Yukon Utilities Board

Appendix A to Board Order 2022-03
Reasons for Decision
March 16, 2022

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1. Introduction

1. On November 20, 2020, Yukon Energy Corporation (YEC) filed an application with the Yukon Utilities Board (Board), pursuant to the *Public Utilities Act* and Order-in-Council (OIC) 1995/90 (referred to as "Rate Policy Directive [1995]," as amended by OIC 2018/220 and OIC 2021/16[1]), for approval of its forecast revenue requirements for the 2021 test year (Application). YEC sought approval of forecast revenue requirements of $75.135 million, representing an increase of $10.971 million for 2021 over revenues from existing rates and riders of $64.164 million (a 17.1-percent increase), with a 2021 total increase of $25.342 million over the 2018 approved revenue requirement.

2. The Board has determined that not all of the forecast revenue requirements for the 2021 test period are reasonable and has consequently adjusted or denied specific components of the revenue requirement. Because the revenue requirement is not approved in full, YEC shall submit a compliance filing with respect to its 2021 GRA within 30 days of the issuance of this Board Order.

3. The Board notes that during this proceeding it approved an interim rate rider increase for retail and industrial firm rates effective July 1, 2021 in Board Order 2021-08, interim fixed charges allocated between VGC Group and Alexco in Board Order 2021-09, and an interim rate rider increase for retail and industrial firm rates effective December 1, 2021 in Board Order 2021-14. The compliance filing to this Board Order will finalize the revenue requirement and true up interim rates.

2. Background

4. On December 14, 2020, the Board issued Board Order 2020-04 providing notice of the Application, initial process steps (including scheduling of intervener registration, a YEC workshop on the Application, and the first round of Information Requests (IRs) to YEC and YEC responses). Ministerial approval was granted for this proceeding on December 23, 2020.[2] In Board Order 2021-01, the Board granted intervener status to ATCO Electric Yukon (AEY), the City of Whitehorse (CW), the Utilities Consumers' Group (UCG) and Nathaniel Yee and invited the public who wished to make their views known without registering as an intervener to make a presentation. The Board granted John Maissan and Florian Boulais presenter status.

5. In Board Order 2021-07, issued on April 16, 2021, the Board determined that Rate Schedule 39, the Low Water Reserve Fund (LWRF) term sheets, and the annual reports for 2019 and 2020 would be considered as part of YEC's 2021 GRA. The Board also found that after the Board made its determination on YEC's Rate Schedule 39 for its interim fixed charge adjustment, YEC's 2021 GRA would be held in abeyance until the conclusion of the YEC Battery Energy Storage System (BESS) proceeding. After the BESS proceeding concluded, the Board resumed YEC's 2021 GRA proceeding and established further process steps on July 5,

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[1] OIC 2021/16, dated February 11, 2021, was issued during the course of the proceeding.

[2] Under Section 50 of the *Public Utilities Act*, the Board requires advance written approval from the Minister for the expenses of holding a public hearing under the *Act*.

2021.[3] In Board Order 2021-11 (issued August 31, 2021), the Board provided the remaining process schedule for this proceeding including intervener evidence, applicant rebuttal evidence, dates for a virtual oral hearing, and deadlines for filing written final argument and reply argument.

6. Ultimately, the Board followed a full process for this Application with two rounds of IRs to YEC, rulings on motions, a virtual oral hearing (held September 27-29, 2021), and written final and reply arguments. The Board considers the record of this proceeding closed on October 19, 2021, the date written reply argument was filed by parties.

7. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in these reasons for decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

8. In these reasons of the Board Order, the Board provides its findings. The Board approves all requests in the Application not specifically addressed in the sections that follow.

3. Business case analyses as evidence

9. In the reasons that follow, the Board makes several statements critical of YEC's consistent failure to present an adequate business case in support of the revenue requirement it is seeking in the current GRA. The Board considers that its concerns may be better understood with the help of a few preliminary remarks about its expectations concerning business case analyses as an important tool for an applicant in discharging its burden of proof. As noted below, failure to provide an adequate business case results in more information requests from the Board and from interveners, the result of which is almost invariably added expense and delay.

10. Applicants coming to the Board – whether by way of a General Rate Application, an application under Part 3 of the Act, or similar applications – are required to establish their case on the balance of probabilities, based on evidence accepted by the Board. In most cases, the Board, in deciding whether the costs of the utility can be added to its rate base or whether a proposed capital project is justified, applies the criteria of reasonableness or prudence to the subject of the Application. These criteria are relative in nature, i.e., they cannot be applied except in the context of relationships with other factors. This is a principle underlying the Board's repeatedly stated expectation that the significant projects it is called on to assess must be supported by an adequate business case.

11. In its Reasons for Decision appended to Board Order 2018-10, regarding the 2017-18 GRA, the Board stated its expectations regarding business case analyses in paragraph 470:

> … 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

3 YUB Memo re Motions re IR Responses and Further Process, Exhibit A-13.

> considers the alternatives to the project … The Board requires a detailed evaluation of alternatives to this project included in the business case.

12. In paragraph 471, the Board further stated:

> … 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.

13. Without a proper business case satisfying the criteria just mentioned, the Board is often left with an incomplete presentation that makes it difficult, if not impossible, to determine whether YEC, as the project proponent, has acted prudently or reasonably. This may result in the Board giving very little weight to the evidence presented. In such circumstances, YEC risks the Application being denied. Alternatively, the hearing process may be delayed or complicated due to the Board and interveners having to extract from YEC information that could and should have been included in business case analyses filed as part of the Application at the outset. If this practice of failing to provide adequate business case information and analyses continues, YEC may find itself at risk of the project costs being denied, as well as reduction of the costs claimed in the proceeding.

4. Comments on Process

14. The Board appreciates that parties generally participated in the proceeding process in good faith and in an efficient manner. However, the Board considers that two process steps, information request response and undertakings, should be improved.

4.1 Information Request (IR) responses

15. The Board establishes deadlines for filing IRs in Board Orders. YEC's practice in this proceeding has been to file the IR responses as separate packages, grouped on the basis of the party that made the IR, and then to file a single consolidated package of the IR responses,[4] usually a few days later.

16. The Board has concerns with this practice. For example, this approach resulted in multiple versions of IR responses (for example, exhibits B-21 to B-24 are the separate packages for IR responses, while exhibit B-27 is the consolidated package of IR information). Further, the separate packages differed at times in functionality. As explained by YEC in respect of the second round of IR responses, the separate IR packages did not include hyperlinks where IR responses reference other IR responses and did not contain Excel attachments.[5] As a result, some parties used the separate packages as a basis for questioning during the oral hearing, while others used the consolidated package. Given this, the Board considers that the current YEC practice increases the risk of confusion of the record and results in inefficiencies to YEC, interveners and the Board.

17. If the practice is based on the fact that YEC requires more time to prepare a consolidated package of the IR responses, the Board's preference is to grant YEC additional time and to have

4 YEC Letter re Round 2 IR Responses and Round 1 Revised Responses, Exhibit B-20, August 24, 2021.
5 YEC Letter re Round 2 IR Responses and Round 1 Revised Responses, Exhibit B-20, August 24, 2021.

YEC file only the consolidated IR response package. The Board will endeavour to schedule more time for filing of IRs in complex proceedings, and alternatively, YEC can request additional time for filing IRs in future proceedings if it is required.

4.2 Undertakings

18. An undertaking is a promise of an individual witness to do something. Undertakings are made during an oral hearing by a witness while they are under oath or affirmation.

19. In the Board's view, some of the undertaking responses provided by YEC contain information which exceeds what was asked in the undertaking. An individual undertaking response is to be confined to the question asked and not used to leverage or bolster the position of a party or its argument and reply argument. This is important as many of the undertakings are necessarily provided after the oral hearing has closed and may add process for written IRs due to new information being provided for the first time in the undertaking response and not necessarily contemplated given the scope of the question asked. This sometimes adds inefficiencies to the Board's process by delaying the close of proceeding.

20. The Board requires that parties limit their responses to undertakings to the information requested and will only consider information that directly responds to the undertaking.

21. Additionally, the Board's expectation is that questions asked during the oral hearing be responded to during the oral hearing when the information is within witnesses' direct knowledge. In practice, undertakings should be required sparingly, and the need for further testing of undertaking responses should be even more limited.

5. The Application

5.1. Sales and Generation

5.1.1. Total firm generation load

22. YEC is the main generator and transmitter of electricity in Yukon, providing 138-kilovolt (kV) and 69-kV transmission facilities for the Yukon Integrated System.

23. YEC directly serves about 2,300 customers at the distribution level. Most of its retail customers live in and around Dawson City, Mayo and Faro. Indirectly, YEC also provides power through the Yukon Integrated System to retail customers located in Whitehorse, Carcross, Carmacks, Haines Junction, Ross River and Teslin, Pelly Crossing, and Keno and Stewart Crossing through its wholesale sales to AEY.

24. In 2019, actual firm load supplied to non-industrial customers increased by 0.9 gigawatt hours (GWh) over 2018 actuals. Full year forecast non-industrial sales in 2020 (reflecting January-June preliminary actuals and forecasts for July-December) was an increase of 24.7 GWh over 2019 actuals. Forecast firm sales to non-industrial customers for the 2021 test year was 392.2 GWh, a decline of 8.7 GWh compared to the 2020 forecast that was due almost entirely to reduced wholesale sales.

25. For 2019 and 2020, industrial sales included sales to the Capstone Mining Corp (Minto mine) and the Victoria Gold Corporation Group's Eagle Gold project (Eagle Gold mine) located

north of Mayo and connected to the YEC grid. For 2021, industrial sales included sales to the Minto mine, Eagle Gold mine and Alexco Resources mine. Alexco Resources mine was forecast to resume industrial operations in late 2020 in the Keno region north of Mayo and east of the Eagle Gold mine with the resulting forecast of firm load for 2021.

26. Overall, total firm generation load to be supplied by YEC on the Yukon Integrated System was forecast at 420.3 GWh in 2018; actual total firm generation load was 450.1 GWh. Actual total firm generation load in 2019 was 440.7 GWh, and the full year forecast for 2020 was 508.0 GWh. Forecast total firm generation load for the 2021 test year was 538.7 GWh.[6]

27. YEC stated that non-firm secondary sales ended in September 2018 due to load growth and lack of water resources for hydro generation. The 2018 forecast for secondary sales was 2.1 GWh compared to the actual secondary sales of 0.3 GWh that year and zero in 2019, and no secondary sales were forecast for 2020 or for the 2021 test year.

28. YEC added that the higher forecast firm generation for 2020 (508.0 GWh) and for the 2021 test year (538.7 GWh) resulted in the forecast hydro generation at LTA supply accounting for 86.4 percent (2020) and 84.0 percent (2021) of grid generation. The related forecast thermal generation accounts for 13.6 percent (2020) and 16.0 percent (2021) of grid generation. Actual hydro generation in 2020 was forecast at 86.0 percent of grid generation, reflecting annual water availability at about LTA. Current forecast hydro generation for 2021 is 94.0 percent of grid generation, reflecting forecast water availability above LTA.[7]

29. In addition to increases in firm energy generation requirements, YEC submitted that winter peak generation continues to increase, with the 2018 peak reaching 93 megawatts (MW), compared to the 2019 actual peak of 90 MW. Peak generation load (including industrial load) is 103.8 MW for 2020 and is forecast at 112.7 MW for 2021. Excluding industrial load, the forecast peak for winter is 100.6 MW in 2021.[8]

5.1.2. Firm sales forecast

30. YEC submitted that total forecast sales are 495.2 GWh for the 2021 test year. Total firm forecast sales for 2021 include 343.5 GWh of firm wholesale sales, 102.9 GWh of major industrial sales, and 48.7 GWh of firm retail sales (i.e., all firm sales other than wholesale or major industrial).[9]

31. In the table below, approved, actual and forecast sales are shown for the years 2012-2021:

Table 1. Summary of energy sales (GWh) 2012-2021

Sales Group	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Industrial	44.0	40.5	36.3	37.2	41.2	43.4	32.2	36.9	27.3	64.9	102.9

6 2021 General Rate Application, pages 2-1 to 2-2, PDF pages 26-27.
7 Ibid., page 2-3, PDF page 28.
8 Ibid., page 2-4, PDF page 29.
9 2021 General Rate Application, page 2-4, PDF page 29.

Sales Group	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Residential	13.1	13.4	13.3	13.1	13.4	15.0	13.7	15.6	15.4	16.7	16.2
General Service	22.4	22.3	23.6	24.5	25.0	26.1	25.4	27.2	29.1	32.3	32.3
Street & Space Lights	0.297	0.295	0.304	0.304	0.270	0.240	0.226	0.235	0.178	0.178	0.178
Total YEC – Firm Retail & Industrial	79.9	76.5	73.6	75.2	79.8	84.8	71.6	79.9	72.0	114.0	151.6
Wholesales	310.3	307.9	295.3	298.0	301.2	328.4	314.7	332.3	331.5	351.8	343.5
Total YEC – Firm	390.1	384.4	368.8	373.1	381.0	413.2	386.3	412.2	403.5	465.8	495.2
Secondary Sales	2.0	4.0	5.4	7.0	4.8	8.4	2.1	0.3	0	0	0
Total Company	**392.1**	**388.4**	**374.2**	**380.2**	**385.9**	**421.6**	**388.3**	**412.5**	**403.5**	**465.8**	**495.2**

Source: 2021 General Rate Application, Table 2.1, page 2-16, PDF page 41; YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-22 Attachment 1, PDF page 1405.

5.1.3. Wholesale sales forecast

32. As shown in Table 1 above, YEC energy sales on the Yukon Integrated System are primarily made up of firm wholesale sales to AEY (69.0 percent in 2021).

33. YEC submitted that firm wholesales to AEY for 2018 have shown material changes since the last GRA. Firm wholesales in 2019 of 331.5 GWh decreases slightly from 2018 levels. The full year forecast wholesales in 2020, at 351.8 GWh, is higher compared to 2019 actual sales primarily due to higher actual sales in the first six months of 2020.

34. Firm wholesales forecast in 2021 at 343.5 GWh is 8.2 GWh lower than the 2020 forecast and reflects Fish Lake hydro generation at 3.6 GWh, which is the same as the 2020 forecast. Higher wholesales in 2020 were primarily due to colder than normal weather (specifically January 2020). Forecast 2021 was prepared based on multi-variate regression assessments of monthly wholesales changes at normal weather conditions. The forecast also reflects incremental forecast micro-generation impact of about 1.5 GWh for 2021 which reduces forecast wholesales.

35. YEC stated that in response to Board Order 2018-10, YEC worked closely with AEY to develop YEC's wholesale sales forecasts for the test year. AEY provided YEC with its forecast power purchase estimate at 345.9 GWh for 2021, and YEC's wholesale sales forecast for 2021 is 343.5 GWh, i.e., 2.4 GWh or 0.7 percent lower than AEY's forecast.[10] YEC explained that, given

[10] 2021 General Rate Application – YEC's Final Argument – Error Correction, letter dated October 29, 2021, page 1, PDF page 1. (YEC stated that YEC's Final Argument had an error and the underlined text should read "2.4 GW.h, or 0.7 percent lower than the AEY estimate").

that AEY's forecast is only for business planning purposes, YEC is using YEC's forecast of 343.5 GWh for the 2021 test year.[11]

Board Findings

36. The Board understands that YEC determines the wholesale sales forecast after running its own multiple regression analysis and that it reflects incremental forecast micro-generation impact.

37. In response to a Board IR, YEC confirmed that the micro-generation data in Table 2, Micro-generation data 2014-2024, below was provided by the manager of energy programs in the Energy branch at Energy, Mines and Resources (EMR) and explained that the actual 2020 program total was embedded in historical sales and was included in the regressed forecasted load. Only the 2021 incremental capacity of 1.5 GWh has been used to reduce the 2021 load. YEC provided the following table showing installed DC capacity at year end and added capacity for each year, starting in 2014:[12]

Table 2. Micro-generation data 2014-2024

	Installed DC Capacity at Year-End [kWdc]	Capacity Added This Year [kWdc]	Exported Energy [kWh]	Payout Value	Forecasted Payout Value
2014	31		2,484	$1,643	$535
2015	83	51	16,576	$4,768	$3,573
2016	424	341	66,586	$16,925	$14,352
2017	972	549	259,673	$57,028	$55,970
2018	2,135	1,163	666,333	$143,623	$143,623
2019	3,058	923	1,357,079	$285,000	$292,508
2020	4,500	1,442	1,951,685	TBD	$420,671
2021	5,918	1,418	2,826,307	TBD	$609,188
2022	6,917	999	3,660,798	TBD	$789,057
2023	7,530	613	4,242,805	TBD	$914,504
2024	7,877	346	4,597,937	TBD	$991,050

38. Based on the information provided in the Application and in response to IRs that were used to derive the wholesale sales forecasts and the resulting amounts of the wholesale sales forecasts, the Board accepts the wholesale sales forecast as reasonable. YEC's explanation for the wholesale sales forecast decrease of 8.2 GWh in 2021 from 2020 was due to colder than normal weather in 2020 and inclusion of the incremental wholesale sales forecast micro-generation impact of about 1.5 GWh for 2021 which reduced forecast wholesales. YEC

[11] 2021 General Rate Application, pages 2-4 to 2-6, PDF pages 29-31.
[12] YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-13, pages 1-2 of 2, PDF pages 1383-1384.

explained that, to develop YEC's wholesale sales forecasts, they worked closely with AEY.[13] For the purposes of this GRA, the Board approves the amount of 343.5 GWh for the 2021 wholesale sales forecast.

39. The Board directs that in future GRA submissions, YEC shall provide the Board with details on discussions with AEY to align their wholesale sales forecasts.

5.1.4. Major industrial customer loads

40. YEC stated that Minto mine continues to be forecast as a major industrial customer in 2021. Minto mine's load was forecast at 29.7 GWh for 2020 and at 35.7 GWh for 2021, reflecting the return to a partial production in late 2019, which is close to the 2018 actual level.[14] In addition, Eagle Gold mine was connected in 2019, and the Alexco Resources mine resumed operation as a major industrial customer in late 2020 with the forecast of firm load for 2021. The Eagle Gold mine has provided a load forecast at 35.1 GWh for 2020 and 43.1 GWh for 2021. Alexco Resources mine has provided a forecast 2021 firm load of 24.1 GWh.

41. Industrial sales were forecast at 64.9 GWh for 2020 and 102.9 GWh for 2021, as compared with 2018 actual sales of 36.9 GWh and 2019 actual sales of 27.3 GWh. YEC submitted that it will continue to monitor additional prospective mine loads within the next few years. YEC is not aware of any other potential near-term mine loads that could be connected to the grid.[15]

Board Findings

42. Based on the details and calculations of the major industrial customer load and the level of mining activity in 2021 as described by YEC in its Application, the Board accepts YEC's explanation for the forecast increase in 2020 and 2021 for major industrial customer loads compared to the actuals in 2018 and 2019. Accordingly, the Board finds that the forecast amount of 102.9 GWh for the industrial sales for 2021 is acceptable.

5.1.5. YEC firm retail sales

43. YEC firm retail sales are comprised of sales to residential, general service, street light and space light customer classes served directly by YEC. YEC explained that residential and general service sales forecasts are done on a community-by-community basis and are based on historical averages and input from YEC staff through their work in the communities. Retail sales are forecast at 48.7 GWh for 2021, as compared with the forecast of 49.2 GWh for 2020, and actual sales of 43.0 GWh and 44.7 GWh for 2018 and 2019, respectively.

44. Residential retail sales have slightly increased from 15.6 GWh in 2018 and 15.4 GWh in 2019 and are expected to grow to 16.7 GWh in 2020 and 16.2 GWh in 2021. This reflects colder than normal weather and ongoing modest growth in the number of customers.[16]

45. YEC stated that general service retail sales have increased from 27.2 GWh in 2018 and 29.1 GWh in 2019 and are expected to grow to 32.3 GWh in both 2020 and 2021. The growth is

13 2021 General Rate Application, page 2-5, PDF page 30.
14 2021 General Rate Application, pages 2-1, 2-2, and 2-6, PDF pages 26, 27, 31.
15 Ibid., pages 2-2, 2-6, and 2-7, PDF pages 27, 31 and 32.
16 Ibid., page 2-7, PDF page 32.

primarily due to the Faro mine remediation which is the largest general service customer. Actual sales to the Faro mine remediation were 7.8 GWh in 2018 and 9.4 GWh in 2019 and are forecast to grow to 14.4 GWh in 2020 and 2021. Alexco Resources mine was also included as a commercial customer with actual sales at 2.4 GWh in 2018 and 1.7 GWh in 2019 and forecast sales at 1.6 GWh in 2020. Street light and space light sales are expected to remain at the same level in both 2020 and 2021, primarily due to conversion to LED street lights.[17]

46. YEC submitted that it currently uses multiple regression analyses to normalize sales for its wholesales forecast, based on the size and importance of these sales within the Yukon Integrated System (approx. 70.0 percent of 2021 sales forecast). The industrial sales represented about 20.0 percent of 2021 sales forecast and the remaining non-industrial retail sales (residential, commercial and street lights) representing about seven percent of the total load forecast for 2021. Historically, non-industrial retail sales categories were fairly stable, with year-over-year variances in the area of three to five percent. Based on this relative stability and the small percentage of total sales represented, separate weather normalization analyses for each of these community's retail sales by customer class has not been considered to be a worthwhile exercise.[18]

Board Findings

47. Based on the evidence provided and given that there is only a small to moderate increase projected in firm retail sales in 2021, the Board finds that the YEC forecast for firm retail sales of 48.7 GWh for 2021 is reasonable and it is approved as filed.

48. In argument, CW recommended that for the next GRA, YEC be directed to investigate the use of a simple linear regression to normalize retail sales and use per customer and to forecast use per customer. The evidence of their expert, Mr. Bell, was that normalizing use per customer would allow YEC to "readily identify trends" and that such information would "facilitate the review of use per customer, and sales, and in fact reduce the regulatory burden of a rate application."[19]

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

50. The Board accepts YEC's submissions that a simple linear regression using weather to normalize retail sales in seven separate communities accounting for seven percent of 2021 forecast firm YEC energy sales would not be representative of other factors, such as the largest driver of forecast load, i.e., the number of accounts. Further, conceptually, a multi-variable regression would produce a more accurate load forecast rather than normalizing data for a single variable. For these reasons, and considering the relative stability of the categories in this rate class and the small percentage of total sales represented by this rate class, the Board does not

17 Ibid., page 2-8, PDF page 33.
18 YEC Final Argument, Section 1.1.3, page 10, PDF page 13.
19 Argument of the City of Whitehorse, paragraphs 35-43, PDF pages 11-14.

find it warranted at this time to direct YEC to investigate the use of a simple linear regression to normalize retail sales.

5.1.6. Secondary sales

51. YEC stated that 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 MWh in 2018 (compared with 2,059 MWh forecast in the 2018 compliance filing) and 0 MWh in 2019 and were forecast at 0 MWh sales in 2020 and 2021 when the 2021 GRA load forecast was prepared. YEC stated that it 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.[20]

52. In argument, UCG noted that other ratepayers have experienced increases in rates over the past 10 years, while secondary sales customers have not experienced the same type of increases. UCG submitted that although there will be no secondary sales going forward for this test year, it is time that the secondary sales customers "pay their fair share of the revenue requirement." Accordingly, UCG is asking the Board to set a new rate for these customers in this rate application. Also, UCG submitted that YEC will have excess energy to sell to secondary sales customers and that the Board should order that all secondary income be placed in a separate savings account for the benefit of ratepayers going forward.[21]

53. On the matter of setting a new rate for the secondary sales customers, YEC submitted that UCG ignored the established mechanism for quarterly adjustment of the secondary sales rate approved in Board Order 2005-12. In Board Order 2005-12, the Board found that:

> The Board agrees that it does have the jurisdiction to set quarterly rates in the manner proposed for the automatic adjustment mechanism at page 4-8 to 4-9 of the Application.
>
> In addition, the Board agrees that although it has reduced the amount of the requested increase approved for 2005 and 2006, it is appropriate to continue to use the quarterly rate-setting mechanism due to the price volatility of fuel oil. Setting the rate once per year may result in Secondary Energy rates that vary considerably from the approved percentage discount. Quarterly rate setting would result in Secondary Energy rates that remain much closer to the approved discounts. To manage revenue or earnings fluctuations as a result of the quarterly rate-setting process, the Board agrees that YEC may normalize Secondary Sales revenues by recording the revenue changes in Rider F as requested in the Application at page 4-9. The Board approves the quarterly rate-setting mechanism as described on pages 4-8 and 4-9 of the Application.[22]

54. On the matter of establishing a new secondary sales deferral account, YEC stated that there was no reasonable basis for segregating any such sales by YEC in this manner and that the Board should deny this recommendation.[23]

20 2021 General Rate Application, page 2-8, PDF page 33.
21 UCG Final Argument, paragraphs 139-141, PDF page 28.
22 Board Order 2005-12, Appendix A: Reasons for Decision, Section 2.1.3.3, page 19 of 48.
23 YEC Reply Argument, pages 6-7, PDF pages 8-9.

Board Findings

55. Based on the information provided in the Application, the Board accepts YEC's explanation regarding the secondary sales forecast for 2021 at 0 MWh given that secondary sales are not expected in 2021 based on hydro availability. Accordingly, the Board finds that the forecast amount of 0 MWh for the secondary sales for 2021 is acceptable and approved as filed. Accordingly, an update of the secondary sales forecast in the compliance filing is not required.

56. The Board agrees with YEC that a new rate for the secondary customers is not required and that the ongoing adjustment mechanism established in Board Order 2005-12 for automatic quarterly adjustment of the secondary sales rate (Rider F) is sufficient to address recovery of amounts related to secondary sales for those customers rather than other ratepayers.

5.1.7. Generation forecast

57. YEC forecast that hydro generation was to remain the predominant source of generation for the test period and that it was expected to be supplemented by LNG and diesel thermal generation as required. A small amount of solar generation, to be provided by independent power producers (IPP), was also expected to make up part of the system. There was no YEC wind generation in 2018 or 2019, and none is forecast for 2020 or for the 2021 test year.

