers to prepare the current application. Discussions are also ongoing with the Yukon government as regards impacts on future peak load growth as a result of Yukon's strategy for climate change, energy and a green economy, particularly as regards future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

Directive #7 (paragraph 77) – Hydro Generation Forecast

- ***Given the above-noted advantages and disadvantages of LTA and ST hydro generation forecasts, the Board finds that, for purposes of this proceeding, it will not use the ST forecast for forecasting levels of hydro electric generation and thermal generation nor direct its use for future GRAs. In determining the revenue requirements for these and future test years, the Board is focusing on the reasonableness of the forecasts and forecasting accuracy. Further, the onus is on YEC to adequately explain any variance between actual results and its forecast amounts. For these reasons, the Board directs YEC in future GRA filings to show actual hydro and thermal generation results when comparing previous and forecast test years.***

Yukon Energy has continued to use a long term average (LTA) hydro and thermal generation forecast (with separate forecasts for thermal maintenance costs) for the 2021 test year. The options of short-term (ST) versus LTA forecasts were reviewed extensively in the 2017-18 GRA proceeding, and the Board in the end retained use of the LTA forecast. The LTA forecast provides a long-term average level of hydro and thermal generation available to supply a test year forecast load, and therefore does not forecast the actual hydro and thermal generation that YEC will provide in any test year.

As required by the Board, Tab 2, Table 2.2 in the current Application provides approved forecast and actual hydro generation for the 2018 test year (for the 2017 test year Order 2018-10 directed the use of 2017 actual results). Actual hydro generation was slightly (about 1.6 GW.h) higher than forecast, even though LTA hydro generation for the actual load was 14.8 GW.h higher than forecast; actual thermal generation was 26.2 GW.h higher than forecast, while LTA thermal generation was 15 GW.h higher than forecast. Variances between forecast and actual hydro generation and thermal results for 2018 generally reflect (a) variances in forecast (420.3 GW.h) versus actual (450.1 GW.h) firm grid load (increased grid load increases LTA thermal generation requirements), and (b) variances in water availability from forecasts (water availability in 2018 was below LTA, further increasing actual thermal generation requirements).

Low Water Reserve Fund filings address these variances in more detail, including removing impacts related to capital projects, RFID and maintenance.

6.1.2 Directives related to Revenue Requirement

Directive #15 (paragraph 133) – Labour cost forecast

- ***Finally, concerning the CW's request for a more complete picture of YEC's total labour costs and FTE count, the Board agrees it would be helpful to have this supplementary labour information available in a central location from the outset of YEC's application. The Board directs YEC in its next GRA to complete the labour schedule identified by CW in its evidence in as much detail (for both cost and FTE) as is applicable to YEC and to submit the information as an additional schedule within YEC's existing Tab 7 format.***

Tab 7, Schedule 10A provides the added labour cost details as directed by the Board. Section 3.3.1 of Tab 3 reviews in detail the labour cost forecast. The new added schedule provides complete information on labour costs in one schedule, including number of FTEs, labour cost to O&M by function and labour cost charged to capital.

Directive #20 (paragraph 212) – Depreciation Study

- ***Nonetheless, the Board considers that, given it has been eight years since the time of YEC's last full depreciation study, it would be beneficial for a full depreciation study to be completed, so as to avoid the potential for large changes to depreciation expense that could be associated with incorporating material changes to asset***

service lives. YEC is directed to submit a full depreciation study at the time of its next GRA.

A depreciation study has been completed and the results are provided in Tab 9 of the Application.

Directive # 21 (paragraph 213) – Depreciation and Amortization Expense Details

- ***The Board, however, does agree with the UCG observation that detail with respect to YEC's depreciation expense calculations was not easily obtained. It was not until asked a second time to provide the detailed depreciation and amortization expense calculations that YEC responded with the requested information. The Board considers this information to be essential in facilitating a review of YEC's depreciation and amortization expense irrespective of whether or not a change in depreciation parameters has been requested. YEC is directed to provide detailed depreciation and amortization calculations in all future GRAs consistent with the attachments provided with its response to YUB-YEC-2-27. This information may be included as an additional schedule within YEC's existing Tab 7 format.***

Tab 7, Schedules 3A and 3B provide detailed depreciation and amortization calculations as directed by the Board.

Directive #23 (paragraph 226) – Improved disclosures on deferral & reserve accounts

- ***It is the Board's view that YEC's management and reporting of deferral and reserve accounts has led to unnecessary inefficiencies and confusion with respect to the processing of its application. For this reason, the Board directs YEC to re-establish its standard of disclosure to one that is transparent, consistent and provides cross-referencing among each of the interrelated rate base and revenue requirement items and the individual components comprising each item. This applies equally to the disclosure on YEC's Tab 7 schedules and any supplementary information within YEC's application.***

Yukon Energy has implemented changes to the structure of Tab 7, Schedules 1 and 3 in order to improve disclosure and reporting of deferral and reserve accounts as directed by the Board.

Directive #24 (paragraph 238) – Cost of Debt

- ***In Board Order 2013-01, the Board directed that a formulaic approach be used for forecasting future costs of debt. This direction was not followed. The Board reiterates the direction and expects this direction to be followed. In future GRAs, both Yukon utilities are to provide their cost-of-debt forecast based on the formulaic approach (long-term Canada bonds plus 120 basis points). If a utility chooses to employ a market-based approach, that utility must also provide a forecast based on the approved formulaic approach.***

Yukon Energy's forecast for new long-term debt interest rate for the 2021 test year is based on long-term Canada bonds plus 120 basis points as directed by the Board. Please see Tab 3, Section 3.5.1. The interest rate adopted for new debt forecast in the test year is 2.19%, determined using a formulaic approach based on the long-term Canada Bonds rate plus 120 basis points (Government of Canada Long-Term Bond Benchmark at 0.99% as of June 30, 2020).

6.1.3 Directives related to Rate Stabilization Mechanisms

Directives 26 through 31 of Board Order 2018-10, addressing Rider F and the DCF/LWRF, were further addressed in Appendix A of Board Orders 2019-04 and 2019-08 and in YEC's compliance filing with regard to the final 2018 LWRF Term Sheet filed December 10, 2019.

Appendix A of Board Order 2019-04, at page 3, relieved YEC of the obligation to comply with Directive 26 for the purpose of setting rates for the 2017-2018 GRA.

Paragraph 94 of Appendix A to Board Order 2019-08 stated as follows regarding issues to address in YEC's next GRA application:

94. Further, the Board's view in Board Order 2019-04 is not a fundamental change in the principle that water availability is a ratepayer risk; it is a proper acknowledgement of the risks that are borne by the utility and the risk borne by the customer. If YEC wishes to provide further views on its risks and ratepayer risks, the appropriate forum for its submissions and evidence on this issue would be YEC's next GRA application.

Paragraph 95 of Appendix A to Board Order 2019-08 (paragraph 95) included the following directions to YEC going forward with regard to the LWRF:

95. Going forward, the Board provides the following summary on its findings in this decision and future directions for YEC regarding the LWRF:

> ***a) For forecasting hydro generation for GRA purposes, the Board's focus in determining the revenue requirements for these and future test years will continue to be on the reasonableness of YEC's forecasts and forecasting accuracy.***
>
> ***b) The Board has previously approved the use of LTA by YEC to forecast its GRA hydro generation requirements. Consideration of future trends due to phenomenon such as climate change will be evaluated by the Board in subsequent proceedings when assessing the forecasting accuracy of hydro generation. This allows YEC the option to continue to use LTA for its hydro generation forecasts.***
>
> ***c) The approved LWRF will continue to cover variances due to deviations from forecast water levels up to forecast load levels. This is expected to reduce the risk to YEC of changes in hydro generation due to changes in water levels up to forecast load levels. As stated in Board Order 2019-04, this maintains the principle that ratepayers carry the risk for changes in water levels that was established when the LWRF was initially established (with the recognition that costs for generation for loads above forecast are a utility risk).***
>
> ***YEC has stated that this should be trued up on an annual basis when there is not a GRA before the Board and as part of a GRA when there is such an application before the Board. Although this proposal is not optimal in that it does not result in an annual trueup, the Board accepts that this will provide a better price signal to customers than the previous LWRF submitted by YEC. As the LWRF will be for actual values compared to forecast values up to the load forecast, this should resolve the issues with respect to fuel mix ratios as the deferral account will reflect actual fuel mix.***
>
> ***d) The Board will not accept YEC's use of the expected long-term cost of power in its LWRF calculations. As stated, this is redundant to accrual and depreciation accounting and creates unnecessary complexities.***
>
> ***e) The Board will not accept YEC's thermal fuel calculations for the reasons cited earlier in the decision. In its future GRAs, YEC is directed to compare actual fuel costs (for up to forecast load) to forecast fuel costs for LWRF and GRA purposes.***

f) YEC should consider the Board's comments in paragraphs 80 and 81. The Board recognizes that the directly focused LWRF above does not provide customer protection in years of drought. Therefore, the Board suggests that YEC examines whether a drought deferral account could be established to mitigate the effects of any future drought event(s). In its review of this issue, for example, YEC could consider the possibility of establishing a rate rider, on a cents/kWh basis, to build up the account and apply to the Board when it recognizes a drought situation and requires mitigation from this account.

g) The Board directs YEC to address intergenerational equity issues with respect to the LWRF in the next GRA.

In response to YEC's December 10, 2019 filing of the Final Annual 2018 LWRF and related documents, the Board on March 19, 2020 acknowledged receipt of the four documents submitted by YEC and directed that any future issues regarding the LWRF term sheet or the ERA are to be addressed in YEC's next GRA and that no basis exists to consider the LWRF reports prior to YEC's next GRA.

An updated LTA Thermal Calculation for this Application is provided in Tab 2, Appendix 2.1, including a revised table for 2021 long term average (LTA) hydro and thermal generation determinations. The LTA forecasts reflect historical water conditions for 38 water years. YEC has not amended the forecast specifically for climate change as the utility concluded, based on climate change modelling completed by Yukon College, that climate change impacts materialize over a very long time frame (50-100 years); accordingly, there is no basis to adopt climate change factors for a short (one year) time frame covered by this Application.

The stabilization mechanism as represented by the LWRF Term Sheet as last approved in the 2017-18 GRA was provided to the Board in December 2019 along with the 2017-2018 LWRF Annual Report and Energy Reconciliation Adjustment ("ERA") filing, and acknowledged by the Board's letter of March 19, 2020. Yukon Energy acknowledges that it has been directed in Board Order 2019-08 to review and update the LWRF Term Sheet in this GRA, and to provide any further views on its risk and ratepayer risks that YEC considers relevant. Yukon Energy has been required, given COVID-19 conditions and other factors related to minimizing any bill impacts on ratepayers, to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application. Yukon Energy is working to complete and file an updated LWRF Term Sheet with the Board as soon as feasible.

6.1.4 Directives related to Capital Projects

Paragraph 374 – Aishihik Electrical and Control Upgrades

- ***For the AH3 control system drawings update, YEC stated that this project will review operator interfaces and correct existing drawings to safely operate the equipment in anticipation of a full control system replacement in future years. The full replacement is expected to occur during the next scheduled overhaul in 2021. Although the Board has concerns about whether the deficiencies identified must be corrected prior to the 2021 replacement, if any components of this project are undertaken as discussed below, the AH3 control systems drawing update is needed to ensure the safe and reliable operation of the system. Accordingly, costs related to this component are to be held in WIP, and the Board will consider the reasonableness and prudency of these costs when approval is sought to add the project to rate base.***

Based on the directive from the Board, for the 2017/18 GRA Compliance Filing purposes YEC kept the project in WIP with 2018 forecast cost at $0.025 million. To date there was no further spending for this project, therefore, there is no impact to the rate base from this project.

Directive 48, (paragraph 438) – Substation Protection and Control Minor Upgrades - Details on upgrade work for capital costs

- ***However, in subsequent GRAs, when requesting approval of any such upgrades, the Board directs YEC to include a detailed description of the work that has been carried out or will be carried out at each substation and more detailed explanations of the need for the work at each substation.***

Total spending on Substation Protection and Control Minor Upgrades over the period from 2019 to 2021 is less than $100,000 ($26,000 in 2019 and $50,000 in 2020) and therefore does not receive detailed review in Tab 5 business case assessments for major projects (costs over $1 million) and projects with costs between $100,000 and $1 million. In response to the Board's directive, a description is provided below of the relevant substation spending included in the Application.

Spending on Substation Protection and Control Minor Upgrades over the period from 2019 to 2021 relates to addressing minor protection issues at various Yukon Energy substations, in order to reduce the impact / severity and extent of customer outages; minimize or eliminate malfunctions with metering equipment; and increase the reliability of information and reporting. For example work scheduled for 2019 included the following: moving check meter to an alternative PT at S170- McIntyre/S164-Takini/S150-Whitehorse to ensure that the revenue streams are accurate and KPIs are correctly reported, and determining if similar work was required at S150 and S164; and at Faro 870S installing three phase VTs for sensing voltages on OCR-505 and 506, and revising settings to provide fault determination on line L356 (Ross River), and reviewing protection settings to ensure correct coordination for clearing bus faults over voltage settings for off frequency operation and investigating and connecting time clocks in S870S.

6.1.5 Directives related to Deferred Projects

Directive #463 – Battery Project

The Board finds that, given the costs and unproven nature of the technology in a northern environment, the project is not viable. If YEC did not have funding from NRCan, it was risky to undertake the project, considering that even the initial costs in the test years are forecast at over $9 million dollars. For these reasons, the Board finds that expenditures on such a project are not warranted.

As noted in Appendix 5.1, YEC applied for and was awarded funding from Canada to support development of the battery project. As reviewed in Appendix 5.1 the project is currently forecast to be completed in 2022, and YEC is not seeking to include the Project in rate base at this time. Further details regarding the project status are provided in Appendix 5.1

Directive #471 – Thermal Plant Project

- ***The Board is of the view that YEC has supported its case that adding capacity is needed to meet system reliability needs under the N-1 criterion and that a greenfield thermal generation plant is one of the preferred methods to add the needed capacity. However, YEC has not provided a business case in support of this project. YEC did not detail the costs and benefits associated with this project. The Board finds that it is not reasonable for YEC to proceed with the project without a detailed business case that considers the alternatives to the project. The Board notes that YEC forecast costs for 2019 and 2020 of $38 million and $20 million respectively. The magnitude of these costs alone is reason for proceeding cautiously. The Board is not persuaded that this project is the only way to address the predicted capacity shortfall and that the forecast costs are reasonable. The Board requires a detailed evaluation of alternatives to this project included in the business case.***

- ***Given the above, the Board accepts Mr. Maissan's recommendation that YEC provide a detailed comparison of alternatives for this project, including the pros, cons, capital costs, operating costs and timeline to in-service and justification for its preferred option. Accordingly, before undertaking any further costs on this project, the Board directs YEC to provide this information in any future application for this project. Any costs incurred to date for this project are to be held in WIP until such time as a new application is brought before the Board and the Board makes a determination on that application and the prudency of the costs incurred.***

Tab 5 and the related Tab 5 Appendices (see Diesel Retirement Replacement (12.5 MW) project described in Appendix 5.3) provide details regarding YEC's ongoing assessments and plans to address shortfalls in dependable capacity required under the single contingency N-1 planning criteria. As summarized in the description of the Diesel Retirement Replacement (12.5 MW) project the focus at this time is on installing new capacity after the Application test year among existing thermal plant facilities (rather than at a new greenfield thermal generation plant). Costs to date for the Diesel Retirement Replacement (12.5 MW) project are held in WIP. Given the importance and urgency of this undertaking YEC must incur the necessary costs to continue the planning phase - realizing the prudency of those costs will have to be demonstrated at a future proceeding when the utility has placed the asset in service and is requesting inclusion of the related costs in revenue requirement.

Directive #62 (paragraph 490) – Resource Plan Update

- ***However, the Board is of the view that it is not prudent for YEC to continue with these significant expenses to update the resource plan every five years. Accordingly, the Board directs YEC to seek Board approval prior to any future updates of its resource plan. Any such application must be accompanied by a detailed proposal for both costs and scope of work, including a description of work to be carried out internally and by consultants. YEC must also include an explanation of why any work to be done by consultants cannot be carried out by internal staff.***

The Tab 5 test year forecasts include capital costs for the Ten Year Renewable Energy Plan which addresses resource planning updates as required for current YEC resource planning. This includes consideration of impacts on future peak load growth and energy generation requirements as a result of Yukon's strategy for climate change, energy and a green economy, particularly as regards IPP policy resource project development impacts on energy and capacity resource balances, and policy impacts on future peak loads related to ongoing initiatives for electrification, electric vehicles, and heat pumps.

YEC must continue to incur the necessary costs to plan its system to meet the needs of current and future ratepayers - realizing that the prudency of those costs will have to be demonstrated at a future proceeding. The Application provides information on costs as required for the Board to review the prudency of these expenditures. See description provided in Appendix 5.4.

Directive #521 – Mt Sumanik Wind Feasibility Study

- ***YEC has not stated the endpoint of this project or what the potential benefits will be. The Board is not prepared to accept these costs until YEC provides a business case and a full justification of these costs.***

Tab 5, Appendix 5.3 provides updated information on the Mt. Sumanik Wind Feasibility Study. Based on the study results and current information regarding resource requirements, the project was closed in 2020. Appendix 5.3 reviews the description of work undertaken and justification of costs incurred for this project.

6.2 BOARD ORDERS 2018-08, 2018-09 AND 2019-03

Cost awards were determined subsequent to the Victoria Gold Power Purchase Agreement (PPA) proceeding, the ERA Part 1 proceeding, and the Yukon Energy 2017/18 GRA. The Board provided the following directives related to hearing cost awards for each of these proceedings:

- Victoria Gold PPA Proceeding (Order 2018-08):
    - o "YEC shall pay the following amounts to the Interveners identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing related costs."
- ERA Part 1 Proceeding (Order 2019-09):
    - o "YEC shall pay the following amounts to the Intervenors identified and the Government of Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs."

- 2017/18 GRA Proceeding (Order 2019-03 as revised by Order 2020-02):
  - "YEC shall pay the following amounts to interveners identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs."
- 2017/18 GRA 2nd Compliance Filing Cost Awards (Order 2020-01):
  - "YEC shall pay the following amounts to interveners identified and the Government of the Yukon within 30 days of the issuance of this Order. The Board directs YEC to amortize these hearing-related costs."

Yukon Energy has established a Hearing Cost Reserve Account in accordance with the direction provided in Board Order 2013-03, and YEC has amortized hearing-related costs to this account for the above proceedings as directed by the Board (see Table 6.1 for a summary of the hearing-related costs for each of the above proceedings).

Table 6.1:
Cost Awards Order 2018-08, 2018-09, Order 2020-01, and Order 2019-03

	Yukon Energy Victoria Gold PPA Proceeding [Order 2018-08]	Yukon Energy ERA Part 1 Proceeding [Order 2018-09]	Yukon Energy 2017/18 GRA [Order 2019-03 as revised by Order 2020-02]	Yukon Energy 2017/18 GRA 2nd Compliance Filing [Order 2020-01]
Yukon Energy	37,868	26,894	515,174	44,221
City of Whitehorse (CW)		4,171	78,197	7,530
Utilities Consumers' Group (UCG)	5,813	2,638	39,181	12,054
John Maissan (JM)	1,515		6,405	
Yukon Government	39,580	36,936	368,225	32,150
Total	**84,776**	**70,639**	**1,007,183**	**95,955**

TAB 7
FINANCIAL SCHEDULES

Yukon Energy Corporation
November 2020

Schedule Index

Yukon Energy Corporation
Computation of Rate Base
($000s)

Schedule 1
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	**Property, Plant and Equipment**							
2	Year end balance	S.3 L.4	612,436	615,387	642,738	677,309	738,663	738,663
	Deduct:							
3	Accumulated depreciation (note 1)	S.3 L.8	163,053	160,541	172,426	185,389	198,334	198,970
4	Construction-in-progress	S.3 L.12	7,620	4,491	8,088	10,796	37,389	37,389
5	Disallowed assets	S.3 L.11	2,193	2,193	1,989	1,785	1,582	1,582
6	Miscellaneous reserves	S.3 L.16	7,808	7,249	6,231	4,849	4,655	5,012
7	Total deductions		180,674	174,474	188,735	202,820	241,960	242,953
	Add:							
8	Deferred study costs and Intangible assets (note 2)	S.3 L.59	41,695	30,118	32,133	37,884	44,400	44,400
9	Less: Studies and Intangible Assets in Progress	S.3 L.60	29,498	18,930	20,881	26,065	29,972	29,972
10	Total additions		12,198	11,188	11,252	11,819	14,428	14,428
	Net plant in Service							
11	Current year-end balance	S.3 L.62	443,960	452,101	465,255	486,307	511,131	510,138
12	Previous year-end balance		446,777	446,782	452,101	465,255	486,307	486,307
13	Mid-year balance		445,368	449,441	458,678	475,781	498,719	498,223
14	Mid-year regulatory deferral		3,879	3,805	3,009	2,484	2,732	2,732
15	Working capital	S.2 L.8	5,344	5,617	5,935	6,592	6,985	7,141
16	**Gross Rate Base**		454,592	458,864	467,622	484,858	508,436	508,096
	Deduct:							
	Contributions for extensions (PP&E)							
17	Current year-end balance		201,232	199,527	211,719	228,231	257,031	257,031
18	Contributions in WIP		-	603	385	776	20,776	20,776
19	Current year-end balance in-service		201,232	198,924	211,333	227,455	236,255	236,255
20	Accumulated amortization of contributions		35,976	34,536	39,276	44,306	48,767	48,767
21	Net current year-end balance in-service		165,256	164,387	172,057	183,149	187,488	187,488
22	Previous year-end balance		168,967	168,967	164,387	172,057	183,149	183,149
23	Mid-year balance		167,112	166,677	168,222	177,603	185,319	185,319
24	**Net Rate Base**	S.5 L.1	287,480	292,186	299,399	307,255	323,117	322,777

Note 1: Including Reserve for Future Removal and Site Restoration
Note 2: Planning and Study costs, Relicencing, Dam Safety costs, Vegetation Management and Intangible Assets. Net of contributions.

Yukon Energy Corporation
Computation of Allowance for Working Capital
($000s)

Schedule 2
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Operating and maintenance	S.5 L.5	23,715	27,794	29,784	37,653	41,119	43,863
2	Taxes other than income	S.5 L.6	708	671	673	739	750	750
3	Non-allowable expenses		(100)	(99)	(166)	(95)	(120)	(120)
4	Cash operating expenses		24,323	28,366	30,290	38,298	41,748	44,492
5	27/365		1,799	2,098	2,241	2,833	3,088	3,291
6	Inventory (three year average)		3,703	3,697	3,837	3,913	4,014	4,014
7	GST Impact on working capital	S.2A L.11	(158)	(178)	(143)	(154)	(117)	(164)
8	Working capital	S.1 L.19	5,344	5,617	5,935	6,592	6,985	7,141

Yukon Energy Corporation
Effect of GST on Working Capital
($000s)

Schedule 2A
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Expenses subject to GST		42,084	37,733	53,916	69,534	99,535	102,279
2	GST Rate		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
3	GST Recoverable		2,104	1,887	2,696	3,477	4,977	5,114
4	Day Factor		14	14	14	14	14	14
5	Recoverable portion of GST impact		81	72	103	133	191	196
6	Revenue subject to GST		49,794	52,059	51,302	59,947	64,164	75,135
7	GST blended rate (2009 GRA)		5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
8	GST payable		2,490	2,603	2,565	2,997	3,208	3,757
9	Day factor		35	35	35	35	35	35
10	Payable portion of GST impact		239	250	246	287	308	360
11	Net impact of GST on working capital	S.2 L.7	(158)	(178)	(143)	(154)	(117)	(164)

Yukon Energy Corporation

Continuity Schedule of Property, Plant and Equipment, Deferred Costs and Intangible Assets
($000s)

Schedule 3
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
	Property, Plant and Equipment							
1	Balance at beginning of year		598,756	598,756	615,387	642,738	677,309	677,309
2	Net Increases to PPE (Table 5.1)		13,680	20,189	29,259	34,571	61,354	61,354
3	Retirements, disposals and adjustments		-	(3,559)	(1,908)	-	-	-
4	Balance at end of year	S.1 L.2	612,436	615,387	642,738	677,309	738,663	738,663
	Accumulated depreciation							
5	Balance at beginning of year		150,857	150,857	160,541	172,426	185,389	185,389
6	Depreciation expense	S.6 L.7	12,196	12,185	12,677	12,963	12,945	13,581
7	Retirements, disposals and adjustments		-	(2,501)	(791)	-	-	-
8	Balance at end of year	S.1 L.3	163,053	160,541	172,426	185,389	198,334	198,970
	Deductions from PP&E:							
9	Disallowed assets		2,746	2,746	2,746	2,746	2,746	2,746
10	Accum. Disallowed depreciation		(553)	(553)	(757)	(961)	(1,164)	(1,164)
11	Net Disallowed	S.1 L.5	2,193	2,193	1,989	1,785	1,582	1,582
12	Construction-in-progress	S.1 L.4	7,620	4,491	8,088	10,796	37,389	37,389
	Miscellaneous Reserves							
13	Fire Insurance Reserve		4,704	4,704	4,442	4,180	3,918	3,918
14	Reserve for Injuries and Damages		(1,035)	(1,419)	(1,002)	(2,121)	(2,053)	(1,697)
15	Reserve for Future Removal and Site Restoration		4,139	3,963	2,790	2,790	2,790	2,790
16	Total Miscellaneous Reserves	S.1 L.6	7,808	7,249	6,231	4,849	4,655	5,012
17	Total Deductions		17,621	13,933	16,308	17,431	43,626	43,983
18	Net Property, Plant and Equipment for Rate Base		431,762	440,913	454,003	474,489	496,703	495,710
	Add:							
19	Deferred study costs and Intangible assets (net of contributions)							
20	Feasibility Studies							
21	Opening balance		18,499	18,499	17,798	16,841	16,791	16,791
22	Additions		14,127	1,091	866	1,819	7,370	7,370
23	Amortization		(1,838)	(1,791)	(1,824)	(1,869)	(2,272)	(2,272)
24	Year-end balance		30,788	17,798	16,841	16,791	21,889	21,889
25	Relicensing							
26	Opening balance		6,604	6,604	8,447	10,123	11,970	11,970
27	Additions		1,544	2,359	2,102	2,148	1,745	1,745
28	Amortization		(515)	(515)	(427)	(301)	(368)	(368)
29	Year-end balance		7,633	8,447	10,123	11,970	13,347	13,347
30	Dam Safety							
31	Opening balance		118	118	89	59	345	345
32	Additions		-	-	-	315	-	-
33	Amortization		(30)	(30)	(30)	(30)	(93)	(93)
34	Year-end balance		89	89	59	345	252	252
35	Vegetation Management							
36	Opening balance		1,994	1,994	1,772	1,551	1,329	1,329
37	Additions		-	-	-	-	-	-
38	Amortization		(222)	(222)	(222)	(222)	(222)	(222)
39	Year-end balance		1,772	1,772	1,551	1,329	1,108	1,108
40	Intangibles							
41	Opening balance		1,859	1,859	1,684	2,339	6,000	6,000
42	Additions		79	308	1,215	4,239	495	495
43	Amortization		(478)	(482)	(560)	(578)	(749)	(749)
44	Year-end balance		1,460	1,684	2,339	6,000	5,746	5,746
45	DSM							
46	Opening balance		990	995	1,253	1,319	1,510	1,510
47	Additions		-	350	210	375	894	894
48	Amortization		(110)	(92)	(144)	(184)	(228)	(228)
49	Year-end balance		880	1,253	1,319	1,510	2,176	2,176
50	Hearing Reserve							
51	Opening balance		(1,026)	(1,026)	(926)	(99)	(61)	(61)
52	Additions		155	155	883	93	-	-
53	Amortization		(55)	(55)	(55)	(55)	(55)	(55)
54	Year-end balance		(926)	(926)	(99)	(61)	(116)	(116)
55	Total Deferred Costs and Intangible Assets							
56	Opening balance		29,038	29,043	30,118	32,133	37,884	37,884
57	Additions		15,906	4,262	5,276	8,989	10,504	10,504
58	Amortization		(3,248)	(3,187)	(3,261)	(3,239)	(3,987)	(3,987)
59	Year-end balance	S.1 L.8	41,695	30,118	32,133	37,884	44,400	44,400
60	Less: Working in Progress	S.1 L.9	29,498	18,930	20,881	26,065	29,972	29,972
61	Total Net Deferred Costs and Intangible Assets for Rate Base		12,198	11,188	11,252	11,819	14,428	14,428
62	Total Net PP&E, Deferred Costs and Intangible Assets for Rate Base	S.1 L.11	443,960	452,101	465,255	486,307	511,131	510,138
63	Other Regulatory							
64	Opening balance		3,868	3,863	3,746	2,272	2,696	2,696
65	Additions		318	141	(1,209)	670	500	500
66	Amortization		(295)	(258)	(266)	(246)	(428)	(428)
67	Year-end balance		3,891	3,746	2,272	2,696	2,768	2,768
68	Total Net PP&E, Deferred Costs and Intangible Assets		447,850	455,847	467,527	489,004	513,899	512,906

Yukon Energy Corporation

Calculation of Depreciation Expense for 2021
($000s)

Schedule 3A
November 2020

Description	Cost at 2020 Year End	2021 Additions	Cost at 2021 Year End	Existing Depreciation Rate (Years)	2021 Existing Forecast Depreciation	Proposed Depreciation Rate (Years)	2021 Proposed Forecast Depreciation
Land							
Hydraulic Production	444.9	0.0	444.9	0	0.0	0	0.0
Diesel Production	27.7	0.0	27.7	0	0.0	0	0.0
Main Transmission Facilities	576.9	0.0	576.9	0	0.0	0	0.0
Distribution System	17.8	0.0	17.8	0	0.0	0	0.0
General Plant	548.0	0.0	548.0	0	0.0	0	0.0
Rights	128.8	0.0	128.8	50	1.6	50	1.6
Depreciation Study Differences					0.0		0.0
Total Land	**1,744.0**	**0.0**	**1,744.0**		**1.6**		**1.6**
Hydro Plant							
Structures and Improvements	37,647.8	17,068.5	54,716.3	72	522.9	72	522.9
Buildings and Improvements	10,278.7	0.0	10,278.7	40	257.0	40	257.0
Reservoirs, Dams, and Waterways	173,561.2	300.0	173,861.2	103	1,685.4	103	1,685.4
Overhaul	6,712.1	0.0	6,712.1	10	671.2	10	671.2
Waterwheels,Turbines & Generation	26,904.6	0.0	26,904.6	85	309.9	60	439.0
Accessory Electric Equipment	27,364.1	750.0	28,114.1	45	608.0	40	684.0
Accessory Digital Equipment	837.9	0.0	837.9	20	41.9	20	41.9
Misc Power Plant Equipment	11,791.4	25.0	11,816.4	30	393.0	30	393.0
Fencing	107.1	0.0	107.1	30	2.7	30	2.7
Depreciation Study Differences					-307.6		-140.5
Total Hydro Plant	**295,205.0**	**18,143.5**	**313,348.5**		**4,184.4**		**4,556.6**
Diesel Production							
Structures and Improvements	1,562.4	0.0	1,562.4	72	21.7	72	21.7
Buildings and Improvements	466.1	0.0	466.1	55	8.5	55	8.5
Fuel Holders, Products, and ACC	1,688.5	0.0	1,688.5	25	41.6	40	26.0
Generating Equipment and Prime	14,596.8	0.0	14,596.8	40	635.2	40	635.2
Overhaul	2,962.8	580.0	3,542.8	5	592.6	5	592.6
Minto Generating Equipment	243.5	0.0	243.5	12	26.1	12	26.1
Accessory Electric Equipment	9,018.9	0.0	9,018.9	45	199.7	45	199.7
Misc Power Plant Equipment	1,837.7	0.0	1,837.7	30	59.2	30	59.2
Depreciation Study Differences					-80.6		-70.2
Total Diesel Production	**32,376.6**	**580.0**	**32,956.6**		**1,503.9**		**1,498.7**
Wind Turbine							
Wind Turbine	0.0	0.0	0.0	0	0.0	0	0.0
Total Wind Turbine	**0.0**	**0.0**	**0.0**		**0.0**		**0.0**
Main Transmission Facilities							
Poles and Fixtures	86,010.6	12,855.0	98,865.6	65	1,323.2	50	1,720.2
Brushing	14,082.3	0.0	14,082.3	50	281.6	60	234.7
Survey Costs	4,380.7	0.0	4,380.7	50	238.7	60	198.9
Overhead Conductors / Poles	20,561.3	0.0	20,561.3	50	411.2	60	342.7
Overhead Conductors / Towers	278.0	0.0	278.0	50	5.6	60	4.6
Substation Equipment	81,331.5	300.0	81,631.5	54	1,512.8	45	1,815.3
Substation Buildings	1,536.2	0.0	1,536.2	55	27.9	55	27.9
Substation Fences	274.5	0.0	274.5	20	13.4	30	8.9
Depreciation Study Differences					-53.4		-79.6
Total Main Transmission Facilities	**208,455.0**	**13,155.0**	**221,610.0**		**3,761.1**		**4,273.7**
Sub Transmission Lines							
Poles and Fixtures	4,579.6	0.0	4,579.6	45	100.0	50	90.0
25Kv Minto Spur- Structure	2,646.1	0.0	2,646.1	12	0.0	12	0.0
Brushing	41.6	0.0	41.6	50	0.8	60	0.7
Brushing Minto	432.5	0.0	432.5	12	0.0	12	0.0
Survey costs	0.0	0.0	0.0	50	0.0	60	0.0
Survey costs Minto	95.1	0.0	95.1	12	0.0	12	0.0
Overhead Conductors	1,840.4	0.0	1,840.4	45	40.7	60	30.5
Underground Conductors / Conduit	83.9	0.0	83.9	45	1.9	45	1.9
Overhead Conductors Minto	920.7	0.0	920.7	12	0.0	12	0.0
Substation Equipment	8,013.6	0.0	8,013.6	40	200.3	45	178.1
Substation Equipment Minto	7,111.2	0.0	7,111.2	12	74.6	12	74.6
Depreciation Study Differences					-27.4		-45.8
Total Sub Transmission Lines	**25,764.8**	**0.0**	**25,764.8**		**391.0**		**330.0**

Yukon Energy Corporation
Calculation of Depreciation Expense for 2021
($000s)

Schedule 3A
November 2020

Description	Cost at 2020 Year End	2021 Additions	Cost at 2021 Year End	Existing Depreciation Rate (Years)	2021 Existing Forecast Depreciation	Proposed Depreciation Rate (Years)	2021 Proposed Forecast Depreciation
Distribution System							
Poles and Fixtures	9,798.1	649.1	10,447.1	35	280.1	40	245.1
Brushing	44.8	0.0	44.8	50	0.9	50	0.9
Survey costs	619.4	0.0	619.4	50	17.7	50	17.7
Overhead conductors - Poles	268.2	0.0	268.2	35	7.7	50	5.4
Overhead Costs	2,117.4	0.0	2,117.4	40	52.9	40	52.9
Underground Services	385.2	0.0	385.2	40	9.6	40	9.6
Underground Conduit	40.5	0.0	40.5	40	1.0	40	1.0
Wind Monitoring Equipment	0.0	0.0	0.0	0	0.0	0	0.0
Meters	312.6	0.0	312.6	30	8.6	16	16.1
Meter Equipment	288.4	0.0	288.4	30	9.2	16	17.2
Substation Equipment	1,287.2	0.0	1,287.2	40	30.3	40	30.3
Substation Buildings	64.8	0.0	64.8	55	1.2	55	1.2
Substation Fences	100.3	0.0	100.3	20	5.0	30	3.3
Street Lights	591.6	0.0	591.6	40	13.8	40	13.8
Line Transformers	4,051.1	0.0	4,051.1	40	98.9	35	113.0
Sentinel Lights	36.4	0.0	36.4	30	1.2	30	1.2
Depreciation Study Differences					-27.6		1.3
Total Distribution System	**20,005.9**	**649.1**	**20,654.9**		**510.5**		**530.1**
Building and Other Equipment							
Survey Costs Land	4.3	0.0	4.3	50	0.1	50	0.1
Structures and Improvements (Hydro)	2,791.6	0.0	2,791.6	40	69.4	50	55.5
Building and Improvements	10,632.1	125.0	10,757.1	55	193.3	50	212.6
Office Furniture and Equipment	1,877.4	25.0	1,902.4	20	47.2	20	47.2
Communication Site Towers	19.3	0.0	19.3	30	0.6	40	0.5
Communication Site Fences	64.1	25.0	89.1	20	3.2	30	2.1
Computer Hardware	2,063.4	230.0	2,293.4	5	188.7	7	134.8
Computer Software	0.0	0.0	0.0	5	0.0	5	0.0
Tool and Instruments	2,157.5	490.0	2,647.5	20	84.4	20	84.4
Wind Monitoring Equipment	14.3	0.0	14.3	20	0.7	15	1.0
Communication Equipment	5,615.6	100.0	5,715.6	20	234.1	20	234.1
Company Owned Houses / Land	59.0	0.0	59.0	30	1.7	40	1.3
Company Owned Houses	2,132.4	230.0	2,362.4	30	22.8	40	17.1
Depreciation Study Differences					-29.0		-19.0
Total Building and Other Equipment	**27,431.1**	**1,225.0**	**28,656.1**		**817.1**		**771.6**
Transportation							
Utility Vehicles	371.6	30.0	401.6	7	29.3	8	25.6
Sedans and Stationwagons	137.8	0.0	137.8	7	9.4	11	6.0
Trucks & Pole Trailer	11.0	0.0	11.0	31	0.4	25	0.4
Pole Trailers > 10,000 Lbs	53.7	0.0	53.7	25	1.7	25	1.7
Trucks 3/4 to 2 Ton	3,378.4	580.0	3,958.4	10	242.4	9	269.3
Trucks > 3 Ton	1,459.8	185.0	1,644.8	20	58.4	20	58.4
Foremost	1,003.9	0.0	1,003.9	25	40.2	20	50.2
Depreciation Study Differences					-0.7		19.3
Total Transportation	**6,416.1**	**795.0**	**7,211.1**		**381.0**		**431.0**
Critical Spares							
Critical Spares	1,193.6	0.0	1,193.6	0	0.0	0	0.0
Total Critical Spares	**1,193.6**	**0.0**	**1,193.6**		**0.0**		**0.0**
LNG Production							
Structures and Improvements	6,184.7	0.0	6,184.7	72	85.9	72	85.9
Fuel Holders	13,200.7	0.0	13,200.7	32	412.5	60	220.0
Generator	20,891.0	0.0	20,891.0	40	522.3	40	522.3
Overhaul	343.3	180.0	523.3	2	171.4	2	171.4
Accessory Electric Equipment	3,655.9	0.0	3,655.9	45	81.2	45	81.2
Misc Power Plant Equipment	2,850.6	35.0	2,885.6	30	95.0	30	95.0
Fence	779.7	0.0	779.7	30	26.0	30	26.0
Depreciation Study Differences					0.0		-14.0
Total LNG Prodution	**47,905.9**	**215.0**	**48,120.9**		**1,394.4**		**1,187.9**
Total	**666,498.0**	**34,762.5**	**701,260.5**		**12,944.9**		**13,581.1**

Yukon Energy Corporation
Cost of Capital Calculation
($000s)

Schedule 4
November 2020

Line No.	Description	Cross Ref.	Mid Year Balance	Ratio		Mid Year Rate Base	Mid Year Cost Rate	Return
	2018 GRA Compliance							
1	Long-Term debt	S.11 L.18	172,472	60.0%		172,473	2.23%	3,844
2	Common Stock	S.7 L. 8	115,005	40.0%		115,007	8.70%	10,006
3	Total	S.5 L.3	287,477	100.0%		287,480	4.82%	13,850
	2018 Actual							
7	Long-Term debt	S.11 L.18	159,362	57.4%		167,813	2.58%	4,336
8	Common Stock	S.7 L. 8	118,109	42.6%		124,373	6.25%	7,773
9	Total	S.5 L.3	277,471	100.0%		292,186	4.14%	12,110
	2019 Actual							
10	Long-Term debt	S.11 L.18	170,377	58.6%		175,532	2.71%	4,757
11	Common Stock	S.7 L. 8	120,229	41.4%		123,867	3.81%	4,723
12	Total	S.5 L.3	290,606	100.0%		299,399	3.17%	9,480
	Existing 2020							
10	Long-Term debt	S.11 L.18	179,873	59.6%		183,023	2.92%	5,339
11	Common Stock	S.7 L. 8	122,093	40.4%		124,232	3.88%	4,824
12	Total	S.5 L.3	301,966	100.0%		307,255	3.31%	10,163
	Existing 2021							
16	Long-Term debt	S.11 L.18	193,756	60.0%		193,870	2.81%	5,446
17	Common Stock	S.7 L. 8	129,171	40.0%		129,247	3.10%	4,002
18	Total	S.5 L.3	322,927	100.0%		323,117	2.92%	9,448
	Proposed 2021				**Deemed Ratio**			
19	Long-Term debt	S.11 L.18	193,505	59.6%	60.0%	193,669	2.81%	5,447
20	Common Stock	S.7 L. 8	131,173	40.4%	40.0%	129,113	8.70%	11,235
21	Total	S.5 L.3	324,678	100.0%	100.0%	322,777	5.17%	16,682

Yukon Energy Corporation
Utility Revenue Requirement
($000s)

Schedule 5
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Net rate base	S.1 L.24	287,480	292,186	299,399	307,255	323,117	322,777
2	Average Rate of return on rate base		4.82%	4.14%	3.17%	3.31%	2.92%	5.17%
3	Utility income	S.8 L.1	13,850	12,110	9,480	10,163	9,448	16,682
4	Utility expenses							
5	Operating and maintenance (note 1)	S.6 L.3	23,715	27,794	29,784	37,653	41,119	43,863
6	Taxes other than income	S.6 L.4	708	671	673	739	750	750
7	Amortization of deferred costs	S.6 L.5	3,543	3,500	3,582	3,540	4,471	4,471
8	Reserve for Injuries and Damages	S.6 L.6	479	479	479	479	479	835
9	Depreciation	S.6 L.7	12,196	12,185	12,677	12,963	12,945	13,581
10	Amortization of contributions and fire insurance recoveries	S.6 L.8	(4,394)	(4,377)	(5,002)	(5,291)	(4,723)	(4,723)
11	Disallowed depreciation		(204)	(204)	(204)	(204)	(204)	(204)
12	Donations		(100)	(99)	(166)	(95)	(120)	(120)
13	Total utility expenses		35,943	39,949	41,822	49,784	54,716	58,453
14	Revenue Requirement	S.6 L.1	49,794	52,059	51,302	59,947	64,164	75,135

Note 1: Includes fuel expenses and purchased power.

Yukon Energy Corporation
Statement of Earnings
($000s)

Schedule 6
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Revenues (note 1)	S.5 L.14	49,794	52,059	51,302	59,947	64,164	75,135
2	**Operating expenses**							
3	Operating and maintenance	S.10 L.15	23,715	27,794	29,784	37,653	41,119	43,863
4	Taxes other than income	S.5 L.6	708	671	673	739	750	750
5	Amortize deferred costs		3,543	3,500	3,582	3,540	4,471	4,471
6	Reserve for Injuries and Damages	S.5 L.8	479	479	479	479	479	835
7	Depreciation	S.3 L.8	12,196	12,185	12,677	12,963	12,945	13,581
8	Amortization of contributions and fire insurance recoveries	S.5 L.10	(4,394)	(4,377)	(5,002)	(5,291)	(4,723)	(4,723)
9	Total		36,247	40,252	42,192	50,083	55,040	58,777
10	**Operating income**		13,546	11,807	9,110	9,864	9,124	16,359
11	**Other income**							
12	Allowed for Funds Used	S.8 L.2	542	539	648	831	1,269	1,269
13	Miscellaneous (note 2)	S.8 L.3	(515)	(824)	(951)	(508)	(307)	(327)
14	Total		28	(284)	(304)	323	961	941
15	**Other expenses**							
16	Interest expense	S.8 L.4	4,431	5,583	6,124	9,663	5,631	5,631
17	Total		4,431	5,583	6,124	9,663	5,631	5,631
18	**Net earnings**	S.8 L.8	9,142	5,939	2,683	524	4,454	11,669

Note 1: Includes revenues from sales and other revenues.
Note 2: Miscellaneous primarily consistent of Regulatory gain/losses and other interest income/expenses.

Yukon Energy Corporation
Statement of Retained Earnings
($000s)

Schedule 7
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast: Existing 2021	Forecast: Proposed 2021
1	Balance at beginning of year		60,775	61,366	67,653	65,606	66,983	69,153
	Add:							
2	Net earnings	S.6 L.18	9,142	5,939	2,683	524	4,454	11,669
3	IFRS Comprehensive Income Adjustment		1,660	348	(1,859)	853	-	-
4	Balance at end of year before dividend		71,577	67,653	68,477	66,983	71,437	80,821
	Less:							
5	Common Dividends (note 1)		10,414	-	2,871	-	-	3,623
6	Balance at end of year		61,163	67,653	65,606	66,983	71,437	77,198
	Shareholder's Equity							
7	Common shares		54,036	53,600	53,600	57,998	61,924	57,998
8	Retained earnings		61,163	67,653	65,606	66,983	71,437	77,198
9	Total		115,200	121,253	119,206	124,981	133,361	135,196

Note:
1. YDC equity injection/dividend estimates required in order to maintain 60/40 debt to equity ratio.

Yukon Energy Corporation
Reconciliation of Utility Income to Net Earnings
($000s)

Schedule 8
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	Utility Income (Return on Rate Base)	S.5 L.3	13,850	12,110	9,480	10,163	9,448	16,682
	Add:							
2	Allowance for funds used	S.6 L.12	542	539	648	831	1,269	1,269
3	Other income (expenses)	S.6 L.13	(515)	(824)	(951)	(508)	(307)	(327)
			13,878	11,825	9,176	10,486	10,409	17,624
	Less:							
4	Interest - long-term	S.6 L.17	4,431	5,583	6,124	9,663	5,631	5,631
5	Donations	S.5 L.12	100	99	166	95	120	120
6	Disallowed costs	S.5 L.13	-	-	-	-	-	-
7	Disallowed depreciation	S.5 L.11	204	204	204	204	204	204
			4,735	5,886	6,494	9,962	5,955	5,955
8	Net earnings	S.6 L.18	9,142	5,939	2,683	524	4,454	11,669

Yukon Energy Corporation

Summary of Customers, Energy Sales and Revenues
($000s)

Schedule 9
November 2020

Line No.	Description	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
1	**Residential**					
2	Customers	1,635	1,689	1,730	1,756	1,780
3	Sales in MWh	13,719	15,626	15,384	16,730	16,210
4	MWh sales per customer	8.4	9.3	8.9	9.5	9.1
5	Revenue ($000s)	2,016	2,262	2,262	2,413	2,384
6	Cents per KWh	14.7	14.5	14.7	14.4	14.7
7	**General Service**					
8	Customers	489	506	517	516	514
9	Sales in MWh	25,436	27,171	29,148	32,250	32,323
10	MWh sales per customer	52.0	53.7	56.4	62.5	62.9
11	Revenue ($000s)	4,054	4,490	4,833	5,351	5,388
12	Cents per KWh	15.9	16.5	16.6	16.6	16.7
13	**Industrial**					
14	Sales in MWh	32,193	36,910	27,286	64,856	102,904
15	Revenue ($000s)	3,952	4,378	3,673	7,260	11,535
16	Cents per KWh	12.3	11.9	13.5	11.2	11.2
17	**Street lights**					
18	Sales in MWh	214	224	168	168	168
19	Revenue ($000s)	56	87	82	82	82
20	Cents per KWh	26.0	39.1	48.8	48.8	48.8
21	**Space lights**					
22	Sales in MWh	12	11	10	10	10
23	Revenue ($000s)	3	3	3	3	3
24	Cents per KWh	22.5	29.2	26.7	28.1	26.6
25	**Total Company - Firm Retail and Industrial**					
26	Customers	2,125	2,195	2,247	2,272	2,293
27	Sales in MWh	71,573	79,941	71,997	114,013	151,614
28	Revenue ($000s)	10,081	11,221	10,853	15,108	19,392
29	Cents per KWh	14.1	14.0	15.1	13.3	12.8
30	**Wholesale sales**					
31	Sales in MWh	314,700	332,270	331,495	351,775	343,537
32	Revenue ($000s)	26,114	27,572	27,507	29,190	28,507
33	Cents per KWh	8.3	8.3	8.3	8.3	8.3
34	**Total Company - Firm**					
35	Sales in MWh	386,273	412,212	403,491	465,788	495,151
36	Revenue ($000s)	36,194	38,792	38,360	44,298	47,899
37	Cents per KWh	9.4	9.4	9.5	9.5	9.7
38	**Secondary**					
39	Sales in MWh	2,059	258	0	0	0
40	Revenue ($000s)	115	20	0	0	0
41	Cents per KWh	5.6	7.6	7.6	0.0	0.0
42	**Total Company**					
43	Sales in MWh	388,332	412,470	403,492	465,788	495,151
44	Revenue ($000s)	36,310	38,812	38,360	44,298	47,899
45	Cents per KWh	9.4	9.4	9.5	9.5	9.7
46	Rider J	13,231	13,329	13,842	15,289	15,897
47	Post-GRA Reconcil Req'd					
48	GRA Increase Req'd				0	10,971
49	Total Sales of Power	49,541	52,141	52,203	59,588	74,767
50	Other Revenues	253	-82	-901	359	369
51	Total Revenues	49,794	52,059	51,302	59,947	75,135

Yukon Energy Corporation
Summary of Operating and Maintenance Expenses
($000s)

Schedule 10
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	**Utility operations**							
2	Production		5,930	7,755	8,402	9,871	10,909	10,909
3	Transmission and distribution		3,445	2,835	2,767	3,215	3,187	3,187
4	General		1,615	1,746	1,921	1,695	1,770	1,770
5	Administration and general		8,917	8,966	9,201	9,603	10,557	10,557
6	Insurance		1,031	1,046	1,117	1,299	1,423	1,423
7	Sub-total		20,938	22,347	23,407	25,684	27,845	27,845
8	Donations		100	99	166	95	120	120
9	Sub-total		100	99	166	95	120	120
10	O&M not including fuel and							
11	purchased power		21,038	22,447	23,574	25,779	27,965	27,965
12	Fuel		2,638	5,295	6,153	11,814	12,787	15,530
13	Purchased power		39	53	57	60	367	367
14	Sub-total		2,677	5,348	6,211	11,874	13,153	15,897
15	Total operating and maintenance	S.6 L.3	23,715	27,794	29,784	37,653	41,119	43,863
	Operating and Maintenance Expense Reported in Tab 3 excludes fuel and purchase power, but also includes the following:							
16	*Reserve for Injuries and Damages*		*479*	*479*	*479*	*479*	*479*	*835*
17	*Property Taxes*		*708*	*671*	*673*	*739*	*750*	*750*
18	*less: Donations*		*-100*	*-99*	*-166*	*-95*	*-120*	*-120*
19	*O&M per Table 3.3 (Tab 3)*		*22,125*	*23,497*	*24,559*	*26,903*	*29,074*	*29,430*

Yukon Energy Corporation
Summary of Labour Costs
($000s)

Schedule 10A
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
1	**Total FTEs**	Tab 3, Table 3.4	93.7	94.9	98.4	97.9	103.6	103.6
2	**Total Labour Costs**		14,394	14,173	14,131	15,420	16,148	16,148
3	O&M Labour Costs	Sum Lines 5-9	11,932	12,083	11,863	12,727	13,310	13,310
4	Labour Costs to Capital		2,461	2,090	2,268	2,694	2,838	2,838
	Labour Costs							
5	Production		4,131	4,455	4,467	4,995	4,931	4,931
6	Transmission		635	526	545	659	674	674
7	Distribution		856	801	625	617	629	629
8	General		395	351	391	343	378	378
9	Administration		5,916	5,949	5,835	6,113	6,699	6,699
10	Total Labour		11,932	12,083	11,863	12,727	13,310	13,310

Yukon Energy Corporation
Summary of Cost of Long - Term Debt
($000s)

Schedule 11
November 2020

Line No.	Description	Cross Ref.	2018 GRA Compliance	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
	General Purpose Long-Term Debt Balance							
1	YDC Mayo B Flexible Term Debt		19,542	19,542	19,205	18,868	18,531	18,531
2	TD Bank Swap (2.69%)		8,991	8,991	8,623	8,245	7,858	7,858
3	Minto Decommissioning Reserve		2,684	2,710	2,769	2,800	2,816	2,816
4	YDC $5.5M Debt (2.40%)		5,505	5,505	5,505	5,505	5,505	5,505
5	YDC $92.5M Debt (2.40%/2.83%)		77,723	77,723	74,039	70,356	66,672	66,672
6	YDC $21.0M Debt (2.21%)		18,466	18,466	17,627	16,788	15,948	15,948
7	YDC $12.1M Debt (2.10%)		12,136	12,136	12,136	12,136	12,136	12,136
8	TD Bank Swap (3.665%)		21,940	23,406	22,811	22,194	21,554	21,554
9	New 2018 Debt-2018 True Up (2.15%)		5,776	0	0	0	0	0
10	TD Bank Swap (2.899%)		0	0	6,688	6,498	6,303	6,303
11	YDC $2.9M Debt (2.899%)		0	0	2,871	2,871	2,871	2,871
12	New 2020 Debt-2019 True Up (2.19%)		0	0	0	8,760	8,760	8,760
13	New 2020 Debt-2020 True Up (2.19%)		0	0	0	12,450	12,450	12,450
14	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	18,638	18,135
15	Current year-end balance		172,763	168,479	172,274	187,471	200,041	199,539
16	Previous year-end balance		172,181	150,244	168,479	172,274	187,471	187,471
17	Mid Year		172,472	159,362	170,377	179,873	193,756	193,505
	Interest Costs							
18	YDC Mayo B Flexible Term Debt		334	771	690	1,049	1,030	1,030
19	TD Bank Swap (2.69%)		247	247	237	227	217	217
20	Minto Decommissioning Reserve		24	45	59	31	16	16
21	YDC $5.5M Debt (2.40%)		132	132	132	132	132	132
22	YDC $92.5M Debt (2.40%/2.83%)		1,954	1,954	1,865	1,984	1,886	1,886
23	YDC $21.0M Debt (2.21%)		427	427	408	390	371	371
24	YDC $12.1M Debt (2.10%)		255	255	255	255	255	255
25	TD Bank Swap (3.665%)		472	287	848	826	803	803
26	New 2018 Debt-2018 True Up (2.15%)		0	0	0	0	0	0
27	TD Bank Swap (2.899%)		0	0	81	191	186	186
28	YDC $2.9M Debt (2.899%)		0	0	42	83	83	83
29	New 2020 Debt-2019 True Up (2.19%)		0	0	0	79	192	192
30	New 2020 Debt-2020 True Up (2.19%)		0	0	0	0	273	273
31	New 2021 Debt-2021 True Up (2.19%)		0	0	0	0	0	0
32	**Total Cost of Interest**		3,844	4,118	4,618	5,247	5,443	5,443
33	Mid-Year Cost of Debt		2.23%	2.58%	2.71%	2.92%	2.81%	2.81%

TAB 8
RETURN ON EQUITY

8.0 RETURN ON EQUITY

Tab 8 reviews the proposed basis for determining the return on equity (ROE) for Yukon Energy in 2021, including the following:

- Background;
- Yukon Energy Fair ROE for 2021; and
- Basis for Risk Premium Adder.

8.1 BACKGROUND

Yukon Energy's rate base is financed by two main sources of capital: long-term debt and shareholder's equity. With respect to the equity component, Yukon Energy's rates are required to include "provision to recover a fair return on the Corporation's equity, less one-half of one per cent (0.5%)" per Order in Council (OIC) 1995/90 Section 2 (see Tab 11 of this Application).

Since 1998, Yukon Energy has focused on using a simplified approach to determining a "fair return" that relies on reference to formulaic approaches established by the British Columbia Utilities Commission (BCUC) or other regulators.[1] Use of a simplified approach has been approved by the Board in each subsequent GRA application as an expedient and cost effective means of determining return. Board Order 2009-08 established the BCUC approach would be the precedent for Yukon, and would continue to be a precedent for the jurisdiction until otherwise ordered.

Since 2009, the BCUC has determined a Benchmark ROE for FortisBC Energy Inc (FEI) through a generic cost of capital proceeding, with relevant risk premiums established separately for other BC regulated utilities. [2] A generic cost of capital proceeding was completed in 2013[3] and in 2016[4] to determine an ROE

[1] A form of BCUC benchmark approach has been used in the 2005 Required Revenues and Related Matters Proceeding; the 2008/2009 YECL General Rate Application; the 2008/09 Yukon Energy General Rate Application; the 2013-15 YECL General Rate Application; the 2016/17 AEY Generation Rate Application; and the Yukon Energy 2017/18 General Rate Application. The Yukon Energy 2012/13 GRA used the Alberta Utilities Commission benchmark for a low risk utility. It was noted at the time that the BCUC had recently initiated a generic cost of capital proceeding; but an up-to-date low risk benchmark was not expected before the end of 2012.

[2] After 2009, BCUC Terasen ROE decision (Order G-158-09) eliminated the automatic adjustment mechanism that had been in place, and ordered Terasen Gas Inc. (now FortisBC Energy) to complete a study of alternative formulae for an automatic adjustment mechanism and report the results to the BCUC by December 31, 2010. The BCUC determined that the 2009 approved ROE for Terasen (9.5%) could continue to be used as the Benchmark ROE in establishing the ROE for rate-setting purposes for other BCUC utilities.

[3] BCUC Generic Cost of Capital Proceeding, Order G-75-13 established a return on equity for the benchmark utility, FortisBC Energy Inc (FEI), at 8.75 percent effective January 1, 2013, and a common equity component of 38.5%.

[4] BCUC Order G-129-16 regarding the FEI Application for its Common Equity Component and Return on Equity for 2016, approved an ROE for FEI of 8.75%, and a common equity component is set at 38.5%.

for Fortis BC Energy (FEI) – the BCUC benchmark utility. The 2016 proceeding re-confirmed the 8.75% benchmark ROE established for FEI by the BCUC in 2013. A separate proceeding to determine cost of capital and relevant risk premiums for other BCUC regulated utilities was completed in 2014.[5]

AEY's most recent 2016/17 GRA Application sought approval of an ROE based on the results of the most recent BCUC GCOC proceeding, as well as a risk premium of 60 basis points.[6] The Board in Order 2017-01 noted that it "continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon" and ordered that AEY use the BCUC GCOC benchmark for ROE of 8.75%.[7] The Board also agreed that a risk premium is appropriate, and ordered AEY to apply a risk premium of 25 basis points. The Board concluded that "in determining relative risk for AEY, [it] should look at size and generation risk".[8]

Yukon Energy's 2017/18 GRA sought approval of an ROE for the 2017 and 2018 test years based on BCUC benchmark ROE of 8.75%,[9] plus a risk premium of 57.5 basis points (0.575%),[10] less 50 basis points (0.5%) as per OIC 1995/90. Yukon Energy's proposed risk premium was based on the mid-point between the risk premium for FortisBC [Electric], at 40 basis points, and PNG West, at 75 basis points. The Board in Order 2018-10 stated that it continues to approve using the BCUC benchmark utility ROE as the base or starting point for determining the ROE for Yukon utilities. However, the Board determined that PNG-West was not a strong comparator to YEC,[11] and awarded YEC 25 basis points for its small size (consistent with the risk premium awarded for AEY) as well as an additional 20 basis points to recognize YEC's higher risk related to generation, isolated grid and customer diversity. This resulted in a total risk premium for YEC of 45 basis points (0.45%) above the BCUC benchmark.

8.2 YUKON ENERGY FAIR ROE FOR 2021

For the 2021 test year, Yukon Energy is proposing an approach for determining fair ROE that is consistent with directions provided in recent Board Orders. The approach steps outlined below include reference to the BCUC benchmark return on equity for a low risk utility, with adjustments to reflect

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[5] BCUC Generic Cost of Capital Proceeding Stage 2 Order G-47-14 established equity risk premium over the benchmark utility for FortisBC (Electric) of 40 basis points and for PNG West of 75 basis points.
[6] AEY General Rate Application, pages 8-2 to 8-4; and Attachment 8-1.
[7] Order 2017-01, page 37, para 182.
[8] Order 2017-01, page 43, para 211. Approved ROE for AEY at 9.0% [8.75%+0.25% as per Order 2017-01, page 44, para 221].
[9] BCUC Generic Cost of Capital (GCOC) benchmark rate as set in BCUC Decision and Order G-129-16.
[10] The risk premium approved for FortisBC Electric in BCUC Order G-47-14 (following the Generic Cost of Capital Proceeding - Stage 2) remains 40%, confirming that the risk premium applicable to YEC is higher than 40%. The risk premiums approved today for the PNG gas utilities are 50% and 75% (the latter for the PNG West utility used as a prior reference when setting the range for YEC's risk premium). This indicates that the risk premium applicable today for YEC, at a midpoint between the FortisBC electric and the PNG West, is 57.5%.
[11] The Board noted that there is no evidence on the record for the 2017/18 GRA proceeding that YEC has encountered a similar situation or will encounter a similar situation over the test period as PNG-West which 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".

specific added risks related to Yukon Energy. This approach offers a simple, transparent and cost effective method to determine a consistent and fair return for Yukon utilities.

- **Step 1 – Determine Low-Risk Benchmark Utility ROE:** For the 2021 test year, Yukon Energy proposes to continue to use the BCUC benchmark ROE of 8.75%,[12] as most recently approved by the Board for the AEY Board Order 2017-01 regarding the 2016/17 GRA, and for YEC in Board Order 2018-10 regarding the 2017/18 GRA.

- **Step 2 – Apply Yukon Energy Fair ROE by Incorporating the Risk Premium for Yukon Energy:** The established approach requires that the appropriate fair return on common equity incorporate a risk premium determined relative to the benchmark utility ROE. The Board recently established a risk premium of 45 basis points (0.45%) for Yukon Energy in Order 2018-10 for the 2017/18 GRA test years. Yukon Energy is proposing to use the same risk premium for the 2021 test year. This would result in a fair return on common equity for Yukon Energy of 9.20% (8.75 + 0.45).

- **Step 3 – Determine Yukon Energy Allowed ROE by Deducting 50 Basis Points from the Yukon Energy Fair Return on Equity:** To reflect OIC 1995/90, Section 2 for each test year, Yukon Energy's allowed ROE is required to be set equal to the Yukon Energy fair return on common equity less 50 basis points (0.5%). This results in an allowed ROE for Yukon Energy of 8.70% that is 0.5 basis points below the low-risk benchmark utility rate of return determined by the BCUC (45 basis point utility specific adder less 50 basis point OIC reduction).

Accordingly, the Yukon Energy proposed ROE in this Application for 2021 test year is 8.70%.

8.3 BASIS FOR RISK PREMIUM ADDER

The 45 basis point risk premium for Yukon Energy was established by the Board in Order 2018/10. In its reasons, the Board noted that it considered a 45 basis point risk premium for YEC to be fair and reasonable based on the following:

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.

[12] BCUC Generic Cost of Capital (GCOC) benchmark rate as set in BCUC Decision and Order G-129-16. At the time of preparation of this Application the benchmark has not been updated from the 8.75% approved in BCUC Decision and Order G-129-16.

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".

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 to FortisBC Electric; and Yukon Energy continues to be subject to material risks related to generation, being on an isolated grid, and customer diversity.

Tables 8.1 and 8.2 provide additional background information regarding YEC's risk relative to FortisBC (Electric) and other BC utilities. This includes information regarding relative size of operations and financial structure; and nature of business.

- **Comparison of YEC to BC Utilities Size of Operations and Financial Structure** – Updated information on FortisBC Electric operations relative to Yukon Energy's operations remains similar to comparisons provided in prior applications in 2005, 2008/09 and 2017/18. In 2019, FortisBC (Electric) operations had approximately 141,000 customers, approximately $1,342 million in rate base, and a 60/40 debt/equity financial structure. Yukon Energy's financial structure is the same as FortisBC (Electric), however, in 2019 Yukon Energy's customer count was 1.6% that of FortisBC (Electric); and its rate base was approximately 22% that of FortisBC (Electric).

- **Comparison of YEC to BC Utilities – Nature of Business** - YEC continues to have greater business risk than the relevant BC utilities based on its reliance on its own generation (far higher than for FortisBC Electric), and its lack of any interconnection with external electricity markets. These material differences have not changed from the assessments provided in prior applications. YEC's business risk related to industrial customers has fluctuated since 2005 due to the connection and loss of industrial customers.

Table 8.1:
Comparison of YEC to BC Utilities Size of Operations and Financial Structure (2019)

	YEC	Fortis BC Inc. (Electric)	PNG West	PNG NE Fort St. John/ Dawson Creek	AEY
Revenues ($millions)	52.2	404.0	42.3	24.0	57.6
Rate base ($millions)	299.4	1,342.0	144.3	72.8	106.5
Number of employees	98	518	98	26	64
Number of customers	2,247	141,027	20,346	12,911	18,926
Capital Structure					
Debt/Equity ratio	60%/40%	60%/40%	53.5%/46.5%	59%/41%	60%/40%
ROE Benchmark	8.75%	8.75%	8.75%	8.75%	8.75%
ROE Risk Adder	-0.05%	0.40%	0.75%	0.50%	0.25%
Fair ROE Approved	8.70%	9.15%	9.50%	9.25%	9.00%

Notes:

1. The information for Yukon Energy as provided in Tab 2 and Tab 3 tables. ROE benchmark and risk adder are based on YUB Order 2018-10 in relation to YEC's 2017/18 GRA. Risk added reflects a risk premium of 45 basis points less 50 basis points pursuant to OIC 1995/90.
2. The information for Fortis BC is based on 2019 Financial Statements available at https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/audited-annual-financial-statements-electric-year-end-2019.pdf?sfvrsn=f40967f4_2 [accessed on August 24, 2020]. The revenue information on page 27; rate base on page 13. Number of customers, capital structure and ROE based on information available from Annual Review for 2020 and 2021 Rates https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/200819-fbc-annual-review-for-2020-and-2021-rates-ff.pdf?sfvrsn=55246399_2#page=38&zoom=100,92,696 [accessed on August 24, 2020]. Number of employees from https://fbcdotcomprod.blob.core.windows.net/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/180925_fbc-ar-2019-rates_bcuc-ir1-response_ff.pdf, response to information request #9 from BCUC.
3. The information for PNG West is based on 2020 and 2021 Revenue Requirement application before BCUC [https://www.bcuc.com/Documents/Proceedings/2019/DOC_56475_B-1-PNG-West-2020-2021-RRA.pdf, accessed on August 24, 2020]. Rate base from Tab 2, Page 1, Schedule 2; number of customers from Tables 7, 8 and 9; Capital structure and ROE information from Table 38. Revenues are from SUMMARY OF GROSS REVENUE, COST OF GAS, GROSS MARGIN Tab 6, Page 7 https://www.bcuc.com/Documents/Proceedings/2018/DOC_50956_B-1-1_PNG-West-AMENDED-2018-2019-RRA.pdf. Number of employees is from Response to BCUC IR No. 46.5 provided on April 15, 2020, Page 135 https://www.bcuc.com/Documents/Proceedings/2020/DOC_57807_B-3-PNG-response-to-BCUC-IR1-with-Attachments.pdf [accessed on August 24, 2020].
4. The information for PNG NE Fort St. John/ Dawson Creek is based on 2020 and 2032 Revenue Requirement Amended application before BCUC [https://www.bcuc.com/Documents/Proceedings/2020/DOC_57395_B-2-PNGNE-Amended-FSJ-DC-TR-2020-2021RRA.pdf, accessed on August 24, 2020]. Revenues are from Tab 1, Schedule 1; rate base from Tab 2, Page 1, Schedule 2; number of customers from Tables 12, 13 and 14 of section 2.1; Capital structure and ROE information from Tables 34 and 36. Number of employees is from Response to BCUC IR No. 46.5 provided on April 15, 2020, Page 135 https://www.bcuc.com/Documents/Proceedings/2020/DOC_57807_B-3-PNG-response-to-BCUC-IR1-with-Attachments.pdf [accessed on August 24, 2020].
5. The capital structure and ROE for Fortis BC, PNG West and PNG NE FSJ reflect allowed structure and allowed ROE.
6. The information for AEY is based on AEY's 2019 Key Performance Indicators filing with YUB. http://yukonutilitiesboard.yk.ca/pdf/Reports/AEY_2019_Key_Performance_Indicators__April_23__2020.pdf [accessed on August 24, 2020]. Approved ROE is based on AEY's 2015-17 GRA and YUB Order 2017-01.

