City of Whitehorse
(CW)

TOPIC: **Peak Load**

REFERENCE: **2021 General Rate Application, Table 2.2**

PREAMBLE: On line 29, YEC indicates the integrated system peak.

QUESTION:

a) Please provide the peaks for each of (i) Wholesale, (ii) Industrial, and (iii) the balance of the YEC system for each of 2018 Approved, 2018 Actual, 2019 Actual, 2020 Forecast and Forecast 2021.

b) Please provide the reason for changes in peak demands for each of the years in each of (i) Wholesale, (ii) Industrial, and (iii) the balance of the YEC system.

c) Please fully explain the impact of changes in peak demand on required capital investment.

ANSWER:

(a) and **(b)**

Table 1 provides the non-industrial and the industrial peaks for 2018/19 to 2021/22 winters – additional splits requested are not readily available.

Table 1: Non-Industrial and Industrial Peak (kW)

	2018/19 Forecast*	**2018/2019 Actual**	**2019/20 Actual**	**2020/21 Forecast**	**2021/22 Forecast****
Non-Industrial	86,400	89,040	97,651	100,653	104,102
Industrial	6,500	1,900	6,200	12,035	9,262
Total	**92,900***	**90,940**	**103,851**	**112,689**	**113,364****

***No specific 2018/19 winter peak was "approved'. The forecast shown was provided for 2018 in the 2017-18 GRA.

****** This winter peak is expected in 2022, i.e., beyond the 2021 test year.

Peak demand is subject to a variety of external factors, including weather, population, and saturation of electric heating. The peak record in 2019/20 reflected cold weather in particular.

(c)

Yukon's isolated grid must self-supply all its own capacity and energy, including securing reserve capacity in order to meet grid loads during winter peak periods, as it has no access to any external North American power grid to secure extra power when it is needed, or to sell surplus renewable generation when it occurs.

Seasonal generation constraints also present additional challenges to the Yukon Integrated System (YIS). Electricity demand on the YIS is highly variable with seasonal mismatch between the timing of maximum available electricity production from renewable generation (which peaks in the summer months) and maximum customer demand (which peaks during a cold period during winter months). The result is surplus renewable generation during summer (which cannot be used or sold to other jurisdictions) and reliance on thermal generation to supply peak load requirements during winter.

Yukon Energy's generation capacity planning criterion for the YIS is based on the single contingency (N-1) dependable capacity criterion, under which the YIS is required to have enough dependable capacity to supply the forecast non-industrial peak winter demand (i.e., excluding major industrial demand) under the largest single contingency.[1] Inability to supply the non-industrial peak winter demand, which is expected to occur during a period of the coldest winter temperatures, presents an obvious and acute risk to human health and safety and public and private infrastructure. Therefore, YEC's planning, including capital planning must include measures that address capacity shortfalls under capacity planning criteria.

As noted in the Application non-industrial peak load has increased from 86.4 MW in the 2018 GRA forecast to 100.7 MW forecast for 2021 (14 MW increase), accounting for most of the 17 MW growth in the N-1 dependable capacity shortfall. Diesel rental unit costs of approximately $3.8 million are forecast for the diesel rental units expected to be required for the 2021 GRA test year, Yukon Energy's ongoing capital program costs include infrastructure to accommodate the rented diesels as well as work to address longer term solutions (e.g., battery energy storage system [BESS], diesel replacement at various grid

[1] YEC also uses Loss of Load Expectation (LOLE) as system capacity planning criteria where the system is planned not to exceed a LOLE of 2 hours/year. The LOLE criterion includes industrial loads as part of the assessment. At the forecast industrial load, however, the LOLE criterion was satisfied in the test year so long as the single contingency, N-1, criterion was met.

locations, Atlin Hydro Expansion Project, and the potential development of pumped storage at Moon Lake).

TOPIC: **Sales**

REFERENCE: **2021 General Rate Application, Table 2.2**

PREAMBLE: YEC provides Actual Sales. CW requires normalized data as well.

QUESTION:

a) Please provide an updated Table 2.1, with sales, sales per customer, revenues, and cents per KWh normalized for weather.

b) Please provide the working papers that were used to do the weather normalization, and the supporting analysis and data.

ANSWER:

(a) and **(b)**

YEC does not prepare weather normalized version of its actual sales to retail and industrial customers. Therefore, YEC is unable to provide updated version of Table 2.1 as requested.

TOPIC: **Sales Forecasts – Wholesale Sales to ATCO Electric Yukon (AEY)**

REFERENCE: **2021 General Rate Application, page 2-5 (PDF page 30 of 441)**

PREAMBLE: YEC discusses its determination of its forecast sales to AEY on page 30.

QUESTION:

a) On lines 15-16, YEC discusses the AEY Fish Lake Generation Facility (AEY Facility). Please provide the maximum capacity of the AEY Facility, and the annual production, on a normalized and actual basis for 2018 and 2019.

b) Please fully explain how the AEY Facility is used in providing service. Is it the first resource that is engaged, or does it only provide peak supply?

c) On lines 18-19 YEC discusses multi-variate regression assessments of wholesale changes at normal weather conditions. Please provide the multi-variate analysis in Excel format. In the response, please also provide the source of all supporting data.

d) Please provide the calculation of normal weather.

e) On lines 19-20, YEC discusses Micro Generation. CW also notes footnote 4. Please provide:
   i. The detailed analysis of the source of the 1.5 GWh forecast for 2021.
   ii. The impact of the AEY Facility on peak demand.

ANSWER:

(a) and **(b)**

YEC does not have information such as the maximum capacity, weather normalized generation, or operation regarding AEY's Fish Lake facility nor does YEC have operational control of this plant. AEY will be in an better position to provide a response to these questions.

YEC receives Fish Lake's annual generation information from AEY for forecasting purposes as well as for the purposes of determination of LWRF and ERA. As noted in the Application [page 2-5], the actual generation from Fish Lake was at about 5.5 GW.h for 2018 and about 5.0 GW.h for 2019; the forecast for 2021 is 3.6 GWh.

(c)

Please see Attachment 1 to this response.

(d)

Please see response to YUB-YEC-1-16 (a).

(e)

(i)

The micro-generation program forecast for total delivered energy was provided by Yukon government. The actual 2020 program total is embedded in historical sales and is included in the regressed forecasted load. Therefore, only the 2021 incremental program total of 1.5 GWh has been used to reduce the 2021 load. No adjustment are made to the peak forecast related to microgen as solar installations do not provide energy during peak winter hours. Please see YUB-YEC-1-13 for the information provided by Yukon government.

(ii)

The AEY Fish Lake facility impact on peak is included in the historical actuals which are subsequently accounted for via the regression analysis used to forecast peak load.

Year	Month	Avg. Temp.	HDD 13	CDD 13	Days with Avg. Temp < -20 oC	Commercial Count	January Dummy	July Dummy	December Dummy	Darkness	Stat/Weekend
0	1	-15	1,105	0	9	2,823	1	0	0	481.19	9
0	2	-13	895	0	5	2,827	0	0	0	387.72	10
0	3	-6	762	0	2	2,831	0	0	0	330.33	9
0	4	1	513	0	0	2,835	0	0	0	228.05	10
0	5	7	345	9	0	2,839	0	0	0	129.54	11
0	6	12	186	31	0	2,843	0	0	0	15.89	9
0	7	14	124	58	0	2,847	0	1	0	94.43	9
0	8	13	175	39	0	2,851	0	0	0	205.39	11
0	9	7	326	3	0	2,855	0	0	0	292.54	9
0	10	1	540	0	0	2,858	0	0	0	389.40	10
0	11	-9	822	0	2	2,861	0	0	0	449.12	10
0	12	-13	1,019	0	10	2,864	0	0	1	503.34	10

Year	Month	Predicted Wholesales Multivariate [MWh]
0	1	37,828,488
0	2	33,825,312
0	3	31,184,131
0	4	27,850,723
0	5	25,407,240
0	6	23,096,455
0	7	23,830,615
0	8	23,746,918
0	9	25,510,225
0	10	28,694,365
0	11	32,968,114
0	12	37,518,588

ID	Weight and Unit	
b0	-6102937.015	Intercept
b1	-243428.8791	Avg. temperature
b2	5823.920775	HDD 13oC (threshold)
b3	11620.22311	CDD 13oC (threshold)
b4	35007.95276	Day with avg temp < -20
b5	2023429.87	Jan Indicator Var.
b6	1066356.647	July Indicator Var.
b7	2238463.68	Dec Indicator Var.
b8	116256.9942	# of Stat/Weekend day in a month
b9	1995.861701	hours of Darkness in a month
b10	10438.60255	Commercial customer

0	351,461.173	

CW-YEC-1-3(c) - Attachment 1

2021 no Micro no Fish Lake

Year	Month	Predicted Wholesales Multivariate [MWh]	Predicted Wholesales Multivariate after Micro Gen and Fish Lake [MWh]
2021	1	37,828	37,250
2021	2	33,825	33,198
2021	3	31,184	30,483
2021	4	27,851	27,126
2021	5	25,407	24,679
2021	6	23,096	22,376
2021	7	23,831	23,116
2021	8	23,747	23,045
2021	9	25,510	24,842
2021	10	28,694	28,063
2021	11	32,968	32,393
2021	12	37,519	36,966
Total		351,461	343,537

TOPIC: **Sales Forecasts – Wholesale Sales to ATCO Electric Yukon (AEY)**

REFERENCE: **2021 General Rate Application, page 2-6 (PDF page 31 of 441)**

PREAMBLE: On lines 1-3, YEC discusses the AEY forecast for 2021.

QUESTION:

a) Please provide copies of all communication between AEY and YEC regarding the 2020 and 2021 forecast wholesale sales.

b) Please provide a calculation of the impact on customer rates if the AEY forecast of 345.9 GW.h were used for 2021.

ANSWER:

(a)

Please see CW-YEC-1-4 Attachment 1 for the copy of the letter sent by YEC to AEY regarding 2021 test year forecast. YEC did not include the information on 2020 forecast considering Jan-June numbers for 2020 are based on preliminary actuals.

Please see CW-YEC-1-4 Attachment 2 for the copy of the AEY forecasts for 2020 and 2021, including annual power purchase forecasts as shown in Schedule 3.2, Line 10.

(b)

Based on a high level estimates the incremental wholesale sales [345.9 GW.h as noted in the question compared to 343.5 GW.h forecast by YEC for the 2021 test year = 2.6 GW.h incremental wholesale] would add approximately $0.40 million thermal fuel cost compared to approximately $0.31 million added revenues resulting in a $0.09 million incremental revenue shortfall or 0.09% additional rate increase for 2021.