58. Total generation is based on the sum of total sales plus losses, which is forecast at 9.1 percent for 2020 and at 8.8 percent for the 2021 test year. The forecast is within the range of historical losses for the last three years, from 2017 (at 8.1 percent) through 2018 and 2019 (both at 9.2 percent).[24] The following table summarizes forecast power generation for the test period:

Table 3. Summary of energy sales and losses and generation (GWh) 2018-2021

Description	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Sales and Losses					
Total Energy Sales	388,332	412,470	403,492	465,788	495,151
Losses – MWh	34,173	37,898	37,185	42,193	43,575
Losses – percent	8.8	9.2	9.2	9.1	8.8
Total Generation	422,506	450,368	440,676	507,980	538,726
Secondary Sales Related Generation	2,241	282	0	0	0
Firm Load Generation	420,265	450,086	440,676	507,980	538,726

[24] 2021 General Rate Application, page 2-8, PDF page 33.

Description	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Source – MWh					
Hydro Generation					
Whitehorse	218,266	228,695	233,673	263,231	259,116
Aishihik	116,503	126,748	97,293	118,792	176,165
Mayo	76,628	57,610	39,853	54,703	71,201
Total Hydro	411,397	413,052	370,819	436,725	506,483
Wind Turbine	0	0	0	0	0
IPPs	0	0	0	56	1,983
Diesel Generation					
Whitehorse	1,000	5,518	2,188	13,848	1,870
Faro	234	302	802	889	237
Dawson	521	1,279	720	2,936	823
Mayo	18	87	84	748	21
Total Diesel	1,772	7,186	3,793	18,422	2,951
LNG Generation*	9,337	30,130	66,065	52,778	27,309
Total Thermal*	11,109	37,316	69,858	71,199	30,260
Source – percent					
Hydro Generation	97.4	91.7	84.1	86.0	94.0
LNG Generation	2.2	6.7	15.0	10.4	5.1
Diesel Generation	0.4	1.6	0.9	3.6	0.5
IPP Generation	0.0	0.0	0.0	0.0	0.4

Source: 2021 General Rate Application, Table 2.2, page 2-17, PDF page 42.

59. YEC forecast generation for the 2021 test year, as proposed on page 8 in Table 2, Micro-generation data 2014-2024, is made up of 94.0 percent hydro, with diesel comprising 0.5 percent of total system generation throughout the test period.

60. YEC submitted that the Yukon Integrated System has 92.1 MW of installed YEC hydro generation, of which approximately 70.5 MW can be relied upon for the winter peak load. YEC also submitted that as per previous Board directives YEC's revenue requirement and annual thermal generation costs are based on LTA hydro generation (rather than actual hydro generation resulting from actual water conditions). Accordingly, for the purpose of the 2021 GRA test year, hydro and thermal generation forecasts were based on LTA water supply for hydro generation as updated with the latest information.[25]

61. YEC added that 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 Yukon Integrated System loads.

62. Actual hydro generation in 2020 was forecast at 86.0 percent of grid generation, reflecting annual water availability at about LTA. Current forecast hydro generation for 2021 is 94.0 percent of grid generation, reflecting forecast water availability above LTA.[26]

63. YEC explained that the impact of increasing relevance of LTA thermal generation on the Yukon hydro grid 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 GWh of solar generation in 2020 and 2.0 GWh of new renewable generation in 2021. YEC will update 2021 test year forecasts for any change in forecast IPP generation for the compliance filing.[27]

64. However, YEC submitted that it has considerable uncertainty as to timing for forecast IPP amounts for 2021.[28] IPP renewable generation was forecast to commence in November 2020 with less than 0.4 percent of forecast generation impact for 2021. In response to a Board IR, YEC explained that the IPP did not commence in November 2020 as scheduled and was delayed into 2021. YEC expects three projects will connect to the grid during October 2021 and the total generation provided was forecast at 0.2 GWh.[29] Further, YEC explained that on the isolated grid there is no opportunity to export surplus hydro, or other renewable generation, that 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.

65. During the hearing, YEC explained that line losses are system-wide and in addition to the infrastructure improvements YEC still has aging infrastructure and even with new modern transformers, the actual core losses within are not materially different from those experienced by aging transformers. Although certain improvements reduce line losses, the overarching

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25 2021 General Rate Application, page 2-4, PDF page 34.
26 Ibid., page 2-3, PDF page 28.
27 Ibid., pages 2-3 and 2-4, PDF pages 28-29.
28 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-10(a), page 1 of 1, PDF page 1377.
29 YEC Consolidated IR Responses, Round 2, Exhibit B-27, YUB-YEC-2-2 (a, b), pages 1-2 of 2, PDF pages 90-91.

calculation of line loss from a system perspective is not materially impacted or changed. Further, YEC explained that the 2021 forecast was based on the three-year average of 2017 to 2019, which is consistent with past practices.[30]

Board Findings

66. The Board accepts the rationale and prepared forecasts generation forecast for 2021. The Board finds the updated information on the renewable generation to be important as this generation can partially offset the impact of increasing LTA thermal generation on the Yukon hydro grid. The Board accepts YEC's explanation regarding the IPP timing uncertainty and directs YEC to update the generation forecast for 2021 in its compliance filing for any change in forecast IPP generation.

67. In reply argument, UCG submitted that the infrastructure improvements should be reflected in less line losses to the Yukon Integrated System and requested that the Board review this issue and lower the 8.8 percent system losses.[31]

68. On the matter of line losses, the Board observes that YEC's line losses percentages for the past five years have ranged from a low 8.8 percent to a high of 9.2 percent. The Board finds that YEC has demonstrated that the proposed 2021 forecast of 8.8 percent falls in the range of historical percentages based on the three-year average calculation, and is an acceptable range of line loss. The Board recognizes that due to the many factors that impact line losses, the line losses percentages will fluctuate over time. For the above reasons, the Board is satisfied with the proposed line losses of 8.8 percent for 2021. The Board understands that not all of the causes of line losses can be eliminated. For the next GRA, the Board directs YEC to provide details on how it calculates the line losses.

5.1.8. Peak demand forecast and dependable capacity

69. In response to Board IRs YEC confirmed that it uses a peak design mean temperature of -35 degree Celsius at Whitehorse Airport. On January 13, 2020, the daily average temperature at the Whitehorse Airport was -37.8 degree Celsius and this resulted in a "colder-than-normal" or colder than design event.[32]

70. YEC stated that peak demand for the Yukon Integrated System is forecast at 112.7 MW for 2021. The actual peak demand was 93 MW for 2018, 90 MW for 2019, and 103.8 MW for 2020.[33] YEC stated that at these forecast peak levels for 2021, thermal generation will be required to supply firm energy demand.

71. YEC indicated that the 2016 Resource Plan and the subsequent 2017/2018 GRA indicated that the existing hydro and diesel infrastructure did not meet the single contingency (N-1) capacity planning criterion in both 2017 and 2018 to meet those forecast grid loads. In 2021, the forecast dependable capacity based on the single contingency (N-1) criterion is forecast to be about

[30] 2021 General Rate Application Proceeding Transcript, Volume 2, September 28, 2021, pages 247-248, PDF pages 79-80.

[31] UCG Reply Argument, paragraph 10, PDF page 4.

[32] YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-19(a), page 1 of 2, PDF page 1399.

[33] 2021 General Rate Application, pages 2-4 and 2-12, PDF pages 29 and 37.

1.25 MW in excess of the forecast non-industrial winter peak. YEC explained that without rented diesel units, the N-1 capacity shortfall would be 25.75 MW in 2021.[34]

Board Findings

72. In Board Order 2018-10, the Board encouraged YEC to communicate closely with all parties (for example, AEY, customers, developers, mining operations) to ensure that it is able to forecast peak demand as accurately as possible to ensure increased peak loads may be met.[35] The Board observes that peak loads are growing and directs YEC in the next GRA to provide a detailed description of the steps it took in complying with Board Order 2018-10 including detailing the dates of meetings with other parties and summarizing the outcomes of those meetings and of the manner in which those outcomes are reflected in the forecast peak demand.

73. For 2021, the Board accepts YEC's forecast peak demand.

5.2. Revenue requirement

74. As noted in Section 3.1 of the Application, YEC forecast a 2021 revenue requirement of $75.135 million. YEC categorized its revenue requirement into four broad classifications: Fuel and Purchased Power, Non-Fuel Operating and Maintenance, Depreciation and Amortization, and Return on Rate Base. Each of these classifications are discussed in the following subsections of this Board Order.

5.2.1 Fuel and purchased power

75. YEC presented its Fuel and Purchased Power position in Section 3.2 of the Application.

Board Findings

76. Subject to the Board Findings in other parts of this Board Order regarding quantities of diesel units and related diesel fuel volumes, the Board accepts the rationale and prepared 2021 forecasts for YEC in terms of its thermal fuel mix, forecast LNG delivered price of $0.4824 per litre, the forecast average efficiency for LNG generation of 2.66 kW.h/litre and the resulting forecast LNG cost of $0.1814/kW.h.

77. The Board also accepts the forecast diesel delivered prices for 2021 of $0.7243 per litre for Whitehorse, $0.7615 per litre for Faro, $0.7898 per litre for Dawson and $0.7696 per litre for Mayo. The Board accepts the 2021 forecast diesel efficiencies for diesel fuel of 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.

78. The Board directs YEC in the compliance filing to this Board Order to reflect purchased power costs in accordance the Board's findings in Section 5.2.2 of this Board Order.

5.2.2 Non-fuel operating and maintenance expense

79. YEC requested approval to include non-fuel operating and maintenance (O&M) expenses forecast to be $29.430 million in revenue requirement for the year 2021. This represented a

[34] Ibid., pages 2-14 to 2-15, PDF pages 39-40.
[35] Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 66, page 13 of 118, PDF page 18.

$7.306 million (or 33 percent) increase in 2021 costs compared to 2018 approved O&M expenses.[36]

80. YEC's recent approved, actual, and forecast non-fuel O&M expenses are shown in the following table:

Table 4. Non-Fuel Operating and Maintenance expenses ($000)

	2018 Approved	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
Labour	11,932	12,083	11,863	12,727	13,310
Production	1,799	3,300	3,938	4,876	5.978
Transmission	1,419	1,058	1,304	1,403	1,394
Distribution	535	449	293	536	491
General O&M	1,219	1,395	1,530	1,532	1,391
Administration	3,001	3,016	3,365	3,491	3,858
Insurance and reserve for injuries/damages	1,510	1,525	1,596	1,778	2,259
Property taxes	708	671	673	739	750
Total non-fuel O&M expenses	**22,125**	**23,497**	**24,559**	**26,903**	**29,430**

Source: 2021 General Rate Application, Table 3.3, page 3-7, PDF page 53.

81. The $7.306-million increase in O&M expenses between 2018 approved and 2021 forecast comprised labour cost increases in the amount of $1.378 million and non-labour cost increases in the amount of $5.928 million. The non-labour cost increases related primarily to $3.834 million in diesel rental unit costs required to meet N-1 contingency planning.[37] The forecast non-fuel O&M increases at issue in the current Application are discussed in more detail in the sections which follow.

5.2.2.1 Labour expense

82. YEC's labour costs are made up of expenditures for its ongoing maintenance and administration activities as well as labour that is charged to capital projects that form a component of rate base upon which return and depreciation expense is calculated. In the current Application, YEC adjusted its capital versus maintenance labour allocations from the percentages approved in 2018 (a ratio of 17.1 to 82.9, capital to maintenance) to the allocation forecast for 2021, being a ratio of 17.6 to 82.4, capital to maintenance.

83. As noted above in Table 4, Non-Fuel Operating and Maintenance expenses ($000), YEC's 2021 forecast labour expense increased by $1.378 million from 2018 approved labour costs. This increase was related to a rise in YEC's forecast employee complement (as

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36 2021 General Rate Application, page 3-6, PDF page 52.
37 Ibid., page 3-7, PDF page 53.

represented by full-time equivalent [FTE] labour) at a cost of $0.882 million and a 2.0-percent escalation in labour rates at a cost of $0.740 million.

Table 5. Employee Complement History (FTEs)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast changes from 2018 Approved	2021 Forecast	Forecast FTEs not hired as of October 5, 2021
President	4.16	5.14	4.82	4.01	-	4.16	
First Nation relations	-	-	-	-	1.00	1.00	
Communications, customer billing/accounting (Note 1)	1.00	1.00	1.00	3.10	3.60	4.60	1.0 FTE Senior Communications Advisor
Human resources & information management	5.25	5.27	5.34	3.52	-	5.25	
Resource planning and environment	5.00	5.00	5.75	5.51	2.05	7.05	1.0 FTE Senior Project Manager
Finance, customer billing/accounting and purchasing (Note 1)	16.79	16.89	17.24	13.54	(2.00)	14.79	
Operations	44.50	46.58	47.12	48.75	4.75	49.25	1.0 FTE Maintenance Mechanic
Engineering services	15.00	13.03	15.16	15.63	0.50	15.50	
Health, safety & environment	2.00	2.00	2.00	2.00	-	2.00	
Total employee complement	**93.70**	**94.91**	**98.44**	**97.86**	**9.90**	**103.60**	

Note 1: Customer accounting was transferred from Finance to Communications in 2020.
Sources: 2021 General Rate Application, Table 3.4, PDF pages 54-58; 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, PDF pages 123-127; and YEC Response to Undertakings, #13 and #14, PDF pages 26-29.

84. YEC stated that its labour expense includes base pay and a number of other employee benefit costs. Other employee benefits include annual performance increments, cost of living adjustments, vacation leave, special leave, and shift premiums (collectively referred to as “other employee benefits”). YEC submitted that labour escalation rates are heavily influenced by YEC’s collective bargaining agreements, advising that the outcome of prior collective bargaining agreements have historically formed the basis for YEC’s forecast labour escalation rates and therefore labour expense costs. In 2020 and as forecast for the 2021 test period, YEC included a labour escalation rate of 2.0 percent. YEC submitted that this rate was consistent with the

previous 2017-2019 collective bargaining agreement which resulted in a negotiated labour rate increase of 2.0 percent.[38]

85. YEC stated that it had benchmarked its collective bargaining agreement increases against other local public entity increases and that this approach has been agreed to by the assigned arbitrators in each of the last three settlements.[39]

86. During the oral hearing, Board counsel questioned the outcome of YEC's arbitration hearing, which was mentioned in YEC's Application as scheduled for April 2021. YEC confirmed that the arbitration hearing concluded in April 2021 as a mediation process and resulted in an increase in base pay of 1.75 percent for 2020-21. The 1.75 percent increase applied to all YEC employees covered under the collective bargaining agreement. YEC indicated that it recommended that its board of directors approve the same increase to its employees outside the collective bargaining agreement and that its board approved this increase.[40] YEC submitted that the 1.75-percent increase was attributable to base pay only and did not include consideration of any increases related to other employee benefits, which accounted for the remaining 0.25 percent of the total 2.0-percent labour escalation rate that YEC applied for in its GRA.[41]

87. Regarding YEC's forecast increases in FTE complement identified in its Application and whether the intended hiring had occurred on an actual basis, as shown on the preceding page in Table 5, Employee Complement History (FTEs), at the oral hearing, YEC confirmed that there were three FTEs intended to be hired between 2018 and 2021 but whose positions had not been filled as of October 5, 2021.[42] YEC did not provide an update to the status of these three FTEs in either argument (October 12, 2021) or reply argument (October 19, 2021).

Board Findings

88. Based on its examination of the evidence and the extended discussion during the oral hearing that established the current state of YEC's labour force, the Board does not consider it reasonable for YEC to collect the labour costs for three FTEs that it has not hired at a point in time that is approximately 10 months into the test year in its 2021 revenue requirement.

89. This finding is irrespective of the information provided by YEC during redirect examination at the oral hearing. Specifically, YEC indicated during redirect that its total applied-for FTE forecast should be approved because it incorporated a vacancy factor of five employees.[43] This rationale is not persuasive because a vacancy rate is applicable for employees YEC has hired and should not be applicable to employees YEC has forecast to hire but subsequently did not hire.

38 2021 General Rate Application, page 3-8, PDF page 54.
39 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-37(f), page 3 of 3, PDF page 1449.
40 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 290, line 7, to page 291, line 16, PDF pages 122-123.
41 YEC Final Argument, page 15, PDF page 18.
42 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 291, line 17, to page 295, line 16, PDF pages 123-127.
43 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 465, line 6, to page 466, line 9, PDF pages 129-130.

90. For these reasons, YEC is directed to remove all capital labour and O&M labour costs associated with the three forecast FTEs that remain vacant positions.

91. The Board finds YEC's request for a labour escalation of two percent (comprising 1.75 percent specific to base pay and 0.25 percent related to other employee benefits) to be reasonable.

5.2.2.2 Production expense – diesel rental units

92. In this Board Order, the Board addresses three issues related to YEC's diesel rental units:

- Diesel rental unit costs as a component of its production expenses;
- Board consideration of whether YEC has exceeded its permitted licensed capacity through its arrangement for seven diesel rental units located at Faro; and
- The evaluation of certain business cases and the costs associated with infrastructure required for the diesel rental units, which is discussed in Capital Section 5.3.2.2.

93. YEC forecast its total labour and non-labour production costs for 2021 in the amount of $10.909 million. This was an increase of $4.979 million over 2018 approved costs of $5.930 million.

94. Higher labour costs accounted for approximately 16 percent (or $0.800 million) of the increase in the 2021 forecast ($4.931 million) compared to 2018 approved ($4.131 million) labour production costs. Non-labour production costs were forecast to increase by 232 percent (or $4.179 million) between 2021 forecast and 2018 approved, the vast majority of this increase being related to thermal generation expenses.

Table 6. Production Costs ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Labour	4,131	4,455	4,467	4,995	4,931
Diesel	425	1,617	1,723	4,370	4,370
LNG	196	357	550	410	410
Hydro	1,093	1,229	1,435	1,082	1,082
Wind	6	(35)	-	-	-
Operation supervision	79	132	226	112	116
Total production costs	**5,930**	**7,755**	**8,402**	**9,871**	**10,909**

Source: 2021 General Rate Application, Table 3.5, page 3-13, PDF page 59.

95. Specifically, as shown above in Table 6, Production Costs ($000), YEC's diesel unit rental costs have increased by $3.945 million between 2021 forecast ($4.370 million) and 2018 approved ($0.425 million). YEC stated that the costs of renting 17 mobile diesel units was required in order to satisfy dependable capacity shortfalls under N-1 conditions.

96. In its Application, YEC stated that its diesel rental unit costs of $3.834 million consisted of 15 units at 1.8 MW for each unit, totaling 27 MW for 2021, plus two spare units for a total of 17 units.[44] To ensure that it had sufficient capacity to meet the N-1 capacity requirement, YEC stated that it rented the two additional units as spares maintained solely for backup purposes.[45]

97. In response to a Board IR, YEC stated that, based on its forecast model, 17 two-MW diesel rental units would be required for the 2020-2021 heating season:[46]

- Ten 1.8 MW units were placed at the Whitehorse Rapids Generation Station (WRGS) under the unit rate costs per the 2019-20 request for proposal (RFP) process.

  The diesel rental units required additional capital costs to accommodate and connect the diesel rental units to the Yukon Integrated System. The capital costs were identified in the N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure project and were forecast to be placed into service in 2021; and

- Seven units were placed at the Faro Generation Station (FGS) through an extension of its 2019-20 contract with Finning Canada. The unit cost rates for the Faro units were based on market conditions at that time.

  The diesel rental units required additional capital costs to accommodate and connect the diesel rental units to the Yukon Integrated System. The capital costs were identified in the N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure project and were placed into service in 2020.

98. In addition to the $3.834-million diesel rental costs, the two infrastructure projects would add an additional $0.243 million of capital costs (consisting of annual depreciation and return on rate base), resulting in a total annual cost for the 17 diesel rental units of approximately $4.1 million for the year 2021.[47]

99. YEC indicated that in addition to the Whitehorse and Faro diesel infrastructure projects, its LNG Third Engine/Critical Spares project provided a third natural gas-fired generation unit of approximately 4.4 MW at the Whitehorse thermal plant to help address, as a permanent solution, the existing dependable capacity shortfall in a cost-effective manner. YEC placed this project into service in November 2018.[48]

100. YEC stated that these three projects were required to meet the N-1 capacity criterion in 2021 and further on a combined basis provided a surplus of 1.25 MW for 2021.[49]

101. YEC clarified that the usage of the Whitehorse and Faro diesel rental units will depend on the peak in the system and the condition of the existing generation capacities. The diesel rental units are primarily in place to provide for the N-1 contingency event.[50] YEC also clarified

[44] 2021 General Rate Application, page 1-8 and footnote 5, PDF page 22.
[45] YEC Consolidated IR Responses, Exhibit B-9, NY-YEC-1-1, pages 1-3 of 3, PDF pages 433-435.
[46] Ibid., YUB-YEC-1-40, pages 1-2 of 2, PDF pages 1467-1468.
[47] Ibid., NY-YEC-1-3, page 1 of 1, PDF page 439.
[48] 2021 General Rate Application, pages 5-5 and 5-6, PDF pages 118-119.
[49] YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-50, pages 1-4 of 4, PDF pages 1505-1508.
[50] Ibid., CW-YEC-1-17(b), page 2 of 3, PDF page 124.

that it was not planning to purchase any of the rented diesel units, nor that it was aware of any vendor offering such units for sale.[51]

102. YEC was asked to provide copies of all analyses or business cases prepared by YEC to evaluate the cost of owning diesel generation compared to renting diesel units. YEC explained that, in response to its 2016 Resource Plan, it had concluded that, rather than building a new 20-MW diesel plant as it had first considered, YEC had instead decided at that time to look at options to replace capacity at its existing generation facilities as diesel engines reached end of life.[52]

103. The Board asked YEC whether it had made plans to implement any other permanent solution in the future to meet the N-1 capacity criterion, including consideration of whether the Battery Energy Storage System (BESS) project would replace the need for diesel rental units. YEC responded that, according to its recent 10-year renewable electricity plan, it still forecast a "substantial annual N-1 capacity shortfall absent diesel rental units that grows to 50 MW by 2035/36 with existing, committed and planned resources that include the Battery Energy Storage System, Diesel Replacement and demand-side management (DSM) program projects."[53]

104. Nathaniel Yee argued that not all of the diesel rental units at the Faro and Whitehorse facilities were permitted to operate. For the Faro facility, Mr. Yee stated that YEC was not given authority by the Yukon Environmental and Socio-Economic Assessment Board (YESAB) to connect more than three of the diesel rental units, even for emergency backup purposes, and that other remaining units could only be connected once approved by YESAB.[54] For the Whitehorse facility, Mr. Yee stated that YEC only received temporary-use authorization for six of the 10 rental units.[55] While YEC indicated that the air emissions permit allowed for 14 MW of diesel generation in Whitehorse, or using up to eight rental units, Mr. Yee submitted that YEC did not provide any documentation supporting this claim. Mr. Yee argued that YEC was in violation of the air emissions permit for the Whitehorse facility,[56] and submitted that costs for rental units that did not go through the required permitting and YESAB processes should not be included in rate base and should not be a part of meeting the N-1 criterion.[57]

105. In response to Mr. Yee's argument, YEC stated it did not need a permit to install capacity and that the actual amount of capacity permitted for normal operation was not tied to specific installed units.[58] While YEC's permits limit normal operations to a certain capacity, under Section 49 of the *Yukon Environmental and Socio-economic Assessment Act,* YEC has the ability to operate any available diesel generating capacity in an N-1 event to protect public health and safety. YEC connected 17 diesel rental units at the Whitehorse and Faro facilities to protect ratepayers in the event of an N-1 event.[59] Additionally, YEC is required to report the total annual operating hours for all sources at all sites, including all of its diesel rental units, to Environment Yukon, and YEC indicated that Environment Yukon has never raised a concern around the

51 Ibid., CW-YEC-1-17(g), page 3 of 3, PDF page 125.
52 Ibid., CW-YEC-1-17(a), page 2 of 3, PDF page 124.
53 Ibid., YUB-YEC-1-50, pages 1-4 of 4, PDF pages 1505-1508.
54 Nathaniel Yee Final Argument, PDF page 3.
55 Ibid., PDF page 3.
56 Ibid., PDF page 4.
57 Ibid., PDF pages 5-6.
58 Yukon Energy Corporation Reply Argument, page 14, PDF page 16.
59 Ibid., pages 14-15, PDF pages 16-17.

rented diesel unit operation at both the Faro and Whitehorse facilities.[60] Given all of this, YEC submitted that there was no basis to disallow any of the diesel rental costs as recommended by Mr. Yee.

Board Findings

106. YEC noted that once the BESS project comes into service in the latter part of 2022, it is expected to provide 7.2 MW dependable capacity (the equivalent of a reduction of four diesel rental units).[61] This project, along with any other permanent solutions proposed by YEC in the future, will assist YEC in the future as meeting the N-1 capacity criterion.

107. Mr. Yee alleged that YEC is in violation of the Yukon Environmental and Socio-economic Assessment Act and the YESAB permit granted to YEC. The Board does not have jurisdiction over YEC's licences approved by YESAB. For clarity, the Board's statutory mandate is to set YEC's just and reasonable rates, and the Board's analysis and findings are necessarily limited to its mandate.

108. The Board does not agree with Mr. Yee's recommendation of excluding the diesel rental unit costs from rate base and excluding the diesel rental units from N-1 events, even if the rentals at issue did not have authorization from YESAB. The Board finds YEC's explanation that it connected the additional rental units to resolve an N-1 dependable capacity shortfall event, not to increase its normal operation capacity, to be credible.[62] The Board accepts YEC's statement that rental of these diesel units was necessary to connect sufficient dependable capacity in the winter to keep customers connected to electricity during an extended cold weather event under N-1 emergency conditions.[63] In the Board's view, this action by YEC is consistent with its statutory obligations to provide service to customers. The Board finds that excluding additional diesel units, other than the two spare backup units, from N-1 events would hinder YEC's provision of reliable service.