Table 8.2:
Comparison of YEC to BC Utilities - Nature of Business (2019)

	YEC	Fortis BC Inc. (Electricity)	PNG West	PNG NE Fort St. John/ Dawson Creek	ATCO Electric Yukon
Services	Electricity	Electricity	Gas	Gas	Electricity
Acquisition of Product					
Hydroelectric	84%	44%			1%
Thermal/Other	16%				6%
Purchased		56%	100%	100%	92%
Revenue share by customer type					
Residential	5.3%	44.7%	46.8%	51.1%	44.9%
Commercial	11.3%	24.7%	32.5%	37.4%	52.8%
Industrial	8.4%	9.8%	19.6%	11.5%	0.0%
Wholesale	75.0%	12.1%	0.0%	0.0%	0.1%
Other/misc	0.0%	8.6%	1.1%	0.0%	2.2%
Energy sales share					
Residential	3.8%	38.3%	25.2%	31.3%	48.9%
Commercial	7.2%	28.2%	23.4%	31.7%	49.6%
Industrial	6.8%	15.0%	50.6%	37.1%	0.0%
Wholesale	82.2%	17.1%	0.0%	0.0%	0.2%
Other/misc	0.0%	1.4%	0.8%	0.0%	1.3%

Notes:

1. The information for Yukon Energy is from Tab 2 tables [generation sources reflect actual generation, not LTA].
2. The information for Fortis BC is based on 2019 Financial Statements available at https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/fortisbc-(electric)_fs-with-notes_q4_2018_g2_pa_sedar.pdf?sfvrsn=8ab664ee_2 , page 27 [accessed on August 24, 2020]; Annual Review for 2020 and 2021 Rates, https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/electric-utility/200819-fbc-annual-review-for-2020-and-2021-rates-ff.pdf?sfvrsn=55246399_2 pages 15 and 35.
3. The information for PNG West is based on 2018 and 2019 Revenue Requirement Amended application before BCUC. Revenues are from SUMMARY OF GROSS REVENUE, COST OF GAS, GROSS MARGIN Tab 6, Page 23 https://www.bcuc.com/Documents/Proceedings/2018/DOC_50956_B-1-1_PNG-West-AMENDED-2018-2019-RRA.pdf [accessed on August 24, 2020].
4. The information for PNG NE FSJ and DC is based on 2018 and 2018 Revenue Requirement Amended application before BCUC: Revenues and sales are from Tab 6, Page 29. https://www.bcuc.com/Documents/Proceedings/2018/DOC_50958_B-1-1_PNGNE-FSJ-DC-TR-AMENDED-2018-2019-RRA.pdf [accessed on August 24, 2020].
5. The information for AEY is based on AEY's 2019 Key Performance Indicators filing with YUB. http://yukonutilitiesboard.yk.ca/pdf/Reports/AEY_2019_Key_Performance_Indicators__April_23__2020.pdf [accessed on August 24, 2020].

TAB 9
DEPRECIATION STUDY

YUKON ENERGY

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

AT DECEMBER 31, 2018

yukon energy

ALLIANCE CONSULTING GROUP

http://www.utilityalliance.com

YUKON ENERGY
ELECTRIC UTILITY PLANT
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY

Yukon Energy ("Yukon" or "Company") engaged Alliance Consulting Group to conduct a depreciation study of the Company's Electric utility plant depreciable assets as of December 31, 2018.

This study recommends an overall decrease of $164 thousand in annual depreciation expenses for all accounts when using the proposed depreciation rates and proposed true-up. This is in comparison to the existing annual depreciation accrual without including the existing true-up. A summary comparison of annual accrual by utility function is shown below.

Function	Existing Annual Accrual	Proposed Annual Accrual	Proposed Annual True-Up	Difference
Land and Land Rights	2,576	2,576	(13)	(13)
Hydro Production	3,739,725	3,942,725	(140,298)	62,701
Diesel Plant	978,694	953,366	(88,166)	(113,493)
Distribution System	480,657	481,697	49,971	51,012
Main Transmission Facilities	2,974,173	3,367,031	(79,597)	313,261
Sub Transmission Lines	1,255,111	1,213,393	(46,022)	(87,739)
Building	1,374,449	1,213,572	(67,334)	(228,211)
Transportation	449,738	475,144	19,268	44,674
LNG Operations	1,221,932	1,029,423	(13,981)	(206,490)
Total Company	12,477,055	12,678,927	(366,170)	(164,299)

Appendix B shows a detailed comparison of the approved versus proposed depreciation rates and annual accruals by account for each utility function.

YUKON ENERGY
ELECTRIC UTILITY PLANT
DEPRECIATION RATE STUDY
AT DECEMBER 31, 2018

Table of Contents

PURPOSE

The purpose of this study is to develop depreciation rates for the depreciable property as recorded on Yukon Energy's books at December 31, 2018. The account based depreciation rates were designed to recover the total remaining undepreciated investment over the remaining life of Yukon Energy's property on a straight-line basis. Land and other non-depreciable property were excluded from this study.

Established in 1987, Yukon Energy is a publicly owned electrical utility that operates as a business, at arms length from the Yukon government. We are the main generator and transmitter of electrical energy in Yukon. Yukon Energy works with its parent company Yukon Development Corporation to provide its customers with safe, reliable power.

There are over 21,000 electricity consumers in the territory. Yukon Energy directly serves about 2,200 of these customers, who live in and around Dawson City, Mayo Faro, and some other communities throughout the Yukon. Indirectly, Yukon provides power to most other Yukon communities through ATCO Electric Yukon. ATCO buys wholesale power from us and sells it to retail customers in the territory.

Yukon Energy has the capacity to generate just over 132 megawatts of power. Most of Yukon's daily generation comes from hydro. Yukon uses diesel and LNG for back-up or emergency power, and to meet peaks during cold weather when Yukon does not have enough renewable electricity to meet the demand. Yukon's headquarters are located near the Whitehorse Rapids hydro plant in Whitehorse, with community offices in Mayo and Dawson City.

STUDY RESULTS

Overall depreciation rates for all Yukon Energy depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $13.0 million based on Yukon Energy's depreciable investment at December 31, 2018. The annual equivalent depreciation expense calculated by the same method using the approved rates was $12.6 million, resulting in a $568 thousand increase in annual depreciation expense. Appendix A presents the calculation of the annual depreciation rates and resulting accrual. Appendix B presents a comparison of approved versus proposed rates and annual accruals by account. Appendix C presents a summary of life and mortality curve parameters by account.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

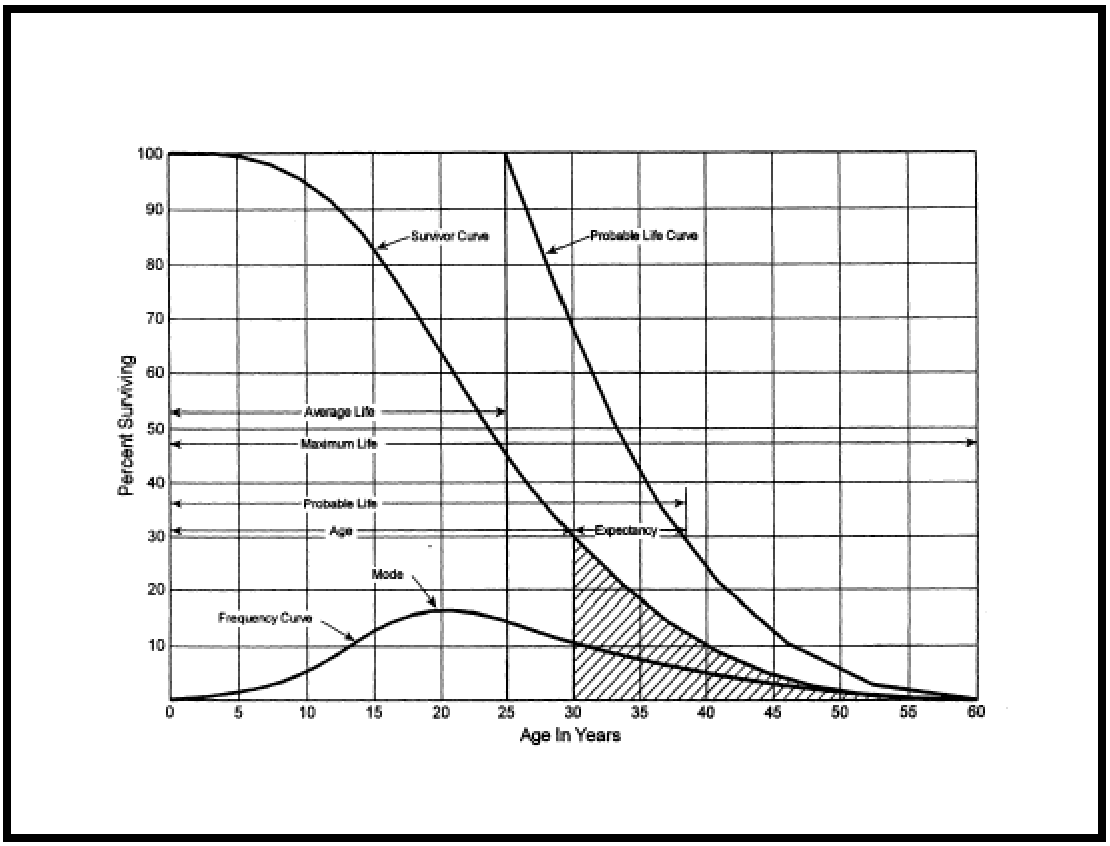
Basis of Depreciation Estimates

The straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group. The computations of the annual functional depreciation rates are shown in Appendix A.

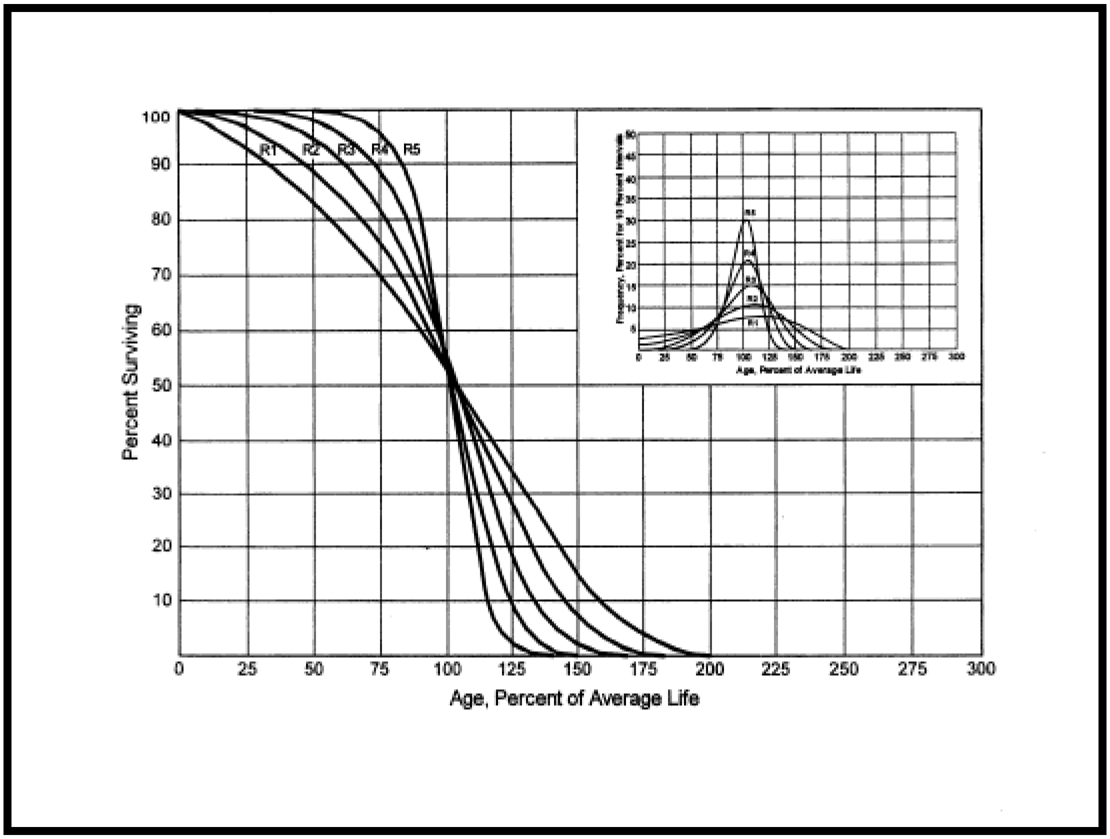
Actuarial analysis was used with each account within a function where sufficient data was available, and judgment was used to some degree on all accounts.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property. An example of an Iowa Curve is shown below.



There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.



Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. An "L" designation (i.e., Left modal) is used for the family whose mode age is less than the average life. A special case of left modal dispersion is the "O" or origin modal curve family. Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency) while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data were available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all of the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, simulated plant record method analysis, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least for example, any analysis requires choosing which bands to place more emphasis.

The establishment of appropriate average service lives and retirement dispersions for the Hydro, Diesel, Distribution, Transmission, Buildings, Transportation and LNG Plant accounts require judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

At the request of Yukon Energy, this study continues to use the ALG depreciation procedure to group the assets within each account. In its last depreciation study, Yukon Energy was authorized to use the average life group, whole life ("ALG-WL") depreciation procedure. This study continues to use the ALG depreciation procedure to group the assets within each account.

In a whole life representation, the annual accrual rate is computed by the following equation,

Annual Accrual rate =1/ Average Service Life

In the last study, Yukon Energy included a True Up amount that recovers the difference between the book reserve and the theoretical depreciation reserve over the remaining life of each account. This study includes the same computation.

Theoretical Depreciation Reserve

The book depreciation reserve was derived from Company records at the individual account level. This study used a reserve model that relied on a prospective concept relating future retirement and accrual patterns for property, given current life and salvage estimates. The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis was evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and the documenting the corresponding recommendations.

During the Phase I data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Also as part of the Phase I data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the Company's actual asset utilization and environment. Information that was gleaned in these discussions is found both in the Detailed Discussion of this study in the life analysis and salvage analysis sections and also in workpapers.

Phase 2 is where the actuarial analysis is performed. Phase 2 and 3 overlap to a significant degree. The detailed property records information is used in phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. In the case of Yukon Energy, no net salvage analysis was performed. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and mortality curve parameters. The historical analysis from phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[1] documents the steps used in conducting this study. Depreciation Systems[2], page 289 documents the same basic processes in performing a depreciation study which are: Statistical analysis, evaluation of statistical analysis, discussions with management and operational personnel, forecast assumptions, and documented recommendations.

[1] Public Utility Finance & Accounting, A Reader
[2] Depreciation Systems, by Drs. W. C. Fitch and F.K. Wolf, Iowa State Press, 1994, page 289.

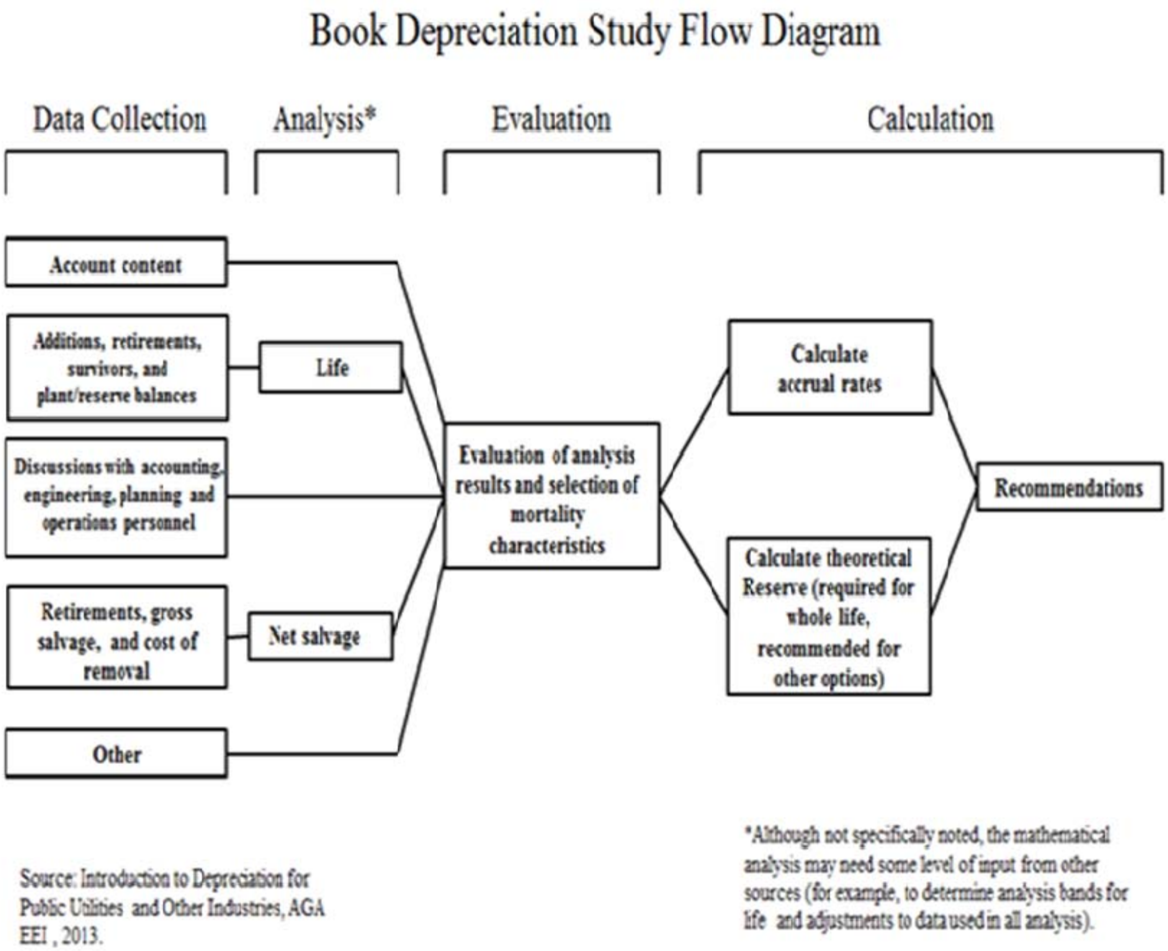


Figure 1

YUKON ENERGY DEPRECIATION STUDY PROCESS

Depreciation True Up Calculation

Annual depreciation expense amounts for the depreciable accounts of Yukon Energy were calculated by the straight-line method, average life group procedure, and remaining-life technique. With this approach, remaining lives were calculated according to standard ALG expectancy techniques, using the Iowa Survivor Curves noted in the calculation. For each plant account, the difference between the book depreciation reserve and theoretical depreciation reserve, was divided by the average remaining life to yield the annual depreciation true up. These calculations are shown in Appendix A.

Depreciation Rate Calculation Process

Annual depreciation expense amounts for accounts all accounts were calculated by the straight-line, average life group procedure, whole-life technique. .

These calculations are shown in Appendix A. The calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in workpapers. Book depreciation reserves were based on Company individual accounts and the theoretical reserve computation was used to compute a composite remaining life for each account.

Life Analysis

The retirement rate actuarial analysis method was applied to all accounts for Yukon Energy. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying width. The historical observed life table was plotted and compared with various Iowa Survivor Curves to obtain the most appropriate match. A selected curve for each account is shown in the Life Analysis Section of this report. The observed life tables for all analyzed placement and experience bands are provided in workpapers.

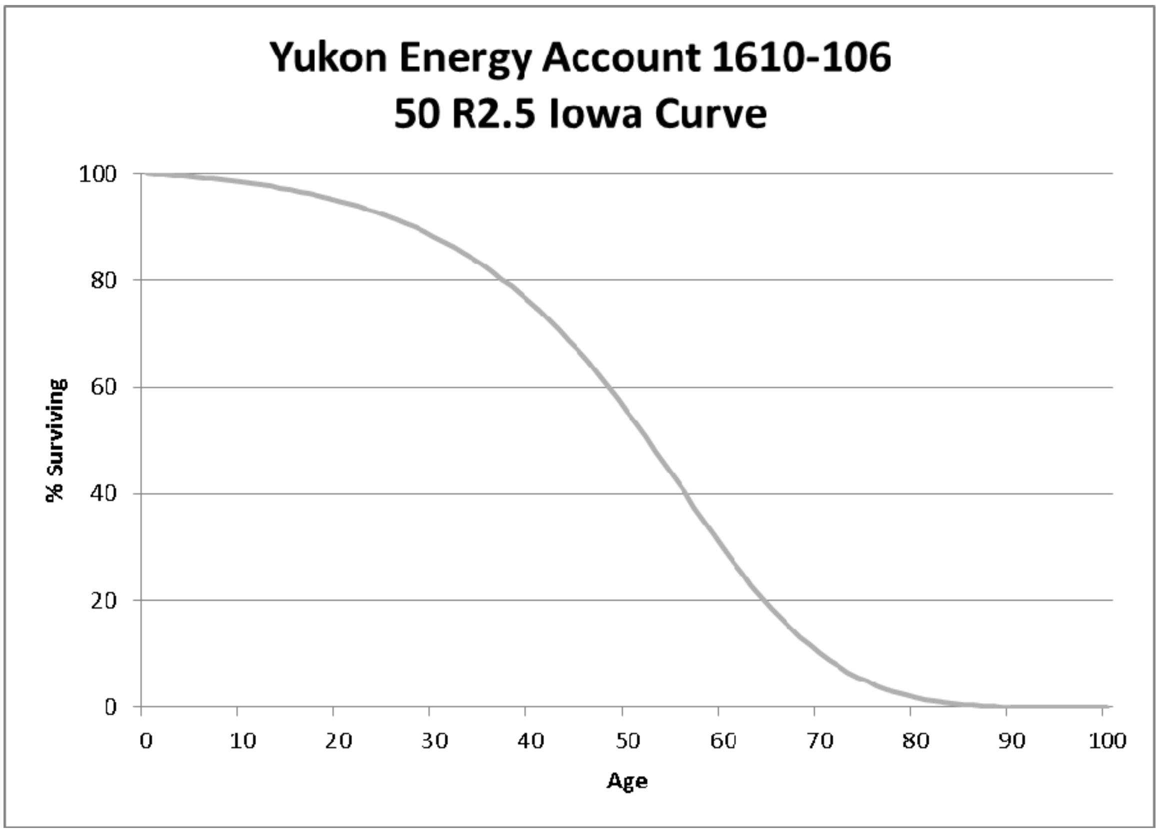
For each account on the overall band (i.e. placement from earliest vintage year which varied for each account through 2018), approved survivor curves from the prior study, if applicable modified by subsequent orders, were used as a starting point. Then using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (i.e. L, S. or R) as an obviously better match than others. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed. Next placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa curve in top and mid range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

LAND AND LAND RIGHTS

Only one account in the land function is depreciable. Most of the assets in this function are non-depreciable property and are excluded from this study.

Account 1610-106 Land Rights

This account consists of land rights associated with general plant operations. The plant balance in this account at December 31, 2018 is $129 thousand. The longest life for general plant assets is 50 years. Yukon currently depreciates land rights over 50 years and uses the R2.5 dispersion. There was insufficient transactional data for an actuarial life analysis. This study recommends retaining the existing life of 50 years and R2.5 dispersion curve. A representative graphs is shown below.



HYDRO PLANT

Yukon Energy has three Hydro Plants: Whitehorse, Aishihik, and Mayo. The Whitehorse hydro plant has served Yukoners since 1958. It was developed to supply electricity to a growing Yukon population. It began with two turbines; a third one was added in 1969, and a fourth in 1985. In the summertime, the Whitehorse hydro facilities can produce 40 megawatts of power. In the winter, when flow in the Yukon River is reduced, it can only produce about 25 megawatts. This is why projects that can supply winter generation are so important to serving customers. When water is least available, Yukon Energy's demand for power is highest.

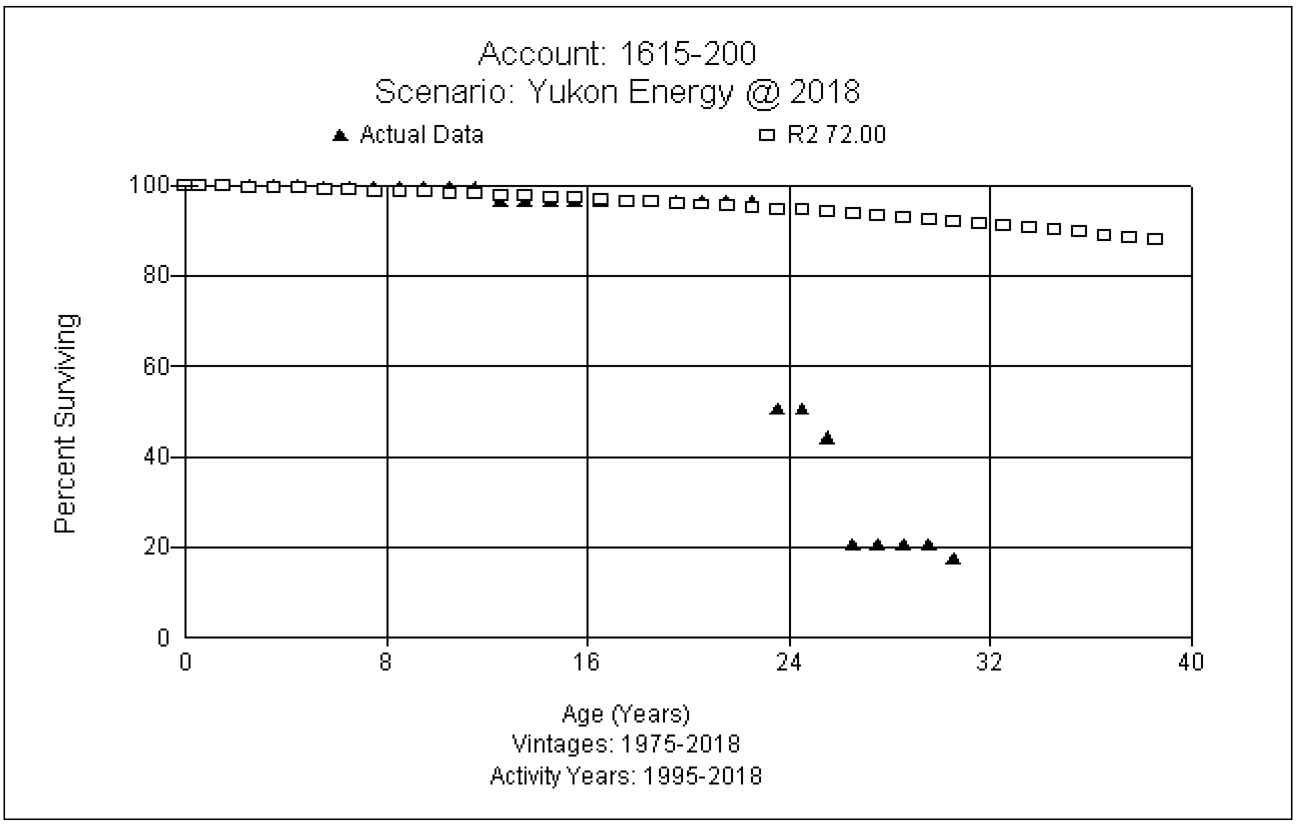
The Aishihik facility is located a remarkable 110 meters underground. It is the first underground power plant north of the 60th parallel in the western world. The original plant included two hydro units that could each produce up to 15 megawatts of renewable power. In 2011, a seven-megawatt hydro generator was added. The facility can now produce enough power to supply about 12,500 non-electrically heated homes. Aishihik annual produces about 25 percent of the total energy generated by Yukon Energy. The Aishihik plant is extremely important to Yukon Energy's operations. Although the 40-megawatt Whitehorse Rapids hydro facility is larger than Aishihik, the effective capacity of the Whitehorse plant is reduced by close to half during the coldest months of the year because of reduced water flow on the Yukon River. Aishihik is the only hydroelectric facility in Yukon that can store energy in the summer when demand is low, to be used in the winter when demand is high. It can also store energy during wet years, to be used in dry years when the levels of the lake water are lower.

The Mayo A hydro facility has served Yukoners since 1951. It was developed to supply electricity to the United Keno Hill Mine at Elsa, about 45 kilometers north of Mayo. It also generates power for other Yukon communities via Yukon Energy's transmission system. The Mayo B hydro project, completed in 2011, involved building a new powerhouse 3.7 kilometers downstream from the existing hydro plant

(Mayo A). This increased the Company's capacity to generate additional renewable energy at the existing site from five megawatts to 15 megawatts, without the need for a new dam or reservoir. Together the two plants can supply electricity to as many as 7,000 non-electrically heated homes. The Mayo hydro facilities are located in the central Yukon about 400 kilometers north of Whitehorse.

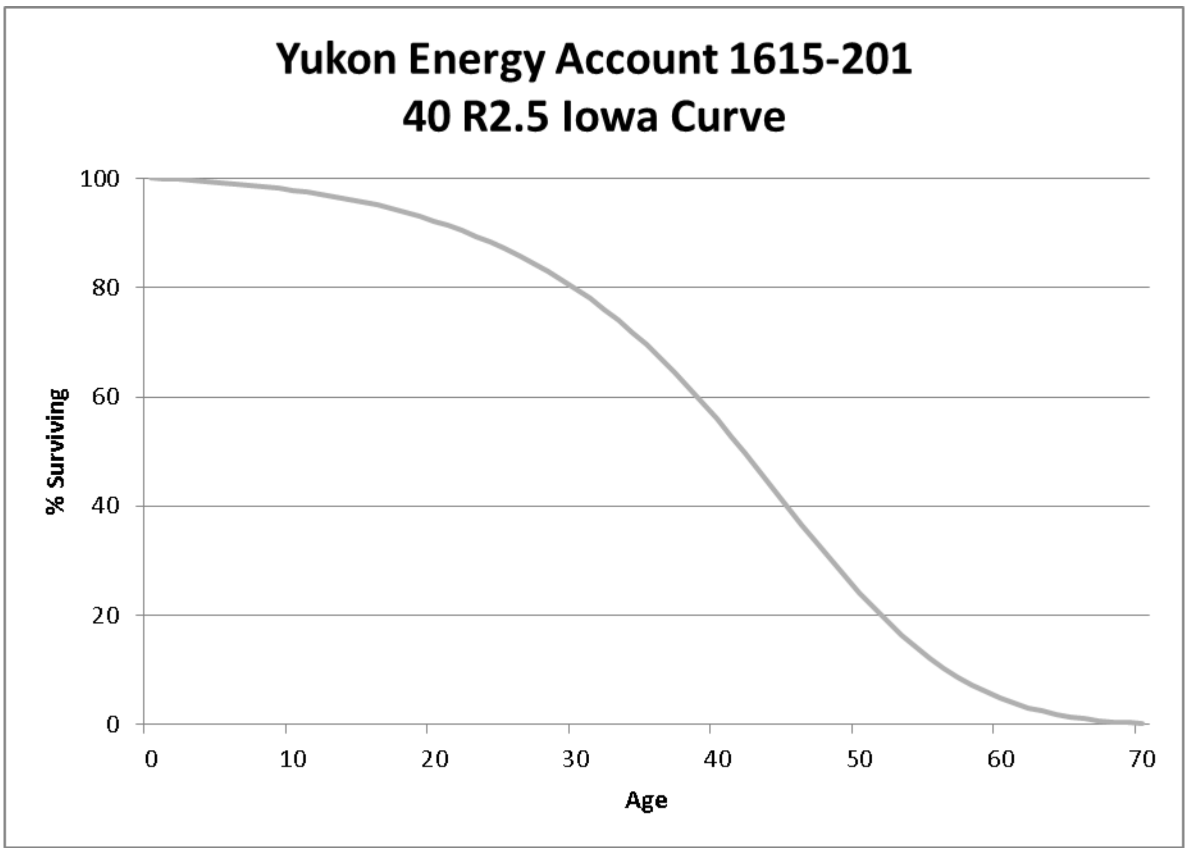
Account 1615-200 Hydro Structures and Improvements 72 R2

This account consists of buildings, structures, and other related assets used in hydro production, including elevator upgrades, bridge work, and gate house improvements. The plant balance in this account at December 31, 2018 is $34.2 million. The approved life and curve for this account is 72 R2. Based on the limited indications from the actuarial analysis, information provided by Company personnel and judgment, this study recommends retaining the existing 72 R2 for this account. A graph of the observed life table versus the recommended curve type is shown below.



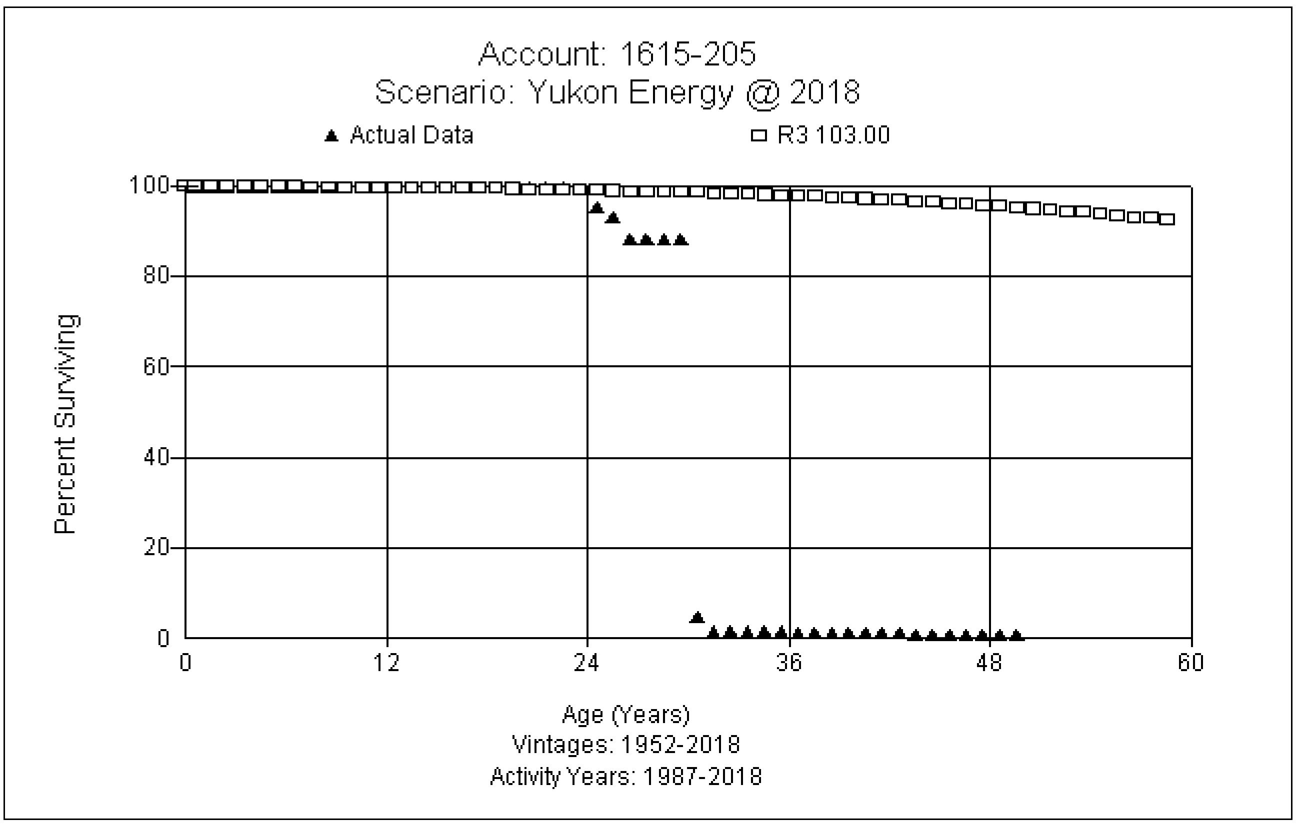
Account 1615-201 Hydro Buildings and Improvements 40 R2.5

This account is a newly created group. In 2019, an asset previously booked in account 1645-200, Buildings- Structures and Improvements. The asset is an elevator at Aishihik Hydro plant. The plant balance in this account will be $10.3 million. The approved life and curve for this account is 40 R2.5. Based on information provided by Company personnel and judgment, this study recommends retaining the existing 40 R2.5 for this account. A representative curve shape is shown below.



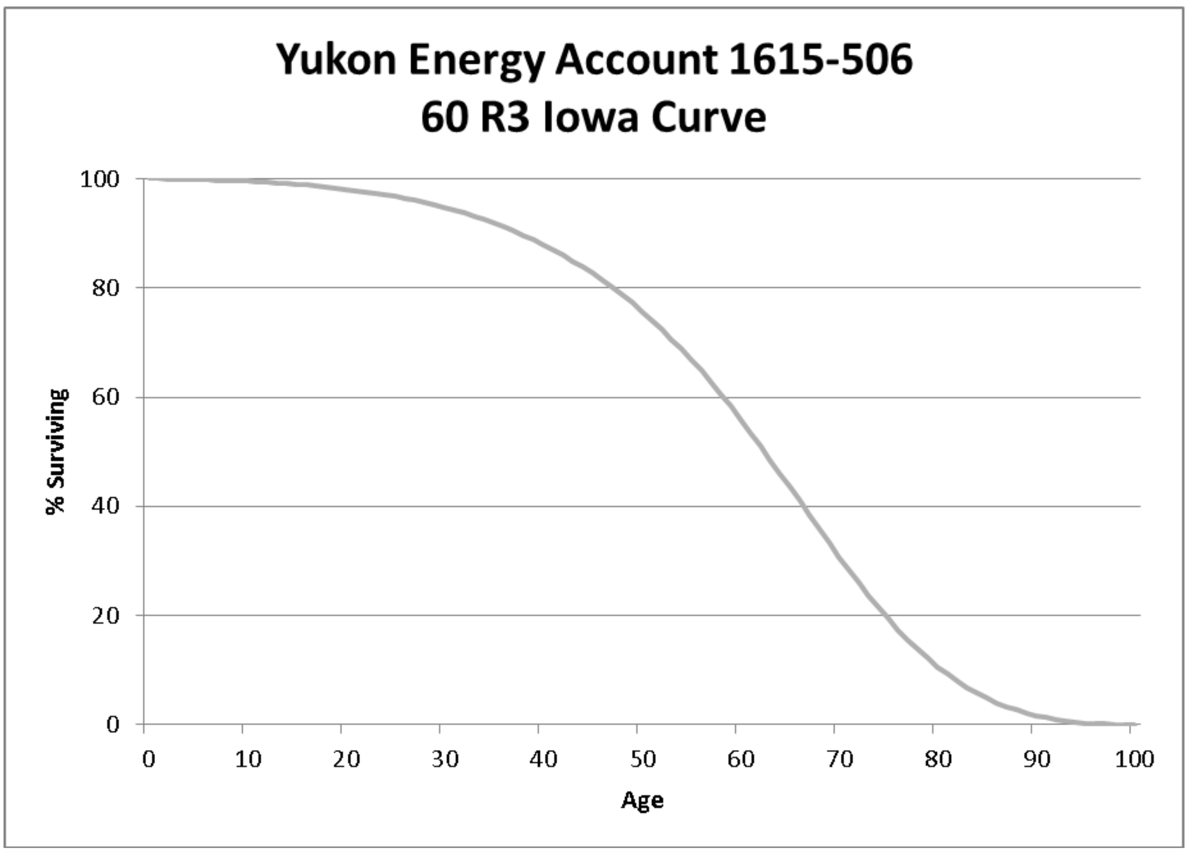
Account 1615-205 & 206 Hydro Reservoirs, Dams, and Waterways 103 R3

This account consists of reservoirs, dams, waterways, and other related assets used in hydro production including bridges, dams, embankments, tunnels and canals. The plant balance in this account at December 31, 2018 is $172.9 million. The approved life and curve for this account is 103 R3. Based on the limited indications from the actuarial analysis, information provided by Company personnel and judgment, this study recommends retaining the existing 103 R3 for this account. A graph of the observed life table versus the recommended curve type is shown below.



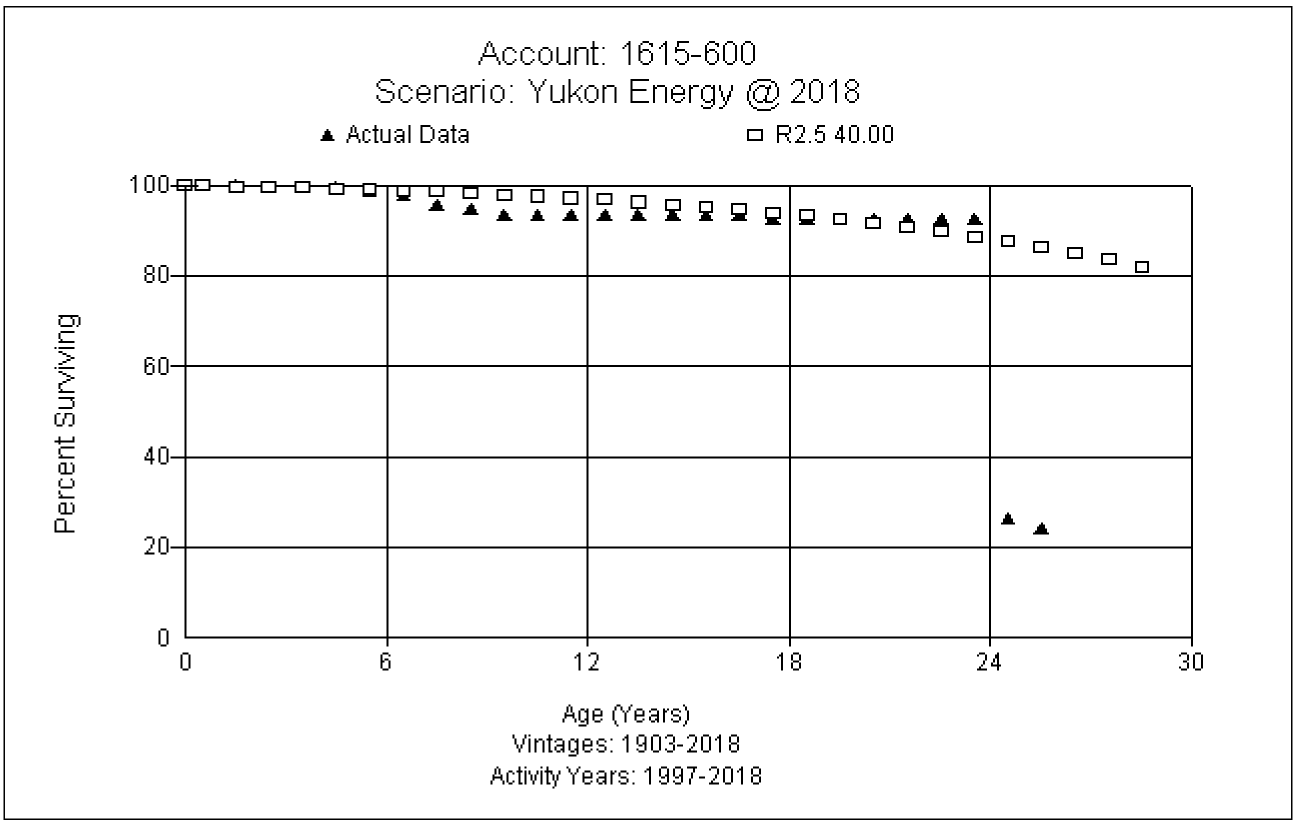
Account 1615-506 Hydro Water Wheels, Turbines, and Generators 60 R3

This account consists of water wheels, turbines, and other related assets used in hydro production including runners, gates, regulator systems, generator cooling systems, and generators. The plant balance in this account at December 31, 2018 is $26.3 million. The approved life and curve for this account is 85 R3. Operational personnel stated the approved life is too long, and that they have already replaced runners and rewound generators prior to reaching 60 years. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel, this study recommends decreasing the life to 60 years and retaining the R3 curve for this account. A representative graph is shown below.



Account 1615-600 Hydro Accessory Electrical Equipment 40 R2.5

This account consists of generator controls, bus equipment, and other related assets used in hydro production including auxiliary generators, switching equipment, excitation systems, and station control systems. The plant balance in this account at December 31, 2018 is $26.6 million. The approved life and curve for this account is 45 R3. Based on information provided by Company personnel and the indications from the actuarial analysis, this study recommends decreasing the life to 40 years and moving to an R2.5 curve for this account. A graph of the observed life table versus the recommended curve type is shown below.

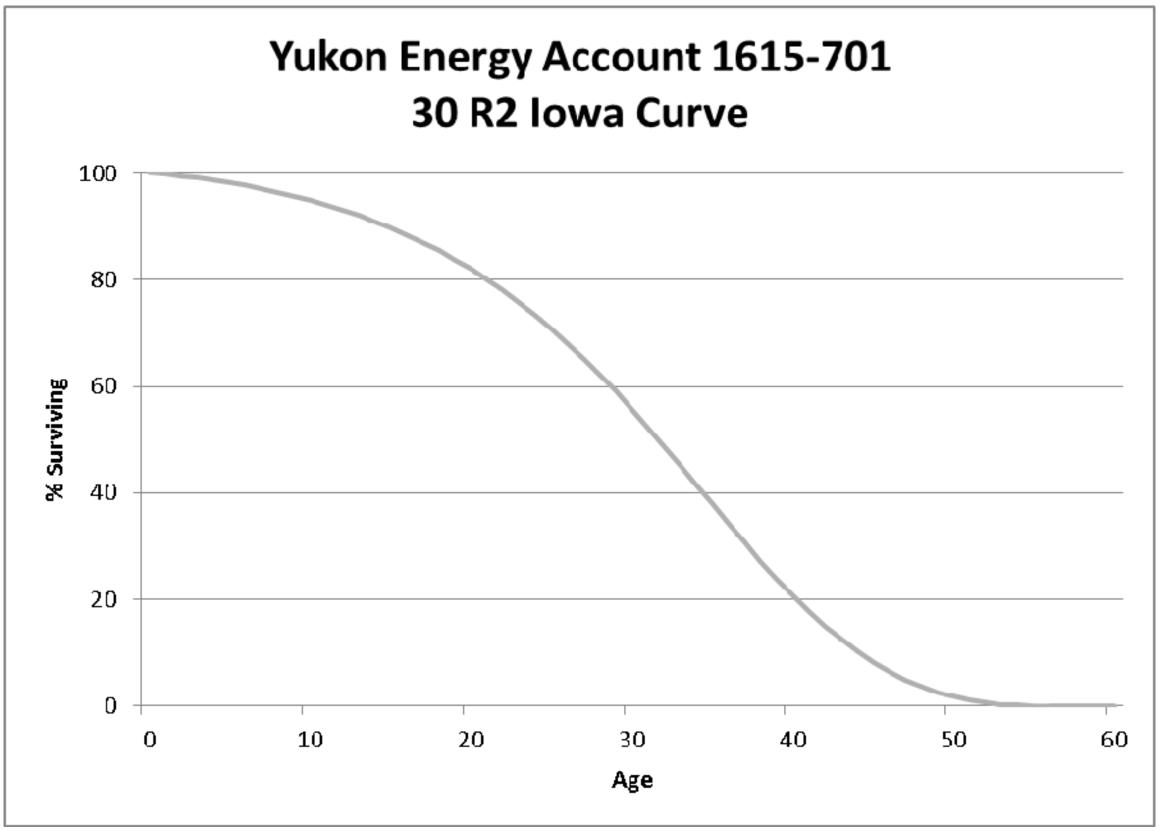


Account 1615-601 Hydro Accessory Digital Equipment 20 SQ

This account consists of digital generating apparatus, conversion and switching equipment, and other related equipment used in hydro production. The plant balance in this account at December 31, 2018 is $838 thousand. The approved life and curve for this account is 20 SQ. Based on type of assets, discussions with Company personnel, and the existing parameters, this study recommends retaining the existing 20 SQ for this account. No graph is shown for this account.

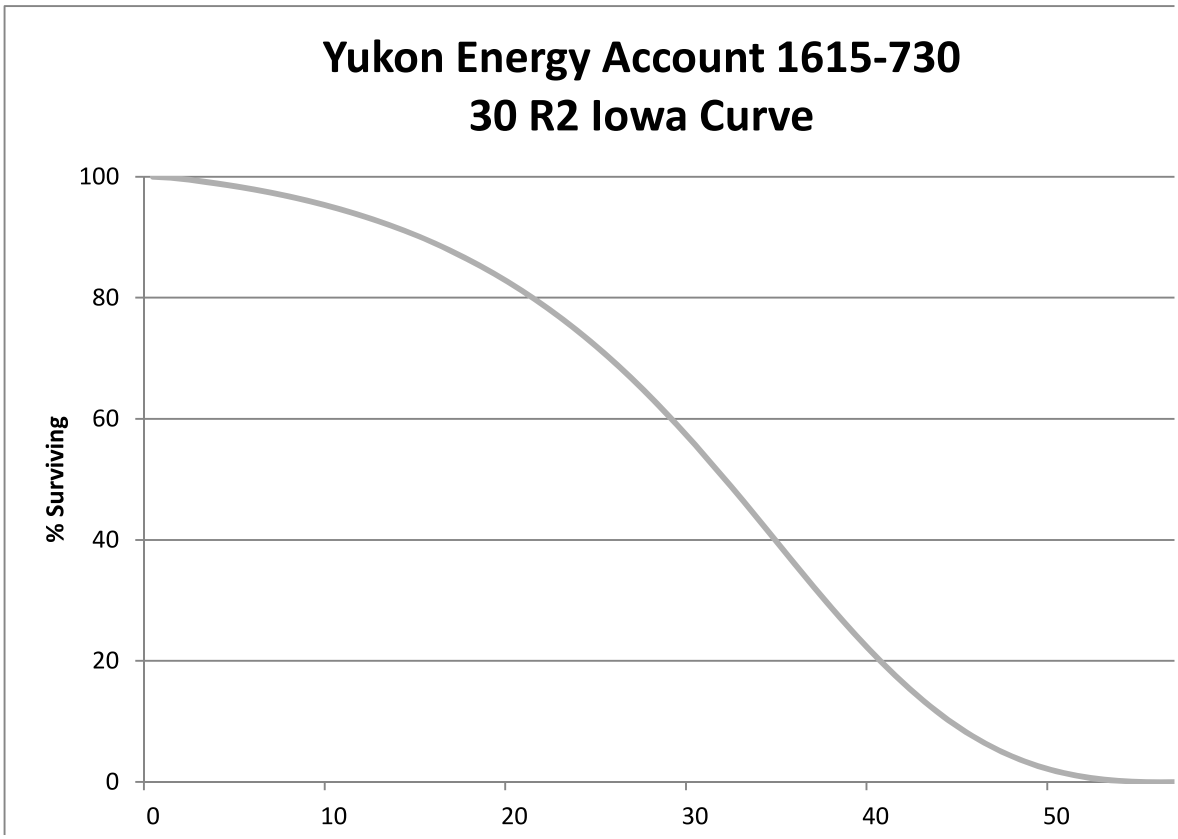
Account 1615-700 Hydro Miscellaneous Power Plant Equipment 30 R2

This account consists of compressed air and vacuum systems, cranes and hoisting equipment, station maintenance equipment, and other miscellaneous equipment used in hydro production. The plant balance in this account at December 31, 2018 is $11.5 million. The approved life and curve for this account is 30 R2. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel, and the existing parameters, this study recommends retaining the existing 30 R2 for this account. A representative graph is shown below.



Account 1615-730 Hydro Fences 30 R2

This account consists of fencing assets located at the hydro plants. The plant balance in this account at December 31, 2018 is $107 thousand. The approved life and curve for this account is 30 R2. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and the existing parameters, this study recommends retaining the existing 30 R2 curve for this account. A representative graph is shown below.

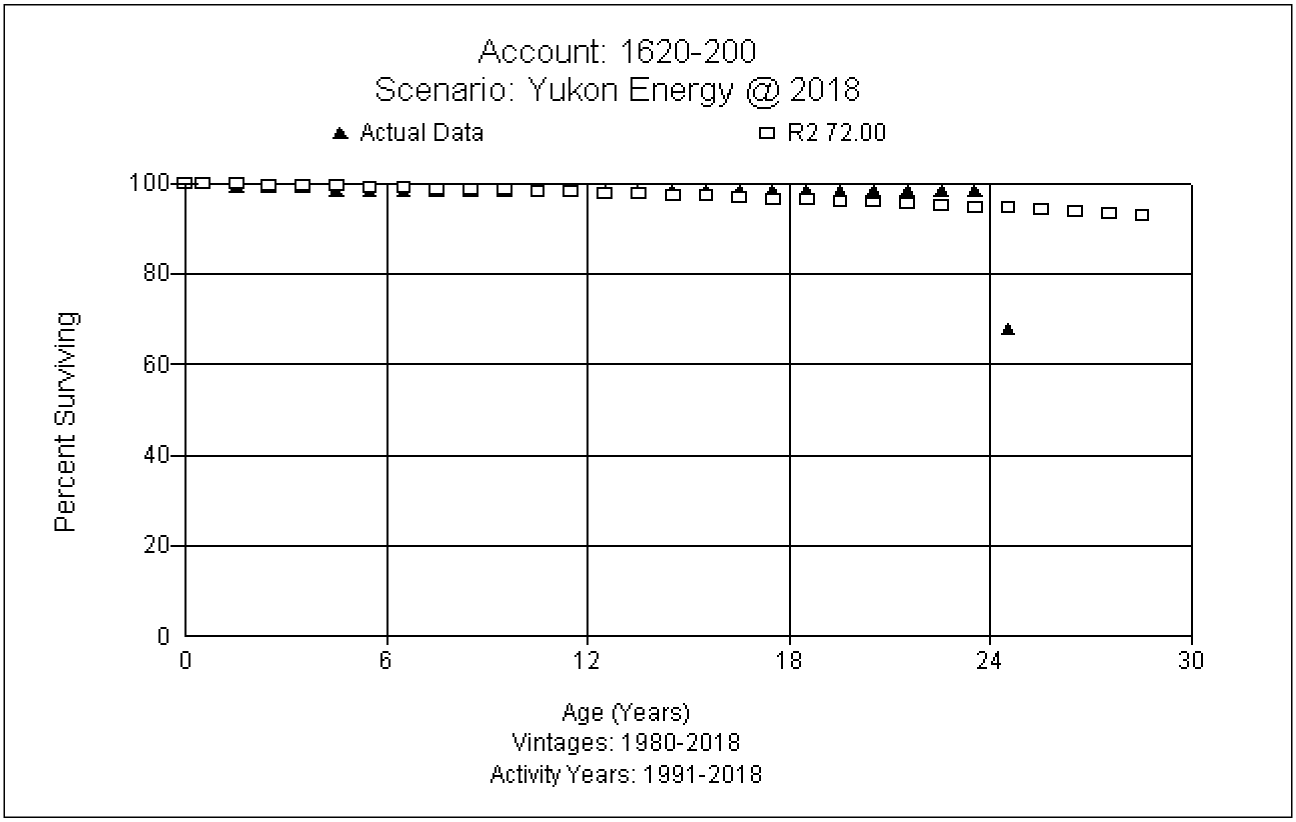


DIESEL PLANT

For most of the year, the Company relies on hydro for energy supply. In 2018, close to 94 percent of the electricity the Company generated was with hydro. However they also use back-up diesel generation during power outages, to supplement their hydro facilities in very cold weather, and during droughts. As an isolated grid in one of the planet's least-forgiving environments, a reliable backup system is crucial. Yukon Energy currently has diesel generators in Whitehorse, Mayo, Dawson, and Faro

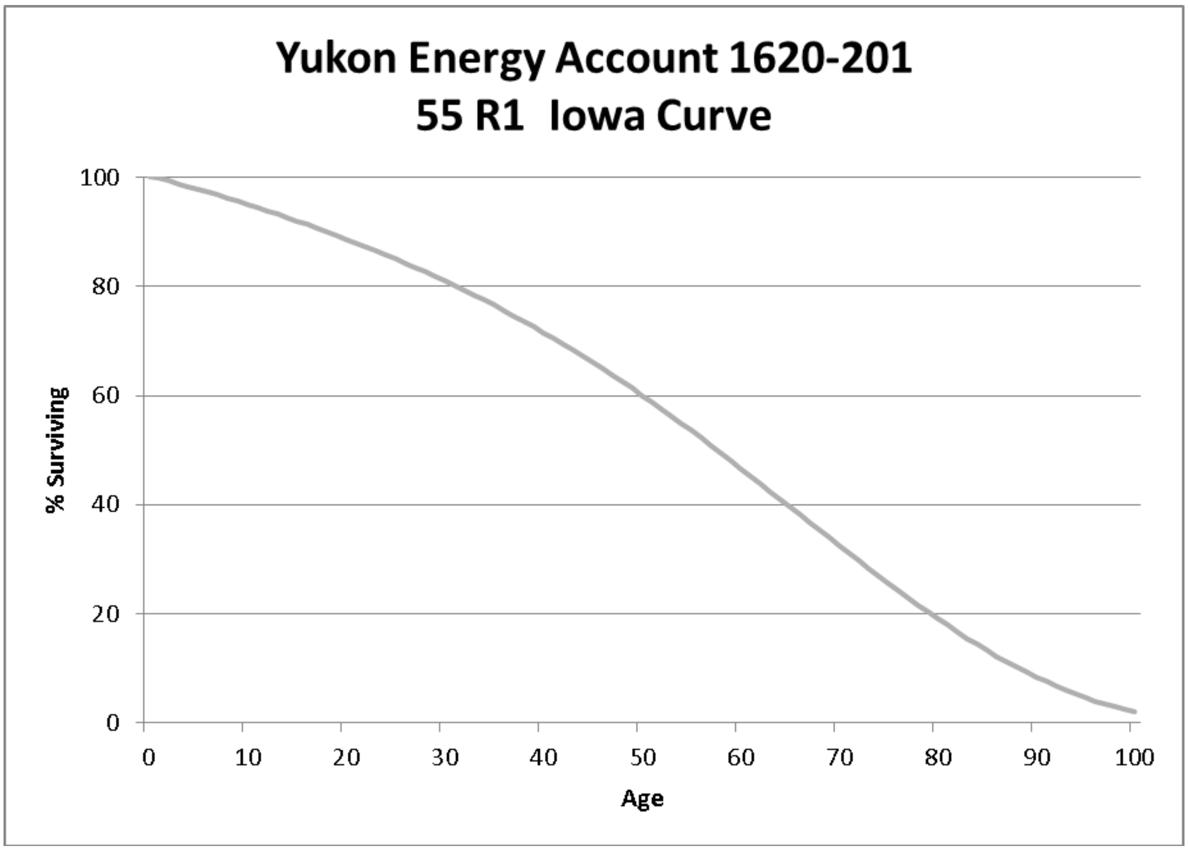
Account 1620-200 Diesel Structures and Improvements 72 R2

This account consists of structures, foundations, and other related assets at the diesel production plants. The plant balance in this account at December 31, 2018 is $1.6 million. The approved life and curve for this account is 72 R2. Based on information provided by Company personnel and judgment, this study recommends retaining the existing 72 R2 for this account. A graph of the observed life table versus the recommended curve type is shown below.


Account: 1620-200
Scenario: Yukon Energy @ 2018
Actual Data
R2 72.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1980-2018
Activity Years: 1991-2018

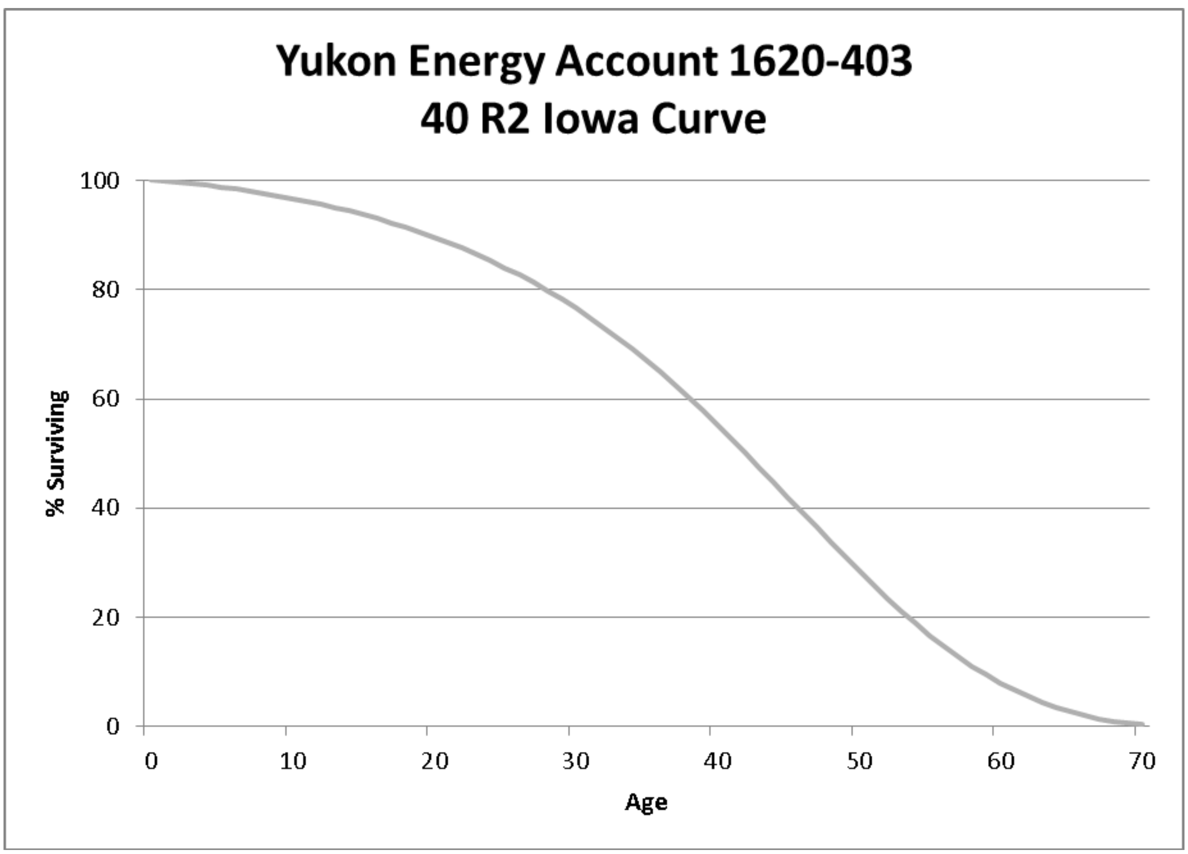
Account 1620-201 Diesel Buildings and Improvements 55 R1

This account consists of diesel production buildings, upgrades, renovations, and other related assets at the diesel production plants. The plant balance in this account at December 31, 2018 is $466 thousand. The approved life and curve for this account is 55 R1. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel and judgment, this study recommends retaining the existing 55 R1 for this account. A representative graph is shown below.



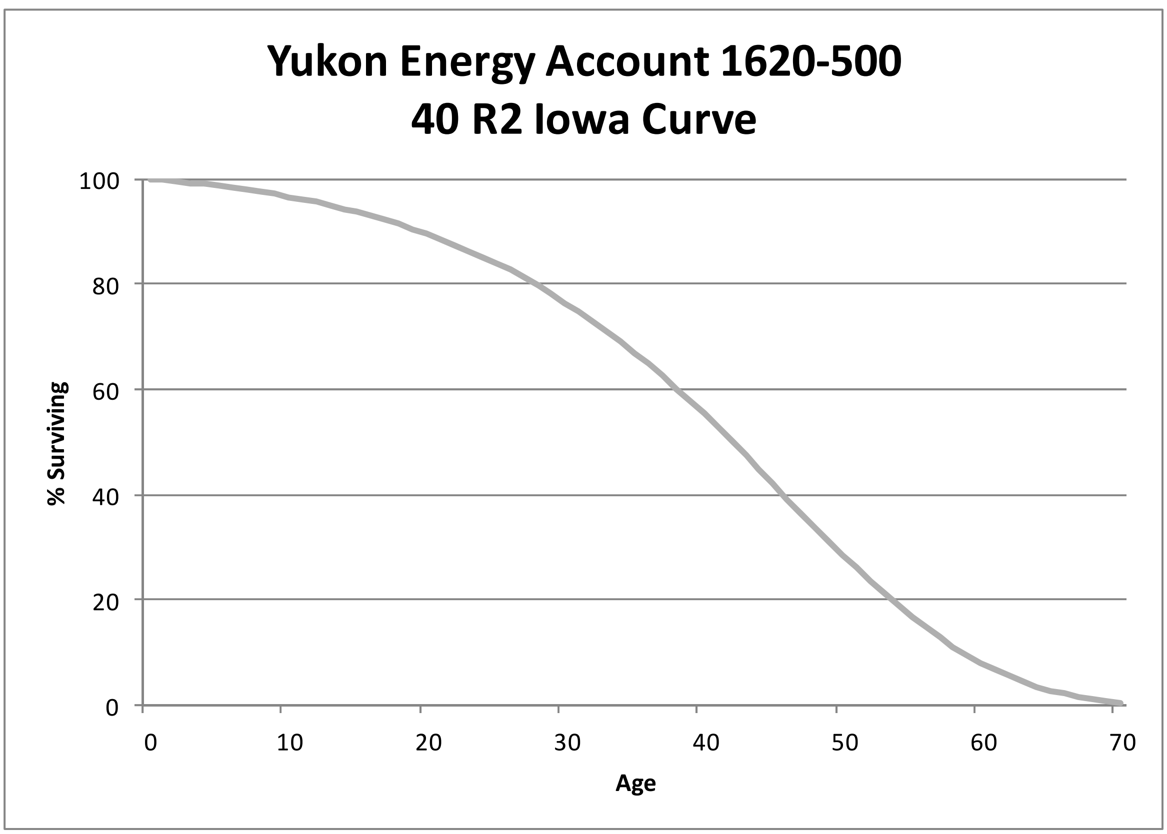
Account 1620-403 Diesel Fuel Holders, Producers, and Accessories 40 R2

This account consists of pumps, storage tanks, natural gas/fuel oil piping and other related assets at the diesel production plants. The plant balance in this account at December 31, 2018 is $1.7 million. The approved life and curve for this account is 25 R2. Discussions with operational personnel stated the existing life seems short, that many of the existing assets are approximately 15 to 20 years old, are still reliable, and not currently in need of replacement. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends increasing to a 40 year life and retaining the existing R2 curve for this account. A representative graph is shown below.



Account 1620-500 Generating Equipment and Prime Movers 40 R2

This account consists of generators, prime movers, and other related assets at the diesel production plants including air filtering systems, engines, cooling systems, and recording instruments. The plant balance in this account at December 31, 2018 is $13.8 million. The approved life and curve for this account is 40 R2. Discussions with operational personnel stated the block is estimated to last 40 years or more and that some smaller components in this account may have a shorter life, but overall a life of 40 years seems reasonable. There was insufficient transactional data for an actuarial life analysis. Based on the type of assets, information provided by Company personnel and judgment, this study recommends retaining the existing 40 R2 for this account. A representative graph is shown below.



Account 1620-501 Generating Equipment and Prime Movers Faro Diesel 11 SQ

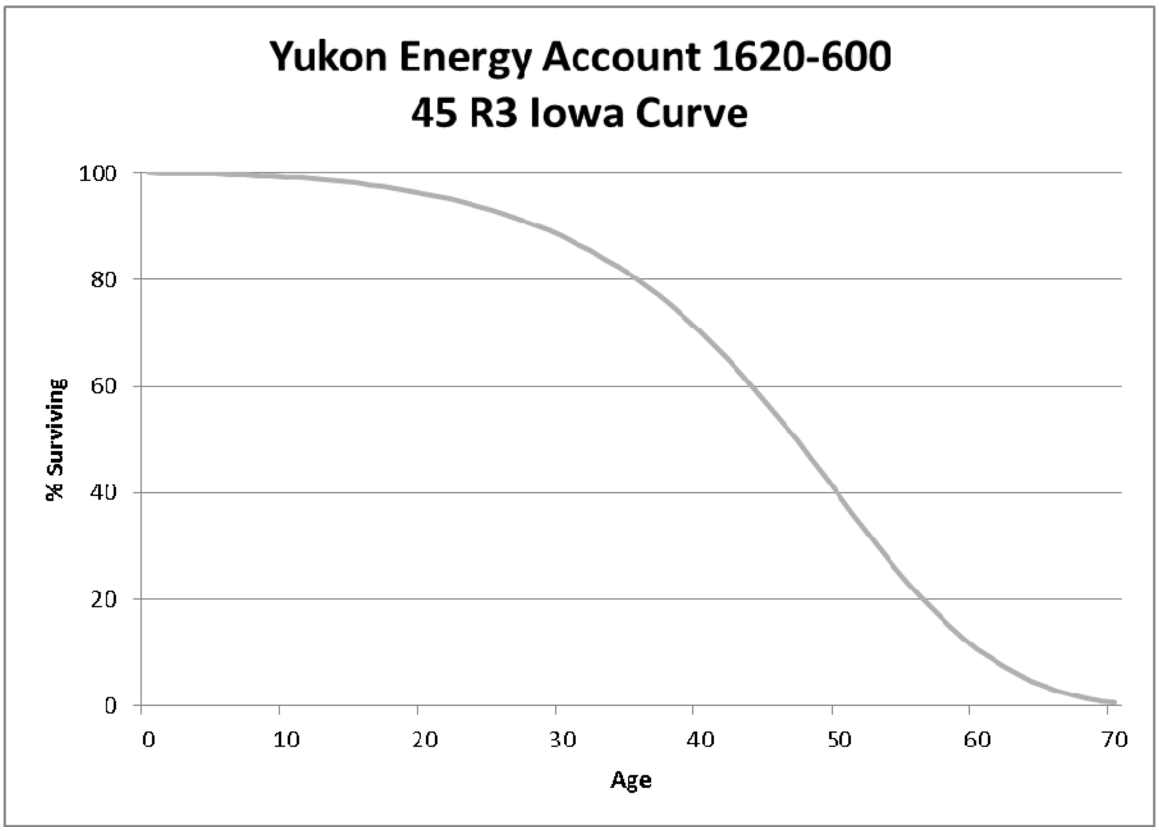
This account consists of generators, prime movers, and other related assets at the diesel production plants including air filtering systems, engines, cooling systems, and recording instruments at the Faro Diesel facility. The plant balance in this account at December 31, 2018 is $2.0 million. The approved life and curve for this account is 11 SQ. The Company will be retiring these assets associated with the Faro diesels in 2021, and the current service life reflects the retirement of those assets. Based on input from the Company, the current plan to retire these assets in 2021 remains the same. No change in life is planned for this account.