#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

Chris Cullingham
Manager, Regulatory
ATCO Electric Yukon

August 31, 2020

Re: 2021 Yukon Energy GRA Wholesale Sales Forecast

Dear Chris,

This letter is an update of the letters sent to ATCO Electric Yukon (AEY) on May 16, 2019, November 26, 2019 and December 18, 2019. In those letters, Yukon Energy Corporation (YEC) stated that the Yukon Utilities Board (YUB) Order 2018-10 directed YEC to refine its methodology of forecasting Wholesale Sales to ensure its forecasts align closely with the AEY forecasts in future GRA submissions. Subsequent to that Board Order, YEC has had communications with you via email and telephone, as well as the letters sent to you referenced above. Those communications had the purpose of informing AEY of YEC's intention to file a GRA, and to directly address the YUB's direction to ensure our forecasts align closely with yours. This letter is to further formally document our discussions and determine whether or not we need to amend our forecasts.

AEY Forecast
Due to the expected timing of our 2021 GRA submission, we plan to use actuals for 2020 up to June 30, 2020 and forecasts for the remainder of 2020. The GRA year of 2021 will be based fully on forecasts. Pursuant to our previous communications, AEY indicated that your forecast was for business plan purposes and it did not necessarily undergo the same rigor as a forecast that you would file in the GRA.

You indicated that your load forecasting methodology has two key inputs, being net customer additions and forecast use per customer (UPC). Net customer additions are based on input from AEY staff that is obtained through their work in the communities, as well as consultations with the City of Whitehorse, Yukon Government and other various local stakeholders and developers. Forecast UPC is based on average, weather-normalized, historical usage.

A summary of key forecasts that AEY provided YEC is below. It is our understanding that our previous interpretation of your forecasts for 2019 and 2020 was that we quoted your Retail Sales, rather than your Purchased Power. Therefore, the below table has been updated to reflect your Purchased Power and Fish Lake Generation.

	2021
AEY Purchased Power (GW.h)	345.9
Fish Lake Generation (GW.h)	3.6

YEC Forecast
YEC's current forecast for Wholesales sales to AEY is 343.5 GW.h in 2021.

Forecast Differences
The difference between AEY and YEC's forecast is 2.4 GW.h higher by AEY, or 0.69%.

#2 Miles Canyon Road
Box 5920, Whitehorse
Yukon Y1A 6S7
yukonenergy.ca

YEC uses a similar forecasting methodology, so inputs are they key area where differences can arise. YEC performed a detailed review of AEY's inputs. The main difference for residential is AEY used a different residential number of accounts growth factor as compared to YEC. YEC used Yukon Government's number of households' growth for the residential growth factor.

Summary
The above represents YEC's understanding of the communications between YEC and AEY. Please let us know if AEY has a different interpretation. In addition, if you have any significant concerns about our forecasts, please provide to us.

We appreciate your continued support in the Yukon regulatory process.

Regards,

Jason Epp CPA, CA
Controller

Schedule 2.1

ATCO Electric Yukon
Summary of Customers, Energy Sales and Revenue

Line No.	Description	2020	2021
1	**Residential**		
2	Customers (average during year)	16,088	16,301
3	Sales in MWh	180,816	174,769
4	MWh sales per customer	11.24	10.72
5	Revenue ($000s)	25,328	24,618
6	Cents per kWh	14.01	14.09
7	**Commercial**		
8	Customers (average during year)	3,180	3,213
9	Sales in MWh	163,088	173,321
10	MWh sales per customer	51.28	53.95
11	Revenue ($000s)	26,668	28,272
12	Cents per kWh	16.35	16.31
13	**Street Lights**		
14	Customers (average during year)	5,777	6,031
15	Sales in MWh	3,886	3,914
16	Revenue ($000s)	1,034	1,060
17	Cents per kWh	26.60	27.07
18	**Private Lights**		
19	Customers (average during year)	772	749
20	Sales in MWh	454	434
21	Revenue ($000s)	122	117
22	Cents per kWh	26.81	26.98
23	**Total Company - Retail - Primary**		
24	Customers	25,817	26,076
25	Sales in MWh	348,245	352,438
26	Revenue ($000s)	53,152	54,067
27	Cents per kWh	15.26	15.33
28	**Secondary Sales**		
29	Customers (average during year)	5	5
30	Sales in MWh	-	-
31	Revenue ($000s)	-	-
32	Cents per kWh	#DIV/0!	#DIV/0!
33	**Wholesale Sales**		
34	Customers (average during year)	2	2
35	Sales in MWh	628	628
36	Revenue ($000s)	54	52
37	Cents per kWh	8.54	8.30
38	**Total Company - Base Revenue**		
39	Customers	25,824	26,300
40	Sales in MWh	348,873	353,066
41	Revenue ($000s)	53,205	54,119
42	Cents per kWh	15.25	15.33

ATCO Electric Yukon
2020 - 2021 Forecast
Schedule of Energy Losses
(MWh)

Line No.	Description	Forecast 2020	Forecast 2021
1	**Sales and Losses**		
2	Total Energy Sales - MWh	348,873	353,066
3	Losses and Company Used - MWh	17,751	17,965
4	Losses -%	5.1%	5.1%
5	Total Generation and Purchases (MWh)	366,624	371,031
		-	
6	**Sources - MWh**		
7	Hydro Generation	3,628	3,628
8	Hydro Grid Standby Diesel Generation	45	45
9	Diesel Generation	21,622	21,423
10	Purchases	341,329	345,934
11	Total Generation and Purchases (MWh)	366,624	371,031
12	**Sources - %**		
13	Hydro Generation	1.0%	1.0%
14	Diesel Generation	5.9%	5.8%
15	Purchases	93.1%	93.2%
16	Total	100.0%	100.0%

TOPIC: **Sales Forecasts – Major Industrial**

REFERENCE: **2021 General Rate Application, page 2-6 (PDF page 31 of 441)**

PREAMBLE: CW notes that YEC discusses its industrial sales forecasts, and also notes footnotes 5, 6, and 7.

QUESTION:

a) For each industrial customer, please fully discuss all communication with the customer regarding load projections and potential changes in load for 2021.

b) Please provide copies of the Power Purchase Agreement referenced in Footnote 6.

ANSWER:

(a)

Finance, Operations and/or Senior Management will have communications with each Industrial on an ongoing basis. As YEC gets closer to finalizing a GRA, YEC will reach out to the Industrial customer to determine if any changes to previous forecasts are required. Communications can be in person, by email or by telephone.

(b)

Please see Attachment 1 to this response.

POWER PURCHASE AGREEMENT

This Agreement dated November 9, 2017 is between:

YUKON ENERGY CORPORATION, a Yukon Territory corporation, having an office at P.O. Box 5920, #2 Miles Canyon Road, Whitehorse, Yukon Territory, Y1A 6S7

("**YEC**")

and:

VICTORIA GOLD CORP., a British Columbia corporation registered in the Yukon Territory under number 634192, having an office at 1050 West Pender Street, Vancouver, British Columbia, V6E 3E7

("**VGC**")

and:

STRATAGOLD CORPORATION., a British Columbia corporation registered in the Yukon Territory under number 631012, having an office at 1050 West Pender Street, Vancouver, British Columbia, V6E 3E7

("**StrataGold**")

(VGC and StrataGold are jointly and severally, the "**VGC Group**")

BACKGROUND:

A. StrataGold is a wholly-owned subsidiary of VGC;

B. VGC Group owns the Mine Site and is in the process of developing the Mine with the intent of commencing initial gold production by June 30, 2019;

C. YEC has agreed to sell to VGC Group and VGC Group has agreed to purchase from YEC Grid Electricity required by VGC Group to operate the Mine, with Commencement of Delivery in March, 2019; and

D. The Parties have agreed to enter into this Agreement to set out their respective rights and obligations with respect to the sale and purchase of Grid Electricity by YEC to VGC Group for the Mine.

AGREEMENTS:

The Parties agree:

PART 1
DEFINITIONS AND INTERPRETATION

1.1 **Definitions**. In this Agreement and in the Schedules which are attached to and form a part of this Agreement:

(a) "**Act**" has the meaning in Section 8.1;

(b) "**Affiliate**" has the meaning set out in the *Business Corporations Act* (Yukon Territory);

(c) "**ampere**" means the unit of measurement of electric current in the International System of Units;

(d) "**Business Day**" means any day which is not a Saturday, Sunday, or a statutory holiday in the Yukon Territory or the Province of British Columbia;

(e) "**Commencement of Delivery**" means for the Mine Facilities the later of the:

(i) McQuesten Substation Operation Date;

(ii) date VGC Group provides notice to YEC to confirm that the VGC Group Power Facilities are complete and the Mine Facilities and the Mine Facilities Spur are available to receive Grid Electricity from YEC; and

(iii) date the Parties execute and deliver the Operating Agreement;

(f) "**Commercial Operation Cessation Date**" means the earlier of the:

(i) Mine Facilities Shut Down Date; and

(ii) date VGC Group provides notice to YEC that the Mine Facilities no longer require, acting reasonably under normal market and operating conditions, an Electric Demand at the Point of Delivery in excess of 1,000 kW;

(g) "**Conditions**" mean the conditions listed in Section 3.1;

(h) "**Confidential Information**" has the meaning in Section 15.1;

(i) "**Defaulting Party**" has the meaning in Section 11.1;

(j) "**Dispute**" means any dispute, difference, or disagreement between the Parties as to:

(i) the meaning, application, or implementation of this Agreement; or

(ii) whether an Event of Default has occurred;

(k) "**Electric Demand**" means the capacity at which Grid Electricity is delivered by YEC to VGC Group expressed in kVA or kW, averaged over a rolling 15 minute period following YEC billing and metering practice for industrial customers receiving Grid Electricity;

(l) "**Electric Energy**" means electric energy, expressed in kWh, delivered by YEC to VGC Group under this Agreement;

(m) "**Electricity**" means Electric Energy and Electric Demand delivered by YEC to VGC Group under this Agreement;

(n) "**Event of Default**" has the meaning in Section 11.1;

(o) "**Event of Insolvency**" means any one or more of the following:

(i) if a Party files a petition for reorganization or for an arrangement under any applicable bankruptcy law or under any similar laws, now or hereafter in effect, is adjudged by a court of competent jurisdiction bankrupt, becomes insolvent,

makes an assignment for the benefit of its creditors, admits in writing its inability to pay its debts generally as they become due, is dissolved, or suspends payment generally of its obligations;

(ii) if a petition is filed proposing the adjudication of a Party as a bankrupt or its re-organization under any applicable bankruptcy law or any similar law, now or hereafter in effect and:

A. the Party consents to the filing thereof;

B. the petition is not discharged or denied within 60 days after the filing thereof; or

C. the petition is not diligently defended against; and

(iii) if a receiver, receiver-manager, trustee, monitor, or liquidator (or other similar official) is appointed to take charge of all or substantially all of the business or assets of a Party and:

A. that Party consents to such appointment; or

B. the appointment is not discharged or withdrawn, or action is not taken by that Party to secure the discharge of that official, within 60 days after the appointment;

(p) "**Firm Mine Rate**" means the rate set out in Schedule A, as may be amended by YUB from time to time;

(q) "**Fixed Charge**" means the fixed charge rate each month applicable to the VGC Group Mine Site under the Firm Mine Rate, equal to one-twelfth of the annual amount determined under Section 7.7;

(r) "**Force Majeure**" means any event or circumstance suffered by a Party which is not within the reasonable control of the Party claiming Force Majeure and includes, without limitation:

(i) acts of God, including wind, ice and other storms, forest fires, lightning, floods, earthquakes, volcanic eruptions, and landslides;

(ii) strikes, lockouts, and other industrial disturbances, it being acknowledged that the settlement of strikes, lockouts, and other labour disturbances depends upon the agreement of employees and other third Persons and therefore is not wholly within the discretion of the Party involved;

(iii) epidemics, war (whether or not declared), terrorism, blockades, acts of public enemies, acts of sabotage, civil insurrection, riots, and civil disobedience;

(iv) acts or omissions of Governmental Authorities; and

(v) explosions and fires;

(s) "**Government Approvals**" means all licences, permits, consents, authorizations, or approvals from, withholding of objection on the part of, or filing, registration or qualification with, any and all Governmental Authorities required for any particular decision, act, or event;

(t) "**Governmental Authority**" means the government of Canada, the government of the Yukon Territory, a municipality or other political subdivision thereof, including any applicable First Nations, and any entity exercising executive, legislative, judicial, regulatory, or administrative functions including, without limitation, the YUB, if applicable;

(u) "**Grid Electricity**" means Electricity delivered under this Agreement at the Point of Delivery by YEC to VGC Group from the Transmission Facilities , through the Mine Facilities Spur to the Mine Facilities;

(v) "**Initial YEC System Improvements**" means the initial system improvement facilities for YEC's power system that YEC is to design, engineer, procure, construct, and commission on YEC's power system under Schedule C;

(w) **"Interest Rate**" means the interest rate charged by the lead banker of YEC from time to time on unsecured commercial loans made to YEC or if YEC does not have any unsecured commercial loans outstanding at such time, the variable nominal interest rate per annum being the prime interest rate of Canadian Imperial Bank of Commerce (or its successor) for Canadian dollar commercial loans in Canada as publicly declared from time to time as its prime rate;

(x) "**International System of Units"** means the international system of weights and measures adopted at the 11th General Conference on Weights and Measures in 1960;

(y) "**kV**" means a kilovolt and one kilovolt equals 1,000 volts;

(z) "**kVA**" means a kV ampere and one kV ampere equals 1,000 volt-amperes;

(aa) "**kW**" means a kilowatt and one kilowatt equals 1,000 watts;

(bb) "**kWh**" means a kW hour, the common unit of electrical energy, equal to one kilowatt of power supplied to or taken from an electric circuit for one hour;

(cc) "**Major Industrial Customer**" means a customer of YEC, or of any other regulated electric utility in the Yukon Territory, engaged in manufacturing, processing, or mining whose electrical service is inter-connected with electrical service provided to any other customer of such electric utilities and whose peak Electric Demand exceeds 1,000 kW or any future replacement definition or replacement service capacity threshold applicable to manufacturing, processing, or mining activities of the VGC Group, as approved by the YUB;

(dd) "**Maximum Electric Demand**" means the maximum Electric Demand for Mine Firm Electricity that YEC is obligated to deliver to the VGC Group at the Point of Delivery under Part 5;

(ee) "**McQuesten Substation**" means the substation located along Transmission Facilities between Mayo and Keno City at approximately the junction of the South McQuesten Road and the Silver Trail Highway, and to be developed by the Parties, but owned and operated by YEC, in accordance with Schedule B and the provisions of this Agreement;

(ff) "**McQuesten Substation Operation Date**" means the date that YEC provides notice to VGC Group to confirm that the Initial YEC System Improvements are complete and the McQuesten Substation is available to deliver Grid Electricity to the Mine Facilities through the Mine Facilities Spur;

(gg) "**Mine**" means the VGC Group's "Eagle Gold Project" located on the Mine Site;

(hh) "**Mine Facilities**" means any mining or other facilities developed or operated by VGC Group at the Mine Site, which Mine Facilities include the Mine;

(ii) "**Mine Facilities Operation Date**" means the date on which VGC Group provides notice to YEC, after commissioning of the Mine Facilities, the Mine Facilities Spur, and the VGC Group Power Facilities to confirm the start of commercial operation of the Mine;

(jj) "**Mine Facilities Shut Down Date**" means the date provided by VGC Group to YEC on which YEC is to initiate permanent termination of any further delivery of Grid Electricity to the Mine Facilities under this Agreement;

(kk) "**Mine Facilities Spur**" means the approximate 44km, 69kV transmission line that VGC Group will construct, own, and operate to connect the Mine Facilities to the Point of Delivery to receive Grid Electricity from YEC under this Agreement;

(ll) "**Mine Firm Electricity**" means Grid Electricity delivered by YEC to the Mine on a firm basis;

(mm) "**Mine Site**" means those lands and premises to be used for the Mine and located on the Dublin Gulch property approximately 40 kilometers from Mayo, Yukon Territory and approximately 25 km straight line northwest from the McQuesten Substation with an approximate 44 km road access to the Mine Site from the Silver Trail Highway along the South McQuesten and Haggart Creek Roads;

(nn) "**MVA**" means thousands of kV amperes;

(oo) "**MW**" means a megawatt, being the electrical unit of power which is equal to 1,000 kW or 1,000,000 watts;

(pp) "**MWh**" means a MW hour, being the electrical energy equal to one megawatt of power supplied or taken from an electric circuit for one hour;

(qq) "**MOU"** has the meaning in Section B.2 of Schedule B;

(rr) "**Non-Defaulting Party**" has the meaning in Section 11.2;

(ss) "**Operating Agreement**" means the operating agreement for the YEC power system and the VGC Group Power Facilities that the Parties will implement under Schedule E, and any amendments to the Operating Agreement made under this Agreement;

(tt) "**Other Industrial Customer"** means a YEC Major Industrial Customer, other than the VGC Group, that receives Grid Electricity from the Transmission Facilities;

(uu) "**Other YEC System Improvements**" means system improvements for YEC's power system undertaken under this Agreement to supply Grid Electricity to the Mine Facilities in response to an agreed increase in the Maximum Electric Demand as provided for in Section 5.5, and excludes the Initial YEC System Improvements;

(vv) "**Parties**" means YEC, VGC, and StrataGold and "**Party**" means any one of them;

(ww) "**Person**" means an individual, firm, partnership, body corporate, or other legal entity, a government or any department or agency thereof, a trustee, any unincorporated organization and the heirs, executors, administrators, or other legal representatives of an individual, as the case may be;

(xx) "**Point of Delivery**" means the point at the McQuesten Substation where the slack span from the McQuesten Substation connects to the deadend insulator at the first Mine Facilities Spur transmission structure, with the insulator and jumper and all of their components being on the VGC Group side and the conductor being on the YEC side, with revenue metering for Grid Electricity located inside the McQuesten Substation at the breaker that the Mine Facilities Spur connects;

(yy) "**Power Factor**" means the ratio at the Point of Delivery of the highest metered kW demand in a billing period to the highest metered kVA demand in that same billing period;

(zz) "**Power Quality Requirements**" means YEC's power quality requirements, as set out in Schedule F, applicable to the VGC Group's operation of the Mine Facilities when receiving Grid Electricity from YEC;

(aaa) "**RAS**" remedial action schemes;

(bbb) "**SCC**" means YEC's system control centre;

(ccc) "**SPS**" means special protection schemes;

(ddd) "**Service Charge**" means the late payment charge on any overdue account of YEC as provided for in the Terms and Conditions;

(eee) "**Step Down Transformer**" means a transformer located in the McQuesten Substation and designed to step down from 138 kV to 69kV;

(fff) "**SPS**" has the meaning in Section c.1(e) of Schedule C;

(ggg) "**Stewart Crossing Substation**" means the YEC substation located south of the Stewart River at Stewart Crossing;

(hhh) "**StrataGold**" has the meaning on page one;

(iii) "**SVC/Statcom**" means voltage support equipment for reactive compensation, consisting of either a static-var compensator (SVC) or a static synchronous compensator (statcom), located at the Stewart Crossing Substation;

(jjj) "**Term**" has the meaning in Section 2.1;

(kkk) "**Terms and Conditions**" means the Terms and Conditions of Service applicable to YEC, or any future replacement terms and conditions applicable to YEC, as approved by the YUB;

(lll) "**Transmission Facilities**" means the Mayo to McQuesten Substation segment of YEC's 69 kV Mayo to Keno City transmission facilities located north of Mayo, Yukon Territory, or any Transmission Facilities Development;

(mmm) "**Transmission Facilities Development**" means any future transmission facilities developed by YEC to replace existing Transmission Facilities and to connect the McQuesten Substation with a substation at either Mayo or Stewart Crossing;

(nnn) "**Transmission Facilities Development Operation Date**" means the date provided by YEC to VGC Group to confirm that the Transmission Facilities Development has been completed and is in service to deliver Grid Electricity to the Mine Facilities through the Mina Facilities Spur;

(ooo) "**Transmission Facilities Fixed Cost**" means YEC's annual cost, as approved by the YUB from time to time, for depreciation and return on rate base related to the Transmission Facilities plus the SVC/Statcom if and when it is installed;

(ppp) "**VGC**" has the meaning on page one;

(qqq) "**VGC Group**" has the meaning on page one;

(rrr) "**VGC Group Capital Costs**" means all of the VGC Group's reasonably incurred costs incurred in the design, engineering, procurement, construction, and commissioning of the Mine Facilities Spur;

(sss) "**VGC Group Forecasts**" has the meaning in Section 5.2;

(ttt) "**VGC Group Power Bill**" means the monthly bill sent by YEC to VGC Group under Section 7.1;

(uuu) "**VGC Group Power Facilities**" means the power facilities that VGC Group is to install and operate as part of the Mine Facilities under Schedule D;

(vvv) "**VGC Group Share**" has the meaning in Section 7.7;

(www) "**volt**" means the unit of electrical potential, electrical potential difference, and electromotive force in the International System of Units;

(xxx) "**watt**" means the electrical unit of power or rate of energy transfer in the International System of Units;

(yyy) "**YEC**" means has the meaning on page one;

(zzz) "**YEC Capital Costs**" means all of YEC's reasonably incurred costs incurred in the design, engineering, procurement, construction, and commissioning of the McQuesten Substation as set out in Schedule B and the Initial YEC System Improvements as set out in Schedule C, YEC's costs reasonably incurred to negotiate and conclude this Agreement, YEC's costs reasonably incurred for the Step Down Transformer if required, and YEC's costs reasonably incurred for any Other YEC System Improvements if required;

(aaaa) "**YEC McQuesten Substation Costs**" means the VGC Group's capital costs for the McQuesten Substation development as specified in Schedule B that VGC Group will incur and recover from YEC under this Agreement;

(bbbb) "**YEC Owner's Costs**" means YEC's capital costs for the McQuesten Substation development as set out in Table B-1 of Schedule B that YEC will recover from VGC Group under this Agreement; and

(cccc) "**YUB**" means the Yukon Utilities Board.