109. Even if some of the generation at issue did not receive a YESAB assessment, as pointed out by YEC, Section 49 of the *Yukon Environmental and Socio-economic Assessment Act* provides that no assessment of an activity is required in certain emergency conditions. Subsection 49(1) states:

> Notwithstanding sections 47 [regulations identifying activities] and 48 [declarations], no assessment is required of an activity that is undertaken in response to a national emergency for which special temporary measures are being taken under the *Emergencies Act*, or in response to an emergency when it is in the interest of public welfare, health or safety or of protecting property or the environment that the activity be undertaken immediately.

110. The Board finds that N-1 emergency conditions described by YEC appear on their face to be consistent with Subsection 49(1) of the Yukon Environmental and Socio-economic Assessment Act and with responding to an emergency that is in the interest of public welfare,

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60 Ibid., page 14, PDF page 16.
61 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-71, pages 1-2 of 3, PDF pages 2401-2402.
62 Yukon Energy Corporation Reply Argument, page 12, PDF page 14.
63 Ibid., page 12, PDF page 14.

health, or safety. The Board considers that its own mandate is to ensure just and reasonable rates, as well as ensuring safe and reliable electricity service in Yukon.

111. While the Board finds the inclusion of some of the diesel units necessary, that does not mean the Board finds YEC's decision to use diesel rental units will be prudent in the future. The Board noted concerns with the use of diesel units in the past in Board Order 2018-10, stating:

> 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.[64]

112. Regarding the diesel rental units, YEC provided testimony regarding the hard life and reliability issues of such units.[65] Further, YEC did not pursue the purchase of diesel units, leasing of diesel units, or the purchase and resale of diesel units as an alternative to the diesel rental choice. In this proceeding, YEC discussed purchase of diesel units in a cursory manner, focusing only on the terms of the purchase applying to the rental units.[66]

113. The forecast capacity shortfall has been identified since Board Order 2009-08 and the Board considers that other planning options should be explored to mitigate the use of diesel rental units. A lack of identified alternatives, planning detail, and a business case have limited the exploration of options other than diesel units to meet capacity shortfalls. Lack of transparency into the options has, in the Board's view, exacerbated the issue and has fettered the options to address the capacity shortfall to the point that, in order to meet N-1 capacity shortfalls, YEC has had no choice but to enter rental agreements for arguably less efficient diesel units. In this proceeding, YEC did not provide any evidence of their pursuit of a least-cost solution to the forecast N-1 capacity shortfall.

114. While the Board makes a general finding that YEC has provided reliable electricity service, the Board notes that YEC included a spare unit at both Faro and Whitehorse and that YEC's total capacity for emergency use was only up to 15 rental units.[67] The Board interprets this to mean that YEC will only use up to 15 diesel rental units for N-1 events. The Board finds that the two spare units are therefore redundant, given that they essentially provide backup to the 15 diesel rental units which themselves are backup to YEC's system. The Board is not persuaded that the costs associated with the two spare units of the 17 diesel rental units (identified by YEC

[64] Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 470, page 89 of 118, PDF page 94.
[65] YEC Battery Energy Storage System Project Transcript, Volume 1, May 4, 2021, page 123, lines 18-23, PDF page 123.
YEC Battery Energy Storage System Project Transcript, Volume 2, May 5, 2021, page 232, line 13, to page 233, line 10, PDF pages 43-44.
2021 General Rate Application Proceedings Transcript, Volume 1, September 27, 2021, page 46 line 14 to page 48 line 5.
[66] 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 304 line 12 to page 307 line 1, PDF pages 136-139.
[67] Yukon Energy Corporation Reply Argument, page 12, PDF page 14.

as spare units at both Whitehorse and Faro) are just and reasonable. Accordingly, the Board directs YEC to remove the costs for two of the rented diesel units from its production expense in its compliance filing to this Board Order.

115. Although the Board will accept the remaining diesel rental costs, subject to the preceding paragraphs and for purposes of this GRA, the Board directs YEC to provide a specific business case going forward for the diesel units (rental, lease and own/resale), other alternatives to rentals and stronger emphasis to least-cost options, the rationale for the options and the timing to implement such options. Of particular interest to assist in evaluating comparisons of Levelized Costs of Capacity would be a sensitivity analysis that includes delays in planned permanent renewable capacity projects and higher-than-forecast peak demand growth over the next 10 years. The Board directs YEC to provide a business case that conforms with these business case criteria in its next GRA.

5.2.2.3 Transmission and distribution brushing costs and Deferred Vegetation Management account

116. Referring to Table 4, Non-Fuel Operating and Maintenance expenses ($000), on pages 16-17 of this Board Order, YEC's forecast 2021 transmission costs of $1.394 million and distribution costs of $0.535 million reflect decreases of $0.025 million and $0.044 million respectively when compared to 2018 approved costs. The decrease in costs were largely attributable to changes in the annual brushing (also referred to as "vegetation management") requirements for each of the two functions as well as changes in the allocation of brushing budgets between transmission and distribution lines.[68]

5.2.2.3.1 Transmission and distribution brushing costs

117. YEC's actual, approved and forecast transmission and distribution brushing costs are shown in Table 7, below:

Table 7. Total Transmission and Distribution Brushing Costs ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Transmission brushing costs	1,161	922	1,149	1,179	1,175
Distribution brushing costs	331	212	28	249	212
Total brushing costs	**1,492**	**1,134**	**1,176**	**1,429**	**1,388**

Source: 2021 General Rate Application, Table 3.6.1, PDF page 61.

118. In comparing 2018 and 2019 actual brushing costs, YEC stated that the 2019 increase in transmission costs of $0.227 million[69] were offset by decreases in distribution costs of $0.184 million.[70] YEC explained that work occurring on the transmission line refurbishment (TLR) program required the reallocation of brushing work from the distribution function to the

68 2021 General Rate Application, Table 3.10, PDF pages 60-61.
69 Calculated as $1.149 million less $0.922 million = $0.227 million increase.
70 Calculated as $0.028 million less $0.212 million = $0.184 million decrease.

transmission function. This is notwithstanding that typically the brushing budget is allocated on an 80/20 transmission/distribution split of costs.[71]

Board Findings

119. The Board accepts YEC's explanation for the variances noted between the 2018 and 2019 actual brushing costs. Further, the Board finds YEC's forecast 2021 brushing costs in the amount of $1.175 million (transmission) and $0.212 million (distribution) to be reasonable and they are approved.

5.2.2.3.2 Deferred Vegetation Management account

120. In Board Order 2013-01, respecting YEC's 2012-13 GRA, the Board directed YEC to hold distribution and transmission vegetation management costs greater than 2011 actual brushing costs of $0.502 million in a newly created Vegetation Management Deferral account. In Board Order 2018-10, respecting YEC's 2017-18 GRA, the Board approved the amortization of the 2016 balance of $2.215 million for this account over a period of 10 years (or $0.222 million per year from 2017 to 2026) and directed that the deferral of these costs is no longer required.

121. Accordingly, YEC did not propose any changes to the amount being recorded in its deferral account and continued to amortize the balance of the costs in the amount of $0.222 million per year as reflected in the following table:

Table 8. Deferred Vegetation Management Account Continuity Schedule ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Opening balance	1,994	1,994	1,772	1,551	1,329
Annual deferred costs	-	-	-	-	-
Annual amortization of costs	(222)	(222)	(222)	(222)	(222)
Closing balance	**1,772**	**1,772**	**1,551**	**1,329**	**1,108**

Source: 2021 General Rate Application, Table 3.14.2, page 3-24, PDF page 70.

Board Findings

122. The Board approves YEC's continued amortization of the balance in its Deferred Vegetation Management account in the amount of $0.222 million for the year 2021.

[71] YEC Consolidated IR Responses, Exhibit B-9, CW-YEC-1-18, page 2 of 2 and page 1 of 2, PDF pages 128-129.

5.2.2.4 **Insurance costs and Reserve for Injuries and Damages (RFID) account**

5.2.2.4.1 Insurance costs

123. As illustrated in Table 9 below, YEC forecast its 2021 insurance expense of $1.423 million to increase substantially from its 2018 approved and 2019 actual costs, which were in the amounts of $1.031 million and $1.117 million, respectively:

Table 9. Insurance costs and Reserve for Injuries and Damages ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Insurance costs	1.031	1,046	1,117	1,423	1,423
Reserve appropriation for RFID	479	479	479	479	835
Total insurance and RFID	**1,519**	**1,525**	**1,596**	**1,902**	**2,259**

Source: 2021 General Rate Application, Table 3.10, page 3-18, PDF page 64.

124. YEC explained that its 2020 insurance costs increased due to overall rate increases to its commercial insurance package of 25 percent and growth in its insured asset values. The market rate increases experienced by YEC as part of its 2020 renewals are consistent with peer utilities in Canada.[72]

125. In response to Board IRs, YEC confirmed that, during its 2020 insurance renewal process, it directed its insurance broker to conduct a full market evaluation for its property insurance policy. The insurers were selected in order to obtain the lowest rates while still providing adequate coverages.[73] YEC expected its 2020 insurance costs to continue to be in the same amount of $1.423 million into the year 2021.

Board Findings

126. The Board approves YEC's forecast 2021 insurance expense in the amount of $1.423 million as reasonable. The Board directs YEC to provide evidence of its continued efforts to achieve the appropriate amount of insurance at the most reasonable cost available at the time of its next GRA.

5.2.2.4.2 Reserve for Injuries and Damages (RFID) account

127. In its Application, YEC stated that its Board-approved RFID account is maintained to address uninsured and uninsurable losses as well as the deductible portion of insured losses. This allows for a balance between purchasing additional insurance as opposed to using a self-insurance mechanism such as the RFID. The RFID account also allows for the costs of unforeseen events to be smoothed out over a number of years in order to provide rate stability for YEC's ratepayers.

72 2021 General Rate Application, page 3-19, PDF page 65.
73 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-44(d), page 3 of 4, PDF page 1447.

128. In Board Order 2018-10, respecting YEC's 2017-18 GRA, the Board approved an annual appropriation of $0.435 million for YEC's RFID account. The amount was comprised of an annual appropriation of $0.267 million and the amortization of a 2016 negative balance (of $1.059 million over a period of five years) in an annual amount of $0.212 million.

129. In the current Application, YEC requested that the annual appropriation be revised to $0.411 million (based on the average of the last 10 years' annual RFID charges).[74] YEC also requested that the 2020 negative balance of $2.121 million be amortized over a period of five years and be revised to an annual amount of $0.424 million. When added, these two amounts[75] would result in an annual appropriation of $0.835 million commencing in the year 2021.

Table 10. Reserve for Injuries and Damages (RFID) Continuity Schedule ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Opening balance	(906)	(1,247)	(1,419)	(1,002)	(2,121)
Annual appropriation	479	479	479	479	835
Annual costs	(267)	(651)	(62)	(1,598)	(411)
Closing balance	**(694)**	**(1,419)**	**(1,002)**	**(2,121)**	**(1,697)**

Source: 2021 General Rate Application, Table 3.11.1, PDF page 66.

130. In its Application, YEC identified that the large annual cost of $1.598 million recorded to its RFID account in 2020 was related to work required at its Whitehorse hydro generation facility ($0.730 million), the Whitehorse LNG Unit #2 ($0.4 million) and an LNG vapourizer ($0.300 million).[76] [77]

131. YEC also confirmed that it had included in its 2020 annual costs approximately $0.073 million in costs related to COVID-19 for items such as "laptop costs to work from home, health and safety supplies and communications costs/signage."[78]

132. Further, when asked why YEC chose to amortize the 2020 negative balance of $2.121 million over a period of five years as opposed to any other period of time, YEC responded that it chose five years because it was consistent with the period of time approved in Board Order 2018-10.[79]

Board Findings

133. As a first matter, the Board does not accept YEC's inclusion of $0.073 million in COVID-19 related costs as recoverable under its RFID account. This is because COVID-19 has caused both increases and decreases in O&M-type costs (e.g., a reduction in travel related costs

74 2021 General Rate Application, Table 3.11, page 3-19, PDF page 65.
75 $0.411 million and $0.424 million.
76 YEC 2021 GRA Application, Table 3.11.1 and page 3-20, PDF page 66.
77 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-44(e), page 3 of 4, PDF page 1447.
78 YEC Consolidated IR Responses, Round 2, Exhibit B-27, YUB-YEC-2-9(a), page 2 of 3, PDF page 110.
79 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-44(g), page 3 of 4, PDF page 1477.

for YEC employees)[80] that could generally be expected to offset each other. The Board is not persuaded that it is reasonable for YEC to collect additional costs related to COVID-19 from ratepayers when those ratepayers will not similarly benefit from any YEC cost reductions related to COVID-19.

134. Accordingly, YEC is directed to remove from its opening 2021 RFID balance of $2.121 million an amount of $0.073 million for those costs identified above in paragraph 128 (Section 5.2.2.4.2) in its compliance filing to this Board Order. To the extent that YEC has included similar COVID-19 costs in its 2021 forecast RFID transactions, the Board directs YEC to similarly remove those costs from its RFID annual costs amount in its compliance filing to this Board Order.

135. As a second matter, having revised YEC's opening 2021 RFID balance by the denied COVID-19 costs in the amount of $0.073 million, YEC is further directed to amortize the resultant balance over a period of 10 years in its compliance filing to this Board Order. This period of time is consistent with the period of amortization the Board has afforded to YEC's Deferred Vegetation Management account.

136. As a final matter, YEC is directed in its compliance filing to this Board Order to revise and re-submit Tables 9 and 10 (Sections 5.2.2.4.1 and 5.2.2.4.2, respectively) as documented support for the dollar impact of the board directions found in this section.

5.2.3 Rate base and depreciation and amortization expense

137. YEC stated in its Application that rate base amounts include all "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, [and] reserves set aside for various regulatory purposes…"[81]

138. Mid-year net plant in service was forecast to reach $498.223 million in 2021 which is an increase of $52.850 million over 2018 approved mid-year plant in service of $445.367 million. The increase in rate base over the 2018 approved forecast reflects sustaining capital investment projects such as the Mayo to McQuesten Transmission Line Upgrade, Transmission Line Refurbishment, WH2 headgate replacement, EAM purchase and implementation and other projects.

139. Increases in net plant in service since 2018 were offset in part by contributions for extensions which totalled $185.2 million in 2021 compared to $167.1 million approved for 2018. New contributions since 2018 include $11.5 million from the VGC Group to fund McQuesten Substation and system improvement capital costs.

140. The balance of the change in YEC's net mid-year rate base reflects increased working capital requirements of $7.141 million. This amount is an increase of $1.797 million over 2018 approved working capital of $5.344 million.

80 Ibid., YUB-YEC-1-37(g), page 3 of 3, PDF page 1449.
81 2021 General Rate Application, page 3-20, PDF page 66.

141. Specific capital additions, including stabilization mechanisms such as deferred charges and reserve accounts, are discussed in subsequent sections of this Board Order.

142. YEC's actual, approved and forecast mid-year rate base is shown in the following table (Table 11):

Table 11. Mid-year rate base ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Previous closing net plant in service	279,708	287,713	193,199	303,158	322,649
Mid-year:					
Current year plant in service	445,367	449,441	458,678	475,781	498,223
Contributions	(167,112)	(166,677)	(168,222)	(177,603)	(185,319)
Net plant in service	**278,255**	**282,764**	**290,456**	**298,178**	**312,904**
Mid-year regulatory deferral excluding DSM and hearing reserve	3,879	3,805	3,009	2,484	2,732
Working capital	5,344	5,617	5,935	6,592	7,141
Net mid-year rate base	**287,478**	**292,186**	**299,399**	**307,255**	**322,777**

Source: 2021 General Rate Application, Table 3.13, PDF page 67.

5.2.3.1 Depreciation expense

143. YEC submitted a full depreciation study dated December 31, 2018, that was prepared by Mr. Dane Watson of Alliance Consulting Group. Mr. Watson proposed changes to the service life and/or Iowa curve (life-curve) depreciation parameters for certain YEC plant asset accounts. The recommended changes were determined based on the analysis of actuarial information as available, comments provided by YEC's management and other internal operational personnel, Mr. Watson's professional judgement and experience and, in some instances, a review of peer electric utilities' life-curve parameters.

144. YEC did not propose to make any changes to the depreciation methodologies approved previously by the Board. Accordingly, YEC continued to rely on a straight-line depreciation method, combined with an average life group (ALG) procedure and a remaining-life technique. These methodologies collectively incorporate the use of an amortization of accumulated reserve differences true-up mechanism. This mechanism allows YEC to refund to, or collect from ratepayers, any differences between what should have been collected in depreciation expense on a theoretical basis and what has been collected on an actual basis. The accumulated reserve difference is determined for each YEC asset account and amortized (as a refund or a collection) over the average remaining life as an annual true-up amount. At December 31, 2018, YEC's

depreciation study determined that, for all depreciation study accounts, the total required annual reserve difference true-up provision was a refund to ratepayers in the amount of $0.366 million.[82]

145. Applying YEC's recommended life-curve parameters to YEC's December 31, 2018, asset account balances resulted in an increase of $0.201 million in depreciation expense when compared to the depreciation expense that would be calculated using YEC's currently approved life-curve parameters.[83]

146. Accordingly, as applicable to YEC's December 31, 2018 asset balances, offsetting the anticipated reduction in depreciation expense ($0.366 million) related to a revised annual true-up provision ($0.366 million) by the anticipated increase related to the proposed changes to life-curve parameters ($0.201 million) resulted in a net decrease in YEC's depreciation expense of $0.165 million.[84]

147. YEC's actual, approved and forecast depreciation expense is shown in the following table:

Table 12. Depreciation and amortization ($000)

	2018 Approved	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Forecast**
Fixed asset depreciation	8,989	8,894	8,906	9,828	10,615
Customer contributions	(3,569)	(3,677)	(3,691)	(3,624)	(4,102)
Amortization of fire insurance recoveries	(262)	(262)	(262)	(262)	(262)
Disallowed depreciation	(16)	(16)	(16)	(16)	(16)
Amortization of deferred charges	3,462	4,561	2,846	2,764	1,581
Total depreciation and amortization	**8,604**	**9,500**	**7,783**	**8,690**	**7,816**

Source: 2021 General Rate Application, Table 3.14, page 3-22, PDF page 68.

Board Findings

148. Of YEC's 77 depreciation study accounts (which the Board notes excludes all land and the critical spares accounts), Mr. Watson recommended life-curve changes to 36 accounts. The Board has examined the evidence submitted by YEC in its depreciation study, responses to IRs and undertakings. The Board is generally satisfied with the analysis conducted and the recommendations contained therein and accepts YEC's recommendations for 30 accounts, which includes the establishment of Account 1615-201 – Hydro Building and Improvement. However,

82 2021 General Rate Application, Tab 9, Depreciation Study, page 9-99, PDF page 334: Total Yukon – the total reserve difference for all accounts is an over collection of $24.047 million and when amortized over each account's applicable remaining life is a total annual amount of $0.366 million to be refunded to ratepayers.

83 Ibid., Tab 9, Depreciation Study, page 9-102, PDF page 337: Total Yukon - calculated as $12.678 million less $12.477 million and does not include the annual true-up provision credit amount of $0.366 million.

84 Ibid., Tab 9, Depreciation Study, page 9-2 PDF page 237.

the Board denies the recommendations for six accounts. Where the Board has determined that a further explanation for its acceptance or denial of a recommended change is required, those reasons are provided in the sections which follow. The Board directs YEC to update its forecast 2021 depreciation expense calculations, including its amortization of reserve differences true-up calculation, to reflect these findings in its compliance filing to this Board Order.

149. The Board has prepared a table of YEC's currently approved, proposed and final Board-approved depreciation parameters. This table can be found as Appendix 1 to this Board Order.

5.2.3.1.1 Account 1615-506 – Hydro Plant - Water Wheels, Turbines, and Generators

150. The balance in Account 1615-506 totalled approximately $26 million at December 31, 2018, with assets in service dating from 1952 to 2017. Over half of the asset costs were added in the years 2011-2012.[85]

151. Mr. Watson proposed to decrease the life-curve for Account 1615-506 from an 85-R3 to a 60-R3 on the basis that YEC operational personnel indicated that the approved 85-year life is too long. YEC stated that they have already replaced some assets prior to reaching 60 years. Given that there was insufficient actuarial data to conduct an actuarially based life analysis, Mr. Watson relied on the information provided by YEC personnel to inform his recommendation of a reduction in service life of 25 years.[86]

Board Findings

152. The Board agrees that there have been too few asset retirements from which to conduct a retirement rate life analysis. This is evident in the observed life table for Account 1615-506, where the Board observes there have been only five age intervals of asset retirements totaling less than $0.200 million.[87] In this context, the Board finds that neither the retirement data, which is limited, nor the comments of YEC personnel that they have replaced some assets prior to reaching 60 years reasonably support the significant 25-year reduction to service life. YEC's proposed reduction to service life for Account 1615-506 is denied. The Board directs YEC to maintain an 85-R3 life-curve for this account in its compliance filing to this Board Order.

5.2.3.1.2 Account 1625-610 – Distribution System – Meters and Account 1625-620 – Distribution System – Meter Equipment

153. As of December 31, 2018, the balance in Account 1625-610 totals approximately $0.313 million, and the balance of Account 1625-620 totals approximately $0.288 million. Because YEC has installed Advanced Metering Infrastructure (AMI) in these accounts, virtually all of the existing meters and related metering equipment operate digitally as opposed to being electro-mechanical as in the past.[88]

154. Mr. Watson understood that YEC pulls meters for testing at eight years and, based on the test results, may use the meter for a maximum period of up to 16 years. Accordingly, Mr. Watson proposed to decrease the life-curve for both Account 1615-506 and Account

85 YEC Response to Undertakings, #21, Attachment 1, page 5, PDF page 45.
86 2021 General Rate Application, PDF page 259.
87 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-111, Attachment 2, pages 64-65, PDF pages 2936-2937.
88 2021 General Rate Application, page 9-44, PDF page 279.

1625-620 from a 30-R2 to a 16-SQ which considered the digital nature of the assets in these two accounts which operate in parallel.[89] [90]

Board Findings

155. The Board agrees with Mr. Watson's rationale for decreasing the service life of YEC Account 1625-610 and Account 1625-620 to a 16-SQ life-curve in order to align with the maximum expected life of YEC's digital meters and metering equipment assets. The Board approves a 16-SQ life-curve for these two accounts.

5.2.3.1.3 Account 1635-300 – Main Transmission Facilities – Poles and Fixtures and Account 1640-300 – Sub-Transmission Lines – Poles and Fixtures

156. The balance in Account 1635-300 totals approximately $60 million at December 31, 2018, with assets in service dating from 1975 to 2018. The majority of the asset costs were added in the years 2003-2018. Mr. Watson proposed to decrease the average service life for this account by 15 years: from a 65-R3 to a 50-R3 life-curve.[91] [92]

157. YEC also maintains sub-transmission Account 1640-300, containing approximately $4.1 million in assets similar to those in the main transmission Account 1635-300. Mr. Watson proposed to increase the average service life for this account by five years: from a 45-R3 to a 50-R3 life-curve. Doing so would result in the two accounts having the same proposed 50-R3 life-curve depreciation parameters.[93] [94]

158. Given that YEC has implemented a transmission line refurbishment program and has targeted replacing poles at 50 years, Mr. Watson stated that setting the life for the two types of poles accounts to the same average life of 50 years was reasonable.

159. YEC confirmed[95] that the life-curve depreciation parameters proposed for its sub-transmission asset accounts (the "1640" series of asset accounts excluding those designated as Minto Mine) are intended to mirror the equivalent main transmission assets accounts (the "1635" series of transmission asset accounts) because they generally include the same types of assets and are subject to the same types of operating conditions.

160. During the hearing, Board counsel questioned Mr. Mollard as to whether new poles, which are being installed as part of the transmission line refurbishment program, were subject to different treatment technology relative to poles already in service such that they could be expected to last longer than 50 years.

161. However, neither Mr. Mollard nor the remaining YEC panel expressed knowledge of whether the current transmission line refurbishment program contemplated the use of better

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89 Ibid., page 9-44, PDF page 279.
90 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-120, Attachment 1 and Attachment 2, PDF pages 3223-3224.
91 2021 General Rate Application, page 9-51, PDF page 286.
92 YEC Response to Undertakings, #21, Attachment 1, page 6, PDF page 46.
93 2021 General Rate Application, page 9-59, PDF page 294.
94 YEC Response to Undertakings, #21, Attachment 1, page 46, PDF page 46.
95 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-124(h), page 4 of 4, PDF page 3240.

preservatives for wood pole treatment that could potentially extend their useful service life.[96] This was notwithstanding that YEC's IR responses confirmed that it established a "Test and Treat" process in 2009 that "determines the pole shell thickness above and below grade, treats cavities and eliminates insect infestations."[97] [98] [99]

Board Findings

162. The Board does not accept YEC's proposal that the service life for its two poles accounts should be set at 50 years.

163. The Board is not persuaded that the transmission line refurbishment program, which purports to remove poles at approximately 50 years, should be the primary reason for a corresponding change in service life. This is particularly relevant given that there appears to be an established "Test and Treat" process that serves to preserve if not extend the average service life of YEC's poles. Further, it is concerning to the Board that no YEC representative could confirm or deny that the transmission line refurbishment program contemplated an expanded use of preservative wood treatment or associated technology that could potentially mitigate any premature damage to these assets.

164. Given this, YEC's proposal to implement a 50-R3 life-curve for the two accounts at issue is denied. YEC is directed to continue to rely on the currently approved 60-R3 for Account 1635-300 and to provide clarification of the use of wood preservative or treatment process no later than the time of YEC's next depreciation study. However, due to the similarity of the assets in accounts 1635-300 and 1640-300, the Board accepts YEC's proposal to align the service lives between these two accounts. Accordingly, the Board directs YEC to incorporate a 60-R3 life-curve for Account 1640-300 in its compliance filing to this Board Order.