Account 1620-508 Diesel Minto Generating Equipment 12 SQ

This account consists of diesel generating and control equipment at Minto Mine. The plant balance in this account at December 31, 2018 is $244 thousand. The approved life and curve for this account is 12 SQ. Yukon amortizes the costs for the plant controls over a 12 year period. Based on information provided by Company personnel, this study recommends retaining the existing 12 SQ for this account. No graph is shown for this account.

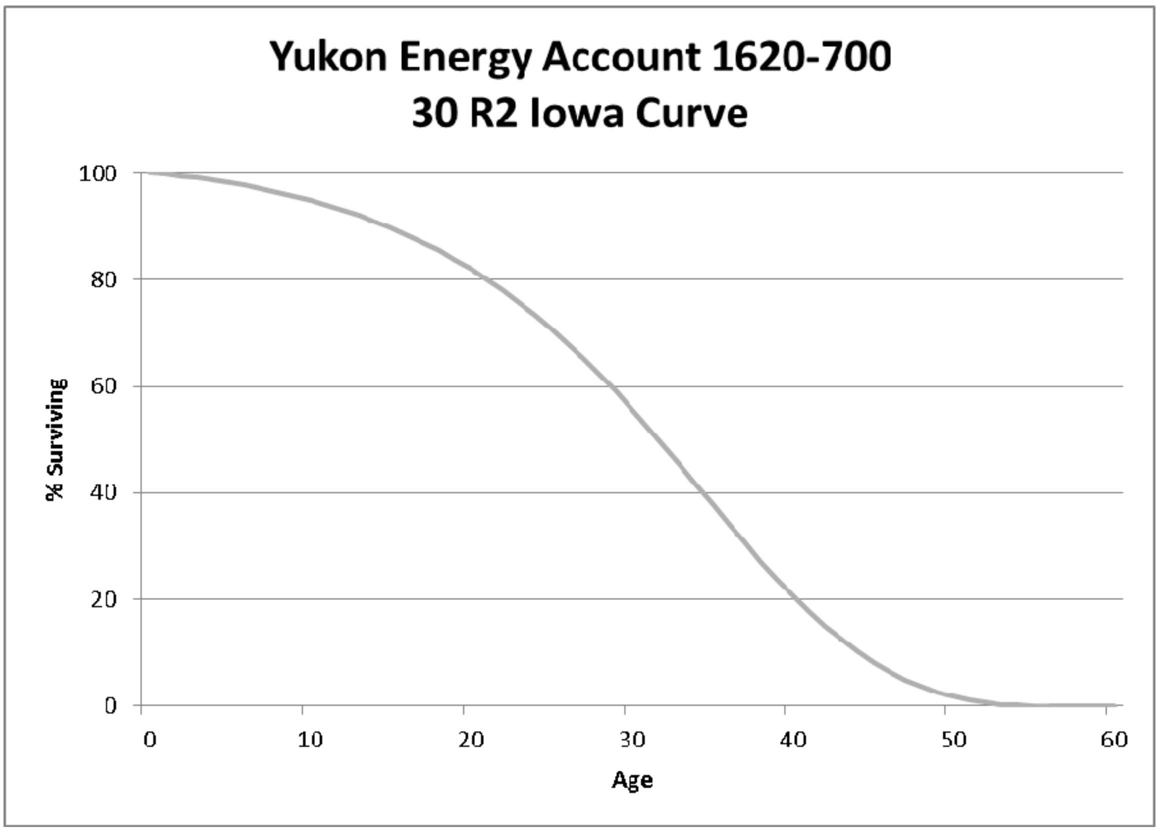
Account 1620-600 Diesel Accessory Electrical Equipment 45 R3

This account consists of auxiliary generators, switching and control equipment, circuit breakers, and other related assets at the diesel production plants. The plant balance in this account at December 31, 2018 is $5.4 million. The approved life and curve for this account is 45 R3. There was insufficient transactional data for an actuarial life analysis. Based on the type of assets, information provided by Company personnel and judgment, this study recommends retaining the existing 45 R3 for this account. A representative graph is shown below.



Account 1620-700 Diesel Miscellaneous Power Plant Equipment 30 R2

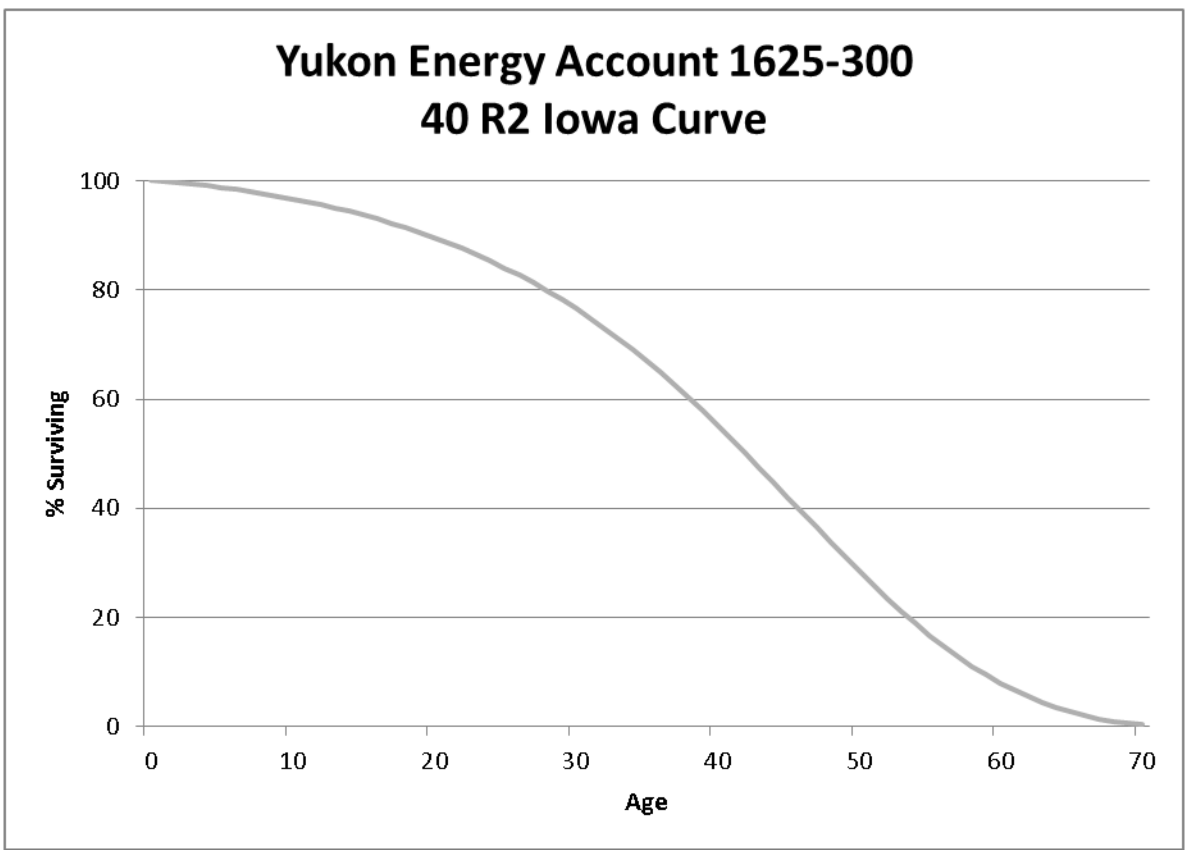
This account consists of compressed air and vacuum systems, crane rails, hoists, lab equipment, ventilating equipment, fire protection systems, and other related assets at each diesel production plant. The plant balance in this account at December 31, 2018 is $1.9 million. The approved life and curve for this account is 30 R2. There was insufficient transactional data for an actuarial life analysis. Based on the type of assets, information provided by Company personnel, this study recommends retaining the existing 30 R2 for this account. A representative graph is shown below.



DISTRIBUTION SYSTEM

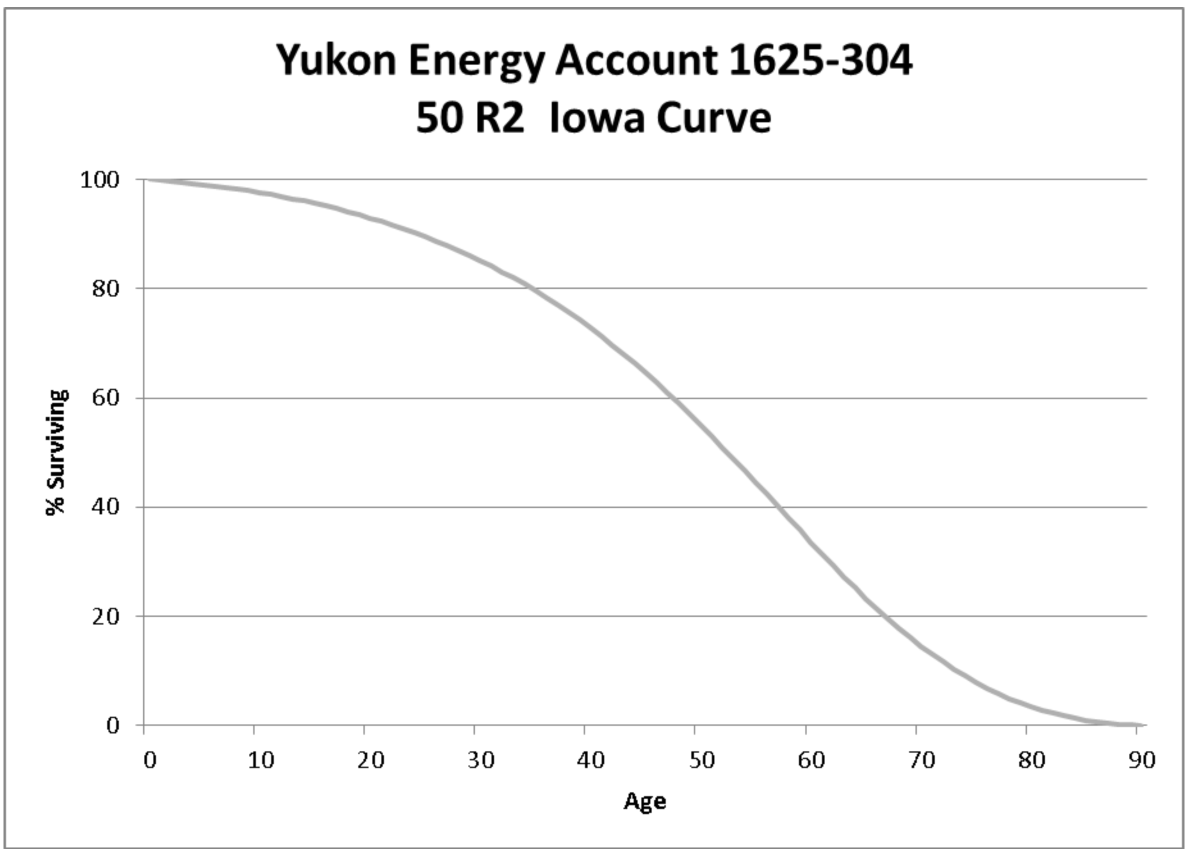
Account 1625-300 Dist. System - Poles and Fixtures 40 R2

This account consists of the installation costs of poles and fixtures used for supporting overhead distribution conductors and service wire. The plant balance in this account at December 31, 2018 is $8 million. The approved life and curve for this account is 35 R2. Discussions with operational personnel stated that right of ways are narrower for distribution, putting the poles closer to vehicles and making them more susceptible to being damaged. Additionally, permafrost puts more stress on the shorter, lower class poles. Overall, operations estimates the life of distribution poles to be 10 years less than transmission poles, which use a life of 50 years. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 40 R2 for this account. A representative graph is shown below.



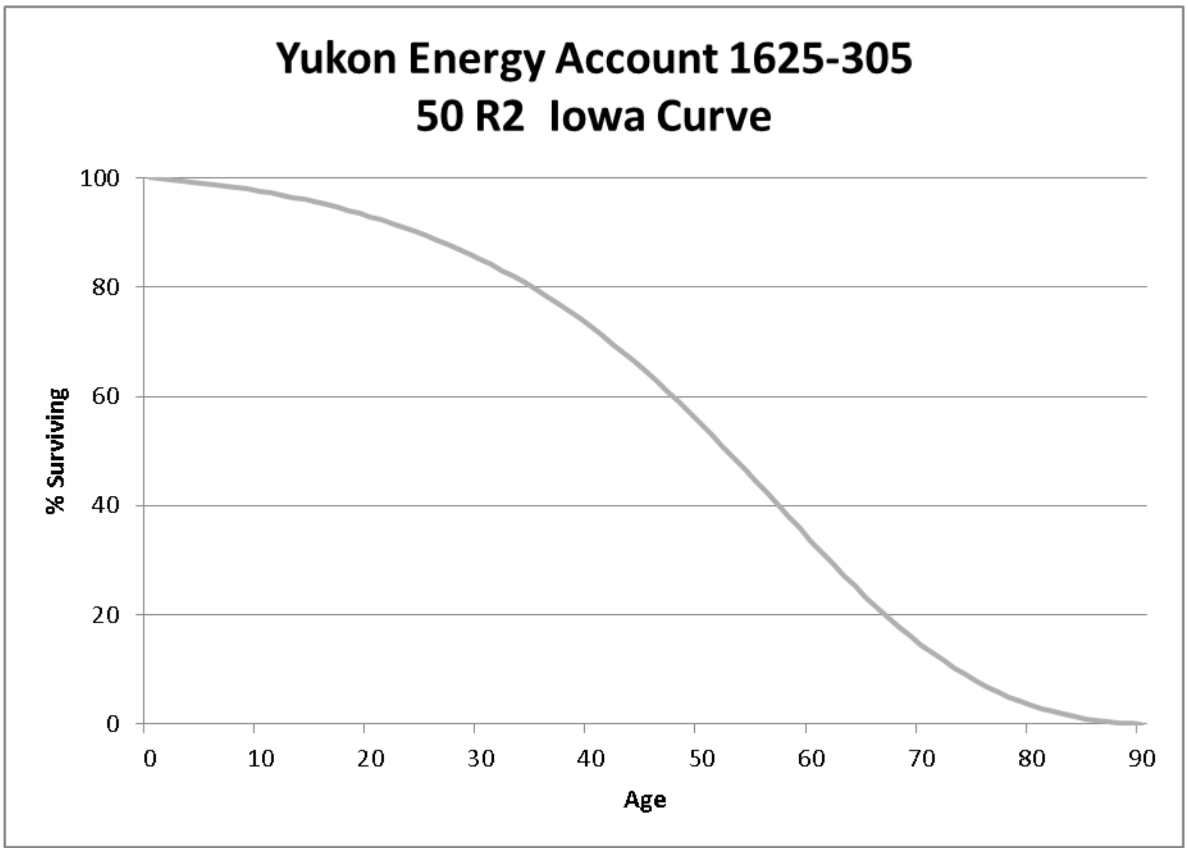
Account 1625-304 Dist. System - Brushing 50 R2

This account consists of costs associated with the brushing of the distribution system. The plant balance in this account at December 31, 2018 is $45 thousand. The approved life and curve for this account is 50 R2. The Company capitalizes the brush clearing of ROWs when installing new lines. Operations stated the existing life is reasonable and matches the life of O/H Conductor, which have a 50 year life. There was insufficient transactional data for an actuarial life analysis. Based on the information provided by Company personnel and judgment, this study recommends retention of the existing 50 R2 for this account. A representative graph is shown below.



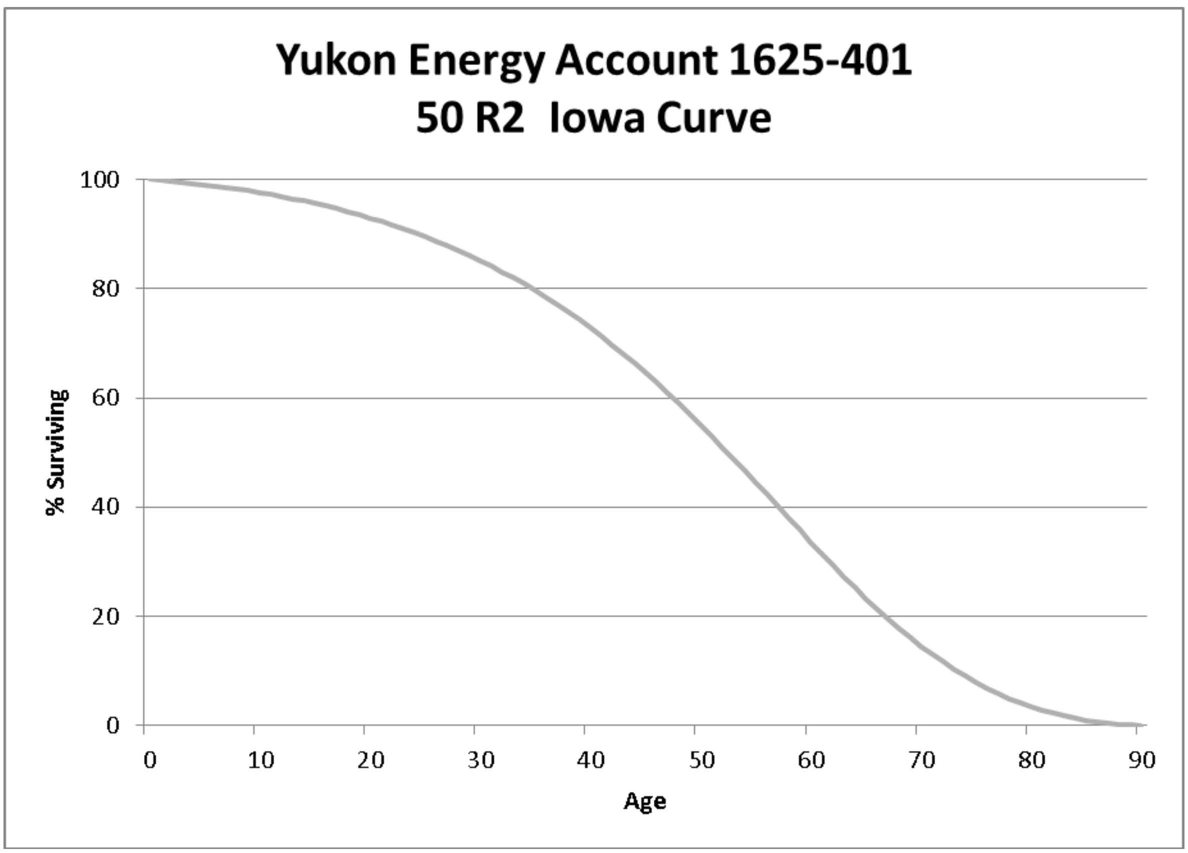
Account 1625-305 Dist. System – Survey Costs 50 R2

This account consists of costs association with land surveys and assessments related to distribution easements. The plant balance in this account at December 31, 2018 is $600 thousand. The approved life and curve for this account is 50 R3. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the existing 50 year life with a slight change in the curve to an R2 for this account. A representative graph is shown below.



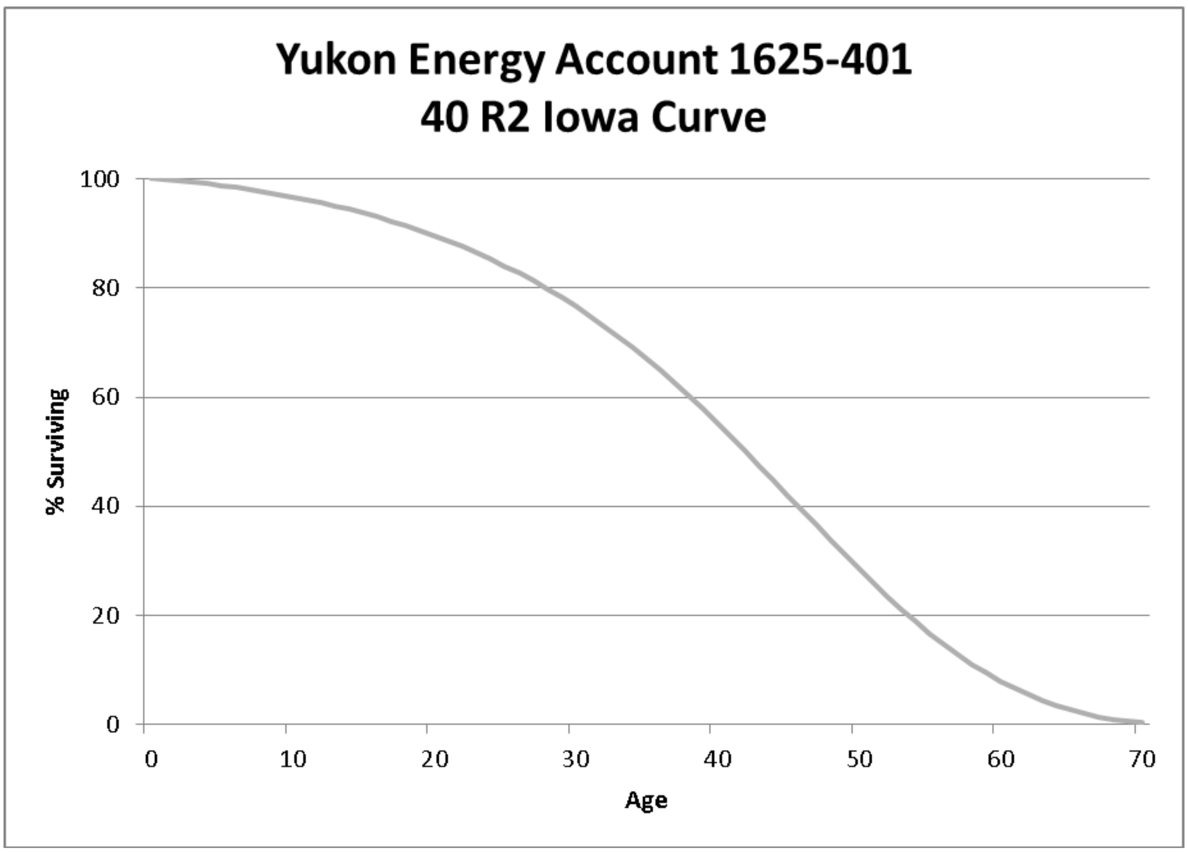
Account 1625-401 Dist. System – O/H Conductors 50 R2

This account consists of overhead conductors and other facilities associated with the distribution system. The plant balance in this account at December 31, 2018 is $75 thousand. The approved life and curve for this account is 35 R2. Discussions with operational personnel stated they would expect the life of distribution conductor to be shorter than transmission conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends increasing the life to 50 years while retaining the R2 curve for this account. A representative graph is shown below.



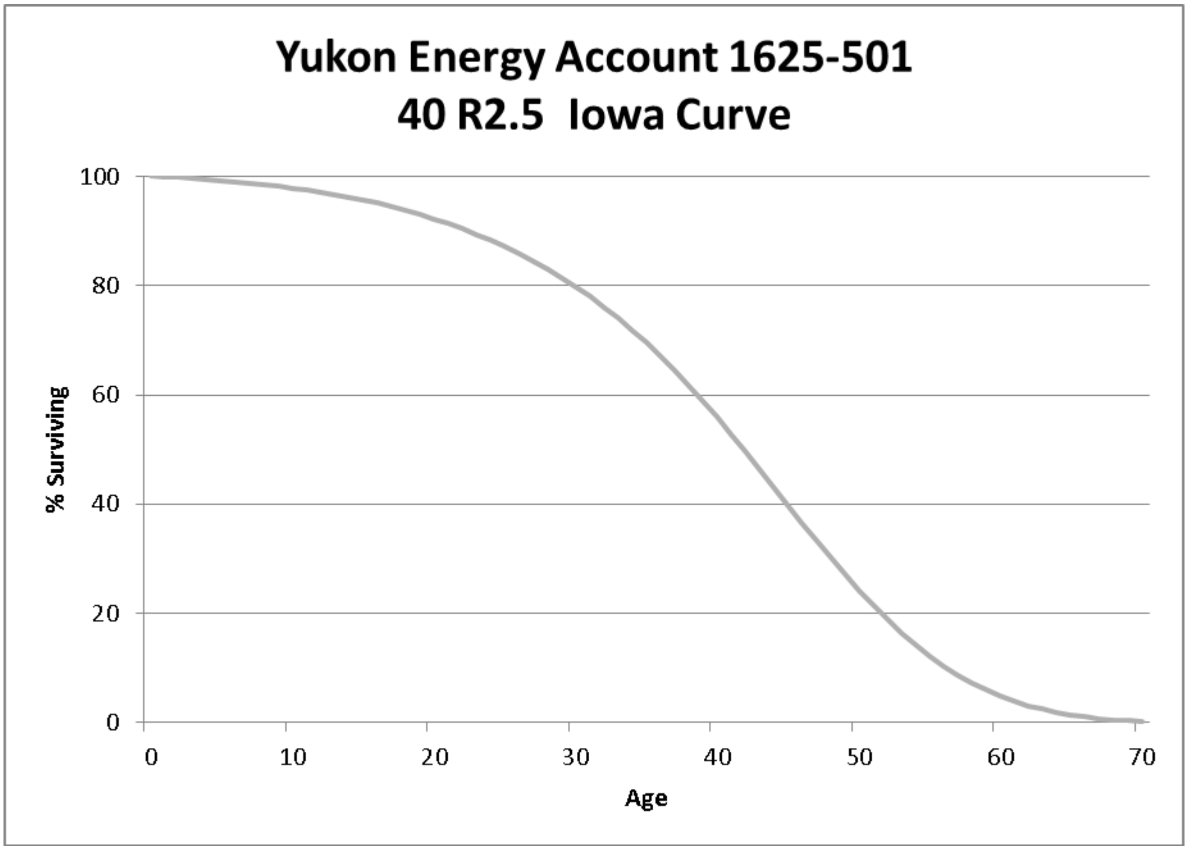
Account 1625-401 Dist. System – O/H Services 40 R2

This account consists of installation costs associated with overhead services such as transmission line installation and upgrades. The plant balance in this account at December 31, 2018 is $2.1 million. The approved life and curve for this account is 40 R2. Discussions with Company personnel indicated the majority of services are overhead. The Company is experiencing an increased number of new services and need to update aging infrastructure. Operations stated commercial services would have a shorter life than residential services. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 40 R2 life and curve for this account. A representative graph is shown below.



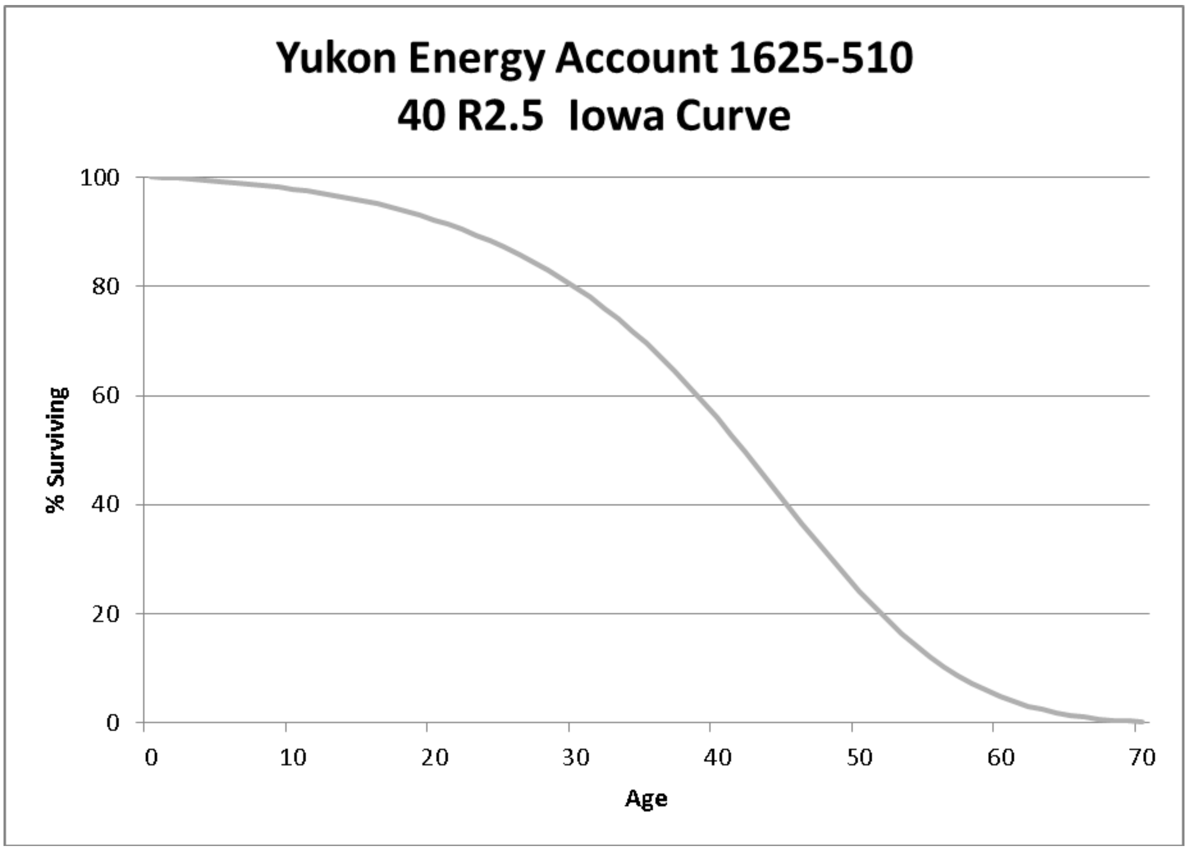
Account 1625-501 Underground Conduit 40 R2.5

This account consists of underground conduit, duct banks, vaults, manholes, insulators, and ventilating system equipment. The plant balance in this account at December 31, 2018 is $385 thousand. The approved life and curve for this account is 40 R2.5. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 40 R2.5 life and curve for this account. A representative graph is shown below.



Account 1625-510 Underground Services 40 R2.5

This account consists of underground services. The plant balance in this account at December 31, 2018 is $40 thousand. The approved life and curve for this account is 40 R2.5. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 40 R2.5 life and curve for this account. A representative graph is shown below.



Account 1625-610 Dist. System – Meters 16 SQ

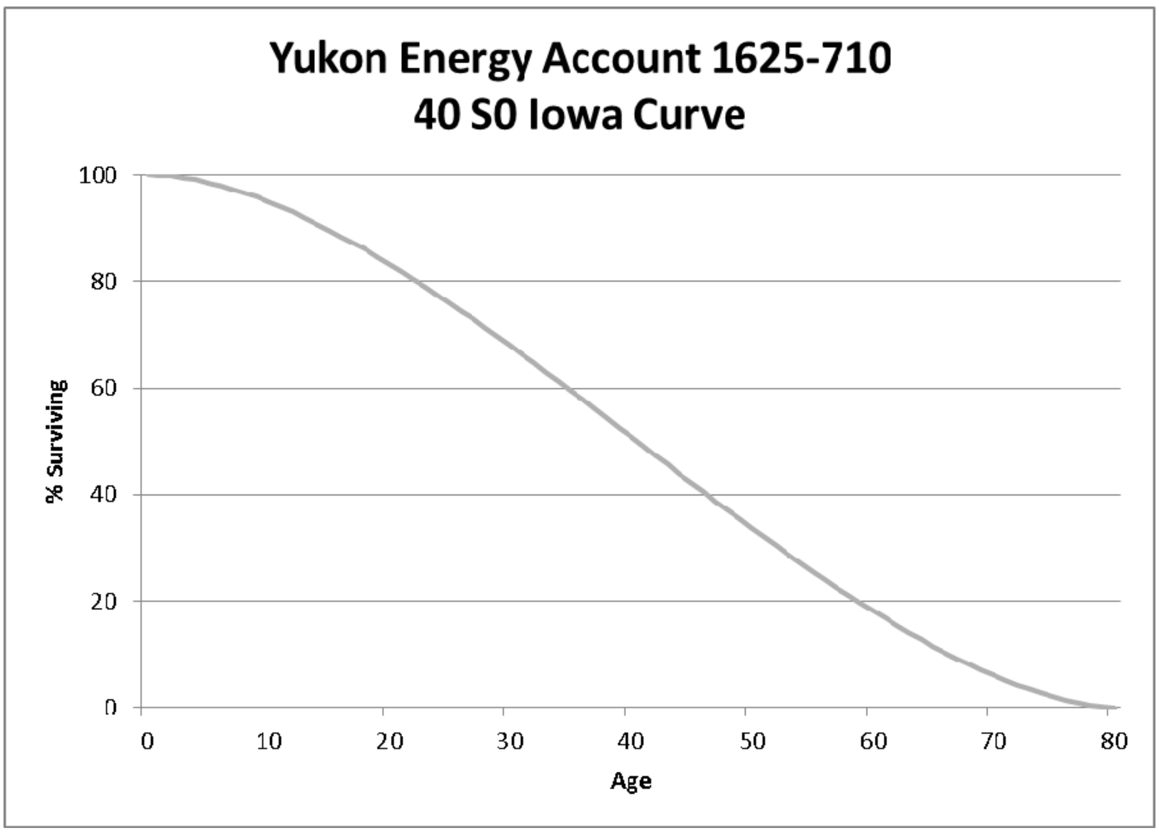
This account includes all distribution meters. The plant balance in this account at December 31, 2018 is $313 thousand. The approved life and curve for this account is 30 R2. Discussions with operations stated nearly all existing meters are digital. The Company pulls meters for testing at eight years and based on test results may use the meter up to 16 years. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 16 SQ life and curve for this account. No graph is shown for this account

Account 1625-620 Dist. System – Meter Equipment 16 SQ

This account includes the costs of metering devices and appurtenances thereto used to transform electricity so that it can be measured by meter when delivered to its users. This includes instrument transformers, meter boards, meter switches, and similar devices. The plant balance in this account at December 31, 2018 is $288 thousand. The approved life and curve for this account is 30 R2 – modeled the same as the meters in Account 1625-610. Based on type of assets, the movement of the meter life to 16 years and judgment, this study recommends continuing to parallel meters and move the life to a 16 SQ life and curve for this account. No graph is shown for this account.

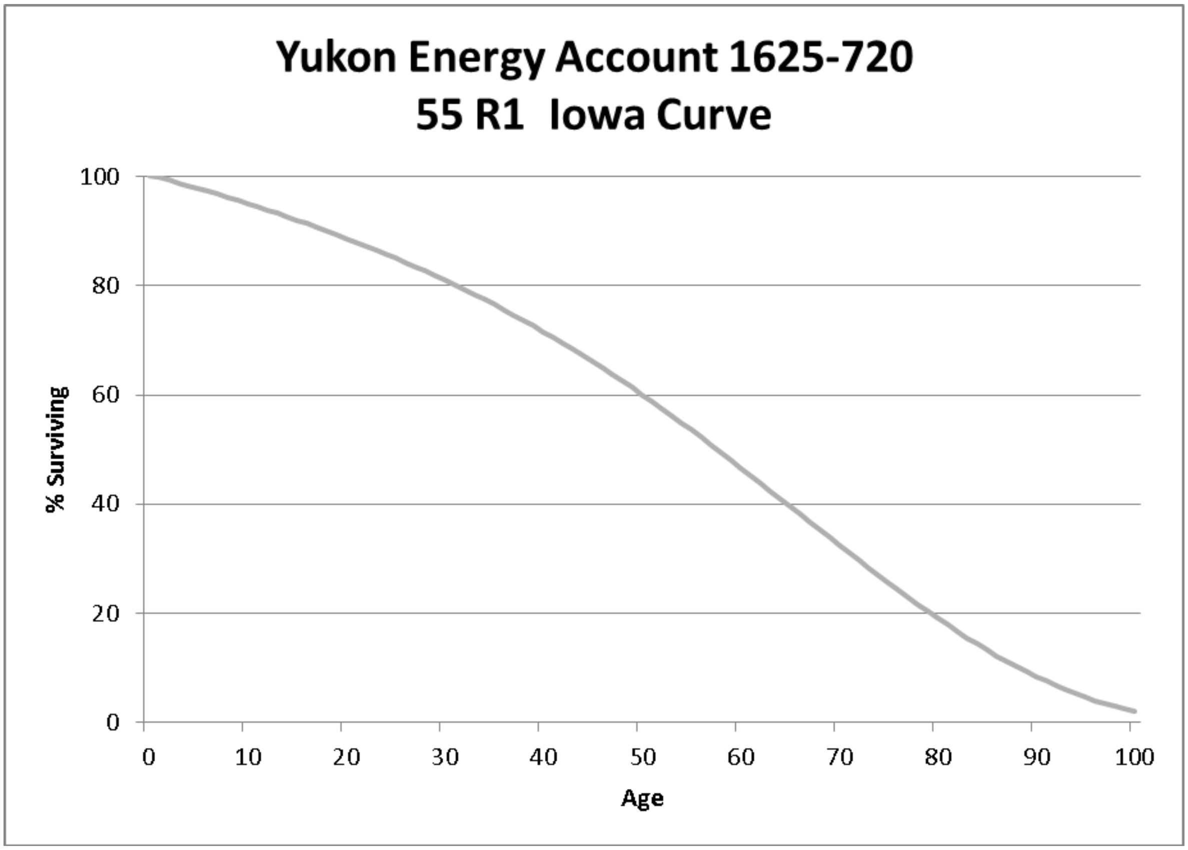
Account 1625-710 Dist. System – Substation Equipment 40 S0

This account includes all distribution substation equipment such as bus compartments, control equipment, ground rods, foundations, and conversion equipment, switching equipment, and switchboards. The plant balance in this account at December 31, 2018 is $1.3 million. The approved life and curve for this account is 40 R2. Discussions with operations indicated the Company is experiencing a shorter life due to an increased number of faults, more short-lived electronic equipment, and the move to SF6 all decreasing the lives of existing assets. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends a 40 S0 life and curve for this account. A representative graph is shown below.



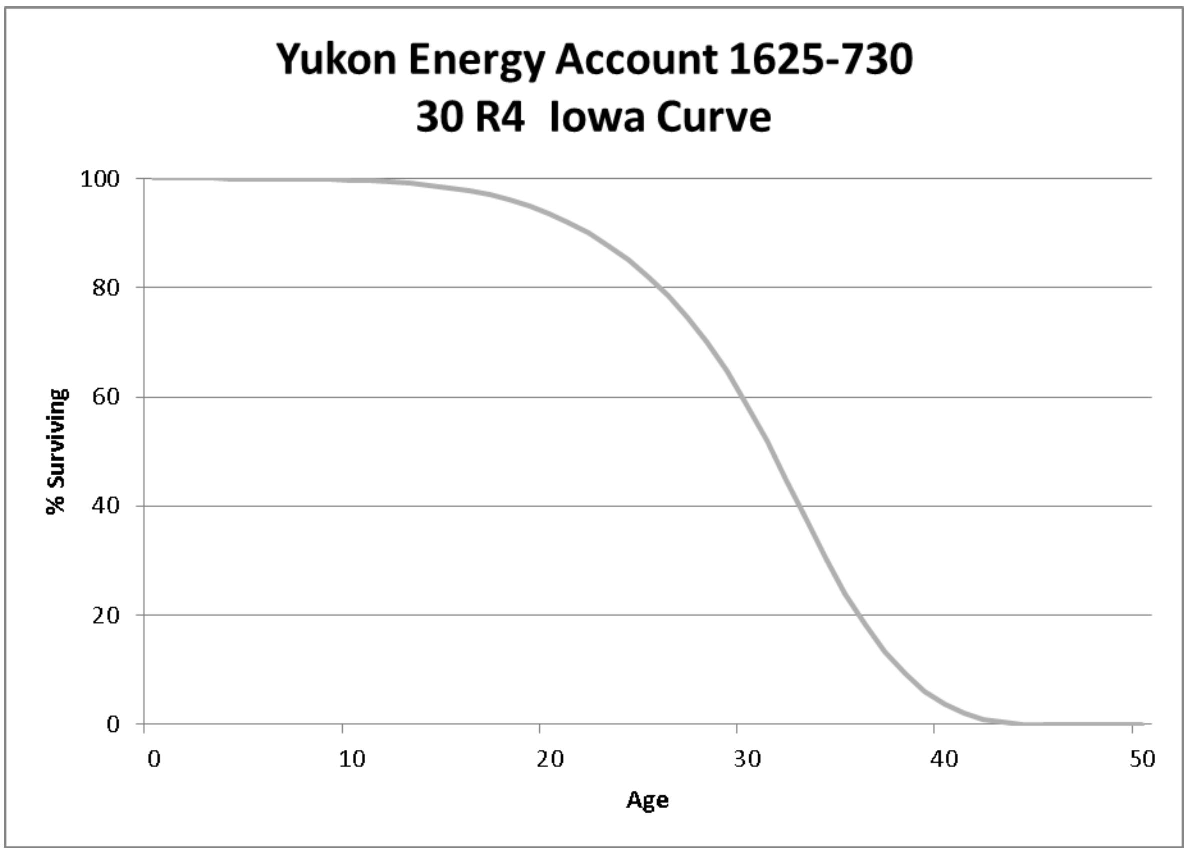
Account 1625-720 Dist. System – Substation Buildings 55 R1

This account includes the costs of buildings located at distribution substations. The plant balance in this account at December 31, 2018 is $65 thousand. The approved life and curve for this account is 55 R1. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 55 R1 life and curve for this account. A representative curve is shown below.



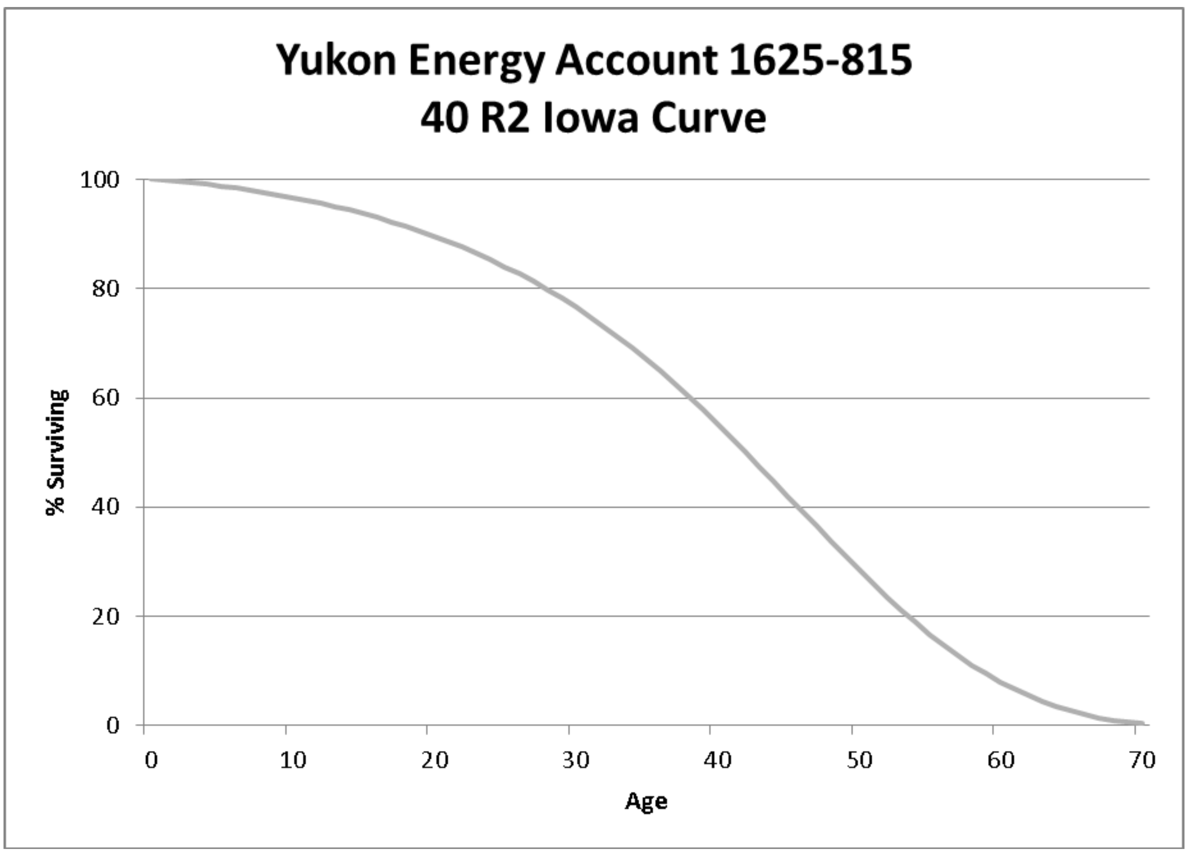
Account 1625-730 Dist. System – Substation Fences 30 R4

This account includes the costs of fences located at distribution substations. The plant balance in this account at December 31, 2018 is $100 thousand. The existing life for this account is 20 R4. The approved life for this account is 20 years. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel and judgment, this study recommends moving to a 30 R4 life and curve for this account. A representative curve is shown below.



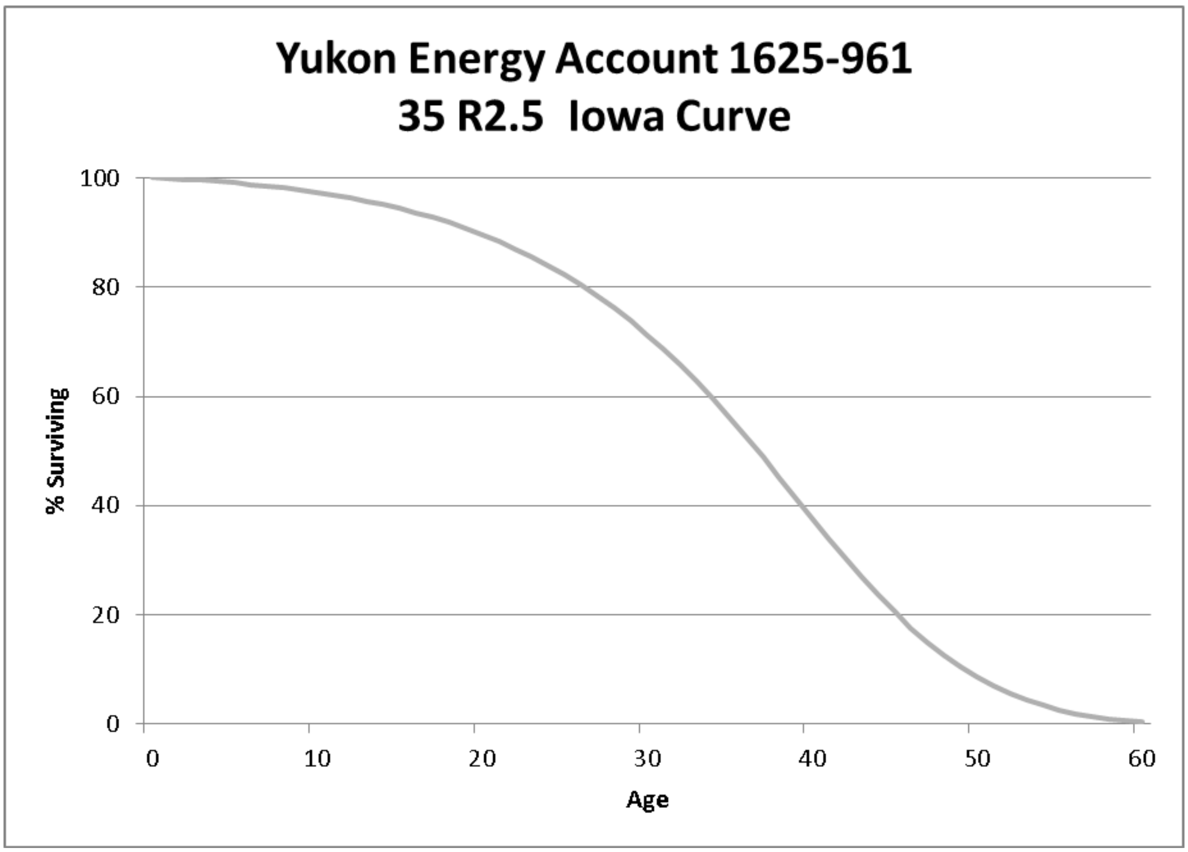
Account 1625-815 Dist. System – Street Lights 40 R2

This account includes Public Street and highway lighting or traffic, fire alarm, police and other signal systems. The plant balance in this account at December 31, 2018 is $589 thousand. The approved life and curve for this account is 40 R2. Discussions with Company personnel indicated all existing street lights are LED. The original LED's are reaching the end of their lifecycle, and the Company is experiencing an increased number of failures and replacing the original installed assets. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 40 R2 life and curve for this account. A representative graph is shown below.



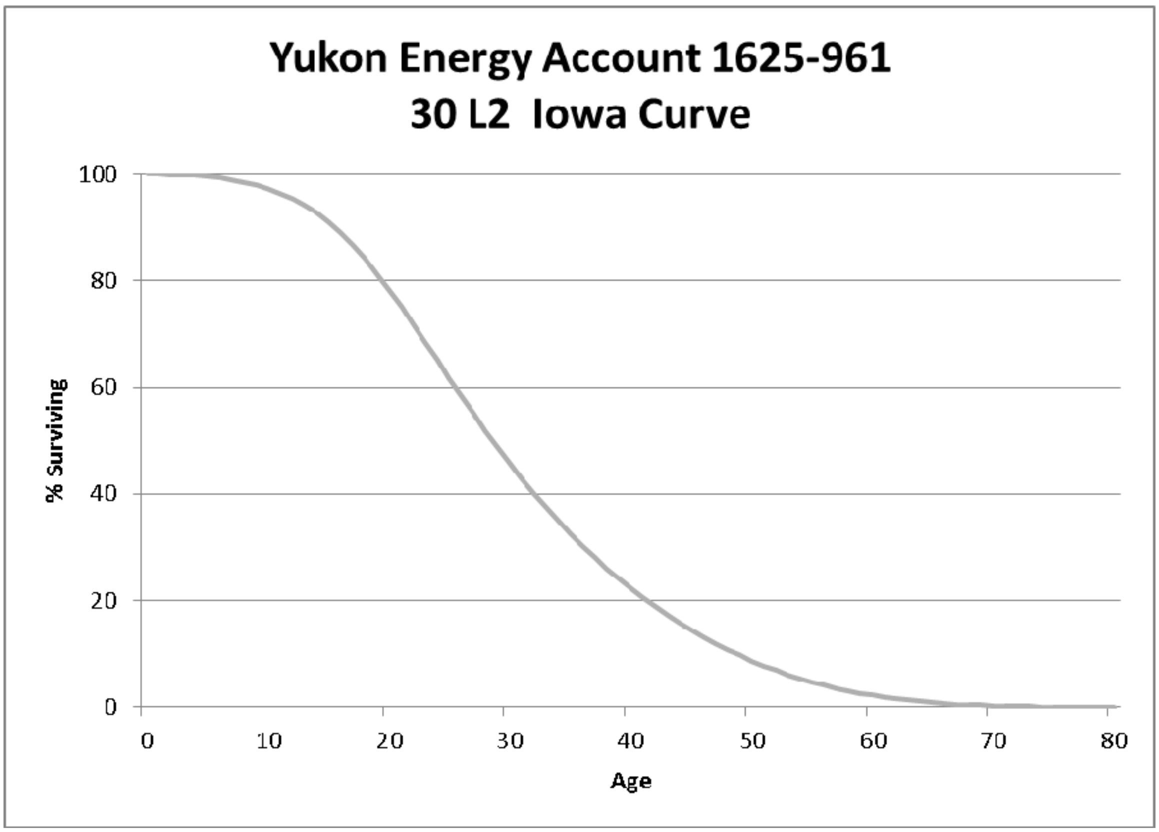
Account 1625-905 Dist. System – Line Transformers 35 R2.5

This account includes all line transformers, capacitors, lightning arrestors, and related equipment. The plant balance in this account at December 31, 2018 is $4 million. The approved life and curve for this account is 40 R2.5. Discussions with operations stated the transformers are subject to higher loading due to growth and expect the life of these assets to decrease as a result. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel and judgment, this study recommends moving to a 35 R2.5 life and curve for this account. A representative graph is shown below.



Account 1625-961 Dist. System – Sentinel Lights 30 L2

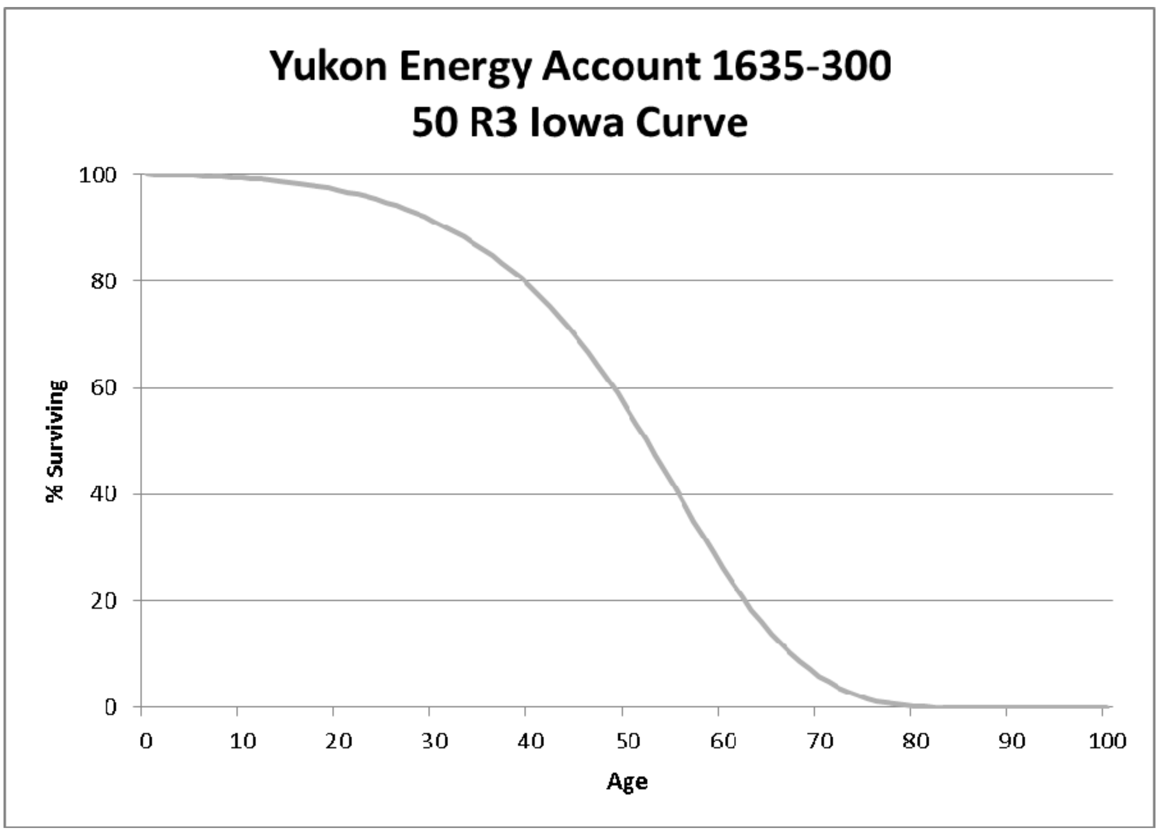
This account includes all sentinel and flood lighting excluding street lights. The plant balance in this account at December 31, 2018 is $36 thousand. The approved life and curve for this account is 30 L2. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retaining the existing 30 L2 for this account. A representative graph is shown below.



MAIN TRANSMISSION FACILITIES

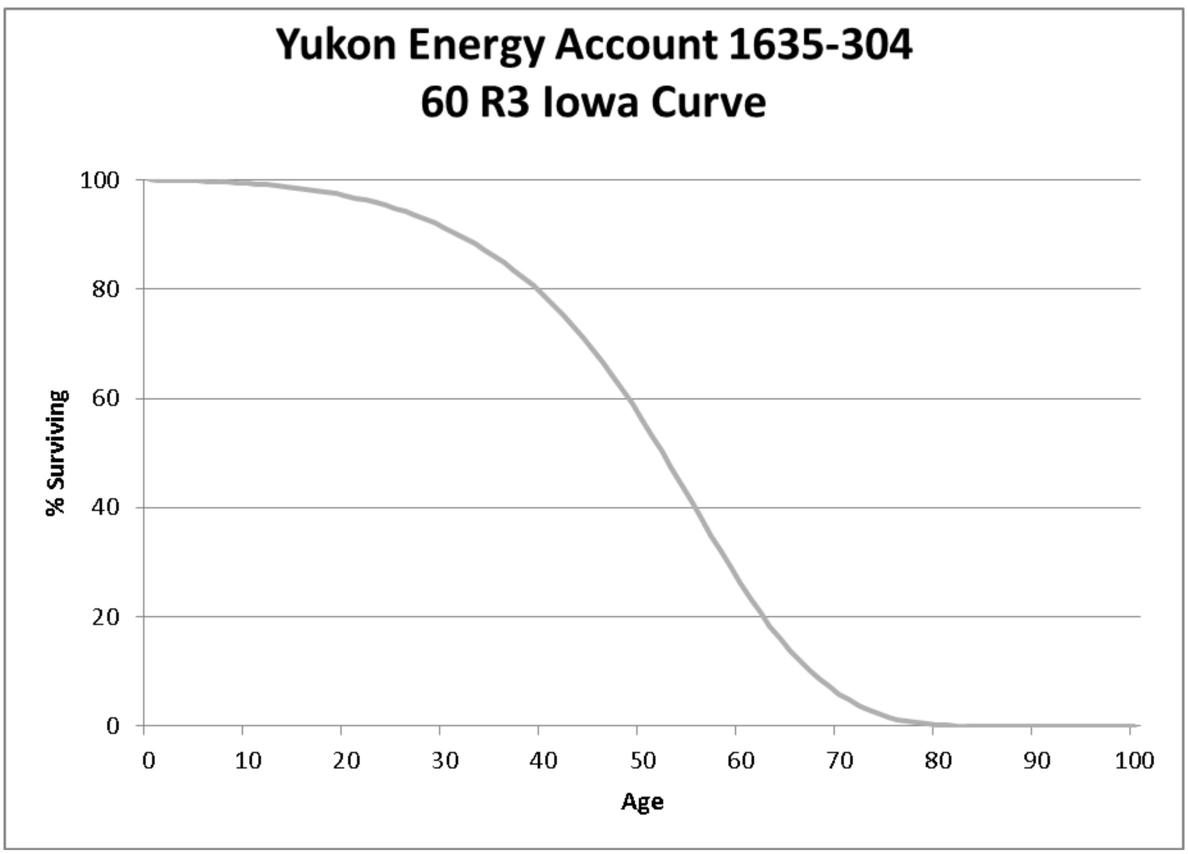
Account 1635-300 Main Trx - Poles and Fixtures 50 R3

This account consists of poles and fixtures used for transmission purposes. The plant balance in this account at December 31, 2018 is $60 million. The approved life and curve for this account is 65 R3. Discussions with Company personnel indicated the Company has a Transmission Line Refurbishment program in place and has started replacing 50 year old poles. Yukon expects this to continue in the future to address its aging infrastructure. Periodically poles are replaced without having to replace the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 50 R3 for this account. A representative curve is shown below.



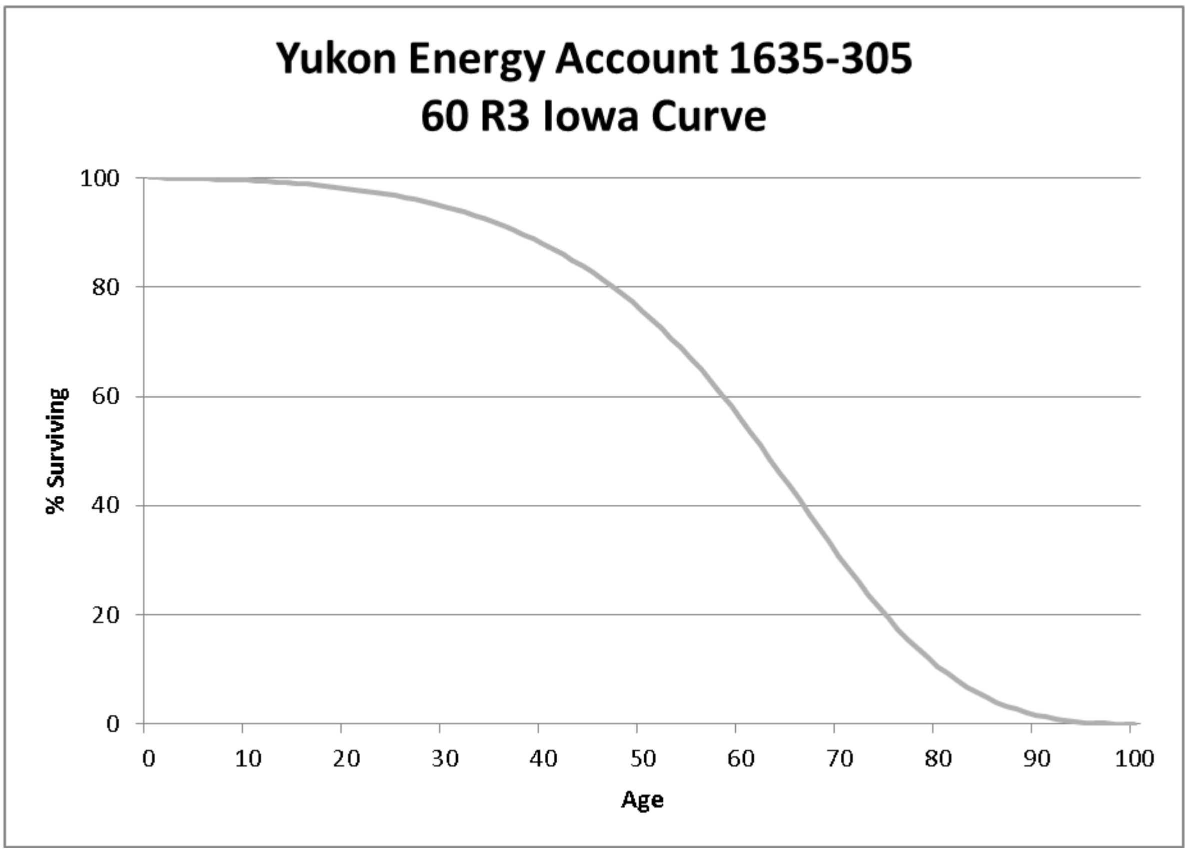
Account 1635-304 Main Trx - Brushing 60 R3

This account consists of brushing and clearing costs associated with main transmission lines and associated facilities. The plant balance in this account at December 31, 2018 is $14.1 million. The approved life and curve for this account is 50 R3. Discussions with operations indicated the life of brush clearing should mirror the life of overhead conductor, which uses a 60 year life. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel and judgment, this study recommends moving to a 60 R3 for this account. A representative curve is shown below.



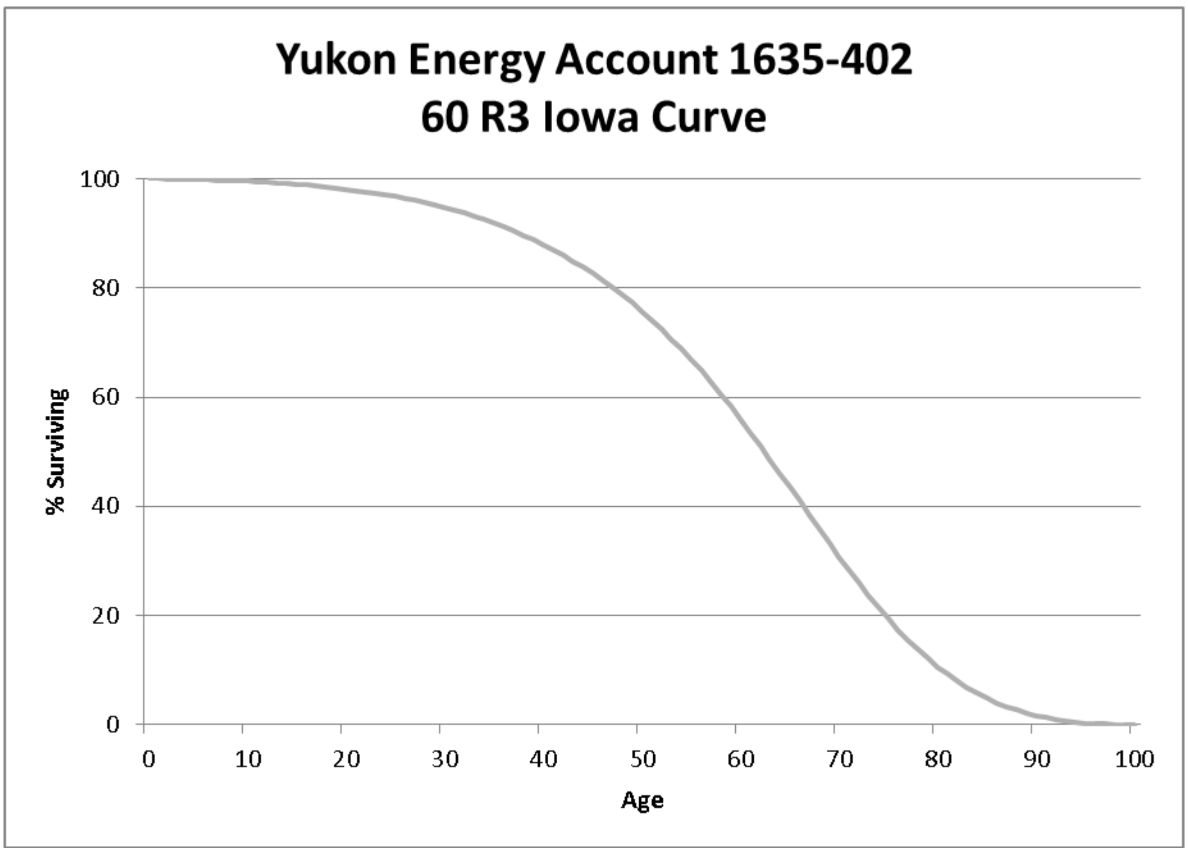
Account 1635-305 Main Trx – Survey Costs 60 R3

This account consists of land survey costs associated with the main transmission facilities. The plant balance in this account at December 31, 2018 is $3.5 million. The approved life and curve for this account is 50 R2.5. Discussions with operations stated the life of survey costs should mirror the life of overhead conductor, which uses a 60 year life. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel and judgment, this study recommends moving to a 60 R3 for this account. A representative curve is shown below.



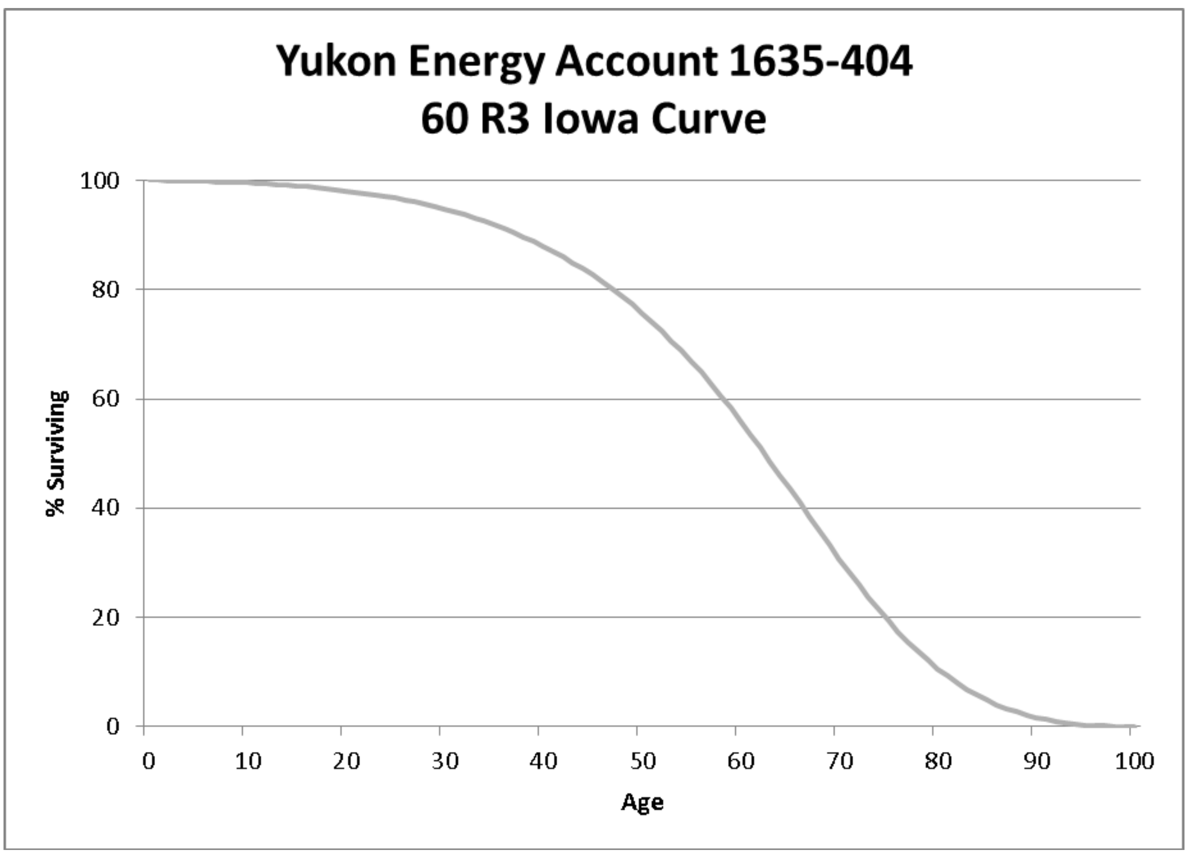
Account 1635-402 Main Trx – O/H Conductors/Poles 60 R3

This account consists of overhead conductors associated with transmission operations. The plant balance in this account at December 31, 2018 is $20.6 million. The approved life and curve for this account is 50 R3. Discussions with operational personnel estimate the life of transmission conductor to be about 10 years longer than distribution conductor, which is moving to a 50 year life. Additionally, the Company periodically replaces the poles without replacing the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 60 R3 for this account. A representative curve is shown below.