1.2 **Schedules**. The following Schedules are attached to and form a part of this Agreement:

(a) Schedule A – Firm Mine Rate and Fixed Charge;

(b) Schedule B –McQuesten Substation;

(c) Schedule C - Initial YEC System Improvements;

(d) Schedule D - VGC Group Power Facilities;

(e) Schedule E - Operating Agreement; and

(f) Schedule F - Power Quality Requirements.

1.3 **Interpretation**. Under this Agreement:

(a) references to voltage are approximate;

(b) words importing the masculine gender include the feminine and neuter genders, and Persons, and words in the singular include the plural, and vice versa, wherever the context requires;

(c) all references to designated Parts and Sections are to the designated Parts and Sections of this Agreement;

(d) using separate Parts and Sections, providing a table of contents, and inserting headings are for convenience only and will not affect how this Agreement is interpreted;

(e) unless otherwise indicated, any reference to a currency is a reference to Canadian currency;

(f) except where otherwise specified, any reference to a statute includes a reference to such statute and to its regulations, with all amendments in force from time to time, and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute or regulation; and

(g) any reference to a Person includes a reference to any Person that is a successor to that Person.

PART 2
DURATION

2.1 **Term**. This Agreement will commence as of the date of this Agreement and, unless terminated earlier under this Agreement, will terminate on the Mine Facilities Shut Down Date (the "**Term**").

PART 3
CONDITIONS PRECEDENT

3.1 **Conditions**. The obligations of the Parties to proceed with their obligations under this Agreement (except for obligations of the Parties under this Section 3.1) are subject to fulfilment of the following conditions:

(a) on or before February 28, 2018, the YUB will have approved the VGC Group payments under Section 6.1, the Transmission Facilities Fixed Cost of $118,621, the provisions under Section 7.7 for amending the Transmission Facilities Fixed Cost and for setting the annual amount of the Fixed Charge, and amendments to the Firm Mine Rate as required to conform to Schedule A and this Agreement;

(b) on or before February 15, 2018 VGC Group will have provided evidence satisfactory to YEC, acting reasonably, that VGC Group has sufficient funds or financing available and adequate approvals to proceed with the design, engineering, procurement, construction, and commissioning of the McQuesten Substation, the Mine, the Mine Facilities, and the

Mine Facilities Spur, on the schedule set out in this Agreement to enable the Mine Facilities Operation Date to occur on or before June 30, 2019;

(c) on or before May 15, 2018 VGC Group will have provided evidence satisfactory to YEC, acting reasonably, that VGC Group has commenced site construction of the Mine Facilities, the Mine Facilities Spur, and the McQuesten Substation and is proceeding diligently and in good faith such that VGC Group is expected to achieve the Mine Facilities Operation Date under Section 3.1(b); and

(d) on or before September 30, 2018 YEC will have received all approvals reasonably required by YEC from Yukon Development Corporation, the Yukon Territorial Government, and such other approvals as YEC may reasonably require to proceed with and complete the design, engineering, procurement, construction, and commissioning of the Transmission Facilities Development as set out in Section 4.5.

Conditions 3.1(a) and (b) are for benefit of both Parties and may only be waived, altered, or the time period extended by agreement between the Parties. Conditions 3.1(c) and (d) are for the benefit of YEC with regard to YEC's obligations under Sections 4.3 and 4.5 and each of these Conditions may be waived, altered, or the time period extended by YEC, in its absolute discretion, by notice by YEC to VGC Group at any time prior to the expiry of the applicable Condition. The Parties will exercise commercially reasonable efforts, to ensure that the Conditions for which they are responsible are fulfilled on or before the date specified. If any of the Conditions set out in Sections 3.1(a), (b), or (c) are neither fulfilled, waived, altered, or the time period extended, on or before the date specified, this Agreement will terminate with immediate effect and neither Party will have any further right or obligation under this Agreement, except for the fulfilment of those obligations which arose prior to the date of termination and except for any rights or obligations which are expressly stated to survive the termination of this Agreement. If Condition 3.1(d) is not fulfilled, waived, altered, or the time period extended before the date specified, this Agreement will not terminate, but YEC will have no obligation to proceed with the Transmission Facilities Development under Section 4.5.

PART 4
INITIAL ACTIVITIES

4.1 **Filing with YUB**. Upon execution and delivery of this Agreement, YEC will proceed diligently and in good faith to file an application with the YUB seeking YUB approval of the VGC Group payments under Section 6.1, the Transmission Facilities Fixed Cost of $118,621, the provisions under Section 7.7 for amending Transmission Facilities Fixed Cost and for setting the annual amount of the Fixed Charge, and amendments to the Firm Mine Rate as required to conform with Schedule A and this Agreement. YEC will provide the YUB with such supporting documentation as required by the YUB for such application. VGC Group will support the YEC application to YUB as YEC may reasonably require to obtain the approval of the YUB under this Section 4.1.

4.2 **McQuesten Substation**. Upon execution and delivery of this Agreement, the Parties will proceed diligently and in good faith and will exercise commercially reasonable efforts to design, engineer, procure, construct, commission and turnover of the McQuesten Substation to YEC under the terms and conditions set out in Schedule B to achieve the McQuesten Substation Operation Date on or before February 28, 2019.

4.3 **Initial YEC System Improvements**. Upon execution and delivery of this Agreement, YEC will proceed diligently and in good faith and will exercise commercially reasonable efforts to design, engineer, procure, construct, and commission the Initial YEC System Improvements under the terms and conditions set out in Schedule C as required to accommodate Commencement of Delivery on a date mutually agreed to by the Parties in March 2019.

4.4 **Mine Facilities, Mine Facilities Spur, and VGC Group Power Facilities.** Upon execution and delivery of this Agreement, VGC Group will proceed diligently and in good faith and will exercise commercially reasonable efforts to design, engineer, procure, construct, and commission the:

(a) Mine Facilities;

(b) Mine Facilities Spur; and

(c) VGC Group Power Facilities as set out in Schedule D;

so as to be able to achieve Commencement of Delivery on a date mutually agreed to and presently estimated by the Parties to be in March 2019. VGC Group will from time to time, and at least once every two months, provide notice to YEC of VGC Group's progress and material milestones under this Section 4.4. VGC Group will provide notice to YEC of the date when the VGC Group Power Facilities are completed and the date when the Mine Facilities and the Mine Facilities Spur are available to receive Grid Electricity from YEC. The Parties will use commercially reasonable efforts to cooperate and coordinate their activities under this Section 4.4 to ensure the Commencement of Delivery occurs on a date mutually agreed to and presently estimated by the Parties to be in March, 2019.

4.5 **Transmission Facilities Development**. VGC Group acknowledges that the Transmission Facilities are at or near their end of life, and the Transmission Facilities must be upgraded before YEC can reliably deliver Grid Electricity to the Mine Facilities. Upon execution and delivery of this Agreement, YEC will, subject to the Condition in Section 3.1(d) being fulfilled, proceed diligently and in good faith and will exercise commercially reasonable efforts to commence, on or before October 1, 2018, the design, engineering, procurement, construction, and commissioning of the Transmission Facilities Development with the expectation that the Transmission Facilities Development Operation Date will occur within:

(a) 21 months of October 1, 2018 if the Transmission Facilities Development includes new Transmission Facilities located between McQuesten Substation and the existing Mayo substation that are to be operated at 69 kV; or

(b) 30 months of October 1, 2018 if the Transmission Facilities Development includes new 138 kV Transmission Facilities connecting the McQuesten Substation with a substation at Stewart Crossing.

YEC will, from time to time, and at least once every two months, provide notice to VGC Group of YEC's progress and material milestones under this Section 4.5. YEC will provide notice to VGC Group of the Transmission Facilities Operation Date. VGC Group will provide to YEC such support as YEC may require, acting reasonably, for YEC to secure funding for the Transmission Facilities Development.

4.6 **Step Down Transformer**. If the Transmission Facilities Development includes a 138 kV transmission line connecting the McQuesten Substation with a substation at Stewart Crossing, YEC will design, engineer, procure, construct, and commission the Step Down Transformer as part of the Transmission Facilities Development.

4.7 **SVC/Statcom**. YEC will design, engineer, procure, construct, and commission the SVC/Statcom at the Stewart Crossing Substation as part of the Transmission Facilities Development that is developed under Section 4.5.

4.8 **Operating Agreement**. Upon execution and delivery of this Agreement the Parties will proceed diligently and in good faith to negotiate, execute, and deliver the Operating Agreement substantially in the form attached to this Agreement as Schedule E on or before the Commencement of Delivery.

PART 5
ELECTRICITY

5.1 **Electricity to be Delivered and Accepted**. From the Commencement of Delivery, YEC will deliver to VGC Group and VGC Group will purchase from YEC Grid Electricity as Mine Firm Electricity at the Firm Mine Rate until the Commercial Operation Cessation Date has occurred, subject to the Maximum Electric Demand and a load Power Factor requirement of 96% leading, as follows:

(a) from the Commencement of Delivery until the Transmission Facilities Development Operation Date, Maximum Electric Demand of up to 10,100 kVA;

(b) after the Transmission Facilities Development Operation Date, Maximum Electric Demand of up to 14,300 kVA; and

(c) subject to the specified Maximum Electric Demand and its constraints on Electric Energy delivered by YEC to the VGC Group, Electric Energy of approximately 51,800 MWh/year in the first twelve months after the Mine Facilities Operation Date, approximately 63,600 MWh/year in the second twelve months after the Mine Facilities Operation Date, approximately 67,400 MWh/year in the third twelve months after the Mine Facilities Operation Date, approximately 70,200 MWh/year in the fourth twelve months after the Mine Facilities Operation Date, approximately 72,600 MWh/year in the fifth twelve months after the Mine Facilities Operation Date, and approximately 74,100 MWh/year thereafter until the Commercial Operations Cessation Date; and

(d) during an approximate 90 day period that falls between December 1 and March 31 of every year during the Term, Electric Demand will be reduced so as not to exceed approximately 6,000 kVA.