165. As a second matter, the Board is concerned with comments from YEC's operations personnel contained in YEC's IR responses, which appear to indicate that YEC is replacing 50-year-old transmission poles without retiring the original pole:

> Transmission poles - Transmission Line Refurbishment (TLR) – Test and treat inspection and detailed line inspections. Results came back with prioritization to replace. The assets being replaced are around 50 years old. <u>They would expect the same 50-year life for the remaining assets (with the caveat that there are no retirements). They are now using steel cross arms. Transmission poles in majority are capitalized when replaced but the original pole is not retired. New lines are capitalized.</u> (underline added)

166. In reference to the quote above, the Board is concerned that YEC's rate base is not reflected accurately. Accordingly, the Board directs YEC to provide its rationale for not retiring assets that have been replaced and to further explain how this rationale aligns with group depreciation practices in its compliance filing to this Board Order. This information is required not only for accounts 1635-300 and 1640-300 but for any other of YEC's depreciation study accounts which would be similarly affected by any YEC practice of not retiring assets that no longer provide utility service, such as appears to be the case for YEC's transmission poles.

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96 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 358, PDF page 22
97 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-53(b), page 4 of 6, PDF page 1730.
98 Ibid., YUB-YEC-1-111(b), Attachment 1, Interview Notes, page 1, PDF page 2869.
99 Ibid., YUB-YEC-1-124(a), page 3 of 4, PDF page 3239.

5.2.3.1.4 Account 1635-710 – Main Transmission Facilities – Substation Equipment and Account 1640-710 – Sub-Transmission Lines – Substation Equipment

167. The balance in Account 1635-710 totals approximately $66 million at December 31, 2018, with assets in service dating from 1975 to 2018. Over half of the asset costs were added in the years 2011-2012. Mr. Watson proposed to change the life-curve parameters for this account from 54-S0 to 45-S0.[100] [101]

168. YEC confirmed during the hearing that the McQuesten Substation asset costs were contained in Account 1635-710 in the amount of approximately $11.5 million.[102] These assets and the related VGC Group contribution toward them are discussed in Section 5.2.3.2 of this Board Order.

169. YEC also maintains sub-transmission Account 1640-710, containing approximately $8 million in assets similar to those in main transmission Account 1635-710. Mr. Watson proposed to increase the average service life for this account by five years: from a 40-S0 to a 45-S0 life-curve. Doing so would result in the two accounts having the same life-curve depreciation parameters.[103] [104]

170. As noted earlier, YEC confirmed[105] that the life-curve depreciation parameters proposed for its sub-transmission asset accounts (the "1640" series of asset accounts excluding those designated as Minto Mine) are intended to mirror the equivalent main transmission asset accounts (the "1635" series of transmission asset accounts) because they generally include the same types of assets and are subject to the same types of operating conditions.

171. With respect to Account 1635-710, Mr. Watson advised that there was insufficient actuarial data available to prepare a retirement rate analysis. Therefore, the proposed 45-S0 life-curve relied on discussions with YEC operational personnel who indicated that the account has been experiencing shorter lives due to the increasing amount of shorter lived electronic assets at the stations.

Board Findings

172. The Board does not accept YEC's proposal that the service life for its substation accounts should be set at 45 years.

173. With respect to Account 1635-710, the Board agrees that there have been too few asset retirements from which to conduct a retirement rate life analysis. This is evident in the observed life table for this account, where the Board observes that there have been only 10 age intervals of asset retirements totaling approximately $0.500 million.[106] YEC did not provide an observed life table for Account 1640-710. Accordingly, the Board finds that neither the limited retirement

[100] 2021 General Rate Application, page 9-56, PDF page 291.
[101] YEC Response to Undertakings, #21, Attachment 1, page 7, PDF page 47.
[102] Ibid., #16, page 1, PDF page 31, YEC Response to Undertakings, #18, page 3, PDF page 35, Table 1 line 4.
[103] 2021 General Rate Application , page 9-66, PDF page 301.
[104] YEC Response to Undertakings, #21, Attachment 1, PDF page 46.
[105] YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-124(h), page 4 of 4, PDF page 3240.
[106] YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-111, Attachment 2, pages 182-183, PDF pages 3054-3055.

data, nor the comments of YEC personnel, provide sufficient justification to persuade the Board that a five-year reduction to service life for Account 1635-710 is reasonable. YEC's proposed reduction to service life for Account 1635-710 is denied and YEC is directed to continue to rely on the currently approved 54-S0 life-curve for this account in its compliance filing to this Board Order.

174. However, due to the similarity of the assets in accounts 1635-710 and 1640-710, the Board accepts YEC's proposal to align the service lives between these two accounts. Accordingly, the Board directs YEC to incorporate a 54-S0 life-curve for Account 1640-710 in its compliance filing to this Board Order.

5.2.3.1.5 Account 1645-201 – Buildings & Other Equipment – Building & Improvement

175. The balance in Account 1645-201 totals approximately $10 million at December 31, 2018, with assets in service dated from 1975 to 2018. This account includes the costs associated with building and improvements that include staff housing, warehouses, offices, fencing, building envelopes, fish hatchery, yard work and guard rails. The largest addition of asset costs, in the amount of $3 million, occurred in the year 1986.[107] [108]

176. Mr. Watson proposed to change the life-curve parameters for this account from 55-R1 to 50-R2 primarily on the basis of statements made by YEC personnel that many of the assets in this account have shorter lives than the building.

177. YEC identified the types of assets that might retire earlier than the building as including facilities signage, fish hatchery upgrades, security systems, guard rail extensions, plug-ins for electric vehicles, alternate road access, paving and water storage closets. However, YEC declined to provide the approximate percent proportion of these assets compared to all assets in the account.[109]

Board Findings

178. In the absence of an actuarial analysis, the Board does not consider that the comments of YEC personnel have provided sufficient support for the proposed life-curve changes for Account 1645-201 from 55-R1 to 50-R2. Without confirmation from YEC that these shorter lived assets are of sufficient quantum such that they will significantly influence the service life of the account as a whole, the Board is unable to approve the change requested.

179. For this reason, YEC is directed to continue to rely on the currently approved 55-R1 life-curve for Account 1635-300 in its compliance filing to this Board Order.

5.2.3.1.6 Account 1665-403 – LNG Plant – Fuel Holders

180. The balance in Account 1665-403 totals approximately $13 million at December 31, 2018, with a single vintage of assets in service being installed in 2015. This account includes the 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 [sic], regenerators, tanks, and vaporizers.

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107 2021General Rate Application, page 9-70, PDF page 305.
108 YEC Response to Undertakings, #21, Attachment 1, page 8, PDF page 48.
109 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-129(a), page 1 of 2, PDF page 3249.

181. When asked to provide objective evidence further supporting the 28-year increase in average service life from 32 to 60 years, YEC provided comments from the designer of the LNG equipment who concluded that "from an engineering perspective, LNG is noncorrosive to stainless steel, so as long as the tank is maintained properly, it should last 60 years."[110]

Board Findings

182. The Board accepts the supplementary information provided by YEC in its IR response. Accordingly, a 60-R2 life-curve is approved for Account 1665-403.

5.2.3.2 VGC Group contribution and amortization of related assets

183. In its Application, YEC requested approval for an accelerated amortization period of 12 years in relation to a contribution from the VGC Group in the amount of $10.688 million. The contribution offset the majority of the total McQuesten Substation costs in the amount of $11.619 million. YEC clarified that the substation project was "required for the Victoria Gold mine [also referred to as the Eagle Gold mine] to receive Grid Electricity from YEC"[111] and was completed and capitalized in 2019.[112]

184. The substation facility was built with the capability to accommodate future connection of 138-kV transmission from Stewart Crossing or from Mayo by way of certain system improvements. The cost of these system improvements was $0.931 million. Specifically, the VGC project requirements at the outset were "for delivery of Grid Electricity to the 69 kV Mine Facilities Spur line" at a cost of $10.688 million whereas the resultant 138-kV service was "required as part of any planned Transmission Facilities Development option" at a cost of $11.619 million[113]

185. With respect to the VGC Group contribution, the effect of incorporating an accelerated amortization period of 12 years based on the life of the Eagle Gold mine was a reduction to YEC's forecast 2021 depreciation expense (and revenue requirement) of $0.700 million.[114]

186. During the hearing, Mr. Mollard confirmed that the McQuesten Substation assets had been capitalized to Account 1635-710 – Main Transmission – Substation Equipment – and was currently depreciated over a period of 54 years.[115] This was in contrast to the amortization period for the VGC Group contribution, which was proposed to be amortized over a period of 12 years.

187. YEC confirmed that the amortization period of 12 years for the contribution considered requirements by YEC's auditors and the Auditor General of Canada and accorded with International Financial Reporting Standards (IFRS) requiring the contribution to be amortized over the expected 12-year life of the Victoria Gold mine.[116]

110 Ibid., YUB-YEC-1-138, pages 1-2 of 2, PDF pages 3317-3318.
111 2021 General Rate Application, page 5-12, PDF page 125.
112 Ibid., page 5-4, PDF page 117.
113 2021 General Rate Application, page 5-13, PDF page 126.
114 Ibid., page 3, PDF page 4.
115 As noted in Section 5.2.3.1.4 of this Board Order, YEC proposed a service life of 45 years for Account 1635-710, which the Board has denied.
116 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-108(e), page 5 of 6, PDF page 2845; Ibid., YUB-YEC-1-110(d) and (e), page 5 of 5, PDF page 2863.

188. YEC also confirmed that it had no prior Board approval for the 12-year amortization period of the VGC Group contributions nor any direction to not follow IFRS requirements.

189. YEC further clarified that the 12-year amortization period proposed for the VGC Group contributions aligned with the approach directed by YECs auditors with respect to the contributions YEC received from the Minto mine customer.[117] In that case, the expected life of all related Minto mine assets are similarly amortized over 12 years.

190. With respect to the Minto mine assets specifically, YEC stated that "in accordance with International Financial Standards and to obtain a clean audit opinion from the Auditor General of Canada, it was determined that these assets were required to have a life equal to the life of the mine."[118]

Board Findings

191. The Board is concerned with YEC's proposal to maintain two different amortization periods for an asset and its related contribution. This is because, as proposed, the VGC Group contribution will be fully amortized at the end of 12 years; however, the unrecovered capital costs related to the McQuesten Substation will not be fully amortized until 42 years later.

192. Accordingly, the Board accepts YEC's proposed 12-year amortization period for the VGC Group contribution at issue in this proceeding as consistent with the requirements of IFRS and the Auditor General of Canada. In making this finding, the Board further considers it reasonable for the related McQuesten Substation assets to be aligned and thus similarly amortized over the same period time, being 12 years.

193. This alignment in service life is to address an unnecessary disconnect in cost recovery that puts customers at risk for the cost of a substation asset that was built to serve the VGC Group mine customer for a period of 12 years[119] and not built to provide utility service more broadly for a period of 54 years as with most YEC transmission substation assets.

194. In addition, the approach of aligning the amortization of the contribution and the substation costs over a period of 12 years is consistent with the treatment currently afforded by the Board for the Minto mine contribution and related capital assets.

195. Accordingly, in order to effect these findings, YEC is directed to create a separate sub-transmission asset account designated as Substation "VGC Group – gold mine" for those assets to which the $10.688 million contribution relates and to amortize these substation costs over a period of 12 years consistent with a 12-SQ. For any difference between the depreciation rate associated with the use of a service life of 54 years since the year 2019, YEC is also directed to update its amortization of reserve differences mechanism to effect a true-up of this amount in its compliance filing to this Board Order.

196. The Board notes that while the preceding discussion, finding and direction was specific to the McQuesten Substation asset and related contribution, the Board finds that all assets

117 Ibid., YUB-YEC-1-110(d) and (e), page 5 of 5, PDF page 2863.
118 Ibid., YUB-YEC-1-127(c), page 2 of 2, PDF page 3246.
119 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 322, lines 10-24, PDF page 154.

constructed for the purpose of servicing the VGC Group mine, regardless of whether there was a related contribution, should similarly be amortized over a period of 12 years. For clarity, YEC is directed to create a separate sub-transmission asset account designated as Substation "VGC Group – gold mine" for each asset category constructed for the purpose of servicing the VGC Group mine and to amortize the related asset costs over a period of 12 years consistent with a 12-SQ. For each asset category (account) affected, YEC is further directed to update its amortization of the reserve differences mechanism to effect a true-up of this amount in its compliance filing to this Board Order.

5.2.4 Rate base – deferral and reserve accounts

197. In this section, the Board reviews YEC's request for the implementation of a pension deferral account. The Board also examines certain costs for which YEC requests recovery of through its hearing cost reserve account.

198. The Board notes that specific determinations with respect to YEC's Vegetation Management Deferral account and RFID account have been dealt with earlier in Sections 5.2.2.3.2 and 5.2.2.4.2 of this Board Order, respectively.

5.2.4.1 Defined benefit pension deferral account

199. In its Application, YEC requested approval to implement a pension deferral account. The purpose of this account would be to track and subsequently recover any variance between forecast and actual contributions to its defined benefit pension plan that result from the required annual actuarial valuations between test years. YEC noted that a similar deferral account was approved for AEY in Board Order 2014-06.[120]

200. YEC also clarified that the GRA process essentially locks in the pension costs recovered through its revenue requirement, whereas the funding requirements vary each year and the variance between approved and actual costs is beyond the utility's ability to control. As such, YEC sought a deferral account to accumulate differences from approved funding versus actual funding requirements and to settle the deferral account from time to time.[121]

201. YEC stated that it faces the same risks as AEY given that "the YEC plan was inherited from ATCO as part of the termination of a management contract in 2017," notwithstanding that YEC's plan is now closed to new hires. YEC submitted that the risks from market fluctuations and the resultant impact on funding its defined benefit pension exists whether the plan is closed to new hires or not.[122]

202. During the hearing, Mr. Mollard submitted that YEC's request for a defined benefit pension deferral account, given the existence of AEY's deferral account, was in part addressing a fairness issue across the utilities in the Yukon. Further, YEC asserted that the risks faced by AEY are "the same risks that we face so we should be entitled to a similar type of regulatory device."[123]

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120 2021 General Rate Application, pages 5, 1-9, and 3-29, PDF pages 6, 23 and 75.
121 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-35(c), (e) and (g), page 3 of 3, PDF page 1441.
122 Ibid., YUB-YEC-1-35, pages 1-3 of 3, PDF pages 1439-1441.
123 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 313, lines 9-16, PDF page 145.

203. When asked during the hearing if Board approval of the requested deferral account should lead to a reduction of YEC's risk that flows through to its return on equity rate, Mr. Mollard stated that the deferral account is a type of device used to manage risk and that the Board has never historically looked at risk at that level.[124]

204. YEC's historical forecast and actual defined benefit pension plan costs are summarized in the following table:

Table 13. Historical defined benefit pension plan costs ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Actual
Pension cost	658	679	606	720	741

Source: YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-35(d), page 3 of 3, PDF page 1441.

Board Findings

205. The Board approves YEC's request for a defined benefit pension deferral account.

206. The Board finds that its reasoning for approving a similar deferral account for AEY is applicable to the current circumstance of YEC. Specifically, there continues to be ongoing and inherent volatility associated with defined benefit pension plan funding and the actuarial assumptions subject to variations in the financial markets that YEC seeks to mitigate through the use of a deferral account.

207. In affording YEC a measure of relief from this inherent market risk, the Board considers it necessary to incorporate a downward adjustment to YEC's risk premium and return on equity. This adjustment will be discussed in further detail in Section 5.2.5.3 of this Board Order.

5.2.4.2 Hearing cost reserve account

208. YEC's hearing cost reserve account was established in Order 2013-01. In Board Order 2018-10 respecting YEC's 2017-18 GRA, the Board approved a net annual appropriation amount of $0.055 million to be included in revenue requirement. The net $0.055 million amount was comprised of the annual appropriation amount of $0.250 million offset by the amortization of a 2016 credit balance in the reserve account of approximately $1.000 million over a period of five years. The amortization of the credit balance over five years resulted in a decrease to the annual appropriation amount by $0.195 million.

[124] Ibid., page 313, line 17, to page 314, line 17, PDF pages 145-146.

209. The net annual appropriation amount of $0.055 million and YEC's actual annual hearing costs since 2018 are reflected in the following continuity schedule:

Table 14. Hearing cost reserve account continuity schedule ($000)

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast
Opening balance	(1,026)	(1,026)	(926)	(99)	(61)
Annual appropriation (net)	(55)	(55)	(55)	(55)	(55)
Annual costs	155	155	883	93	0
Closing balance	**(926)**	**(926)**	**(99)**	**(61)**	**(116)**

Source: 2021 General Rate Application, Table 3.14.1, page 3-23, PDF page 69.

210. During the oral hearing, Board counsel confirmed with Mr. Mollard that YEC's legal costs in relation to appeals of Board decisions to the Yukon Court of Appeal were included in revenue requirement as attributable to the regulatory process. Mr. Mollard stated his view that appeal costs should be paid for in the same manner as those costs more generally associated with a general rate application and its defense. Mr. Mollard took no position on whether the recovery of appeal costs through revenue requirement was dependent upon YEC's success in an appeal, stating that it is entirely at the Board's discretion as to what gets paid or doesn't get paid through the hearing cost reserve account.[125]

211. Mr. Mollard was further questioned during the hearing regarding why ratepayers should have costs related to YEC's unsuccessful appeals of Board decisions imposed on them. Mr. Mollard responded with a parallel example describing an application placed before the Board for a rate increase that touches on all aspects of YEC business. Even though YEC might not "win everything" requested within the Application, YEC nonetheless gets paid through its hearing costs reserve account for preparing and defending it. Mr. Mollard suggested that appeals could be considered in the same light irrespective of whether the appeal itself was accepted or rejected by the Court of Appeal.[126]

212. In an undertaking, YEC provided a breakdown of its costs for appeals and costs for other categories of hearing costs charged to the related reserve account. The information provided by YEC is summarized in the following table.

[125] 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 316, lines 10-21, PDF page 148.

[126] 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 391, line 9, to page 392, line 6, PDF pages 55-56.

Table 15. Categories of costs charged to the hearing reserve account between January 1, 2019, and September 30, 2021 ($)

2017-18 GRA – approved costs per Board Order 2019-03	882,983
2017-18 GRA – second compliance filing approved costs per Board Order 2020-01	92,955
R&V of YEC GRA cost awards in Board Order 2019-03 per Board Order 2020-02	124,200
DSM Appeal costs	118,968
Total	**1,219,106**

Source: YEC Response to Undertakings, #15, page 317, PDF page 30; YEC Response to Undertakings, #30, page 390, PDF page 252.

Board Findings

213. The Board agrees that YEC is entitled to its reasonable costs, as determined by the Board, in relation to the performance of YEC's utility function, including its reasonable costs incurred in connection with regulatory proceedings. In the *Public Utilities Act*, "costs" is defined to include "fees, counsel fees, and expenses". Under Section 56 of the Act, the Board "may order to whom or by whom any costs incidental to any proceeding before the board are to be paid, and may set the costs to be paid." The Board's Rules of Practice include Schedule 1, Scale of Costs, which deals with the type of "costs" discussed above. However, such costs do not apply to proceedings outside the Board's direct jurisdiction. Accordingly, the Board's Scale of Costs does not apply to appeals of Board Orders to the courts.

214. Instead, the Board considers that a utility's application to include, as part of its revenue requirement, its actual out-of-pocket costs incurred in pursuing such court proceedings should be treated in the same way as any other costs sought to be included in the utility's revenue requirement or rate base. As with other elements claimed in a GRA, the applicant's onus is to satisfy the Board that the expense claim is reasonable or prudent and therefore ought to be fairly included in the utility's revenue requirement or rate base.

215. In 2019, following the Board's issuance of Board Order 2019-05, YEC appealed the Board's order to the Yukon Court of Appeal, alleging that the Board erred in law in certain respects relating to YEC's application to include certain DSM costs as part of its rate base. In its judgment on the appeal,[127] the court upheld the Board's view that YEC that Yukon Energy had not acted prudently by incurring these DSM costs at its own risk when it had been put on notice that the Board was not committing to include any DSM costs in the rate base beyond the end of 2015 unless it gave prior approval. Consequently, the Court of Appeal dismissed YEC's appeal.

216. In the current GRA, YEC is seeking to recover, as part of its revenue requirement, its expenses incurred in prosecuting the failed appeal. In asserting this claim, YEC has failed to discharge its onus to show that the appeal expenses were reasonably and prudently incurred. From the evidence on the record, as well as the Court of Appeal's reasons for decision, there is little to persuade the Board that the appeal was reasonably undertaken. Indeed, the Court of Appeal upheld the Board's decision that YEC had not acted prudently in incurring DSM costs at

[127] *Yukon Energy Corporation v Yukon (Utilities Board)*, 2021 YKCA 1.

its own risk when the Board had put YEC on notice that DSM costs could not be included in the rate base beyond 2015 unless the Board gave its prior approval.

217. As with other elements claimed in a GRA, the applicant's onus is to satisfy the Board that the claim is reasonable or prudent and therefore ought fairly to be included in the utility's revenue requirement or rate base. In the case of the expenses YEC incurred in prosecuting the failed appeal, it has failed to discharge that onus for the purposes of the current GRA. The Board cannot consider the costs of that appeal to have been prudently incurred when the Court of Appeal deemed the subject of the appeal to have resulted from YEC's imprudence.

218. Accordingly, the Board denies YEC's DSM appeal costs charged to the hearing reserve account between January 1, 2019, and September 30, 2021. The Board directs YEC to remove those costs from its hearing costs reserve account in its compliance filing to this Board Order.

219. From a policy perspective, allowing YEC to claim the costs of appeals without justification criteria would be to grant the utility carte blanche to appeal YUB orders with impunity. By contrast, requiring YEC to fully justify the expense to the Board may compel the utility to carefully examine whether the appeal is necessary, i.e., whether the benefit hoped for is worth the cost. Accordingly, the Board puts YEC on notice that the claims for costs associated with appeals or any other form of court action will not be accepted as a matter of course. Such claims will be scrutinized carefully on their merits on a case-by-case basis.

5.2.5 Return on rate base

220. YEC's rate base is financed by two main sources of capital: long-term debt and shareholder equity. For this Application, YEC forecast an average cost of debt of 2.81 percent and a return on equity of 8.70 percent, giving an average cost of capital of 5.17 percent.[128]

5.2.5.1 Cost of debt

221. YEC forecast new debt issues of $21.210 million in 2020 and $18.135 million in 2021 at a rate of 2.19 percent. In Board Order 2018-10, the Board set YEC's cost of debt using the long-term Canada bond rate plus 120 basis points.[129]

Board Findings

222. No issues were discovered upon review of YEC's 2021 forecast cost of debt. The method for setting the cost of debt and the corresponding calculation of cost of debt are consistent with Board Order 2018-10. The Board approves YEC's 2021 forecast cost of debt of 2.19 percent for 2021 as reasonable, as it was determined using a previously Board-approved methodology.

5.2.5.2 Capital structure and Board Findings

223. YEC proposed to maintain its existing capital structure. In the current proceeding, there was no evidence to suggest that a change to the existing capital structure was required for 2021. For 2021, the Board approves YEC's capital structure of 60 percent debt and 40 percent equity as reasonable.

[128] 2021 General Rate Application, Table 3.15, page 3-25, PDF page 71.
[129] Ibid., page 3-27, PDF page 73. YEC used the June 30, 2020 benchmark of 0.99 percent.

5.2.5.3 Return on equity (ROE) and risk premium

224. YEC proposed to continue with the British Columbia Utilities Commission (BCUC) benchmark utility ROE and maintain the same risk premium adder that was approved in Board Order 2018-10. YEC stated that the current BCUC benchmark ROE is 8.75 percent. YEC advised that Board Order 2018-10 established a risk premium of 45 basis points for YEC over the BCUC benchmark ROE. YEC highlighted that the Rate Policy Directive, OIC 1995/90, Section 2 requires YEC's allowed ROE to be set equal to YEC's fair return on common equity less 50 basis points. As a result, YEC is requesting an ROE of 8.70 percent.[130]

225. Regarding the issue of whether the LWRF and the OIC afford protection to YEC against risks to the utility, YEC stated in responses to Board IRs and the hearing that it did not believe that its risk profile had changed.[131]

226. YEC submitted the following in argument:

- OIC 2021/16 did not change YEC's risk profile.
- The Low Water Reserve Fund (LWRF) provides rate volatility protection for customers rather than load risk protection for YEC.
- Prior to Board Order 2015-01, the Board did not address any variation in application of the LWRF or Diesel Contingency Fund (DCF) pertaining to load levels either above or below forecast, nor did any Board Orders prior to Board Order 2015-01.
- Similarly, the issue of risk responsibility for generation costs above load forecast was not addressed in Board Order 2018-10 and only came about in subsequent compliance filings to Board Order 2018-10.
- Undertaking 11 in this proceeding revealed that directions from Board Order 2019-08 resulted in YEC incurring an added $0.738 million of thermal generation fuel costs for 2019 due to water conditions below the long-term average and load above the last approved GRA forecast.
- Requiring YEC to bear any water-related risk, including risk for load above approved load forecasts, is not consistent with prior Board Orders. Further, the evidence reviewed in the 2017-18 proceeding confirmed that no such water-related risk applied to FortisBC (electric), as a comparator to YEC, and that any such added risk being applicable to YEC would require adding to the ROE risk premium for YEC.

130 BCUC benchmark ROE of 8.75 percent plus premium adder of 0.45 percent less OIC 1995/90 of 0.5 percent = 8.70 percent.
131 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 180, lines 17-24, PDF page 12.

Board Findings

227. The setting of the ROE includes determining the risk premium of YEC that should be approved in a given test year or years.

228. The Board is not persuaded by YEC's evidence and arguments on maintaining the risk premium that was approved in past Board Orders. In Board Order 2018-10, the Board did not make adjustments to YEC's risk premium due to the existence of rate stabilization measures, including the LWRF. The Board recognized that YEC, by its own admission, stated that it accepted the risk of incremental loads, but YEC is not accepting the full generation costs and risks with those incremental loads.