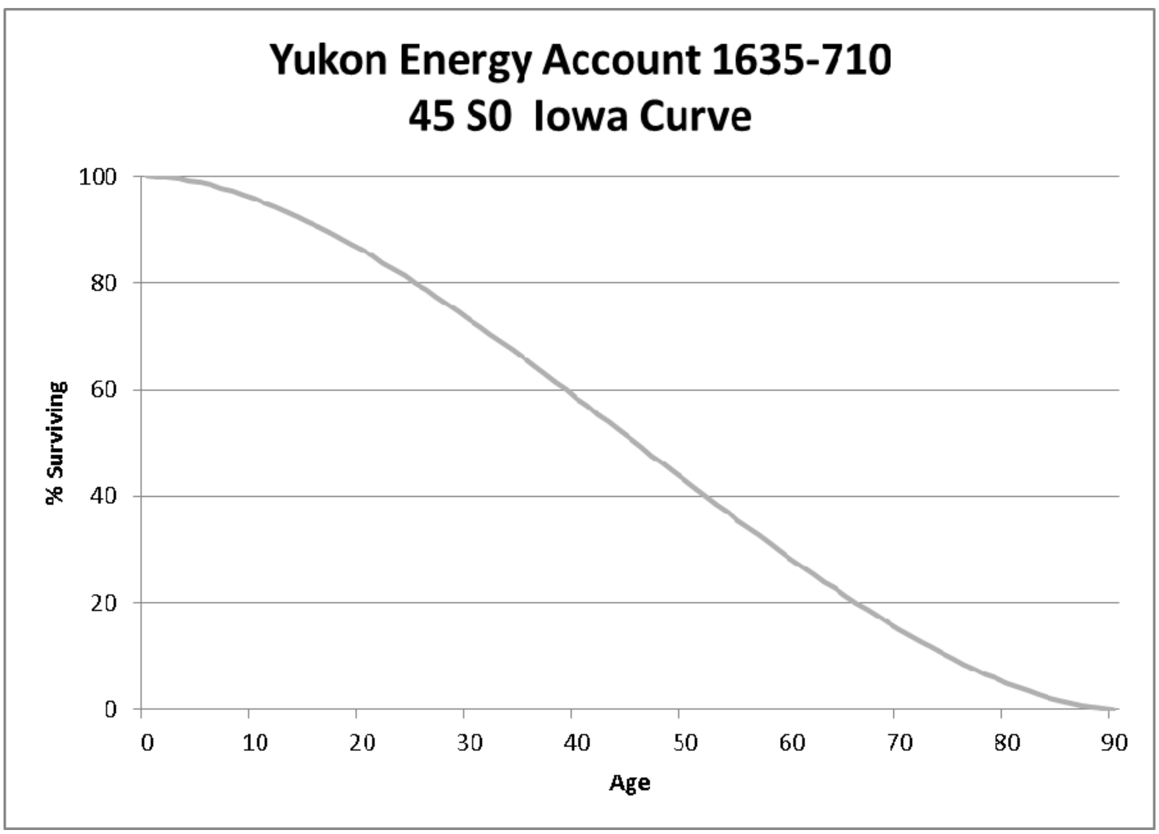
Account 1635-404 Main Trx – O/H Conductors/Towers 60 R3

This account consists of overhead conductor used in transmission operations. The plant balance in this account at December 31, 2018 is $278 thousand. The approved life and curve for this account is 50 R3. Discussions with operational personnel estimate the life of transmission conductor to be about 10 years longer than distribution conductor, which is moving to a 50 year life. Additionally, the Company periodically replaces the poles/towers without replacing the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 60 R3 for this account. A representative curve is shown below.



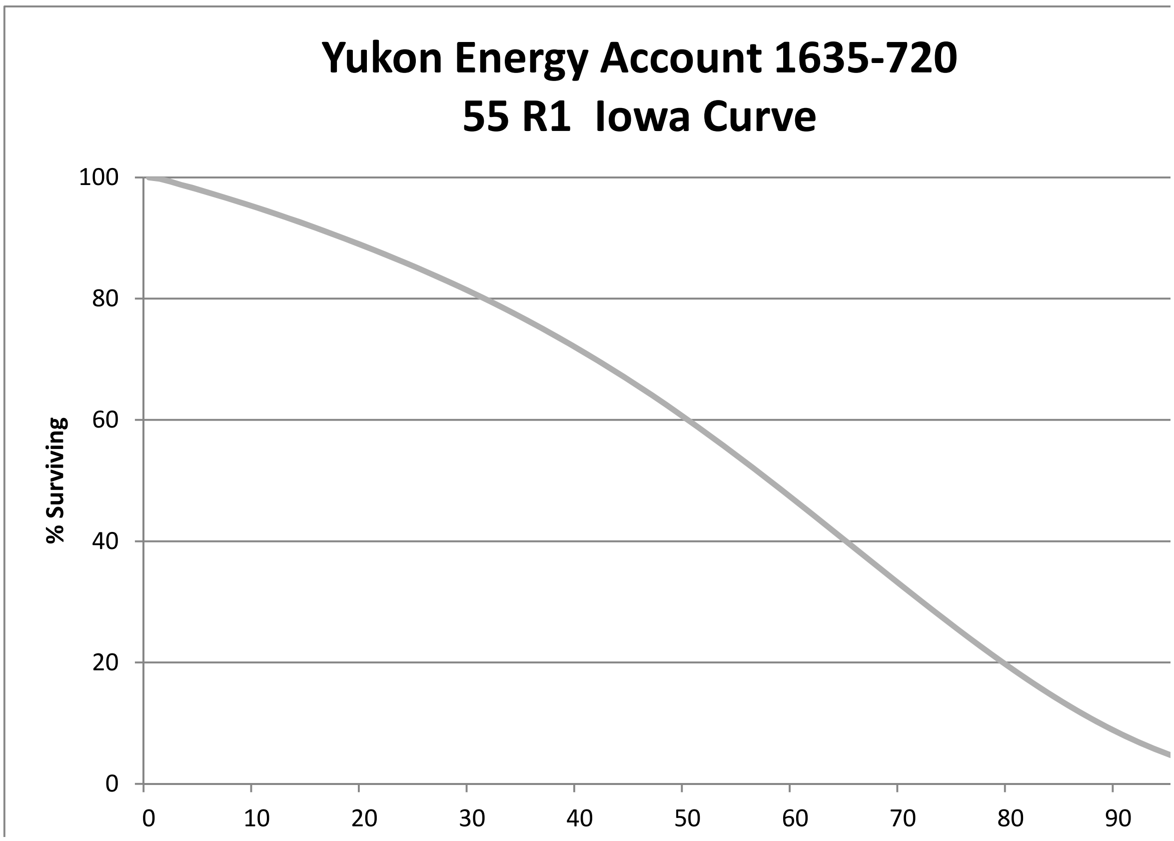
Account 1635-710 Main Trx – Substation Equipment 45 S0

This account consists of bus compartments, batteries, control equipment, transformers, breakers, and other related station equipment used in transmission operations. The plant balance in this account at December 31, 2018 is $66.6 million. The approved life and curve for this account is 54 S0. Discussions with Company personnel indicated they are experiencing a shorter life for the assets in this account due to the increasing amount of short lived electronic assets at the stations. Operations also stated that transformers typically last between 40 to 50 years; breakers have a 35 year life for OCB and 50 years for SF6. Several breakers have already been replaced in 2018 and 2019. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 45 S0 for this account. A representative curve is shown below.



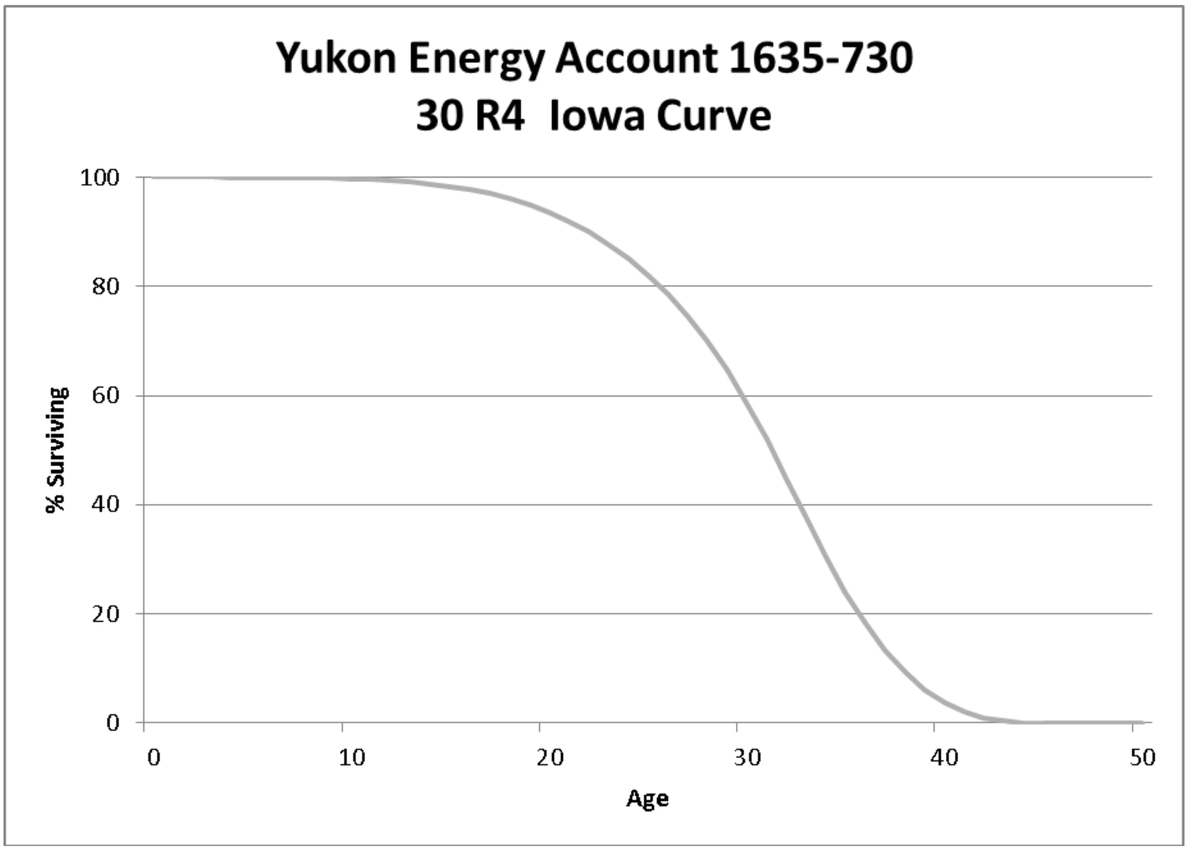
Account 1635-720 Main Trx – Substation Buildings 55 R1

This account consists of buildings at transmission substations. The plant balance in this account at December 31, 2018 is $1.5 million. The approved life and curve for this account is 55 R1. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retaining a 55 R1 for this account. A representative curve is shown below.



Account 1635-730 Main Trx – Substation Fences 30 R4

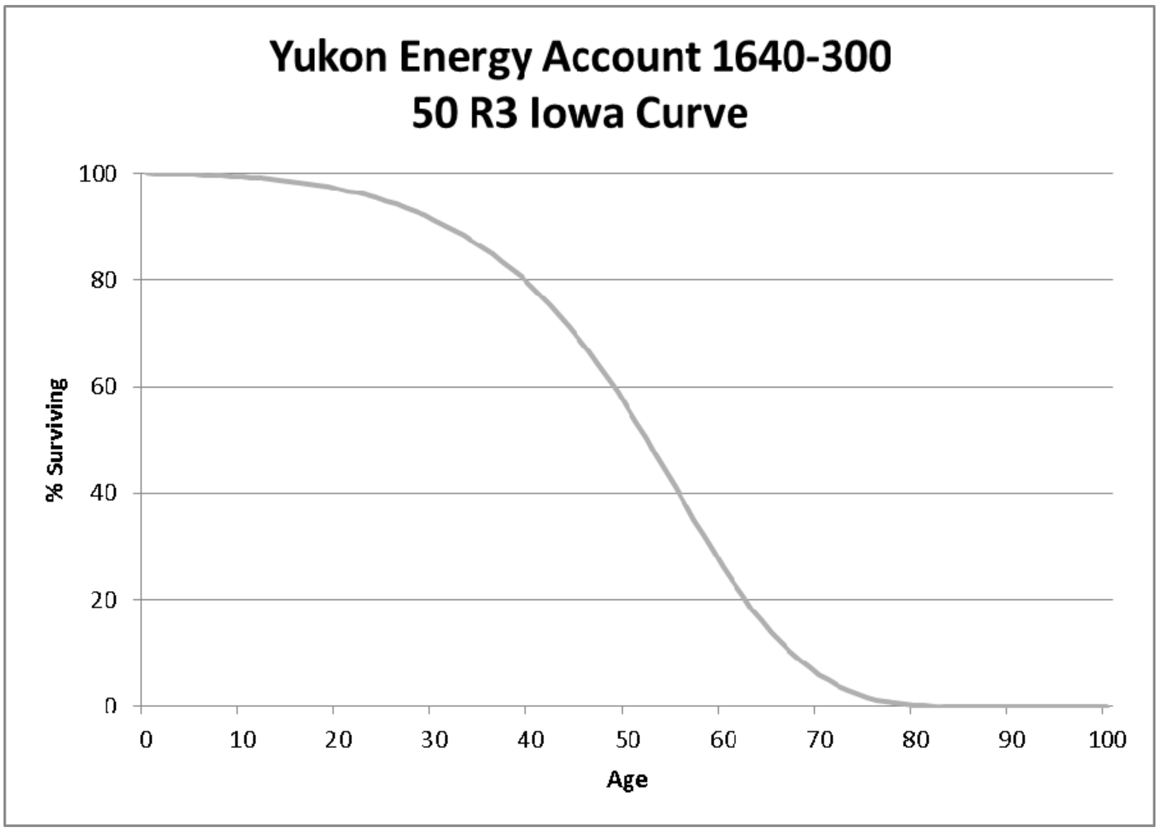
This account consists of fences located at transmission substations. The plant balance in this account at December 31, 2018 is $274 thousand. The approved life and curve for this account is 20 R4. Company personnel believe that substation fencing would last longer than 20 years. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 30 R4 for this account. A representative curve is shown below.



SUB TRANSMISSION LINES

Account 1640-300 Sub Trx – Poles & Fixtures 50 R3

This account consists of poles, fixtures, and other related assets used in transmission operations, including anchors, brackets, cross arms, braces, and foundations. The plant balance in this account at December 31, 2018 is $4.1 million. The approved life and curve for this account is 45 R3. Discussions with Company personnel indicated the Company has a Transmission Line Refurbishment program in place and has started replacing 50 year old poles. Yukon expects this program to continue in the future to address its aging infrastructure. Periodically poles are replaced without having to replace the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 50 R3 for this account. A representative curve is shown below.

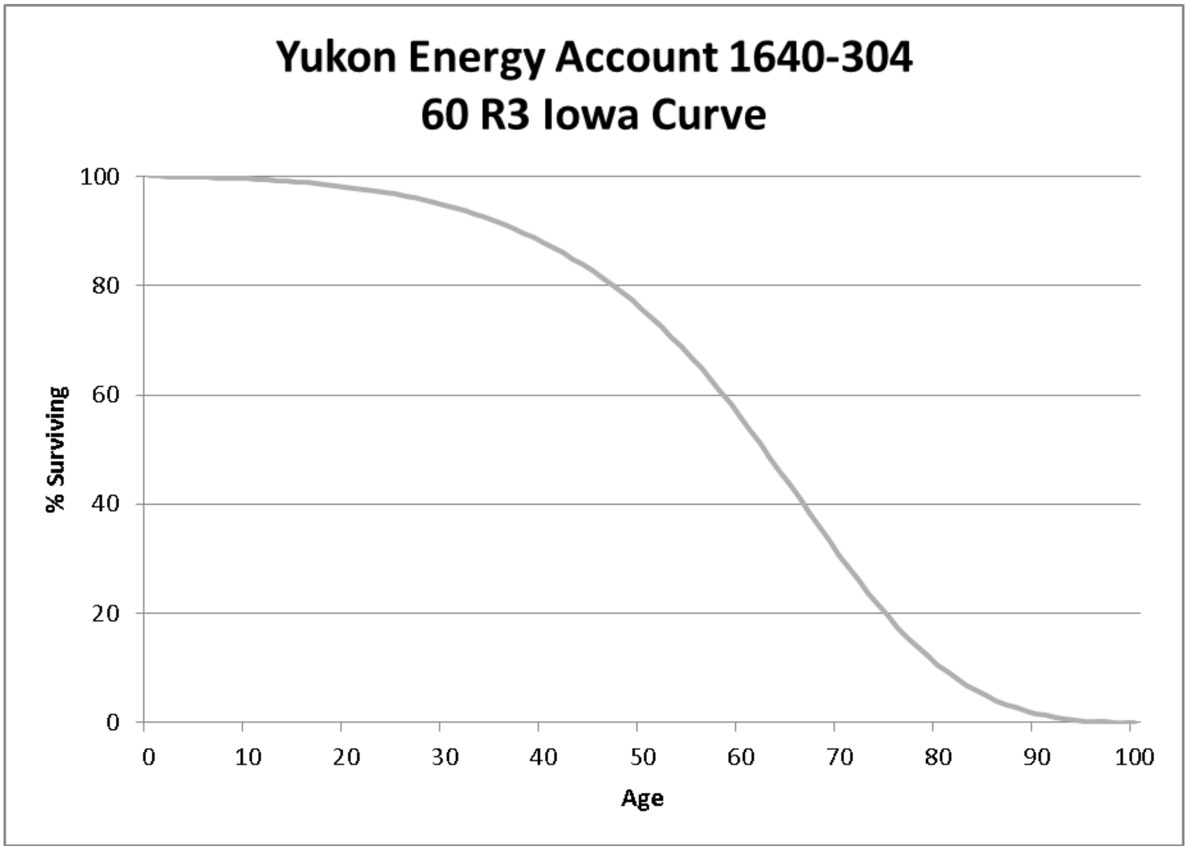


Account 1640-301 Sub Trx – Poles & Fixtures Minto Mines 12 SQ

This account consists of poles, fixtures, and other related assets used in transmission operations at Minto Mines, including anchors, brackets, cross arms, braces, and foundations. The plant balance in this account at December 31, 2018 is $2.6 million. The approved life and curve for this account is 12 SQ. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the 12 SQ for this account. No graph is shown for this account.

Account 1640-304 Sub Trx – Brushing 60 R3

This account consists of brushing and clearing costs associated with main transmission lines and associated facilities. The plant balance in this account at December 31, 2018 is $42 thousand. The approved life and curve for this account is 50 R3. There was insufficient transactional data for an actuarial life analysis. Based on information provided by Company personnel and judgment, this study recommends moving to a 60 R3 for this account. A representative curve is shown below.



Account 1640-306 Sub Trx – Brushing Minto Mines 12 SQ

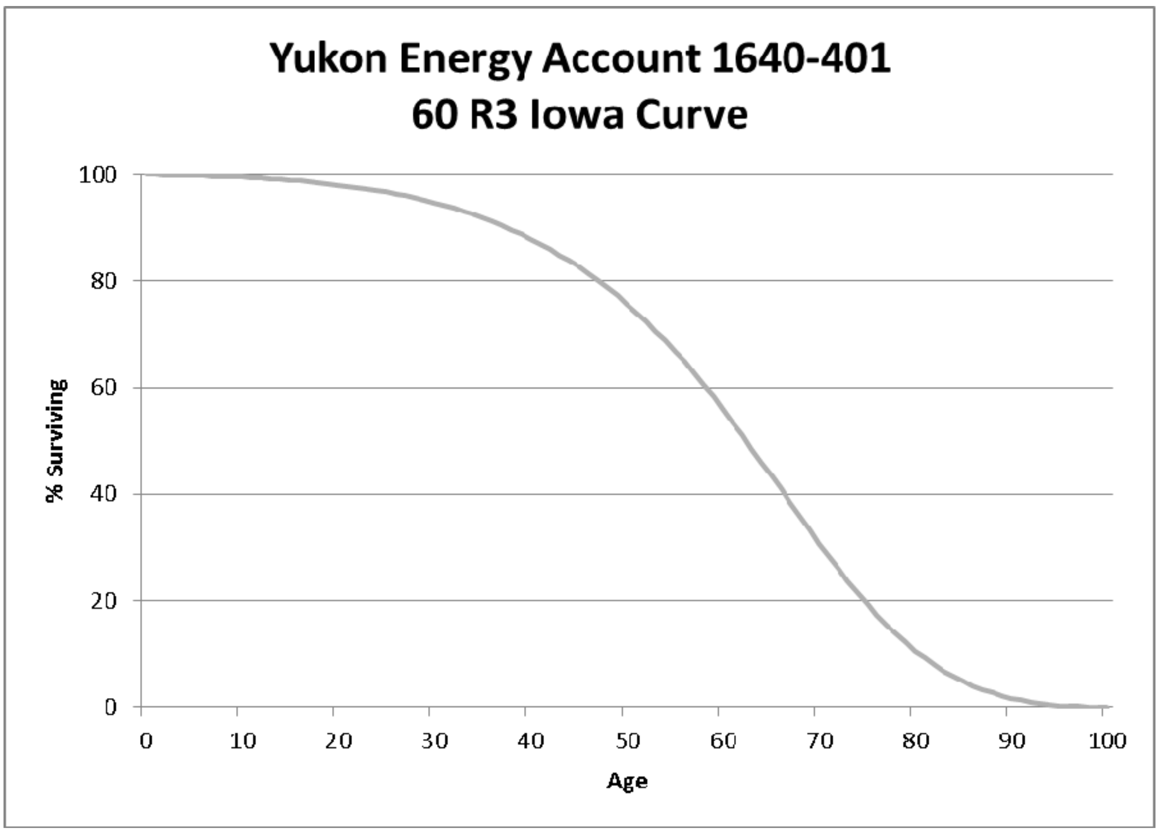
This account consists of brushing and clearing costs associated with main transmission lines at Minto Mines. The plant balance in this account at December 31, 2018 is $433 thousand. The approved life and curve for this account is 12 SQ. Based on information provided by Company personnel and judgment, this study recommends retention of the existing 12 SQ for this account. No graph is shown for this account.

Account 1640-307 Sub Trx – Survey Costs Minto Mines 12 SQ

This account consists of buildings, structures, and other related assets used in hydro production, including elevator upgrades, bridge work, and gate house improvements. The plant balance in this account at December 31, 2018 is $95 thousand. The approved life and curve for this account is 12 SQ. Based on information provided by Company personnel and judgment, this study recommends retention of the existing 12 SQ for this account. No graph is shown for this account.

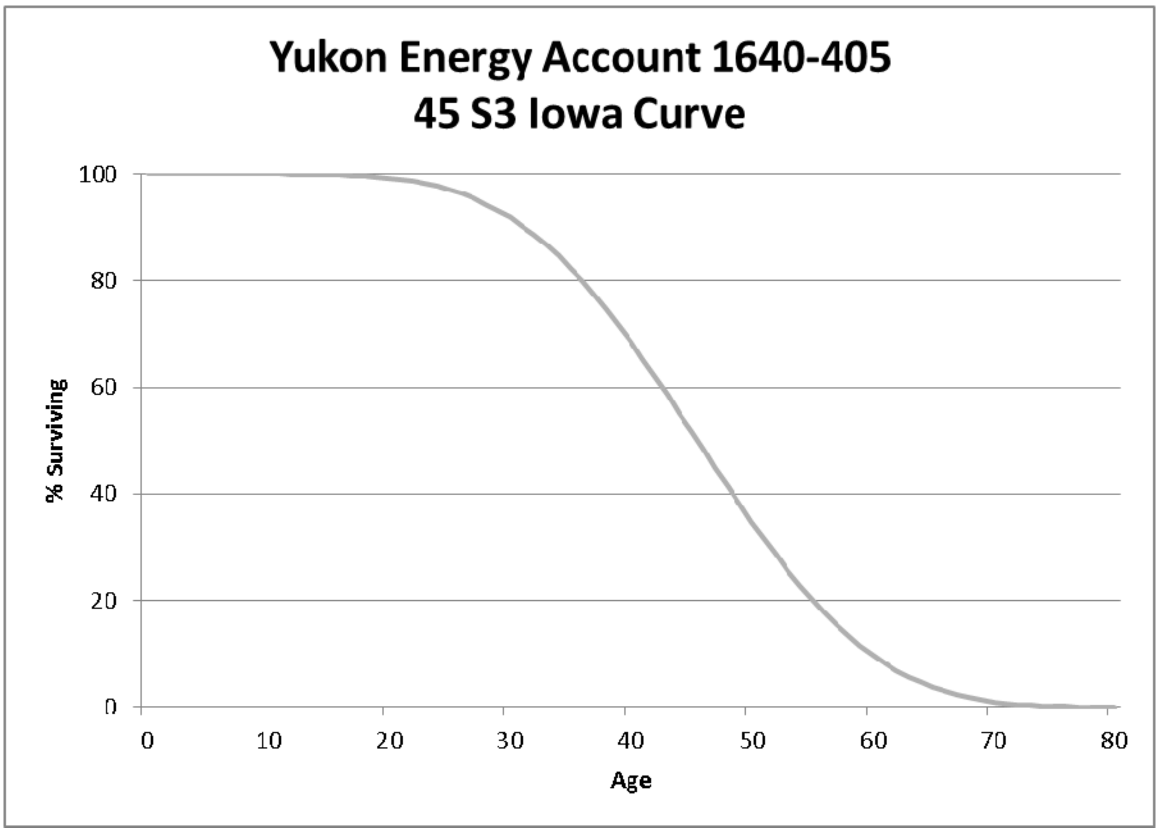
Account 1640-401 Sub Trx – O/H Conductors 60 R3

This account consists of overhead conductors and devices used in transmission operations, including armor rods, brackets, circuit breakers, switches, and other line accessories. The plant balance in this account at December 31, 2018 is $1.8 million. The approved life and curve for this account is 45 R3. Discussions with operational personnel indicated they estimate the life of transmission conductor to be about 10 years longer than distribution conductor, which is moving to a 50 year life. Additionally, the Company periodically replaces the poles without replacing the conductor. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 60 R3 for this account. A representative curve is shown below.



Account 1640-405 Sub Trx – Underground Conductors and Conduit 45 S3

This account consists of underground conduit and devices used in transmission operations, including ground rods and wires, concrete and paving work, and tunnels and bracing. The plant balance in this account at December 31, 2018 is $84 thousand. The approved life and curve for this account is 45 S3. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends retention of the existing 45 S3 for this account. A representative curve is shown below.

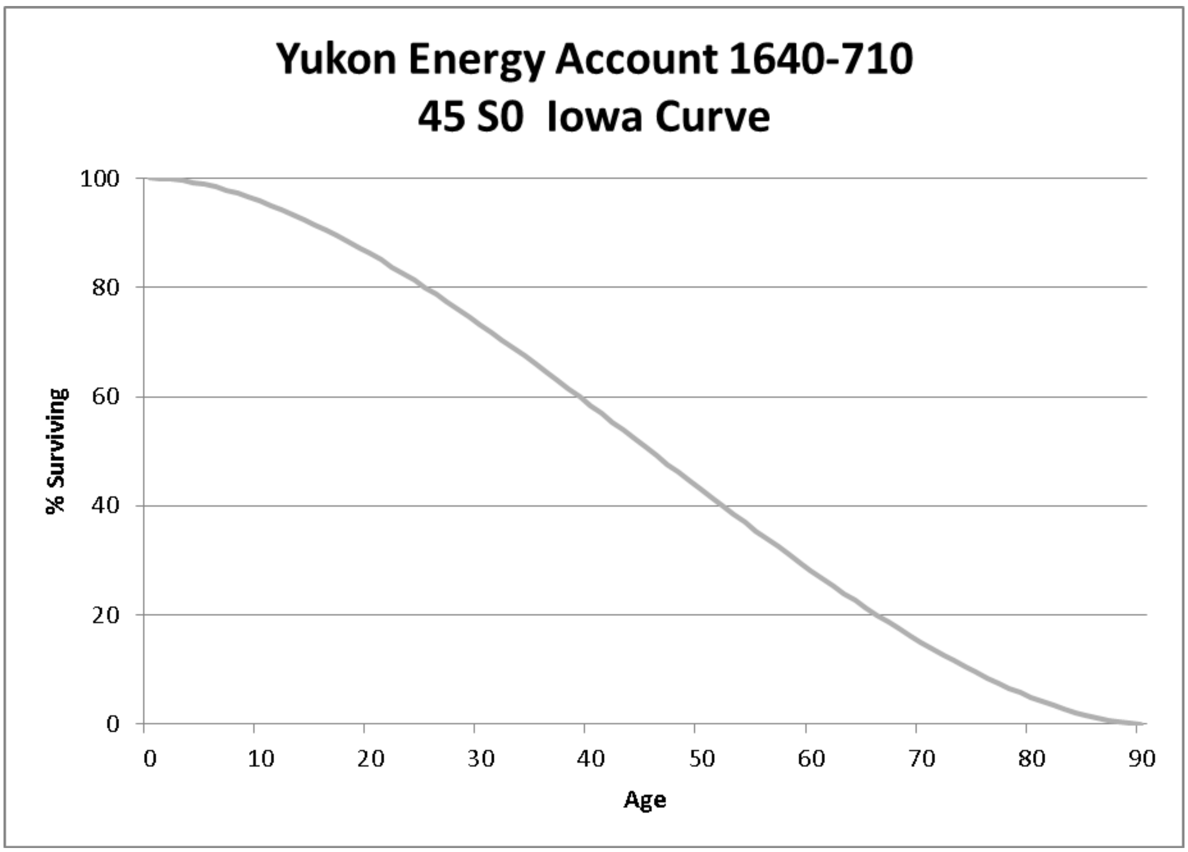


Account 1640-407 Sub Trx – Overhead Conductors Minto Mines 12 SQ

This account consists of overhead conductors and devices used in transmission operations at Minto Mines, including armor rods, brackets, circuit breakers, switches, and other line accessories. The plant balance in this account at December 31, 2018 is $921 thousand. The approved life and curve for this account is 12 SQ. Based on information provided by Company personnel and judgment, this study recommends retention of the existing 12 SQ for this account. No graph is shown for this account.

Account 1640-710 Sub Trx – Substation Equipment 45 S0

This account consists of bus compartments, batteries, control equipment, transformers, breakers, and other related station equipment used in transmission operations. The plant balance in this account at December 31, 2018 is $8 million. The approved life and curve for this account is 40 S0. There was insufficient transactional data for an actuarial life analysis. Based on type of assets, information provided by Company personnel and judgment, this study recommends moving to a 45 S0 for this account. A representative curve is shown below.



Account 1640-711 Sub Trx – Substation Equipment Minto Mines 12 SQ

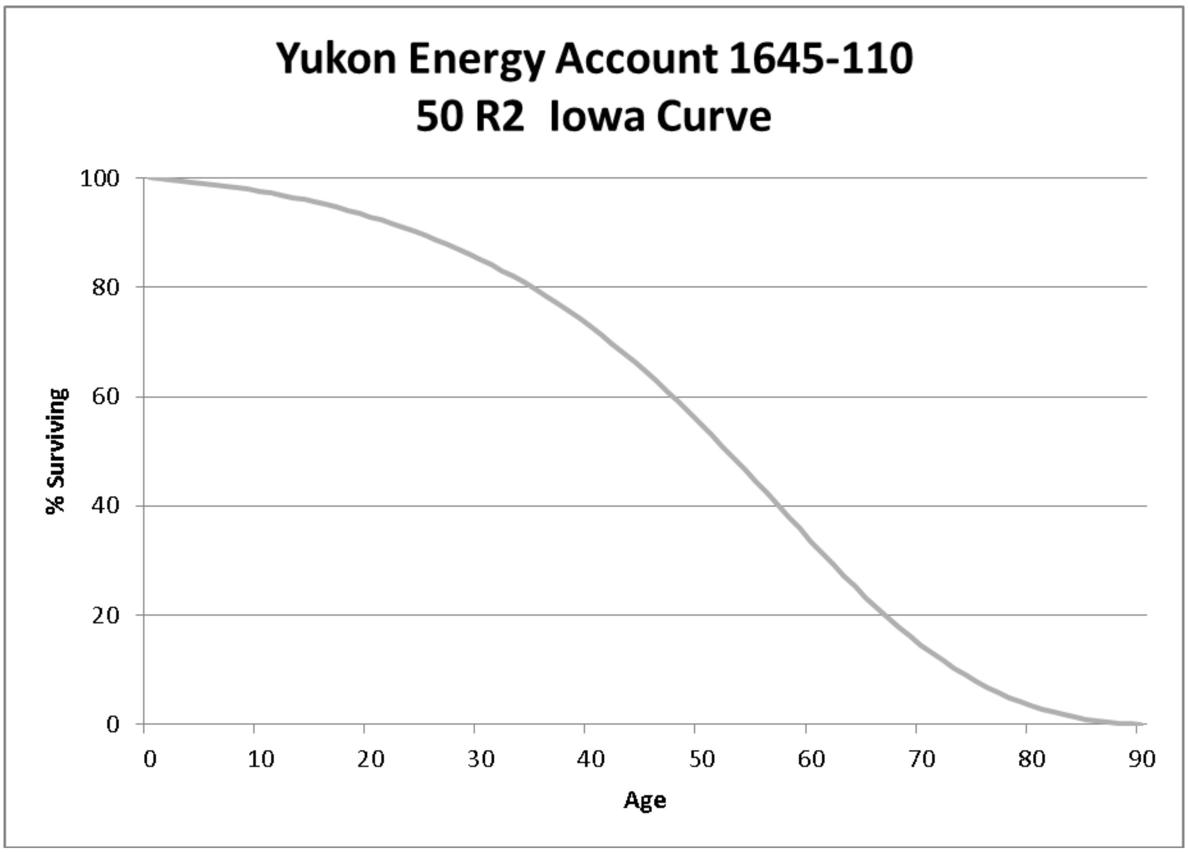
This account consists of substation equipment and upgrades at Minto Mines, including bus compartments, batteries, control equipment, transformers, breakers, and other related station equipment. The plant balance in this account at December 31, 2018 is $6.9 million. The approved life and curve for this account is 12 SQ. Based on information provided by Company personnel and judgment, this study recommends retention of the existing 12 SQ for this account. No graph is shown for this account.

BUILDINGS & OTHER EQUIPMENT

This function consists of all general office buildings, furniture, and equipment used to support overall utility service and operations.

Account 1645-110 Bldg & Otr – Survey Costs Land 50 R2

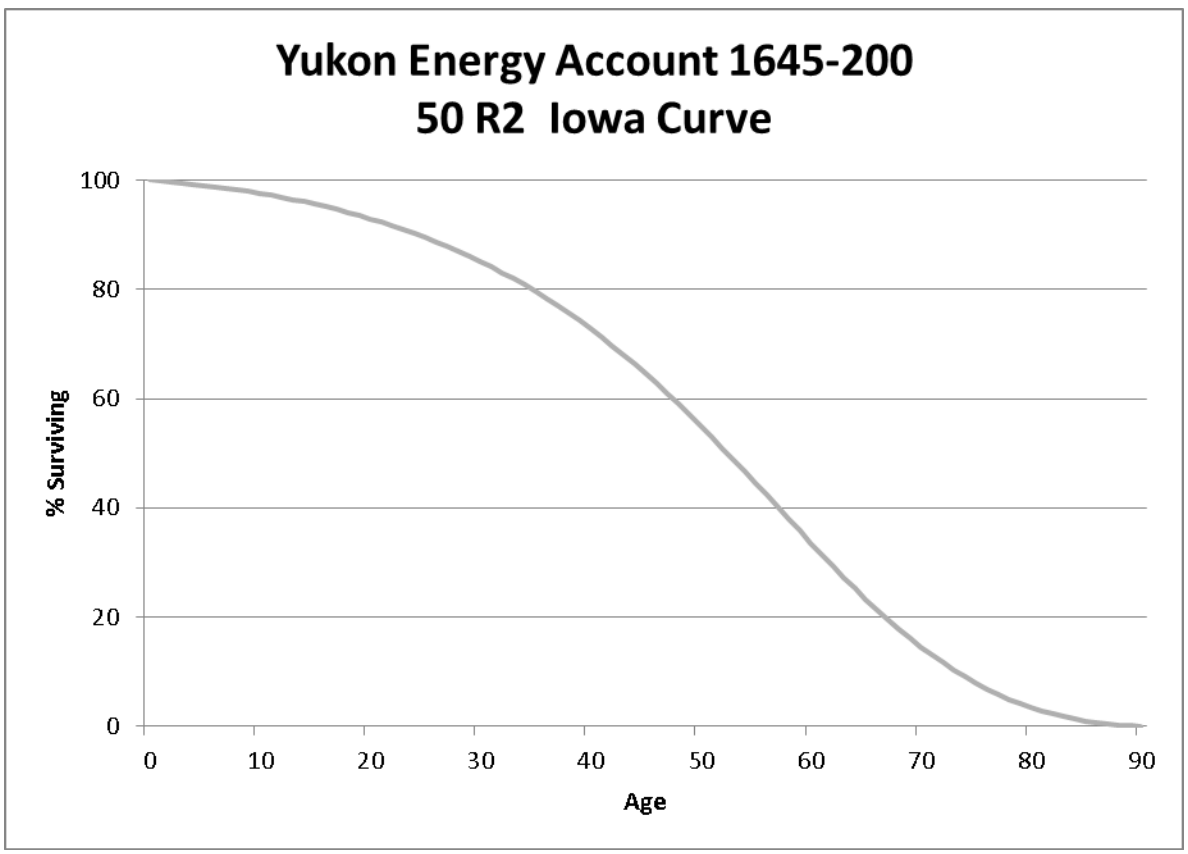
This account includes the cost associated with land survey of general plant. The plant balance in this account at December 31, 2018 is $4 thousand. The approved life and curve for this account is 50 R2. There is limited activity, not enough to change from existing. This study proposes retention of 50 R2 at this time. A representative curve is shown below.



65

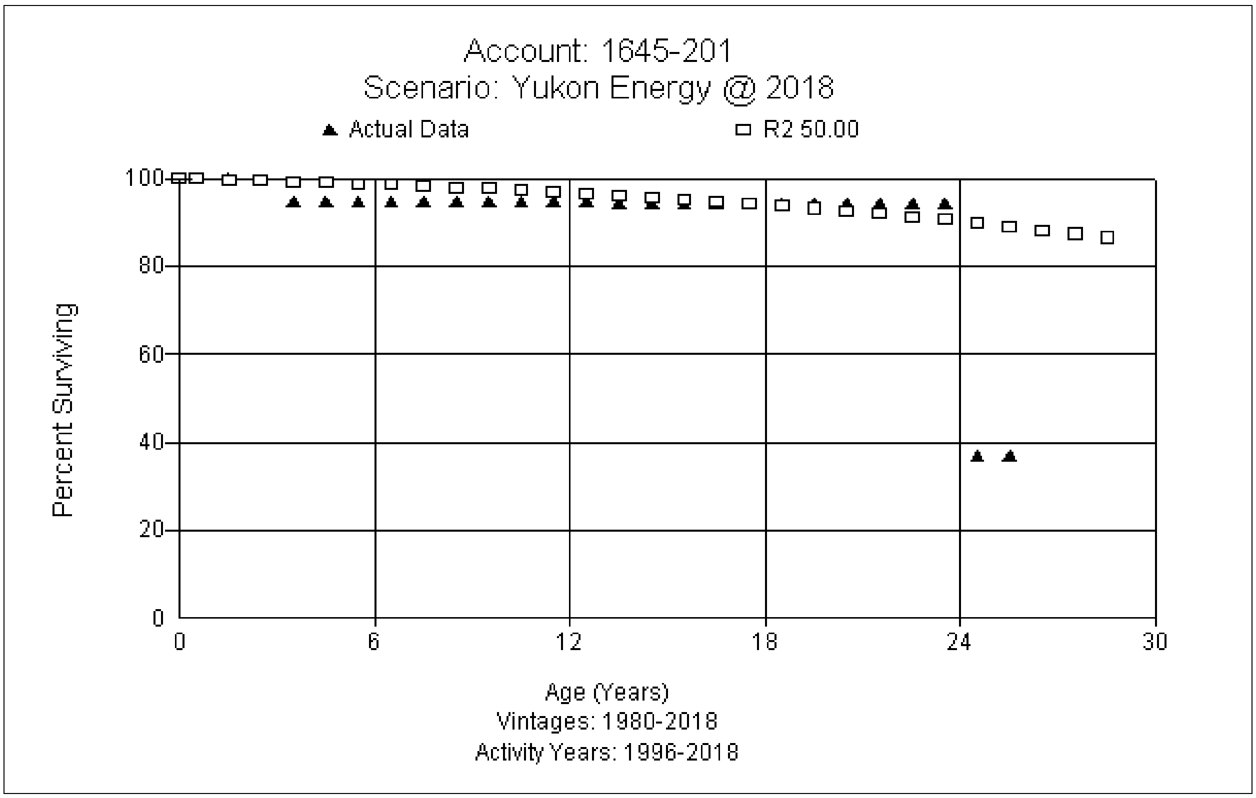
Account 1645-200 Bldg & Otr – Structures and Improvements Hydro 50 R2

This account includes the cost associated with the structures and improvements associated with a hydro facility including berms, signage, roads, boilers, and other related assets used to support general operations. The plant balance in this account will be $2.2 million, which reflects a transfer of $10.3 million from this account into account 1615-201. The approved life and curve for this account is 40 R2.5. There is no historical activity to analyze. Discussions with Company personnel indicated these structures are on the water so they would have a little shorter life for various components. However, the existing 40 years is shorter than what would be expected. The newer buildings are more technology driven and have a little less longevity than the older built structures. There was insufficient transactional data for an actuarial life analysis. Based on the type and use of assets and judgment, this study proposes moving to 50 R2 at this time. A representative curve is shown below.



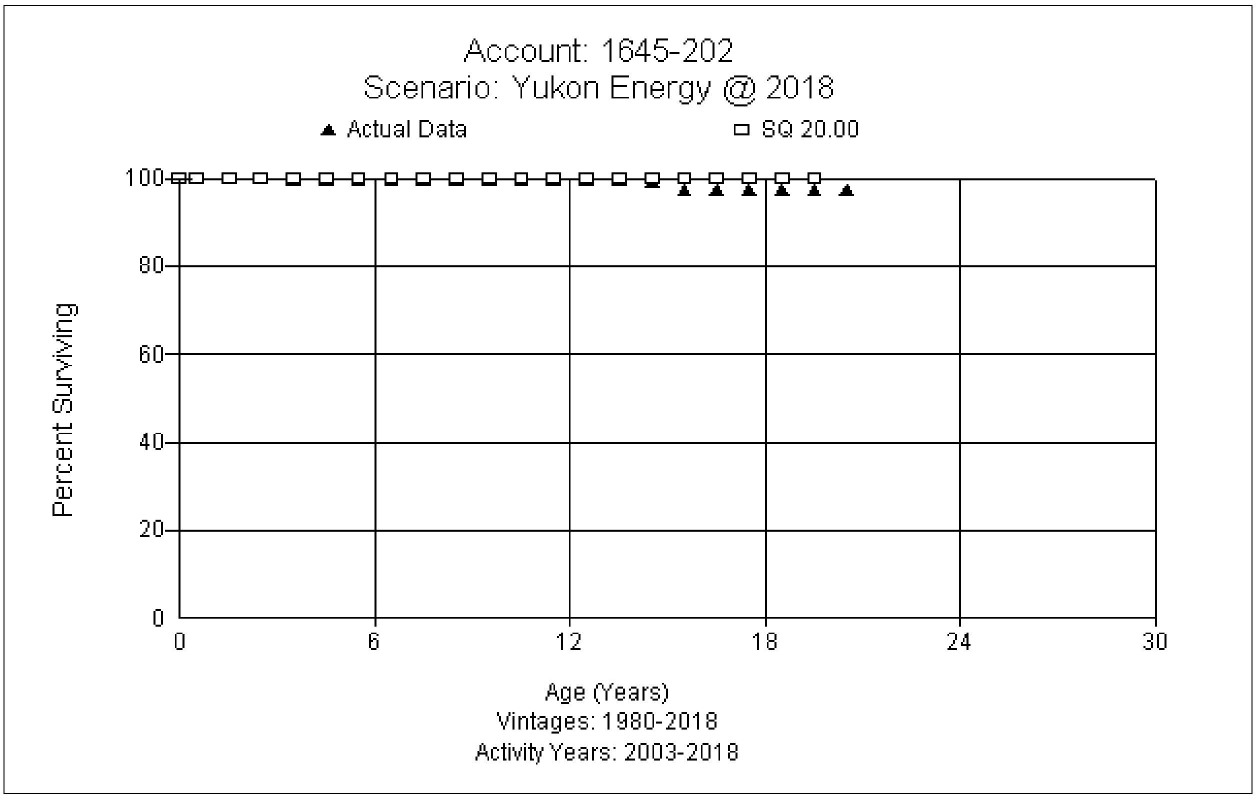
Account 1645-201 Bldg & Otr – Building and Improvements 50 R2

This account includes the cost associated with buildings and improvements that includes staff housing, warehouses, offices, fencing, building envelopes, fish hatchery, yard work, guard rails. The plant balance in this account at December 31, 2018 is $10.1 million. The approved life and curve for this account is 55 R1. There is very limited historical activity to analyze. Discussions with Company personnel indicated many of the assets in this account have shorter lives than the building. Based on the limited indications from the actuarial analysis, mix and type of assets, and judgment, this study proposes moving to 50 R2 at this time. A graph of the observed life table versus the recommended curve type is shown below.



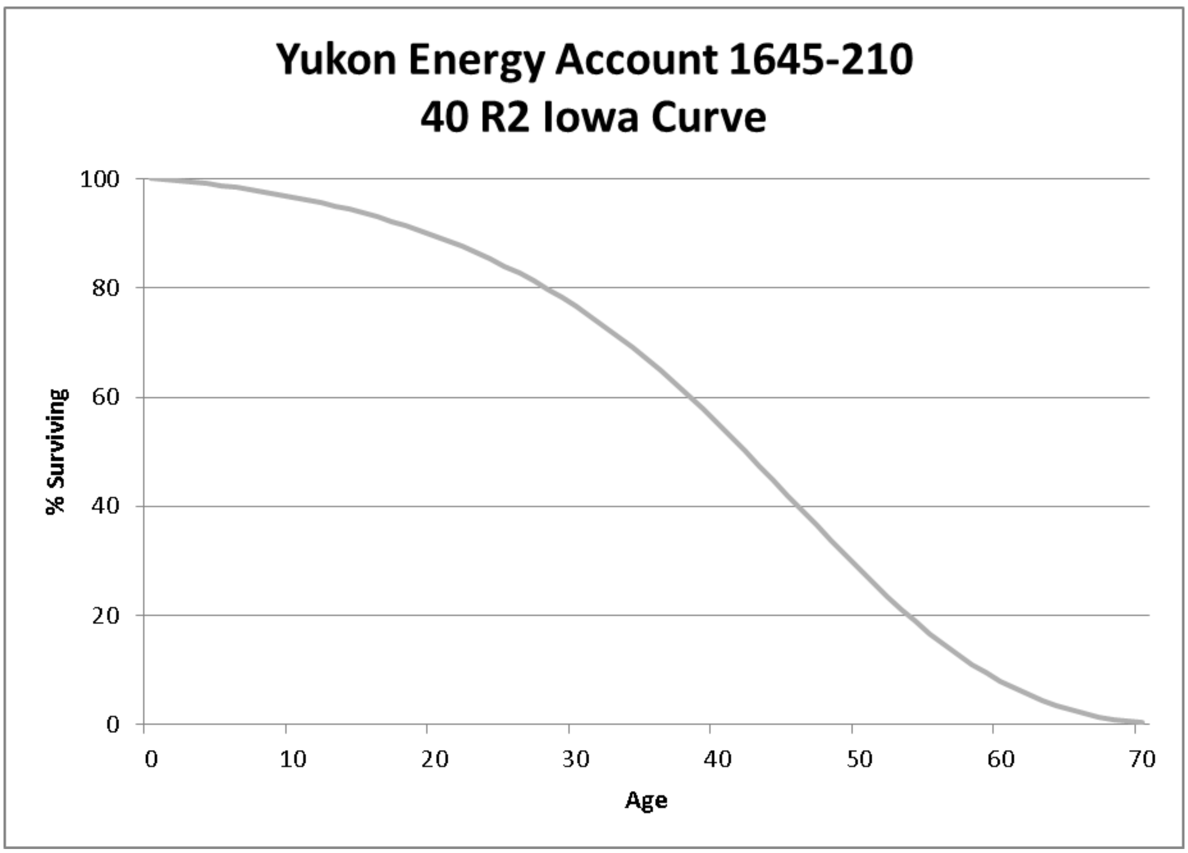
Account 1645-202 Bldg & Otr – Office Furniture & Equipment 20 SQ

This account includes the cost of office furniture and equipment owned by the utility and devoted to utility service and not permanently attached to buildings including desks, chairs, bookcases, filing cabinets, tables, and other related equipment. The plant balance in this account at December 31, 2018 is $1.7 million. The approved life and curve for this account is 20 SQ. Discussions with Company personnel indicated that when furniture is removed from a location, it is either transferred or disposed of. It is generally no reused. Based on the type and use of assets, and judgment, this study proposes retaining the existing 20 SQ at this time. A graph of the observed life table versus the recommended curve type is shown below.



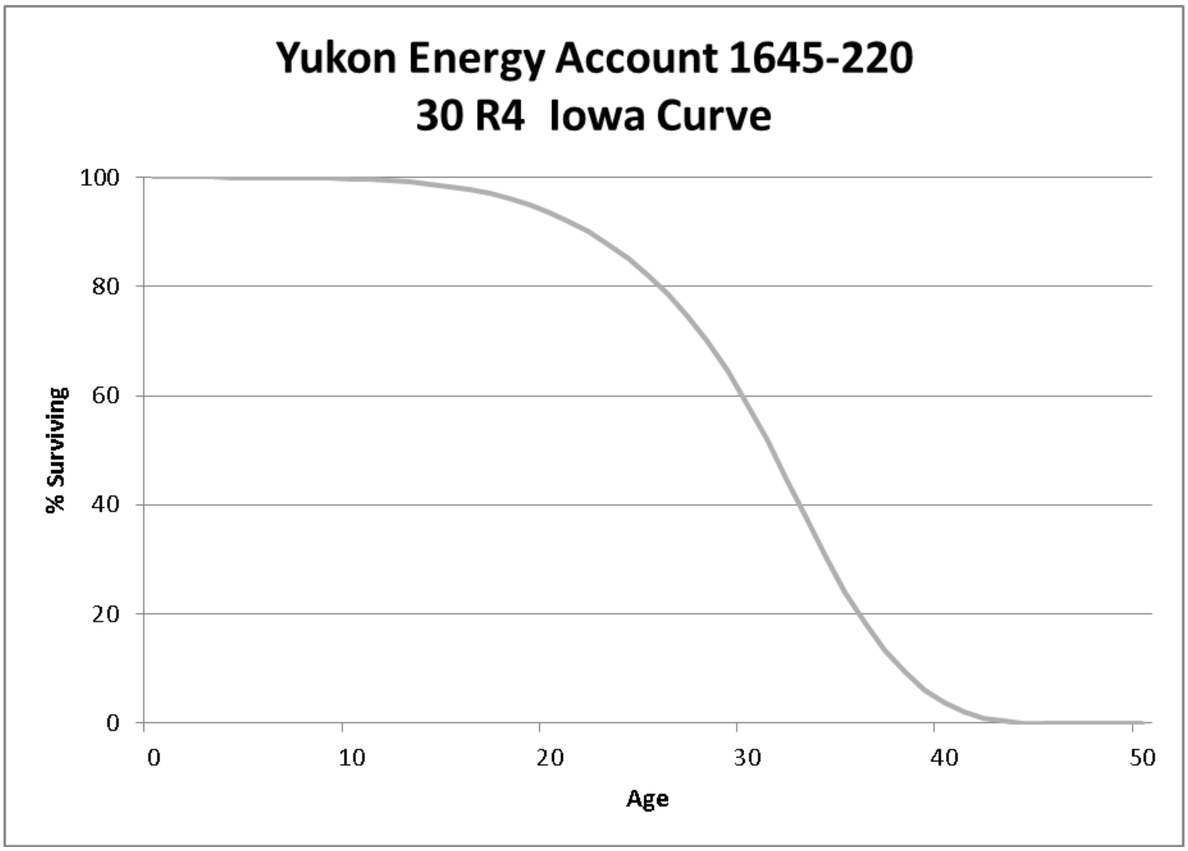
Account 1645-210 Bldg & Otr – Communication Site Towers 40 R2

This account includes the cost of communication site towers associated with general plant. The plant balance in this account at December 31, 2018 is $19 thousand. The approved life and curve for this account is 30 R2. There is no historical data to analyze. Discussions with Company personnel indicated the towers are for satellite and microwave equipment. They are designed for a 30 year life, but towers would likely have a longer life than 30 years. There was insufficient transactional data for an actuarial life analysis. Based on the type and use of assets, existing life, and judgment, this study proposes moving to 40 R2 at this time. A representative curve is shown below.



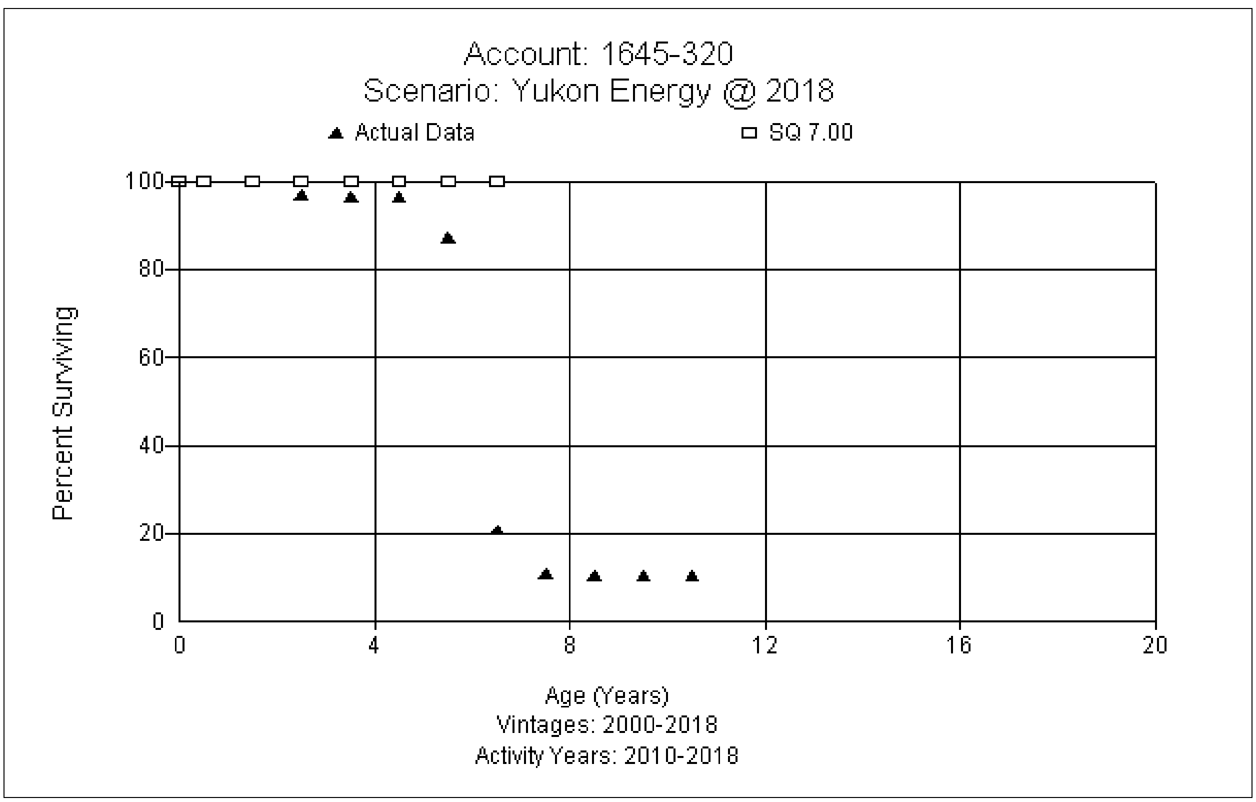
Account 1645-220 Bldg & Otr – Communication Site Fences 30 R4

This account shall include costs of communication site fences associated with general plant. The plant balance in this account at December 31, 2018 is $64 thousand. The approved life and curve for this account is 20 R4. There is no historical data to analyze. Discussions with Company personnel indicated fences should last longer than 20 years. There was insufficient transactional data for an actuarial life analysis. Based on the type of assets, existing life, Company input, and judgment, this study proposes moving to 30 R4 at this time. A representative curve is shown below.



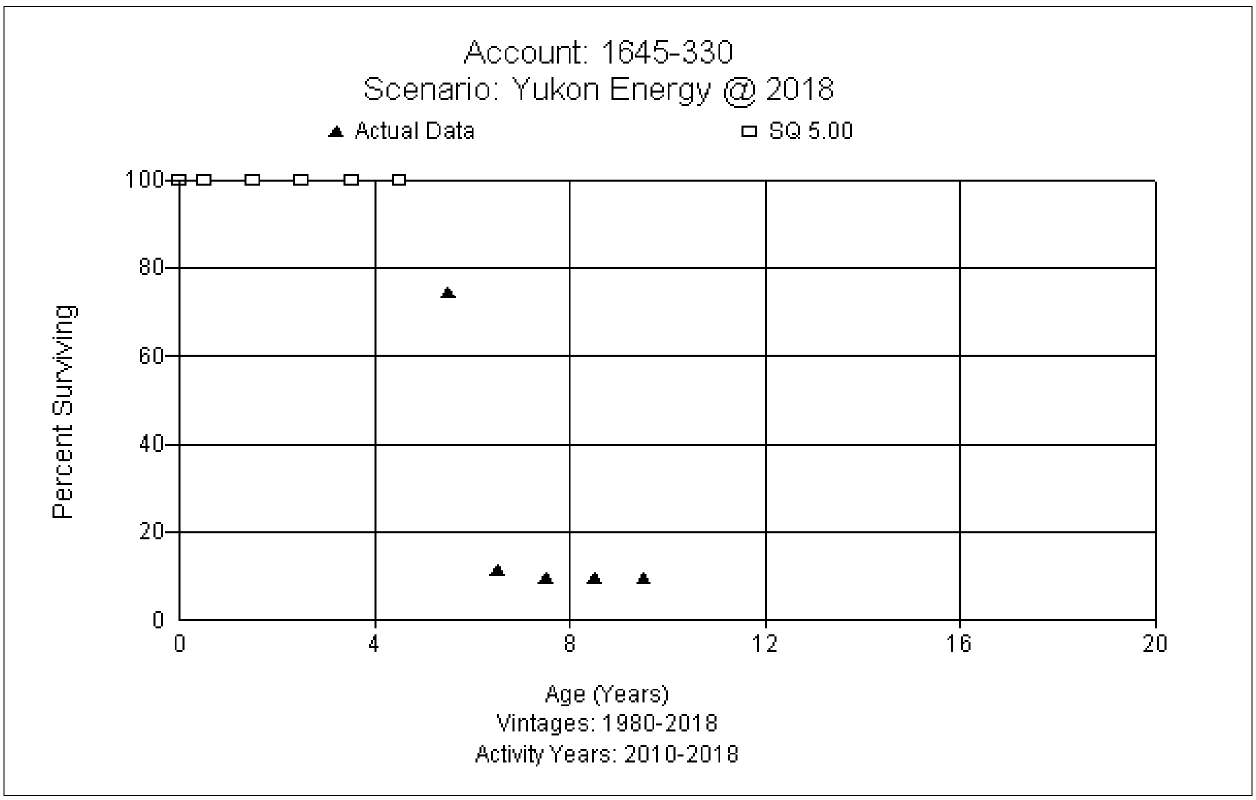
Account 1645-320 Bldg & Otr – Computer Hardware 7 SQ

This account includes the full cost of computer equipment (other than mainframe), which is owned and includes personal computers, printers, terminals, keyboards, storage devices and other related equipment. The plant balance in this account at December 31, 2018 is $1.7 million. The approved life and curve for this account is 5 SQ. Discussions with Company personnel indicated approximately 70 percent of workstations are four years old or older. They have not established a solid refresh cycle or plan yet. Company personnel expect the servers would have a longer life and believe a seven year life is reasonable for now. They expect the life to decrease as they implement and manage a plan. Based on the actuarial analysis, the type and use of assets, existing life, and judgment, this study proposes moving to 7 SQ at this time. A graph of the observed life table versus the recommended curve type is shown below.



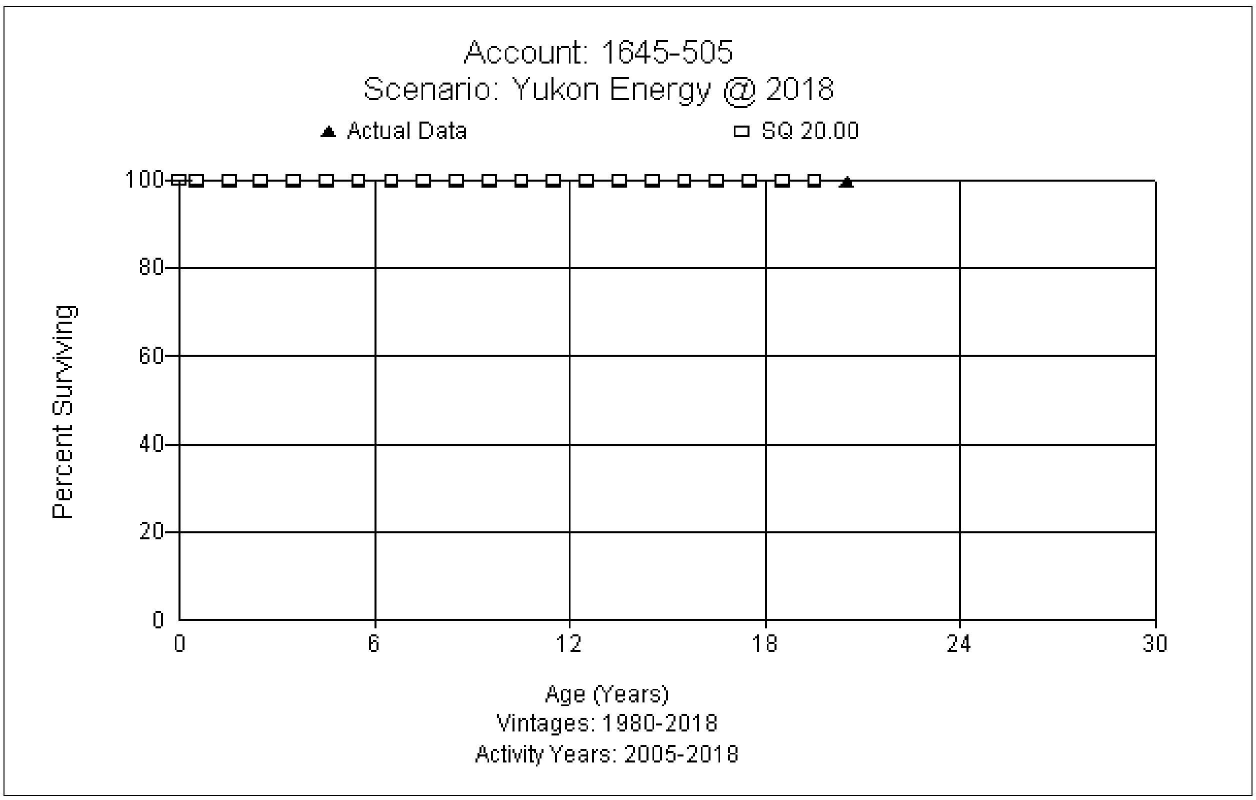
Account 1645-330 Bldg & Otr – Computer Software 5 SQ

This account includes the cost of computer software purchases, including upgrades, enhancements and maintenance. The plant balance in this account at December 31, 2018 is $304 thousand. The approved life and curve for this account is 5 SQ. Company plans to evaluate the individual software packages in the future for possible different life categorization. Based on the current analysis, type of assets, existing life, and judgment, this study proposes retention of 5 SQ at this time. A graph of the observed life table versus the recommended curve type is shown below.



Account 1645-505 Bldg & Otr – Tools and Instruments 20 SQ

This account includes the cost of tools, implements and equipment used on construction, repair work, general shops and garages including air compressors, auto repair equipment, gasoline pumps and storage tanks, hoists, machine tools, pumps, portable tools, and other related equipment. The plant balance in this account at December 31, 2018 is $1.7 million. The approved life and curve for this account is 20 SQ. Based on the current analysis, type of assets, existing life, and judgment, this study proposes retention of 20 SQ at this time. A graph of the observed life table versus the recommended curve type is shown below.

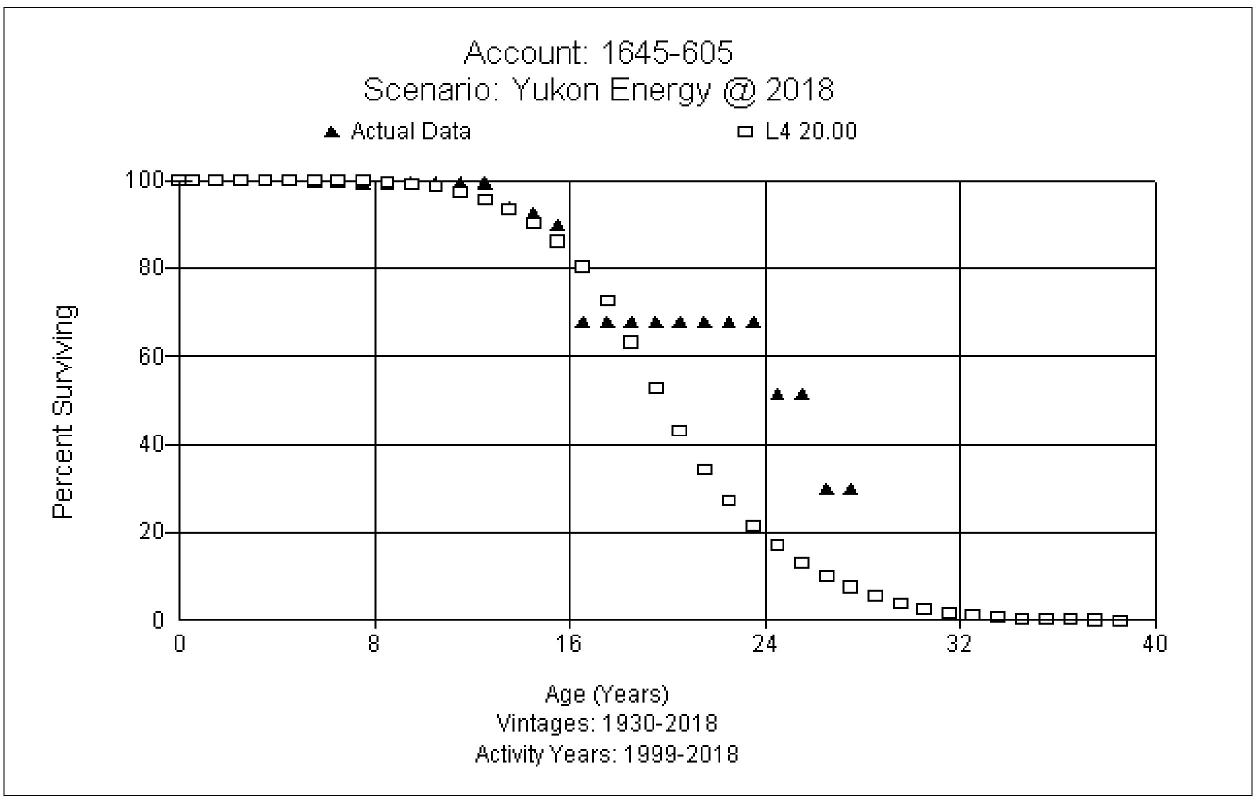


Account 1645-507 Bldg & Otr – Wind Monitoring Equipment 15 SQ

This account includes costs associated with wind monitoring equipment. This includes tall towers and ultrasonic anemometers. The plant balance in this account at December 31, 2018 is $14 thousand. The approved life and curve for this account is 20 SQ. There is no historical data to analyze. Discussions with Company personnel indicated there is one wind monitoring site, which will likely be out of this process within a year. Company believes it might be 10 years old now. Based on the type of assets, existing life, Company input, and judgment, this study proposes moving to 15 SQ at this time. No graph is shown for this account.