5.2 **VGC Group Forecasts**. VGC Group will provide to YEC annual forecasts ("**VGC Group Forecasts**") of the Grid Electricity requirements of the Mine Facilities at the Point of Delivery in accordance with the following provisions:

(a) VGC Group Forecasts for each of the succeeding calendar years that the Mine Facilities are expected to require Grid Electricity, so as to allow YEC to forecast the future Electric Demand and Electric Energy loads on the Mine Facilities. The VGC Group Forecast will be provided to YEC eight months in advance of each calendar year end, starting upon execution and delivery of this Agreement, and will include load patterns showing the characteristics of the expected Mine Firm Electricity, including the characteristics for Electric Demand and Electric Energy on a monthly basis. With regard to Grid Electricity requirements after year six of Mine Facilities operation, the VGC Group Forecasts will update YEC on VGC Group plans related to changes in Mine Facilities, the steps and schedule to implement these plans, and the expected impacts of Grid Electricity requirements for the Mine Facilities.

(b) VGC Group will advise YEC by notice forthwith of any material change to the VGC Group Forecasts for Mine Firm Electricity, including the characteristics for Electric Energy or Electric Demand.

(c) During the first week of each month after Commencement of Delivery, VGC Group will advise YEC by notice of its estimated daily requirements for Mine Firm Electricity during the following month.

5.3 **Point of Delivery** . YEC will deliver Grid Electricity to VGC Group and VGC Group will receive Grid Electricity from YEC at the Point of Delivery.

5.4 **Maximum Electric Demand**. YEC's obligation to supply Mine Firm Electricity to VGC Group will not exceed the Maximum Electric Demand in effect at any time at the Point of Delivery, and, in accordance with Schedule E, YEC is entitled to cease delivery of Grid Electricity to the Mine Facilities if VGC Group continues to receive Mine Firm Electricity in excess of the Maximum Electric Demand after notice from YEC that VGC Group's load is exceeding the Maximum Electric Demand cap. Notwithstanding such Maximum Electric Demand, if VGC Group receives from YEC Mine Firm Electricity in excess of the Maximum Electric Demand, VGC Group will pay for the billing demand charge on all metered kVA billing demand recorded at the Firm Mine Rate.

5.5 **Increase in Maximum Electric Demand**. If VGC Group requires an increase to its Maximum Electric Demand in excess of that under Section 5.1, the following will apply:

(a) VGC Group will provide YEC with notice of the specified amount of the requested increase together with the period of time during which the increase is required and the related increase in Mine Firm Electricity requirement together with such information and documents as YEC may reasonably require to consider the request;

(b) after receipt of such notice, YEC will have a reasonable period of time to determine whether or not the Transmission Facilities and YEC's other facilities have the ability to supply and maintain that increased Electric Demand, as well as any potential requirement for an increase to the Mine Firm Rate, Other YEC System Improvements, and new YEC Capital Costs related to such increase in Mine Firm Electricity, and YEC will forthwith provide notice to VGC Group of YEC's determination;

(c) following such notice by YEC to the VGC Group, if the Parties are unable to agree on the matters set out under Section 5.5(b) within a period of 90 days from the date of such written notice by YEC to the VGC Group, no increase in Maximum Electric Demand will be provided. For greater certainty the Parties' failure to agree on the matters set out in this Section 5.5(c) will not be a Dispute and will not be subject to Part 12; and

(d) if the Parties are able to agree on the matters set out in Section 5.5(b) within 90 days then the Parties will enter such amendments to this Agreement as the Parties may reasonably require to reflect such agreements, including provision for YUB approval of any changes required to the Firm Mine Rate. If the Parties are unable to execute and deliver such agreements within a period of 120 days of the notice under Section 5.5(c), no amendments to this Agreement will occur. For greater certainty the Parties' failure to agree on such agreements will not be a Dispute and will not be subject to Part 12.

5.6 **VGC Group Standards for Usage of Electricity**. The Parties will comply with the Operating Agreement and VGC Group will regulate its electrical load in accordance with the Power Quality Requirements, including the requirement to maintain a 96% leading load Power Factor for Grid Electricity delivered to VGC Group at the Point of Delivery, or as otherwise agreed to by the Parties from time to time, acting reasonably. VGC Group will operate its equipment and use the Grid Electricity at the Mine so as not to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations of YEC's electrical system. VGC Group will comply with reasonable standards of operation under the Operating Agreement or the Power Quality Requirements or as otherwise provided by YEC to VGC Group by notice from time to time. If VGC Group fails to comply with these requirements or standards of operation so as to endanger any of YEC's plant or equipment or cause any unacceptable fluctuations on YEC's electrical system, YEC may by notice to VGC Group require that VGC Group remedy the situation. Should VGC Group fail to immediately comply with this Section 5.6 upon receiving such notice regarding the Point of Delivery, YEC may immediately suspend the supply of Grid Electricity to VGC Group at such Point of Delivery and continue such suspension until the situation is remedied. Upon receipt of such notice VGC Group may provide notice to YEC that VGC Group wishes YEC to operate any such equipment endangering YEC's plant, or equipment, or electrical system at VGC Group's sole cost and expense. Upon receipt of such notice YEC will provide notice to VGC Group as to whether YEC will operate such

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equipment and in such case VGC Group will indemnify and save harmless YEC against any costs, damages, or losses associated with such operations.

5.7 **Terms and Conditions of Service**. The Terms and Conditions apply to the Parties with regard to Grid Electricity delivered by YEC to VGC Group under this Agreement including, without limitation, the provisions regarding the responsibility and liability of each Party. If there is an inconsistency between the Terms and Conditions and this Agreement the Terms and Conditions will govern.

5.8 **Commercial Operation Cessation Date**. VGC Group will provide notice to YEC of a Commercial Operation Cessation Date within 30 days of the occurrence of such Commercial Operation Cessation Date.

5.9 **Suspension of Commercial Operation**. VGC Group will provide notice to YEC as provided for in Section 4 of Schedule E of planned maintenance and scheduling for the Mine Facilities. Such notice will include the date on which Commercial Operation will cease, VGC Group's reasonable estimate of the length of the period during which Commercial Operation will be suspended, and the related adjustments to VGC Group Forecasts as required under Section 5.2. If VGC Group suspends Commercial Operation and such suspension continues for five consecutive years without VGC Group providing notice to YEC of a Mine Facilities Shut Down Date during this suspension, VGC Group will then be deemed to have provided notice to YEC that the Mine Facilities Shut Down Date has occurred as of the last day of the five years of continuous suspension. VGC Group will provide copies to YEC of any VGC Group notice to the Minister under the Quartz Mining Act regarding specified events at the Mine where such notice is required, including commencement of active operations, discontinuance or resumption of operations, and plans to bring the Mine back into operations.

5.10 **Planned YEC Maintenance**. YEC may, from time to time, for planned annual maintenance of its transmission and generation facilities, require a curtailment or suspension in the Grid Electricity supplied to the Mine for a period of up to 14 days per calendar year and YEC will provide notice to VGC Group, as provided for in Section 4 of Schedule E, of any such planned maintenance. Such notice will include the date on which such maintenance will commence, YEC's expected duration of the maintenance, and the impact on YEC's obligations to deliver Grid Electricity to VGC Group under this Agreement.

PART 6
YEC CAPITAL COSTS

6.1 **YEC Capital Costs**.

(a) As of the date of this Agreement YEC's estimate for the YEC Capital Costs not paid to date by VGC Group for the negotiation and conclusion of this Agreement is $200,000. Within 15 days of the execution and delivery of this Agreement YEC will invoice VGC Group for 50% of YEC's estimated YEC Capital Costs under this Section 6.1(a), and within 15 days of receipt of said invoice VGC Group will pay such amount to YEC. YEC will invoice VGC Group for the balance of the amount owing as soon as is reasonably practicable after YEC determines the actual amount of YEC Capital Costs incurred under this Section 6.1(a) and VGC Group will pay such amount within 15 days of receipt of such invoice.

(b) As of the date of this Agreement YEC's estimate of the YEC Capital Costs that YEC is to recover from VGC Group for the Initial YEC System Improvements is $1,677,883. Within 15 days of the execution and delivery of this Agreement YEC will invoice VGC Group for 50% of YEC's estimated YEC Capital Costs under this Section 6.1(b), and within 15 days of the date of the approval of this Agreement by the YUB VGC Group will pay such amount to YEC. YEC will invoice VGC Group for the balance of the amount owing as soon as is reasonably practicable after YEC has completed the Initial YEC System Improvements as required by Section 4.3 and has determined the actual cost of the Initial YEC System Improvements under this Section 6.1(b), and VGC Group will pay such

amount within 15 days of receipt of such invoice. Provided however that if the amount to be invoiced VGC Group for the Initial YEC System Improvements exceeds $1,677,883 then YEC will provide VGC Group with details of the increase in cost and confirm to VGC Group that such increase in cost is not caused by a change to the scope of the work for the Initial YEC System Improvements as set out in Schedule C and was otherwise a reasonably necessary increase in cost to complete the Initial YEC System Improvements.

(c) As of the date of this Agreement YEC's estimate for the YEC Owner's Costs that YEC is to recover from VGC Group for the McQuesten Substation is $483,240. Within 15 days of the execution and delivery of this Agreement YEC will invoice VGC Group for 50% of YEC's estimated YEC Owner's Costs under this Section 6.1(c), and within 15 days of the date of the approval of this Agreement by the YUB, VGC Group will pay such amount to YEC. YEC will invoice VGC Group for the balance of the amount owing as soon as is reasonably practicable after the Commencement of Delivery and after YEC has determined the actual cost of the YEC Owner's Costs, and VGC Group will pay such amount within 15 days of receipt of such invoice. Provided however that if the amount to be invoiced to VGC Group for the YEC Owner's Costs exceeds $483,240 then YEC will provide VGC Group with details of the increase in cost and confirm to VGC Group that such increase in cost is not caused by a change to the scope of the work for the YEC Owner's Costs as set out in Schedule C and was otherwise a reasonably necessary increase in cost to complete the YEC Owner's Costs.