229. However, in this proceeding, the Board finds that YEC has narrowly focused on rate stabilization measures — e.g., those that occur through the LWRF — rather than assisting the Board with determining a fair apportionment of risk between YEC and its customers for costs and risks in providing utility service. The risk premium approved should compensate YEC for risks it assumes and should exclude risks related to costs that are covered through customer rates.

230. The Board is not prepared to accept past Board Orders as determinative of the risk premium to be set for 2021, particularly with the legislature passing OIC 2021/16 that addresses cost recovery through the LWRF and provides mitigation of some of the risks related to low water conditions and the associated costs. This OIC effectively requires the Board, for applications after November 1, 2020 to:

- Include in the rates of YEC provision to recover forecast fuel costs for the amount of thermal generation needed to meet forecast customer requirements.

- Determine the forecast of the amount of renewable generation available to contribute to meeting forecast customer requirements based on long-term average annual renewable source availability.

- Review and approve the fuel costs resulting from any shortfall between actual renewable generation and actual customer requirements (and if renewable generation had been consistent with long-term annual renewable source availability).[132]

231. OIC 2021/16 includes provisions that YEC is to credit or charge its customers for the difference in fuel costs for thermal generation when a credit or charge occurs[133] through the LWRF. The OIC provides parameters and greater certainty for costs, accounting for actual renewable generation and actual customer requirements, and the operation of the LWRF. The Board's view is that the certainty afforded by the OIC for these items provides assurance of YEC's forecast to actual cost recovery for fuel costs related to incremental loads resulting from extreme low water conditions. This in turn reduces the risks to YEC because customers will ultimately be charged if YEC under-recovers its costs (although some forecast risk[134] would

132 See OIC 2021/16, amending the Rate Policy Directive (1995) by adding Section 9.
133 See OIC 2021/16, amending the Rate Policy Directive (1995) by adding Section 9(7) to the directive.
134 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 180, lines 22-24, PDF page 12. YEC testimony noting that YEC will have forecast risk.

remain until the LWRF is trued-up). However, in Board Order 2018-10, the Board determined that those costs for incremental loads above forecast should not be a burden to customers.

232. YEC points out that it has been harmed by higher 2019 thermal generation fuel costs (of $0.738 million) due to loads above forecast (due to Board Orders 2018-10 and 2019-04). However, it should be noted that YEC fails to point out the increased revenues from that incremental load, which mitigate the incremental $0.738 million in costs.

233. The Board can only determine if the risks to YEC warrant the requested risk premium or whether an adjustment must be made to the risk premium adder to recognize the shifting of risk of incremental load from YEC to customers through the OIC and the further addition of the pension deferral account.[135] Although YEC disagreed that a reduction to the risk premium is necessary to reflect the shifting of these risks, for the reasons above, the Board does not agree. The OIC reduces YEC's risks in providing utility service and the Board determines that a reduction of 50 basis points is warranted in YEC's risk premium. Therefore, in the compliance filing to this Board Order, YEC shall reflect the Board-approved ROE of 8.20 percent for 2021.

5.3 Capital projects

234. Capital projects are long-term, capital-intensive projects with the purpose of building upon, adding to or improving a capital asset. YEC generally groups capital project investments in one of the three categories: (i) capital works on property, plant and equipment; (ii) deferred costs; and (iii) intangible assets. For this Application, YEC indicated that capital works spending included projects required to improve aging infrastructure and sustain capital requirements, to support new supply options, to address load growth capacity requirements and to refurbish old assets and improve grid reliability. Spending for deferred costs included feasibility studies, continued relicensing work, regulatory work and dam safety review work. Finally, intangible assets spending included financial software, customer service costs and costs related to the development of an asset management framework.

235. In its Application, YEC provided its total actual capital spending for 2018 to 2019, along with its actual or forecast capital spending for 2020 and the 2021 test year. Costs for each capital project category were divided into major projects — which were projects with capital spending over $1 million — and projects between $100,000 and $1 million. For 2021, YEC stated that major projects would have a net rate base impact of $55.526 million and projects between $100,000 and $1 million would have an impact of $15.8 million.[136] Over the course of the GRA proceeding, YEC updated the costs for some of the capital projects, which included both major projects and certain projects between $100,000 and $1 million. Reasons for updates included YEC adjusting the actual 2020 costs and revising the scope of the project, such as including additional work required for the project or deferring certain parts of the project to a later date.

236. As a preliminary matter, YEC requested that cost updates for major projects be considered by the Board because these projects had a limited number of discrete cost elements within the Application and costs for each impacted project could be updated with minimal likely impact on other test year forecast costs.[137] In contrast, YEC requested that the Board not consider

[135] For full context, see 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 180, line 10, to page 181, line 20.
[136] YEC Final Argument, Sections 3.1 and 3.2, pages 34 and 40, PDF pages 37 and 43.
[137] Ibid., Section 3.0, page 33, PDF page 36.

the cost updates for projects between $100,000 and $1 million because these capital projects were subject to a wide range of interacting factors and focusing on cost updates for these specific projects would not address consideration of other projects that were not included in evidence.[138] YEC also provided information on major capital works projects, major deferred costs and deferred costs between $100,000 and $1 million that did not affect rate base. YEC indicated that these projects were expected to remain in the work-in-progress (WIP) stage in the 2021 test year and, as a consequence, did not affect the test year rate base or revenue requirement.[139]

Board Findings

237. For clarity, the Board will consider all cost information, including updates, filed on the record of this proceeding because it should take into account the most up-to-date information at the close of the evidentiary record for the cost related to YEC's capital projects. For cost updates of projects between $100,000 and $1 million, YEC did not identify any specific interacting factors and it did not adequately explain how updates for some capital projects would fail to address its consideration of other capital projects commencing in the test year. Absent compelling reasons to the contrary, the Board maintains its past practice which is to consider the most up-to-date information provided on the record for capital projects for a test year or years. Accordingly, because the Board finds that YEC has not fully substantiated its rationale for including some updates and for excluding updates for capital projects between $100,000 and $1 million to be persuasive in setting YEC's capital forecasts for 2021, YEC's request is denied.

5.3.1 General Matters

238. In addition, the Board also makes two general findings regarding the adequacy of information provided by YEC in its Application and provides its expectations regarding the minimum required filing of information by YEC in future GRAs.

239. The Board is concerned about the level of information provided in YEC's Application which, in some cases, the Board has found to be too high-level and lacking in expected detail. The City of Whitehorse and UCG shared this concern. For example, YEC did not provide the studies it conducted for projects or the various alternatives explored. YEC only provided such information in its responses to extensive information requests from the Board and from interveners. By providing incomplete or inadequate business case analyses up front in its Application, YEC has caused unnecessary cost, delay, and inconvenience to the Board and to the interveners in this proceeding.

240. The Board expects the information requests process to be more efficient and YEC to provide more details about its capital projects in the original application. The onus falls on the applicant to prepare its application with sufficient supporting information. The Board is concerned that, to date, YEC appears to be shifting the burden to the Board and interveners to identify further information that is required to fill important gaps in YEC's application through the IR and hearing process. As mentioned in Section 3 of this Board Order, if YEC's practice of failing to provide adequate business case information and analysis continues, YEC may find itself at risk of its project costs being reduced or denied. The Board expects YEC to include a

138 Ibid., Section 3.0, pages 33-34, PDF pages 36-37.
139 YEC Final Argument, Section 3.3, page 41, PDF page 44.

comprehensive business case as part of each significant component of the Application at the time it is filed with the Board.

241. Further, the Board is concerned with YEC's inconsistent reporting of cost breakdowns for capital projects. In its second round of information requests, YEC indicated that it did not use any uniform cost estimate breakdown for all projects due to differences in project requirements and the magnitude of the projects, and this means that costs were not reported in a consistent format.[140] While the Board agrees that projects can have different requirements, it found YEC's presentation of costs for capital projects in its Application to be unnecessarily complex and difficult to follow. UCG shared this sentiment[141] and also advised that YEC's failure to produce clear continuity schedules made it difficult to assess how YEC allocated project costs in previous years and how it planned to allocate project costs in the forecast test year.[142]

Board Findings

242. Due to these concerns, the Board directs YEC to present cost breakdowns for its capital projects in a uniform manner in future GRA proceedings. The Board further directs YEC to provide schedules for all capital projects in the CWIP continuity format — the template for which was provided in information request YUB-YEC-2-16 — in future GRA proceedings. In order to ensure a fair and efficient process for future GRAs, if YEC does not comply with this direction, the Board may request YEC to update and refile its application or may deny the application.

243. For the reasons that follow in the subsections below, the Board does not accept all of the applied-for actual and forecast costs for major projects (inclusive of capital works projects, deferred costs and intangible assets) and projects between $100,000 and $1 million (also inclusive of capital works projects, deferred costs and intangible assets) as reasonable.

5.3.2 Capital Works on Property, Plant, and Equipment

244. YEC indicated that spending for capital works included projects required to improve aging infrastructure and sustain capital requirements, to support new supply options, to address load growth capacity requirements, and to refurbish old assets and improve grid reliability. YEC had a total of 11 major projects, with a forecast cost of $47.846 million in the 2021 test year, and a total of 29 capital projects between $100,000 and $1 million, with a forecast cost of $11.586 million. These costs amounts were originally provided in the GRA, and YEC updated these costs in its responses to the Board's second round of information requests.

245. The major projects in this Application are as follows:

- LNG Third Engine Project;
- N-1 Capacity Shortage Thermal Rental Site Infrastructure Projects at the Whitehorse and Faro sites;
- Mayo to McQuesten Transmission Line and McQuesten Substation Projects;

[140] YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 6 of 29, PDF page 142.
[141] UCG Final Argument, paragraph 79, PDF page 15.
[142] Ibid., Capital Projects, paragraph 74, PDF page 14.

- Transmission Line Refurbishment Projects;
- Breaker Replacement Project;
- P125 Headgate Replacement Project;
- Whitehorse Hydro unit 2 (WH2) Uprate Project; and
- Whitehorse Hydro unit 4 (WH4) Uprate Servomotor Replacement Project.

The following subsections address the major projects individually and the capital projects between $100,000 and $1 million.

5.3.2.1 LNG Third Engine Project

246. YEC requested that the Board approve $8.261 million for the LNG Third Engine Project, which included the actual capital spending amounts for 2017, 2018 and 2019.[143] YEC stated that the LNG Third Engine Project, which has been in service since 2018, provided a third natural gas-fired generating unit, rated at approximately 4.4 MW, at the Whitehorse thermal plant. YEC submitted that the LNG Third Engine Project helped address the existing dependable capacity shortfall and that this additional generating unit, combined with the rented diesel units at the Whitehorse and Faro sites, resulted in a dependable capacity surplus of 1.25 MW for 2021.[144] YEC advised that the LNG Third Engine Project was reviewed during the 2017/18 GRA proceeding and that, in Board Order 2018-10, the Board noted that the cost per MW of the third generating unit was favourable compared to the alternatives and that it was reasonable for YEC to continue with the project.[145] Because the project was not forecast to be in service in the 2017-2018 GRA test years, it was not part of the rate base additions in those test years. YEC stated that most of the construction associated with the project was completed in the second and third quarters of 2018, that receipt of approval to operate the generating unit was obtained from the Government of Yukon in November 2018 and that testing and commissioning was completed in December 2018.[146]

Board Findings

247. The Board finds that the LNG Third Engine Project is necessary for YEC to address its dependable capacity shortfall. The Board continues to find the cost per MW of the LNG Third Engine Project favourable when compared to alternative projects, particularly as there was no evidence to the contrary on the record.[147] Given that the costs of the project ($8.261 million) are below the 2017/18 budget ($8.9 million[148]) and that no material issues around costs were identified, the Board finds that YEC has prudently incurred costs for this project. For these reasons, the Board finds the $8.261 million of actual cost incurred for this project is prudent and directs YEC to add this amount to the 2021 rate base.

143 2021 General Rate Application, Section 5.2.1.1, page 5-6, PDF page 119.
144 YEC Consolidated IR Responses, YUB-YEC-1-50, page 3 of 4, PDF page 1507.
145 YEC Final Argument, Section 3.1.1, pages 34-35, PDF pages 37-38.
146 2021 General Rate Application, Section 5.2.1.1, page 5-6, PDF page 119.
147 Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 412, page 79 of 118, PDF page 84.
148 2021 General Rate Application, Section 5.2.1.1, page 5-6, PDF page 119.

5.3.2.2 N-1 Capacity Shortage Thermal Rental Site Infrastructure Projects at the Whitehorse and Faro sites

248. YEC requested that the Board approve $1.298 million for the N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure Project, which included the actual capital spending amounts for 2018 and 2019.[149] The project, which was completed in 2019, involved designing infrastructure to accommodate temporary rented diesel units at the Whitehorse site that would address the capacity shortfall projected for the 2018/19 and 2019/20 winters. YEC stated it installed six temporary diesel units, rated at 1.8 MW, in the winter of 2018/19 and installed two additional temporary diesel units in 2019. YEC clarified that the scope of the project included planning support, limited engineering design assistance and protection settings and installation support.[150]

249. YEC also requested that the Board approve $2.037 million for the N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure Project, which included the forecast capital spending amount for 2020.[151] Similar to the rental infrastructure project at Whitehorse, this project involved the design and installation of infrastructure to support the increase in rented diesel units at the Faro site.[152] YEC indicated that the scope included engineering and design, procurement of materials, installation and construction and other internal and project management costs.[153] This project was completed in 2020[154] and YEC updated the costs for this project to $2.446 million in responses to the Board's first round of information requests, which reflected the actual project costs.[155] YEC's stated reasons for the variances included:[156]

- Requiring additional materials after completion of the detailed design;
- Higher than expected costs for procuring a 138-kV disconnect switch and a 25-kV breaker and for refurbishing a spare transformer;
- Expanding the scope due to additional safety and environmental requirements;
- Expanding the scope in order to relocate warehouse materials, installing a ground grid in the generator area, rental generator prep, pulling and terminating cables to rental generators and installation of unit transformers and generator berms;
- A higher than expected budget for crane rental and SCADA commissioning;
- Requiring a rented crane for an additional day and requiring an additional 3.5 days to establish communication with the Finning units;

149 2021 General Rate Application, Section 5.2.1.2, page 5-7, PDF page 120.
150 Ibid., Section 5.2.1.2, page 5-7, PDF page 120.
151 Ibid., Section 5.2.1.2, page 5-8, PDF page 121.
152 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, pages 364-365, PDF pages 28-29.
153 2021 General Rate Application, Section 5.2.1.2, page 5-7, PDF page 120.
154 YEC Consolidated IR Responses, YUB-YEC-1-50, pages 3 of 4, PDF page 1507.
155 Ibid., YUB-YEC-1-49, page 5 of 7, PDF page 1501.
156 Ibid., CW-YEC-1-26, pages 1 and 2 of 2, PDF pages 149-150.

- Requiring more internal manpower for construction, testing and commissioning than originally envisioned; and

- Providing more responsibility to an external consultant during a four-week absence of the YEC project manager, due to unforeseen circumstances.

Board Findings

250. In Section 5.2.2.2 of this Board Order, the Board did not approve the rental costs of the two spare units at Faro and Whitehorse, as they were redundant. Nevertheless, the Board acknowledges that YEC uses the rented diesel units for meeting its capacity requirements and requires infrastructure support for operating the units. The Board finds that the $1.298 million associated with the N-1 Capacity Shortage Whitehorse Thermal Rental Site Infrastructure Project is reasonable and directs YEC to add this amount to the 2021 rate base. The Board also accepts the $2.446 million associated with the N-1 Capacity Shortage Faro Thermal Rental Site Infrastructure Project and directs YEC to add this amount to the 2021 rate base.

5.3.2.3 Mayo to McQuesten Transmission Line and McQuesten Substation Projects

251. The Mayo to McQuesten Transmission Line Project involved constructing a new 138-kV transmission line from the Mayo to McQuesten substations and installing STATCOM, described as a voltage source converter that provided fast-acting reactive power in order to regulate the transmission voltage and improve the power quality of the system at the Stewart Crossing Substation in order to improve overall reliability and power quality in the system. YEC stated that the existing 69-kV transmission line, originally constructed in 1951, was at the end of its life and in need of replacement, having experienced both reliability and power quality issues over a number of years.

252. YEC noted that the transmission line had been experiencing issues since the early 1990s but that it could not justify a rebuild at the time. This was because YEC concluded that, with the closure of the United Keno Hill Mines (UKHM),[157] there were very few customers along the transmission line and it could maintain service levels with the existing line. Thus, YEC conducted minimal capital improvements over the past 15 years to address reliability concerns.[158] With the connection of the Eagle Gold facility in 2019,[159] YEC had an opportunity to interconnect new industrial load in a manner that would facilitate the replacement of the existing transmission line infrastructure.[160] YEC decided to upgrade the transmission line to a 138-kV rating because the cost reduction for using a 69-kV design was less than 10 percent and because benefits included an increase in line capacity and in reliability.[161] YEC provided supporting studies and assessments in this proceeding, which included transmission line design criteria, clearance and structural evaluation criteria, the Chimax Inc. transmission line preliminary design

157 YEC Consolidated IR Responses, YUB-YEC-1-51, page 4 of 10, PDF page 1512.
158 Ibid., YUB-YEC-1-51, page 4 of 10, PDF page 1512.
159 2021 General Rate Application, Section 5.2.1.3, page 10-19, PDF page 360.
160 YEC Final Argument, Section 3.1.2, page 35, PDF page 38.
161 YEC Consolidated IR Responses, YUB-YEC-1-51, page 8 of 10, PDF page 1516.

report and transmission line scope extension report and a document summarizing the public consultation.[162]

253. YEC also decided to install STATCOM at the Stewart Crossing Substation. YEC stated STATCOM was installed because of the Eagle Gold facility, indicating the load could draw the voltage down.[163] In YEC's view, STATCOM was required to ensure the system remained stable as the Eagle Gold facility consumed electricity from the grid. YEC chose STATCOM over alternatives such as static VAR compensators because of STATCOM's fast response time and the fact that STATCOM did not require harmonic filters, thereby having a smaller footprint.[164]

254. In its Application, YEC summarized the work to be completed, which included transmission line survey and brushing, transmission line construction and commissioning and decommissioning of the existing line. YEC provided that the contributions for the project include the Yukon government's $5.3-million funding to advance the project, payments by the VGC Group to YEC and federal funding through the Investing in Canada Infrastructure Program.[165] After contributions are accounted for, the project costs provided by YEC in the Application are $8.027 million, which included actual capital spending amounts for 2018 and 2019 and forecast capital spending amounts for 2020 and 2021. In response to the Board's second round of information requests, YEC updated the cost to $8.628 million to reflect for actual costs in 2020 and an updated capital spending forecast for 2021.[166] YEC indicated that the reasons for variances included higher than forecasted costs for brushing and access work, lower than forecasted costs for transmission line construction work and cost increases relating to substation construction and STATCOM installation.[167]

255. Relating to the above project, YEC proposed to complete the McQuesten Substation Project. YEC indicated that it needed to complete this project in order for the Eagle Gold facility to receive electricity from the grid. The project was developed by the VGC Group and YEC, with the intention that it would be owned and operated by YEC, and the scope of work included designing, engineering, procuring, constructing and commissioning the McQuesten Substation. The costs for this project included the actual capital spending amount for 2018 and 2019, and YEC received an asset contribution from the VGC Group valued at $10.688 million, resulting in a net cost of $0.931 million.[168] Accordingly, YEC proposed to add $0.931 million to rate base for the McQuesten Substation Project for 2021.

Board Findings

256. The Board finds there is a necessity for both projects in supporting the connection of the Eagle Gold facility and in improving the reliability and power quality of the power system. The Board also agrees with the timing of this project, given that in the past transmission upgrades

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162 YEC Consolidated IR Responses, YUB-YEC-1-51(a), Attachments 1 and 2; YUB-YEC-1-51(g), Attachments 1 and 2; and YUB-YEC-1-51(i), Attachment 1.

163 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 368, PDF page 32.

164 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-18, page 7 of 12, PDF page 172.

165 2021 General Rate Application, Section 5.2.1.3, pages 5-10 to 5-11, PDF pages 123-124.

166 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 8 of 29, PDF page 144.

167 Ibid., YUB-YEC-2-17, pages 8 and 9 of 29, PDF pages 144-145.

168 2021 General Rate Application, Section 5.2.1.4, pages 5-11 to 5-13, PDF pages 124-126.

could not be justified due to the low number of non-industrial customers along the transmission line.

257. For the Mayo to McQuesten Transmission Line Project, the facts support that the STATCOM device is only required because the Eagle Gold facility impacts the system voltage significantly. However, YEC does need to mitigate the voltage impacts caused by the Eagle Gold facility, meaning that voltage support infrastructure is required on the system. Accordingly, the Board finds that YEC has demonstrated the need for the STATCOM device for voltage support and that the costs associated with the STATCOM device are reasonable.

258. The Board is prepared to accept the $8.628 million actual and forecast costs for the Mayo to McQuesten Transmission Project as just and reasonable and directs YEC to include the actual capital spending amounts for this project in the 2021 rate base. Additionally, the Board accepts the $0.931 million after-contribution amount for the McQuesten Substation Project as reasonable and directs YEC to add this amount to the 2021 rate base.

259. The Board notes that, in the Board Order associated with the power purchase agreement between YEC and Victoria Gold Corp. and StrataGold Corp., when the mine is operational, the amount non-industrial ratepayers would have to pay for STATCOM is significantly reduced.[169] Additionally, as discussed in Section 5.2.3.2, all assets associated with the mine are amortized over 12 years, which includes the STATCOM device. This means that the costs of the STATCOM device will be paid for over the lifetime of the mine, thereby limiting the exposure of costs to non-industrial ratepayers even if the life of the STATCOM device exceeds the life of the mine.

5.3.2.4 Transmission Line Refurbishment Projects

260. YEC stated that the Transmission Line Refurbishment Projects are associated with its 138-kV Whitehorse-Aishihik-Faro (WAF) transmission system, constructed in the late 1960s and early 1970s, and that studies conducted in 2017 indicated that key components of the system were at end of life, in poor condition and required replacement.[170] YEC separated the projects into two phases: The first phase will address replacement of components of transmission lines L170, L171 and L172, and the second phase will address replacement of components of transmission line L178. YEC requested approval of $4.272 million for the first phase dealing with transmission lines L170, L171 and L172, which was the actual capital spending amount for 2019. YEC also requested approval of $1.3 million for the second phase dealing with transmission line L178 in the 2021 test year, which was the forecast capital spending amount for 2021.

261. YEC noted that transmission lines L170, L171 and L172 had installation dates of 1968, 1975 and 1968, respectively. Through various studies,[171] YEC found that a large number of cross arms and insulators were at end of life with a high risk of failure for transmission lines L170, L171 and L172. YEC indicated that the total cost to respond to outages for transmission lines L170, L171 and L172 amounted to $313,500, $100,500 and $25,400, respectively.[172] YEC stated that the work for this project could not be effectively completed within a reasonable time frame

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169 Board Order 2018-04, Appendix A: Reasons for Decision, paragraph 65, page 15 of 16, PDF page 17.
170 2021 General Rate Application, Section 5.2.1.5, page 5-13, PDF page 126.
171 YEC Consolidated IR Responses, YUB-YEC-1-53(a), Attachments 1 to 5, PDF pages 1734-1977.
172 Ibid., YUB-YEC-1-53, pages 4 and 5 of 6, PDF pages 1730 and 1731.

through the annual transmission maintenance program and that a stand-alone project was required to complete the full scope of the refurbishment.[173] YEC submitted that the project was reviewed as part of the 2017/18 GRA proceeding and that project components were capitalized as completed and placed into service, with approved costs to the end of 2018 included in rate base.[174]

262. YEC also presented the business case for refurbishing transmission line L178, which was projected to commence in 2021. YEC indicated that outages on transmission line L178 currently trip at the Takhini Substation and failure to mitigate this concern increased the risk of component failure on the transmission line.[175] YEC stated that the scope of the project involved like-for-like replacement of components on the authorized transmission right-of-way. YEC updated the costs for this project to $0.3 million, which was the actual 2021 capital spending amount, as part of its responses to the second round of information requests.[176] While YEC originally budgeted $1.3 million for the 2021 test year in its Application, YEC noted later in the GRA process that structure replacements on transmission line L178 required blasting rocks, and given YEC's lack of experience in blasting to install structures, the tendering process resulted in bids higher than their budget.[177] As such, YEC reduced the project scope for 2021 to reflect work completed by its power line crews.

Board Findings

263. The Board finds there is a necessity for these projects given the age of the transmission lines and the outages experienced on these lines. The Board also finds that YEC carried out its due diligence in determining the key components required for refurbishment of transmission lines. In its Application, YEC indicated that the alternative to the project was to respond to structure and component failures as they occurred. The Board agrees with YEC's statement that this alternative would lead to significant reliability impacts as well as higher overall costs, as well as employee safety issues.

264. Regarding the refurbishment of transmission line L178, the Board finds YEC acted reasonably in reducing the costs and the scope of the project in 2021 because of its lack of experience in replacing structures in rocky terrain.

265. For these reasons, the Board finds the $4.272 million incurred for the first phase to be prudent and directs YEC to include this amount in the 2021 rate base. The Board also accepts the $0.3 million for the second phase to be reasonable and approves the actual capital spending amount incurred by YEC to date. However, the $0.3 million will not be added to the 2021 rate base, as the project is not complete. Costs for the second phase will only be added to the rate base once the second phase is complete and YEC provides the actual capital spending amount incurred in the next GRA.

173 2021 General Rate Application, Section 5.2.1.5, page 5-14, PDF page 127.
174 Ibid., Section 5.2.1.5, page 5-15, PDF page 128.
175 Ibid., Section 5.2.1.6, page 5-15, PDF page 128.
176 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 10 of 29, PDF page 146.
177 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, pages 369-370, PDF pages 33-34.