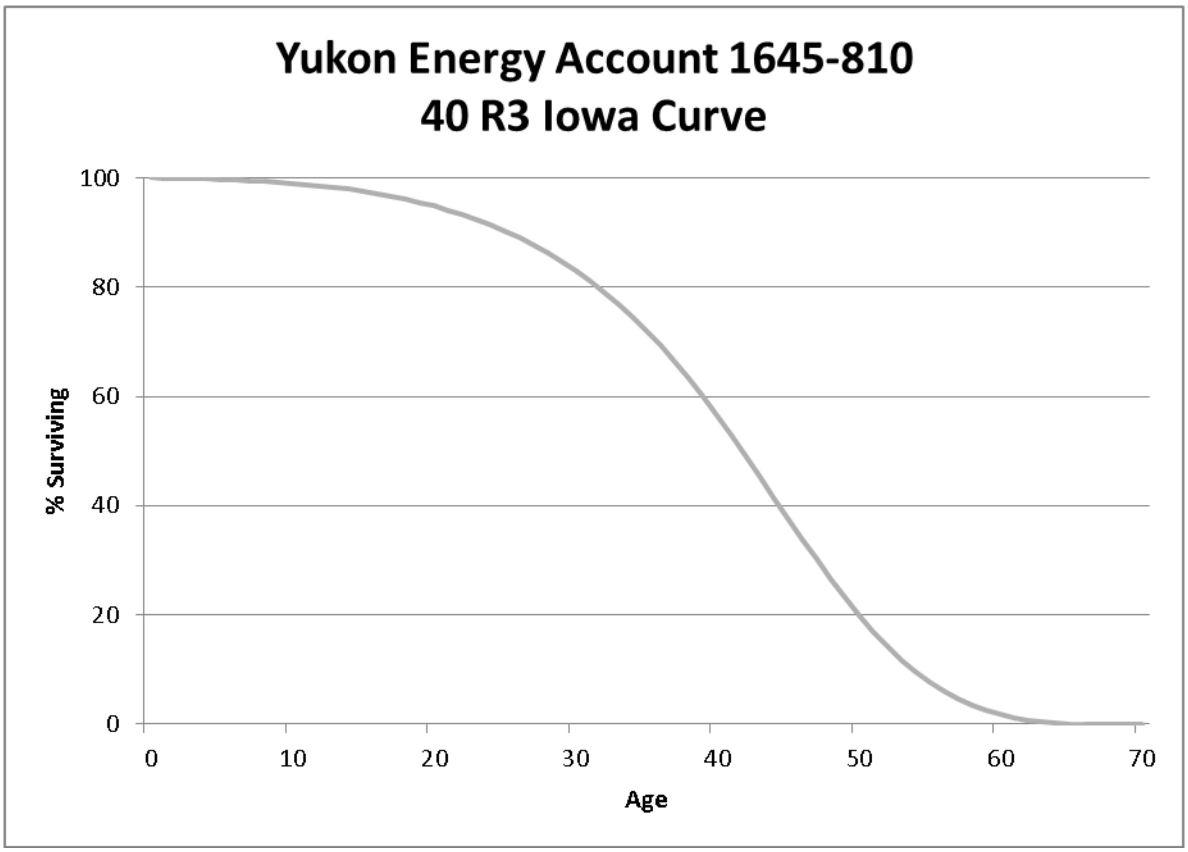
Account 1645-605 Bldg & Otr – Communication Equipment 20 L4

This account includes the installation costs of telephone, fibre optic and wireless equipment for general use in connection with utility operations and includes antennae, booths, cable, handsets, insulators, poles and fixtures, remote control equipment and line, storage batteries, switchboards, underground conduit and cable for telephone or fibre optics and other related equipment. The plant balance in this account at December 31, 2018 is $4.6 million. The approved life and curve for this account is 20 L4. Discussions with Company personnel indicated there is a variety of equipment types and varying lives. The life analysis indicates a life between 20-25 years. Based on the type and use of the equipment, Company input, life analysis indications, and judgment, this study proposes retention of 20 L4 at this time. A graph of the observed life table versus the recommended curve type is shown below.



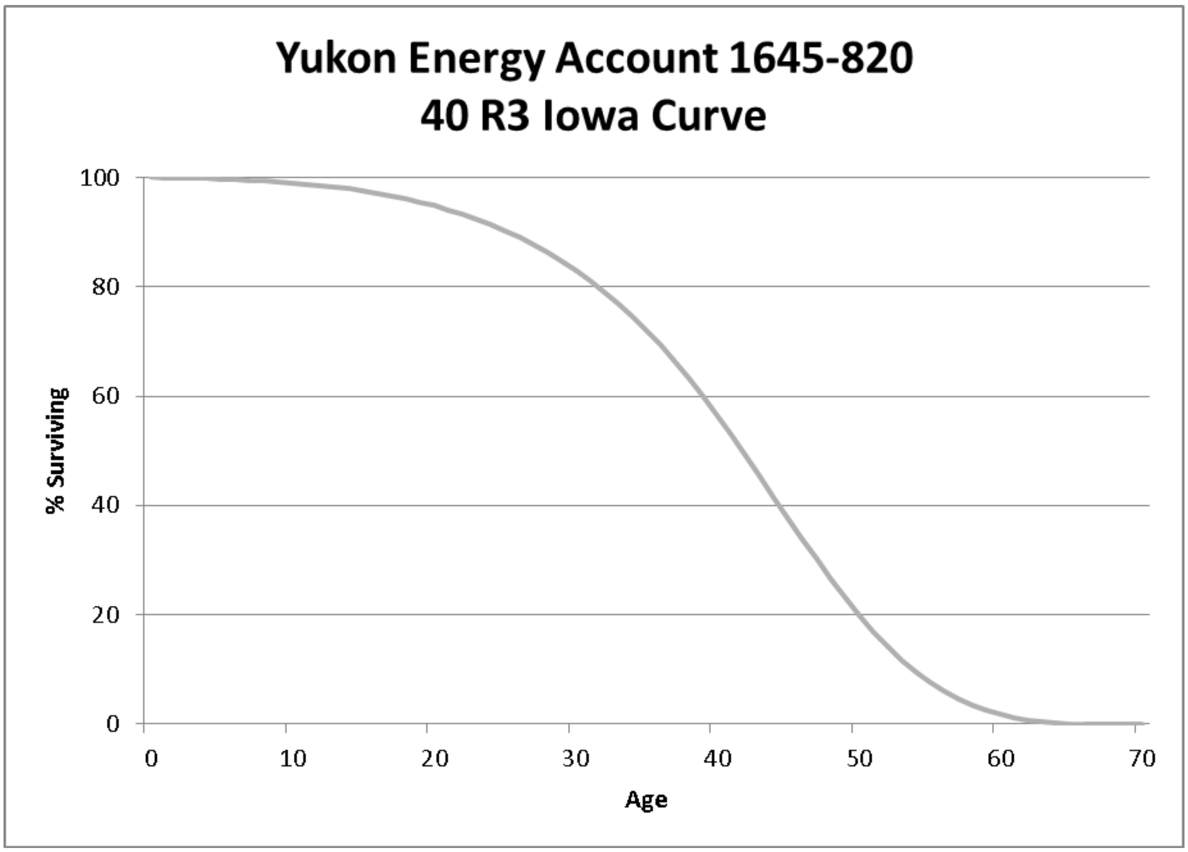
Account 1645-810 Bldg & Otr – Company Owned Houses/Land 40 R3

This account includes the costs of upgrades and maintenance associated with the land of houses owned by the company. The plant balance in this account at December 31, 2018 is $59 thousand. The approved life and curve for this account is 30 R3. Discussions with Company personnel indicated the newest house is from 2005 and the oldest is pre-1980. Company believes the existing life is too low. There is not enough historical experience for analysis. Based on the type of assets, Company input, and judgment this study proposes moving to 40 R3 for this account. A representative curve is shown below.



Account 1645-820 Bldg & Otr – Company Owned Houses/Buildings 40 R3

This account includes the cost of upgrades and maintenance associated with the buildings of houses owned by the company. The plant balance in this account at December 31, 2018 is $2.1 million. The approved life and curve for this account is 30 R3. There was insufficient transactional data for an actuarial life analysis. Based on the type of assets, Company input, and judgment, this study proposes moving to 40 R3 for this account. A representative curve is shown below.

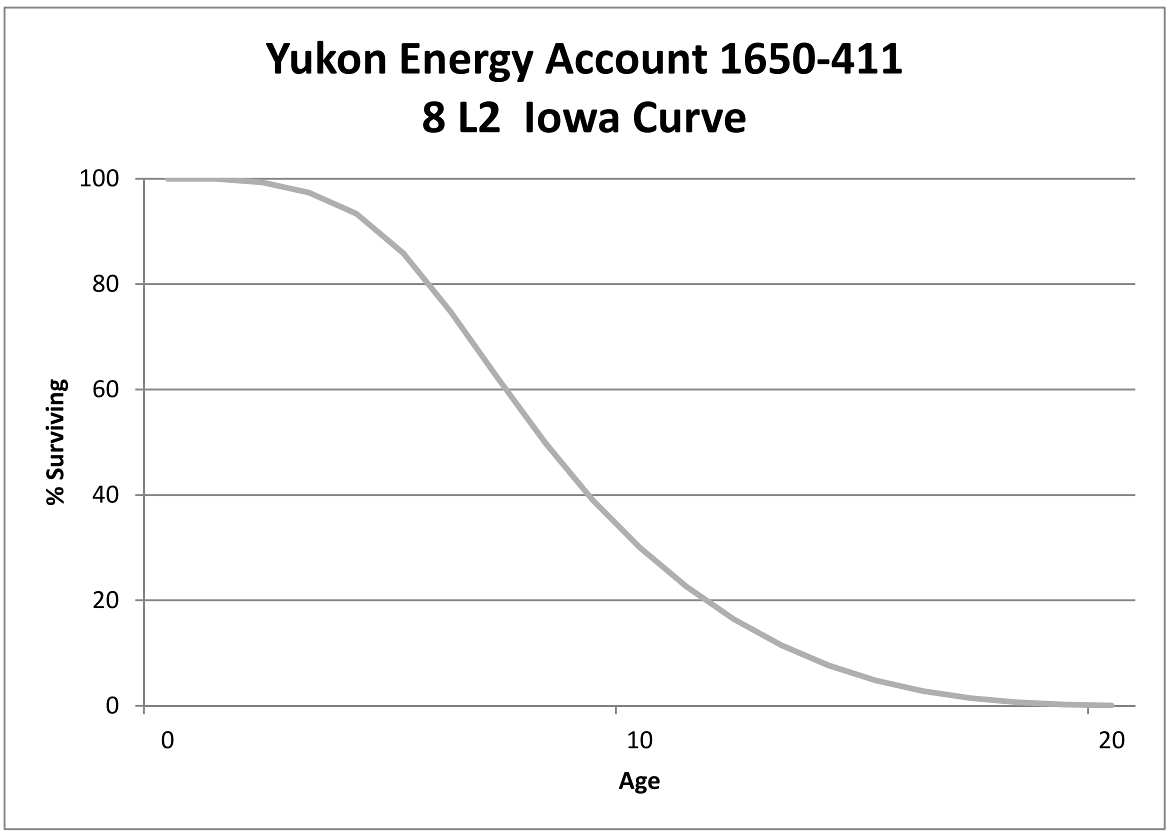


TRANSPORTATION

This function consists of all classes of cars, trucks, and other motorized utility vehicles used in general utility service.

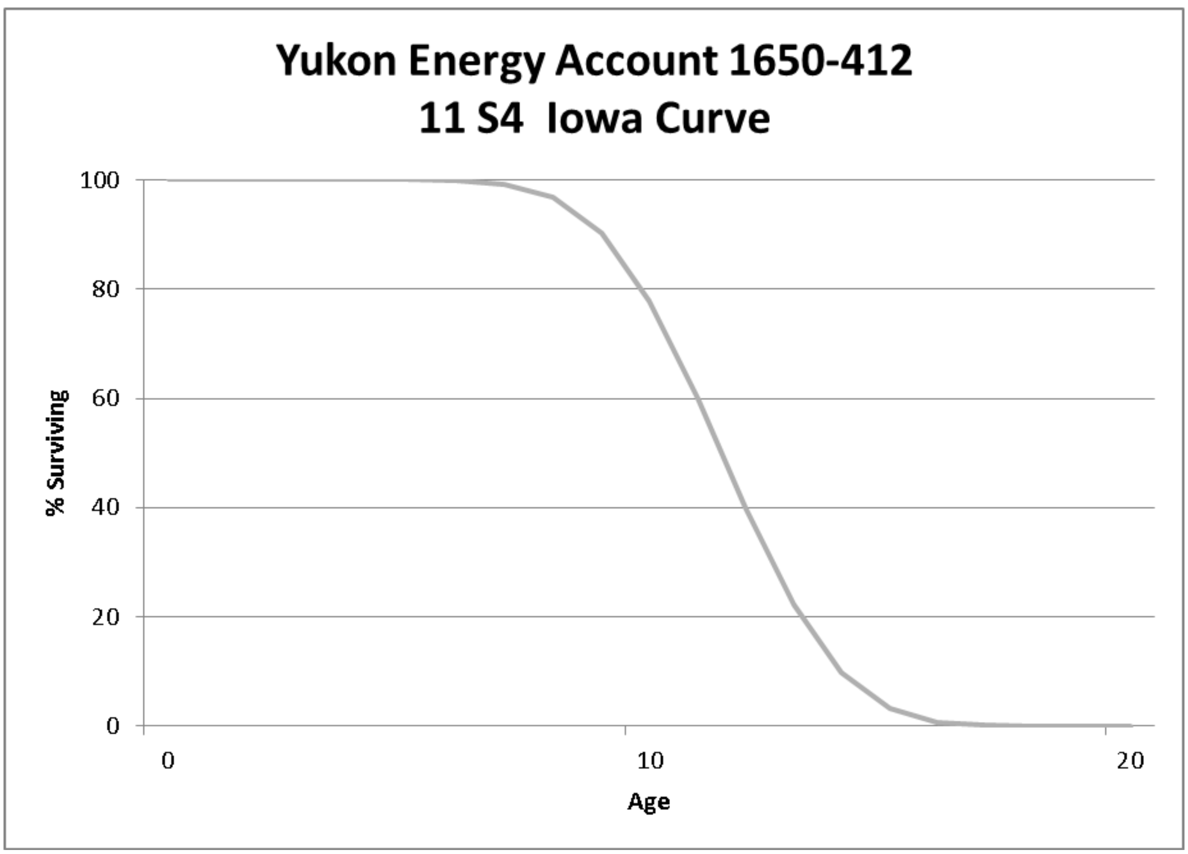
Account 1650-411 Trxptn – Utility Vehicles 8 L2

This account includes the cost of utility trailers, cargo trailers, ATVs, snowmobiles, and boats. The plant balance in this account at December 31, 2018 is $344 thousand. The approved life and curve for this account is 7 L2. Discussions with Company personnel indicated the line crews use these types of vehicles for seven years before it is retired. Company indicated that occasionally, a quad or snow mobile will move to a plant and have a longer life, but an estimated 80% of these types of assets do not. However, the life analysis indicates a longer life than existing and longer than what the Company expects, which ranges from 10 to 15 years. Giving consideration to the type and use of assets, Company input and expectations, we propose moving the average out to eight years to reflect the 20% of assets that remain longer. This study proposes 8 L2 for this account. A representative graph is shown below.



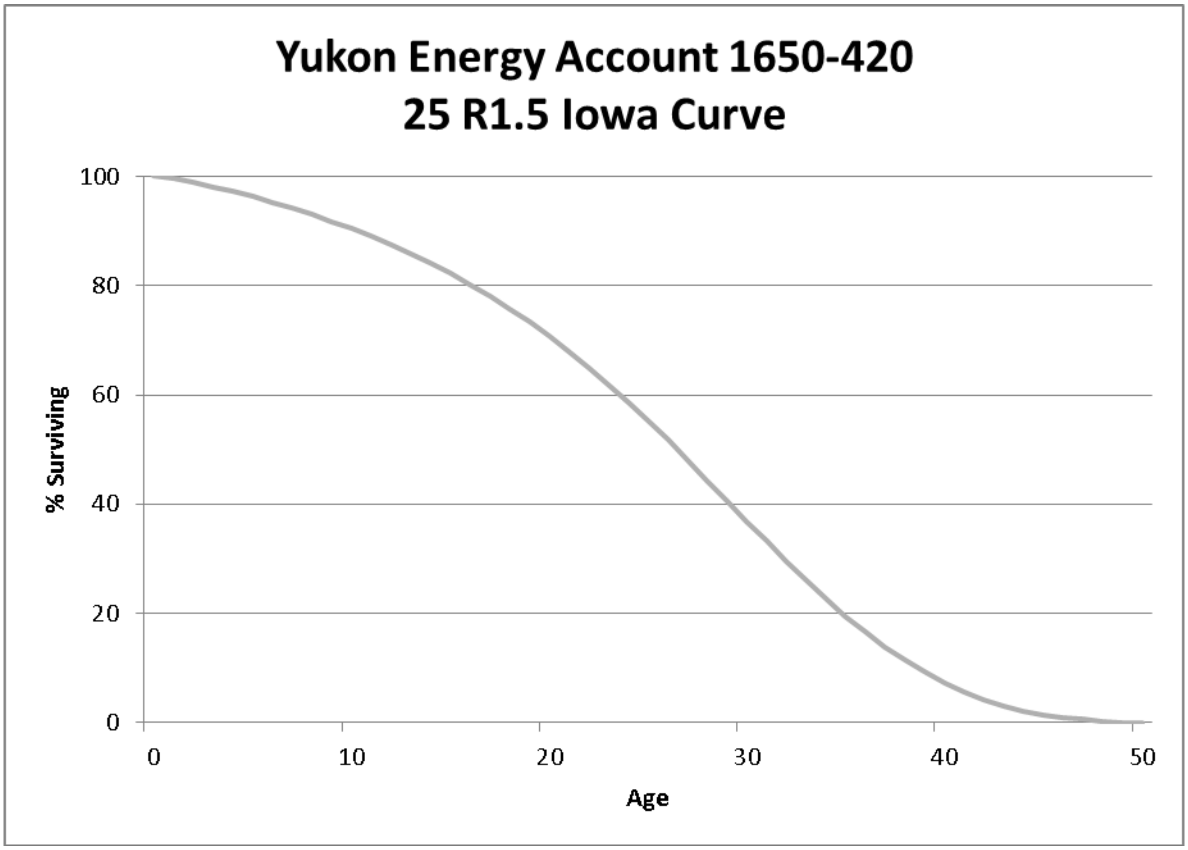
Account 1650-412 Trxptn – Sedans and Station Wagons 11 S4

This account includes the cost of vans, cars and smaller vehicles. The plant balance in this account at December 31, 2018 is $138 thousand. The approved life and curve for this account is 7 L2. Discussions with Company personnel indicated these vehicles are lasting longer than the existing seven years. Company policy is if a vehicle is 8 years or older, has 160,000 km, and has incurred maintenance costs greater than 15% in one year, they would retire. However, they have fallen behind on this schedule. The life analysis supports Company discussion that these vehicles are lasting longer and the slippage in the schedule, with a life indication of at least 12 years or more with a steeper dispersion pattern. Giving consideration to the Company policy, recent experience, expectations and judgment, this study proposes moving from 7 L2 to 11 S4 at this time. A representative graph is shown below.



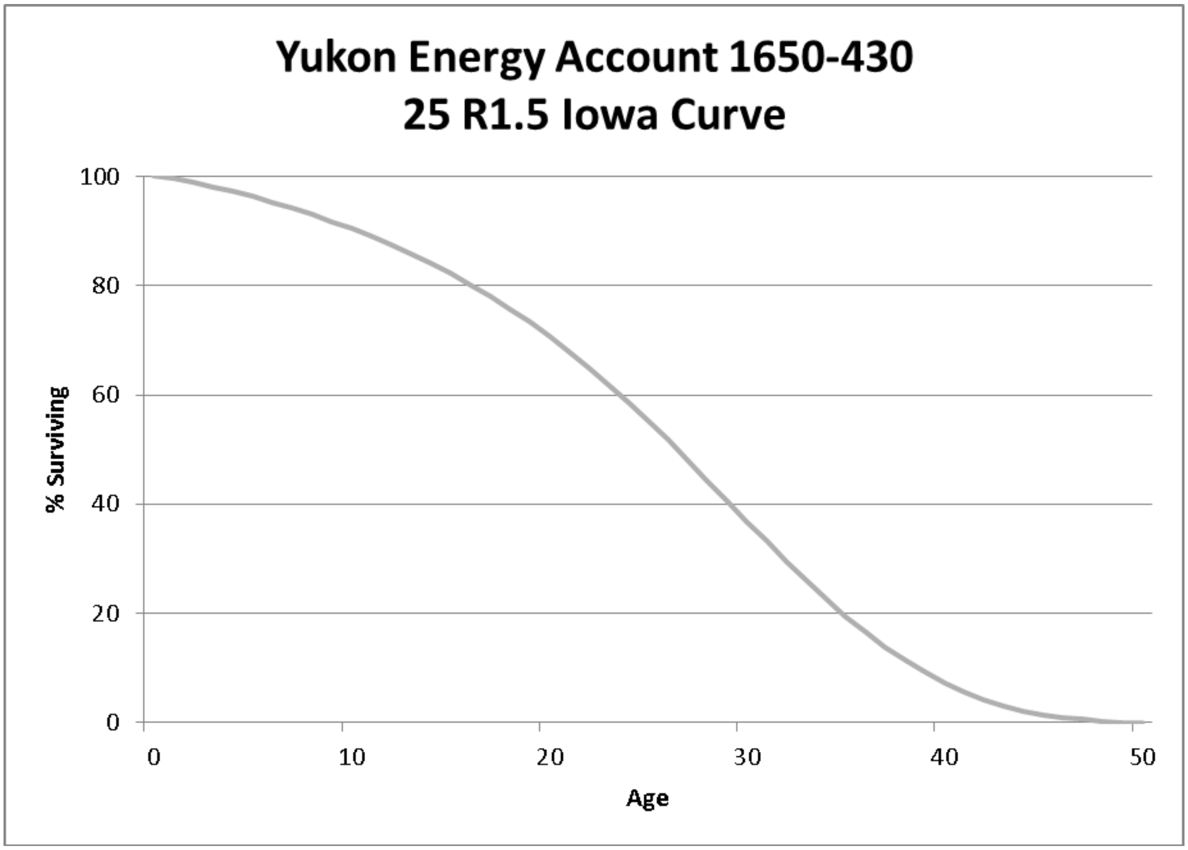
Account 1650-420 Trxptn – Trucks and Pole Trailers 25 R1.5

This account includes the cost of large trucks and pole trailers that carry less than 10,000 lbs. The plant balance in this account at December 31, 2018 is $11 thousand. The approved life and curve for this account is 25 R1.5. Discussions with Company personnel indicated the existing 25 year life is reasonable for the assets. There is no historical experience to analyze. Giving consideration to the type of assets, existing life, Company expectations, and judgment, this study proposes retention of the 25 R1.5 at this time. A representative graph is shown below.



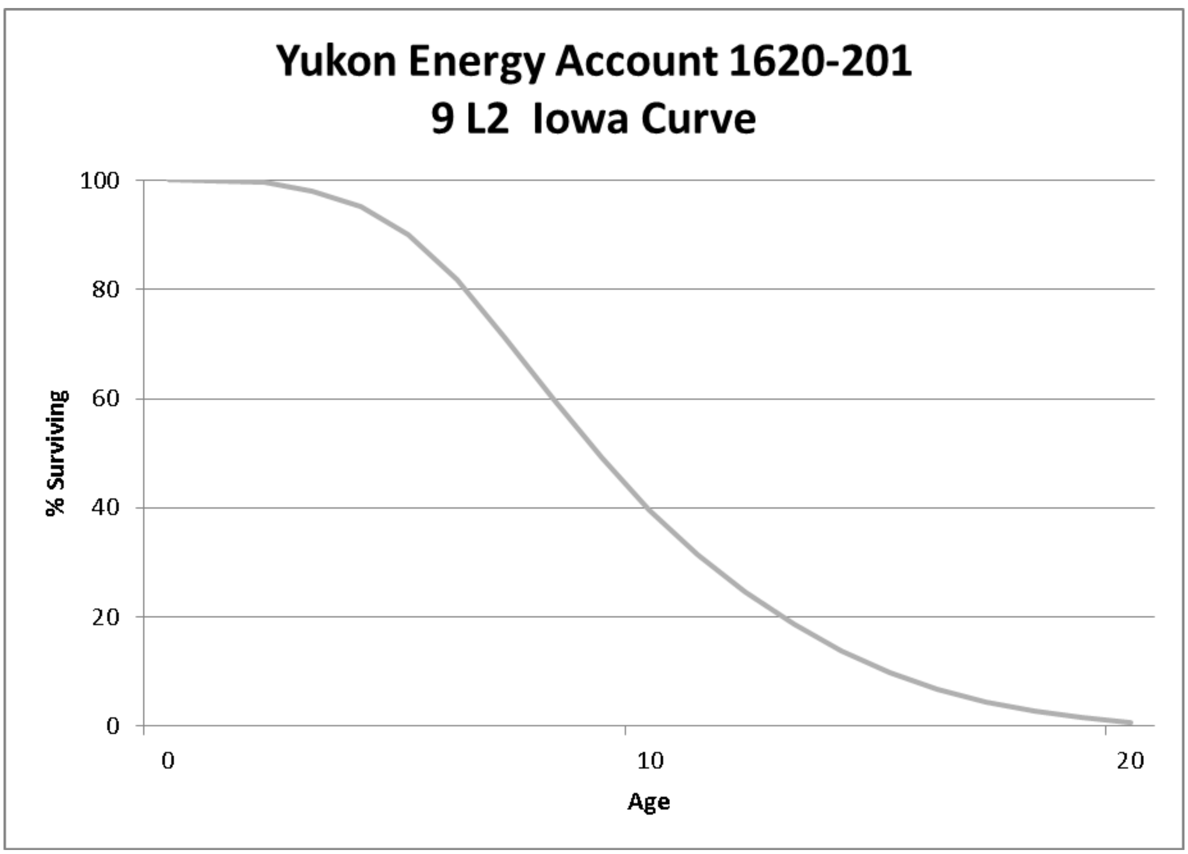
Account 1650-430 Trxptn – Pole Trailers > 10,000 lbs. 25 R1.5

This account includes the cost of pole trailers that carry greater than 10,000 lbs. The plant balance in this account at December 31, 2018 is $54 thousand. The approved life and curve for this account is 25 R1.5. Discussions with Company personnel indicated the existing 25 year life is reasonable for the assets. There is no historical experience to analyze. Giving consideration to the type of assets, existing life, Company expectations, and judgment, this study proposes retention of the 25 R1.5 at this time. A representative graph is shown below.



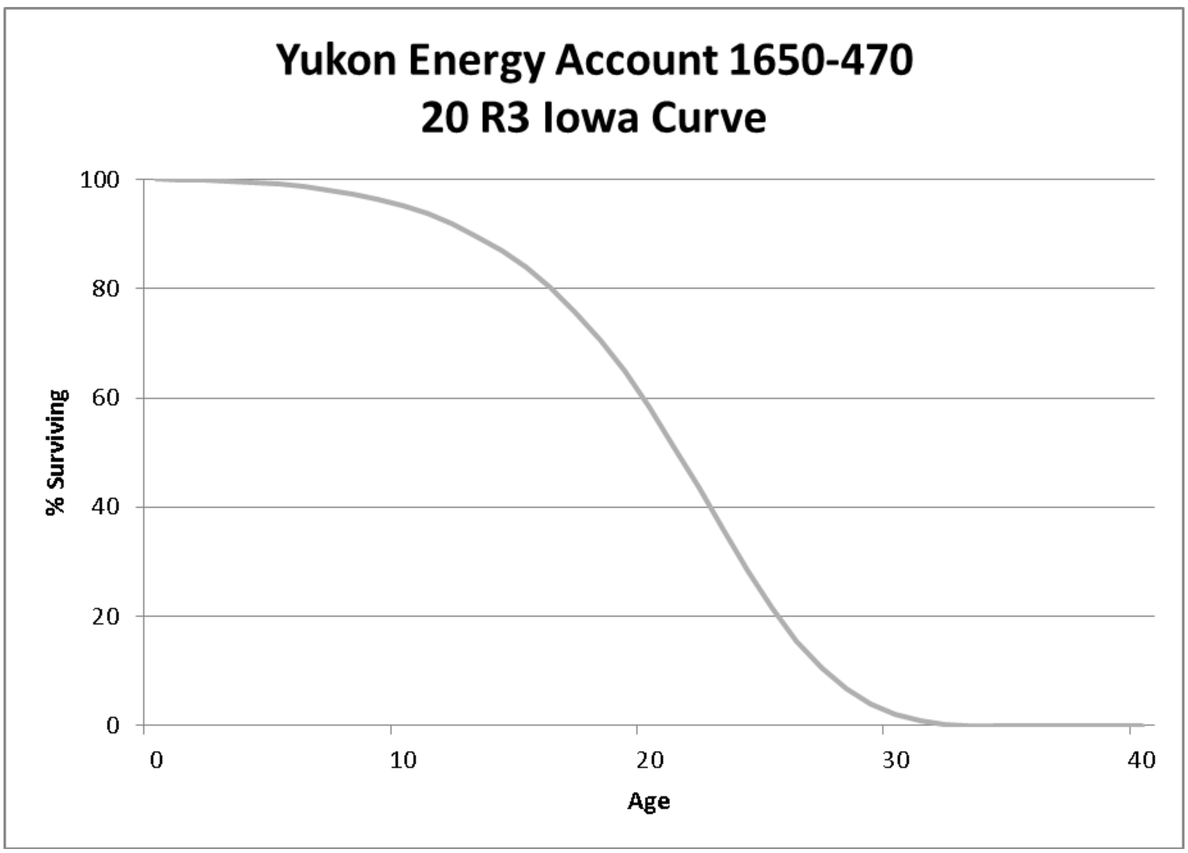
Account 1650-440 Trxptn – Trucks ¾ to 2 Tons 9 L2

This account includes the cost of trucks that are ¾ to 2 Tons used by employees to perform day to day duties. The plant balance in this account at December 31, 2018 is $2.6 million. The approved life and curve for this account is 10 R2. Discussions with Company personnel indicated that electricians would drive 90,000 and operations 70,000 in approximately 10 years. Linemen would drive 115,000 and would hit the maximum mileage in 3-4 years but there are other factors that cause the Company to retain these vehicles longer. There are equal numbers of each type of vehicle. Company expects they will be replaced by 8 years. However, the life analysis indicates a life between 10 to 11 years. Giving consideration to Company policy, recent experience, expectations and judgment, this study proposes moving from 10 R2 to 9 L2 at this time. A representative graph is shown below.



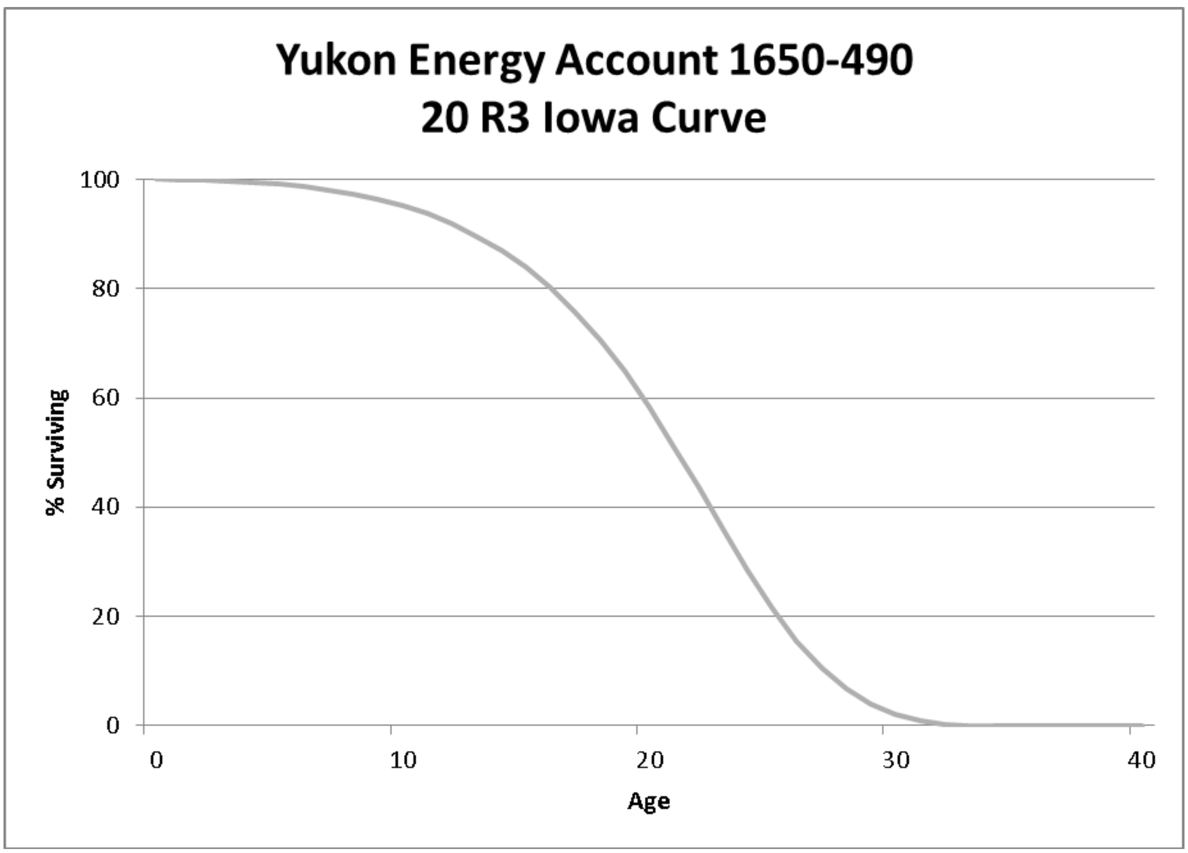
Account 1650-470 Trxptn – Trucks > 3 Tons 20 R3

This account includes the cost of trucks that are greater than 3 Tons including diggers, crane trucks, forklifts, and bucket trucks used to perform day to day duties. The plant balance in this account at December 31, 2018 is $1.5 million. The approved life and curve for this account is 20 R3. Discussions with Company personnel indicated that the approved 20 year life is reasonable. They just spent $40,000 to overhaul a 10 year old vehicle for its continued use. There is no historical experience to analyze. Giving consideration to Company input, recent overhaul, expectations and judgment, this study proposes retention of 20 R3 at this time. A representative graph is shown below.



Account 1650-490 Trxptn – Foremost 20 R3

This account includes the cost of large specialty vehicles which are usually tracked not wheeled vehicles. The plant balance in this account at December 31, 2018 is $1.0 million. The approved life for this account is 25 years. Discussions with Company personnel indicated that there is one tracked vehicle and a 2011 Kenworth truck equipped with an auger. Company personnel believe the life should match the life of the greater than 3 ton trucks of 20 years. There is no historical experience to analyze. Giving consideration to type of assets, Company input and expectations and judgment, this study proposes moving to 20 R3 at this time. A representative graph is shown below.



CRITICAL SPARES

Account 1655-750 Critical Spares – Non Depreciable

This account shall include repair and replacement parts for units that are critical to keep in working order. These parts have long lead time and/or difficult to source. These are not depreciated until they are put in service. The plant balance in this account at December 31, 2018 is $1.2 million.

LNG PLANT

Natural gas is a type of fuel, like gasoline or diesel, used to drive engines or heat buildings. After it is removed from the ground it can be refrigerated to minus 162°C; at that temperature it turns into liquid (referred to as LNG or liquefied natural gas) that takes up far less space so that it can be economically transported. It is also stored as a liquid until ready for use, at which time it is returned to a gas. As an isolated grid in one of the world's least-forgiving environments, it's crucial that we have a reliable backup system. Until recently, the Company used diesel generators during power outages, to supplement their hydro facilities in very cold weather, and during droughts.

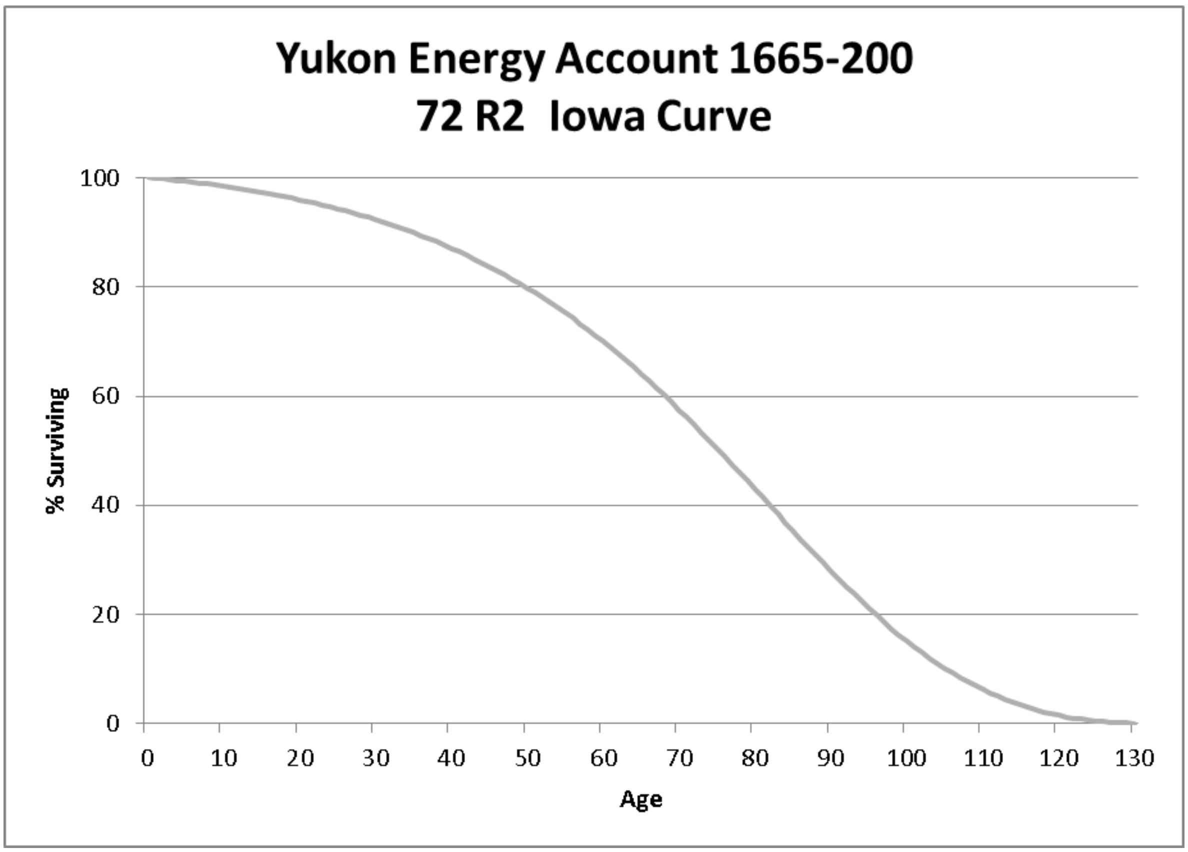
With the retirement of older backup diesel generators, Yukon Energy was mandated to provide a backup system and needed to replace the old diesel generators. Three life cycle assessments were performed by independent agencies showed that switching from diesel to natural gas would save significant amounts of money, produce fewer greenhouse gas, particulate and nitrogen oxide air emissions, and would be quieter and more efficient to operate. Three of the oldest diesels were replaced with natural gas generators.

As with diesel, Yukon Energy uses its natural gas units for emergency back-up, during years of low water at its hydro facilities, or peaking during the cold winter months. The vast majority of power the Company produces continues to be from renewable sources (in 2018 close to 94 percent of the electricity generated was from hydro). Yukon Energy's LNG facility has been operating since 2015 without incident.

This function consists of LNG facilities, of which there are three units, all with a four day full run capacity. Two of the units were placed in-service in 2015 and one unit was placed in-service in 2018. These are first run units, which have over 7,500 hours since 2015 and the 2018 unit has over 3,000 hours. The Company expects each unit will run around 4,000 hours per year.

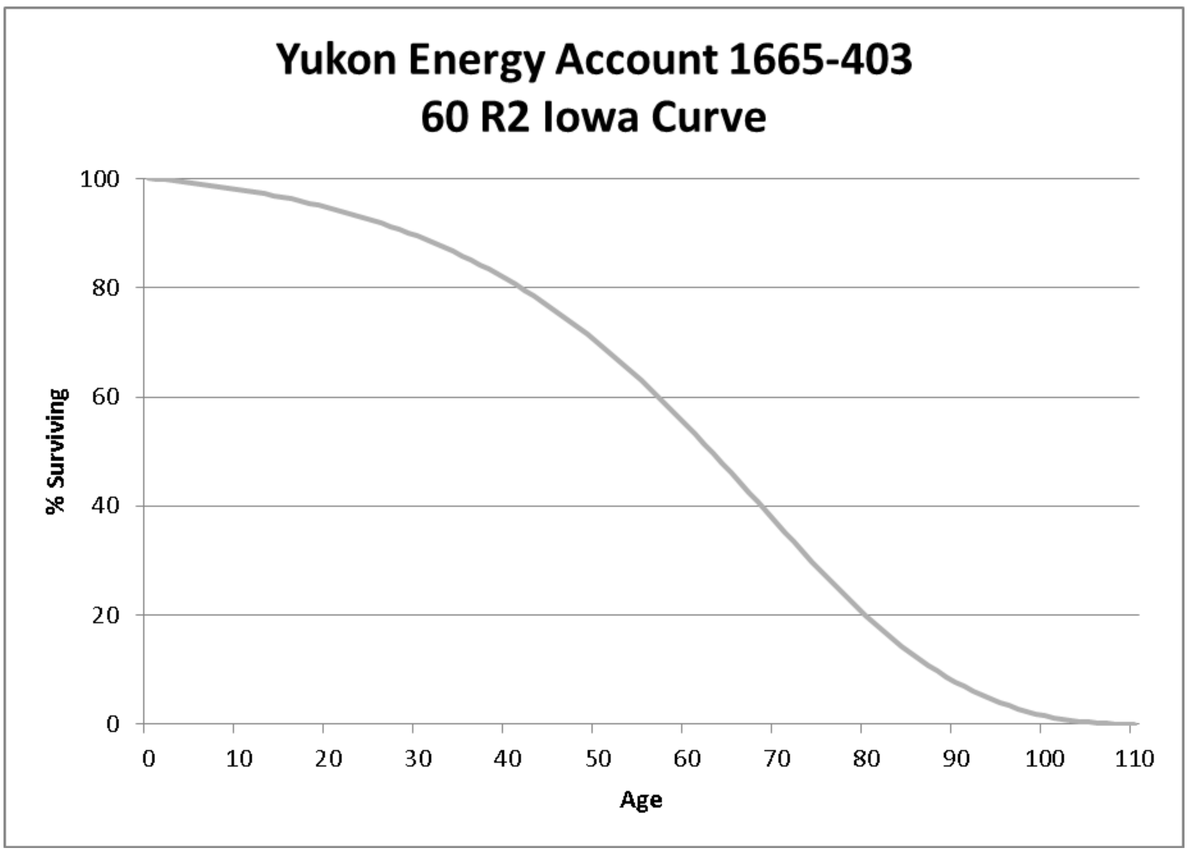
Account 1665-200 LNG Plant – Structures and Improvements 72 R2

This account includes the installed cost of all buildings and facilities including foundations, wiring, HVAC systems, plumbing, fire protection systems, paving and yard lighting and surfacing. The plant balance in this account at December 31, 2018 is $6.2 million. The approved life for this account is 72 years. The assets are new so there is limited historical data. Based on the type of assets, information provided by Company personnel, and judgment, this study recommends retaining the existing 72 years with the R2 for this account. A representative graph is provided below.



Account 1665-403 LNG Plant – Fuel Holders 60 R2

This account includes the installed cost of fuel handling and storage equipment used between the point of fuel delivery to the station and the intake pipe including boilers, pumps, produces, regenerators, tanks, and vaporizers. The plant balance in this account at December 31, 2018 is $13.2 million. The approved life for this account is 32 years. The assets are new so there is limited historical data. Discussions with Company personnel indicated the tanks are nickel, double walled with no moisture ingress. The existing fuel holder life of 32 years is considered to be low and with reasonable maintenance, a 60 year life is expected. Considering the type of assets, information provided by Company personnel and judgment, this study recommends moving the life to 60 years with the R2 for this account. A representative graph is provided below.

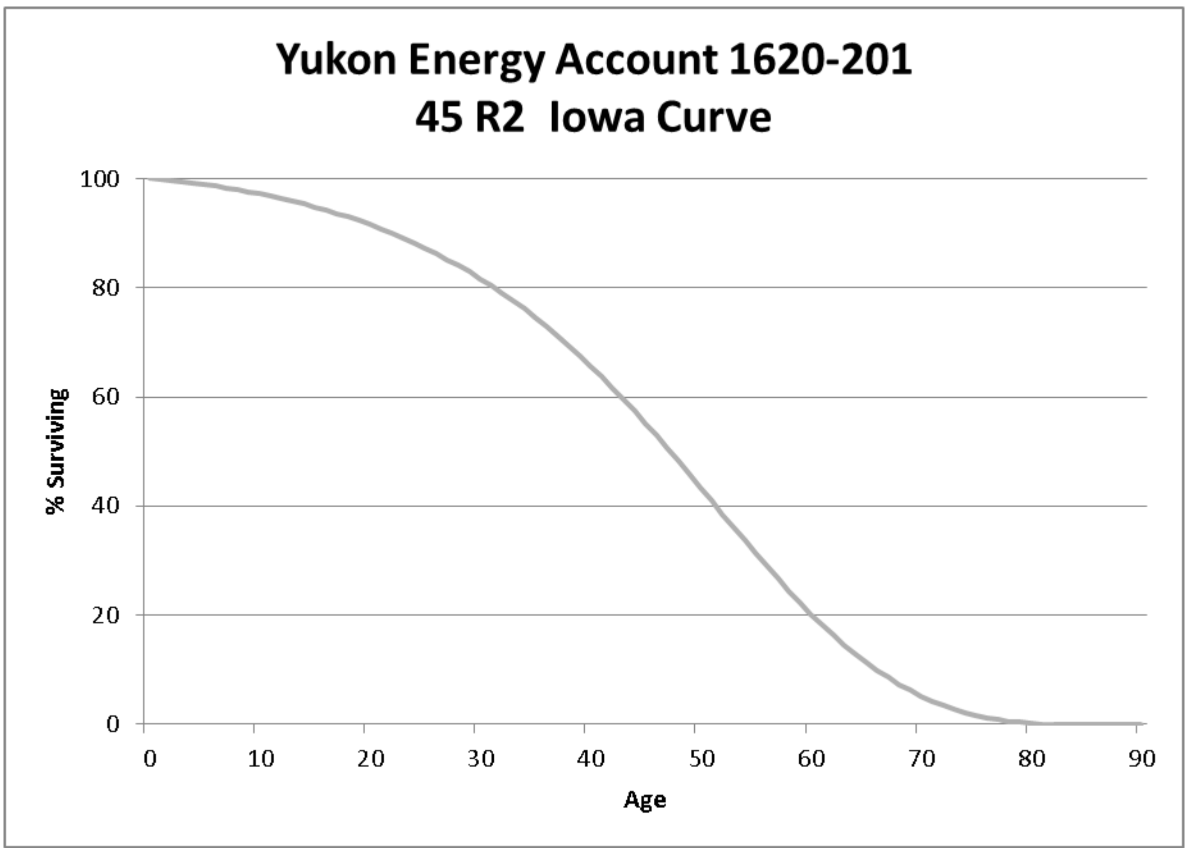


Account 1665-500 LNG Plant – Generators 40 SQ

This account includes the installed cost of other prime movers including engines, piping, air-filtering system, towers, pumps, hoists, compressors, tanks, waste heat boilers, antifluctuators and other related equipment. The plant balance in this account at December 31, 2018 is $20.9 million. The approved life for this account is 40 years. The assets are new so there is limited historical data. Discussions with Company personnel indicated the current life is still applicable for this account. Considering the type of assets, information provided by Company personnel and judgment, this study retaining the life of 40 years and using a SQ dispersion for this account. No graph is shown for this account.

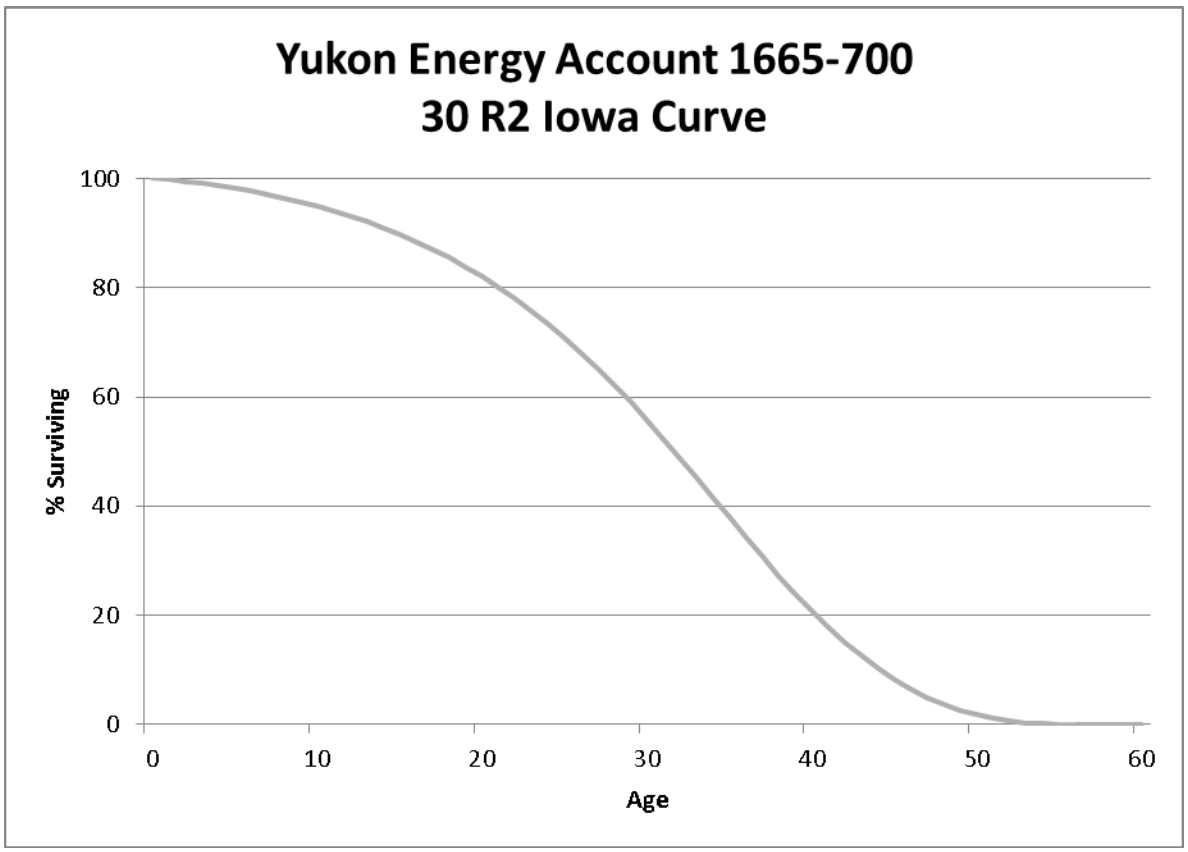
Account 1665-600 LNG Plant – Accessory Electric Equipment 45 R2

This account includes the installed cost of auxiliary generating and conversion equipment including generators, switching and station control equipment, excitation system, circuit breakers, panels, transformers, relays and other related equipment. The plant balance in this account at December 31, 2018 is $3.7 million. The approved life for this account is 45 years. The assets are new so there is limited historical data. Considering the type of assets, information provided by Company personnel and judgment, this study recommends retaining the 45 year life with the R2 curve for this account. A representative graph is provided below.



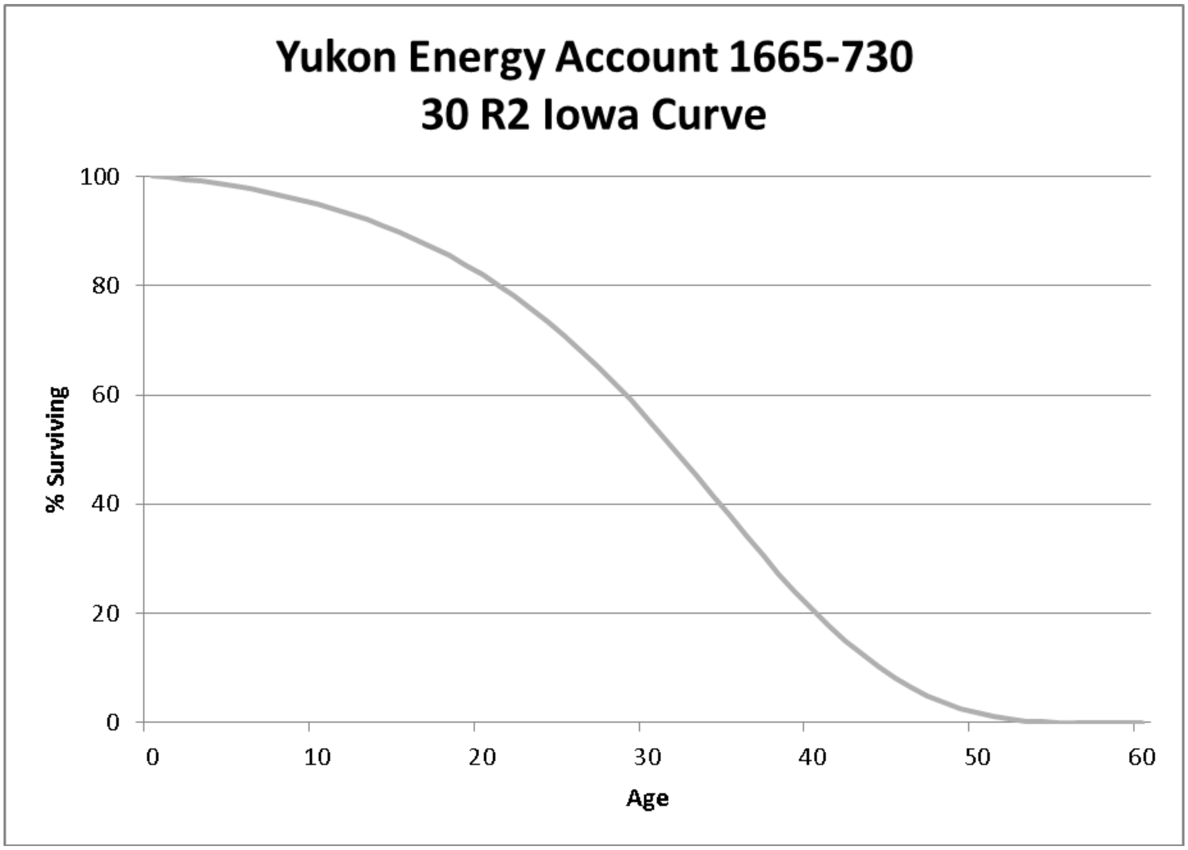
Account 1665-700 LNG Plant–Miscellaneous Power Plant Equipment 30 R2

This account includes the installed cost of compressors, exhausters, air filters, piping, refrigerating systems, fire-extinguishing and other miscellaneous equipment. The plant balance in this account at December 31, 2018 is $2.8 million. The approved life for this account is 30 years. The assets are new so there is limited historical data. Considering the type of assets, information provided by Company personnel and judgment, this study recommends retaining the 30 year life with the R2 curve for this account. A representative graph is found below.



Account 1665-730 LNG Plant – Fence 30 R2

This account includes the installed cost of fences surrounding the site which includes a corrugated metal fence that is solid and is built to prevent vapour dispersion. The plant balance in this account at December 31, 2018 is $780 thousand. The approved life for this account is 30 years. The assets are new so there is limited historical data. Considering the type of assets, information provided by Company personnel and judgment, this study recommends retaining the 30 year life with the R2 curve for this account. A representative graph is found below.



APPENDIX A

Depreciation Rate Calculations

YUKON ENERGY
COMPUTATION OF PROPOSED DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Asset Class ID	Asset Class ID Description	Plant	Accumulated Depreciation	AD Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accumulated Depreciation	Accumulated Depreciation Variance	Proposed Depreciation Rate	Proposed Depreciation Amount	Remaining Life	Depreciation True-Up Annual Provision for True Up
	Land											
1610-003	Land Hydro Production	444,912	0			444,912						
1610-004	Land Diesel Production	27,680	0			27,680						
1610-006	Land Main Trx Facilities	576,862	0	699	(199)	577,363						
1610-008	Land Distribution System	17,775	0			17,775						
1610-009	Land General Plant	547,992	0			547,992						
1610-106	Land Rights	128,780	(25,910)			102,870	(25,391)	(519)	2.00%	2,576	40.14	(13)
		1,744,002	(25,910)	699	(199)	1,718,592	(25,391)	(519)		2,576		(13)
	Hydro Plant											
1615-200	Hydro-Strctrs & Imprvmts	34,163,123	(6,803,403)	(977,149)	63,766	26,446,337	(7,308,246)	(408,540)	1.39%	474,488	56.60	(7,218)
1615-201	Hydro-Building & Imprvmnt	10,278,688	(427,340)			9,851,348	(362,324)	(65,016)	2.50%	256,967	38.59	(1,685)
1615-205 & 1615-206	Hydro-Rsrvoirs Dams & Wtrways	172,919,206	(52,689,116)	(18,131,142)	1,386,390	103,485,339	(49,449,636)	(19,984,232)	0.97%	1,678,827	73.55	(271,727)
1615-506	Hydro-Wtrwhls, Trbines & Gen's	26,339,447	(3,747,076)	(269,433)	44,824	22,367,762	(6,351,635)	2,379,950	1.67%	438,991	45.53	52,271
1615-600	Hydro-Accessory Electric Equip	26,598,355	(5,186,340)	65,942	(23,197)	21,454,761	(7,445,689)	2,302,095	2.50%	664,959	28.80	79,926
1615-601	Hydro Accessory Digital Equip	837,945	(63,362)			774,582	(62,846)	(517)	5.00%	41,897	18.50	(28)
1615-700	Hydro-Misc Power Plant Equip	11,490,781	(3,087,765)	83,244	(46,809)	8,439,452	(3,223,878)	172,549	3.33%	383,026	21.58	7,995
1615-730	Hydro- Fences	107,086	(25,967)			81,119	(29,641)	3,674	3.33%	3,570	21.70	169
	Hydro Plant Total	282,734,632	(72,030,369)	(19,228,538)	1,424,975	192,900,700	(74,233,895)	(15,600,037)		3,942,725		(140,298)
	Diesel Plant											
1620-200	Diesel-Strctrs and Imprvmts	1,562,352	(781,875)	(432,852)	106,295	453,920	(634,175)	(474,257)	1.39%	21,699	42.77	(11,087)
1620-201	Diesel-Building & Imprvmnt	466,054	(99,651)	(20,501)	3,345	349,246	(62,300)	(54,507)	1.82%	8,474	47.65	(1,144)
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	1,688,501	(954,217)	(122,114)	114,775	726,946	(589,294)	(372,262)	2.50%	42,213	26.04	(14,296)
1620-500	Diesel-Gnrtng Equip & Prime	13,841,607	(8,510,645)	(732,079)	1,052,443	5,651,327	(7,105,089)	(1,085,191)	2.50%	346,040	19.47	(55,744)
1620-501	Diesel-Gnrtng Equip & Prime Retire	1,970,549	(974,499)			996,050	(1,522,697)	548,198	NA	332,017	0.00	0
1620-508	Diesel-Minto Gnrtng Equip	243,548	(176,888)			66,660	(192,809)	15,921	8.33%	20,296	2.50	6,368
1620-600	Diesel-Acc Electric Equip	5,416,976	(1,583,903)	(478,962)	171,809	3,525,920	(1,850,307)	(40,749)	2.22%	120,377	29.63	(1,375)
1620-700	Diesel-Misc Power Plant Equip	1,867,523	(825,077)	(371,646)	240,340	911,140	(763,247)	(193,136)	3.33%	62,251	17.74	(10,888)
	Diesel Plant Total	27,057,109	(13,906,754)	(2,158,154)	1,689,007	12,681,208	(12,719,918)	(1,655,983)		953,366		(88,166)
	Distribution System											
1625-300	Dist System - Poles & Fxtrs	7,969,883	(1,905,688)	(14,629)	6,125	6,055,691	(1,614,735)	(299,457)	2.50%	199,247	31.90	(9,389)
1625-304	Dist System - Brushing	44,763	(17,835)	(3,235)	996	24,689	(26,238)	6,164	2.00%	895	20.69	298
1625-305	Dist System - Survey Costs	600,378	(168,274)	297		432,401	(112,698)	(55,279)	2.00%	12,008	40.61	(1,361)
1625-401	Dist System - O/H Cndctrs	74,570	(31,009)			43,561	(19,120)	(11,889)	2.00%	1,491	37.18	(320)
1625-410	Dist System - O/H Services	2,117,381	(847,311)	(78,539)	30,910	1,222,442	(931,877)	36,937	2.50%	52,935	22.40	1,649
1625-501	Underground Conduit	385,155	(26,519)			358,636	(22,631)	(3,888)	2.50%	9,629	37.65	(103)
1625-510	Dist System - Undrgrnd Cnduit	40,460	(7,467)	(454)	171	32,710	(6,862)	(888)	2.50%	1,012	33.22	(27)
1625-610	Dist System - Meters	312,633	(185,181)	(33,787)	18,820	112,484	(266,434)	66,286	6.25%	19,540	2.36	28,035
1625-620	Dist System - Meter Equip	288,392	(148,993)	3,308	(968)	141,739	(237,596)	90,943	6.25%	18,025	2.82	32,270
1625-710	Dist System - Sbstn EEquip	1,287,180	(512,564)	(50,938)	22,068	745,746	(473,237)	(68,197)	2.50%	32,180	25.29	(2,696)
1625-720	Dist System - Sbstn Buildings	64,798	(35,020)	(19,520)	7,988	18,246	(31,214)	(15,339)	1.82%	1,178	28.51	(538)
1625-730	Dist System- Substation Fences	100,328	(15,200)			85,128	(11,684)	(3,517)	3.33%	3,344	26.51	(133)
1625-815	Dist System - Street Lights	588,493	(206,165)	(99,674)	39,803	322,456	(181,113)	(84,924)	2.50%	14,712	27.69	(3,067)
1625-905	Dist System - Line Trxformers	4,000,082	(1,959,650)	(564,652)	249,975	1,725,756	(2,362,021)	87,694	2.86%	114,288	14.33	6,118
1625-961	Dist System - Sentinel Lights	36,443	(25,911)	(12,948)	9,589	7,173	(16,992)	(12,278)	3.33%	1,215	16.01	(767)
	Distribution System Total	17,910,940	(6,092,787)	(874,771)	385,478	11,328,860	(6,314,451)	(267,629)		481,697		49,971
	Main Transmission Facilities											
1635-300	Main Trx - Poles & Fxtrs	60,444,290	(11,208,130)	(1,367,921)	441,757	48,309,996	(12,407,344)	273,051	2.00%	1,208,886	39.74	6,872
1635-304	Main Trx - Brushing	14,082,336	(3,234,991)	48,456	(13,702)	10,882,098	(2,588,715)	(611,522)	1.67%	234,706	48.97	(12,488)
1635-305	Main Trx - Survey Costs	3,541,446	(866,916)	(61,687)	17,348	2,630,191	(759,406)	(151,849)	1.67%	59,024	47.13	(3,222)
1635-402	Main Trx - O/H Cndctrs/Poles	20,561,275	(5,081,116)	(45,903)	11,990	15,446,247	(4,166,859)	(948,169)	1.67%	342,688	47.84	(19,819)
1635-404	Main Trx - O/H Cndctrs/Towers	277,975	(110,991)	(7,067)	2,070	161,987	(136,749)	20,761	1.67%	4,633	30.48	681
1635-710	Main Trx - Sbstn Equip	66,600,655	(14,772,921)	(633,579)	246,252	51,440,407	(13,394,976)	(1,765,271)	2.22%	1,480,015	35.95	(49,104)
1635-720	Main Trx - Sbstn Buildings	1,536,213	(216,619)	(2,223)	480	1,317,851	(156,704)	(61,659)	1.82%	27,931	49.39	(1,248)
1635-730	Main Trx - Sbstn Fences	274,477	(92,674)	769	(605)	181,968	(63,234)	(29,275)	3.33%	9,149	23.09	(1,268)
	Main Transmission Facilities Total	167,318,667	(35,584,356)	(2,069,155)	705,591	130,370,747	(33,673,988)	(3,273,933)		3,367,031	322.59	(79,597)

YUKON ENERGY
COMPUTATION OF PROPOSED DEPRECIATION ACCRUAL RATE
AT DECEMBER 31, 2018

Asset Class ID	Asset Class ID Description	Plant	Accumulated Depreciation	AD Difference	Accumulated Depreciation of A/D Difference	Net Book Value	Calculated Accumulated Depreciation	Accumulated Depreciation Variance	Proposed Depreciation Rate	Proposed Depreciation Amount	Remaining Life	Depreciation True-Up Annual Provision for True Up
	Sub Transmission Lines											
1640-300	Sub Trx - Poles & Fxtrs	4,092,701	(2,281,354)	(780,721)	281,918	1,312,545	(2,059,673)	(720,483)	2.00%	81,854	24.84	(29,008)
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	2,646,132	(2,223,467)			422,665	(2,205,110)	(18,357)	8.33%	220,511	2.00	(9,179)
1640-304	Sub Trx - Brushing	41,597	(834)			40,763	(1,023)	189	1.67%	693	58.52	3
1640-306	Sub Trx - Brushing Mnt Mn	432,533	(363,453)			69,080	(360,444)	(3,009)	8.33%	36,044	2.00	(1,504)
1640-307	Sub Trx - Survey Costs Mnt Mn	95,136	(79,940)			15,196	(79,280)	(660)	8.33%	7,928	2.00	(330)
1640-401	Sub Trx - O/H Cndctrs	1,840,369	(564,991)	(112,184)	41,214	1,204,408	(490,758)	(145,203)	1.67%	30,673	44.00	(3,300)
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	83,873	(47,669)	(194)	121	36,130	(57,555)	9,813	2.22%	1,864	14.12	695
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	920,693	(773,631)			147,062	(767,244)	(6,387)	8.33%	76,724	2.00	(3,194)
1640-710	Sub Trx - Sbstn EEquip	8,013,609	(756,527)			7,257,082	(557,208)	(199,319)	2.22%	178,080	41.87	(4,760)
1640-711	Sub Trx - Sbstn Equips Mnt Mn	6,948,253	(5,781,101)			1,167,153	(5,790,211)	9,111	8.33%	579,021	2.00	4,555
	Sub Transmission Lines Total	25,114,895	(12,872,966)	(893,099)	323,253	11,672,083	(12,368,507)	(1,074,306)		1,213,393		(46,022)
	Buildings & Other Equipment											
1645-110	Bldg&Otr - Survey Costs Land	4,321	(1,950)	(601)	193	1,963	(2,837)	479	2.00%	86	17.18	28
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	2,243,942	(333,448)	(3,049)	1,122	1,908,567	(251,936)	(83,440)	2.00%	44,879	44.39	(1,880)
1645-201	Bldg&Otr - Building & Imprvmnt	10,102,549	(3,653,478)	(946,961)	232,163	5,734,274	(3,535,922)	(832,354)	2.00%	202,051	32.50	(25,611)
1645-202	Bldg&Otr-Office Frntr & Equip	1,736,569	(1,267,513)	(130,011)	120,096	459,141	(1,272,514)	(4,914)	5.00%	86,828	5.34	(919)
1645-210	Bldg&Otr - Comm Site Towers	19,297	(11,471)	(1,115)	557	7,268	(7,109)	(4,920)	2.50%	482	25.26	(195)
1645-220	Bldg&Otr - Comm Site Fences	64,126	(30,756)	326	(241)	33,456	(19,994)	(10,676)	3.33%	2,138	20.65	(517)
1645-320	Bldg&Otr - Computer Hardware	1,715,886	(1,022,714)	70,421	(70,023)	693,569	(982,253)	(40,064)	14.29%	245,127	2.99	(13,386)
1645-330	Bldg&Otr - Computer Software	304,004	(132,784)	(7,872)	7,872	171,220	(148,885)	16,101	20.00%	60,801	2.55	6,311
1645-505	Bldg&Otr - Tools & Instruments	1,654,638	(904,640)	(168,321)	140,874	722,551	(889,892)	(42,195)	5.00%	82,732	9.24	(4,565)
1645-507	Bldg&Otr - Wind Mntrng Equip	14,283	(11,022)		1,332	4,592	(12,854)	3,164	6.67%	952	1.50	2,109
1645-605	Bldg&Otr - Comm Equip	4,583,047	(2,453,712)	(53,911)	52,353	2,127,778	(2,365,191)	(90,078)	5.00%	229,152	9.68	(9,307)
1645-810	Bldg&Otr - Houses/Land	59,031	(22,410)	7,862	(4,433)	40,050	(14,986)	(3,996)	2.50%	1,476	29.85	(134)
1645-820	Bldg&Otr - Houses/Buildings	2,051,769	(1,430,615)	365,433	(190,775)	795,812	(777,167)	(478,790)	2.50%	51,294	24.85	(19,268)
	Total Building	24,553,463	(11,276,513)	(867,799)	291,091	12,700,242	(10,281,540)	(1,571,682)		1,007,998		(67,334)
	Transportation											
1650-411	Trxptn - Utility Vehicles	344,073	(193,559)	12,716	(12,716)	150,514	(173,164)	(20,395)	12.50%	43,009	3.97	(5,132)
1650-412	Trxptn - Sedans & Stn Wagons	137,764	(90,423)	6,160	(6,160)	47,340	(78,421)	(12,003)	9.09%	12,524	4.74	(2,533)
1650-420	Trxptn - Trucks & Pole Trailer	11,000	(2,686)			8,314	(2,724)	37	4.00%	440	18.81	2
1650-430	Trxptn -Pole Trailer>10,000lbs	53,711	(18,374)	(748)	445	35,033	(17,243)	(1,434)	4.00%	2,148	16.97	(84)
1650-440	Trxptn - Trucks 3/4 to 2 Ton	2,644,537	(1,015,122)	(17,178)	17,178	1,629,415	(1,106,240)	91,118	11.11%	293,837	5.24	17,405
1650-470	Trxptn - Trucks > 3Tons	1,459,849	(401,649)	(12,391)	9,860	1,055,670	(453,561)	49,382	5.00%	72,992	13.79	3,582
1650-490	Trxptn - Foremost	1,003,858	(352,963)			650,895	(422,764)	69,801	5.00%	50,193	11.58	6,029
	Total Transporation	5,654,791	(2,074,777)	(11,441)	8,608	3,577,181	(2,254,117)	176,507		475,144		19,268
	Critical Spares											
1655-750	Critical Spares	1,170,184	0			1,170,184						
	LNG Plant											
1665-200	Structures and Improverments	6,184,735	(301,000)			5,883,735	(270,787)	(30,213)	1.39%	85,899	68.85	(439)
1665-403	Fuel Holders	13,200,669	(1,445,518)			11,755,151	(692,600)	(752,919)	1.67%	220,011	56.85	(13,243)
1665-500	LNG Generator	20,880,293	(1,157,153)			19,723,140	(1,233,591)	76,437	2.50%	522,007	37.64	2,031
1665-600	Accessory Electric Equipment	3,655,939	(282,214)			3,373,725	(253,176)	(29,038)	2.22%	81,243	41.88	(693)
1665-700	Miscellanours Power Plant Equi	2,828,210	(321,574)			2,506,636	(287,467)	(34,106)	3.33%	94,274	26.95	(1,266)
1665-730	LNG Fence	779,651	(91,066)			688,585	(81,109)	(9,957)	3.33%	25,988	26.88	(370)
	Total LNG	47,529,497	(3,598,525)	0	0	43,930,972	(2,818,729)	(779,796)		1,029,423		(13,981)
	Total Yukon	600,788,180	(157,462,958)	(26,102,258)	4,827,804	422,050,768	(154,690,534)	(24,047,378)		12,473,354		(366,170)