(d) The YEC McQuesten Substation Costs under Section B.4 of Schedule B associated with the McQuesten Substation being able to operate at 138 kV is $930,563. At the time that the McQuesten Substation is transferred to YEC by VGC Group under Schedule B, VGC Group will invoice YEC for, and within 15 days after Commencement of Delivery, YEC will pay VGC Group, $930,563 for the YEC McQuesten Substation Costs. Provided however that if there is a change in the scope of the McQuesten Substation work that:

(i) is approved by YEC; and

(ii) results in VGC Group incurring an increase in the YEC McQuesten Substation Costs;

VGC Group will:

(iii) provide YEC with details of the increase in the costs due to the change in scope; and

(iv) confirm to YEC that such increase in costs was a reasonably necessary increase to complete the YEC McQuesten Substation Costs.

Subject to YEC's review and confirmation of the VGC Group submission, YEC will pay to VGC Group the reasonable increase in the costs due to the change in scope affecting the YEC McQuesten Substation Costs.

(e) If the Step Down Transformer is required to be provided by YEC under Section 4.6, YEC will invoice VGC Group when YEC orders the Step Down Transformer for 50% of all of YEC's estimated costs and expenses reasonably required for design, engineering, procurement, construction, and commissioning of the Step Down Transformer and VGC Group will pay such invoice within 15 days of receipt. YEC will invoice VGC Group for the remainder of YEC's reasonably incurred costs and expenses to design, engineer, procure, construct, and commission the Step Down Transformer within 30 days of when the Step Down Transformer is commissioned and VGC Group will pay such invoice within 15 days of receipt.

(f) If YEC incurs Other System Improvement capital costs caused by an increase in Maximum Electric Demand under Section 5.5, the related amendments to this Agreement will provide for YEC to recover from VGC Group any reasonably incurred YEC Capital Costs for the required Other System Improvements.

PART 7
BILLING/PAYMENT

7.1 **VGC Group Power Bill**. As soon as practicable following the last day of each month after the Commencement of Delivery, YEC will deliver the VGC Group Power Bill to VGC Group setting out the amount payable to YEC by VGC Group under this Agreement for all Electricity delivered by YEC to VGC Group during such month. VGC Group will pay YEC the amount set out in each VGC Group Power Bill within 15 Business Days of the date of delivery of the VGC Group Power Bill to VGC Group. Electricity provided by YEC to VGC Group will be charged to VGC Group at the rates provided for in this Agreement.

7.2 **Canadian Funds**. All payments by VGC Group to YEC will be made in Canadian funds to an office or banker of YEC, as YEC may direct to VGC Group in writing, at Whitehorse, Yukon Territory.

7.3 **Failure to Render Invoice**. Failure to render an invoice within the time periods set out in this Agreement will not abrogate YEC's right to receive payment of the VGC Group Power Bill, VGC Group Capital Cost, Decommissioning Costs, or other amounts payable under this Agreement.

7.4 **Late Payment** Any payment to be made by VGC Group to YEC under this Agreement that remains unpaid, in whole or in part, when due will be subject to a late payment charge at a rate of interest equivalent to the Service Charge calculated on the amount unpaid from the due date of payment until payment is made in full.

7.5 **Prepayments**. Any payments to be made by VGC Group to YEC under this Agreement may be prepaid by VGC Group at any time in whole or in part without penalty.

7.6 **Taxes**. All sales taxes, excise taxes, or similar charges payable on Electricity delivered to VGC Group under this Agreement will be added to the VGC Group Power Bill and paid by VGC Group under Section 7.1.

7.7 **Fixed Charge**. The Fixed Charge will be determined as follows:

(a) Prior to the Transmission Facilities Development Operation Date, the Transmission Facilities Fixed Cost used to determine the Fixed Charge is $118,621, or any amended amount approved by the YUB from time to time.

(b) After the Transmission Facilities Development Operation Date, YEC will apply to the YUB to amend the Transmission Facilities Fixed Cost based on YEC's adjusted annual costs for depreciation and return on rate base related to the Transmission Facilities plus the SVC/Statcom and YEC's McQuesten Substation Costs. The adjusted Transmission Facilities Fixed Cost will apply until otherwise amended by the YUB.

(c) The annual Fixed Charge amount will be determined by YEC as follows:

(i) in calendar years when there is no Other Industrial Customer, the annual amount for the Fixed Charge will equal 85% of the Transmission Facilities Fixed Cost as last determined by the YUB; and

(ii) in calendar years when there is one or more Other Industrial Customers, the estimated VGC Group portion of the Major Industrial Customer MWh load on the

Transmission Facilities during the calendar year (the "**VGC Group Share**") will be estimated by YEC and the Fixed Charge for months during the calendar year will equal the VGC Group Share of 85% of the Transmission Facilities Fixed Cost as last determined by the YUB. Within 60 days of the calendar year end, YEC will adjust the Fixed Charge based on the actual VGC Group Share as determined by actual MWh load during the calendar year for VGC Group and any Other Industrial Customers. The fixed charge applicable to each Other Industrial Customer in any calendar year will be determined in the same manner, based on each such customer's share of the Major Industrial Customer MWh load on the Transmission Facilities during the calendar year.

(iii) With regard to securing any required YUB approvals related to Fixed Charge amounts, including any approvals related to the VGC Group Share or the Transmission Facilities Fixed Cost, YEC will provide the YUB with such supporting documentation as required by the YUB, and will use commercially reasonable efforts to obtain the approval of the YUB, and VGC Group will use commercially reasonable efforts to support such application by YEC.

PART 8
METERING

8.1 **Metering**. The Grid Electricity purchased by VGC Group under this Agreement will be measured and recorded at the Point of Delivery by revenue meters having one hour integrating intervals, which meters, will be types approved for revenue metering by Industry Canada and will comply with the *Electricity and Gas Inspection Act* (the "**Act**").

8.2 **Testing**. YEC will test its metering equipment under Section 8.1 and field test the metering installation in compliance with the Act. If requested to do so by VGC Group, YEC will make additional tests or inspections of such installations, the expense of which will be paid by VGC Group, unless VGC Group has confirmed by such testing that the metering is faulty in which case such testing will be paid for by YEC. YEC will give reasonable written notice to VGC Group of the time when any such test or inspection is to be made. VGC Group may have representatives present at such test or inspection. Any component of such installations found to be defective or inaccurate will be adjusted, repaired, or replaced by YEC to provide accurate metering. If a meter is found not to be functioning within the prescribed limit of error, the Electricity purchased will be determined under the Act.

8.3 **Backup Metering**. VGC Group may, at its cost and expense, install a backup metering system to check YEC's metering system performance and, if so, VGC Group will own, operate, and maintain this system, at VGC Group's sole cost and expense.

8.4 **Costs**. All costs and expenses incurred by YEC, beyond normal reading and testing of meters and other costs that YEC is to pay under Section 8.2, in complying with its obligations under Section 8.2 will be invoiced separately to VGC Group by YEC and will be paid by VGC Group upon receipt.

PART 9
FORCE MAJEURE

9.1 **Force Majeure**. Subject to Section 9.3, neither Party will be liable to the other Party for any delay in or inability of the first Party to perform its obligations under this Agreement if any such delay or inability is a direct result of Force Majeure.

9.2 **Notice of Force Majeure**. If a Party suffers a Force Majeure it will promptly notify the other Party in writing and within 10 days of becoming so aware will give written notice to the other Party:

(a) describing the Force Majeure in reasonable detail and stating, to the extent reasonably practicable at such time, its estimate of the duration of the Force Majeure;

(b) setting out in reasonable detail the obligations under this Agreement which it is unable to perform or will be delayed in performing as a direct result of the Force Majeure;

(c) containing particulars of the circumstances causing the Party to be unable to perform or delayed in performing its obligations under this Agreement as a direct result of the Force Majeure; and

(d) describing what needs to be done and what will be done to end the Force Majeure.

(e) During a Force Majeure a Party invoking the Force Majeure will exercise commercially reasonable efforts to end the Force Majeure.

9.3 **Exclusions**. A Party may not invoke Force Majeure:

(a) for lack of money or credit;

(b) if the Force Majeure is the result of a breach by the Party seeking to invoke Force Majeure of a permit, certificate, licence, approval, or of any applicable laws, regulations, or orders;

(c) if the Party seeking to invoke Force Majeure has failed to use commercially reasonable efforts to prevent or remedy the situation and remove, so far as possible and with reasonable dispatch, the effects of the Force Majeure; or

(d) if the Force Majeure was caused by a breach of, or default under this Agreement or a wilful or negligent act or omission by the Party seeking to invoke Force Majeure.

If a Party is required to perform an obligation by a certain date or with a specified time period and the Party is delayed in performing that obligation by a Force Majeure the date or time for the performance of that obligation will be extended by a period of time equal to the length of the Force Majeure.

PART 10
REPRESENTATIONS AND WARRANTIES

10.1 **YEC Representations and Warranties**. To induce VGC Group to enter into this Agreement YEC hereby represents and warrants to VGC Group as of the effective date of this Agreement, upon each of which representations and warranties VGC Group specifically relies, as follows:

(a) YEC Corporate Organization and Authority: YEC has been duly incorporated and is a validly existing corporation under the laws of the Yukon Territory, is in good standing with respect to all required filings in the office of the Registrar of Companies and has the full corporate power and capacity to execute and deliver this Agreement and perform its obligations under this Agreement.

(b) Authorization, Consents, and Enforceability: The execution and delivery of this Agreement by YEC and the consummation by YEC of the transactions contemplated hereby have been duly authorized by the Board of Directors of YEC and this Agreement constitutes valid and binding obligations of YEC, enforceable against YEC in accordance with its terms, subject to the availability of equitable remedies and enforcement of creditors' rights generally.

(c) Compliance: The entering into and compliance by YEC with this Agreement is legal, does not violate any provisions of any requirement of law and does not result in any breach of any of the provisions of, or constitute a default under any charter document, by-law, unanimous shareholder agreement, loan agreement, or other agreement or instrument to which YEC is a party or by which it is or its property may be bound.

10.2 **VGC Group Representations and Warranties**. To induce YEC to enter into this Agreement VGC Group hereby represents and warrants to YEC as of the effective date of this Agreement, upon each of which representations and warranties YEC specifically relies, as follows:

(a) VGC Group Corporate Organization and Authority: Each of the members of the VGC Group has been duly incorporated and is a validly existing corporation under the laws of the Province of British Columbia and is in good standing with respect to all required filings in the office of the Registrar of Companies and has the full corporate power and capacity to perform business in the Yukon Territory and to execute and deliver this Agreement and perform its obligations under this Agreement.