5.3.2.5 Breaker Replacement Project

266. YEC requested that the Board approve $2.260 million for the Breaker Replacement Project, which included the actual capital spending amount for 2018 and 2019.[178] YEC indicated that this project involved the replacement of 12 aging circuit breakers in various substations throughout Yukon, including the replacement of five 34.5-kV medium voltage and seven 138-kV high voltage breakers. YEC explained that many of the breakers are 40 years old, that replacement parts are not available and that damages to aging components could result in lengthy outages to implement repairs or the eventual replacement of a breaker, impacting system reliability. YEC replaced the five medium voltage breakers in 2018 and the seven high voltage breakers in 2019. YEC commented that the costs for replacing the five medium voltage breakers were reviewed in the 2017-18 GRA and approved for inclusion in the rate base at that time.

Board Findings

267. The Board finds there is a necessity for the Breaker Replacement Project given the age of the components and the reliability issues identified by YEC. Thus, the Board finds that the $2.260 million in actual costs associated with this project appears to be prudent and directs YEC to add the costs to the 2021 rate base.

5.3.2.6 P125 Headgate Replacement Project

268. The P125 Hydro Plant was originally commissioned in 1958 and houses three of the four hydro power units at the Whitehorse Rapids Generating Station, namely Whitehorse Hydro units 1, 2 and 3 (WH1, WH2 and WH3). YEC stated that the headgates at the P125 Hydro Plant, located above the plant at the water intake structure, are critical for operating and maintaining the plant and played a critical role in protecting the hydro units and water conveyance system. The headgates for units WH1 and WH2 were installed in 1958 and the headgate for unit WH3 was installed in 1969.[179] In 2019, SNC Lavalin performed tests and structural assessments[180] of the headgates and found that the headgates could no longer be relied upon for emergency closure or for single device isolation. In SNC Lavalin's assessment report, it was determined that stresses in all three headgate skinplates were far beyond acceptable limits and that the headgates for units WH1 and WH2 needed to be replaced due to extensive corrosion.[181] While the headgate for unit WH3 could be refurbished, SNC Lavalin indicated that replacement was favourable since it involved less risk of cost and schedule variation and could result in a longer service life.[182] YEC indicated that failure to close during emergency conditions could result in a unit over-speed that could cause severe damage to a hydro unit and the plant itself.

269. YEC planned to replace the headgates for all of the units at the P125 Hydro Plant and stated that the scope of the P125 Headgate Replacement Project included removing the existing headgates, designing and installing new headgates and control systems, and refurbishing the headgate hoist mechanism.[183] YEC tendered and proceeded with work on the headgate for unit WH2 in 2020 and stated in its Application that it was assessing team capacity to complete

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178 2021 General Rate Application, Section 5.2.1.7, pages 5-16 to 5-17, PDF pages 129-130.
179 YEC Consolidated IR Responses, YUB-YEC-1-56(b), Attachment 1, page 4, PDF page 1992.
180 Ibid., YUB-YEC-1-56(b), Attachments 1 and 2, PDF pages 1989-2012 .
181 Ibid., YUB-YEC-1-56(b), Attachment 1, page 14, PDF page 2002.
182 Ibid., YUB-YEC-1-56(b), Attachment 1, page 14, PDF page 2002.
183 2021 General Rate Application, Section 5.2.1.8, page 5-17, PDF page 130.

replacement and refurbishment of the headgates for units WH1 and WH3 in 2021.[184] YEC's costs for the project amounted to $5.893 million, which included the actual capital spending amount for 2019 and the forecast capital spending amount for 2020 and 2021.[185] However, during YEC's annual business planning process, YEC determined that the replacement and refurbishment of the headgates for units WH1 and WH3 would be deferred to 2022 and 2023, respectively. Thus, YEC updated the actual costs for this project to $2.072 million to reflect the work it actually conducted on the headgate for unit WH2 alone.[186]

Board Findings

270. The Board finds there is a necessity for this project, given the age of the headgates and based on the results of tests and assessments conducted by SNC Lavalin. The Board also finds YEC acted reasonably in updating its costs for this project since headgate work for units WH1 and WH3 was delayed to 2022 and 2023, respectively. For these reasons, the Board finds the actual capital spend of $2.072 million for this project reasonable. However, this $2.072 million will not be added to the 2021 rate base, as the project is not complete. Costs for this project will only be added to rate base once the project is complete and YEC provides the actual capital spending amount incurred in the next GRA.

5.3.2.7 WH2 Uprate Project

271. YEC stated that the purpose of the WH2 Uprate Project was to resolve existing issues around unit WH2 and to help address the existing capacity shortfall in the near term. YEC mentioned that issues had been identified with oil leaks from the runner blade to hub seals, with possible voids in the concrete behind the draft tube liner.[187] Additionally, YEC indicated the project could help address the existing capacity shortfall by adding 6.4 GWh of generation per year.[188] YEC stated the project was expected to increase dependable capacity of the WH2 unit by 0.94 MW.

272. In 2017, YEC contracted Hatch Ltd to conduct a technical and economic study that considered uprating units WH1, WH3 and WH4 at the Whitehorse Rapids Generating Station.[189] Because the WH1 and WH2 units were identical, Hatch stated that the issues, costs and benefits relating to the WH1 unit also applied to the WH2 unit.[190] In the report, Hatch indicated that the principal benefit of uprating the turbines was the ability for YEC to offset more costly thermal generation and that replacing the existing turbine runners with a new runner of modern design would increase generating unit efficiency and power output.[191]

273. Hatch concluded that uprating the WH1 unit resulted in a positive economic benefit, with a net present value between $0.2 million and $2.26 million over a 30-year lifetime and a payback period of 9 to 19 years.[192] Hatch estimated a cost of approximately $1.99 million for uprating the

184 Ibid., Section 5.2.1.8, page 5-17, PDF page 130.
185 YEC Consolidated IR Responses, YUB-YEC-1-49, page 3 of 7, PDF page 1499.
186 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 10 of 29, PDF page 146.
187 2021 General Rate Application, Section 5.2.1.9, page 5-18, PDF page 131.
188 Ibid., Section 5.2.1.9, page 5-18, PDF page 131.
189 YEC Consolidated IR Responses, YUB-YEC-1-57(d), Attachment 1, pages 1-136, PDF pages 2043-2178.
190 Ibid., YUB-YEC-1-57(d), Attachment 1, page 8, PDF page 2050.
191 Ibid., YUB-YEC-1-57(d), Attachment 1, page 5, PDF page 2047.
192 Ibid., YUB-YEC-1-57(d), Attachment 1, page 66, PDF page 2108.

WH1 unit and maintaining the same turbine flow and approximately $4.78 million for uprating the unit and increasing the turbine flow.[193] Uprating the WH1 unit increased efficiency by approximately four percent and allowed for a 10-percent increase in turbine flow.[194] Another alternative proposed by Hatch was the "replacement of the cams that define the WH1 and WH2 wicket gate runner blade relationship…"[195] This alternative presented an efficiency gain of two percent and still allowed for an offset in thermal generation, though the offset amount would be half that of the WH2 Uprate Project.[196]

274. YEC decided to uprate the WH2 unit over the WH1 unit since the WH2 unit produced more energy and the WH2 governor was having issues with power control.[197] YEC indicated that the scope of work included unit rehabilitation, runner replacement, generator station and rotor rewinding, governor replacement, exciter replacement and upgrading the control and condition monitoring systems.

275. YEC estimated a cost of $12.038 million in its Application, which included the actual capital spending amounts for 2019 and the forecast capital spending amounts for 2020 and 2021.[198] However, in response to the Board's second round of information requests, YEC updated the cost for the project to $12.267 million to reflect the project's actual costs for 2020 and an updated forecast capital spending amount for 2021.[199] Respecting the variance, YEC indicated that once the WH2 unit was disassembled, it undertook assessments of embedded and removable components. YEC stated that the assessments revealed that the condition of the components was worse than expected and that these components had to be refurbished. YEC also found that certain components of the WH2 unit were misaligned and that additional machining was required to bring the components back to proper alignment.

276. YEC noted that costs for the project also included an additional $0.259 million for the WH2 Uprate Engineering Study,[200] for which costs were allocated in this Board Order under Section 5.3.3 – Deferred Costs.

Board Findings

277. With respect to the WH2 Uprate Project, the Board finds there is value in addressing the existing capacity shortfall and offsetting thermal generation but is not persuaded that the applied-for costs for this project are reasonable. YEC's costs for this project were $12.267 million even though Hatch's cost estimates for uprating the WH1 unit, which would be similar to the cost estimates for uprating the WH2 unit, were approximately $1.99 million with the same original turbine flow and $4.78 million with an increase in turbine flow. However, YEC never discussed the reasons for these cost differences in its business case or why the WH2 Uprate Project exceeded the Hatch estimates. Additionally, Hatch presented an alternative in its report that also allowed for efficiency gain of two percent and an offset in thermal generation half of that achieved with the WH2 Uprate Project. YEC did not discuss this alternative, any costs associated

193 Ibid., YUB-YEC-1-57(d), Attachment 1, page 23, PDF page 2065.
194 Ibid., YUB-YEC-1-57(d), Attachment 1, page 15, PDF page 2057.
195 Ibid., YUB-YEC-1-57(d), Attachment 1, page 67, PDF page 2109.
196 Ibid., YUB-YEC-1-57(d), Attachment 1, page 67, PDF page 2109.
197 Ibid., YUB-YEC-1-57, page 5 of 5, PDF page 2039.
198 2021 General Rate Application, Section 5.2.1.9, page 5-19, PDF page 132.
199 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 11 of 29, PDF page 147.
200 2021 General Rate Application, Appendix 5.4, pages 5.4-3 to 5.4-4, PDF pages 188-189.

with this alternative, and the reasons for dismissing this alternative over the proposed project in its business case. While the metrics associated with Hatch's alternative are quantified at a lesser value compared to the WH2 Uprate Project, the Board finds that the reduction in efficiency gain and thermal generation offset is not notably significant. Finally, while Hatch concluded a positive economic benefit from the project, it indicated uncertainty in both the measured performance of the existing unit and the predicted performance of an uprated turbine. Hatch also commented that the payback period was fairly long even under higher demand assumptions.[201]

278. Given the business case, the Board finds YEC's business plan for this project did not adequately justify the costs and benefits of this project, nor did it adequately explain the reasons the project was the preferred alternative. Given the Board's concerns with the reasonableness of the costs, the recommendations in the Hatch report and the deficiencies in the business case, the Board finds it appropriate to approve costs of $4.78 million, which was the Hatch cost estimate for uprating a unit with increased turbine flow, plus 20 percent for cost overruns. The Board directs YEC to include this cost in its compliance filing.

5.3.2.8 WH4 Uprate Servomotor Replacement Project

279. YEC advised that the purpose of pursuing the WH4 Uprate Servomotor Replacement Project related to its 10-year renewable electricity plan to provide incremental sources of renewable energy in the short to medium term. YEC stated the primary benefit of this project was a 0.8 MW increase in the maximum output of WH4, resulting in an estimated energy production gain of 0.9 GWh per year, and that the secondary benefits included reduced stress levels in the servomotors, governor and wicket gates.[202] YEC noted that the current servomotors were not meeting industry code in terms of operation and reliability and that, because of the undersized servomotors, gate opening was only 92 percent and the WH4 output was consequentially limited.[203]

280. For this project, YEC replaced the existing servomotors with spring-assisted servomotors that would allow the WH4 unit to operate at 100-percent gate opening, which in turn would increase the energy and capacity of the unit.[204] YEC stated that this project involved the detailed design, procurement and installation of the two new servomotors. In its Application, YEC forecast costs of $1.531 million for this project, which included the actual capital spending amounts for 2018 and 2019 and the forecast capital spending amounts for 2020 and 2021. However, in response to the Board's second round of information requests, YEC updated the costs of the project to $1.400 million to reflect actual costs in 2020 and an updated forecast capital spending amount for 2021.[205]

Board Findings

281. The Board finds there is a value for the WH4 Uprate Servomotor Replacement Project in 2021 but is not persuaded that the applied-for costs are reasonable. YEC, as part of its responses to the Board's second round of information requests, provided the Hatch report's recommendation to replace the existing servomotors. In that report, Hatch provided a cost

201 YEC Consolidated IR Responses, YUB-YEC-1-57(d), Attachment 1, page 66, PDF page 2108.
202 Ibid., YUB-YEC-1-58, page 2 of 3, PDF page 2180.
203 YEC Consolidated IR Responses, YUB-YEC-1-58, page 3 of 3, PDF page 2181.
204 Ibid., YUB-YEC-1-58, page 3 of 3, PDF page 2181.
205 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 12 of 29, PDF page 148.

estimate of $457,000 for replacing the servomotors.[206] During the proceeding, YEC did not explain why the costs for this project increased from the original Hatch cost estimate. Thus, the Board finds that YEC did not provide an adequate business case or justification that supports the significant cost increase from the original Hatch estimate. Furthermore, the Board finds that the benefits espoused by YEC do not fully justify the costs that were incurred or forecast for this project. The WH4 unit will have an additional maximum output of 0.8 MW once this project is completed, but the unit will not always be operating at its maximum output. Additionally, the improvement in operating the unit with 100-percent gate opening is not significant, especially when the unit was operating with 92-percent gate opening.

282. Accordingly, given the Board's concerns with the reasonableness of the costs and a lack of a business case for the project to support the magnitude of costs compared to the expected benefits for the project, the Board finds it appropriate to approve costs of $457,000 based on the Hatch cost estimate, plus 20 percent for cost overruns, which amounts to $548,400. The Board directs YEC to include these updated costs in its compliance filing.

5.3.2.9 Projects between $100,000 and $1 million

283. YEC stated that the costs for this category included spending for the following project classifications: (i) generation; (ii) transmission; (iii) distribution; (iv) general plant and equipment; and (v) overhauls and reserve for site restoration.

284. YEC submitted a net rate base impact of $3.105 million for generation projects[207] and indicated that the actual and forecast capital spending included projects required to address prior and recent dam safety review recommendations and to sustain capital requirements.[208] YEC submitted a net rate base impact of $2.608 million less $0.55 million in contributions for transmission projects[209] and advised that actual and forecast capital spending focused on upgrading transmission lines and substations and meeting safety, reliability and/or regulatory requirements.[210] YEC submitted a net rate base impact of $2.491 million less $2.011 million in contributions for distribution projects[211] and indicated actual and forecast capital spending focused on customer extensions and addressing voltage issues and system improvements.[212] YEC submitted a net rate base impact of $4.190 million for general plant and equipment projects[213] and indicated actual and capital forecast spending focused on completing required communications and building upgrades, as well as addressing sustaining capital requirements.[214] Finally, YEC submitted a net rate base impact of $1.753 million, which included actual and forecast capital spending for overhauls and reserve for site restoration projects.[215]

206 Ibid., YUB-YEC-2-23(a), Attachment 1, page 20 of 56, PDF page 213.
207 YEC Final Argument, Section 3.2, page 40, PDF page 43.
208 2021 General Rate Application, Appendix 5.2, page 5.2-1, PDF page 167.
209 YEC Final Argument, Section 3.2, page 40, PDF page 43.
210 2021 General Rate Application, Appendix 5.2, page 5.2-4, PDF page 170.
211 YEC Final Argument, Section 3.2, page 40, PDF page 43.
212 2021 General Rate Application, Appendix 5.2, page 5.2-6, PDF page 172.
213 YEC Final Argument, Section 3.2, page 40, PDF page 43.
214 2021 General Rate Application, Appendix 5.2, pages 5.2-7 and 5.2-8, PDF pages 173-174.
215 YEC Final Argument, Section 3.2, page 40, PDF page 43.

285. In its response to the Board's information requests, YEC provided updated costs for the following projects:[216]

- Dam Safety Recommendation 2017-18 Project – updated from $681,995 in the Application to $506,006[217] in the responses;
- Wareham Gate Refurbishment Project – updated from $250,000 in the Application to $146,300[218] in the responses;
- WH4 Ventilation Project – updated from $750,000 in the Application to $150,000[219] in the responses;
- L177 Re Route Project – updated from $355,000 in the Application to $178,600[220] in the responses;
- Protection and Control Program Project – updated from $300,000 in the Application to $125,000[221] in the responses;
- Transmission Line Access Project – updated from $839,300 in the Application to $541,900[222] in the responses;
- Mayo Earthworks Project – updated from $300,000 in the Application to $87,900[223] in the responses;
- New Mobile Office Unit Project – updated from $230,000 in the Application to $0[224] in the responses;
- Vehicle Purchases Project – updated from $1,574,400 in the Application to $1,476,200[225] in the responses;
- Water Improvement Upgrades Project – updated from $150,000 in the Application to $63,000[226] in the responses;
- FD7 Overhaul Project – updated from $580,000 in the Application to $0[227] in the responses;

216 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, pages 14, 15 and 25-28 of 29, PDF pages 150, 151 and 161-164.
217 $109,720 + $272,275 + $124,011 = $506,006 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 14 of 29, PDF page 150.
218 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 25 of 29, PDF page 161.
219 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 25 of 29, PDF page 161.
220 $103,600 + $75,000 = $178,600 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 25 of 29, PDF page 161.
221 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 26 of 29, PDF page 162.
222 $215,400 + $323,900 + $2,700 = $541,900 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 26 of 29, PDF page 162.
223 $37,900 + $50,000 = $87,900 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 26 of 29, PDF page 162.
224 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 26 of 29, PDF page 162.
225 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 27 of 29, PDF page 163. The Board notes that the costs are an aggregation of vehicle purchases from 2018 to 2021. The costs on an annual basis were under $1 million, hence its inclusion in this section.
226 $56,300 + $6,800 = $63,000 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 27 of 29, PDF page 163.
227 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 27 of 29, PDF page 163.

- Compact Digger Truck Project – updated from $185,000 in the Application to $0[228] in the responses; and
- Building Upgrades Project – updated from $721,737 in the Application to $683,017[229] in the responses.

286. YEC indicated that costs were updated due to refinement of the scope of work, lower than expected actual and forecast costs in some areas, deferral of projects to later dates, or because only high-level estimates were available at the time of filing the GRA.

Board Findings

287. The Board is not prepared to approve the costs for the WH4 Ventilation Project. YEC pursued this project to mitigate overheating issues seen with the WH4 unit during the summertime, which it currently addresses by limiting the summer output capacity. With this project, YEC stated it could obtain extra capacity from the unit. As part of its responses to the Board's information requests, YEC included a Hatch report studying the capacity increase at the WH4 unit.[230] Hatch determined that the unit's operating temperature at its maximum power output, or 23.6 megavolt ampere (MVA), was 87 degrees Celsius (°C) and that the unit could be operated above the 23.6 MVA rating without exceeding the stator temperature limits.[231] While the Board has a good understanding of the WH4 unit's operating limits, because insufficient information was provided by YEC, it is unclear whether temperatures during the summer caused the unit to exceed operational limits in a manner that would impact the unit. Additionally, the original 2021 forecast of this project was $750,000, which was then reduced to $150,000 because YEC delayed the project and needed to conduct additional studies to determine greater cost certainty.[232] Given this missing information and the fact that the project is delayed for additional studies, the Board finds YEC has not adequately supported the business case for this project and finds it is not necessary at this time. Thus, the Board denies the costs for the WH4 Ventilation Project and directs YEC to reflect this denial in the compliance filing.

288. The Board has reviewed the rationale provided and costs for the remaining projects in this category and finds that the actual and forecast costs for these projects appear to be reasonable. The Board notes that not all projects for this category were explicitly mentioned in the preceding paragraphs. If a project was not specifically addressed, it was because the Board considered that YEC's costs associated with the project are reasonable.

289. The Board directs that YEC include the updated costs, excluding the WH4 Ventilation Project, for any projects that have been completed prior to or during the 2021 test year period. Costs for these projects will only be added to rate base once YEC provides the actual capital spending amount in the next GRA and demonstrates that the costs were prudently incurred.

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228 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 28 of 29, PDF page 164.

229 $76,807 + $369,930 + $236,280 = $683,017 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 15 of 29, PDF page 151.

230 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-23(a), Attachment 1, PDF pages 194-249.

231 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-23(a), Attachment 1, pages 17-18 of 56, PDF pages 210-211.

232 Ibid., YUB-YEC-2-17, page 25 of 29, PDF page 161.

5.3.3 Deferred Costs

290. YEC indicated that spending for deferred costs included feasibility studies for a wide range of projects, continued relicensing work, regulatory work and dam safety review work. YEC had a total of two major projects, with a forecasted amount of $4.478 million in the 2021 test year, and a total of 12 deferred projects between $100,000 and $1 million, with a forecasted amount of $4.046 million. These cost amounts were originally provided in the GRA and in YEC's responses to the Board's second round of information requests.

291. The major projects in this Application are as follows:

- Aishihik Relicensing – Three-Year Licence Renewal; and
- Demand-Side Management.

292. The following subsections address the major projects individually and the capital projects between $100,000 and $1 million. For the reasons that follow, the Board does not accept the full amount of applied-for costs for either categories of projects.

5.3.3.1 Aishihik Relicensing – Three-Year Licence Renewal

293. YEC stated the Aishihik Generating Station (AGS) facility licence was set to expire at the end of 2019 and that a water use licence renewal was required for the continued operation of the AGS facility. YEC begin a process in 2016, working with the Champagne and Aishihik First Nations (CAFN), to prepare a long-term renewal application for review and approval before the end of 2019. YEC had to adjust the regulatory review timelines beyond 2019 due to delays in filing the *Yukon Environmental and Socio-economic Assessment Act* (YESAA) project proposal. In order to avoid a lapse in YEC's water use licence, YEC brought forward the AGS Relicensing Project Proposal in February 2019 for a renewal term of three years. YEC stated that over the course of 2019 and 2020, it completed the regulatory review process and incurred costs related to YESAA-designated office review, the preparation of its Yukon Water Board application, the preparation of an application to extend its federal *Fisheries Act* authorization, and costs related to negotiations with CAFN.[233] In its Application, YEC provided a project cost of $1.005 million, which included the actual capital spending amount for 2019 and the forecast capital spending amount for 2020. In response to the Board's second round of information requests, YEC updated the project cost to $916,872, indicating the actual costs for 2020 were lower due to project management and assessment costs being lower than initially forecast in the Application.[234]

Board Findings

294. The Board finds the costs incurred for the Aishihik Relicensing Project were necessary, given that there is a need for YEC to renew its water use licences associated with the AGS facility, and that the applied-for costs are reasonable. As such, the Board directs YEC to include the updated cost of $916,872 in the 2021 rate base.

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[233] 2021 General Rate Application, Section 5.3.1.1, pages 5-21 to 5-22, PDF pages 134-135.
[234] YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 16 of 29, PDF page 152.

5.3.3.2 Demand-Side Management

295. YEC summarized the DSM net costs requested to be included in rate base or forecast for 2021 as follows: The updated DSM net cost is $68,307 for 2019, $91,545 for 2020 and $120,000 for 2021. As such, the overall updated DSM net cost forecast for 2019, 2020 and 2021 is $279,852. YEC's $279,852 in DSM costs for 2019-21 consists of the following:

- Residential Demand Response Pilot - $186,266 ($68,307 in 2019, $82,969 in 2020, and $35,000 in 2021), net of contributions ($365,315 in 2019, $488,932 in 2020, and $215,000 in 2021). This is a pilot program testing, internet connected, Wi-Fi-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.

- LED Street Light Retrofit Program (High pressure sodium vapor [HPS] light disposal) and inCharge maintenance - $8,576 in 2020.

- DSM Program Design - $85,000 in 2021.[235] [236]

296. YEC referred to the Yukon government's climate change policy initiative called *Our Clean Future*: A Yukon strategy for climate change, energy and a green economy in support of its DSM programs.[237] YEC stated that this policy emphasizes the importance of DSM as a valuable resource to reduce the Yukon's energy and capacity requirements.[238] In response to UCG-YEC 1-46, YEC confirmed that it has not yet initiated the implementation of any DSM programs that are complimentary to the inCharge program.[239]

297. With respect to DSM Program Design, YEC explained that it has engaged with the Yukon government to ensure that the existing DSM programs offered or planned by the Energy branch are considered in YEC's program design to avoid duplication.[240] In response to Board IRs,[241] YEC noted that since OIC 2021/16 — which relates to DSM programs — was not issued

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235 2021 General Rate Application, page 5-42, PDF pages 137-138; Exhibit B-9, YUB-YEC-1-59, pages 2-4, PDF pages 2183-2186 ; YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, pages 17-18 of 29, PDF pages 153-154; 2021 General Rate Application Proceeding Transcript, Volume 2, September 28, 2021, pages 192-193, PDF pages 24-25; YEC Final Argument, page 39, PDF page 42; YEC Consolidated IR Responses.

236 In its application, YEC originally applied for: $0.833 million up to the end of 2019 and forecast $0.375 million in 2020 and $0.894 million in 2021, with contributions of $0.365 million in 2019, i.e., net rate base impact of approximately $1.737 million by the end of 2021 excluding reductions due to amortization for various demand-side management (DSM) projects [2021 General Rate Application, PDF pages 136-138].

237 *Our Clean Future: A Yukon strategy for climate change, energy and a green economy*, last updated September 2020.

238 2021 General Rate Application, page 5-23, PDF page 136.

239 The inCharge program included LED lighting, automotive heater timer rebates, and low-cost, energy efficient products program components. The Board approved the inCharge program in Board Order 2014-06, Yukon Utilities Board Order 2014-06, Appendix A: Reasons for Decision, April 23, 2014, pages 100-101, PDF pages 105-106. At the oral hearing, YEC confirmed that the inCharge program has been completed and stopped in 2020 [General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 270, PDF page 102].

240 YEC Consolidated IR Responses, Round 2, Exhibit B-27, YUB-YEC-2-31(d), page 4 of 4, PDF page 416; 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, pages 196-198, PDF pages 28-30.

241 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-59(b);

until February 2021, the DSM 2020 program costs were delayed, resulting in lower actual 2020 costs of $0.092 million (compared to $0.375 million forecast for 2020 in the Application). The only DSM program costs in 2020 were related to the Residential Demand Response Pilot and a small amount for HPS light disposal and administering the inCharge rebate.