Note: The following accounts were excluded from the depreciation study:
1615-504
1620-504
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

APPENDIX B

Depreciation Expense Comparison

YUKON ENERGY
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION RATES
AT DECEMBER 31, 2018

			Existing		Proposed				
Asset Class ID	**Asset Class ID Description**	**Plant**	**Rate**	**Amount**	**Rate**	**Amount**	**Annual True-Up**	**Total Accrual**	**Difference**
		$	%	$	%	$	$	$	$
	Land								
1610-003	Land Hydro Production	444,912		0.00	0.00%		0	0	0
1610-004	Land Diesel Production	27,680		0.00	0.00%		0		0
1610-006	Land Main Trx Facilities	576,862		0.00	0.00%		0	0	0
1610-008	Land Distribution System	17,775		0.00	0.00%		0	0	0
1610-009	Land General Plant	547,992		0.00	0.00%		0	0	0
1610-106	Land Rights	128,780	2.00%	2,576	2.00%	2,576	(13)	2,563	(13)
	Land Total	1,744,002		2,576	2.00%	2,576	(13)	2,563	(13)
	Hydro Plant								
1615-200	Hydro-Strctrs & Imprvmts	34,163,123	1.39%	474,488	1.39%	474,488	(7,218)	467,270	(7,218)
1615-201	Hydro-Building & Imprvmnt	10,278,688	2.50%	256,967	2.50%	256,967	(1,685)	255,282	(1,685)
1615-205 & 1615-206	Hydro-Rsrvoirs Dams & Wtrways	172,919,206	0.97%	1,678,827	0.97%	1,678,827	(271,727)	1,407,100	(271,727)
1615-506	Hydro-Wtrwhls, Trbines & Gen's	26,339,447	1.18%	309,876	1.67%	438,991	52,271	491,261	181,386
1615-600	Hydro-Accessory Electric Equip	26,598,355	2.22%	591,075	2.50%	664,959	79,926	744,885	153,810
1615-601	Hydro Accessory Digital Equip	837,945	5.00%	41,897	5.00%	41,897	(28)	41,869	(28)
1615-700	Hydro-Misc Power Plant Equip	11,490,781	3.33%	383,026	3.33%	383,026	7,995	391,021	7,995
1615-730	Hydro- Fences	107,086	3.33%	3,570	3.33%	3,570	169	3,739	169
	Hydro Plant Total	282,734,632		3,739,725		3,942,725	(140,298)	3,802,427	62,701
	Diesel Plant								
1620-200	Diesel-Strctrs and Imprvmts	1,562,352	1.39%	21,699	1.39%	21,699	(11,087)	10,612	(11,087)
1620-201	Diesel-Building & Imprvmnt	466,054	1.82%	8,474	1.82%	8,474	(1,144)	7,330	(1,144)
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	1,688,501	4.00%	67,540	2.50%	42,213	(14,296)	27,917	(39,623)
1620-500	Diesel-Gnrtng Equip & Prime	13,841,607	2.50%	346,040	2.50%	346,040	(55,744)	290,296	(55,744)
1620-501	Diesel-Gnrtng Equip & Prime Retire 2021	1,970,549	NA	332,017	NA	332,017	0	332,017	0
1620-508	Diesel-Minto Gnrtng Equip	243,548	8.33%	20,296	8.33%	20,296	6,368	26,664	6,368
1620-600	Diesel-Acc Electric Equip	5,416,976	2.22%	120,377	2.22%	120,377	(1,375)	119,002	(1,375)
1620-700	Diesel-Misc Power Plant Equip	1,867,523	3.33%	62,251	3.33%	62,251	(10,888)	51,363	(10,888)
	Diesel Plant Total	27,057,109		978,694		953,366	(88,166)	865,201	(113,493)
	Distribution System								
1625-300	Dist System - Poles & Fxtrs	7,969,883	2.86%	227,711	2.50%	199,247	(9,389)	189,858	(37,852)
1625-304	Dist System - Brushing	44,763	2.00%	895	2.00%	895	298	1,193	298
1625-305	Dist System - Survey Costs	600,378	2.00%	12,008	2.00%	12,008	(1,361)	10,647	(1,361)
1625-401	Dist System - O/H Cndctrs	74,570	2.86%	2,131	2.00%	1,491	(320)	1,172	(959)
1625-410	Dist System - O/H Services	2,117,381	2.50%	52,935	2.50%	52,935	1,649	54,584	1,649
1625-501	Underground Conduit	385,155	2.50%	9,629	2.50%	9,629	(103)	9,526	(103)
1625-510	Dist System - Undrgrnd Cnduit	40,460	2.50%	1,012	2.50%	1,012	(27)	985	(27)
1625-610	Dist System - Meters	312,633	3.33%	10,421	6.25%	19,540	28,035	47,575	37,154
1625-620	Dist System - Meter Equip	288,392	3.33%	9,613	6.25%	18,025	32,270	50,295	40,681
1625-710	Dist System - Sbstn EEquip	1,287,180	2.50%	32,180	2.50%	32,180	(2,696)	29,483	(2,696)
1625-720	Dist System - Sbstn Buildings	64,798	1.82%	1,178	1.82%	1,178	(538)	640	(538)
1625-730	Dist System- Substation Fences	100,328	5.00%	5,016	3.33%	3,344	(133)	3,212	(1,805)
1625-815	Dist System - Street Lights	588,493	2.50%	14,712	2.50%	14,712	(3,067)	11,645	(3,067)
1625-905	Dist System - Line Trxformers	4,000,082	2.50%	100,002	2.86%	114,288	6,118	120,407	20,404
1625-961	Dist System - Sentinel Lights	36,443	3.33%	1,215	3.33%	1,215	(767)	448	(767)
	Distributution System Total	17,910,940		480,657		481,697	49,971	531,668	51,012
	Main Transmission Facilities								
1635-300	Main Trx - Poles & Fxtrs	60,444,290	1.54%	929,912	2.00%	1,208,886	6,872	1,215,757	285,845
1635-304	Main Trx - Brushing	14,082,336	2.00%	281,647	1.67%	234,706	(12,488)	222,218	(59,429)
1635-305	Main Trx - Survey Costs	3,541,446	2.00%	70,829	1.67%	59,024	(3,222)	55,802	(15,026)
1635-402	Main Trx - O/H Cndctrs/Poles	20,561,275	2.00%	411,226	1.67%	342,688	(19,819)	322,869	(88,357)
1635-404	Main Trx - O/H Cndctrs/Towers	277,975	2.00%	5,560	1.67%	4,633	681	5,314	(246)
1635-710	Main Trx - Sbstn Equip	66,600,655	1.85%	1,233,345	2.22%	1,480,015	(49,104)	1,430,910	197,565
1635-720	Main Trx - Sbstn Buildings	1,536,213	1.82%	27,931	1.82%	27,931	(1,248)	26,683	(1,248)
1635-730	Main Trx - Sbstn Fences	274,477	5.00%	13,724	3.33%	9,149	(1,268)	7,881	(5,843)
	Main Transmission Facilities Total	167,318,667		2,974,173		3,367,031	(79,597)	3,287,435	313,261
	Sub Transmission Lines								

YUKON ENERGY
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION RATES
AT DECEMBER 31, 2018

			Existing		Proposed				
Asset Class ID	**Asset Class ID Description**	**Plant**	**Rate**	**Amount**	**Rate**	**Amount**	**Annual True-Up**	**Total Accrual**	**Difference**
1640-300	Sub Trx - Poles & Fxtrs	4,092,701	2.22%	90,949	2.00%	81,854	(29,008)	52,846	(38,103)
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	2,646,132	8.33%	220,511	8.33%	220,511	(9,179)	211,332	(9,179)
1640-304	Sub Trx - Brushing	41,597	2.00%	832	1.67%	693	3	697	(135)
1640-306	Sub Trx - Brushing Mnt Mn	432,533	8.33%	36,044	8.33%	36,044	(1,504)	34,540	(1,504)
1640-307	Sub Trx - Survey Costs Mnt Mn	95,136	8.33%	7,928	8.33%	7,928	(330)	7,598	(330)
1640-401	Sub Trx - O/H Cndctrs	1,840,369	2.22%	40,897	1.67%	30,673	(3,300)	27,373	(13,524)
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	83,873	2.22%	1,864	2.22%	1,864	695	2,559	695
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	920,693	8.33%	76,724	8.33%	76,724	(3,194)	73,531	(3,194)
1640-710	Sub Trx - Sbstn EEquip	8,013,609	2.50%	200,340	2.22%	178,080	(4,760)	173,320	(27,020)
1640-711	Sub Trx - Sbstn Equips Mnt Mn	6,948,253	8.33%	579,021	8.33%	579,021	4,555	583,576	4,555
	Sub Transmission Lines Total	25,114,895		1,255,111		1,213,393	(46,022)	1,167,371	(87,739)
	Buildings & Other Equipment								
1645-110	Bldg&Otr - Survey Costs Land	4,321	2.00%	86	2.00%	86	28	114	28
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	12,522,631	2.50%	313,066	2.00%	250,453	(1,880)	248,573	(64,493)
1645-201	Bldg&Otr - Building & Imprvmnt	10,102,549	1.82%	183,683	2.00%	202,051	(25,611)	176,440	(7,243)
1645-202	Bldg&Otr-Office Frntr & Equip	1,736,569	5.00%	86,828	5.00%	86,828	(919)	85,909	(919)
1645-210	Bldg&Otr - Comm Site Towers	19,297	3.33%	643	2.50%	482	(195)	288	(356)
1645-220	Bldg&Otr - Comm Site Fences	64,126	5.00%	3,206	3.33%	2,138	(517)	1,620	(1,586)
1645-320	Bldg&Otr - Computer Hardware	1,715,886	20.00%	343,177	14.29%	245,127	(13,386)	231,740	(111,437)
1645-330	Bldg&Otr - Computer Software	304,004	20.00%	60,801	20.00%	60,801	6,311	67,112	6,311
1645-505	Bldg&Otr - Tools & Instruments	1,654,638	5.00%	82,732	5.00%	82,732	(4,565)	78,167	(4,565)
1645-507	Bldg&Otr - Wind Mntrng Equip	14,283	5.00%	714	6.67%	952	2,109	3,061	2,347
1645-605	Bldg&Otr - Comm Equip	4,583,047	5.00%	229,152	5.00%	229,152	(9,307)	219,845	(9,307)
1645-810	Bldg&Otr - Houses/Land	59,031	3.33%	1,968	2.50%	1,476	(134)	1,342	(626)
1645-820	Bldg&Otr - Houses/Buildings	2,051,769	3.33%	68,392	2.50%	51,294	(19,268)	32,026	(36,366)
	Total Building	34,832,152		1,374,449		1,213,572	(67,334)	1,146,238	(228,211)
	Transportation								
1650-411	Trxptn - Utility Vehicles	344,073	14.29%	49,153	12.50%	43,009	(5,132)	37,877	(11,277)
1650-412	Trxptn - Sedans & Stn Wagons	137,764	14.29%	19,681	9.09%	12,524	(2,533)	9,991	(9,690)
1650-420	Trxptn - Trucks & Pole Trailer	11,000	3.23%	1,571	4.00%	440	2	442	(1,129)
1650-430	Trxptn -Pole Trailer>10,000lbs	53,711	4.00%	1,733	4.00%	2,148	(84)	2,064	331
1650-440	Trxptn - Trucks 3/4 to 2 Ton	2,644,537	10.00%	264,454	11.11%	293,837	17,405	311,242	46,789
1650-470	Trxptn - Trucks > 3Tons	1,459,849	5.00%	72,992	5.00%	72,992	3,582	76,574	3,582
1650-490	Trxptn - Foremost	1,003,858	4.00%	40,154	5.00%	50,193	6,029	56,222	16,068
	Total Transporation	5,654,791		449,738		475,144	19,268	494,412	44,674
	Critical Spares								
1655-750	Critical Spares	1,170,184		0	0.00%	0	0	0	0
	LNG Plant								
1665-200	Structures and Improverments	6,184,735	1.39%	85,899	1.39%	85,899	(439)	85,460	(439)
1665-403	Fuel Holders	13,200,669	3.13%	412,521	1.67%	220,011	(13,243)	206,768	(205,753)
1665-500	LNG Generator	20,880,293	2.50%	522,007	2.50%	522,007	2,031	524,038	2,031
1665-600	Accessory Electric Equipment	3,655,939	2.22%	81,243	2.22%	81,243	(693)	80,550	(693)
1665-700	Miscellanours Power Plant Equi	2,828,210	3.33%	94,274	3.33%	94,274	(1,266)	93,008	(1,266)
1665-730	LNG Fence	779,651	3.33%	25,988	3.33%	25,988	(370)	25,618	(370)
	Total LNG	47,529,497		1,221,932		1,029,423	(13,981)	1,015,442	(206,490)
	Total Yukon	611,066,869		12,477,055		12,678,927	(366,170)	12,312,757	(164,299)

Note: The following accounts were excluded from the depreciation study:

1615-504 Hydro Assets Overhaul
1620-504 Diesel Assets Overhaul
1620-504 Diesel Assets Overhaul
Asset 7060 removed from asset group 1615-506
Asset 8856 transferred from asset group 1645-200 to 1615-201

APPENDIX C

Depreciation Parameter Comparison

YUKON ENERGY
COMPARISON OF LIFE PARAMETERS
AT DECEMBER 31, 2018

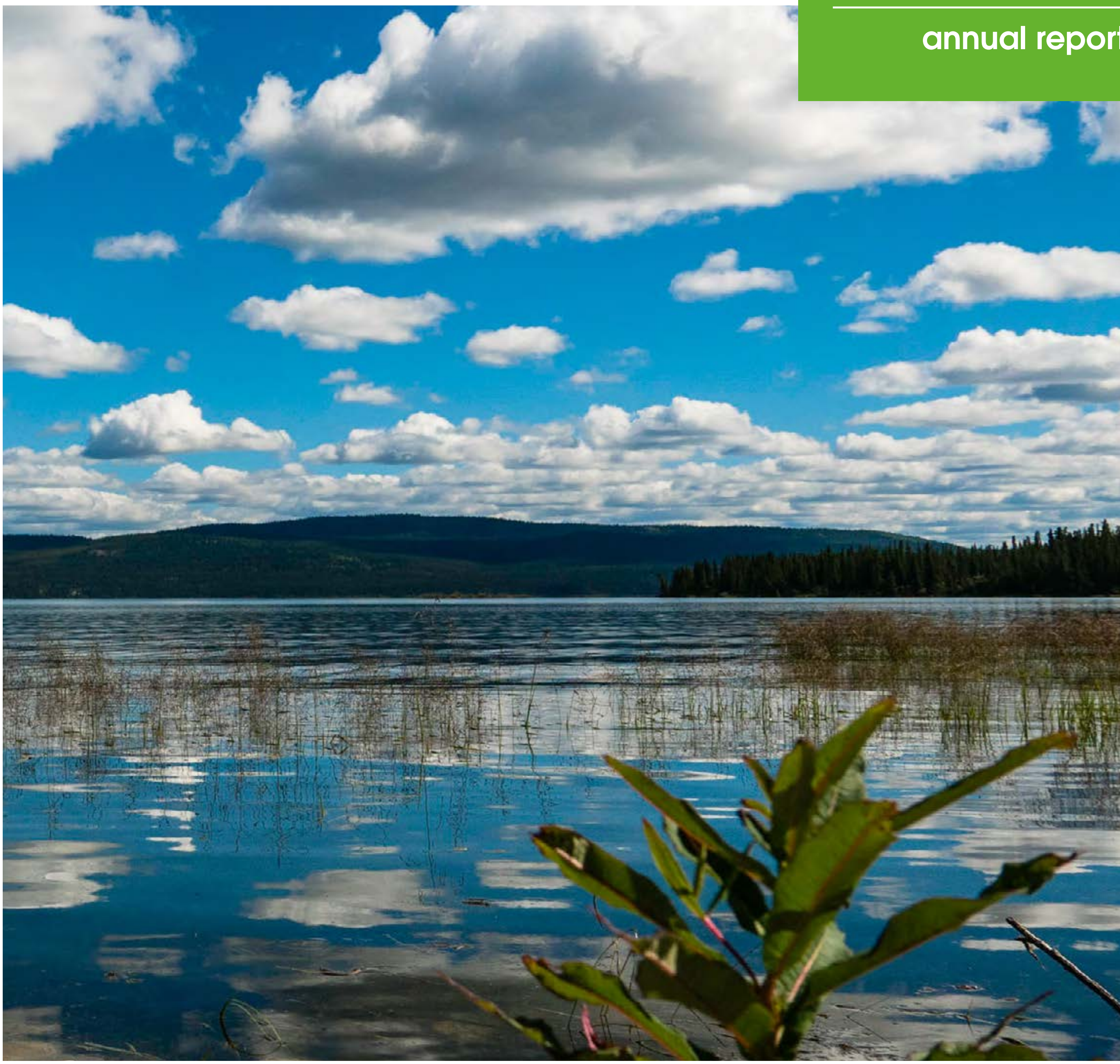
			Existing		Proposed		Difference
Asset Class ID	Old Function	Asset Class ID Description	Life	Iowa Curve	Life	Iowa Curve	Life
		Land					
1610-003	140002	Land Hydro Production	NA	NA	NA	NA	
1610-004	140002	Land Diesel Production	NA	NA	NA	NA	
1610-006	140002	Land Main Trx Facilities	NA	NA	NA	NA	
1610-008	140002	Land Distribution System	NA	NA	NA	NA	
1610-009	140002	Land General Plant	NA	NA	NA	NA	
1610-106	140002	Land Rights	50	R2.5	50	R2.5	0
		Hydro					
1615-200	140003	Hydro-Strctrs & Imprvmts	72	R2	72	R2	0
1615-201	140003	Hydro-Building & Imprvmnt	40	R2.5	40	R2.5	0
1615-205	140003	Hydro-Rsrvoirs Dams & Wtrways	103	R3	103	R3	0
1615-206	140003	Hydro, Dams wtwys Twin Assets	103	R3	103	R3	0
1615-506	140003	Hydro-Wtrwhls, Trbines & Gen's	85	R3	60	R3	-25
1615-600	140003	Hydro-Accessory Electric Equip	45	R3	40	R2.5	-5
1615-601	140003	Hydro Accessory Digital Equip	20	SQ	20	SQ	0
1615-700	140003	Hydro-Misc Power Plant Equip	30	R2	30	R2	0
1615-730	140003	Hydro- Fences	30	R2	30	R2	0
		Diesel					
1620-200	140004	Diesel-Strctrs and Imprvmts	72	R2	72	R2	0
1620-201	140004	Diesel-Building & Imprvmnt	55	R1	55	R1	0
1620-403	140004	Diesel-Fuel Hldrs,Prdcts&Accss	25	R2	40	R2	15
1620-500	140004	Diesel-Gnrtng Equip & Prime	40	R2	40	R2	0
1620-501	140004	Diesel-Gnrtng Equip & Prime Retire 2021	11	SQ	11	SQ	0
1620-508	140004	Diesel-Minto Gnrtng Equip	12	SQ	12	SQ	0
1620-600	140004	Diesel-Acc Electric Equip	45	R3	45	R3	0
1620-700	140004	Diesel-Misc Power Plant Equip	30	R2	30	R2	0
		Distribution					
1625-300	140008	Dist System - Poles & Fxtrs	35	R2	40	R2	5
1625-304	140008	Dist System - Brushing	50	R2	50	R2	0
1625-305	140008	Dist System - Survey Costs	50	R3	50	R2	0
1625-401	140008	Dist System - O/H Cndctrs	35	R2	50	R2	15
1625-410	140008	Dist System - O/H Services	40	R2	40	R2	0
1625-501	140008	Underground Conduit	40	R2.5	40	R2.5	0
1625-510	140008	Dist System - Undrgrnd Cnduit	40	R2.5	40	R2.5	0
1625-610	140008	Dist System - Meters	30	R2	16	SQ	-14
1625-620	140008	Dist System - Meter Equip	30	R2	16	SQ	-14
1625-710	140008	Dist System - Sbstn EEquip	40	R2	40	S0	0
1625-720	140008	Dist System - Sbstn Buildings	55	R1	55	R1	0
1625-730	140008	Dist System- Substation Fences	20	SQ	30	R4	10
1625-815	140008	Dist System - Street Lights	40	R2	40	R2	0
1625-905	140008	Dist System - Line Trxformers	40	R2.5	35	R2.5	-5
1625-961	140008	Dist System - Sentinel Lights	30	L2	30	L2	0
		Main Transmission					
1635-300	140006	Main Trx - Poles & Fxtrs	65	R3	50	R3	-15
1635-304	140006	Main Trx - Brushing	50	R3	60	R3	10
1635-305	140006	Main Trx - Survey Costs	50	R2.5	60	R3	10
1635-402	140006	Main Trx - O/H Cndctrs/Poles	50	R3	60	R3	10
1635-404	140006	Main Trx - O/H Cndctrs/Towers	50	R3	60	R3	10
1635-710	140006	Main Trx - Sbstn Equip	54	S0	45	S0	-9
1635-720	140006	Main Trx - Sbstn Buildings	55	R1	55	R1	0
1635-730	140006	Main Trx - Sbstn Fences	20	R4	30	R4	10

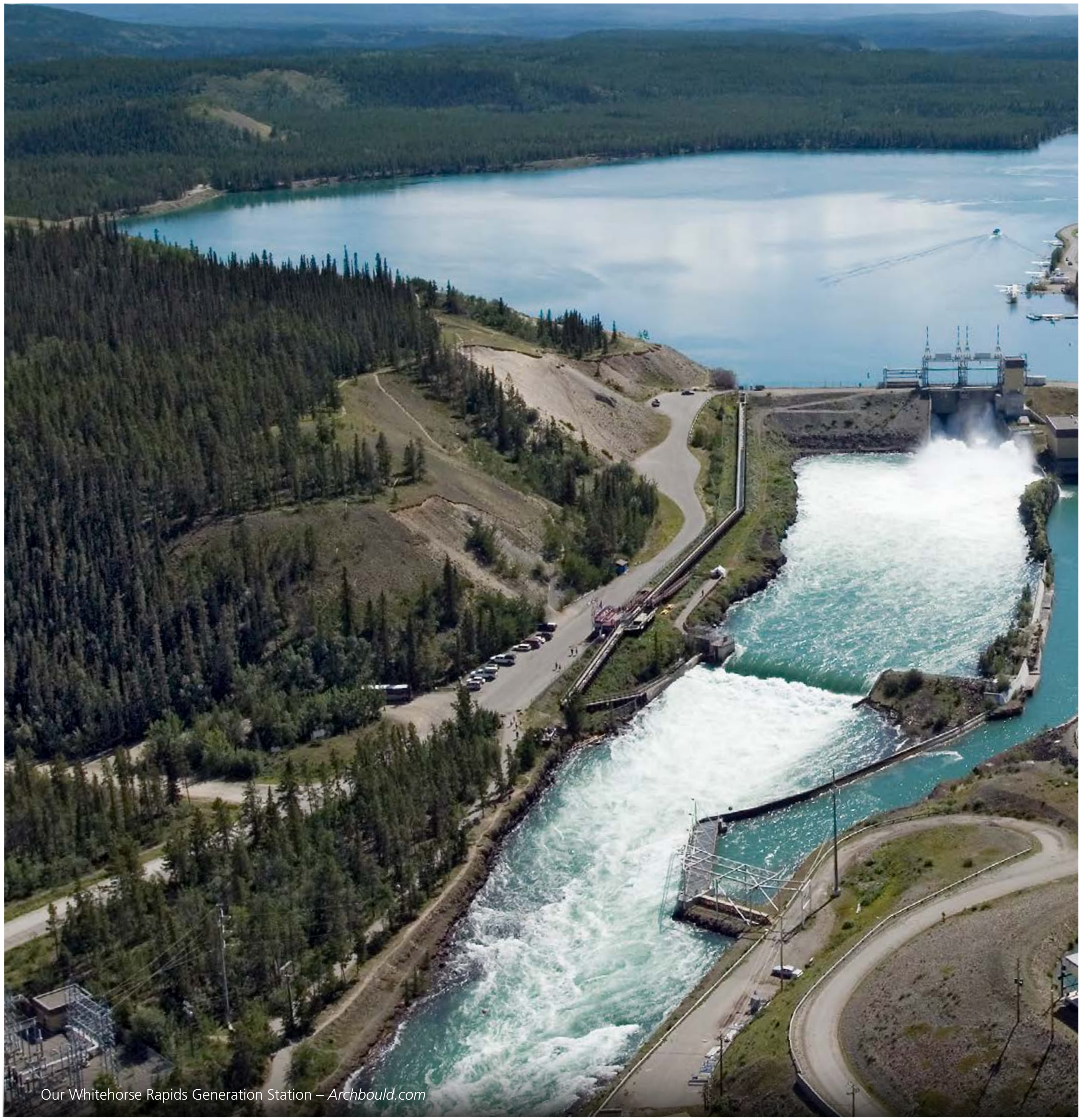
YUKON ENERGY
COMPARISON OF LIFE PARAMETERS
AT DECEMBER 31, 2018

Asset Class ID	Old Function	Asset Class ID Description	Existing Life	Existing Iowa Curve	Proposed Life	Proposed Iowa Curve	Difference Life
		Sub Transmission					
1640-300	140007	Sub Trx - Poles & Fxtrs	45	R3	50	R3	5
1640-301	140007	Sub Trx - Poles & Fxtrs Mnt Mn	12		12	SQ	0
1640-304	140007	Sub Trx - Brushing	50		60	R3	10
1640-306	140007	Sub Trx - Brushing Mnt Mn	12		12	SQ	0
1640-307	140007	Sub Trx - Survey Costs Mnt Mn	12		12	SQ	0
1640-401	140007	Sub Trx - O/H Cndctrs	45	R3	60	R3	15
1640-405	140007	Sub Trx - Undrgrnd Cndctrs/Cnd	45	S3	45	S3	0
1640-407	140007	Sub Trx - O/H Cndctrs Mnt Mn	12		12	SQ	0
1640-710	140007	Sub Trx - Sbstn EEquip	40		45	S0	5
1640-711	140007	Sub Trx - Sbstn Equips Mnt Mn	12		12	SQ	0
		Buildings & Other Equipment					
1645-110	140009	Bldg&Otr - Survey Costs Land	50	R2	50	R2	0
1645-200	140009	Bldg&Otr-Strctrs/Imprvmnt Hyd	40	R2.5	50	R2	10
1645-201	140009	Bldg&Otr - Building & Imprvmnt	55	R1	50	R2	-5
1645-202	140009	Bldg&Otr-Office Frntr & Equip	20	SQ	20	SQ	0
1645-210	140009	Bldg&Otr - Comm Site Towers	30	R2	40	R2	10
1645-220	140009	Bldg&Otr - Comm Site Fences	20	R4	30	R4	10
1645-320	140009	Bldg&Otr - Computer Hardware	5	SQ	7	SQ	2
1645-330	140009	Bldg&Otr - Computer Software	5	SQ	5	SQ	0
1645-505	140009	Bldg&Otr - Tools & Instruments	20	SQ	20	SQ	0
1645-507	140009	Bldg&Otr - Wind Mntrng Equip	20	SQ	15	SQ	-5
1645-605	140009	Bldg&Otr - Comm Equip	20	L4	20	L4	0
1645-810	140009	Bldg&Otr - Houses/Land	30	R3	40	R3	10
1645-820	140009	Bldg&Otr - Houses/Buildings	30	R3	40	R3	10
		Transportation					
1650-411	140014	Trxptn - Utility Vehicles	7	L2	8	L2	1
1650-412	140014	Trxptn - Sedans & Stn Wagons	7	L2	11	S4	4
1650-420	140014	Trxptn - Trucks & Pole Trailer	31	R1.5	25	R1.5	-6
1650-430	140014	Trxptn -Pole Trailer>10,000lbs	25	R1.5	25	R1.5	0
1650-440	140014	Trxptn - Trucks 3/4 to 2 Ton	10	R2	9	L2	-1
1650-470	140014	Trxptn - Trucks > 3Tons	20	R3	20	R3	0
1650-490	140014	Trxptn - Foremost	25		20	R3	-5
		Critical Spares					
1655-750		Critical Spares	NA		NA	NA	NA
		LNG					
1665-200		Structures and Improverments	72		72	R2	0
1665-403		Fuel Holders	32		60	R2	28
1665-500		LNG Generator	40		40	SQ	0
1665-600		Accessory Electric Equipment	45		45	R2	0
1665-700		Miscellanours Power Plant Equi	30		30	R2	0
1665-730		LNG Fence	30		30	R2	0

TAB 10
2019 AUDITED FINANCIAL STATEMENTS

2019
annual report




Our Whitehorse Rapids Generation Station – *Archbould.com*

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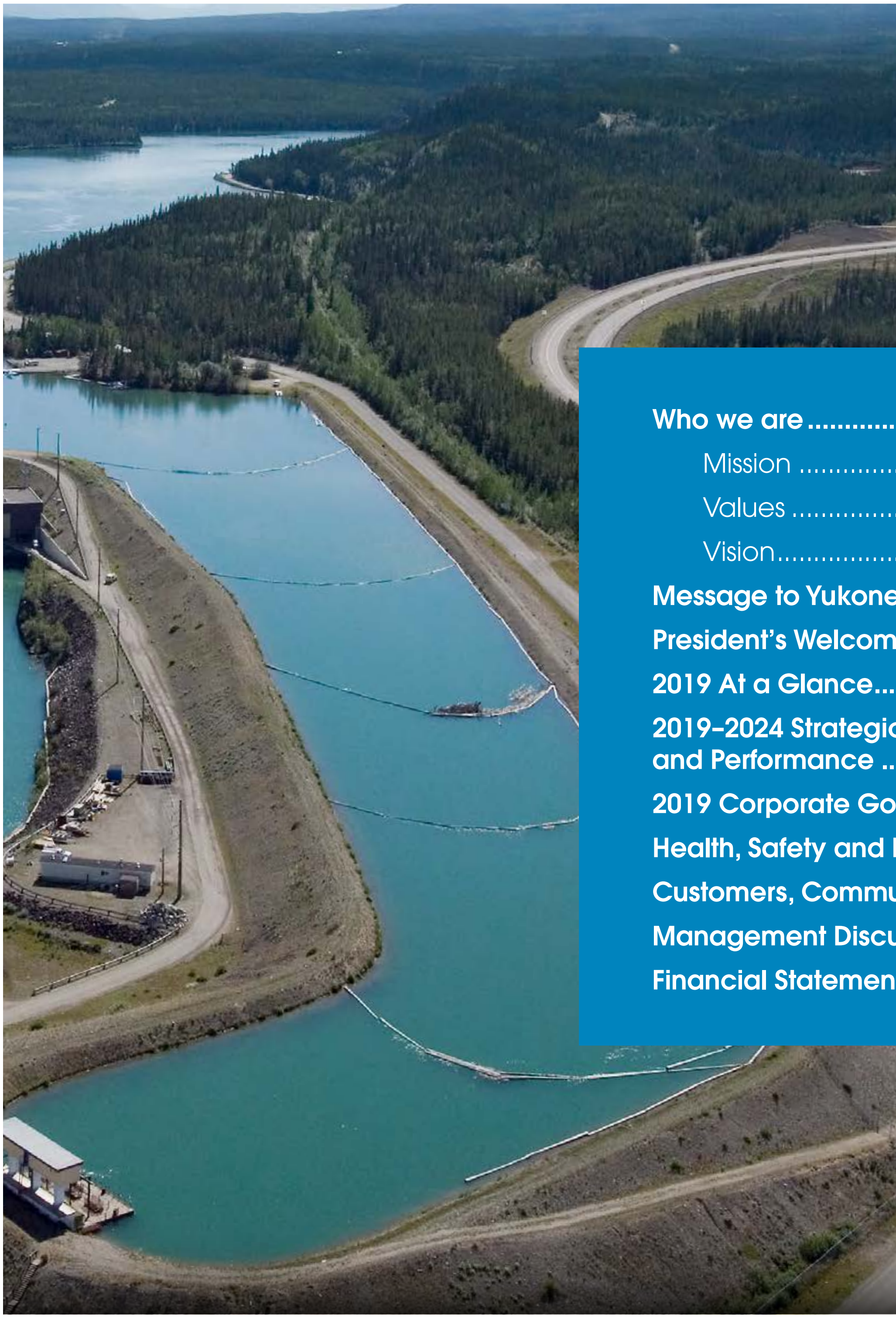


who we are

Established in 1987, Yukon Energy is a publicly owned electrical utility that operates as a business, at arms-length from the Yukon government. We are the main generator and transmitter of electrical energy in Yukon. We work with our parent company, Yukon Development Corporation, to provide Yukoners with sustainable, cost-effective and reliable electricity.

There are over 21,000 electricity consumers in the territory. Yukon Energy directly serves over 2,200 of these customers, most of whom live in and around Dawson City, Mayo and Faro. Indirectly, we provide power to most other Yukon communities through ATCO Electric Yukon. ATCO buys wholesale power from us and sells it to retail customers in the territory.

Most of the electricity we produce is renewable, coming primarily from hydro resources generated at our Whitehorse, Aishihik and Mayo hydroelectric facilities. A small amount of liquefied natural gas (LNG) and diesel are also used to ensure reliable and cost-effective electricity is available when it's needed at peak times, during emergencies and when renewable sources of electricity are not available.

Our headquarters are located near the Whitehorse Rapids hydro plant in Whitehorse, with community offices in Mayo and Dawson City.

Mission

To enable Yukon's prosperity with sustainable, cost-effective and reliable electricity

Values

- Safety
- Accountability
- Continuous Improvement
- Teamwork
- Professionalism
- Good Corporate Citizenship

Vision

To establish a sustainable legacy for Yukon's future

Our corporate office in Whitehorse – Archbould.com

3

Looking downstream of the Mayo hydro facility – Archbould.com

2019

Board of Directors

- Lesley Cabott
  Chair
- Clint McCuaig
  Vice-Chair
- Susan Craig
- John Jensen
- Gary Jones
- Simon Lapointe
- Mike Pemberton
- Wendy Shanks
- Rod Snow
- Jim Stephens

message to yukoners

In July 2019, we released our 5-year strategic plan with a bold vision to be a Canadian leader in sustainable energy by 2030.

In 10 years, we envision a robust and affordable energy system in Yukon that:

- is based on sustainable, renewable and low-carbon sources;
- abundantly supports Yukon's growth and prosperity;
- is reliable enough to keep the lights on in -45ºC weather conditions, even if a major hydroelectric facility or system component fails; and
- exemplifies respectful, mutually beneficial and truly collaborative partnerships with First Nations.

Our work to begin drafting our 10-Year Renewable Electricity Plan in late 2019 is a clear demonstration of our commitment to fulfilling this strategy.

Our 10-Year Renewable Electricity Plan is a bold plan, developed in response to our Board of Directors' decision not to proceed with a new thermal generation facility in 2019 and Yukon government's draft *Our Clean Future* strategy. Our plan features innovation and three new renewable electricity projects that set us up to be, on average, 97% renewable by 2030.

1. Sourcing renewable electricity from the planned Atlin hydro expansion.
2. Building a new pumped storage facility at Moon Lake.
3. Expanding and upgrading the Southern Lakes transmission network.

Yukon Energy recognizes First Nations governments as energy proponents, partners and investors in Yukon's electricity system. First Nations governments, development corporations and Citizens will all have a key role in helping us refine and deliver our 10-Year Renewable Electricity Plan over the next decade.

A new Vice President of First Nation Relations role in our organization in 2020 will lead us on the path to proactively engage and develop mutually beneficial partnerships with First Nations governments as we begin to work on the projects identified in the renewable electricity plan next year.

Our 10-Year Renewable Electricity Plan doesn't come without its challenges. Building and maintaining such a high degree of renewable electricity generation – especially as Yukon's economy and communities continue to grow and Yukoners increasingly invest in electric vehicles and heating – will come at a cost.

More than $500 million is needed to build the projects identified in the plan. With just over 21,000 electricity customers in Yukon, federal funding will be key to keeping the plan affordable for our customers and minimizing project risks. However, as provinces and territories across Canada also work to combat climate change, one can only imagine that there will be more projects than available funding across Canada.

Yukon Energy and Yukoners will need to help pay for the renewable energy future we all want. Electricity rates will need to increase over the next 10 years. By how much? It's too early to tell, but as the fruits of our labour showed this past year when we received funding for a new grid-scale battery, the Mayo to McQuesten Transmission Line Replacement project, and the Peak Smart program, we are committed to pursuing the government funding and partnerships needed to help minimize the impact of rate increases on Yukoners.

This is an exciting and challenging time in Yukon Energy's history. Our Board of Directors and staff look forward to working together to capitalize on the opportunities in front of us and to report back to you on our continued progress in future reports.

Lesley Cabott
Chair, Yukon Energy Corporation Board of Directors

president's welcome

Being responsible for keeping the lights on in Yukon is a sincere privilege. It not only means a great deal to me, but also to the team of dedicated individuals that I'm fortunate to lead.

Yukon Energy generates most of our electricity from hydroelectric facilities, making our energy production among the greenest in the world. During emergencies or low water periods, we generate additional electricity through our LNG and diesel plants. That's how we do it.

We have a vision of being a Canadian leader in sustainable energy by 2030. To achieve it, we make it our mission each day to provide sustainable, cost-effective and reliable electricity, while also working to plan, permit and build the renewable electricity resources that are needed in the future. That's why we do it.

The why behind our work sheds light on our activities over the past year and provides perspective on why we plan, propose, build, operate, maintain and upgrade the things we do.

I'd like to share three examples with you of how that played out in 2019.

1. Sustainable

Being sustainable means having a robust and affordable electricity system made up of the right mix of renewable and low-carbon sources of electricity. It means having an electricity system reliable enough to keep the lights on in -45°C weather conditions during the winter, even if a major hydroelectric facility or system component fails. It means having enough electricity generation resources available to support Yukon's growth and prosperity. It also means building, operating and maintaining those assets in a way that exemplifies respectful, mutually beneficial and truly collaborative partnerships with Yukon First Nations, other governments, communities and industry.

2. Cost-effective

Operating as we do on an isolated and far-flung grid in a lightly populated region subject to weather extremes, means costs could easily become prohibitive for our customers. One of our most important jobs on behalf of Yukoners is to secure outside funding. In 2019, we secured nearly $40 million from the federal government for three significant projects: replacing and upgrading the ailing, 65-year old Mayo to McQuesten transmission line, building an 8 MW grid-scale storage battery and piloting the Peak Smart demand-side management program. While our electricity rates increased in 2019, what Yukoners pay for power remains the lowest in Canada's North.

Full moon over Dawson City – Archbould.com

3. Reliable

Running a hydro operation means being at the mercy of available water. Over the past two winters, low snowpack resulted in lower than normal inflows at all three of our hydroelectric facilities. Regardless of what Mother Nature delivered, our mission to provide reliable electricity to Yukoners did not change. This past year, we used more LNG to generate electricity to make up for the shortfall in hydro generation and rented diesel generators to meet growing demands for power during winter months. In the coming years, as our grid-scale battery comes on line and we continue to build and integrate more sources of renewable electricity on the grid, we will have other, greener options to serve our customers and keep the lights on.

This work is complex and challenging. But the satisfaction of fulfilling our vision and mission is what gets us up and out the door every morning.

That's the power of Yukon.

Andrew Hall
President and CEO, Yukon Energy Corporation

generating capacity in the summer

124 megawatts

peak demand [1]

generating capacity in the winter [2]

106 megawatts

0

reportable motor vehicle incidents [3]

[1] recorded on January 8, 2019
[2] caused by a lower supply of hydro resources during winter months
[3] with damage exceeding $5,000 as defined by the Canadian Electricity Association

2019 at a glance

90 megawatts

electricity supplied
440 gigawatt hours

renewable generation [4]
84 per cent

0
environmental spills [5]

[4] due to low water levels in spring 2019
[5] as defined by *Yukon Spills Regulations*

2019–2024 strategic priorities and performance

STRATEGIC PRIORITY	PERFORMANCE
Generate reliable and renewable energy	Historically, more than 90% of the electricity we generate comes from renewable resources, primarily hydro. This year we were only able to generate 84% renewable electricity due to low water levels and inflows in the Whitehorse, Mayo and Aishihik reservoirs. However, we were able to continue to provide reliable power in the winter months by renting diesel generators. We also began work on our draft 10-Year Renewable Electricity Plan that will set us up to be a Canadian leader in sustainable energy by 2030. The projects and partnerships outlined in the plan will help us to generate more than 97% renewable electricity, on average, each year.
Secure long-term sustainable funding	We worked with our shareholder, Yukon Development Corporation, to secure funding for projects outlined in our 5-year capital project plan. We also secured nearly $40 million in federal funding for the Mayo to McQuesten Transmission Line Replacement project, Peak Smart program and Grid-Scale Battery Storage project.
Develop mutually beneficial First Nations partnerships	We recognize First Nations as energy proponents, partners and investors. First Nations participation in assessments, permitting and approval stages is critical to the success of any new project. This year, we signed a Project Agreement with the First Nation of Na-Cho Nyäk Dun for the Mayo to McQuesten Transmission Line Replacement project. This agreement creates First Nations procurement opportunities and provides legacy benefits to the First Nation.

STRATEGIC PRIORITY	PERFORMANCE
Achieve excellence in employee engagement	Results from an employee survey conducted in late 2019 showed an increase in performance in almost all areas of the survey. The greatest overall performance increases were in the information sharing, information to make decisions, and trusting your supervisor categories. In 2019, we also established an Extended Leadership Team that continues to provide input and support of corporate initiatives today.
Streamline and clarify governance	In 2019, a Protocol Agreement was signed between the Chair of Yukon Energy Corporation's Board of Directors and the Chair of Yukon Development Corporation's Board of Directors. The Agreement describes Yukon Energy's accountabilities in relation to Yukon Development Corporation's performance expectations for the utility. It outlines both corporations' agreement to each of their respective roles and responsibilities, and provides a framework that encourages strong corporate governance of Yukon Energy.
Provide outstanding, reliable customer value	This year, we continued to work on our *My Account* online customer portal. The new system will provide customers with the ability to view current and past bill statements, compare monthly electricity usage, pay electricity bills and request electrical services online. The online system will be released in late 2020.

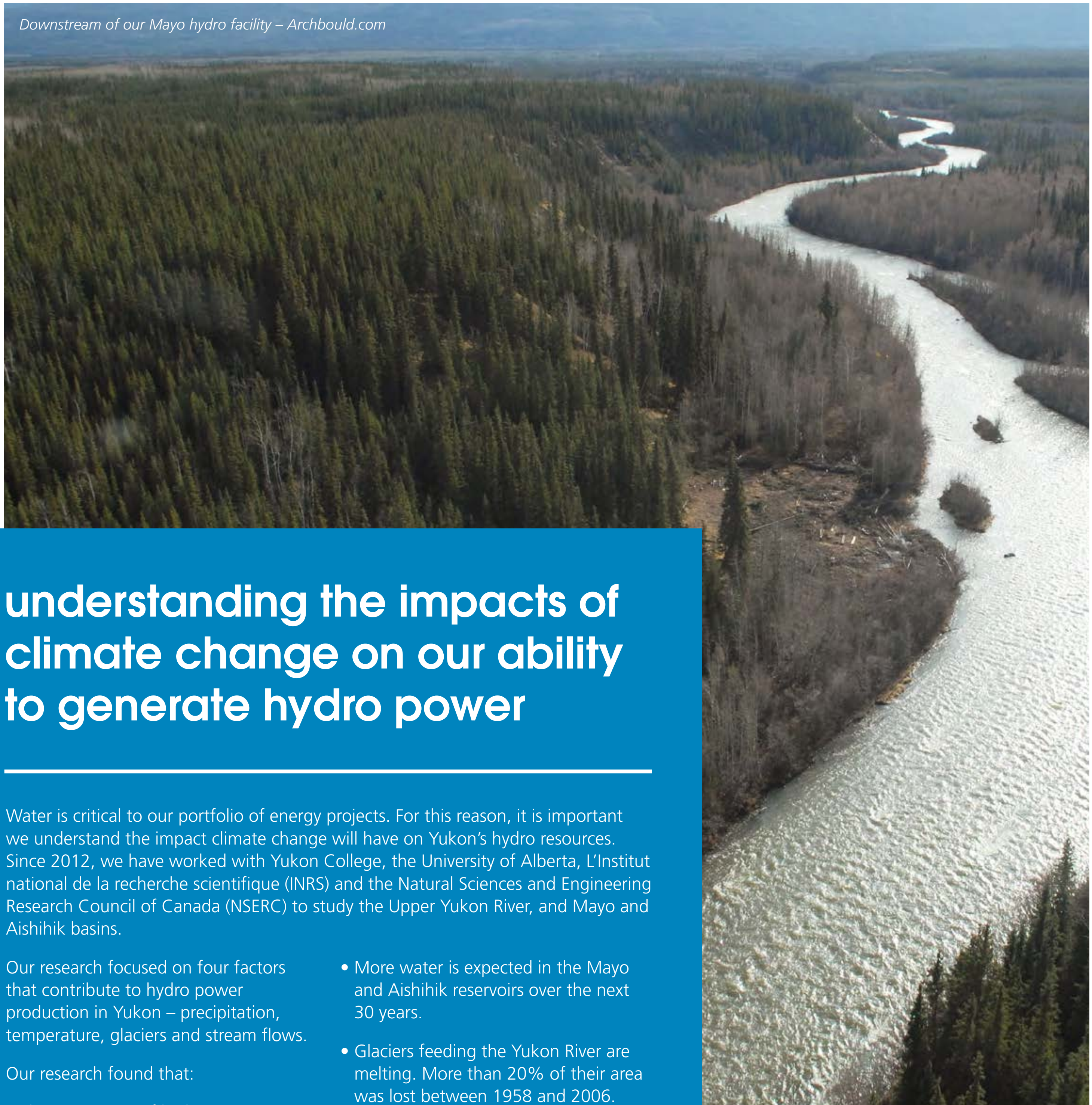
2019 corporate goals and performance

CORPORATE GOAL	PERFORMANCE
Achieve an All Injury Frequency Rate of 1.0 or less	In 2019, we had an All Injury Frequency Rate of 7.6, the result of 5 Medical Aids and 1 Lost Time Injury within the organization. Employee, contractor and public safety remain a key area of focus for us in 2020.
Achieve a Reportable Motor Vehicle Incident Rate of 0	Achieved.
Achieve 10 or less controllable outages	We had 13 controllable outages in 2019, compared to 12 in 2018.
Achieve a Return on Equity (ROE) of 5.58%	The 2019 ROE was 3.52%, down from 6.54% in 2018.
Complete key employee development and engagement initiatives	In 2019, we established an Extended Leadership Team that continues to provide input and support of corporate initiatives today.
Develop a plan to advance a new mid-scale hydro project	We completed an updated scan of potential mid-scale hydro sites across Yukon as part of the work on our 10-Year Renewable Electricity Plan. We have identified the Atlin Expansion project as a project of focus in the plan.
Develop a plan for temporary thermal rental (2019–2022)	Achieved. A contract to secure the temporary thermal rentals needed to meet peak demands for power between 2019 and 2022 was executed.
Complete preliminary engineering and select a site for the new thermal plant	A fulsome public engagement process was executed. Based on public input, Yukon Energy made the decision not to proceed with a new green-field thermal plant.
Complete key projects for the Eagle Mine grid connection	Achieved. The Eagle Mine was connected to the Yukon grid on May 10, 2019.
Complete Year 2 deliverables for the Asset Management project	More than 75% of the work planned for Year 2 was completed. A Managed System Governance Model was added to the scope of the project and also developed. This resulted in a shift of the remaining Year 2 project deliverables to Year 3.
Complete the Yukon Water Board hearing for the Aishihik hydro re-licensing project	The decision bodies (Government of Yukon Department of Energy, Mines and Resources, and the Department of Fisheries and Oceans Canada) issued a joint decision document on the 3-year licence renewal YESAA project proposal on October 21, 2019. The Yukon Water Board approved the 3-year water use licence renewal on February 19, 2020.

Gathering public input on our proposed new 20 megawatt thermal facility – Yukon Energy

0

reportable motor vehicle incidents



Downstream of our Mayo hydro facility – Archbould.com

understanding the impacts of climate change on our ability to generate hydro power

Water is critical to our portfolio of energy projects. For this reason, it is important we understand the impact climate change will have on Yukon's hydro resources. Since 2012, we have worked with Yukon College, the University of Alberta, L'Institut national de la recherche scientifique (INRS) and the Natural Sciences and Engineering Research Council of Canada (NSERC) to study the Upper Yukon River, and Mayo and Aishihik basins.

Our research focused on four factors that contribute to hydro power production in Yukon – precipitation, temperature, glaciers and stream flows.

Our research found that:

- The generation of hydro power is not expected to be negatively impacted by climate change.
- It has and will continue to get warmer and wetter in Yukon.
- We can expect more variability in precipitation in the future, but wet years will be wetter and dry years will be wetter than today's averages.
- More water is expected in the Mayo and Aishihik reservoirs over the next 30 years.
- Glaciers feeding the Yukon River are melting. More than 20% of their area was lost between 1958 and 2006.
- Glacier melt and wastage makes up 23% of inflows in the Upper Yukon River. Glacier melt is causing more inflows in the Yukon River right now.
- More research is needed to understand the implications of climate change on the Upper Yukon River system over the next 30 to 80 years.

health, safety and environment

Health and Safety

We believe our employees to be our greatest asset. That's why their health and safety is part of every decision we make and every action we take.

- 93% of Yukon Energy employees attended monthly safety meetings.
- We had zero reportable motor vehicle incidents in 2019.
- 407 employees from 93 contract companies completed our safety orientation.
- 50% of Yukon Energy staff utilized the company's wellness subsidy.

Sustainability and Environment

Yukoners have significant concerns about climate change and its impacts on the place they call home. We share those concerns and are actively working to build a sustainable energy future in Yukon.

- We raised and released about 133,000 chinook salmon from our Whitehorse Rapids Fish Hatchery.
- About 23,000 imported Lyndon rainbow trout, 1,100 Kathleen rainbow trout, 4,600 imported Kamloops rainbow trout, 33,000 Icy Waters Arctic char and 41,000 kokanee salmon were raised at the Whitehorse Rapids Fish Hatchery.
- We continued our support of the Celebration of Swans Festival.
- We completed work with the L'Institut national de la recherche scientifique (INRS), the Natural Science and Engineering Research Council of Canada (NSERC) and Yukon College to monitor and assess the long-term effects of climate change in the Mayo and Aishihik reservoirs. Research on the Whitehorse reservoir continues in 2020.

customers, community and partnerships

Customers

We are committed to providing sustainable, reliable and cost-effective electricity service to our customers. We also believe in providing Yukoners with the information and tools they need to better manage their electricity use and to conserve energy, when and where possible.

RELIABILITY OF SERVICE

- Low snowpack in Yukon over the last two winters has meant that less water has been available to generate renewable electricity. As a result, we've had to run our LNG and diesel generators to fill the gap that could not be met by hydro power.
- The demand for electricity is growing in Yukon. Under certain emergency conditions, the demand for power exceeds what's available. Because of this, we continued to rent portable diesel generators this winter to protect Yukoners from prolonged outages.

OUTAGES

Total Number of System Outages in 2019: 79

Top Causes of System Outages in 2019:

- Planned outages
- Adverse weather
- External interference (e.g., third-party contact, wildlife)

CUSTOMER RATES

Yukoners need sustainable, reliable and cost-effective electricity today and into the future. To ensure we have it, Yukon Energy invests millions of dollars to build, operate and maintain our electricity supply and transmission assets.

On November 24, 2019, our regulator, the Yukon Utilities Board, approved a 4.7% permanent increase to electricity bills, effective December 1, 2019. The decision followed a 29-month review of our 2017/2018 General Rate Application and a 4.6% interim increase to bills on September 1, 2017. An additional temporary rate rider of 7.1% was also approved to allow us to collect revenue from 2017, 2018 and 11 months of 2019 that we couldn't otherwise collect during the regulatory process.

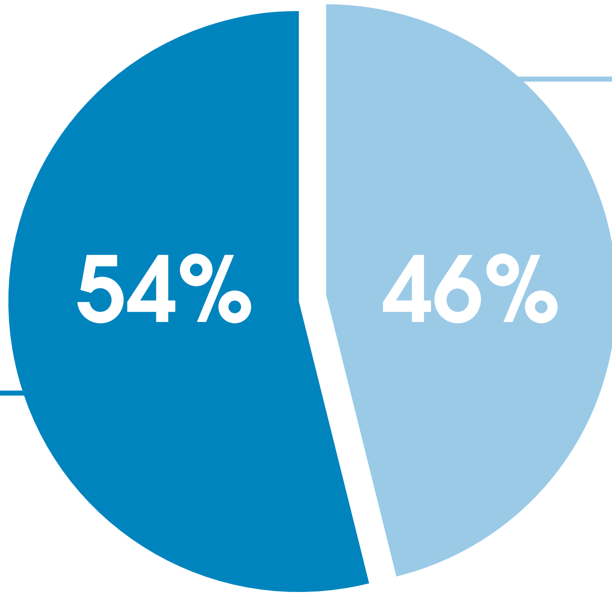
Why the increase was needed

Yukon's continuing demand for sustainable and reliable electricity comes at a cost. The increase to electricity bills was needed to pay for:

- past costs to upgrade aging infrastructure and build new projects; and
- inflation costs related to running our business, operations and maintenance.

Drivers for the increased costs

Past costs to upgrade aging infrastructure and build new projects, e.g., upgrades to the Takhini substation, building the Whitehorse LNG facility (units 1 and 2) and major repairs to the elevator shaft at our Aishihik hydro facility.



Inflation costs to run our business, operations and maintenance, e.g., increasing costs for labour, materials and contractors.

Even with the rate increase, Yukon's residential electricity bills are still the lowest in the North and competitive with other jurisdictions in Canada and the United States.

ENERGY CONSERVATION

Peak Smart

- This year, in partnership with ATCO Electric Yukon, Yukon Development Corporation and Natural Resources Canada, we launched a two-year pilot project called Peak Smart.
- Peak Smart aims to shift peak demands for power by using Internet-connected devices on electric hot water tanks and baseboard heaters to shift the times these heaters are used away from peak times of electricity consumption which typically happen during the breakfast and dinner hours.
- By shifting peak demands for power, we hope to be able to use less diesel to generate electricity during peak times.

OTHER MILESTONES

- We connected Victoria Gold's Eagle Gold Project to the Yukon grid on May 10, 2019.
- By connecting Eagle Gold to the Yukon grid, we are supplying the mine with renewable sources of electricity and reducing its carbon footprint.
- Without access to renewable electricity, the mine would have to rely on thermal resources to generate power.

hydro power – what happens when there's not enough?

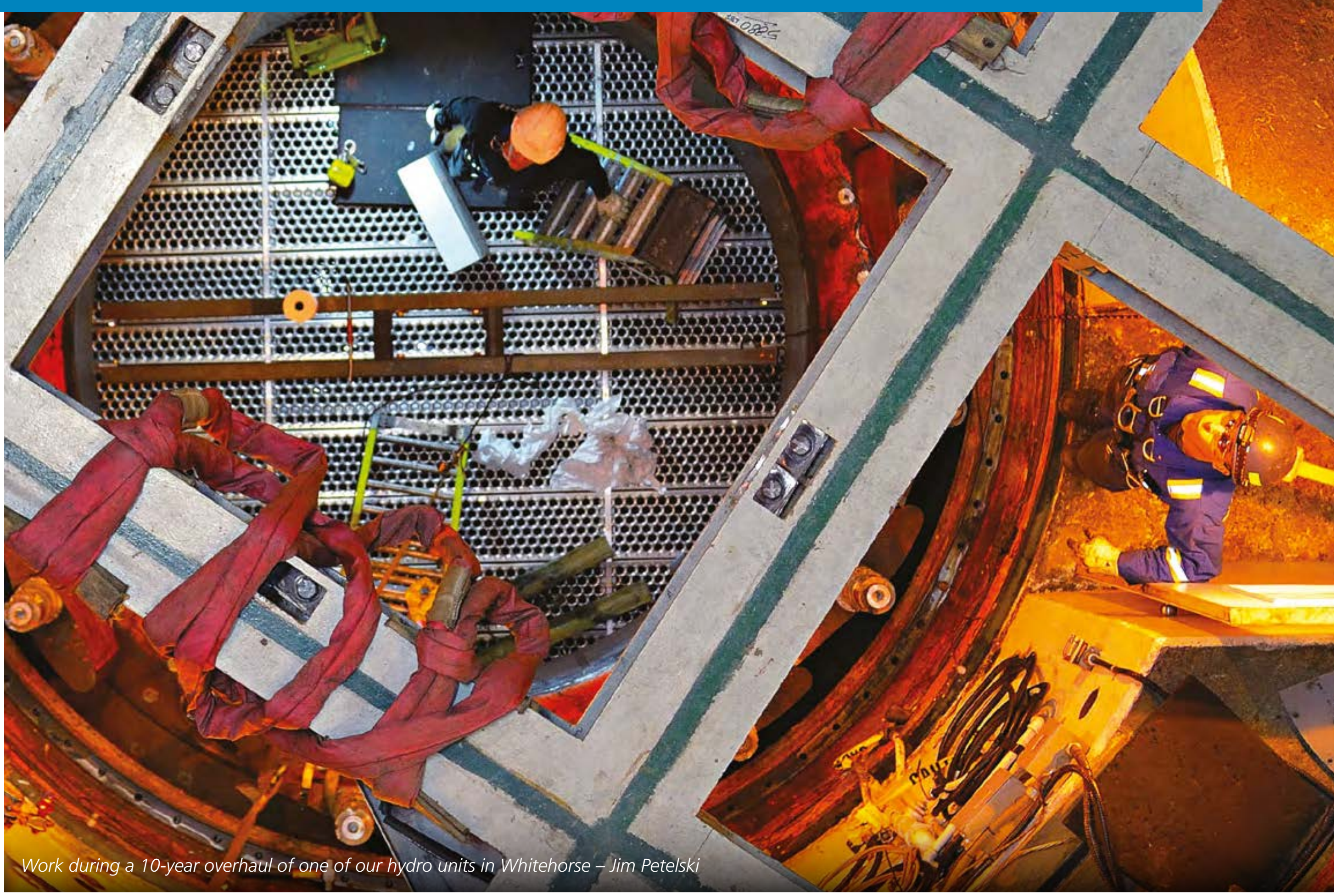
Running a hydro operation means we need a steady and reliable supply of water. We had enough in 2018 to generate 92% of the electricity needed in Yukon. Liquefied natural gas and diesel generators made up the other 8%.

But 2019 was a very different year. By March of 2019, there was reduced snowpack and lower water inflow levels at all three of our hydroelectric facilities compared to previous years. Snowpack levels at our Whitehorse reservoir were 63% of normal levels, Aishihik at 45% and Mayo at 70%.

Because Yukoners need electricity even when Mother Nature changes things up, we were required to use more LNG and diesel than normal in 2019. Hydroelectricity accounted for 84% of our total energy supply in 2019, LNG 15% and diesel 1%.

We continue to pursue renewable alternatives to LNG and diesel such as grid-scale battery storage, and solutions that maximize existing hydro infrastructure, like hydro upratings and the Southern Lakes and Mayo Lake Enhanced Storage projects. We will also explore new sources of dependable renewable capacity as part of our 10-Year Renewable Electricity Plan.

Finally, we will continue to encourage Yukoners to use electricity wisely with programs such as Peak Smart.



Work during a 10-year overhaul of one of our hydro units in Whitehorse – Jim Petelski

Community

As a Crown corporation, the "shareholders" of Yukon Energy are ultimately Yukoners themselves. We never lose sight of that fact. Engaging with Yukoners is high on our list of operating practices. So, too, is giving back to the communities we are privileged to serve.

NEW THERMAL GENERATION PROJECT

In 2019, we asked Yukoners for their feedback on our proposed new 20 megawatt (MW) thermal generation facility. The facility was meant to provide electricity quickly during loss of hydro generation, peak hours of consumption, low water periods, extreme low temperatures and emergencies.

Four open houses were held in the first week of June, generating over 500 questions and comments. An online survey was also available, garnering 447 responses, along with several other comments we received by email and phone. From the feedback we received, it was clear that Yukoners did not want us to proceed with building a new green-field diesel or LNG facility.

Based on the feedback, the Yukon Energy Board of Directors agreed to explore other alternatives.

SOUTHERN LAKES ENHANCED STORAGE PROJECT

Since 2009, Yukon Energy has collected input from Southern Lakes residents and property owners about the Southern Lakes Enhanced Storage Project. The project would help us generate more electricity using water each winter, and reduce the use of fossil fuels. Over the years, the Corporation has also had discussions with the Carcross/Tagish First Nation, Kwanlin Dün First Nation and Ta'an Kwäch'än Council to understand potential impacts of the project on Traditional and Settlement Lands in the project area.

In 2019, at the direction of a newly appointed Yukon Energy Board of Directors and in follow-up to a request made by the Yukon Utilities Board to re-examine the proposed project, Yukon Energy undertook a comprehensive final round of public and stakeholder engagement to obtain information about the current level of social licence for the project, both amongst Southern Lakes residents and property owners, and other Yukoners.

Between August 2019 and January 2020, feedback was collected through five community meetings, three Local Advisory Council meetings, four pop-up booths, an online input form, email submissions and both a Southern Lakes residents and Yukon-wide web and phone survey.

All feedback is being compiled into a What We Heard report that will be released in 2020. The Board's decision about whether to move forward on the project will also be released in 2020.

Community

CORPORATE CONTRIBUTIONS

At Yukon Energy, we believe in the importance of giving back to our community. In 2019 we:

- Increased our corporate contributions budget and developed a giving category specific to First Nations culture and community programming.
- Contributed more than $116,000 to more than 25 community organizations across Yukon in the following areas.
    - Arts, culture and tourism
    - Sports and recreation
    - Health, social services and education
    - Sustainable development
    - First Nations culture
- Made an additional one-time $100,000 contribution to the 2020 Arctic Winter Games.
- Donated more than $23,000 to United Way Yukon during our annual United Way campaign.
    - Employees and Yukon Energy board members donated $11,842 through online auction purchases, pay-roll deductions and one-time donations of cash or meeting honourariums.
    - Yukon Energy matched donations dollar-for-dollar.
    - Seven Yukon Energy employees donated their time to pack emergency food kits and stock shelves at the Whitehorse Food Bank.
- Awarded $12,000 in post-secondary scholarships.

Partnerships

FIRST NATIONS

We recognize First Nations as governments and energy proponents, partners and investors. We are committed to working with First Nations governments and development corporations to forge partnerships and create opportunities for investment, contracting, employment and training.

- On November 23, 2019, we signed a Project Agreement with the First Nation of Na-Cho Nyäk Dun for the Mayo to McQuesten Transmission Line Replacement project that:
    - provides a legacy benefit to the First Nation;
    - creates First Nations procurement opportunities with a 20% weighting of First Nations benefits in each Request for Proposals (RFP);
    - enables the First Nation to provide input into the RFP terms and evaluation criteria;
    - provides for one local First Nations Citizen to be employed as a First Nations Wildlife Monitor during periods of construction; and
    - makes salvageable wood accessible.

We are also committed to creating a diverse and inclusive workplace representative of the communities we live and work in. That commitment means implementing strategies to guide increased participation of First Nations Citizens in our workplace and enhancing our cultural awareness and understanding of Yukon First Nations.

- All employment opportunities during the year were shared with Yukon First Nations.

- In 2019, all Yukon Energy board members and 56% of our employees participated in Yukon College's Yukon First Nations Core Competency course. The remainder of our staff will complete the training in 2020. This training is also now a requirement for all new Yukon Energy employees and board members.

We also continue to work on our Canadian Council for Aboriginal Business Progressive Aboriginal Relations (PAR) Committed designation, which recognizes results in aboriginal relations through leadership actions, employment, business development and community relationships.

- We are in Phase 2 of 3 of the PAR Committed designation and are preparing our application for PAR certification.

Progressive Aboriginal RELATIONS COMMITTED

Canadian Council for Aboriginal Business

UTILITY AND INDUSTRY

- We partnered with ATCO Electric Yukon, Yukon Development Corporation and Natural Resources Canada on our Peak Smart program.
- We actively participated in subgroups of the Canadian Electricity Association sharing industry best practices.

YUKON AND FEDERAL GOVERNMENTS

Our large and far-flung electrical system serves a modest group of rate payers. It requires the support of outside funding for substantial projects. In 2019, Yukon Energy secured almost $40 million in federal funding. This funding went towards the following.

Peak Smart

- We received $650,000 from the federal government to implement Peak Smart, a two-year pilot program meant to shift energy use away from periods of peak demand and thus reduce the use of fossil fuels.

Mayo to McQuesten Transmission Line Replacement Project

- We received $22.7 million in federal funding to proceed with this critical project needed to improve power quality and reliability, improve public safety, and foster future economic growth in the Mayo and Keno areas.

Grid-Scale Battery Storage

- We received $16.5 million in federal funding to support the construction of our new battery storage system. Once completed, the new battery will be one of the largest grid-connected batteries in Canada.

Photo – aasman brand communications

$2.3

million net income in 2019

management discussion and analysis

Core Business and Strategy

Our business is the generation and transmission of electrical energy to most of Yukon. We also distribute electricity to a number of Yukon communities including Dawson City, Mayo and Faro. We strive for energy production that is sustainable, reliable and cost-effective. Our primary source of power comes from our legacy hydro assets and our goal is to minimize the use of non-renewable sources due to higher variable cost and environmental impacts.

Yukon Energy's strategy is based on the following key strategic pillars.

SUSTAINABILITY

Yukon Energy is committed to the principles of sustainability in all our business practices, with the objective of protecting and enhancing Yukon's human and natural resources. Yukon Energy developed a Sustainability Policy in 2017 and was awarded the "Sustainable Electricity Company" designation by the Canadian Electricity Association (CEA) in 2017. In terms of the development of new energy resources, Yukon Energy is committed to developing renewable resources while recognizing the limitations of certain forms of renewable generation in meeting the energy and capacity needs of Yukon's isolated grid. Thermal generation will continue to play an important role in meeting peak electricity demand cost-effectively, and providing insurance against contingent events such as drought and outages of key hydro facilities. Yukon Energy applies a social cost of carbon to the economics of future thermal generation resources, in order to level the playing field between renewable and fossil fuel options when planning new resource investments.