(b) Authorization, Consents, and Enforceability: The execution and delivery of this Agreement by VGC Group and the consummation by VGC Group of the transactions contemplated hereby have been duly authorized by the respective Boards of Directors of VGC Group and this Agreement has been duly executed and delivered by VGC Group and constitutes valid and binding obligations of VGC Group, enforceable against VGC Group in accordance with its terms, subject to the availability of equitable remedies and enforcement of creditors' rights generally.

(c) Compliance: The entering into and compliance by VGC Group with this Agreement is legal, does not violate any provisions of any requirement of law and does not result in any breach of any of the provisions of, or constitute a default under any charter document, by-law, loan agreement, or other agreement or instrument to which VGC Group is a party or by which they or their property are or may be bound.

PART 11
DEFAULT

11.1 **Event of Default**. Each of the following events constitutes an "**Event of Default**" for a Party in question (the "**Defaulting Party**"):

(a) an Event of Insolvency of such Party; or

(b) any representation or warranty of such Party contained in this Agreement being untrue in any material respect unless the default is of a nature that can be cured and it is cured within 30 days, or such reasonable time period as may be required given the default, following receipt by the Defaulting Party of written notice from the other Party specifying the nature of the default and requiring that the default be cured; or

(c) any default (other than defaults of a non-material nature) by such Party in the performance or observance of any of the covenants, agreements, and obligations on its part to be performed or observed under this Agreement, unless the default is of a nature that can be cured and it is cured within 30 days, or such reasonable time period as may be required given the default, following receipt by the Defaulting Party of written notice from the other Party specifying the nature of the default and requiring that the default be cured.

11.2 **Remedies**. If an Event of Default under Section 11.1 occurs, any Party not in default (the "**Non-Defaulting Party**") may do one or more of the following:

(a) pursue any remedy available to it in law or equity, it being acknowledged by the Parties that specific performance, injunctive relief (mandatory or otherwise), or other equitable relief may be the only adequate remedy for an Event of Default; or

(b) if the Event of Default is curable, take all actions in its own name or in the name of the Defaulting Party as may reasonably be required to cure the Event of Default, in which event all payments, costs, and expenses incurred therefore will be payable by the Defaulting Party to the Non-Defaulting Party on demand with interest at the Interest Rate; or

(c) waive the Event of Default, provided any waiver of the particular Event of Default will not operate as a waiver of any subsequent or continuing Event of Default; or

(d) in the case of an Event of Default by VGC Group under Section 7.1 YEC may upon 15 days' notice to VGC Group suspend or discontinue the supply of Grid Electricity to VGC Group, but no such suspension or discontinuance by YEC will relieve VGC Group of its obligations under this Agreement, including the obligation to make payment of any sum, nor will any such suspension or discontinuance constitute or be deemed to constitute rescission of this Agreement.

PART 12
DISPUTE RESOLUTION

12.1 **Confidentiality of Process**. The Parties will maintain the dispute resolution process set out in this Part 12 as confidential and such process will not be disclosed, unless otherwise required by law, by any Party to any other Person unless previously discussed and agreed to in writing by the Parties. For greater certainty, no part of the dispute resolution process will be open to the public.

12.2 **Stages**. Disputes that arise among the Parties will progress, until resolved, through the following stages of the dispute resolution process:

Step 1: Within 10 days of one Party providing written notice to the other Parties that a Dispute exists, the Presidents of each of the Parties, or their nominees in the first instance or themselves if they cannot resolve the Dispute, will meet and make good faith efforts to resolve the Dispute through collaborative negotiation by:

(i) identifying underlying interests;

(ii) isolating points of agreement and disagreement;

(iii) exploring alternative solutions;

(iv) considering compromises or accommodations; and

(v) taking any other measures that may assist in resolution of the Dispute.

Step 2: If the Presidents of each of the Parties are unable to resolve the Dispute themselves within 30 days of the written notice under Step 1, either Party may give written notice to the other Party of a desire to commence mediation and the Parties will jointly appoint a mutually acceptable mediator within 30 days after the date that such notice is given. If the Parties are unable to agree upon the appointment of a mediator within 30 days after a Party has given notice of a desire to mediate the Dispute, either Party may apply to the British Columbia Mediator Roster Society for appointment of a mediator. The Parties agree that the mediation will be conducted under the Mediation Rules of the British Columbia Mediator Roster Society.

Step 3: If a Dispute has not been resolved through mediation under Step 2 within 30 days of the appointment of a mediator, either Party, by notice in writing to the other Party, may refer such unresolved Dispute to binding arbitration under the *Arbitration Act*, (R.S.Y., 2002, c.8). The Parties will agree upon an Arbitrator within 30 days of the notice of arbitration being provided, failing which the Arbitrator will be selected under the *Arbitration Act*, (R.S.Y., 2002, c.8). The decision of the arbitrator will be final and binding on the Parties.

12.3 **Availability of Argument**. In any Dispute, a Party may raise any defence or argument that it would otherwise have been able to raise at law, equity, or otherwise, had the Dispute been referred to a court of competent jurisdiction, including a defence that the Dispute is statute-barred by the *Limitation of Actions Act*, (R.S.Y., 2002, c.139).

12.4 **No Further Claims**. When Disputes are settled among the Parties to the Agreement under this Part 12 no further:

(a) claim may be made; and

(b) compensation will be payable by any Party,

for the same Dispute.

12.5 **Continued Payment**. Pending resolution of any Dispute, VGC Group will continue to pay to YEC any sums payable under this Agreement and YEC may avail itself of its remedy under Section 11.2(d) in relation to a failure by VGC Group to do so.

PART 13
INDEMNITY

13.1 **Limitation of Liability**. No Party will be liable to the other Party in contract, tort, warranty, strict liability, or any other legal theory for any indirect, consequential, incidental, punitive, or exemplary damages arising under or in connection with this Agreement or in connection with the failure to perform or observe obligations under this Agreement. No Party will have any liability to the other Party except under, or for breach of, this Agreement provided, however, that this Section 13.1 is not intended to constitute a waiver of any rights of one Party against the other Party for matters which are unrelated to this Agreement.

13.2 **Indemnification**

(a) VGC Group will indemnify and save YEC harmless for any loss or damage to property, death, or injury to Persons (or any claim against YEC in respect thereof) and all expenses relating thereto (including without limitation reasonable legal fees) suffered or incurred by YEC in connection with this Agreement resulting from any negligence or wilful default of VGC Group in connection with the performance of its obligations under this Agreement or a breach by VGC Group of its obligations under this Agreement. The indemnity will not extend to any loss, damage, death, or injury (or any claim in respect thereof) or any expenses relating thereto to the extent that it was caused by the negligence or wilful default of YEC or the failure of YEC to take reasonable steps in mitigation thereof. Notwithstanding anything to the contrary contained in the preceding sentence, nothing in this Section 13.2(a) will apply to any loss, damage, cost, or expense in respect to which, and to the extent that, YEC is compensated under any insurance, agreement, or through any other means.

(b) YEC will indemnify and save VGC Group harmless for any loss of or damage to property, death or injury to person (or any claim against VGC Group in respect thereof) and all expenses relating thereto (including without limitation reasonable legal fees) suffered or

incurred by VGC Group in connection with this Agreement from any negligence or wilful default of YEC in connection with the performance of its obligations under this Agreement or a breach by YEC of its obligations under this Agreement. The indemnity will not extend to any loss, damage, death, or injury (or any claim in respect thereof) or any expenses relating thereto to the extent that it was caused by the negligence or wilful default of VGC Group or the failure of VGC Group to take reasonable steps in mitigation thereof. Notwithstanding anything to the contrary contained in this preceding sentence, nothing in this Section 13.2(b) will apply to any loss, damage, cost or expense in respect of which, and to the extent that, VGC Group is compensated under any insurance, agreement, or through any other means.

(c) If such injury or damage results from the joint or concurrent negligent or intentional acts of the Parties each will be liable under this indemnification in proportion to its relative degree of fault.

13.3 **Assertion of Claims**. No Party will be entitled to assert any claim for indemnification until such time as all claims of such Party for indemnification under this Agreement exceed an amount equal to $10,000, in the aggregate, at which time all claims of such Party for indemnification under this Agreement may be asserted; provided, however, that when such claims have been asserted the same rule will apply in respect of future claims. Notwithstanding the preceding sentence, a Party may assert a claim for indemnification regardless of amount upon the expiry or earlier termination of this Agreement or if such claim would otherwise be barred by the *Limitation of Actions Act*, (R.S.Y., 2002, c.139).

13.4 **Defence of Claims**. The indemnified Party will have the right, but not the obligation, to contest, defend, and litigate any claim, action, suit, or proceeding by any Person alleged or asserted against such Party in respect of, resulting from, related to, or arising out of any matter for which it is entitled to be indemnified under this Agreement, and the reasonable costs and expenses thereof will be subject to the indemnification obligations of the indemnifying Party under this Agreement provided, however, that if the indemnifying Party acknowledges in writing its obligations to indemnify the indemnified Party in respect of loss to the full extent provided by Section 13.2, the indemnifying Party will be entitled, at its option, to assume and control the defence of such claim action, suit, or proceeding at its expense and through counsel of its choice if it gives prompt notice of its intention to do so to the indemnified Party and, reimburses the indemnified Party for the reasonable costs and expenses incurred by the indemnified Party prior to the assumption by the indemnifying Party of such defence, and provides reasonably adequate security for any judgment for costs that might be imposed on the indemnified Party. The indemnified Party will not be entitled to settle or compromise any such claim action, suit, or proceeding without the prior written consent of the indemnifying Party, which consent will not be unreasonably withheld or delayed. The indemnified Party will have the right to employ its own counsel and such counsel may participate in such action (but the fees and expenses of such counsel will be at the expense of such indemnified Party), provided that the:

(a) employment of counsel by such indemnified Party has been authorized in writing by the indemnifying Party;

(b) indemnified Party will have reasonably concluded that there may be a conflict of interest between the indemnifying Party and the indemnified Party in the conduct of the defence of such action;

(c) indemnifying Party will not in fact have employed independent counsel reasonably satisfactory to the indemnified Party to assume the defence of such action and will have been so notified by the indemnified Party; or

(d) indemnified Party will have reasonably concluded and specifically notified the indemnifying Party either that there may be specific defences available to it which are different from or additional to those available to the indemnifying Party or that such claim

action, suit, or proceeding involves or could have a material adverse effect upon it beyond the scope of this Agreement.

If Sections 13.4(a), (b), (c), or (d) are applicable, then counsel for the indemnified Party will have the right to direct the defence of such claim, action, suit, or proceeding on behalf of the indemnified Party and the reasonable fees and disbursements of such counsel will constitute legal or other expenses under this Agreement.

PART 14
ASSIGNMENT

14.1 **Assignment**. No Party may assign this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld.