298. Additionally, the scope of work initially included implementation of a full suite of DSM programming in 2021, assuming program design was completed in 2020. Since the program design completion was shifted to 2021, the program implementation costs have also been shifted for completion to 2022 and beyond. The result is lower 2021 costs of $0.600 million compared to $0.894 million of 2021 costs forecast in the Application.[242] In response to Board IR round 2, YEC further updated the 2021 forecast DSM costs from $0.600 million to $0.120 million based on completing program design and the costs of the demand response pilot after funding contributions.[243]

299. For the Residential Demand Response Pilot, YEC noted that the Yukon government's climate change policy initiative provided the following policy directions regarding DSM:

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

- YEC is to complete the Peak Smart pilot project[244] by 2022 to evaluate the use of smart devices to shift energy demand to off-peak hours.[245]

300. The pilot is underway and is managed by YEC with funding support from AEY, Yukon Development Corporation, and Natural Resources Canada (NRCan). During the hearing, YEC confirmed that the installation of the devices, the recruitment of participants, and the running of test events over the 2020-21 winter are what has been completed in the pilot so far. The plan is to complete the pilot in 2022.[246]

301. With respect to the LED Street Light Retrofit Program, YEC applied-for costs related to the continuation of this program. YEC noted that in Board Order 2018-10, the Board approved the continuation of the LED Street Light Retrofit Program because it "considers that retrofitting street lights 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."[247] Street lights in downtown Dawson and Mayo were retrofit in 2016 with plans to retrofit the remaining street lights in Faro, Mendenhall and Champagne in 2018. As a result, $0.273 million was added to rate

YEC Consolidated IR Responses, Round 2, Exhibit B-27, YUB-YEC-2-17, PDF page 153.

242 YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-59, pages 1-4 of 4, PDF pages 2183-2186. Exhibit B-27, YUB-YEC-2-35, pages 1-3 of 3, PDF pages 428-430.

243 YEC Consolidated IR Responses, Round 2, Exhibit B-27, YUB-YEC-2-17, page 18 of 29, PDF page 154.

244 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 194, PDF page 26. In the hearing, YEC confirmed that "…the Peak Smart program is the residential demand response pilot. So the name that we use for that program is the Peak Smart pilot, so they're one in the same."

245 2021 General Rate Application, page 5-24, PDF page 137.

246 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 194, PDF page 26.

247 Board Order 2018-10, paragraph 481, page 91 of 118, PDF page 96.

base in 2018.[248] In response to YUB-YEC-2-13, YEC confirmed that there were still 194 high pressure sodium street lights in service by the end of 2018. Costs of $0.008 million were added in 2020 for the environmental disposal of the old HPS street light heads.[249] YEC confirmed that no street light retrofitting costs were added to rate base for 2019, 2020 and 2021.[250]

5.3.3.2.1 History of DSM and Board guidance on future recovery of costs for DSM programs

302. Until recently, the Board had full discretion to approve or deny DSM programs and associated costs under the act and Rate Policy Directive (1995). YEC has proposed that DSM programs be recovered from ratepayers since at least 1992.[251]

303. Part 2 of the *Public Utilities Act* addresses the regulation of public utilities. Sections 27 to 29 set out the Board's authority to set rates and the requirements of the public utility when it proposes a new rate. Section 27(a) allows the Board to make orders setting the rates of a public utility. Section 27(b) allows the Board to make orders prohibiting or limiting any proposed rate change. Section 28(2) specifies that no public utility shall begin to charge a new rate except on receipt from the Board of an order authorizing it to do so. Section 29 sets out the factors affecting the setting of just and reasonable rates, including that the Board may consider the revenues and costs of the public utility that relate to a proceeding before the Board. Pursuant to Section 32, the Board must determine a rate base for the property of a public utility used or required to be used to provide service to the public.

304. In a February 5, 2021, judgment, the Yukon Court of Appeal found that the Board was entitled to exercise its discretion under Section 32(1) in setting Yukon Energy's rate base. Justice Tysoe, on behalf of the court, also confirmed that, in setting a rate base under Section 32(1) of the act, "…the wording gives the Board a discretion to include in a rate base any property that is used to provide service or to include only property that is required to be used for the provision of the service."[252] The Board also had discretion not to include the costs of such programs in Yukon Energy's rate base.[253]

305. The Government of Yukon issued OIC 2021/16 on February 11, 2021, which added sections to the Rate Policy Directive (1995) for the recovery of costs for DSM programs. The result of this OIC is that "demand-side management programs" are now defined in Subsection 10(1) of the Rate Policy Directive (1995) as "a measure, action or program intended to promote customer use of electricity that optimizes economy or efficiency of electricity

248 2021 General Rate Application, page 5-25, PDF page 138.

249 Exhibit YEC Consolidated IR Responses, Exhibit B-9, YUB-YEC-1-62(c), page 2 of 2, PDF page 2196; YEC Response to Undertakings, #6 at page 221, page 1, PDF page 9: In an undertaking, YEC explained that high pressure sodium street lights contain mercury and are therefore considered hazardous waste. Yukon Energy paid a local accredited disposal company (KBL Environmental Ltd.) to safely dispose of retired HPS street lights at a cost of $7,900.

250 YEC Response to Undertakings, #7, page 10, PDF page 10.

251 In Appendix A to Board Order 2019-05: Review of Yukon Utilities Board Order 2018-10 the review panel of the Board noted at Footnote 20 that "Earlier Yukon Utilities Board Orders dealing with Yukon Energy Corporation's DSM programs in terms of: the reasonableness of Yukon Energy Corporation's DSM programs and forecast costs for the 1991-92 revenue requirement found in Board Order 1992-1 re: Yukon Energy Corporation, January 17, 1992, at pages 45-47.

252 *Yukon Energy Corporation v Yukon (Utilities Board)*, 2021 YKCA 1, paragraph 25, page 9, PDF page 9.

253 Ibid., paragraphs 31 and 33, pages 10-11, PDF pages 10-11.

generation or transmission of a public utility, including the promotion of customer use of electricity that (a) is more efficient, or (b) better aligns electricity supply and demand." Because of the OIC, the Board must include in rates for retail customers and major industrial customers the costs the public utility reasonably incurs to provide or participate in a DSM program (Subsection 10(2)). Pursuant to Subsection 10(3), the Board must consider the extent of any duplication between the DSM program for which costs are incurred and a DSM program provided by the Government of Yukon or in which the Government of Yukon is a participant. Subsection 10(4) set out the OIC's retroactive application to YEC's 2021 GRA that had already been filed with the Board when the OIC was issued.

306. Given Section 10 of the OIC, in assessing YEC's Application, the Board must consider whether the programs applied for meet the definition of a "demand-side management program" and apply the OIC to YEC's proposed DSM programs for 2021.

307. As stated above, Section 10 requires the Board to include in the rates of a public utility for retail and industrial customers the recovery of reasonably incurred costs for DSM programs if the definition of a "demand-side management program" is met. The Board finds that it must continue to assess whether the costs associated with DSM programs meet the requirements of Part 2 of the *Public Utilities Act* and the Rate Policy Directive (1995), i.e., the prudent recovery of costs and the setting of just and reasonable rates. In doing so, the Board will assess the cost recovery of DSM programs consistent with this legislative framework, and it will consider the following for the current Application and for future applications:

- The explanation of how the proposed DSM program meets the definition of a "demand-side management program" set out in Subsection 10(1) of the Rate Policy Directive (1995). Public utilities have the burden of proof of demonstrating that a program meets the definition of a "DSM program" and is a DSM program to which Section 10 applies.

- A business case justifying the cost recovery for DSM programs must be provided to support: (i) that duplication with government programs has been avoided, (ii) whether the program will be a short-term or long-term program, (iii) the preferred option for the timing of implementation with alternative timing options for the program, (iv) the costs associated with each option, and (v) other relevant information, including input from stakeholders and the Yukon government that may impact DSM program costs.

- For DSM programs that have been approved in a past GRA or other application, the public utility must provide reporting on the following:

    - How the program optimizes economic or efficient electricity generation;

    - How the program better aligns electricity supply and demand;

    - Why the costs were reasonably incurred for retail and major industrial customers to provide or participate in a DSM program; and

    - A cost/benefit analysis demonstrating how the program was evaluated, key performance indicators, the results of the program including such factors as decreasing demand or load, any generation costs that have been avoided due to the program, and the total cost impact of the program on the public utilities rates.[254]

308. As stated in Board Order 2014-06, the Board must carefully weigh the benefits arising from the program with the costs of implementing the program.[255] For its proposed DSM program that it is requesting cost recovery from ratepayers, YEC is expected to continue to work in conjunction with the Government of Yukon to ensure that duplication is avoided. As stated above, evidence of how duplication was avoided should be included in any DSM program business case. An affidavit from a senior officer of YEC or, if an affidavit is not practicable, other supporting evidence should be provided to verify that duplication was avoided with Government of Yukon programs. For its proposed DSM program that involves retail customers, YEC should consult with AEY regarding the expected costs of implementing a DSM program and the impact upon retail customers in the AEY's service area.

309. Any supply-side options or programs for increasing energy efficiency and energy conservation must be submitted to the Board for approval in a separate YEC business case because supply-side options were not included in OIC 2021/16. Therefore, supply-side programs are subject to the Board's usual discretion and authority for approval in rates pursuant to Part 2 of the *Public Utilities Act*.

5.3.3.2.2 Board Findings on 2021 costs for DSM programs

310. UCG objected to YEC's DSM costs "to the tune of $1.737 million in the 2021 test year" and stated that these costs should not be approved. UCG submitted that it was difficult to determine exactly what costs YEC was applying to the Residential Demand Response Pilot and what costs they were applying to other DSM portfolio costs. UCG argued that no DSM costs from the Residential Demand Response Pilot or other DSM costs should go into rate base.[256] The Board agrees with UCG that YEC's requested DSM costs were difficult to follow because of changing circumstances, as were the updates provided during the course of the proceeding, particularly because some of the costs were updated after OIC 2021-16 was issued. While some updates are unavoidable over the course of a proceeding, it was not until final argument that YEC confirmed that the DSM Program Design would be completed in 2021, with program implementation shifted to 2022 or later and some costs written off. Therefore, its DSM cost amounts were adjusted for 2019, 2020 and 2021 to $279,852 rather than the $1.737 million included in the Application.[257] The Board is sympathetic with UCG's argument that it was difficult to follow numerous DSM cost adjustments and updates and directs YEC in future GRAs to provide any DSM cost updates and variance explanations at the time of filing its rebuttal evidence.

311. However, the Board disagrees with UCG that no DSM costs should be approved. The Board has reviewed the evidence on the record of the proceeding and accepts YEC's explanation

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[254] Some of the information in this bullet has been provided in past proceedings. For example, in past applications, YEC has provided four cost effectiveness measures for DSM costs. Board Order 2014-06, Appendix A: Reasons for Decision, page 95 of 105, PDF page 100, reads: "…four standard cost-effectiveness tests, namely the total resource cost test (TRC), the program administration cost test (PAC), the rate-impact measure test (RIM), and the participant cost test (PCT).

[255] Board Order 2014-06, Appendix A: Reasons for Decision, page 100 of 105, PDF page 105.

[256] UCG Final Argument, Section 89, PDF page 20.

[257] YEC Final Argument, page 39, PDF page 42.

for the adjusted DSM costs of $279,852 for 2019, 2020 and 2021. The Board finds that the YEC actual and forecast for Residential Demand Response Pilot at $186,266 ($68,307 in 2019, $82,969 in 2020 and $35,000 in 2021) and DSM Program Design of future DSM programs forecast at $85,000 in 2021 are reasonable for the following reasons.

312. For the Residential Demand Response Pilot, the Board accepts YEC's submissions that the costs that were incurred for this pilot program in 2019, 2020 and 2021 were related to the government's direction for YEC to "evaluate the use of smart devices to shift energy demand to off-peak hours." The costs of the pilot were not substantial given the magnitude and the nature of the pilot program which was used to evaluate a method to shift energy demand to off-peak hours, as well as the fact that this pilot project received funding support from AEY, YDC, and NRCan. For the DSM program design, the Board accepts YEC's explanation that, because YEC engaged with the Government of Yukon to ensure that the existing DSM programs offered or planned by the Energy branch were considered in YEC's program design, duplication with Government programs was avoided.

313. For the LED Street Light Retrofit Program, the Board also accepts YEC's explanation at the oral hearing that there were no street light retrofitting costs added to rate base for 2019, 2020 and 2021. Regarding the $8,576 added in 2020 for the LED Street Light Retrofit Program, HPS light disposal and inCharge maintenance, the Board accepts YEC's explanation in an undertaking that HPS street lights contain mercury and are therefore considered hazardous waste, requiring safe disposal. Included in the costs was $7,900 for YEC to pay a local accredited disposal company (KBL Environmental Ltd.) to safely dispose of retired HPS street lights. The Board observes that total costs of $8,576 was necessarily related to the program, and this is not a material amount. The Board accepts the inclusion of the $8,576 for the LED Street Light Retrofit Program as filed.

314. Similarly, the DSM program design of future DSM programs at a forecast cost of $85,000 in 2021 was also supported and is approved as filed.

5.3.3.2.3 Projects between $100,000 and $1 million

315. YEC stated that the costs for projects between $100,000 to $1 million included capital spending for studies undertaken for potential renewable generation options, studies to ensure continued reliability or to determine requirements for business improvements for existing assets, and studies for regulatory and dam safety review. YEC submitted rate base additions of $1.267 million, $1.551 million and $1.228 million for studies undertaken for potential renewable generation options, for studies undertaken to ensure reliability or for business improvements and for regulatory and dam safety review, respectively.[258]

316. In its response to the Board's information requests, YEC provided updated costs for the following projects:[259]

- Mayo and Aishihik Hydro Climate Change Study – updated from $638,562 in the Application to $667,053[260] in the responses;

[258] 2021 General Rate Application, Appendix 5.4, pages 5.4-1 to 5.4-2, PDF page 186-187.
[259] YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, pages 19-21 and 28-29 of 29, PDF pages 155-157 and 164-165.

- Transmission Access Road Program Study – updated from $332,787 in the Application to $87,526[261] in the responses;
- IPP Standing Offer Program Implementation – updated from $232,039 in the Application to $330,057[262] in the responses;
- Mt. Sumanik Wind Feasibility Study – updated from $775,581 in the Application to $750,587[263] in the responses;
- 10-Year Renewable Electricity Plan – updated from $713,000 in the Application to $634,000[264] in the responses;
- Atlin Hydro EPA Preparation – updated from $200,000 in the Application to $516,700[265] in the responses;
- Dam Safety Review – updated from $315,000 in the Application to $253,600[266] in the responses;
- Building Condition Reports 2021-2024 – updated from $175,000 in the Application to $0[267] in the responses; and
- Whitehorse Diesel Rental Substation Improvements – updated from $100,000 in the Application to $0[268] in the responses.

317. For projects that had updated costs lower than originally forecast, YEC indicated that the updates were due to deferring projects to later dates, refining the scope of work, or savings in capital spending.

318. The Mayo and Aishihik Hydro Climate Change Study, IPP Standing Offer Program Implementation, and Atlin Hydro EPA Preparation had updated costs that were higher than originally forecast.

319. YEC stated that the Mayo and Aishihik Hydro Climate Change Study was required to understand the future climate change impacts on its hydrological system and its hydroelectric generation. More specifically, YEC advised that understanding the expected long-term impact of climate on its hydro resources was critical to its long-term resource planning, risk mitigation and developing adaptation plans.[269] While its current YECSIM model had 35 years of actual

260 $19,061 + $102,469 + $183,227 + $169,556 + $124,249 + $68,491 = $667,053 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 19, PDF page 155.

261 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 19, PDF page 155.

262 $48,127 + $183,912 + $48,018 + $50,000 = $330,057 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 20, PDF page 156.

263 $12,607 + $372,821 + $154,852 + $77,904 + $76,242 + $31,155 + $25,005 = $750,587 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 21, PDF page 157.

264 $310,800 + $323,100 = $634,000 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 28, PDF page 164.

265 $201,700 + $315,000 = $516,700 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 28, PDF page 164.

266 $173,600 + $80,000 = $253,600 (differences due to rounding). Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 29, PDF page 165.

267 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 29, PDF page 165.

268 Please see YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 29, PDF page 165.

269 YEC Consolidated IR Responses, YUB-YEC-1-63, page 2 of 4, PDF page 2198.

historical data, YEC indicated that this model did not predict or account for the expected future impact of climate change on the inflows. In contrast, the model developed as part of this study would not only allow YEC to incorporate historical actual data but also future climate change predictions. YEC stated that the original scope of the Mayo and Aishihik Hydro Climate Change Study only focused on the impact of climate change on the Mayo and Aishihik facilities. However, after reviewing the outcomes and the functionality of the model, YEC determined that the model could also be used for assessing the climate change impact on the Whitehorse facility. Thus, YEC expanded the scope of the project and the capital spending increased.[270]

320. YEC indicated that it developed the Independent Power Producer (IPP) Standing Offer Program Implementation based on the direction from the Government of Yukon to implement IPP policy.[271] YEC also advised that the documents developed as part of this project were contract templates and policy rules protecting ratepayers.[272] YEC stated the increase in project capital spending largely arose from increased legal costs, as the full scope of legal work was not known at the time it prepared the project budget.[273]

321. Atlin Hydro EPA Preparation costs are related to the negotiation of the Electricity Purchase Agreement (EPA) between YEC and the Tlingit Homeland Energy Limited Partnership (THELP). The Atlin Hydro EPA Preparation costs are reflective of the scope and costs of the Atlin Hydro Expansion project. YEC stated that the additional costs for this project were incurred when the proponent, THELP, hired new engineers, impacting the project economies and operating regime of the Atlin Hydro Expansion Project. Further, YEC submitted that the additional capital spending occurred due to the significant work required to collaborate on technical information and in developing a pricing regime for both capacity and energy for the Atlin Hydro EPA.[274]

Board Findings

322. The Board provides its specific reasons for the approval of the Mayo and Aishihik Hydro Climate Change Study and the Mt. Sumanik Wind Feasibility Study below. The Board is not prepared to approve the costs for the Atlin Hydro EPA Preparation project because YEC currently has an application for review of the Atlin EPA before the Board.[275] The Board finds it necessary to complete the regulatory process for the Atlin EPA before it can assess the prudence of costs for preparation work. Thus, the Board denies the costs for the Atlin Hydro EPA Preparation project and directs YEC to reflect this denial in the compliance filing.

323. For all other costs in this category, the Board has reviewed the business cases and costs for projects in this category and finds the actual capital spending for these projects prudent. The Board notes that not all projects for this category were explicitly mentioned in the preceding paragraphs. If a project is not specifically addressed, it is because the Board considered that

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270 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, pages 378-380, PDF pages 42-44.
271 2021 General Rate Application, Appendix 5.4, page 5.4-2, PDF page 187.
272 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 382, PDF page 46.
273 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 20 of 29, PDF page 156.
274 Ibid., page 28 of 29, PDF page 164.
275 Proceeding can be found through the following link: https://yukonutilitiesboard.yk.ca/proceedings/electricity-purchase-agreement-with-tlingit-homeland-energy/.

YEC's costs associated with the project are reasonable. To ensure that actual capital spending to the end of 2021 is accurately reflected in rate base, the Board directs YEC include the updated costs for any projects that have been completed prior to or during the 2021 test year period. Costs for these projects will only be added to rate base once YEC provides the actual capital spending amount in the next GRA.

324. The Board did not approve the applied-for costs for the Mayo and Aishihik Hydro Climate Change Study in Board Order 2018-10. At the time, the Board determined that YEC had not adequately demonstrated that the Mayo and Aishihik Hydro Climate Change Study was necessary given that the YECSIM model included climate change impacts.[276] However, the Board finds YEC has provided more support for the study and has demonstrated the necessity of the study in its Application, stating that the study will allow YEC to evaluate the long-term impacts of climate change on its energy supply and to develop strategies to mitigate potential impacts to utility operations and ratepayers.[277] The Board finds the outcomes of the study will help YEC in its long-term resource planning and accepts YEC's expansion of the scope to include the impacts on the Whitehorse facility. Thus, the Board finds the capital spending amount for this project reasonable and directs YEC to include the updated spending amount in the 2021 rate base.

325. YEC applied to amortize five years of costs for the Mt. Sumanik Wind Feasibility Study, which was decommissioned in 2020. Costs for this study were brought forward in the 2017/18 GRA proceeding, but the Board did not approve the applied-for costs at that time, determining that YEC did not provide adequate justification for the project benefits.[278] In this Application, YEC indicated that it initiated the project to complete early feasibility studies for potential wind farm sites throughout the Yukon and that Mt. Sumanik was identified as a particular site of interest.[279] YEC then installed wind monitoring equipment and engaged in data collection to assess the viability of wind resources on Mt. Sumanik. YEC noted that the need for this study has been eliminated since independent power producers are more likely to develop future wind resources.[280] YEC explained that the purpose of this study was assessing the potential for wind resources in the Yukon, which also aligns with the 2016 Resource Plan for reducing thermal generation. While the study was ultimately decommissioned, the Board is persuaded that YEC acted reasonably in undertaking the study given the alignment of the project with the resource plan.

326. For these reasons, the Board finds that it was prudent for YEC to undertake this study in the circumstances and that the capital spending for this project is reasonable. The Board directs YEC to include the updated spending amount in the 2021 rate base.

5.3.4 Intangible assets

327. YEC indicated that spending for intangible assets included financial software, customer service costs and costs related to the development of an asset management framework. YEC had a total of one major project, with a forecasted amount of $4.938 million in the 2021 test year, and a total of one project between $100,000 and $1 million, with a forecasted amount of $200,000.

276 Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 516, page 97 of 118, PDF page 102.
277 YEC Consolidated IR Responses, YUB-YEC-1-63, page 2 of 4, PDF page 2198.
278 Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 521, page 97 of 118, PDF page 102.
279 2021 General Rate Application, Appendix 5.4, page 5.4-2, PDF page 187.
280 Ibid., Appendix 5.4, page 5.4-3, PDF page 188.

These cost amounts were originally provided in the GRA, and YEC updated the costs for the major project in its responses to the second round of information requests.

328. The projects for this category included the Enterprise Asset Management (EAM) System Purchase and Implementation Project and the ERP System Upgrades Project. The following paragraphs address the major projects individually and the capital projects between $100,000 to $1 million. For the reasons that follow, the Board denies costs for the EAM System Purchase and Implementation Project but approves costs for the ERP System Upgrades Project.

5.3.4.1 Enterprise Asset Management System Purchase and Implementation Project

329. YEC undertook a multi-year process to develop and implement a formal Physical Asset Management Managed System (PAMMS) that aligned its practices with the ISO 55000 standard for physical asset management. YEC stated that a key part of this initiative was selecting and implementing an EAM solution that operationalized the framework developed under PAMMS.[281] While the 2017/18 GRA proceeding included feasibility costs for developing an Asset Management Program, YEC stated that there was no asset management methodology for managing critical hydro and transmission assets, which could result in unplanned ad hoc repairs and replacements projects.[282] YEC also indicated that its existing Computerized Maintenance Management System had significant shortcomings and was not capable of planning and executing planned preventative maintenance work, resulting in the development of in-house solutions and significant duplication of effort.[283]

330. YEC stated that the tangible benefits of the EAM project included productivity gains, improved inventory management and procurement, improved reliability with regards to extended asset life, reduced diesel consumption and revenue recovery, and being eligible for warranty claim reimbursement.[284] For example, YEC estimated a productivity improvement range of 12 to 25 percent, which was calculated utilizing a case study discussing workforce productivity.[285] YEC also mentioned the intangible benefits of the project, which included process improvement, availability and retention of information, contributions to safety, improved decision-making, increased compliance with regulatory requirements, improved accountability and increased accuracy in performance measurement.[286]

331. As noted in the Application, YEC commenced work on this project in 2018 and since that time has conducted activities that included procuring project management services and procuring and implementing the software solution.[287] YEC stated that the software solution procurement involved a total of 27 potential suppliers, eight of which were invited to complete a full request for proposal process. YEC selected the second lowest bidder, stating that the vendor scored higher on technical merits compared to the lowest bidder. In its Application, YEC provided a total cost of $4.938 million to complete the project, which included the actual capital spending

281 YEC Final Argument, Section 3.1.5, page 39, PDF page 42.
282 2021 General Rate Application, Section 5.4.1.1, page 5-28, PDF page 141.
283 YEC Consolidated IR Responses, YUB-YEC-1-64, pages 5 and 6 of 7, PDF pages 2205-2206.
284 Ibid., YUB-YEC-1-64, pages 3 and 4 of 7, PDF pages 2203-2204.
285 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-24(a), Attachment 1, pages 1 to 12 of 12, PDF pages 254-265.
286 YEC Consolidated IR Responses, YUB-YEC-1-64, pages 4 and 5 of 7, PDF pages 2204-2205.
287 2021 General Rate Application, Section 5.4.1.1, pages 5-28 to 5-29, PDF pages 141-142.

amounts for 2019 and the forecasted amounts for 2020 and 2021. However, YEC later updated the cost to $4.657 million, noting that there was an error in the GRA forecast for this project.[288]

Board Findings

332. The Board accepts that there is a requirement to keep asset management practices aligned with industry standards such as ISO 55000. However, the Board is concerned with the EAM project as proposed in this Application. YEC justified the tangible benefits related to productivity gains by referencing the results of a case study by Booz & Company and the anticipated savings from better inventory management by providing a BC Hydro document; it cited non-YEC-specific case studies to determine the reductions in long-term asset costs.[289] None of this evidence was prepared based on project-specific information, which in the Board's view limits the evidence's persuasiveness. As an example, YEC mentioned that organizations with EAM have reported reductions in long-term asset costs of up to five percent[290] but could not provide any organizations that showed reductions in long-term asset costs.[291] Thus, the Board finds it was not reasonable for YEC to proceed with the project given that the benefits lacked project-specific evidence.