FIRST NATIONS RELATIONSHIPS

Yukon Energy is committed to active engagement with Yukon First Nations, striving to meet the spirit and intent of Land Claims obligations. We recognize First Nations as decision bodies and energy proponents, partners and investors. We seek to leverage Yukon Energy's ongoing business operations and future project development work to create opportunities for economic, social and cultural development for Yukon First Nations. Key First Nations initiatives include project-specific agreements, and Yukon Energy's First Nations Employment and Procurement policies. Yukon Energy is pursuing certification under the Canadian Council for Aboriginal Business Progressive Aboriginal Relations (PAR) program to manage and benchmark its First Nations engagement program.

DISCIPLINED FINANCIAL MANAGEMENT

Given the rate pressures faced by Yukon Energy's customers and the prospect for future rate increases driven by the Corporation's capital investment needs, disciplined financial management of Yukon Energy's operating and project-related business is essential. Yukon Energy is also committed to continuous improvement as a management philosophy to drive sustained improvements in its operational performance and efficiency.

RIGOROUS AND PROACTIVE PLANNING

Yukon Energy applies industry best practices and processes for the planning of future capital investments required to sustain the Corporation's aging infrastructure and address growing demand for energy and capacity. Rigorous planning of future investments is required to optimize and prioritize capital expenditures, accounting for the financial constraints within which the Corporation operates. Key business processes that support these planning activities include Integrated Resource Planning and Asset Management. Yukon Energy has developed and annually updates its 5-year capital plan, including investments required to sustain existing assets and meet future growth, as a key tool to document and communicate the Corporation's longer-term capital needs.


Photo – Archbould.com

STAKEHOLDER AND EMPLOYEE ENGAGEMENT

As a public utility, Yukon Energy is committed to broadly engage and consult with stakeholders during the planning of new projects and initiatives, and to incorporate to the extent possible, the preferences of stakeholders in those plans. This consultation is essential to securing social license for corporate initiatives, while also balancing the obligations of the Corporation to its shareholder and its primary regulators (the Yukon Utilities Board and the Yukon Water Board). In addition, the Corporation's employees are critical to the company's success. Maintaining a safe, strong and engaged workforce capable of executing Yukon Energy's ambitious plans remains a key strategic priority.

Capability to Deliver Results

In order to deliver on our strategic goals and achieve planned results, Yukon Energy maximizes the use of available resources while considering risks and impacts to stakeholders. These resources include leadership, labour force, working capital, systems and processes, liquidity, and capital resources.

We continue to develop human resources policies to adapt to our seasoned workforce.

We monitor and forecast our cash and financial strength on an ongoing basis, including current and future projections. We expect to require cash to finance our capital projects in 2020 and are in the process of securing these resources.

Through established policies and procedures Yukon Energy maintains a capital structure ratio of 60% long-term debt and 40% equity.

We continually monitor and evaluate the condition of our assets, and allocate a material portion of our capital budget for maintenance of these assets, thereby ensuring reliability of service to our customers.

We make it a priority to maintain and improve our key relationships with Yukoners including the Yukon government, Yukon Development Corporation, First Nations governments and development corporations, stakeholders, and our bankers. We are currently transitioning our primary banking services from TD Bank to CIBC.

Results

Net income for the 2019 fiscal year was $2.3 million, $3.8 million less than the previous year. The decrease in net income was primarily due to an increase in operations and maintenance expenditures.

Revenue from the sale of power was $50.5 million; $2.5 million higher than the prior year due to an increase in all major power sales categories resulting from increased rates and increased consumption.

The regulated rate of Return on Equity for 2019 is 3.52%, down from 6.54% the prior year.

Outlook

Net income for 2020 is forecast to remain constant due to an increase in sales of power of $8.6 million offset by increased fuel and operations and maintenance costs. We expect COVID-19 impacts to have both positive and negative effects on Yukon Energy's financial position, net income and cash flows.

The forecast return for 2020 is 4.95%, 3.75% less than the Return on Equity that we were approved in our 2017–2018 GRA of 8.70%.

Yukon Energy is planning for a General Rate Application (GRA) for future years. The GRA will give us the opportunity to adjust rates to reflect the Corporation's cost requirements and capital plans.

Risk Management

Yukon Energy is exposed to numerous risks in providing service to our customers. Risk impacts include staff and public safety, financial, reputation, long-term and short-term load/resource balance, stakeholder relationships and funding. These risks can range in scale from minor to catastrophic. Yukon Energy endeavors to manage all the risks we face on a cost-effective basis, taking into account the potential reward to be gained in return for the acceptance of the risk. We have an enterprise risk management framework that provides the basis for consistently applying risk management practices.

KEY STRATEGIES BY IMPACT AREA

- The safety of our employees, contractors, and members of the public is managed through a well-developed health and safety program that meets or exceeds established standards for the industry.
- Yukon Energy is exposed to reputational impacts from several risks including key asset failure, First Nations consent, social license, cyber security, and insufficient installed capacity. Mitigation strategies used to address these risks include adequate stakeholder engagement, development of an asset management plan, and long-term resource planning.
- Risks that can potentially have a negative financial impact include financing risk, government & shareholder relationship risk, project costs and timeline overrun, regulatory risk, and loss of demand. These are managed through an extensive budgeting process, board oversight of major projects, and keeping the Yukon Utilities Board informed of company plans and activities through regulatory hearings.

Key Performance Drivers

There are several performance drivers and key performance indicators that are critical to the successful implementation of our strategy and achievement of our goals. Below is an outline of four of our most important performance drivers.

HEALTH AND SAFETY

Given the nature of our industry, Yukon Energy takes health and safety seriously. The two primary indicators for measuring success in this area are:

- All Injury Frequency Rate; and
- Reportable Motor Vehicle Incidents

With respect to the former, the Corporation failed to meet its target of an All Injury Frequency Rate of 1.0 or lower. In 2019, we had an All Injury Frequency Rate of 7.6, the result of 5 Medical Aids and 1 Lost Time Injury within the organization. Employee, contractor and public safety remain a key area of focus for us in 2020.

In 2019, Yukon Energy had 0 Reportable Motor Vehicle Incidents – incidents defined by the Canadian Electricity Association as those with damages that exceed $5,000.

RETURN ON EQUITY (ROE)

In the process of regulating and setting rates for Yukon Energy, the Yukon Utilities Board must ensure that the rates are sufficient to allow us to provide reliable electric service while maintaining the financial integrity of the utility, including a return on invested capital.

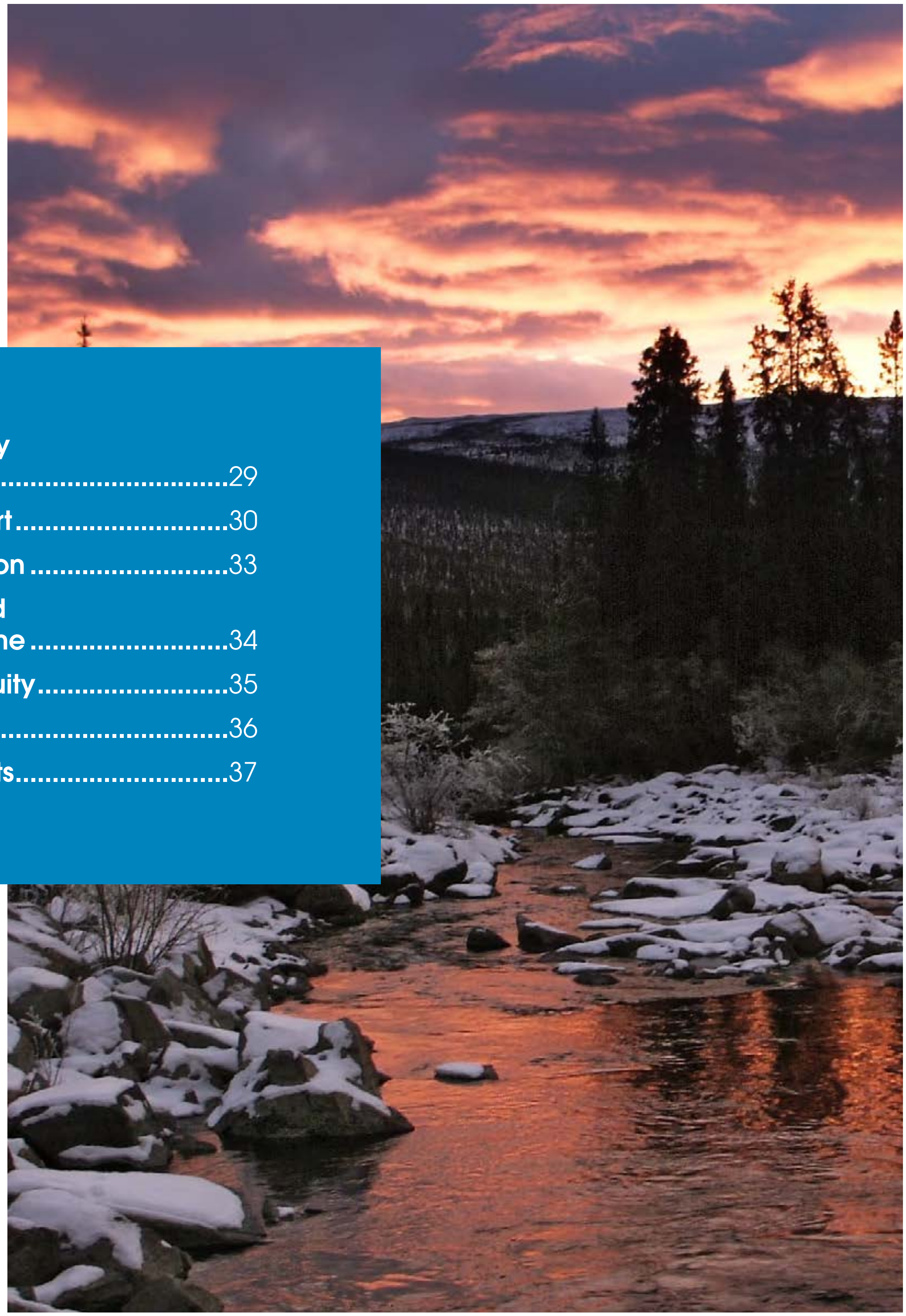
WORKFORCE

A stable workforce is crucial for delivering services required to achieve our business objectives. We regularly monitor our vacancy and turnover rate to ensure that our staffing is at appropriate levels. We set our human resources policies to recruit and retain a competent workforce, provide opportunities for professional development and perform succession planning.

RELIABILITY OF SERVICE

Reliability of service is one of our most important objectives. Improving reliability requires a long-term investment strategy and commitment. Trends in recent performance measures are compared against past results. Senior management reviews performance indicators and acts when actual performance deviates from forecast.

financial statements



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Yukon Y1A 6S7
yukonenergy.ca

Management's Responsibility for Financial Reporting

Management is responsible for the preparation of the financial statements and all other financial information relating to the Utility contained in this annual report. The financial statements have been prepared in conformity with International Financial Reporting Standards using methods appropriate for the industry in which the Utility operates and necessarily include some amounts that are based on informed judgments and best estimates of management. The financial information contained elsewhere in the annual report is consistent with that in the financial statements. The Auditor General of Canada is the external auditor of the Corporation.

Management has established internal accounting control systems to meet its responsibilities for reliable and accurate reporting. These systems include policies and procedures, the careful selection and training of qualified personnel and an organizational structure that provides for the appropriate delegation of authority and segregation of responsibilities.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management and the independent auditor to discuss auditing and financial matters to assure that management is carrying out its responsibilities and to review the financial statements. The auditors have full and free access to the Audit Committee and management.

Andrew Hall
President and CEO

Ed Mollard
Chief Financial Officer

May 6, 2020

Office of the Auditor General of Canada
Bureau du vérificateur général du Canada

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors of the Yukon Energy Corporation

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of the Yukon Energy Corporation (the Corporation), which comprise the statement of financial position as at 31 December 2019, and the statement of operations and other comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at 31 December 2019, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRSs).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on Compliance with Specified Authorities

Opinion

In conjunction with the audit of the financial statements, we have audited transactions of the Yukon Energy Corporation coming to our notice for compliance with specified authorities. The specified authorities against which compliance was audited are the *Public Utilities Act* and regulations, the *Business Corporations Act* and regulations and the articles and by-laws of the Yukon Energy Corporation.

In our opinion, the transactions of the Yukon Energy Corporation that came to our notice during the audit of the financial statements have complied, in all material respects, with the specified authorities referred to above.

Responsibilities of Management for Compliance with Specified Authorities

Management is responsible for the Yukon Energy Corporation's compliance with the specified authorities named above, and for such internal control as management determines is necessary to enable the Yukon Energy Corporation to comply with the specified authorities.

Auditor’s Responsibilities for the Audit of Compliance with Specified Authorities

Our audit responsibilities include planning and performing procedures to provide an audit opinion and reporting on whether the transactions coming to our notice during the audit of the financial statements are in compliance with the specified authorities referred to above.

Lana Dar

Lana Dar, CPA, CA
Principal
for the Interim Auditor General of Canada

Vancouver, Canada
6 May 2020

Yukon Energy Corporation
Statement of Financial Position
(in thousands of Canadian dollars)

As at	December 31 2019	December 31 2018
Assets		
Current		
Cash	$ 521	$ 581
Accounts receivable (Note 5)	10,317	6,873
Inventories (Note 6)	4,017	3,709
Prepaid expenses	741	661
	15,596	11,824
Non-current		
Property, plant and equipment (Note 7)	468,229	451,893
Intangible assets (Note 8)	12,462	10,584
Right-of-use assets (Note 9)	546	-
Total assets	**496,833**	474,301
Regulatory deferral account debit balances (Note 10)	38,988	34,788
Total assets and regulatory deferral account debit balances	**$ 535,821**	$ 509,089
Liabilities		
Current		
Bank indebtedness (Note 11)	$ 19,681	$ -
Accounts payable and accrued liabilities (Note 12)	10,241	11,088
Construction financing (Note 13)	26,344	22,385
Current portion of deferred revenue (Note 17)	2,661	1,700
Current portion of lease liability (Note 9)	151	-
Current portion of long-term debt (Note 14)	6,054	80,210
	65,132	115,383
Non-current		
Post-employment benefits (Note 15)	7,689	5,768
Contributions in aid of construction (Note 16)	149,461	151,794
Deferred revenue (Note 17)	17,994	10,194
Lease liability (Note 9)	405	-
Derivative related liability (Note 25)	1,930	1,042
Long-term debt (Note 14)	163,602	86,058
Total liabilities	**406,213**	370,239
Equity		
Share capital		
Authorized: Unlimited number of a single class of shares with no par value		
Issued and fully paid: 3,900 shares	39,000	39,000
Contributed surplus	14,600	14,600
Retained earnings	65,596	68,014
Total equity	**119,196**	121,614
Total liabilities and equity	**525,409**	491,853
Regulatory deferral account credit balances (Note 10)	10,412	17,236
Total liabilities, equity and regulatory deferral account credit balances	**$ 535,821**	$ 509,089

Commitments and Contingencies (Notes 22 and 23)

The accompanying notes are an integral part of these financial statements.

Approved by the Board

_______________, Chair _______________, Director

Yukon Energy Corporation

Statement of Operations and Other Comprehensive Income

(in thousands of Canadian dollars)

For the year ended December 31		2019		2018
Revenues				
Sales of power (Note 18)	$	50,489	$	47,991
Other		1,474		318
		51,963		48,309
Operating expenses				
Operations and maintenance (Note 19)		32,725		23,487
Depreciation and amortization (Notes 7, 8 and 9)		13,397		13,035
Administration (Note 20)		11,997		11 801
		58,119		48,323
Loss before other income and other expenses		**(6,156)**		(14)
Other income				
Amortization of contributions in aid of construction (Note 16)		2,860		3,574
Allowance for funds used during construction		648		540
		3,508		4,114
Other expenses				
Interest on borrowings		5,176		4,594
Unrealized loss on interest rate swap (Note 25)		888		986
		6,064		5,580
Net loss for the year before net movement in regulatory deferral account balances		**(8,712)**		(1,480)
Net movement in regulatory deferral account balances related to net income (Note 10 (d))		11,024		**7,577**
Net income for the year and net movement in regulatory deferral account balances		**2,312**		**6,097**
Other comprehensive (loss) income (Note 3 (o))				
Item that will not be reclassified to net income in subsequent periods				
Re-measurement of defined benefit pension plans (Note 15)		(1,859)		550
Total comprehensive (loss) income for the year	**$**	**453**	$	6,647

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Changes in Equity
(in thousands of Canadian dollars)

	Share Capital Number of shares	Share Capital $	Contributed surplus	Retained earnings	Accumulated other comprehensive Income (loss)	Total
Balance at December 31, 2017	**3,900**	**$ 39,000**	**$ 14,600**	**$ 61,367**	**$ -**	**$ 114,967**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	6,097	-	6,097
Other comprehensive income	-	-	-	-	550	550
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	550	(550)	-
Balance at December 31, 2018	**3,900**	**$ 39,000**	**$ 14,600**	**$ 68,014**	**$ -**	**$121,614**
Net income for the year and net movement in regulatory deferral account balances	-	-	-	2,312	-	2,312
Other comprehensive loss	-	-	-	-	(1,859)	(1,859)
Transfer of re-measurement of defined benefit pension plans to retained earnings	-	-	-	(1,859)	1,859	-
Dividends	-	-	-	(2,871)	-	(2,871)
Balance at December 31, 2019	**3,900**	**$ 39,000**	**$ 14,600**	**$ 65,596**	**$ -**	**$119,196**

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation
Statement of Cash Flows
(in thousands of Canadian dollars)

For the year ended December 31		2019		2018
Operating activities				
Cash receipts from customers	$	46,257	$	48,600
Cash receipts from contributions in aid of construction		527		78
Cash paid to suppliers		(32,015)		(20,319)
Cash paid to employees		(11,962)		(12,455)
Interest paid		(5,043)		(4,196)
Cash (used in) provided by operating activities		**(2,236)**		11,708
Financing activities				
Receipt of construction financing		3,959		-
Proceeds from long-term debt		6,688		23,600
Repayment of long-term debt		(6,248)		(5,103)
Lease payments		(166)		-
Cash provided by financing activities		**4,233**		18,497
Investing activities				
Additions to property, plant and equipment		(19,392)		(19,695)
Additions to intangible assets		(2,346)		(2,875)
Cash used in investing activities		**(21,738)**		(22,570)
Net (decrease) increase in cash		(19,741)		7,635
Cash, beginning of year		**581**		(7,054)
Cash, end of year	**$**	**(19,160)**	$	581
Cash includes:				
Cash	$	521	$	581
Bank indebtedness		(19,681)		-
	$	(19,160)	$	581

The accompanying notes are an integral part of these financial statements.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2019

1. NATURE OF OPERATIONS

a) General

Yukon Energy Corporation ("the Utility") is incorporated under the Yukon *Business Corporations Act* and is a wholly-owned subsidiary of Yukon Development Corporation ("YDC" or "the Parent"), a corporation owned by the Yukon Government ("the Government" or "YG"). The Utility generates, transmits, distributes and sells electrical energy in the Yukon. The Utility is not subject to income taxes. The Utility's principal place of business is located at #2 Miles Canyon Road, Whitehorse, Yukon, Y1A 6S7.

The Utility is subject to overall regulation by the Yukon Utilities Board ("YUB") and specific regulation by the Yukon Water Board. Both boards are consolidated by the Government and as such are considered to be related parties for accounting purposes. Management has assessed that these boards operate independently from the Utility from a rate setting and operating perspective.

b) Rate regulation

The operations of the Utility are regulated by the YUB pursuant to the *Public Utilities Act*. The Utility is subject to a cost of service regulatory mechanism under which the YUB establishes the revenues required (i) to recover the forecast operating costs, including depreciation and amortization, of providing the regulated service, and (ii) to provide a fair and reasonable return on utility investment in rate base. There is no minimum requirement for the Utility to appear before the YUB to review rates. However, the Utility is not permitted to charge any rate for the supply of power that is not approved by an Order of the YUB. As actual operating conditions may vary from forecast, actual returns achieved can differ from approved returns.

The regulatory hearing process used to establish or change rates typically begins when the Utility files a General Rate Application ("GRA") for its proposed electricity rate changes over the next one or two forecast years. The YUB must ensure that its decision, which fixes electricity rates, complies with appropriate principles of rate making, all relevant legislation including the *Public Utilities Act* and directives issued by the Government through Orders-In-Council ("OIC") that specify how the interests of the customer and Utility are to be balanced.

The YUB typically follows a two-stage decision process. In the first stage, the total costs that the Utility expects it will incur to provide electricity to its customers over the immediate future are reviewed and approved. The approval of these costs determines the total revenues the Utility is allowed to collect from its customers. It is the responsibility of the YUB to examine the legitimacy of three classes of costs:

- the costs to the Utility to run its operations and maintain its equipment (personnel and materials);
- the cost associated with the depreciation of all capital equipment; and
- the return on rate base (the borrowing costs related to borrowing that portion of rate base which is financed with debt plus the costs to provide a reasonable rate of return on that portion of rate base which is financed with equity).

The YUB assesses the prudency of costs added to rate base, which includes an allowance for funds used during construction ("AFUDC") charged to capital projects. The YUB also reviews the appropriateness of property, plant and equipment depreciation rates, which are periodically updated by the Utility through depreciation studies.

In the second stage, the YUB approves how the revenue will be raised. This stage essentially determines the electricity rates for the various customer classes in the Yukon: wholesale, general service, industrial, residential, sentinel and street lights and secondary sales. This process is guided mainly by requirements of OIC 1995/90 and can include a cost-of-service study which allocates the Utility's overall cost of service to the various customer classes on the basis of appropriate costing principles.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2019

1. NATURE OF OPERATIONS - continued

b) Rate regulation - continued

In June 2017, the Utility filed a GRA for the years 2017 and 2018 requesting approval of revenue requirement and related rate increases. The GRA requested rate increases of 9.04% and 2.07% for the years 2017 and 2018 respectively. A refundable interim rider (5.50%) was approved effective September 1, 2017. After responding to multiple rounds of interrogatories and participating in an oral public hearing, the Utility received a preliminary order on its application in December 2018. During 2019 the Utility submitted an initial compliance filing, provided a technical session and submitted a second compliance filing. The Utility received a final order on its application in November 2019. The YUB approved Rider J at 22.32% for retail customers and 18.67% for industrial customers, effective December 1, 2019, as well as a time-limited Rider J1 of 9.25% for a period of 24 months.

The GRA included requested board orders related to the regulatory deferral accounts, specifically: increase of the annual appropriation for uninsured losses and change to the rate of amortization; elimination of the requirement to defer vegetation management costs in excess of the 2011 actual brushing costs and amortization of previously deferred costs; change to the long-term average for fuel costs to better reflect current market conditions; and, decrease of the annual appropriation for the hearing reserve and change to the rate of amortization.

The key findings in YUB Board Order 2018-10 was a direction to the Utility to update the 2017 revenue requirement based on the 2017 actual results and to replace the Diesel Contingency Fund ("DCF") with the Low Water Reserve Fund ("LWRF"). The key finding in YUB Board Order 2019-08 was to amend the calculation of the LWRF. See Note 10(b)(iii) for details on the LWRF impact.

These financial statements reflect the approved rate increase, and all other YUB board orders approved in the GRA which affect the Utility's financial statements for 2019. Refer to Note 4 Regulatory deferral account balances.

c) Water regulation

The Yukon Water Board ("YWB"), pursuant to the Yukon *Waters Act,* decides if and for how long the Utility will have water licences for the purposes of operating hydro generation stations in the Yukon. The licences will also indicate terms and conditions for the operation of these facilities. The current water licences have the following terms:

Aishihik Generating Station	February 28, 2023
Mayo Generating Station	December 31, 2025
Whitehorse Generating Station	December 31, 2025

d) Capital structure

The Utility's policy which has been approved by the YUB is to maintain a capital structure of 60% debt and 40% equity (Note 26). When dividends are declared to the Parent, they are typically loaned back in order to maintain this ratio during normal on-going operations.

2. BASIS OF PRESENTATION

a) Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

These financial statements were authorized for issue by the Board of Directors on May 6, 2020.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2019

2. BASIS OF PRESENTATION - continued

b) Basis of measurement
The financial information included in the financial statements has been prepared on a historical cost basis, except for some financial instruments, as described in Note 3(f), which are measured at fair value.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied to all periods presented in these financial statements except for the changes related to adoption of IFRS 16, *Leases*, as described in Note 3(p).

a) Revenue recognition
The Utility recognizes revenue from contracts where the right to consideration from a customer corresponds directly with the value to the customer of the Utility's performance completed to date.

The majority of the Utility's revenues from contracts with customers are derived from the generation, transmission, distribution, purchase and sales of electricity under the *Public Utilities Act*. The Utility evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and ongoing basis if there is an indication of a significant change in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control over a promised good or service is transferred to the customer and the Utility is entitled to consideration as a result of completion of the performance obligation.

The Utility recognizes a contract asset or deferred revenue for the contracts where the performance obligation has not been satisfied. Deferred revenue is recognized when the Utility receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Utility has rights to consideration for the completion of a performance obligation when that right is conditional on something other than the passage of time. The Utility recognizes unconditional rights to consideration separately as a trade receivable. Contract assets are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

Electricity sales contracts are deemed to have a single performance obligation as the promise to transfer individual goods or services is not separately identifiable from other obligations in the contracts and therefore not distinct. These performance obligations are considered to be satisfied over time as electricity is delivered because of the continuous transfer of control to the customer. The method of revenue recognition for the electricity is an output method, which is based on the volume delivered to the customer.

The Utility's electricity sales are calculated based on the customer's usage of electricity during the period at the applicable published rates for each customer class. Electricity rates in the Yukon are set by the YUB. Electricity sales include an estimate of electricity deliveries not yet billed at period-end. The estimated unbilled revenue is based on several factors, including estimated consumption by customer, applicable customer rates and the number of days between the last billing date and the end of the period.

b) Translation of foreign currencies
The functional currency of the Utility is the Canadian Dollar. Revenue and expense items denominated in foreign currencies are translated at exchange rates prevailing during the period. Monetary assets and liabilities denominated in foreign currencies are translated at period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or the obligations are incurred. Foreign exchange gains and losses are reflected in net income for the period.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2019

3. SIGNIFICANT ACCOUNTING POLICIES - continued

c) Allowance for funds used during construction
The cost of the Utility's property, plant and equipment, intangible assets and certain regulatory deferral accounts includes an allowance for funds used during construction ("AFUDC"). The AFUDC rate is based on the Utility's weighted average cost of debt.

d) Cash
Cash is comprised of bank account balances (net of outstanding cheques).

e) Inventories
Inventories consist of materials and supplies, diesel fuel and liquefied natural gas. Inventories are carried at the lesser of weighted average cost and net realizable value. Cost includes all expenditures incurred in acquiring the items and bringing them to their existing condition and location. Critical spare parts are recognized in the Utility's property, plant and equipment.

The recoverable value of inventory considers its net realizable value, including required processing costs, and is impacted by estimates and assumptions on prices, quality, recovery and exchange rates. Obsolete materials and supplies are recorded at salvage value in the period when obsolescence is determined.

f) Financial instruments
Financial assets and financial liabilities are recognized on the Utility's Statement of Financial Position when the Utility becomes party to the contractual provisions of the instrument.

i) Financial assets

Cash and accounts receivable, plus any transaction costs that are directly attributable to the acquisition of the financial asset, are initially measured at fair value. Subsequent to initial recognition, cash is measured at amortized cost and accounts receivable are measured at amortized cost using the effective interest rate method less any impairment. The Utility's business model is to hold these assets to collect contractual cash flows.

A provision for impairment of accounts receivable is established applying the expected credit loss model based on all possible default events over the expected life of the financial asset. For trade accounts receivable, the Utility applies the simplified approach which requires expected lifetime losses to be recognized from initial recognition of the receivables. For other receivables, at the reporting date, if credit risk has increased significantly since initial recognition, the Utility measures the loss allowance at an amount equal to the lifetime expected credit losses, otherwise, if the credit risk has not increased significantly since initial recognition, the Utility measures the loss allowance at an amount equal to 12-month expected credit losses.

Significant financial difficulties of the debtor, probability that the debtor will enter into bankruptcy or require financial reorganization, and default or delinquency in payments are considered indicators that the related accounts receivable are impaired. The accounts receivable carrying amount is reduced through the use of an allowance account and the loss is recognized in net income. A financial asset is derecognized when the rights to receive cash flows from the asset have expired, or the Utility has transferred its rights to receive cash flows from the asset and has transferred substantially all the risk and rewards of the asset.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2019

3. SIGNIFICANT ACCOUNTING POLICIES - continued

f) Financial instruments - continued

ii) Financial liabilities

Bank indebtedness, accounts payable and accrued liabilities, construction financing and long-term debt are initially measured at fair value less any transaction costs that are directly attributable to the issuance of the financial liability. Subsequent to initial recognition, these financial liabilities are measured at amortized cost using the effective interest method.

Transaction costs are presented as a reduction from the carrying value of the related debt and are amortized using the effective interest rate method over the terms of the debts to which they relate. Transaction costs include fees paid to agents, brokers and advisors but exclude debt discounts and lender financing costs.

Derivative financial instruments are financial contracts that derive their value from changes in an underlying variable. The Utility has entered into interest rate swaps to manage interest rate risk. The Utility's interest rate swap is classified as fair value through profit and loss and is thus recognized at fair value on the date the contract has been entered into with any subsequent realized and unrealized gains and losses recognized in net income during the period in which the fair value movement occurred.

A financial liability is derecognized when the obligation is discharged or cancelled, or expires.

g) Property, plant and equipment
Property, plant and equipment are carried at cost, less accumulated depreciation and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs, AFUDC and any asset retirement costs associated with the property, plant and equipment.

AFUDC is applied to actual costs in work-in-progress less any contributions in aid of construction. For items of property, plant and equipment acquired prior to January 1, 2011, the AFUDC rate also included a regulatory cost of equity component as allowed by the YUB. Capitalization of AFUDC ceases when the asset being constructed is substantially ready for its intended purpose.

Assets under construction are recognized as in construction work-in-progress until they are operational and available for use, at which time they are transferred to the applicable component of property, plant and equipment.

Depreciation is recognized in net income based on the straight-line method over the estimated useful life of each major component of property, plant and equipment.

Yukon Energy Corporation

Notes to Financial Statements
(tabular amounts in thousands of Canadian dollars)

December 31 2019

3. SIGNIFICANT ACCOUNTING POLICIES - continued

g) Property, plant and equipment - continued
The range of the estimated useful lives of the major classes and subclasses of property, plant and equipment is as follows:

Generation	
Hydroelectric plants	30 to 103 years
Thermal plants	12 to 72 years
Transmission	20 to 65 years
Distribution	12 to 55 years
Buildings	20 to 55 years
Transportation	9 to 31 years
Other equipment	5 to 20 years

Depreciation commences when an asset is available for use. The estimated useful lives of the assets are based upon depreciation studies conducted periodically by the Utility and any changes in the estimated useful lives are accounted for prospectively.

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period of the expected useful life (until the next major overhaul) which varies from 5 to 10 years. Repairs and maintenance costs of property, plant and equipment are expensed as incurred unless they meet the criteria of a betterment.

h) Intangible assets
Intangible assets are carried at cost less accumulated amortization and any asset impairment charges. Cost includes the direct costs of acquisition and materials, direct labour, and, if applicable, an allocation of directly attributable overhead costs and AFUDC.

Amortization is recognized in net income on a straight-line basis over the estimated useful lives as follows:

Software	5 years
Deferred service costs	12 years
Financial software	10 years
Licensing costs	
Hydro generation	17 to 25 years
Diesel generation	3 years

The water licence for the Aishihik generating station received a 3 year extension. Costs associated with the 3 year extension are being amortized over 3 years (see Note 22).

i) Leases
At inception of a contract, the Utility assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset. The Utility assesses whether:

- The contract involves the use of an identified asset;
- The Utility has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- The Utility has the right to direct the use of the asset.

At inception, the Utility allocates the consideration in the contract to each lease component on the basis of the relative stand-alone prices.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

3. SIGNIFICANT ACCOUNTING POLICIES - continued

i) Leases - continued

The Utility recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The Utility elected to exclude short-term leases with a term of twelve months or less as well as leases of low-value assets, and accounts for the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those property, plant and equipment. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability. Right-of-use assets are tested for impairment in accordance with IAS 36, *Impairment* of Assets, and impairments are recorded in net income.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Utility's incremental borrowing rate. Generally, the Utility uses its incremental borrowing rate as the discount rate. Subsequent to recognition, the lease liability is measured at amortized cost using the effective interest rate method. A lease liability is remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, or if the Utility changes its assessment of whether it will exercise a renewal or termination option. When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in net income if the carrying amount of the right-of-use assets has been reduced to zero.

j) Impairment of non-financial assets

Property, plant and equipment, and intangible assets with finite lives are reviewed for impairment on an annual basis if there is an indication that the carrying amount may not be recoverable. Impairment is assessed at the level of cash-generating units, which are identified as the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or group of assets.

When an impairment review is undertaken, the recoverable amount is assessed by reference to the higher of value in use and fair value less costs to sell ("FVLCS"). Value in use is the net present value of expected future cash flows of the relevant cash-generating unit in its current condition.

The best evidence of FVLCS is the value obtained from an active market or binding sale agreement. Where neither exists, FVLCS is based on the best information available to reflect the amount the Utility could receive for the cash-generating unit in an arm's length transaction. This is often estimated using discounted cash flow techniques and where unobservable inputs are material to the measurement of the recoverable amount, the measurement is classified as level 3 in the fair value hierarchy. The cash flow forecasts for FVLCS purposes are based on management's best estimates of expected future revenues and costs, including the future cash costs of production, capital expenditure, closure, restoration and environmental cleanup. For regulatory deferral account debit balances the impairment review focuses on whether the amount is considered collectible based on the expected cash flows from the rates approved by the YUB.

Yukon Energy Corporation

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3. SIGNIFICANT ACCOUNTING POLICIES - continued

j) Impairment of non-financial assets - continued
These determinations and their individual assumptions require that management make a decision based on the best available information at each reporting period. Changes in these assumptions may alter the results of impairment testing, impairment charges recognized in net income and the resulting carrying amounts of the assets.

k) Rate regulated accounting policies

Regulatory deferral accounts
Regulatory deferral accounts in these financial statements are accounted for differently than they would be in the absence of rate regulation. The Utility defers certain costs or revenues as regulatory deferral account debit balances or regulatory deferral account credit balances on the Statement of Financial Position and recognizes changes in the regulatory deferral account balances in the net movement in regulatory deferral account balances in the Statement of Operations and Other Comprehensive Income. The amounts recognized as regulatory deferral account balances are expected to be recovered or refunded in future rates, based on approvals by the YUB. The recovery or settlement of regulatory deferral account balances through future rates is impacted by demand risk and regulatory risks (e.g. potential future decisions of the YUB which could result in material adjustments to these regulatory deferral account debit balances and regulatory deferral account credit balances as described in Note 1(b)).

i) Regulatory deferral account debit balances
Regulatory deferral account debit balances represent costs which are expected to be recovered from customers in future periods through the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, *Regulatory Deferral Accounts*, such costs would be expensed as incurred.

ii) Regulatory deferral account credit balances
Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process. In the absence of rate regulation and the Utility's adoption of IFRS 14, such amounts would be recorded in income as performance obligations are met.

Note 10 describes the individual regulatory deferral accounts, the Utility's related regulatory deferral and amortization policies and describes the related account activity in the relevant periods.

l) Provision for asset retirement obligations
The Utility has legal obligations related to the closure and restoration of property, plant and equipment, which includes the costs of dismantling, demolition of infrastructure and the removal of residual materials and remediation of the disturbed areas.

Where a reliable estimate of the present value of these obligations can be determined, the total retirement costs are recognized as a provision in the accounting period when the obligation arises. There is also a corresponding increase to property, plant and equipment upon recognition of the obligation. Management estimates its costs based on feasibility and engineering studies and assessments using current restoration standards and techniques.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

3. SIGNIFICANT ACCOUNTING POLICIES - continued

m) Provision for environmental liabilities
Environmental liabilities consist of the estimated costs related to the remediation of environmentally contaminated sites. The Utility will accrue a provision when it has a present obligation as a result of a past event to remediate the contaminated site, it is expected that future economic benefits will be given up to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

If the likelihood of the Utility's obligation to incur these costs is either not determinable or the amount of the obligation cannot be reliably estimated, the contingency is disclosed in the notes to the financial statements.

The Utility reviews its provision for environmental liabilities on an ongoing basis and any changes are recognized in net income for the current period.

n) Contributions in aid of construction
Certain property, plant and equipment additions are made with financial assistance from the Utility's Parent, the YG, or the Government of Canada. These contributions are deferred upon receipt and amortized to income on the basis of the life of the asset to which they relate.

o) Post-employment benefits and other comprehensive income
The Utility sponsors an employee defined benefit pension plan for employees joining the Utility before January 1, 2002. The Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates. The Utility contributes amounts to the pension plans as recommended by an independent actuary.

For the defined benefit plans the cost of pension benefits is actuarially determined using the projected benefits method, prorated on service, and reflects management's best estimates of investment returns, wage and salary increases, and age at retirement. Re-measurements of the net defined benefit liability, including actuarial gains and losses and return on plan assets, are recognized in other comprehensive income ("OCI") and are not reclassified to net income in a subsequent period. The Utility's policy is to immediately transfer actuarial gains and losses recognized in OCI to retained earnings. The expected return on plan assets is based on the fair value of these assets.

Employees joining the Utility after January 1, 2002 are eligible for a defined contribution retirement plan and are not eligible to participate in the defined benefit pension plan. The Utility has no legal or constructive obligation to pay further contributions with respect to this plan. Contributions are recognized as an expense in the year when employees have rendered service and represent the obligation of the Utility.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

3. SIGNIFICANT ACCOUNTING POLICIES - continued

p) Impact of adoption of new accounting standard

Impact of Adoption of IFRS 16, *Leases*

The Utility has adopted IFRS 16, *Leases*, using the modified retrospective approach without restatement with a date of initial application of January 1, 2019. On transition to IFRS 16, the Utility identified and reviewed each contract that had a lease. Previously, the Utility classified leases as operating or finance leases based on its assessment of whether the lease transferred significantly all of the risks and rewards incidental to ownership of the underlying asset to the Utility and classified operating lease payments as operating costs. Under IFRS 16, a lessee is required to recognize a right-of-use asset representing its right to use the underlying leased asset and a lease liability representing its obligation to make lease payments.

The Utility has applied the following practical expedients:

- Account for existing leases with terms of twelve months or less from the date of initial application as short-term leases and expense on a straight-line basis over the lease term;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of low dollar value;
- Exclude indirect costs from the measurement of right-of-use assets at the date of initial application;
- Use hindsight, such as in determining the lease term in relation to extension options or termination options;
- Measure the right-of-use assets under lessee arrangements at the same amount as the lease liability, adjusted by the amount of any prepaid or accrued lease payments before the date of initial application; and
- Not re-assess IAS 17 and IFRIC 4 determinations of which contracts that existed at or prior to the date of initial application were a lease, or contained a lease.

As a result of IFRS 16 adoption, the Utility recognized right-of-use assets and a corresponding lease liability of $702,000, with no effect on opening retained earnings. On transition, the weighted average incremental borrowing rate applied to lease liability recognized under IFRS 16 was 3.2%.

The following is a reconciliation of the total commitments as at December 31, 2018 to the lease liability recognized at January 1, 2019.

Total commitments as at December 31, 2018	$	2,935
Less: Non-lease commitments		(1,408)
Total operating lease commitments as at December 31, 2018		1,527
Recognition exemption for short-term leases		(771)
Operating lease liability before discounting	$	756
Discounted using incremental borrowing rate		(54)
Operating lease liability at January 1, 2019		702
Reasonably certain extension options		-
Other		-
Total lease liability recognized under IFRS 16 at January 1, 2019	$	702

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements requires the use of judgment in applying accounting policies and in making critical accounting estimates that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of any contingent assets and liabilities. These judgments and estimates are based on management's best knowledge of the relevant facts and circumstances, having regard to previous experience, but actual results may differ from the amounts included in the financial statements. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which estimates are revised and in any future periods affected. Information about such judgments and estimates is contained in the accounting policies and/or the notes to the financial statements, and the key areas are summarized below.

Areas of significant judgment and estimates made by management in preparing these financial statements include:

Impairment of non-financial assets – Note 3(j)
An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Management continually monitors the Utility's operations and makes judgments and assessments about conditions and events in order to conclude whether possible impairment exists.

Asset retirement obligations – Notes 3(l) and 23
In determining the present value of the obligation, the Utility must estimate the amount and timing of the future cash payments and then apply an appropriate risk-free interest rate. Any changes to the anticipated amounts or timing of future payments or risk-free interest rate can result in a change to the obligation.

Depreciation – Notes 3(g), 7 and 9
Significant components of property, plant and equipment are depreciated straight line over their estimated useful lives. Useful lives are determined based on current facts and past experience and the results of depreciation studies. While these useful life estimates are reviewed on a regular basis and depreciation calculations are revised accordingly, actual lives may differ from the estimates. As such, assets may continue in use after being fully depreciated, or may be retired or disposed of before being fully depreciated. The latter could result in additional depreciation expense in the period of disposition.

Intangible assets – Notes 3(h) and 8
In determining whether to recognize costs as intangible assets, management makes judgments about when the criteria for recognition are met. Changes to management's judgments would affect the carrying amount of the Utility's intangible assets and amortization recognition.

Post-employment benefits – Notes 3(o) and 15
The Utility accrues for its obligations under defined benefit pension plans using actuarial valuation methods and other assumptions to estimate the projected benefit obligation and the associated expense related to the current period. The key assumptions utilized include the long-term rate of inflation, rates of future compensation, liability discount rates and the expected return on plan assets. The Utility consults with qualified actuaries when setting the assumptions used to estimate benefit obligations. Actual rates could vary significantly from the assumptions and estimates used.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

4. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS - continued

Revenue – Notes 3(a) and 18
The Utility estimates usage not yet billed at year end, which is included in revenues from sales of power. This accrual is based on an assessment of unbilled electricity supplied to customers between the date of the last meter reading and the year end. Management applies judgment to the measurement of the estimated consumption. Significant judgments have also been made in determining the nature of the Utility's performance obligations, the appropriate process measure and the contract terms to be used in recognizing the related revenue.

Provisions and Contingencies – Notes 3(m) and 23
Management is required to make judgments to assess if the criteria for recognition of provisions and contingencies are met, in accordance with IAS 37, *Provisions, Contingent Liabilities and Contingent Assets.*

Key judgments are whether a present obligation exists and the probability of an outflow being required to settle that obligation. Key assumptions in measuring recognized provisions include the timing and amount of future payments and the discount rate applied in measuring the provision.

Where the Utility is defending certain lawsuits management must make judgments, estimates and assumptions about the final outcome, timing of trial activities and future costs as at the period end date. Management will obtain the advice of its external counsel in determining the likely outcome and estimating the expected obligations associated with these lawsuits; however, the ultimate outcome or settlement costs may differ from management's estimates.

Financial Instruments – Notes 3(f) and 25
The Utility enters into financial instrument arrangements which may require management to make judgments to determine if such arrangements are derivative instruments in their entirety or contain embedded derivatives, in accordance with IFRS 9, *Financial Instruments*. Key judgments are whether certain non-financial items are readily convertible to cash, whether similar contracts are routinely settled net in cash or delivery of the underlying commodity taken and then resold within a short period, and whether the value of a contract changes in response to a change in an underlying rate, price, index or other variable.

Regulatory deferral account balances – Notes 1(b), 3(k) and 10
The Utility accounts for its regulatory deferral accounts in accordance with IFRS 14 and the decisions of the YUB. As discussed in Note 1(b) the recovery of these balances will be determined by the YUB as part of the regulatory proceeding to approve the GRA. Management is required to make judgments as to the amounts that the YUB will approve the Utility to collect deferred costs through future rates.

5. ACCOUNTS RECEIVABLE

	December 31 2019	December 31 2018
Trade accounts receivable		
Wholesale energy sales	$ 5,676	$ 4,599
Retail energy sales	2,414	1,601
Due from related parties (Note 21)	522	32
Other	1,705	641
	$ 10,317	$ 6,873

Included in Accounts receivable - Other is an amount of $939,000 related to a power purchase agreement. Refer also to Note 17.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

5. ACCOUNTS RECEIVABLE - continued

At December 31, 2019, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 8,647	$ 800	$ 880	$ 10,327
Allowance for doubtful accounts	-	-	(10)	(10)
	$ 8,647	$ 800	$ 870	$ 10,317

At December 31, 2018, the aging of accounts receivable is as follows:

	Current	31 - 90 Days	Over 90 Days	Total
Accounts receivable	$ 6,202	$ 677	$ 4	$ 6,883
Allowance for doubtful accounts	-	(6)	(4)	(10)
	$ 6,202	$ 671	$ -	$ 6,873

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	December 31 2019	**December 31 2018**
Allowance for doubtful accounts at beginning of year	$ (10)	$ (10)
Amounts written off as uncollectable	-	-
Allowance for doubtful accounts at end of year	$ (10)	$ (10)

6. INVENTORIES

	December 31 2019	**December 31 2018**
Materials and supplies	$ 3,396	$ 3,067
Diesel fuel	520	457
Liquefied natural gas	101	185
	$ 4,017	$ 3,709

Yukon Energy Corporation

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December 31 2019

7. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Generation	Transmission & Distribution	Land, Buildings & Other Equipment	Transportation	Construction Work-in Progress	Total
Cost:						
At December 31, 2017	$ 295,078	$ 169,142	$ 18,022	$ 4,581	$ 3,775	$ 490,598
Additions	-	-	-	-	19,832	19,832
Transfers	10,182	8 733	969	306	(20,190)	-
Disposals	(1,783)	(47)	(220)	-	-	(2,050)
At December 31, 2018	$ 303,477	$ 177,828	$ 18,771	$ 4,887	$ 3,417	$ 508,380
Additions	-	-	-	-	29,928	29,928
Transfers	2,634	21,225	1,592	285	(25,736)	-
Disposals	(1,771)	-	-	-	-	(1,771)
At December 31, 2019	$ 304,340	$ 199,053	$ 20,363	$ 5,172	$ 7,609	$ 536,537
Accumulated depreciation:						
At December 31, 2017	$ 20,614	$ 20,219	$ 3,543	$ 991	$ -	$ 45,367
Depreciation	6,571	4,486	617	319	-	11,993
Disposals	(643)	(10)	(220)	-	-	(873)
At December 31, 2018	$ 26,542	$ 24,695	$ 3,940	$ 1,310	$ -	$ 56,487
Depreciation	6,351	4,818	747	339	-	12,255
Disposals	(434)	-	-	-	-	(434)
At December 31, 2019	$ 32,459	$ 29,513	$ 4,687	$ 1,649	$ -	$ 68,308
Net book value:						
At December 31, 2018	$ 276,935	$ 153,133	$ 14,831	$ 3,577	$ 3,417	$ 451,893
At December 31, 2019	$ 271,881	$ 169,540	$ 15,676	$ 3,523	$ 7,609	$ 468,229

The total AFUDC capitalized for 2019 was $648,000 (2018 - $540,000). The AFUDC rate estimate for 2019 was 2.57% (2018 - 2.36%).

Yukon Energy Corporation

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December 31 2019

8. INTANGIBLE ASSETS

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Software	Deferred Service Costs	Financial Software	Aishihik Water Licensing	Thermal and Water Licensing	Total
Cost:						
At December 31, 2017	$ 690	$ 443	$ 2,406	$ 5,944	$ 2,825	$ 12,308
Additions	791	-	-	1,983	376	3,150
Disposals	-	-	-	(466)	-	(466)
At December 31, 2018	$ 1,481	$ 443	$ 2,406	$ 7,461	$ 3,201	$ 14,992
Additions	235	-	533	1,289	806	2,863
Transfers	(276)	-	276	-	-	-
Disposals	-	-	-	(2,475)	-	(2,475)
At December 31, 2019	$ 1,440	$ 443	$ 3,215	$ 6,275	$ 4,007	$ 15,380
Accumulated amortization:						
At December 31, 2017	$ 277	$ 256	$ 1,134	$ 2,068	$ 97	$ 3,832
Amortization	183	64	284	479	32	1,042
Disposals	-	-	-	(466)	-	(466)
At December 31, 2018	$ 460	$ 320	$ 1,418	$ 2,081	$ 129	$ 4,408
Amortization	213	64	284	394	30	985
Disposals	-	-	-	(2,475)	-	(2,475)
At December 31, 2019	$ 673	$ 384	$ 1,702	$ -	$ 159	$ 2,918
Net book value:						
At December 31, 2018	$ 1,021	$ 123	$ 988	$ 5,380	$ 3,072	$ 10,584
At December 31, 2019	$ 767	$ 59	$ 1,513	$ 6,275	$ 3,848	$ 12,462

The internally generated costs and externally purchased costs for Software and Financial Software are approximately 50% internal and 50% external at December 31, 2019 and December 31, 2018. All other categories are almost exclusively internally generated.

9. LEASES

The Utility leases industrial land and building space. The lease terms typically run for five years. The right-of-use asset consists of land of $122,000 and building of $424,000.

Right-of-use asset	
As at January 1, 2019	$ 702
Depreciation expense	(156)
As at December 31, 2019	$ 546

Maturity analysis	
Less than one year	$ 167
One to five years	423
More than five years	-
Total undiscounted lease liabilities	$ 590

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

9. LEASES - continued

Lease liabilities	
Lease liabilities	$ 556
Less current portion	151
Non-current portion	$ 405

Amounts recognized in net income	
Depreciation expense on right-of-use assets	$ (156)
Interest expense on lease liabilities	$ (20)
Expense relating to short-term leases	$ (1,411)

10. REGULATORY ACCOUNTS

a) Regulatory deferral account debit balances

	Feasibility Studies (i)	IFRS Planning (ii)	Regulatory Costs (iii)	Vegetation Management (iv)	Dam Safety (v)	Uninsured Losses (vi)	Subtotal see next page
Cost:							
At December 31, 2017	$ 21,855	$ -	$ 4,429	$ 2,216	$ 148	$ 1,459	$ 30,107
Costs incurred	1,091	-	645	-	-	651	2,387
Regulatory provision	-	-	-	-	-	(267)	(267)
Disposals	(69)	-	-	-	-	-	(69)
At December 31, 2018	$ 22,877	$ -	$ 5,074	$ 2,216	$ 148	$ 1,843	$ 32,158
Costs incurred	1,383	-	1,657	-	-	62	3,102
Regulatory provision	-	-	(883)	-	-	(267)	(1,150)
Disposals	(553)	-	(768)	-	-	-	(1,321)
Contributions received	-	-	(365)	-	-	-	(365)
At December 31, 2019	$ 23,707	$ -	$ 4,715	$ 2,216	$ 148	$ 1,638	$ 32,424
Accumulated amortization:							
At December 31, 2017	$ 3,357	$ -	$ 596	$ 222	$ 30	$ 212	$ 4,417
Amortization	1,791	-	405	222	30	212	2,660
Disposals	(69)	-	-	-	-	-	(69)
At December 31, 2018	$ 5,079	$ -	$ 1,001	$ 444	$ 60	$ 424	$ 7,008
Amortization	1,823	-	465	222	29	212	2,751
Disposals	(36)	-	(243)	-	-	-	(279)
At December 31, 2019	$ 6,866	$ -	$ 1,223	$ 666	$ 89	$ 636	$ 9,480
Net book value:							
At December 31, 2018	$ 17,798	$ -	$ 4 073	$ 1,772	$ 88	$ 1,419	$ 25,150
At December 31, 2019	$ 16,841	$ -	$ 3 492	$ 1,550	$ 59	$ 1,002	$ 22,944
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement in regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):							
December 31, 2018	$ (700)	$ -	$ 240	$ (222)	$ (30)	$ 172	$ (540)
December 31, 2019	$ (957)	$ -	$ (581)	$ (222)	$ (29)	$ (417)	$ (2,206)
Remaining recovery years							
At December 31, 2018	1 to 8 years		1 to 35 years	8 years	3 years	Indeterminate	
At December 31, 2019	1 to 7 years		1 to 34 years	7 years	2 years	Indeterminate	
Absent rate regulation, net income for the year and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:							
December 31, 2018	$ 700	$ -	$ (240)	$ 222	$ 30	$ (172)	$ 540
December 31, 2019	$ 957	$ -	$ 581	$ 222	$ 29	$ 417	$ 2,206

Yukon Energy Corporation

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December 31 2019

10. REGULATORY ACCOUNTS - continued

	Carry Forward	Deferred Overhauls (vii)	Fuel Price Adjustment (viii)	2017/18 GRA (ix)	Total
Cost:					
At December 31, 2017	$ 30,107	$ 2,768	$ 498	$ 4,319	$ 37,692
Costs incurred	2,387	-	-	-	2,387
Regulatory provision	(267)	-	1,32'	2,696	3,750
Disposals	(69)	-	-	(1,705)	(1,774)
At December 31, 2018	$ 32,158	$ 2,768	$ 1,819	$ 5,310	$ 42,055
Costs incurred	3,102	-	-	-	3,102
Regulatory provision	(1,150)	-	3,760	10,388	12,998
Disposals	(1,321)	-	(3,940)	(3,378)	(8,639)
Contributions received	(365)	-	-	-	(365)
At December 31, 2019	$ 32,424	$ 2,768	$ 1,639	$ 12,320	$ 49,151
Accumulated amortization:					
At December 31, 2017	$ 4,417	$ 112	$ -	$ -	$ 4,529
Amortization	2,660	147	-	1,705	4,512
Disposals	(69)	-	-	(1,705)	(1,774)
At December 31, 2018	$ 7,008	$ 259	$ -	$ -	$ 7,267
Amortization	2,751	424	-	3,378	6,553
Disposals	(279)	-	-	(3,378)	(3,657)
At December 31, 2019	$ 9,480	$ 683	$ -	$ -	$ 10,163
Net book value:					
At December 31, 2018	$ 25,150	$ 2,509	$ 1,819	$ 5,310	$ 34,788
At December 31, 2019	$ 22,944	$ 2,085	$ 1,639	$ 12,320	$ 38,988
Net increase (decrease) in regulatory deferral account debit balances (which are recognized in the net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income):					
December 31, 2018	$ (540)	$ (147)	$ 1 321	$ 991	$ 1,625
December 31, 2019	$ (2,206)	$ (424)	$ (180)	$ 7,010	$ 4,200
Remaining recovery years					
At December 31, 2018		3 to 8 years	1 year	1 year	
At December 31, 2019		2 to 7 years	1 year	1 year	
Absent rate regulation, net income for the year and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:					
December 31, 2018	$ 540	$ 147	$ (1,321)	$ (991)	$ (1,625)
December 31, 2019	$ 2,206	$ 424	$ 180	$ (7,010)	$ (4,200)

(i) Feasibility studies and infrastructure planning

The Utility undertakes certain studies to determine the feasibility of a range of projects and infrastructure proposals. While in progress, the costs of these studies are deferred within this account. The Utility is directed to defer and amortize the costs over terms (between five and ten years) at the discretion of the YUB. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(ii) IFRS planning

These deferred costs are associated with the conversion from previous GAAP to IFRS and are amortized over a term of five years. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

10. REGULATORY ACCOUNTS - continued

(iii) Regulatory costs
These costs are associated with the YUB regulatory proceedings. The costs consist primarily of various rate and project review proceedings but also include resource plans, hearing costs from before 2012 and demand side management costs (consumer energy conservation program). The Utility is directed to defer and amortize the costs over terms at the discretion of the YUB. The regulatory provision for the year reflects an amount transferred of $883,000 to the regulatory deferral account credit balance class Hearing Reserve (see Note 10(b)(ii)). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iv) Vegetation management
Prior to 2017, the Utility was deferring annual brushing costs in excess of a prescribed maximum annual amount based on a review of prior year brushing costs. In 2017, the Utility established a vegetation management policy and as a result of expected annual costs, deferral is no longer required. The Utility completes a full cycle of all of its brushing requirements every 10 years and is amortizing previously deferred costs over a 10 year period. This change is consistent with the 2017-2018 GRA. Refer to Note 1(b). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(v) Dam safety review
The Utility has a program of conducting safety reviews of its dams in accordance with standards set by the Canadian Dam Association. External consultants are hired every five years with intermittent costs incurred in the interim periods. These costs are being amortized over five years. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(vi) Uninsured losses
Uninsured losses is an account maintained to address uninsured and uninsurable losses as well as the deductible portion of insured losses. The account is maintained through an annual provision and collected through customer rates. There is an annual regulatory provision of $267,000 and amortization of the 2016 accumulated balance of $1,059,000 over five years ($212,000 per year). This change is consistent with the 2017-2018 GRA. Refer to Note 1(b). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

vii) Deferred overhauls
YUB Order 2013-01 restricted inclusion of property, plant and equipment overhaul depreciation expense in rates charged to customers until the Utility comes before the YUB for a prudence review. As such, starting in 2013 the Utility deferred depreciation expense related to overhauls. In 2017, the Utility came before the YUB for a prudence review and began to recognize these deferred depreciation amounts. In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(viii) Fuel price adjustment
OIC 1995/90 directs the YUB to permit the Utility to adjust electricity rates to reflect fluctuations in the price of diesel fuel. The amount by which actual fuel prices vary from the long-term average prices is deferred and recovered from or refunded to customers in a future period. In 2017 the Utility updated the long-term average cost to better reflect current market conditions. This change is consistent with the 2017-2018 GRA. Refer to Note 1(b). As part of the 2017-18 GRA, the balance as at June 30, 2019 of $3,940,000 was transferred to the regulatory deferral account debit balance class 2017/18 GRA (see Note 10(a)(ix)). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS - continued

(ix) 2017/18 GRA
The Utility recognizes a regulatory deferral account debit balance when the Utility has the right, as a result of the actual or expected actions of the rate regulator, to increase rates in future periods in order to recover its allowable costs plus return on rate base, as described in Note 1(b). The amount recognized represents the amount approved by the YUB in November 2019, less amounts received from customers during the year. The ending balance at December 31, 2019 comprises the Utility's remaining revenue shortfall and the amount transferred from the regulatory deferral account debit balance class Fuel Price Adjustment (see Note 10(a)(viii)) during the year to be collected from customers in future years. This change is consistent with the 2017-2018 GRA. Refer to Notes 1(b) and 4.

(x) Deferred gains and losses
Deferred gains and losses represent amounts from disposals of property, plant and equipment that have or will be submitted for approval by the YUB to be deferred. There are no deferred gains or losses during any of the reporting years.

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS - continued

b) Regulatory deferral account credit balances

	Deferred Insurance Proceeds (i)	Hearing Reserve (ii)	Low Water Reserve Fund (iii)	Future Removal and Site Restoration (iv)	Contracts with Customers (v)	Total
Cost:						
At December 31, 2017	$ 11,602	$ 1,220	$ 8,742	$ 4,303	$ 4,153	$ 30,020
Cost incurred	-	(155)	(893)	(339)	-	(1,387)
Regulatory provision	-	250	(2,033)	-	471	(1,312)
Cash received	-	-	77	-	-	77
Cash refunded	-	-	(2,875)	-	-	(2,875)
At December 31, 2018	$ 11,602	$ 1 315	$ 3,018	$ 3,964	$ 4,624	$ 24,523
Cost incurred	-	-	(4,038)	(1,173)	-	(5,211)
Regulatory provision	-	(633)	-	-	471	(162)
Cash received	-	-	11	-	-	11
Cash refunded	-	-	(1,004)	-	-	(1,004)
At December 31, 2019	$ 11,602	$ 682	$ (2,013)	$ 2,791	$ 5,095	$ 18,157
Accumulated amortization:						
At December 31, 2017	$ 6,637	$ 194	$ -	$ -	$ -	$ 6,831
Amortization	262	194	-	-	-	456
Disposals	-	-	-	-	-	-
At December 31, 2018	$ 6,899	$ 388	$ -	$ -	$ -	$ 7,287
Amortization	263	195	-	-	-	458
Disposals	-	-	-	-	-	-
At December 31, 2019	$ 7,162	$ 583	$ -	$ -	$ -	$ 7,745
Net book value:						
At December 31, 2018	$ 4,703	$ 927	$ 3,018	$ 3,964	$ 4,624	$ 17,236
At December 31, 2019	$ 4,440	$ 99	$ (2,013)	$ 2,791	$ 5,095	$ 10,412
Net (increase) decrease in regulatory deferral account credit balances (which are recognized in the net movement of regulatory deferral account balances related to net income on the Statement of Operations and Other Comprehensive Income):						
December 31, 2018	$ 262	$ 99	$ 5,724	$ 339	$ (471)	$ 5,953
December 31, 2019	$ 263	$ 828	$ 5,031	$ 1,173	$ (471)	$ 6,824
Remaining recovery years						
At December 31 2018	18 years	Indeterminate	Indeterminate	Indeterminate	49 years	
At December 31, 2109	17 years	Indeterminate	Indeterminate	Indeterminate	48 years	
Absent rate regulation, net income for the year end and net movement in regulatory deferral account balances on the Statement of Operations and Other Comprehensive Income would increase (decrease) by:						
December 31, 2018	$ (262)	$ (99)	$ (5,724)	$ (339)	$ 471	$ (5,953)
December 31, 2019	$ (263)	$ (828)	$ (5,031)	$ (1,173)	$ 471	$ (6,824)

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

10. REGULATORY ACCOUNTS - continued

(i) Deferred insurance proceeds
The deferred insurance proceeds represents a gain on fire insurance proceeds related to a fire at the Whitehorse Rapids Generating Station in 1997 which is being amortized to income at the same rate as depreciation of the related replacement assets. In the absence of rate regulation, IFRS requires the gain to have been fully recognized as income in the year received.

(ii) Hearing reserve
The Utility has established a deferral account for future regulatory hearing costs. In 2017 the Utility adjusted the annual provision and recognition of the accumulated balance to more accurately reflect expected hearing costs. This change is consistent with the 2017-2018 GRA. Refer to Note 1(b). The regulatory provision for the year reflects an annual provision of $250,000 less $883,000 of costs transferred from the regulatory deferral account debit balance class Regulatory Costs (see Note 10(a)(iii)). In the absence of rate regulation, IFRS requires these costs to be expensed as incurred.

(iii) Low Water Reserve Fund
The Low Water Reserve Account ("LWRF") was established by YUB Order 2018-10. The LWRF is used to protect the Utility and ratepayers for costs associated with variability in thermal generation required when there is a thermal cost variance due solely to water-related hydro generation variances from YUB approved GRA forecasts. YUB Order 2019-08 amended how the LWRF is calculated. As a result, the costs incurred for the year of $4,038,000 reflect a decrease of $360,000 from the amount previously recognized as at December 31, 2018.

The LWRF attracts interest based upon short/intermediate term bond rates. Any negative balance attracts interest at the lowest short-term bond rates available to the Utility through its line of credit. The Utility is required to file quarterly reports with the YUB on the LWRF's activity.

In accordance with YUB Order 2015-01, the Utility defers recognition of the additional amounts collected from rate payers when the cost of thermal consumed in the period is less than the long-term average thermal requirements estimated for the actual annual generation load. These deferred amounts are recognized as revenue in the period when the cost of thermal incurred for the period is greater than the long-term average thermal requirements and the reason for the shortfall is a shortage of water in the hydro system. The YUB has set a cap of +/- $8 million for the LWRF. If the balance falls outside of this range, the Utility is to make an application to the YUB requesting recovery or a refund to customers. In accordance with YUB Order 2015-06, the Utility was providing a refund to the customers of 0.68 cents/kWh effective September 1, 2015. YUB Order 2019-02 set the refund rider to 0.00 cents/kWh effective April 1, 2019.

In the absence of rate regulation, IFRS would require any amounts earned or incurred related to the LWRF to be included in the Utility's net income in the year incurred.

Yukon Energy Corporation

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10. REGULATORY ACCOUNTS - continued

(iv) Future removal and site restoration costs
The Utility maintains a regulatory provision for future removal and site restoration related to property, plant and equipment, which is incremental to that required to be recognized as an asset retirement provision under IAS 37. The reserve has been established through amortization rates based upon depreciation studies conducted periodically by the Utility. As a result of YUB Order 2005-12, effective January 1, 2005, the provision is not to exceed the cumulative value of the provision at December 31, 2004 of $5,757,000.

Costs of dismantling capital assets, including site remediation, will be applied to this regulatory deferral account credit balance if they do not otherwise relate to an asset retirement provision. The period over which the provision will be reduced is dependent on the timing of future costs of demolishing, dismantling, tearing down, site restoration or otherwise disposing of the asset net of actual recoveries, and is therefore indeterminate. In the absence of rate regulation, IFRS requires these costs to be expensed or included in the gain or loss on disposal of the related property, plant and equipment, as applicable.

(v) Contracts with customers
Effective January 1, 2018 the Utility adopted IFRS 15, *Revenue from Contracts with Customers*. As a result of the impacts of IFRS 15, certain revenues are recognized in net income over a shorter period than allowed by the YUB for rate-setting purposes. The timing difference is reflected as a regulatory deferral account credit balance.

(c) Regulatory account expenses

Regulatory account expenses represent costs incurred related to regulatory account debit balances of $3,102,000 (2018 - $2.387,000) and regulatory account credit balances of $5,211,000 (2018 - $1,387,000).

(d) Net movement in regulatory deferral account balances related to net income

Net movement in regulatory deferral account balances related to net income is $11,024,000 (2018 - $7,577,000) represents the adjustment to net income for the year before net movement in regulatory deferral account balances for the effects of rate regulation in accordance with IFRS 14. The net movement figure of $11,024,000 is comprised of an increase of $4,200,000 for regulatory account debit balances and a decrease of $6,824,000 for regulatory account credit balances for rate regulation compared to the amounts that are recognized under IFRS. The net movement figure of $7,577,000 for 2018 is comprised of an increase of $1,625,000 for regulatory account debit balances and $5,953,000 decrease for regulatory account credit balances respectively for rate regulation compared to the amounts that would be recorded under IFRS absent rate regulation.

Yukon Energy Corporation

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11. BANK INDEBTEDNESS

The line of credit accrues interest on withdrawals at prime rate minus 0.75% per annum. Refer to the interest rate risk section within Note 25.

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31 2019	December 31 2018
Trade payables	$ 8,523	$ 9,105
Employee compensation	794	955
Due to related parties (Note 21)	699	835
Other	225	193
	$ 10,241	$ 11,088

13. CONSTRUCTION FINANCING

	December 31 2019	December 31 2018
Construction financing, due December 31, 2019 bearing interest at 2.74% approved to a maximum of $8.4 million	$ -	$ 8,400
Construction financing, due December 31, 2019 bearing interest at 2.74% approved to a maximum of $14 million	-	13,985
Construction financing, due December 11, 2020 bearing interest at 2.32% approved to a maximum of $4.0 million	3,959	-
Construction financing, due December 31, 2020 bearing interest at 2.36% approved to a maximum of $8.4 million	8,400	-
Construction financing, due December 31, 2020 bearing interest at 2.36% approved to a maximum of $14 million	13,985	-
	$ 26,344	$ 22,385

Construction financing balances are monies advanced from the Parent to assist in the development of the Utility's infrastructure. Interest is payable annually at December 31 and at the maturity date.

During the year the Utility did not make any principal repayments. Prior year debt was extinguished and replaced with new debt with no impact on cash flows. New financing of $3,959,000 was received during 2019.

Yukon Energy Corporation

Notes to Financial Statements
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14. LONG-TERM DEBT

The Utility's long-term debt is summarized as follows:

	December 31 2019	December 31 2018
Yukon Development Corporation		
$92,458,473 term note bearing interest at 2.40% repayable in annual installments of $3,683,800 principal, plus accrued interest with the balance of $77,723,273 due December 31, 2019	$ -	$ 77,723
$21,900,000 flexible term note bearing interest up to 5.46% repayable in annual installments of $336,923 principal, plus accrued interest with the balance of $8,423,078 due December 31, 2051 (i)	19,205	19,880
$5,505,000 term note bearing interest at 2.40% interest only payable annually, due December 31, 2039	5,505	5,505
$20,984,404 term note bearing interest at 2.21% repayable in annual installments of $839,376 principal, plus accrued interest with the balance due December 31, 2040	17,627	18,466
$12,136,000 term note bearing interest at 2.10% interest only payable annually, due December 31, 2041	12,136	12,136
$2,871,000 term note bearing interest at 2.90% interest only payable monthly, due June 30, 2044	2,871	-
$77,723,273 term note bearing interest at 2.68% repayable in annual installments of $3,683,800 principal, plus accrued interest with the balance of $59,304,273 due December 31, 2024	74,039	-
TD Bank		
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptances amounts from a variable interest rate based on the Bankers' Acceptances rates to a fixed rate of 2.69% per annum. Payable in monthly installments of $50,407 interest and principal with the balance due on December 28, 2022 (ii)	8,623	8,991
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 3.67% per annum. Payable in monthly installments of $120,246 interest and principal with the balance due on August 23, 2038 (iii)	22,811	23,406
The Utility entered into an interest rate swap to convert the interest rate on the Bankers' Acceptance amounts from a variable interest rate based on the Bankers' Acceptance rates to a fixed rate of 2.90% per annum. Payable in monthly installments of $31,726 interest and principal with the balance due on July 14, 2039 (iv)	6,688	-
Carmacks Stewart First Nation Liability		
Long-term liability payable to several First Nations related to the building of the Carmacks Stewart Transmission Line. These are non-interest bearing, repayable in varying installments, due in 2028	151	161
	169,656	166,268
Less current portion	6,054	80,210
	$ 163,602	$ 86,058

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

14. LONG-TERM DEBT - continued

(i) **$21,900,000 Flexible Term Note**
The terms of the flexible term note provide for a maximum amount of interest payable within a calendar year, calculated based on the actual grid generation on the electrical grid system connected with the Mayo Hydro Enhancement Project. The amount of interest payable as a result of the interest rate exceeding the maximum interest payable will abate forever. The actual interest rate on this flexible note was 3.53% (2018 - 3.88%).