333. Additionally, YEC stated that it explored other software alternatives but did not provide any details on these alternatives and why they were ruled out in favour of the EAM project. Regarding the chosen vendor for the software solution, YEC stated it scored higher on technical merits compared to the lowest bidder. However, YEC did not provide any details on these technical merits. Accordingly, the Board does not have sufficient evidence to assure itself that the EAM project was a reasonable alternative for YEC to pursue with regard to asset management. For these reasons, the Board finds the costs associated with this project are not reasonable and denies inclusion of the costs for this project in the 2021 rate base. The Board directs YEC to reflect the denial in the compliance filing to this Board Order.

5.3.4.2 Projects between $100,000 and $1 million

334. In its Application, YEC included the costs for one project in this category, namely the ERP System Upgrades Project, which had a forecasted capital spending amount of $200,000 in 2020.[292]

Board Findings

335. The Board has reviewed the business case and costs for the project in this category. Based on the information provided by YEC, the Board finds there is a need for this project. The Board directs YEC include the actual capital spending amount for the ERP System Upgrades Project in the 2021 rate base.

5.3.5 Projects not included in rate base

336. YEC also included business cases and costs for major capital projects, major deferred projects and deferred projects between $100,000 and $1 million not affecting rate base.[293] YEC

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288 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-17, page 22 of 29, PDF page 158.
289 Ibid., YUB-YEC-2-24, page 3 of 4, PDF page 252.
290 YEC Consolidated IR Responses, YUB-YEC-1-64, pages 4 of 7, PDF pages 2204.
291 YEC Consolidated IR Responses, Round 2, YUB-YEC-2-24, page 3 of 4, PDF page 252.
292 2021 General Rate Application, Appendix 5.6, pages 5.6-1, PDF page 196.

indicated these projects were forecast to remain in WIP in the 2021 test year and did not affect the test year rate base or revenue requirement.

Board Findings

337. Given that the costs for the projects in this category do not affect the test year rate base or revenue requirement, the Board makes no findings regarding these projects at this time.

6. Additional matters related to the GRA

6.1 Rate Schedule 39 fixed charge

338. YEC filed an application for approval of an interim fixed charge, effective April 1, 2021, to adjust the Rate Schedule 39 Industrial Primary Fixed Charge applicable to the VGC Group mine and the Alexco Resource Corporation mine and mill. This amendment to Rate Schedule 39 reflects completion of the McQuesten Substation, the replacement of the Mayo to McQuesten Substation segment of YEC's 69-kV Mayo to Keno City transmission line, and the installation of the SVC/STATCOM and related equipment at Stewart Crossing. YEC forecast that it would complete SVC/STATCOM and related equipment work in late November 2021. YEC proposed that, when the SVC/STATCOM at Stewart Crossing is completed and final costs are known, it would file an application to finalize Rate Schedule 39 fixed charges within 60 days of the completed installation of the SVC and related facilities.

339. The Board approved YEC's interim Rate Schedule 39 fixed charge in Board Order 2021-09, issued on April 30, 2021.

Board Findings

340. Based on the Board's determinations elsewhere in this Board Order, notably in Section 5.2.3.2, certain adjustments to Rate Schedule 39 fixed charges are required. The Board directs YEC to reflect the changes in the depreciation parameters for calculating the fixed charges that are directed in this Board Order in its future application to finalize Rate Schedule 39 fixed charges. These charges are to be effective January 1, 2021.

6.2 Low water reserve fund

341. A fund to account for water availability was first established out of retained earnings in 1987 and was given no-cost capital treatment.[294] Since that time, the regulatory account for the fund has undergone several changes and names including a long period of dormancy starting in the latter 1990s and continuing to approximately 2014, when YEC requested to restore the fund. In Board Order 2018-10, the Board directed that the account for the fund be named the "Low Water Reserve Fund" (LWRF) to incorporate a broader range of thermal generation. The Board stated that "YEC will adjust the balance in the LWRF on an annual basis for the difference in forecast thermal generation from actual thermal generation based on forecast load and only adjusting for the changes in hydro generation that are a result of changes in water availability."[295]

293 Ibid., Appendices 5.1, 5.3 and 5.5, pages 5.1-1 to 5.1-8, 5.3-1 to 5.3-6 and 5.5, respectively, PDF pages 157-165, 178-184 and 193, respectively.

294 Board Order 1989-4, page 19, PDF page 23.

295 Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 322, page 63 of 118, PDF page 68.

Over the years, the fund has also undergone significant changes, some of which have been determined by the courts or OICs prior to Board Order 2018-10.

342. In Board Order 2018-10, the Board found that:

> … a utility should neither make a profit nor suffer a loss from variances in forecasting due to water levels. The Board considers that the risk of low water conditions, with respect to added costs for thermal generation, should be borne by the customers of the utility.[296]
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> …
>
> … the Board directs YEC to create a deferral account that records the variance between actual thermal generation fuel costs (based on volume only) and the GRA forecast thermal generation fuel costs (based on volume only) that are due to changes in water conditions. Factors such as equipment failure, force majeure, capital or planned maintenance events are not to be included in the calculations for this deferral account.[297]
>
> …
>
> YEC will take the forecast risk for incremental generation costs for incremental loads outside of the forecast period with the exception of incremental load covered by the ERA [Energy Reconciliation Adjustment].[298]

343. YEC has provided its comments on the LWRF in Section 3.6.3 of the Application but did not include an updated LWRF term sheet. After YEC received the first round of IRs from the Board and interveners, YEC submitted an updated LWRF application and term sheet on April 8, 2021, noting OIC 2021/16. The provisions of OIC 2021/16 pertaining to the LWRF continued many of the Board's previous determinations regarding the LWRF, but it also created new requirements. Firstly, the OIC dictates that the LWRF is to be applied to all actual generation; that is, the recovery of amounts for LWRF is ultimately to be reconciled to actual generation rather than to the latest approved forecast generation amounts. OIC 2021/16 also requires that the maximum and minimum balances for the LWRF be sufficient to minimize the effect on rates for retail customers and major industrial customers that would otherwise be caused by variation on actual renewable source availability. The Board notes that this would include the variation in low water availability caused by drought conditions.

344. The Board identifies four areas of concern regarding the LWRF:

(1) Issues regarding the filing of LWRF annual reports;

(2) LWRF and ratepayer risk;

(3) The LWRF maximum and minimum balance (the LWRF cap); and

(4) LWRF as an offset to rate base.

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296 Ibid., paragraph 318, page 63 of 118, PDF page 68.
297 Ibid., paragraph 321, page 63 of 118, PDF page 68.
298 Ibid., paragraph 323, pages 63 and 64 of 118, PDF pages 68-69.

6.2.1 LWRF annual reports

345. UCG stated that YEC was negligent in filing its annual reports and that, by using OIC 2021/16 to capture 2019 results, ratepayers pay an extra $0.715 million in the future.[299] UCG requested that the $0.715 million it identified be deducted from the LWRF record.

346. YEC replied that UCG was actually referring to the LWRF term sheet filed in December 2019 and not Board Order 2019-08, which was issued in November 2019. YEC further added that the term sheet does not provide a firm date for filing an annual report. YEC concluded with "OIC 2021-16 establishes the Board's mandate in relation to the LWRF. The LWRF must now comply with the directions as outlined in OIC 2021/16."[300]

Board Findings

347. A revised term sheet could not be filed until after OIC 2021/16 was in force and the Board is satisfied that the term sheet complies with the OIC. The Board does not find the use of the 2019 term sheet unfair to customers as it is trued-up to actuals and therefore declines to deduct UCG's requested amount from the LWRF record. On a go-forward basis, the Board directs YEC to submit its annual LWRF report to the Board on within 60 days of the close of the year. YEC shall reflect this direction in its revised LWRF term sheet to be filed in the compliance filing to this Board Order.

6.2.2 LWRF and ratepayer risk

348. Board Order 2018-10 determined that "YEC will take the forecast risk for incremental generation costs for incremental loads outside of the forecast period with the exception of incremental load covered by the ERA."[301]

349. Although YEC agreed in testimony that it had less forecast risk due to the LWRF, it stated that "we never had that forecast risk since '91 when this fund was created."[302] YEC further stated that the LWRF was not so much about removing risk to the utility due to variations in water levels but more about rate stabilization.[303]

Board Findings

350. Board Order 2018-10 stated that there is forecast risk for incremental generation costs for incremental loads outside of a test period. In Board Order 2019-04, the Board provided further explanation of the forecast risk and stated that the risk outside of the test period should be borne by the utility. The Board stated as follows:

> The Board considers it necessary to preserve the principle that costs should be assigned to the utility when total load varies from forecast. YEC's proposal in the compliance filing is creating an asymmetrical risk profile whereby YEC is imposing certain risks – e.g.

299 Versus if the LWRF calculations were determined according to Board Order 2019-08.
300 YEC Reply Argument, page 25, PDF page 27.
301 Board Order 2018-10, Appendix A: Reasons for Decision, paragraph 323, page 64 of 118, PDF page 69.
302 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 175, lines 18 to 20, PDF page 7.
303 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 341, line 15, to page 343, line 4, PDF pages 5-7.

> incremental generation costs to customers – and yet there is no offsetting of potential benefits that YEC would gain, and those benefits would not be shared with customers – e.g. incremental sales and amortization of costs over greater sales volumes. Therefore, the Board considers that the incremental generation due to incremental load must be removed from the LWRF calculations because this is a risk properly borne by the utility. This adjustment is required in order for the LWRF to reflect Board Direction 29 in Board Order 2018-10.[304]

351. In past Board Orders, the Board identified asymmetric risk-sharing between YEC and customers regarding costs associated with incremental loads and gave specific directions to ensure that YEC was bearing forecast risk for incremental generation costs for loads above forecast outside of a test period.

352. YEC was requested to provide an undertaking regarding the asymmetric risk identified in Board Order 2018-10. YEC's immediate response was:

> MR. MOLLARD: I understand that, Ms. Graham. I'm not sure I can do that. To my recollection, I wasn't here for all of the proceedings, and we will check, but it wasn't until the last proceeding that the Board brought up this issue of variability related to GRA forecast. That was never an issue in prior proceedings. It was always long-term average and it was whatever the actual load was.
>
> …
>
> To my knowledge, the Board brought that up in the last proceeding and it hadn't occurred before that.[305]

353. In response to another undertaking, YEC could not provide a specific reference from a Board Order whereby the Board affirmed that customers assume risk for incremental generation costs for loads above forecast.[306]

354. The Board is concerned that customers are bearing additional risk that is properly be YEC's responsibility in developing its forecast for generation load. While the Board considers that asymmetrical risk sharing regarding incremental generation load recovered in rates ultimately harms ratepayers (as reflected in Board Orders 2018-10 and 2019-04) OIC 2021/16 has changed the law in that regard. That OIC directs that risks and costs for incremental generation loads be borne by customers, as reflected in the amended subsections 9(4) and 9(7) of the Rate Policy Directive (1995). Consequently, the Board now has less discretion to determine who should properly bear forecast risk of low generation, YEC or ratepayers.

355. As discussed in Section 5.2.5.3 – Return on equity (ROE) and risk premium, the Board found that YEC risks with respect to the LWRF have decreased and directed that YEC's risk premium be adjusted downward to reflect this reduced risk of the utility.

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304 Board Order 2019-04, Appendix A: Reasons for Decision, pages 9 and 10 of 12, PDF pages 9-10.

305 2021 General Rate Application Proceedings Transcript, Volume 3, September 29, 2021, page 343, lines 15-25, PDF page 7.

306 YEC Response to Undertakings, #20, page 11, PDF page 11.

6.2.3 LWRF maximum/minimum balance

356. YEC has applied to increase the maximum/minimum balance (the LWRF cap) for the LWRF to +/- $16 million from the currently approved cap of +/- $8.0 million. YEC stated that the requested change in cap level reflects the material increase in YEC's forecast generation load for the 2021 test year compared to the last GRA 2018 test year forecast. YEC stated that the "objective is to reduce Rider E[307] impact frequency and enable the LWRF to be more robust in dealing with severe drought."[308]

357. YEC's 2021 forecast firm load of 495.2 MWh is 28 percent higher than the 2018 approved firm load of 386.3 MWh. YEC is asking for an increase in the LWRF cap in part due to the increase in firm load.

Board Findings

358. When the LWRF was established, part of the objective was to reduce the immediate cost impacts of drought conditions. At that time, Yukon had two separate grids (WAF and Mayo-Dawson). Since that time, the two grids have been connected and represent the total available hydro generation for YEC. The Board notes that OIC 2021/16 directs amendments to certain subsections of Section 9 of the Rate Policy Directive (1995), including the following:

> (6) The Board must require Yukon Energy Corporation to operate a low water deferral account for the purpose of minimizing the effect on rates for retail customers and major industrial customers that would otherwise be caused by the variation in actual renewable source availability, including the variation caused by drought conditions.
>
> …
>
> (8) The Board must set the maximum balance and minimum balance for the low water deferral account at amounts sufficient to achieve the purpose described in subsection (6).

359. In its LWRF term sheet, YEC stated: "In compliance with OIC 2021/16 [Sections 9(6) and 9(8)] the updated LWRF Term Sheet increases the LWRF cap from +/- $8 million to +/- $16 million."[309]

360. The Board accepts the submissions of YEC that the change to the LWRF cap to +/- $16 million will satisfy the directions as provided in Sections 9(6) and 9(8) of OIC 2021/16 and directs YEC to reflect this in the revised LWRF Term Sheet. YEC shall include an updated LWRF term sheet as part of its compliance filing to this Board Order.

6.2.4 LWRF as an offset to rate base

361. A related issue to the LWRF cap was discussed in the oral hearing, i.e., should the amounts in the LWRF be treated as an offset to rate base?

362. In testimony at the hearing, YEC stated: "So the low water reserve fund itself is really just a smoothing mechanism so that ratepayers don't have to pay for the drought all at once."[310]

307 Rider E is the rider used by YEC to adjust the LWRF through rates when the balance is outside the cap limitations.
308 YEC LWRF Term Sheet, page 1-4, PDF page 7.
309 Ibid.

YEC also added that the LWRF is expected to maintain a positive balance.[311] When asked if the LWRF should be treated as a long-term asset, YEC responded that it did not believe that the LWRF should be treated as a long-term asset but rather as a "ratepayer trust account" upon which the utility does not earn a return.[312] YEC added that it did not consider the LWRF to be a part of rate base.[313]

363. In its Application, YEC stated that the LWRF is a deferral account and that 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)."[314]

Board Findings

364. The LWRF term sheet states that "Yukon Energy Corporation (YEC) manages the LWRF as a ratepayer 'trust fund'. The Fund is only to be used for variations from long-term average annual renewable source availability as determined in accordance with this Term Sheet."[315] The phrase "manages the LWRF as a ratepayer 'trust fund'" tells the Board that the LWRF is only nominally a trust fund.

365. OIC 2021/16 added Subsection 9(6) to the Rate Policy Directive (1995) and states:

> The Board must require Yukon Energy Corporation to operate a low water deferral account for the purpose of minimizing the effect on rate for retail customers and major industrial customers that would otherwise be caused by variation in actual renewal source availability, including the variation caused by drought conditions.

366. Given this language, the LWRF has all the characteristics of a deferral account and the Board is not persuaded by YEC's characterization of the LWRF as a "trust fund". The evidence on the record shows that this account operates as a deferral account. For example, Tab 10 (2019 Audited Financial Statement) of YEC's 2021 GRA shows the LWRF receiving similar reporting treatment as other deferral accounts with credit balances.[316] Further, the notes to the 2019 Audited Financial Statement do not show a trust account set up on the Balance Sheet of YEC for the LWRF. It shows the LWRF as a deferral account and the features of the account are consistent with a deferral account.

367. In its testimony, YEC stated that the LWRF has been in place since the early 1990s.[317] In Board Order 1992-1, the Board determined that reserves such as a low water reserve account should apply to YEC's rate base, and in that Board Order, the Board had the balance of the

310 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 184, line 25, to page 185, line 2, PDF pages 16-17.
311 Ibid., page 185, lines 16-25, PDF page 17.
312 Ibid., page 188, lines 13-22, PDF page 20.
313 Ibid., page 189, lines 11-23, PDF page 21.
314 2021 General Rate Application, page 3-31, PDF page 77.
315 YEC LWRF Term Sheet, page 1.1-1, PDF page 8
316 2021 General Rate Application, Tab 10, 2019 audited financial statements, page 10-59, PDF page 400. Note 10 (iii) Low Water Reserve Fund does not describe the account as a "trust fund".
317 2021 General Rate Application Proceedings Transcript, Volume 2, September 28, 2021, page 175, lines 12-17, PDF page 7.

reserve accounts removed from YEC's mid-year capital and deducted the amount from mid-year rate base.[318]

368. The testimony of YEC in this proceeding stated that YEC expects the LWRF to maintain a positive balance (i.e., collecting funds for future low water events) and that a positive balance is expected to exist in most years. Further, OIC 2021/16 states that the LWRF must be operated to minimize the effect on rates for retail customers and major industrial customers that would be caused by variation in actual renewable source availability. Given at least one past Board Order directing the treatment of low water reserve funds as an offset to rate base, the Board directs YEC, on a go-forward basis, to treat the balance in the LWRF as an offset to rate base. The Board directs YEC to reflect this change in its compliance filing.

7. Review and variance of Board Orders

369. The Board considers applications for reviews and variances of Board Orders under Section 62 of the *Public Utilities Act* and Section 31 of its *Rules of Practice*. The Board's *Rules of Practice* do not establish a deadline for filing an application for review and variance. Finality of decisions is an important principle in administrative decision-making, and the Board considers that imposing a time limit for the filing of any application for review and variance of this Board Order is appropriate given this principle. Under Subsection 3(1) of the *Rules of Practice*, the Board may set time limits for doing anything provided for in these rules. Accordingly, the Board establishes a time limit for filing an application for review and variance of this Board Order for 30 days after this Board Order is issued. This 30-day period aligns with the appeal period pursuant to Subsection 69(1) of the *Public Utilities Act*.

318 Board Order 1992-1, pages 20-21, PDF pages 25-26.

Appendix 1: Summary of YEC depreciation parameters

Asset Class ID	Asset Class ID Description	Currently Approved Depreciation	Proposed Depreciation Paramters	Approved Depreciation Parameters
	Land			
1610-003	Land Hydro Production	n/a	n/a	n/a
1610-004	Land Diesel Production	n/a	n/a	n/a
1610-006	Land Main Trx Facilities	n/a	n/a	n/a
1610-008	Land Distribution System	n/a	n/a	n/a
1610-009	Land General Plant	n/a	n/a	n/a
1610-106	Land Rights	50-R2.5	50-R2.5	50-R2.5
	Hydro Plant			
1615-200	Hydro-Strctrs & Imprvmts	72-R2	72-R2	72-R2
1615-201	Hydro-Building & Imprvmnt **- new account**	n/a	40-R2.5	40-R2.5
1615-205	Hydro-Rsrvoirs Dams & Wtrways	103-R3	103-R3	103-R3
1615-206	Hydro-Dams & Wtrways Twin Assets	103-R3	103-R3	103-R3
1615-506	Hydro-Wtrwhls, Trbines & Gen's	85-R3	60-R3	85-R3
1615-600	Hydro-Accessory Electric Equip	45-R3	40-R2.5	40-R2.5
1615-601	Hydro Accessory Digital Equip	20-SQ	20-SQ	20-SQ
1615-700	Hydro-Misc Power Plant Equip	30-R2	30-R2	30-R2
1615-730	Hydro- Fences	30-R2	30-R2	30-R2
	Diesel Plant			
1620-200	Diesel-Strctrs and Imprvmts	72-R2	72-R2	72-R2
1620-201	Diesel-Building & Imprvmnt	55-R1	55-R1	55-R1
1620-403	Diesel-Fuel Hldrs,Prdcts&Accss	25-R2	40-R2	40-R2
1620-500	Diesel-Gnrtng Equip & Prime	40-R2	40-R2	40-R2
1620-501	Diesel-Gnrtng Equip & Prime Retire 2021	11-SQ	11-SQ	11-SQ
1620-508	Diesel-Minto Gnrtng Equip	12-SQ	12-SQ	12-SQ
1620-600	Diesel-Acc Electric Equip	45-R3	45-R3	45-R3
1620-700	Diesel-Misc Power Plant Equip	30-R2	30-R2	30-R2
	Distribution System			
1625-300	Dist System - Poles & Fxtrs	35-R2	40-R2	40-R2
1625-304	Dist System - Brushing	50-R2	50-R2	50-R2
1625-305	Dist System - Survey Costs	50-R3	50-R2	50-R2
1625-401	Dist System - O/H Cndctrs	35-R2	50-R2	50-R2
1625-410	Dist System - O/H Services	40-R2	40-R2	40-R2
1625-501	Underground Conduit	40-R2.5	40-R2.5	40-R2.5
1625-510	Dist System - Undrgrnd Cnduit	40-R2.5	40-R2.5	40-R2.5
1625-610	Dist System - Meters	30-R2	16-SQ	16-SQ
1625-620	Dist System - Meter Equip	30-R2	16-SQ	16-SQ
1625-710	Dist System - Sbstn EEquip	40-R2	40-S0	40-S0
1625-720	Dist System - Sbstn Buildings	55-R1	55-R1	55-R1
1625-730	Dist System- Substation Fences	20-R4*	30-R4	30-R4
1625-815	Dist System - Street Lights	40-R2	40-R2	40-R2
1625-905	Dist System - Line Trxformers	40-R2.5	35-R2.5	35-R2.5
1625-961	Dist System - Sentinel Lights	30-L2	30-L2	30-L2
	Main Transmission Facilities			
1635-300	Main Trx - Poles & Fxtrs	65-R3	50-R3	65-R3
1635-304	Main Trx - Brushing	50-R3	60-R3	60-R3
1635-305	Main Trx - Survey Costs	50-R2.5	60-R3	60-R3
1635-402	Main Trx - O/H Cndctrs/Poles	50-R3	60-R3	60-R3
1635-404	Main Trx - O/H Cndctrs/Towers	50-R3	60-R3	60-R3
1635-710	Main Trx - Sbstn Equip	54-S0	45-S0	54-S0
1635-720	Main Trx - Sbstn Buildings	55-R1	55-R1	55-R1
1635-730	Main Trx - Sbstn Fences	20-R4	30-R4	30-R4
	Sub Transmission Lines			
1640-300	Sub Trx - Poles & Fxtrs	45-R3	50-R3	65-R3
1640-301	Sub Trx - Poles & Fxtrs Mnt Mn	12-SQ*	12-SQ	12-SQ
1640-304	Sub Trx - Brushing	50-R3*	60-R3	60-R3
1640-306	Sub Trx - Brushing Mnt Mn	12-SQ*	12-SQ	12-SQ
1640-307	Sub Trx - Survey Costs Mnt Mn	12-SQ*	12-SQ	12-SQ
1640-401	Sub Trx - O/H Cndctrs	45-R3	60-R3	60-R3
1640-405	Sub Trx - Undrgrnd Cndctrs/Cnd	45-S3	45-S3	45-S3
1640-407	Sub Trx - O/H Cndctrs Mnt Mn	12-SQ*	12-SQ	12-SQ
1640-710	Sub Trx - Sbstn EEquip	40-S0*	45-S0	54-S0
1640-711	Sub Trx - Sbstn Equips Mnt Mn	12-SQ*	12-SQ	12-SQ
	Buildings & Other Equipment			
1645-110	Bldg&Otr - Survey Costs Land	50-R2	50-R2	50-R2
1645-200	Bldg&Otr-Strctrs/Imprvmnt Hyd	40-R2.5	50-R2	50-R2
1645-201	Bldg&Otr - Building & Imprvmnt	55-R1	50-R2	55-R1
1645-202	Bldg&Otr-Office Frntr & Equip	20-SQ	20-SQ	20-SQ
1645-210	Bldg&Otr - Comm Site Towers	30-R2	40-R2	40-R2
1645-220	Bldg&Otr - Comm Site Fences	20-R4	30-R4	30-R4
1645-320	Bldg&Otr - Computer Hardware	5-SQ	7-SQ	7-SQ
1645-330	Bldg&Otr - Computer Software	5-SQ	5-SQ	5-SQ
1645-505	Bldg&Otr - Tools & Instruments	20-SQ	20-SQ	20-SQ
1645-507	Bldg&Otr - Wind Mntrng Equip	20-SQ	15-SQ	15-SQ
1645-605	Bldg&Otr - Comm Equip	20-L4	20-L4	20-L4
1645-810	Bldg&Otr - Houses/Land	30-R3	40-R3	40-R3
1645-820	Bldg&Otr - Houses/Buildings	30-R3	40-R3	40-R3
	Transportation			
1650-411	Trxptn - Utility Vehicles	7-L2	8-L2	8-L2
1650-412	Trxptn - Sedans & Stn Wagons	7-L2	11-S4	11-S4
1650-420	Trxptn - Trucks & Pole Trailer	25-R1.5*	25-R1.5	25-R1.5
1650-430	Trxptn -Pole Trailer>10,000lbs	25-R1.5	25-R1.5	25-R1.5
1650-440	Trxptn - Trucks 3/4 to 2 Ton	10-R2	9-L2	9-L2
1650-470	Trxptn - Trucks > 3Tons	20-R3	20-R3	20-R3
1650-490	Trxptn - Foremost	25**	20-R3	20-R3
	Critical Spares			
1655-750	Critical Spares	n/a	n/a	n/a
	LNG Plant			
1665-200	Structures and Improverments	72**	72-R2	72-R2
1665-403	Fuel Holders	32**	60-R2	60-R2
1665-500	LNG Generator	40**	40-SQ	40-SQ
1665-600	Accessory Electric Equipment	45**	45-R2	45-R2
1665-700	Miscellanours Power Plant Equi	30**	30-R2	30-R2
1665-730	LNG Fence	30**	30-R2	30-R2

* Approved Iowa curves and dispersion were provided within the details of the depreciation study for these accounts.

** Only approved service lives were provided within the details of the depreciation study for these accounts.

Source: YEC Application, Appendix C, page 9-104 to 9-105, PDF pages 339-340