(ii) **TD Bank Loan and 2.69% Interest Rate Swap**
On December 28, 2012, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures December 28, 2022.

(iii) **TD Bank Loan and 3.67% Interest Rate Swap**
On August 23, 2018, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures August 23, 2038.

(iv) **TD Bank Loan and 2.90% Interest Rate Swap**
On July 15, 2019, the Utility entered into a loan and interest rate swap with TD Bank to arrange financing for the purpose of continuing to develop the electrical infrastructure in the Yukon. The interest rate swap matures July 14, 2039.

Long-term debt repayment
Scheduled repayments for all long-term debt are as follows:

2020	6,061
2021	6,089
2022	13,590
2023	5,763
2024	61,415
Thereafter	76,738
	$ 169,656

The change in long-term debt arising from financing activities during the year related to principal repayments of $6,248,000 and the issuance of additional debt in the amount of $9,636,000. The Utility renegotiated the $77,723,000 note with the parent with terms based on market conditions at the time of renewal.

Fair value
The fair value of long-term debt at December 31, 2019 is $165,800,000 (2018 - $163,000,000). The fair value for all long-term debt including current portions was estimated using discounted cash flows based on an estimate of the Utility's current borrowing rate for similar borrowing arrangements.

Yukon Energy Corporation

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15. POST-EMPLOYMENT BENEFITS

Characteristics of benefit plans
The Utility sponsors a defined benefit pension plan for employees joining the Utility before January 1, 2002. The Utility also sponsors an executive defined benefit pension plan and supplemental executive retirement plan for a former executive. Benefits provided are calculated based on length of pensionable service, pensionable salary at retirement age and negotiated rates.

Employees joining the Utility after January 1, 2002 are not eligible to participate in the employee defined benefit pension plan. The Utility makes contributions to a Registered Retirement Savings Plan ("RRSP") on behalf of these employees and employees hired before January 1, 2002 who belonged to the employee defined benefit plan and elected to opt out of that plan. The RRSP is a defined contribution retirement plan. The costs recognized for the period are equal to the Utility's contribution to the plan. During 2019, these were $418,000 (2018 - $499,000).

The defined benefit pension plan for employees is regulated by the Office of the Superintendent of Financial Institutions ("OSFI") through the *Pension Benefits Standards Act* and regulations. This Act and accompanying regulations impose, among other things, minimum funding requirements. The executive defined benefit pension plan and supplemental executive retirement plan are not registered with OSFI and are not subject to minimum funding requirements of the Act.

These minimum funding requirements require the Utility make special payments as prescribed by the OSFI to repay any unfunded liability or deficit that may exist. For the employee defined benefit pension plan the Utility is required to pay $184,300 as a minimum annual payment during years 2020-2026, reducing to $38,000 for 2027, $49,300 per year during years 2028-2031, $61,000 for 2032 and $36,000 for 2033 (2018 - $148,300 as a minimum annual payment during years 2018-2027, reducing to $110,300 for 2028, and further reducing to $61,000 per year during years 2029-2032).

A committee of the Utility's Board of Directors oversees these plans and is responsible for the investment policy with regard to the assets of these funds.

Risks associated with defined benefit plans
The defined benefit pension plans expose the Utility to risk such as investment risk and actuarial risk. Investment risk is the risk that the assets invested will be insufficient to meet expected benefits. Actuarial risk is the risk that benefits paid will be more than expected. There are no particular unusual, entity-specific or plan-specific risks or any significant concentration of risk.

Yukon Energy Corporation

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15. POST-EMPLOYMENT BENEFITS - continued

Net defined benefit liability

	December 31 2019	December 31 2018
Present value of benefit obligations		
Balance, beginning of year	$ 23,499	$ 24,775
Employee contributions	51	73
Current service cost	313	403
Interest cost	915	847
Benefits paid	(758)	(680)
Actuarial losses (gains) on experience	853	(235)
Actuarial losses on demographic assumptions	-	215
Actuarial losses (gains) on financial assumptions	3,202	(1,899)
Balance, end of year	$ 28,075	$ 23,499
Fair value of plan assets		
Balance, beginning of year	17,731	18,659
Interest income on plan assets	687	632
Gains (losses) on plan assets	2,196	(1,369)
Employee contributions	51	74
Employer contributions	544	438
Benefits paid	(758)	(643)
Administrative costs	(65)	(60)
Balance, end of year	$ 20,386	$ 17,731
Net defined benefit liability	$ 7,689	$ 5,768

Components of benefit plan cost:

	December 31 2019	December 31 2018
Current service cost	$ 313	$ 403
Interest cost	915	847
Interest income on plan assets	(687)	(632)
Administrative costs	65	60
Defined benefit expense in Statement of Operations	606	678
Defined contribution expense	418	499
Total benefit expense in Statement of Operations	$ 1,024	$ 1,177
Actuarial losses (gains) on obligation	4,055	(1,919)
(Gains) losses on plan assets	(2,196)	1,369
Total re-measurements included in Other Comprehensive Income	$ 1,859	$ (550)
Total benefit costs recognized in Statement of Operations and Other Comprehensive Income	$ 2,883	$ 627

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15. POST-EMPLOYMENT BENEFITS - continued

Distribution of plan assets of defined benefit pension plans
The fair value of the defined benefit pension plans' assets are based on market values as reported by the defined benefit pension plans' custodians as at each applicable Statement of Financial Position date. The distribution of assets by major asset class is as follows:

	December 31, 2019	December 31, 2018
Equities	50.9%	48.6%
Fixed income securities	39.1%	40.9%
Real estate	10.0%	10.5%

Significant assumptions:

	December 31, 2019	December 31, 2018
Discount rate - accrued benefit obligation	3.10%	3.90%
Assumed rate of salary escalation	2.80%	2.80%
Pension growth	2.00%	2.00%

Sensitivity analysis of the defined benefit pension plans:
The sensitivities of each key assumption used in measuring accrued benefit obligations at each Statement of Financial Position date have been calculated independently of changes in other key assumptions. Actual experience may result in changes in a number of assumptions simultaneously. The sensitivity analysis has been determined based on reasonably possible changes of the respective assumptions occurring at the end of the reporting period. The mortality assumptions are based on the 2014 Canadian Pensioner Mortality Private Table projected with full generational mortality improvements using scale MI-2017.

Assumptions and sensitivity to the recognized post-employment benefits liability balance at December 31, 2019

Assumption	+1%	-1%	+1%	-1%
Discount rate	-13.95%	17.69%	$ (3,918)	$ 4,966
Salary growth	1.04%	-0.99%	278	(265)
Pension growth	15.74%	-12.90%	4,200	(3,442)
Life expectancy (1 year movement)	2.74%	-2.77%	770	(777)

Assumptions and sensitivity to the recognized post-employment benefits liability balance at December 31, 2018

Assumption	+1%	-1%	+1%	-1%
Discount rate	-13.39%	16.97%	$ (3,146)	$ 3,988
Salary growth	1.58%	-1.41%	351	(313)
Pension growth	14.80%	-12.13%	3,287	(2,694)
Life expectancy (1 year movement)	2.51%	-2.45%	589	(575)

The sensitivity analysis presented above may not be representative of the actual change in the defined benefit obligation as it is unlikely that the change in assumptions would occur in isolation of one another as some of the assumptions may be correlated.

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15. POST-EMPLOYMENT BENEFITS - continued

Furthermore, in presenting the above sensitivity analysis, the present value of the defined benefit obligation has been calculated using the projected unit credit method at the end of the reporting period, which is the same that is applied in calculating the defined benefit obligation liability recognized in the Statement of Financial Position.

The Utility pays the balance of the cost of the employee benefit plan over the employee contributions, as determined by the actuary. Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings ("YMPE") plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. Employees can make additional contributions to purchase ancillary benefits. Members choose the ancillary benefit on termination of service or on retirement.

The average duration of the benefit obligation is 16.0 years (2018 - 16.0 years). The Utility expects to make payments of $718,600 (2018 - $606,000) to the defined benefit plans during the next financial year.

16. CONTRIBUTIONS IN AID OF CONSTRUCTION

	Government of Canada	Parent since 1998	Yukon Government since 1998	Pre-1998 contributions	Total
Cost:					
At January 1, 2018	$ 71,000	$ 91,810	$ 11,391	$ 1,739	$ 175,940
Additions	-	-	79	-	79
Disposals	-	(2,080)	-	-	(2,080)
At December 31, 2018	$ 71,000	$ 89,730	$ 11,470	$ 1,739	$ 173,939
Additions	299	-	228	-	527
At December 31, 2019	$ 71,299	$ 89,730	$ 11,698	$ 1,739	$ 174,466
Accumulated amortization:					
At January 1, 2018	$ 6,020	$ 11,203	$ 2,049	$ 1,379	$ 20,651
Amortization	991	1,662	220	43	2,916
Disposals	-	(1,422)	-	-	(1,422)
At December 31, 2018	$ 7,011	$ 11,443	$ 2,269	$ 1,422	$ 22,145
Amortization	991	1,604	222	43	2,860
At December 31, 2019	8,002	13,047	2,491	1,465	25,005
Net book value:					
At December 31, 2018	$ 63,989	$ 78,287	$ 9,201	$ 317	$ 151,794
At December 31, 2019	$ 63,297	$ 76,683	$ 9,207	$ 274	$ 149,461

Yukon Energy Corporation

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17. DEFERRED REVENUE

	Customer Contributions	Decommissioning Fund	Total
At January 1, 2018	$ 9,546	$ 2,665	$ 12,211
Additions	1,304	48	1,352
Revenue recognized in Sales of Power (Note 18)	(1,669)	-	(1,669)
At December 31, 2018	$ 9,181	$ 2,713	$ 11,894
Additions	11,055	56	11,111
Revenue recognized in Sales of Power	(2,350)	-	(2,350)
At December 31, 2019	$ 17,886	$ 2,769	$ 20,655

Customer contributions represent monies paid or assets contributed by customers for connection to the grid. The contributions are recognized into revenue when the performance obligation is satisfied. Additions during 2019 include assets contributed valued at $10,345,000, received as part of a power purchase agreement.

The decommissioning fund represents monies paid in advance by an industrial customer to decommission the spur line that connects its operation to the Utility's grid. Under a power purchase agreement, the customer has the financial responsibility for decommissioning activities to be performed by the Utility on its behalf. Any amounts not required for decommissioning will be refunded to the customer. This money accrues interest at the rate equal to the three month Canadian Dealer Offered Rate ("CDOR"). This amount will be recognized to revenue when uncertainty associated with its recognition is satisfied.

18. SALES OF POWER

	2019	2018
Wholesale	$ 34,520	$ 32,911
Industrial	6,958	6,894
General service	6,065	5,359
Residential	2,840	2,700
Sentinel and street lights	106	108
Secondary sales	-	19
	$ 50,489	$ 47,991

Yukon Energy Corporation

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December 31 2019

19. OPERATIONS AND MAINTENANCE EXPENSES

	2019	2018
Fuel	$ 10,331	$ 6,309
Regulatory account expenses (Note 10 (c))	8,313	3,774
Wages and benefits	6,030	6,234
Contractors	2,563	2,706
Materials and consumables	2,161	1,400
Rent	1,547	1,332
Loss on asset disposal	1,337	1,177
Travel	369	480
Communication	74	75
	$ 32,725	$ 23,487

20. ADMINISTRATION EXPENSES

	2019	2018
Wages and benefits	$ 5,835	$ 6,050
Insurance and taxes	1,883	1,807
Materials, consumables and general	1,849	1,596
External labour	1,440	1,452
Licences and fees	674	599
Travel	224	197
Board fees	92	100
	$ 11,997	$ 11,801

21. RELATED PARTY TRANSACTIONS

The Utility is related in terms of common ownership to all YG departments, agencies and Territorial Corporations. Transactions are entered into in the normal course of operations with these entities. All sales of power transactions are recorded at the rates approved by the YUB.

Interim Electrical Rebate program revenues are received from YDC in accordance with terms established by YG which established the program to protect certain ratepayers. These revenues are included in sales of power on the Statement of Operations and Other Comprehensive Income.

Yukon Energy Corporation

Notes to Financial Statements
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21. RELATED PARTY TRANSACTIONS - continued

The following table summarizes the Utility's related party transactions with YDC for the year:

	2019	2018
Revenue		
Sales of service	$ 4	$ 4
Rate subsidy	283	298
Operating expenses		
Interest expense	$ 4,010	$ 4,017
Dividend paid	$ 2,871	$ -
Other receipts		
Construction financing	3,959	-
Long-term debt	2,871	-
Other payments		
Repayment of long-term debt	$ 5,197	$ 4,522

During the year, the Utility refinanced its construction financing (Note 13).

At the end of the year, the amounts receivable from and due to related parties are as follows:

	December 31 2019	December 31 2018
YDC		
Accounts receivable	$ 370	$ 28
Accounts payable	695	769
Construction financing	26,344	22,385
Current portion of long-term debt	4,860	79,238
Long-term debt	126,523	54,472
YG		
Accounts receivable	$ 152	$ 4
Accounts payable	4	66

These balances are non-interest bearing and payable on demand except for construction financing and long-term debt.

Transactions with Key Management Personnel
The Utility's key management personnel include members of the senior management team and the Board of Directors, a total of 18 individuals (2018 - 17 individuals). Key management personnel compensation is as follows:

Year ended December 31	2019	2018
Short-term employee benefits	$ 1,423	$ 1,567
Post-employment benefits	161	159
	$ 1,584	$ 1,726

Yukon Energy Corporation

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22. COMMITMENTS

Aishihik water licence
The Yukon Water Board issued a water use licence in 2002, valid until December 31, 2019, for the Utility's Aishihik Lake facility. In addition to maintaining a minimum and maximum water level, this licence commits the Utility to meet a number of future requirements including annual fish monitoring programs. Due to outstanding issues with affected stakeholders, the Utility was unable to secure a long term renewal of the licence prior to expiry. During 2019, a two month extension was granted and then, in order to ensure continued generation from this plant, the Utility made application for a short term (three year) renewal to the existing licence. This application was approved and a renewed licence was granted by the YWB effective March 1, 2020. This short term licence includes additional monitoring and potential operational adjustments, the cost of which will be charged to the fiscal year in which they occur. The Utility continues to work with affected parties with the objective of a longer term licence agreement prior to the expiry of the extension.

Fish monitoring programs are also required under an authorization provided by the federal government Department of Fisheries and Oceans, which is valid until December 31, 2022. The costs of meeting these requirements are accounted for as water licence costs in the year they are paid.

Contractual obligations
The Utility has entered into contracts to purchase products or services for which the liability has not been incurred as at December 31, 2019 as the product or service had not been provided. The total commitments at year end are $8,761,000 (2018 - $2,935,000).

23. CONTINGENCIES

Aishihik Third Turbine Project
This project was commissioned into service in December 2011. On March 2, 2012, the general contractor filed a claim with the Supreme Court of Yukon for $4,000,000 plus interest and costs alleging the Utility has not paid for work performed. During 2017, the Yukon Supreme Court issued an award in favor of the contractor. The Utility successfully appealed the award in 2018. A re-trial was held in November 2019; the decision of the judge on this proceeding is outstanding. The matter is still before the courts. Legal costs are being expensed as incurred. The outcome of the court process is not determinable at this time and no estimate of settlement has been recognized in the financial statements.

Asset Retirement Obligations
The Utility has not recognized a provision for the closure and restoration obligations for certain generation, transmission and distribution assets which the Utility anticipates maintaining and operating for an indefinite period, making the date of retirement of these assets indeterminate. These significant uncertainties around the timing of any potential future cash outflows are such that a reliable estimate of the liability is not possible at this time. A provision will be recognized when the timing of the retirement of these assets can be reasonably estimated.

Yukon Energy Corporation

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24. PROVISION FOR ENVIRONMENTAL LIABILITIES

The Utility's activities are subject to various federal and territorial laws and regulations governing the protection of the environment or to minimize any adverse impact thereon. The Utility conducts its operations so as to protect public health and the environment and believes its operations are materially in compliance with all applicable laws and regulations.

The Utility has conducted environmental site assessments at all its diesel plant sites. At sites where environmental contamination was found and a legal obligation to remediate the site existed, the Utility has conducted a full remediation. As at December 31, 2019 no new provisions for environmental liabilities, for which a legal obligation exists to remediate, have been identified by the Utility. The Utility will continue to use its Environmental Management System to monitor and assess previous and potential existing environmental liabilities on an ongoing basis. The Utility does not have a provision for environmental liabilities as there is no present obligation to remediate.

25. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

At December 31, 2019, the Utility's financial instruments included cash, accounts receivable, accounts payable and accrued liabilities, construction financing, long-term debt and interest rate swaps. The fair values of cash, accounts receivable, accounts payable and accrued liabilities and construction financing approximate their carrying values due to the immediate or short-term maturity of these financial instruments.

The long-term debt is accounted for at amortized cost using the effective interest rate method. The fair value of the long-term debt is estimated by discounting the future cash flows using current rates for debt instruments subject to similar risks and maturities as disclosed in Note 14.

Interest rate swaps are financial contracts that derive their value from changes in an underlying variable. The fair value of the interest rate swaps is estimated using standard market valuation techniques and is provided to the Utility by the financial institution that is the counterparty to the transactions.

Interest rate risk
Interest rate risk is the risk that future cash flows or fair value of a financial instrument will fluctuate due to changes in market interest rates. The Utility's future cash flows are not exposed to significant interest rate risk due to its long-term debt having fixed interest rates, with the exception of the Bankers' Acceptances from the TD Bank. The Bankers' Acceptances have had the variable rate converted to a fixed rate using an interest rate swap to eliminate the interest rate risk.

As at December 31, 2019, the Utility had three interest rate swap agreement in place. The first agreement has a notional principal amount of $8.6 million (2018 - $9.0 million) and the agreement effectively changes the Utility's interest rate exposure on this notional amount from a floating rate to a fixed rate of 2.69%. The second agreement has a notional principal amount of $22.8 million (2018 - $23.4 million) and the agreement effectively changes the Utility's interest rate exposure on the notional amount from a floating rate to a fixed rate of 3.67%. The third agreement has a notional principal amount of $6.7 million (2018 - $0) and the agreement effectively changes the Utility's interest rate exposure on the notional amount from a floating rate to a fixed rate of 2.90%.

The fair value of the interest rate swap agreement on December 31, 2019 was a liability of $1,930,000 (2018 -$1,042,000). The decrease in the fair value in 2019 of $888,000 (2018 – $986,000) is recognized on the Statement of Operations and Other Comprehensive Income as an unrealized loss. A 100 basis point increase or decrease in the interest rate assumption would have resulted in an increase/decrease in the interest rate swap agreements fair value of $3,534,000 (2018 - $2,911,000).

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

25. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

Interest rate risk - continued

The Utility has access to a $10 million line of credit. Effective June 6, 2019, the line of credit was increased temporarily to $26.5 million. The temporary increase expires May 31, 2020. The account accrues interest on withdrawals at prime rate minus 0.75% per annum. By agreement the financial institution has a legally enforceable right to set off the outstanding balance under the line of credit by cash balances in other accounts with the same bank. The amount outstanding on the line of credit balance at year end was $22.5 million (2018 - $2.4 million). The Utility has cash balances with the same financial institution of $2.9 million (2018 - $2.9 million). Due to the short-term nature of the amount drawn on the line of credit and the Utility's cash balances with the same financial institution, the interest rate risk is minimal.

Credit risk
Credit risk is the risk of failure of a debtor or counterparty to honour its contractual obligations resulting in financial loss to the Utility.

The following table illustrates the maximum credit exposure to the Utility if all counterparties defaulted:

	December 31 2019	December 31 2018
Cash	$ 521	$ 581
Accounts receivable	10,317	6,873
	$ 10,838	$ 7,454

Credit risk on cash is considered minimal as the Utility's cash deposits are held by a Canadian Schedule 1 Chartered bank.

Credit risk on accounts receivable is considered minimal as the Utility has experienced insignificant bad debt in prior years. In addition, its primary customer is a rate regulated utility that purchases power from the Utility for resale and as such these receivables are considered fully collectible. Included in the accounts receivable past due but not impaired at December 31, 2019 are $1,680,000 (2018 - $681,000) which management believes will be received in full.

Liquidity risk
Liquidity risk is the risk that the Utility will not be able to meet its financial obligations as they fall due. The Utility manages liquidity risk through regular monitoring of cash and currency requirements by preparing cash flow forecasts to identify financing requirements. The Utility's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Utility's reputation.

Yukon Energy Corporation

Notes to Financial Statements
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December 31 2019

25. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS - continued

Liquidity risk - continued
The Utility's largest current liability is current portion of long-term debt which is predominantly due to the Parent. In addition, rate regulation assists the Utility with liquidity management by providing consistent revenues and a consistent debt to equity ratio.

Fair values
The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2019:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$1,930	-	$1,930
Long-term debt	-	-	$165,800	$165,800

The following table illustrates the fair value hierarchy of the Utility's financial instruments as at December 31, 2018:

	Quoted prices in active markets (Level 1)	Other observable inputs (Level 2)	Unobservable inputs (Level 3)	Total
Derivative related liability	-	$1,042	-	$1,042
Long-term debt	-	-	$166,000	$166,000

26. CAPITAL MANAGEMENT

The Utility's capital is its shareholder's equity which is comprised of share capital, contributed surplus and retained earnings. The Utility manages its equity by managing revenues, expenses, assets and liabilities to ensure the Utility effectively achieves its objectives while remaining a going concern.

The Utility has a policy which defines its capital structure at a ratio of 60% debt and 40% equity. This policy has been reviewed and accepted by the YUB.

The Utility monitors its capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, which is comprised of long-term debt, including the portion of long-term debt due within one year, as well as the decommissioning fund (Note 17). Short-term debt related to assets under construction at the Statement of Financial Position date is excluded from the calculation of total debt, as the assets are similarly excluded from the determination of rate base. Total capitalization is calculated as total debt plus total shareholder's equity as shown on the Statement of Financial Position. The Utility maintains a balance in retained earnings as an indicator of the Utility's equity position.

Yukon Energy Corporation

Notes to Financial Statements
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26. CAPITAL MANAGEMENT - continued

The table below summarizes the Utility's total debt to total capitalization position:

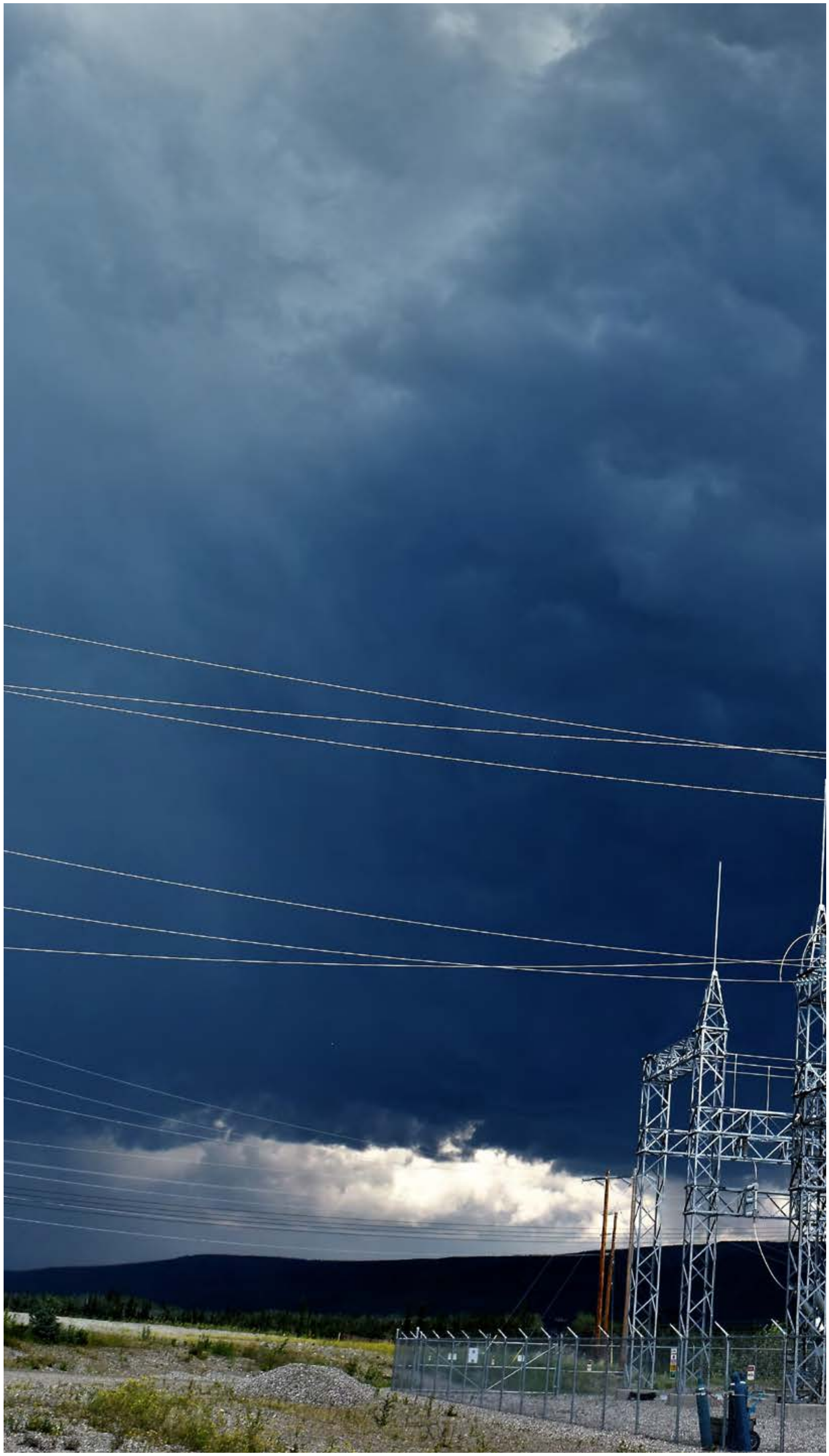
	December 31 2019	2018
Long-term debt due within one year	$ 6,054	$ 80,210
Long-term debt	163,602	86,058
Total debt	169,656	166,268
Add decommissioning fund (Note 17)	2,769	2,713
Total debt to include in the calculation	$ 172,425	$ 168,981
Share capital	$ 39,000	$ 39,000
Contributed surplus	14,600	14,600
Retained earnings	65,596	68,014
Total shareholder's equity	119,196	121,614
Total capitalization	$ 291,621	$ 290,595
Total debt to total capitalization	59 %	58 %

There were no changes in the Utility's approach to capital management during the period.

27. SUBSEQUENT EVENTS

Subsequent to year-end, the Utility entered into a contract to purchase certain products or services. The total commitment for four years is approximately $20 million, subject to demand and fluctuations in market prices.

As a result of the spread of the COVID-19 coronavirus, economic uncertainties have arisen which are likely to impact forecasts. The potential financial impact cannot be reasonably estimated at this time, but is expected to both positivley and negatively affect the Utility's financial position, results of operations and cashflows.



Storm brewing over Mayo substation – Yukon Energy

Environmental Benefits Statement

This report is printed on 100 percent postconsumer waste material. It is Forest Stewardship Council TM Canada certified, processed chlorine free, alkaline pH, and meets the credibility of Canadian Standards Association (CSA) for longevity.

By using this paper, Yukon Energy saved the following resources based on a copy run of 50 reports:

Wood Use: 450 kg

Water: 1,850 L

Energy: 300 kWhr

Solid Waste: 25 kg

Greenhouse Gases: 62.50 kg CO_2 equiv.

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TAB 11

ORDERS IN COUNCIL

O.I.C. 1995/090
PUBLIC UTILITIES ACT

PUBLIC UTILITIES ACT

Pursuant to sections 17 and 18 of the *Public Utilities Act*, the Commissioner in Executive Council orders as follows:

1. Order-in-Council 1991/062 is hereby revoked.

2. The annexed Rate Policy Directive (1995) is hereby made.

Dated at Whitehorse, in the Yukon Territory, this 29th day of May, 1995.

____
Commissioner of the Yukon

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

Le Commissaire en conseil exécutif, conformément aux articles 17 et 18 de la *Loi sur les entreprises de service public*, décrète ce qui suit :

1. Le décret 1991/062 est, par les présentes, abrogé.

2. Les instructions sur la politique tarifaire (1995), paraissant en annexe, sont par les présentes adoptées.

Fait à Whitehorse, dans le territoire du Yukon, ce 29 mai 1995.

____
Commissaire du Yukon

O.I.C. 1995/090
PUBLIC UTILITIES ACT

RATE POLICY DIRECTIVE (1995)

Interpretation

1. In this Directive

"customer" refers to a purchaser of electricity; « *client* »

"government customer" means a retail customer

(a) who is a federal or territorial department or agency;

(b) a body, other than one carrying on a business with a view to making a profit, that derives all or substantially all of its funding from a body referred to in paragraph (a); « *client gouvernemental* »

"isolated industrial customer" means a customer engaged in manufacturing, processing, or mining and whose electrical service is not inter-connected with electrical service provided to any other customer; « *client industriel isolé* »

"major industrial customer" means a customer engaged in manufacturing, processing, or mining, whose peak demand for electricity exceeds 1 MW, but it does not include an isolated industrial customer; « *client industriel majeur* »

"natural gas" includes liquefied natural gas; « *gaz naturel* »

("natural gas" added by O.I.C. 2018/220)

"province" has the same meaning as in the Interpretation Act; « *province* »

"retail customer" means a customer of Yukon Energy Corporation or of The Yukon Electrical Company Limited, other than a major industrial customer, an isolated industrial customer, or a wholesale customer; « *client au détail* »

"wholesale customer" means the Yukon Electrical Company Limited when it purchases electricity from Yukon Energy Corporation. « *client en gros* »

Normal return on equity

2.(1) Subject to subsection (2), the Board must include in the rates of Yukon Energy Corporation and the Yukon

DÉCRET 1995/090
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTIONS SUR LA POLITIQUE TARIFAIRE (1995)

Définitions

1. Les définitions qui suivent s'appliquent aux présentes instructions :

« client » Acheteur d'électricité; "*client*"

« client au détail » Client de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited qui n'est ni un client industriel majeur, ni un client industriel isolé, ni un client en gros; "*retail Customer*"

« client en gros » La Yukon Electrical Company Limited lorsqu'elle achète de l'énergie de la Société d'énergie du Yukon; "*wholesale customer*"

« client gouvernemental » Client au détail qui est:

a) soit un organisme gouvernemental, un ministère fédéral ou territorial;

b) soit un organisme qui n'exploite aucune entreprise à des fins lucratives et dont le financement provient en totalité, ou pour l'essentiel, d'un organisme décrit à l'alinéa a); "*government customer*"

« client industriel isolé » Client qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont l'approvisionnement en électricité est indépendant de celui de tout autre client; "*isolated industrial customer*"

« client industriel majeur » Client autre qu'un client industriel isolé qui se livre à une activité de fabrication, de traitement ou à l'exploitation d'une mine et dont la demande de pointe d'électricité dépasse 1 MW. "*major industrial customer*"

« gaz naturel » S'entend notamment du gaz naturel liquéfié. "*natural gas*"

(« gaz naturel » ajoutée par Décret 2018/220)

« province » S'entend d'une province au sens de la *Loi d'interprétation*. "*province*"

Rendement normal sur la valeur nette

2.(1) Sous réserve du paragraphe 2, la Commission doit prévoir dans les tarifs de la Société d'énergie du Yukon

Electrical Company Limited provision to recover a fair return on their equity used to finance their rate base.

(2) The Board must include in the rates of the Yukon Energy Corporation provision to recover a fair return on the Corporation's equity, less one-half of one per cent (.5%).

(3) When finalizing the interim 1997 rates made by Board Order 1997-6, the Board may adjust the 1997 fair return provided on Yukon Energy Corporation's equity and on Yukon Electrical Company Limited's equity.

(Section 2 replaced by O.I.C. 1998/32)

Retail and major industrial rate adjustments

2.1(1) The Board must ensure that rate adjustments for retail customers and major industrial customers apply equally, when measured as percentages, to all classes of retail customers and to the class of major industrial customers.

(Subsection 2.1(1) added by O.I.C. 2008/149)
(Subsection 2.1(1) replaced by O.I.C. 2012/68)
(Subsection 2.1(1) amended by O.I.C. 2018/220)

(2)

(Subsection 2.1(2) added by O.I.C. 2008/149)
(Subsection 2.1(2) replaced by O.I.C. 2012/68)
(Subsection 2.1(2) repealed by O.I.C. 2018/220)

(3)

(Subsection 2.1(3) added by O.I.C. 2012/68)
(Subsection 2.1(3) amended by O.I.C. 2014/23)
(Subsection 2.1(3) repealed by O.I.C. 2018/220)

Normal principles to apply

3. Except to the extent otherwise stated by this Directive or the Act, the Board must review and approve rates in accordance with principles established in Canada for utilities, including those principles established by regulatory authorities of the Government of Canada or of a province regulating hydro and non-hydro electric utilities.

Retail rates: non-government customers

4.(1) The Board must fix rates for retail customers, other than government customers, in accordance with the following rate policy for Yukon,

et de la Yukon Electrical Company Limited les mesures pour réaliser un rendement équitable sur leur valeur nette utilisé pour financer leurs tarifs de base.

(2) La Commission doit inclure dans les tarifs de la Société d'énergie du Yukon des mesures pour réaliser un rendement équitable sur la valeur nette de cette dernière, moins 5 dixièmes pour cent (,5 %).

(3) Lorsqu'elle met au point les tarifs intérimaires de 1997 établis par l'ordonnance 1997-6 de la Commission, cette dernière peut rajuster le rendement équitable de 1997 découlant de la valeur nette de la Société d'énergie du Yukon et de la Yukon Electrical Company Limited.

(Article 2 remplacé par Décret 1998/32)

Ajustements tarifaires pour les clients au détail et industriels majeurs

2.1(1) La Commission veille à ce que les ajustements tarifaires pour les clients au détail et industriels majeurs s'appliquent de façon uniforme en pourcentage à toutes les catégories de clients au détail et à toutes les catégories de clients industriels majeurs.

(Paragraphe 2.1(1) ajouté par Décret 2008/149)
(Paragraphe 2.1(1) modifié par Décret 2012/68)
(Paragraphe 2.1(1) modifié par Décret 2018/220)

(2)

(Paragraphe 2.1(2) ajouté par Décret 2008/149)
(Paragraphe 2.1(2) modifié par Décret 2012/68)
(Paragraphe 2.1(2) abrogé par Décret 2018/220)

(3)

(Paragraphe 2.1(3) ajouté par Décret 2012/68)
(Paragraphe 2.1(3) modifié par Décret 2014/23)
(Paragraphe 2.1(3) abrogé par Décret 2018/220)

Application des principes normaux

3. Sauf indication contraire dans les présentes instructions ou dans la Loi, la Commission examine et approuve les tarifs aux clients selon les principes établis au Canada pour des services publics, y compris les principes établis par les organismes régulateurs des gouvernements fédéral et provinciaux réglementant les entreprises de services publics, que ces derniers soient reliés à l'électricité ou pas.

Tarifs au détail pour les clients non-gouvernementaux

4.(1) La Commission fixe les tarifs pour les clients au détail non-gouvernementaux selon la politique tarifaire suivante pour le Yukon :

(a) the rates for non-government retail customers must be sufficient to recover costs that are not to be recovered from government customers or from major industrial customers;

(b) rates for each class of non-governmental retail customer must be the same throughout the Yukon without variation between Yukon Energy Corporation and The Yukon Electrical Company Limited customers;

(2) The Board must fix a runoff rate block for each non-government retail customer class applicable to all consumption by each customer of the class in excess of a specified consumption level per billing period, and such specified consumption level per customer is not to be less than 1,000 kWh for residential non-government retail customers and 2,000 kWh for general service non-government retail customers.

(3) The Board must fix runoff rates for each non-government retail customer class on the basis of rate design principles to promote economy and efficiency, and separate runoff rates may be allowed in this regard for customers in different communities or rate zones, provided that such runoff rates for customers in each non-government retail customer class are fixed for each community or rate zone throughout Yukon in accordance with the same rate design principles.

Retail rates: government customers

5.(1) The Board must fix rates for government customers in accordance with the following power rate policy for Yukon

(a) rates for government customers may be adjusted so as to simplify the rate structure and make the rates more consistent throughout Yukon;

(b) the rate for government customers in a community may not be lower than the rate for

a) les tarifs pour les clients non-gouvernementaux doivent suffire à générer les recettes nécessaires afin de recouvrer les coûts, lesquels ne doivent pas être récupérés des clients gouvernementaux ou des clients industriels majeurs;

b) les tarifs pour chaque catégorie de clients au détail non-gouvernementaux s'appliquent uniformément à la grandeur du Yukon et sans distinction entre la Société d'énergie du Yukon et la Yukon Electrical Company Limited.

(2) La Commission doit déterminer une série de primes de dépassement pour chaque catégorie visée de clients au détail non-gouvernementaux, lesquelles s'appliquent à la consommation de chaque client qui excède un niveau de consommation déterminée, au cours d'une période de facturation et un tel niveau de consommation déterminé par client ne peut s'appliquer qu'à la consommation atteignant 1 000 kWh ou plus pour la catégorie résidentielle de clients au détail non-gouvernementaux et de 2 000 kWh pour la catégorie de services généraux de clients au détail non-gouvernementaux.

(3) La Commission doit déterminer des primes de dépassement pour chaque catégorie de clients au détail non-gouvernementaux sur la base de principes pour l'élaboration des taux afin de favoriser l'efficacité et l'économie et, dans cette optique, des primes de dépassement peuvent être permises à l'intention de clients demeurant dans différentes communautés ou dans des zones où les taux diffèrent, en autant que ces primes de dépassement dans chaque catégorie de clients au détail non-gouvernementaux soient les mêmes pour chaque communauté ou chaque zone tarifaire à travers le Yukon, conformément aux principes pour l'élaboration des tarifs.

Tarifs au détail pour les clients gouvernementaux

5.(1) La Commission fixe les tarifs pour les clients gouvernementaux selon la politique tarifaire énergétique du Yukon qui suit :

a) les tarifs pour les clients gouvernementaux peuvent être ajustés aux fins de simplifier la structure tarifaire et d'uniformiser les tarifs à la grandeur du Yukon;

b) le tarif pour les clients gouvernementaux dans une agglomération ne peut être moindre que le similar service to non-government retail customers in that community.

(2) Upon application of Yukon Energy Corporation, The Yukon Electrical Company Limited, or a customer, the Board must determine whether a customer is or is not a government customer.

Rates - major and isolated industrial customers

6.(1) The Board must ensure that the rates charged to major industrial customers, whether pursuant to contracts or otherwise, are sufficient to recover the costs of service to that customer class; those costs must be determined by treating the whole Yukon as a single rate zone and the rates charged by both utilities must be the same.

(Subsection 6(1) amended by O.I.C. 2018/220)

(2) Rates of isolated industrial customers served by Yukon Energy Corporation or The Yukon Electrical Company Limited must conform with any contract between the customer and Yukon Energy Corporation or The Yukon Electrical Company Limited and the costs and revenues related to those contracts may not be considered by the Board when establishing rates for other customers.

(3) Despite subsection (1), the Board must ensure that the rates charged to major industrial customers conform to section 2.1.

(Subsection 6(3) added by O.I.C. 2007/94)
(Subsection 6(3) replaced by O.I.C. 2012/68)
(Subsection 6(3) amended by O.I.C. 2014/23)
(Subsection 6(3) replaced by O.I.C. 2018/220)

Wholesale rates

7. The Board must fix rates of Yukon Energy Corporation for the wholesale power customer in accordance with the following rate policy for Yukon:

(a) Yukon Energy Corporation shall sell electricity to The Yukon Electrical Company Limited at the same demand rate and the same energy rate throughout the Yukon and those rates must be sufficient to enable Yukon Energy Corporation to recover its costs that are not recovered from its other customers;

(b) the wholesale rate to The Yukon Electrical Company Limited shall include appropriate provisions to ensure that Yukon Energy Corporation will recover its costs for retail and

tarif pour un service semblable pour les clients au détail non-gouvernementaux dans cette agglomération.

(2) À la demande de la Société d'énergie du Yukon ou de la Yukon Electrical Company Limited, ou d'un client, la Commission prend une décision sur le statut de client gouvernemental d'un client.

Tarifs pour les clients industriels majeurs et isolés

6.(1) La Commission doit s'assurer que les tarifs facturés aux clients industriels majeurs, en vertu d'un contrat ou autrement, suffisent à recouvrer les coûts du service pour cette catégorie de clients. Ces coûts sont déterminés en considérant tout le Yukon comme une zone tarifaire unique et les tarifs facturés par les deux services publics doivent être les mêmes.

(2) Les tarifs s'appliquant aux clients industriels et isolés desservis par la Société d'énergie du Yukon ou la Yukon Electrical Company Limited doivent être conformes à tout contrat entre le client et ces sociétés; les coûts et les revenus reliés à ces contrats ne peuvent être considérés par la Commission lorsqu'elle établit les tarifs pour d'autres clients.

(3) Malgré le paragraphe (1), la Commission veille à ce que les tarifs facturés aux clients industriels majeurs soient conformes à l'article 2.1.

(Paragraphe 6(3) ajouté par Décret 2007/94)
(Paragraphe 6(3) remplacé par Décret 2012/68)
(Paragraphe 6(3) modifé par Décret 2014/23)
(Paragraphe 6(3) remplacé par Décret 2018/220)

Tarifs de gros

7. La Commission doit déterminer les tarifs facturés par la Société d'énergie du Yukon au client en gros selon la politique tarifaire du Yukon qui suit :

a) la Société d'énergie du Yukon vend de l'électricité à la Yukon Electrical Company Limited au même tarif de demande et au même tarif d'énergie à la grandeur du Yukon et ces tarifs doivent suffire à la Société d'énergie du Yukon pour recouvrer les coûts qui ne sont pas recouverts de ses autres clients;

b) le tarif de gros facturé à la Yukon Electrical Company Limited comprend les mesures appropriées pour permettre à la Société d'énergie du Yukon de recouvrer ses coûts de service au major industrial power service with adoption of the rates for retail power customers and major industrial power customers as specified herein.

Fuel Price adjustment

8. The Board must permit Yukon Energy Corporation and The Yukon Electrical Company Limited to adjust their rates to retail customers, major industrial customers, and isolated industrial customers so as to reflect fluctuations in the prices for which the two utilities pay for diesel fuel and natural gas, without the requirement for specific application to and approval of the Board.

(Section 8 amended by O.I.C. 2018/220)

détail et ses coûts de service aux clients industriels majeurs au moyen de tarifs qui s'appliquent à ces services en vertu des présentes.

Ajustement du prix du combustible

8. La Commission permet à la Société d'énergie du Yukon et à la Yukon Electrical Company Limited d'ajuster les tarifs facturés aux clients au détail, aux clients industriels majeurs et aux clients industriels isolés de manière à refléter les fluctuations des prix payés pour le mazout et le gaz naturel par ces deux sociétés, sans avoir à faire une demande particulière à la Commission pour obtenir son autorisation.

(Article 8 modifié par Décret 2018/220)

SCHEDULE A

("Schedule A, Industrial Primary Rate Schedule 39" added by O.I.C. 2007/94)
("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2012 see Subsection 6(3))
("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2013 see Subsection 6(3), amended by O.I.C. 2012/68)
("Schedule A, Industrial Primary Rate Schedule 39" valid until Dec. 31, 2018 see Subsection 6(3), amended by O.I.C. 2014/23)
(Schedule A repealed by O.I.C. 2018/220)

ANNEXE A

(« Annexe A, Clients industriels annexe tarifaire nº 39 » ajoutée par décret 2007/94)
(« Annexe A, Clients industriels annexe tarifaire nº 39 » valide jusqu'au 31 décembre 2012, voir paragraphe 6(3))
(« Annexe A, Clients industriels annexe tarifaire nº 39 » valide jusqu'au 31 décembre 2013, voir paragraphe 6(3), modifié par Décret 2012/68)
(« Annexe A, Clients industriels annexe tarifaire nº 39 » valide jusqu'au 31 décembre 2018, voir paragraphe 6(3), modifié par Décret 2014/23)
(Annexe A abrogée par Décret 2018/220)

O.I.C. 2019/25
PUBLIC UTILITIES ACT

PUBLIC UTILITIES ACT

Pursuant to the *Public Utilities Act*, the Commissioner in Executive Council orders

1 The attached *Direction to the Yukon Utilities Board (Independent Power Production)* is made.

Dated at Whitehorse, Yukon, January 25, 2019.

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Commissioner of Yukon

DÉCRET 2019/25
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est établi l'*Instruction à l'intention de la régie des entreprises de service public (production indépendante d'énergie)* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 25 janvier 2019.

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Commissaire du Yukon

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

Definitions

1 In this Direction

"ATCO Electric Yukon" means The Yukon Electrical Company Limited doing business as ATCO Electric Yukon; « *ATCO Electric Yukon* »

"CPI" means the All-Items Consumer Price Index for Canada published by Statistics Canada; « *IPC* »

"electrical grid" means the interconnected network of equipment and infrastructure, owned by Yukon Energy Corporation and ATCO Electric Yukon, for the generation, transmission and delivery of electricity in Yukon; « *réseau de distribution d'électricité* »

"electrical grid service area" means the area of Yukon to which electricity is delivered by means of the electrical grid; « *région desservie par le réseau de distribution d'électricité* »

"electrical utility" means Yukon Energy Corporation or ATCO Electric Yukon; « *service public d'électricité* »

"electricity purchase agreement" means an agreement between an electrical utility and the owner of an independent power production facility for the purchase, by the utility, of electricity generated by the facility; « *contrat d'achat d'électricité* »

"generating unit" means a device used to generate electricity; « *unité de production* »

"independent power production facility" means a facility in Yukon that

(a) comprises one or more generating units each of which generates electricity exclusively from a renewable energy source,

(b) has a nameplate capacity of at least 30 kW, and

(c) is a prescribed undertaking under the *Independent Power Production and Micro-Generation Regulation*;
« *installation indépendante de production d'énergie* »

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

Définitions

1 Les définitions suivantes s'appliquent à la présente instruction :

« ATCO Electric Yukon » La Yukon Electrical Company Limited faisant affaires sous le nom d'ATCO Electric Yukon. "*ATCO Electric Yukon*"

« capacité nominale » À l'égard d'une installation de production indépendante d'énergie, la puissance maximale de sortie nominale d'électricité de l'installation. "*nameplate capacity*"

« collectivité hors-réseau » Beaver Creek, Burwash Landing, Old Crow ou Watson Lake. "*off-grid community*"

« contrat d'achat d'électricité en réseau » Un contrat d'achat d'électricité à l'égard d'une installation de production indépendante d'énergie qui est située dans la région desservie par le réseau de distribution d'électricité. "*on-grid electricity purchase agreement*"

« contrat d'achat d'électricité hors-réseau » Un contrat d'achat d'électricité à l'égard d'une installation de production indépendante d'énergie qui est située dans une collectivité hors-réseau. "*off-grid electricity purchase agreement*"

« contrat d'achat d'électricité » Un contrat entre un service public d'électricité et le propriétaire d'une installation de production indépendante d'énergie pour l'achat par le service public d'électricité produite par cette installation. "*electricity purchase agreement*"

« installation de production indépendante d'énergie » Une installation au Yukon qui :

a) comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

b) possède une capacité nominale d'au moins 30 kW;

c) est une entreprise visée par règlement en vertu "nameplate capacity", of an independent power production facility, means the maximum rated output of electricity of the facility; « *capacité nominale* »

"off-grid community" means Beaver Creek, Burwash Landing, Old Crow or Watson Lake; « *collectivité hors-réseau* »

"off-grid electricity purchase agreement" means an electricity purchase agreement in respect of an independent power production facility that is located in an off-grid community; « *contrat d'achat d'électricité hors-réseau* »

"on-grid electricity purchase agreement" means an electricity purchase agreement in respect of an independent power production facility that is located in the electrical grid service area; « *contrat d'achat d'électricité en réseau* »

"renewable energy source" means

(a) moving water,

(b) wind,

(c) heat from the earth,

(d) sunlight, or

(e) biomass;
« *source d'énergie renouvelable* »

"thermal generation" means the generation of electricity from diesel or natural gas. « *production thermique* »

du Règlement portant sur la production indépendante d'énergie et la micro-production.
"*independent power production facility*"

« IPC » L'indice d'ensemble des prix à la consommation pour le Canada publié par Statistique Canada. "*CPI*"

« production thermique » La production d'électricité à partir de diesel ou de gaz naturel. "*thermal generation*"

« région desservie par le réseau de distribution d'électricité » La région du Yukon où l'électricité est livrée au moyen du réseau de distribution d'électricité. "*electrical grid service area*"

« réseau de distribution d'électricité » Le réseau interconnecté d'équipement et d'infrastructure, appartenant à la Société d'énergie du Yukon et à ATCO Electric Yukon, pour la production, la transmission et la livraison de l'électricité au Yukon. "*electrical grid*"

« service public d'électricité » La Société d'énergie du Yukon ou ATCO Electric Yukon. "*electrical utility*"

« source d'énergie renouvelable » S'entend des sources suivantes :

a) l'eau en mouvement;

b) le vent;

c) la chaleur de la terre;

d) la lumière du soleil;

e) la biomasse.
"*renewable energy source*"

« unité de production » Un appareil utilisé pour produire de l'électricité. "*generating unit*"

Costs recoverable by electrical utility

2(1) In setting rates that an electrical utility is permitted to charge, the board must allow the utility to recover the costs described in subsection (2) if the electricity purchase agreement in respect of which the costs are incurred provides for the matters set out in sections 3 to 6.

Coûts recouvrables par un service public d'électricité

2(1) Lorsque la régie fixe les taux qu'un service public d'électricité est autorisé à exiger, elle doit lui permettre de recouvrer les coûts visés au paragraphe (2) si le contrat d'achat d'électricité à l'égard duquel les coûts sont engagés prévoit les éléments énoncés aux articles 3 à 6.

(2) For the purposes of subsection (1), the costs are the following:

(a) the cost of purchasing electricity under an electricity purchase agreement;

(b) third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement;

(c) the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

Price for electricity under electricity purchase agreement

3(1) The price paid by an electrical utility for a kWh of electricity under an off-grid electricity purchase agreement

(a) is to be based on the weighted average cost of fuel purchased by the utility for the purpose of producing electricity by means of thermal generation for the five years immediately preceding the date on which the agreement takes effect; and

(b) is to account for any reduction in the maintenance, capital or other costs arising from the displacement of thermal generation as a result of the electricity generated by the facility.

(2) The price paid by an electrical utility for a kWh of electricity under an on-grid electricity purchase agreement is to be based on the utility's average blended fuel price per kWh for thermal generation most recently approved by the board before the date on which the agreement takes effect.

Annual CPI adjustment

4(1) The price paid by an electrical utility for a kWh of electricity under an electricity purchase agreement is to be adjusted annually in accordance with subsection (2) or (3).

(2) In the case of an off-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with the percentage increase, if any, in the CPI.

(2) Pour l'application du paragraphe (1), les coûts sont les suivants:

a) le coût d'achat de l'électricité en vertu d'un contrat d'achat d'électricité;

b) les coûts pour un consultant indépendant, y compris les frais juridiques, engagés par un service public d'électricité relativement à l'élaboration et à la mise en œuvre du contrat;

c) les coûts de l'entretien ou du remplacement de l'équipement ou de l'infrastructure nécessaires à l'achat d'électricité en vertu du contrat.

Prix de l'électricité en vertu du contrat d'achat d'électricité

3(1) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité hors-réseau :

a) repose sur le coût moyen pondéré du combustible acheté par le service public aux fins de production d'électricité par production thermique pendant les cinq années précédant immédiatement la date à laquelle le contrat entre en vigueur;

b) tient compte de toute réduction des coûts d'entretien, d'immobilisations ou autres coûts découlant du déplacement de la production thermique par suite de l'électricité produite par l'installation.

(2) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité en réseau repose sur le prix moyen du combustible mixte par kWh de la production thermique approuvée en dernier lieu par la régie avant la date à laquelle le contrat entre en vigueur.

Rajustement annuel en fonction de l'IPC

4(1) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité est rajusté annuellement conformément au paragraphe (2) ou (3).

(2) Pour un contrat d'achat d'électricité hors-réseau, le prix d'un kWh d'électricité pour une année donnée est calculé en augmentant le prix payé au cours de l'année précédant immédiatement l'année donnée par l'augmentation en pourcentage, le cas échéant, de l'IPC.

(3) In the case of an on-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with 50% of the percentage increase, if any, in the CPI.

(3) Pour un contrat d'achat d'électricité en réseau, le prix d'un kWh d'électricité pour une année donnée est calculé en augmentant le prix payé au cours de l'année précédant immédiatement l'année donnée par 50 % de l'augmentation en pourcentage, le cas échéant, de l'IPC.

Compensation

5(1) An electricity purchase agreement is to provide for reasonable compensation to be paid by the electrical utility to the owner of the independent power production facility in the event that the facility is unable to deliver electricity to the utility as a result of damage to, or a failure of, infrastructure or equipment for which the utility is responsible.

(2) An electricity purchase agreement need not provide for reasonable compensation to be paid by the utility to the owner of the facility in the event that the facility is unable to deliver electricity to the utility as a result of a planned outage.

Indemnisation

5(1) Un contrat d'achat d'électricité prévoit le versement d'une indemnité raisonnable par le service public d'électricité au propriétaire de l'installation de production indépendante d'énergie lorsque l'installation est incapable de lui fournir de l'électricité en raison de dommages ou d'une défaillance des infrastructures ou de l'équipement dont le service public est responsable.

(2) Un contrat d'achat d'électricité n'est pas tenu de prévoir une indemnisation raisonnable que le service public doit verser au propriétaire de l'installation dans l'éventualité où l'installation est incapable de lui fournir de l'électricité en raison d'un arrêt planifié.

Term of electricity purchase agreement

6 The term of an electricity purchase agreement is to be at least 20 years.

Durée du contrat d'achat d'électricité

6 La durée d'un contrat d'achat d'électricité est d'au moins 20 ans.

O.I.C. 2019/26
PUBLIC UTILITIES ACT

PUBLIC UTILITIES ACT

Pursuant to the *Public Utilities Act*, the Commissioner in Executive Council orders

1 The attached *Independent Power Production and Micro-Generation Regulation* is made.

Dated at Whitehorse, Yukon, January 25, 2019.

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Commissioner of Yukon

DÉCRET 2019/26
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est établi le R*èglement portant sur la production indépendante d'énergie et la micro-production* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 25 janvier 2019.

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Commissaire du Yukon

INDEPENDENT POWER PRODUCTION AND MICRO-GENERATION REGULATION

Interpretation

1(1) In this Regulation

"director" means the director of the Energy Branch in the Department of Energy, Mines and Resources; « *directeur* »

"electrical system", of a public utility, means equipment or facilities in Yukon

(a) owned or operated by the public utility, and

(b) used by the public utility for the production, generation, storage, transmission, distribution, sale, delivery or furnishing of electricity;
« *système électrique* »

"facility" means all of the generating units and related electrical equipment that are connected to the same meter; « *installation* »

"generating unit" means a device used to generate electricity; « *unité de production* »

"independent power production facility" means a facility in Yukon that

(a) comprises one or more generating units each of which generates electricity exclusively from a renewable energy source, and

(b) has a nameplate capacity of at least 30 kW;
« *installation indépendante de production d'énergie* »

"micro-generation facility" means a facility in Yukon

(a) that comprises one or more generating units each of which generates electricity exclusively from a renewable energy source,

(b) whose nameplate capacity does not exceed the lesser of

(i) 50 kW, and

(ii) the maximum capacity that can be accommodated by the electrical system of a

RÈGLEMENT PORTANT SUR LA PRODUCTION INDÉPENDANTE D'ÉNERGIE ET LA MICRO-PRODUCTION

Interprétation

1(1) Les définitions suivantes s'appliquent au présent règlement :

« capacité nominale » À l'égard d'une installation, la puissance maximale de sortie nominale d'électricité de l'installation. "*nameplate capacity*"

« directeur » Le directeur de la Direction générale de l'énergie, ministère de l'Énergie, des Mines et des Ressources. "*director*"

« installation » Toutes les unités de production ou de matériel électrique connexe reliés au même compteur. "*facility*"

« installation de micro-production » Une installation au Yukon :

a) qui comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

b) dont la capacité nominale ne dépasse pas la moins élevée des capacités suivantes :

(i) 50 kW,

(ii) la capacité maximale que peut atteindre le système électrique d'une entreprise de service public à laquelle l'installation est reliée;

c) qui n'est pas en mesure de produire annuellement plus de deux fois la consommation d'énergie annuelle moyenne estimée de la charge avec laquelle l'installation partage un compteur. "*micro-generation facility*"

« installation indépendante de production d'énergie » Une installation au Yukon qui :

a) comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

public utility to which the facility is connected, and

(c) that is not capable of generating annually more than two times the estimated average annual energy consumption of the load with which the facility shares a meter;
« *installation de micro-production* »

"nameplate capacity", of a facility, means the maximum rated output of electricity of the facility; « *capacité nominale* »

"renewable energy source" means

(a) moving water,

(b) wind,

(c) heat from the earth,

(d) sunlight, or

(e) biomass. « *source d'énergie renouvelable* »

(2) A person is affiliated with a public utility if the person and the public utility are "affiliated persons" or "persons affiliated with each other" within the meaning of the *Income Tax Act* (Canada).

Excluded undertaking — independent power production facility

2(1) For the purposes of the definition "excluded undertaking" in subsection 1(1) of the Act, an independent power production facility is a prescribed undertaking if

(a) the facility is not owned, in whole or in part, by a public utility or a person affiliated with a public utility; and

(b) the only electrical system, other than that of the person who owns the facility, to which the facility is connected is that of a public utility.

b) possède une puissance nominale d'au moins 30 kW. "*independent power production facility*"

« source d'énergie renouvelable » S'entend des sources suivantes :

a) l'eau en mouvement;

b) le vent;

c) la chaleur de la terre;

d) la lumière du soleil;

e) la biomasse. "*renewable energy source*"

« système électrique » À l'égard d'une entreprise de service public, les équipements ou les installations au Yukon :

a) dont elle est le propriétaire ou l'exploitant;

b) qu'elle utilise pour produire, stocker, transmettre, distribuer, vendre, livrer ou fournir de l'électricité. "*electrical system*"

« unité de production » Un appareil utilisé pour produire de l'électricité. "*generating unit*"

(2) Une personne est affiliée à une entreprise de service public si la personne et l'entreprise sont des « personnes affiliées » ou « des personnes affiliées les unes aux autres » au sens de la *Loi de l'impôt sur le revenu* (Canada).

Entreprise exclue — installation de production indépendante d'énergie

2(1) Pour l'application de la définition « entreprise exclue » au paragraphe 1(1) de la loi, une installation indépendante de production d'énergie est une entreprise visée par règlement si, à la fois :

a) l'installation n'appartient pas, en tout ou en partie, à une entreprise de service public ou à une personne affiliée à une telle entreprise;

b) le seul système électrique, autre que celui du propriétaire de l'installation, auquel l'installation est reliée, est celui d'une entreprise de service public.

(2) A public utility and the owner of an independent power production facility who intends to supply electricity generated by the facility, by means of one or more generating units, to the electrical system of the public utility may enter into an agreement for that purpose, on the terms agreed to by the parties.

Excluded undertaking — micro-generation facility

3 For the purposes of the definition "excluded undertaking" in subsection 1(1) of the Act, a micro-generation facility is a prescribed undertaking if

(a) the facility is not owned, in whole or in part, by a public utility or a person affiliated with a public utility;

(b) a portion of the electricity generated by the facility, by means of one or more generating units, is consumed by the person who owns the facility, their employees or their tenants; and

(c) the only electrical system, other than that of the person who owns the facility, to which the facility is connected is that of a public utility.

Connection of micro-generation facility to electrical system

4(1) The owner of a micro-generation facility must not supply electricity generated by the facility, by means of one or more generating units, to the electrical system of a public utility unless the owner has received approval from the director to do so, in accordance with this section.

(2) The owner of a micro-generation facility who intends to supply electricity generated by the facility, by means of one or more generating units, to the electrical system of a public utility must submit an application to the director in the form, if any, required by the director, that contains the following information:

(a) the name and contact information of the owner;

(b) the address of the facility;

(c) the nameplate capacity of the facility;

(2) Une entreprise de service public et le propriétaire d'une installation indépendante de production d'énergie qui a l'intention de fournir de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, au système électrique de l'entreprise, peuvent conclure une entente à cette fin, selon les modalités convenues par les parties.

Entreprise exclue — installation de micro-production

3 Pour l'application de la définition « entreprise exclue » au paragraphe 1(1) de la loi, une installation de micro-production est une entreprise visée par règlement si, à la fois :

a) l'installation n'appartient pas, en tout ou en partie, à une entreprise de service public ou à une personne affiliée à une telle entreprise;

b) une partie de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, est consommée par la personne qui en est propriétaire, ses employés ou ses locataires;

c) le seul système électrique, autre que celui du propriétaire de l'installation, auquel l'installation est reliée est celui d'une entreprise de service public.

Installation de micro-production reliée au système électrique

4(1) Le propriétaire d'une installation de micro-production ne doit pas fournir de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, au système électrique d'une entreprise de service public sans avoir obtenu l'autorisation du directeur à cet effet, conformément au présent article.

(2) Le propriétaire d'une installation de micro-production qui a l'intention de fournir de l'électricité produite par l'installation, au moyen d'une ou de plusieurs unités de production, au système électrique d'une entreprise de service public doit présenter au directeur une demande en la forme exigée par ce dernier, le cas échéant, et qui contient les renseignements suivants :

a) le nom et les coordonnées du propriétaire;

b) l'adresse de l'installation;

c) la capacité nominale de l'installation;

(d) the renewable energy source from which the facility generates electricity;

(e) the manufacturer of each generating unit that is a part of the facility;

(f) the information required by the director for the purposes of determining the estimated average annual energy consumption of the load with which a facility shares a meter, which may include records showing the actual energy consumption of the load;

(g) any other information required by the director.

(3) On receipt of an application under subsection (2), the director must provide written notice of the application to the public utility to whose electrical system the facility is to be connected.

(4) A public utility that receives notice under subsection (3) must, within 60 days after receiving the notice, respond to the director in writing as to whether the nameplate capacity of the facility exceeds the maximum capacity that can be accommodated by the electrical system to which the facility is to be connected.

(5) After receiving an application under subsection (2) and a response from the public utility under subsection (4) in relation to the application, the director must determine whether the facility to which the application relates qualifies as a micro-generation facility.

(6) If the director determines that a facility to which an application under subsection (2) relates does not qualify as a micro-generation facility, the director must

(a) refuse the application; and

(b) provide written notice to the owner of the facility that the application is refused, including reasons for the refusal.

(7) If the director determines that a facility to which an application under subsection (2) relates qualifies as a micro-generation facility, the director must

(a) approve the application; and

d) la source d'énergie renouvelable à partir de laquelle l'installation produit de l'électricité;

e) le fabricant de chaque unité de production faisant partie de l'installation;

f) les renseignements dont le directeur a besoin pour déterminer la consommation d'énergie annuelle moyenne estimée de la charge avec laquelle une installation partage un compteur, ce qui peut comprendre des registres indiquant la consommation d'énergie réelle de la charge;

g) toute autre information requise par le directeur.

(3) Sur réception d'une demande visée au paragraphe (2), le directeur doit en aviser par écrit l'entreprise de service public dont le système électrique sera relié à l'installation.

(4) L'entreprise de service public qui reçoit l'avis prévu au paragraphe (3) doit, dans les 60 jours suivant la réception de l'avis, indiquer par réponse écrite au directeur si la capacité nominale de l'installation dépasse la capacité maximale que peut atteindre le système électrique auquel l'installation doit être reliée.

(5) Après avoir reçu la demande visée au paragraphe (2) et la réponse de l'entreprise de service public visée au paragraphe (4), le directeur doit déterminer si l'installation visée par la demande est admissible à titre d'installation de micro-production.

(6) Si le directeur détermine qu'une installation à laquelle s'applique une demande visée au paragraphe (2) n'est pas admissible à titre d'installation de micro-production, il doit :

a) refuser la demande;

b) aviser par écrit le propriétaire de l'installation que la demande est refusée, en indiquant les motifs du refus.

(7) Si le directeur détermine qu'une installation à laquelle s'applique une demande visée au paragraphe (2) est admissible à titre d'installation de micro-production, il doit

a) approuver la demande;

(b) provide written notice to the owner of the facility that the application is approved.

Connection of micro-generation facility to electrical system

5(1) Subject to subsection (2), the owner of a micro-generation facility whose application has been approved under section 4 may connect the facility to the electrical system of a public utility but only on the terms agreed to by the public utility and the owner of the facility.

(2) The owner of a micro-generation facility is responsible for the following costs:

(a) the costs of connecting the facility to the electrical system of a public utility, including the costs of making any necessary modifications or upgrades to the electrical system for the purposes of connecting the facility to the electrical system;

(b) the costs of operating the facility.

Change to nameplate capacity of micro-generation facility

6(1) The owner of a micro-generation facility that is connected to the electrical system of a public utility must not increase the nameplate capacity of the facility unless the increase has been approved by the director in accordance with this section.

(2) The owner of a micro-generation facility that is connected to the electrical system of a public utility who intends to increase the nameplate capacity of the facility must submit an application to the director, in the form, if any, required by the director and that contains the information required by the director.

(3) On receipt of an application under subsection (2), the director must provide written notice of the application to the public utility to whose electrical system the facility is connected.

(4) A public utility that receives notice under subsection (3) must, within 60 days after receiving the notice, respond to the director in writing as to whether the proposed increase to the nameplate capacity of the facility exceeds the maximum capacity that can be accommodated by the electrical system to which the facility is connected.

b) aviser par écrit le propriétaire de l'installation que la demande est approuvée.

Installation de micro-production reliée au système électrique

5(1) Sous réserve du paragraphe (2), le propriétaire d'une installation de micro-production dont la demande a été approuvée en vertu de l'article 4 peut relier l'installation au système électrique d'une entreprise de service public, mais seulement aux conditions convenues entre l'entreprise et le propriétaire de l'installation.

(2) Le propriétaire d'une installation de micro-production est responsable des coûts suivants :

a) les coûts pour relier l'installation au système électrique d'une entreprise de service public, y compris les coûts des modifications ou des améliorations nécessaires au système électrique pour relier l'installation au système électrique;

b) les coûts d'exploitation de l'installation.

Changement de la capacité nominale de l'installation de micro-production

6(1) Le propriétaire d'une installation de micro-production reliée au système électrique d'une entreprise de service public ne peut augmenter la capacité nominale de l'installation que si le directeur a approuvé l'augmentation conformément au présent article.

(2) Le propriétaire d'une installation de micro-production reliée au système électrique d'une entreprise de service public et qui a l'intention d'augmenter la capacité nominale de l'installation doit présenter une demande au directeur, en la forme exigée par ce dernier, le cas échéant, comprenant les renseignements que le directeur exige.

(3) Sur réception de la demande visée au paragraphe (2), le directeur doit en aviser par écrit l'entreprise de service public dont le système électrique est relié à l'installation.

(4) Une entreprise de service public qui reçoit l'avis prévu au paragraphe (3) doit, dans les 60 jours suivant la réception de l'avis, indiquer par réponse écrite au directeur si l'augmentation proposée de la capacité nominale de l'installation dépasse la capacité maximale que peut atteindre le système électrique auquel l'installation est reliée.

(5) After receiving an application under subsection (2) and a response from the public utility under subsection (4) in relation to the application, the director must determine whether the facility to which the application relates qualifies as a micro-generation facility despite the increase to the nameplate capacity of the facility proposed in the application.

(6) If, as a result of an increase to the nameplate capacity of a facility proposed in an application under subsection (2), the facility would no longer qualify as a micro-generation facility, the director must

(a) refuse the application; and

(b) provide written notice to the owner of the facility that the application is refused, including reasons for the refusal.

(7) If, despite an increase to the nameplate capacity of a facility proposed in an application under subsection (2), the facility would continue to qualify as a micro-generation facility, the director must

(a) approve the application; and

(b) provide written notice to the owner of the facility that the application is approved.

(5) Après avoir reçu la demande visée au paragraphe (2) et la réponse de l’entreprise de service public en vertu du paragraphe (4), le directeur doit déterminer si l'installation visée par la demande est admissible à titre d'installation de micro-production malgré l'augmentation de la capacité nominale de l'installation proposée dans la demande.

(6) Si, par suite de l'augmentation de la capacité nominale d'une installation proposée dans une demande présentée en vertu du paragraphe (2), l'installation ne serait plus admissible à titre d'installation de micro-production, le directeur doit :

a) refuser la demande;

b) aviser par écrit le propriétaire de l'installation que la demande est refusée, en indiquant les motifs du refus.

(7) Si, malgré l'augmentation de la capacité nominale d'une installation proposée dans une demande présentée en vertu du paragraphe (2), l'installation continuerait d'être admissible à titre d'installation de micro-production, le directeur doit

a) approuver la demande;

b) aviser par écrit le propriétaire de l'installation que la demande est approuvée.