14.2 **Sale of the Transmission Facilities** . If YEC disposes of all or any interest in the Transmission Facilities, YEC will ensure that the obligation to sell Grid Electricity from the Transmission Facilities, on the same basis as provided for in this Agreement will continue and be assumed by the purchaser of such interest, for the Term. YEC will require, as a condition of the closing of the disposition of such interest, that the purchaser sign an agreement in a form satisfactory to VGC Group, acting reasonably, which provides that the purchaser agrees to be bound by this Agreement.

14.3 **Sale of the Mine**. If VGC Group disposes of all or any interest in the Mine, the Mine Facilities, or the VGC Group Power Facilities, VGC Group will ensure that the obligation to purchase Grid Electricity from YEC on the same basis as provided for in this Agreement will continue and be assumed by the purchaser of the Mine, the Mine Facilities, or the VGC Group Power Facilities for the Term. VGC Group will require as a condition of the closing of the disposition of the Mine, the Mine Facilities, or the VGC Group Power Facilities that the purchaser sign an agreement in a form satisfactory to YEC, acting reasonably, which provides that the purchaser agrees to be bound by this Agreement for the Term.

PART 15
CONFIDENTIALITY

15.1 **Confidentiality**. Except as required by law, and subject to Section 15.1, a Party will not disclose to a third person who is not a Party any information, data, or documents, supplied by one Party to the other Parties under this Agreement (collectively, the "**Confidential Information**") without the consent of the other Party, such consent not to be unreasonably withheld.

15.2 **Exceptions**. Section 15.1 will not:

(a) extend to information that is already in the public domain or becomes, after having been disclosed to a Party, generally available to the public unless the disclosure was made directly or indirectly by a Party in breach of this Agreement;

(b) prevent a Party from divulging Confidential Information in confidence to its Affiliates and to its or their officers, directors, employees, agents, or other representatives on a "need-to-know" basis;

(c) prevent a Party from divulging Confidential Information in confidence to third parties (provided the third party is subject to similar confidentiality restrictions), in order to permit the operation of the Mine or the Transmission Facilities, as the case may be, in the ordinary course, all on a "need-to-know" basis;

(d) prevent a Party from divulging Confidential Information to the extent required by applicable legislation or stock exchange requirements;

(e) prevent a Party from divulging Confidential Information to the extent necessary in connection with any dispute resolution commenced under this Agreement or any litigation commenced in respect of this Agreement;

(f) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to any financial institution for the purpose of obtaining financing for such Party or any of its Affiliates;

(g) prevent a Party from divulging Confidential Information to the extent required by any Governmental Authority having jurisdiction to require the production of such Confidential Information; and

(h) prevent a Party from divulging Confidential Information to the extent necessary, in confidence, to a prospective purchaser of the Mine or the Transmission Facilities or YEC's other assets required to meet YEC's obligations under this Agreement, as the case may be, on a "need to know" basis.

If any Party is required to disclose Confidential Information under Sections 15.2(d), (e), or (g), such Party will advise the other Party in writing in advance of any such disclosure where reasonable so that the other Party may take such action as they consider necessary to maintain the confidentiality of such Confidential Information, and will take reasonable steps to limit the extent of the disclosure and to make such disclosure confidential under the applicable legislation, stock exchange rules, or rules of any governmental or regulatory authority having jurisdiction, as the case may be.

15.3 **Survival**. The obligations of confidentiality in Section 15.1 will survive the termination or expiry of this Agreement indefinitely, and any Party who ceases to be a Party will continue to be bound by such obligations following such termination or expiry.

15.4 **Injunctive Relief**. Each Party acknowledges that all Confidential Information is proprietary to the disclosing Party and that breach of this Agreement by a Party may result in irreparable injury to the other Party. Accordingly, in the event of any breach of Section 15.1 by a Party, the other Party will be entitled to seek and obtain an order of specific performance, restraining order, or injunctive relief, in addition to any other legal or equitable remedies provided under this Agreement.

PART 16
GENERAL

16.1 **Notices**. Except as otherwise provided in this Agreement, any notice, direction, demand, request, or document required or permitted to be given by any Party to any other Party under this Agreement will be in writing and deemed to have been sufficiently given if signed by or on behalf of the Party giving the notice and delivered or transmitted by facsimile to the other Party's address or facsimile number as shown below:

(a) To YEC:

Yukon Energy Corporation
P.O. Box 5920, #2 Miles Canyon Road
Whitehorse, YT Y1A 6S7

Attention: President

Facsimile: 867-393-5323

with a copy to:

DLA Piper (Canada) LLP
2800 - 666 Burrard Street
Vancouver, BC V6C 2Z7

Attention: John Landry

Facsimile: 604-605-3588

(b) To VGC:

Victoria Gold Corp.
1050 West Pender Street
Vancouver, BC V6E 3E7

Attention: Mark Aryanto

Facsimile: 604-682-5232

(c) To StrataGold:

StrataGold Corporation
1050 West Pender Street
Vancouver, BC V6E 3E7

Attention: Mark Aryanto

Facsimile: 604-682-5232

or to such other address or facsimile number or to the attention of such other official or individual as a Party will have most recently notified the other Party of in the manner hereinbefore provided. Any such notice, direction, request, or document will conclusively be deemed to have been received by the intended recipient on the date of delivery or transmission, as the case may be, except that if it is not received at such address or at the facsimile device by 5:00 P.M. on a Business Day (at the place of receipt) it will conclusively be deemed to have been received by the intended recipient on the next Business Day immediately following its receipt at such address or at such facsimile device.

16.2 **Coordination of Communications**. Each Party agrees to cooperate with the other Parties in order to coordinate all press, news, or other releases to private or public media groups in connection with this Agreement. Each Party will use all reasonable efforts to allow the other Parties to review such releases in advance of release and will comply with all reasonable requests from the other Parties as to the content or manner of publication of such releases.

16.3 **Amendment**. The only amendments, which may be made to this Agreement are amendments in writing which have been approved by the Parties.

16.4 **Governing Law and Language**. This Agreement will be governed by and construed under the laws of the Yukon Territory and applicable Canadian law and will be treated in all respects as a Yukon Territory contract.

16.5 **Submission to Jurisdiction**. Each of the Parties will:

(a) submit to the jurisdiction of the Yukon Territory courts;

(b) if not incorporated or registered in the Yukon Territory appoint an agent to receive service of any process in the Yukon Territory; and

(c) if any appointed agent is required, notify the others of the name and address of its appointed agent.

16.6 **Severability**. Each provision of this Agreement is intended to be severable and if any provision is illegal or invalid, such illegality or invalidity will not affect the validity of this Agreement or the remaining provisions.

16.7 **Entire Agreement**

(a) This Agreement and any other arrangement in writing between any of the Parties, which is entered into substantially contemporaneously with this Agreement constitute the entire agreement between the Parties relating to the subject matter of this Agreement and supersedes all prior negotiations and agreements, whether written, oral, implied or collateral, between the Parties, provided, however, that any confidentiality agreements, or confidentiality provisions contained in any agreements, executed between the Parties in connection with the transactions contemplated in this Agreement will continue in full force and effect and will survive any termination of this Agreement.

(b) No representation or inducement whether made by statement or delivery of data or other information of any kind or nature whatsoever and whether in writing, orally or in any other manner conveyed by any Party to any other Party survives the execution of this Agreement unless expressly made in this Agreement.

16.8 **Further Assurances**. As and so often as any Party may reasonably require, the Parties agree to execute and deliver further and other documents, assurances and conveyances as may be necessary to properly carry out the intention of this Agreement.

16.9 **Successors and Assigns**. This Agreement enures to the benefit of and will be binding upon the Parties and their respective permitted successors and permitted assigns.

16.10 **Waivers**. No provision of this Agreement may be waived except by a written instrument and any waiver of a provision:

(a) is valid only in respect of the specific instance to which it relates and is not a continuing waiver; and

(b) is not to be construed as a waiver of any other provision.

16.11 **Time**. Subject to Part 9, time is of the essence of this Agreement.

16.12 **Counterparts**. This Agreement may be executed in any number of counterparts with the same effect as if the Parties had signed and delivered the same document. All counterparts will be construed together and will constitute one and the same agreement. This Agreement will be duly executed and delivered if facsimile signature pages are exchanged by the Parties.

16.13 **Joint and Several**. The obligations of VGC Group under this Agreement are joint and several obligations of VGC and StrataGold.

This Agreement is executed by the Parties in multiple originals effective as of the day and year first written above.

YUKON ENERGY CORPORATION

By: _____

President & CEO
Authorized Signatory

Dated: 9 November 2017

VICTORIA GOLD CORP.

By: _____

Authorized Signatory

Dated: November 10, 2017

STRATAGOLD CORPORATION

By: _____

Authorized Signatory

Dated: November 10, 2017

Effective: 2018 02 28
Supercedes: 2012 01 01

SCHEDULE A

RATE SCHEDULE 39

INDUSTRIAL PRIMARY

AVAILABLE: Throughout the service areas of Yukon Energy Corporation ("**YEC**") and The Yukon Electrical Company Limited ("**YECL**") served by the Yukon Integrated Grid.

APPLICABLE: To all major industrial customers engaged in manufacturing, processing or mining with an electric service capacity in excess of 1,000 kW.

RATE: Charges in any one billing month will be the sum of the following:

(a) Demand Charge of $15.94/kVA of Billing Demand

(b) Energy Charge of 8.08¢/kWh for all energy used.

(c) Fixed Charge

For service to Minto mine site, the Fixed Charge each month shall equal the payments required under the amended Power Purchase Agreement (the "**Minto PPA**") dated May 14, 2007 between YEC and Minto Explorations Ltd. ("**Minto**") for monthly Capital Cost Contributions for transmission connection to the mine.

For service to Alexco mine and mill sites, the Fixed Charge each month will equal the amounts under the Power Purchase Agreement (the "**Alexco PPA**") dated September 1, 2010 between YEC and Alexco Resource Corp. ("**Alexco**") for existing transmission connection to the mine and mill sites, until such time as this amount is amended by the YUB based on the VGC Group PPA.

For service to VGC Group mine site, the Fixed Charge each month will equal the amounts under the Power Purchase Agreement (the "**VGC Group PPA**") dated November 9, 2017 between YEC, Victoria Gold Corp., and StrataGold Corporation ("Victoria Gold Corp. and StrataGold Corporation are collectively, the "**VGC Group**") for transmission connection to the mine site, subject to

amendment from time to time as provided for in Section 7.7 of the VGC Group PPA.

PEAK SHAVING CREDIT:

For customers with an established Winter Contract Load in good standing, a Peak Shaving Credit in each billing month equal to 50% of the Demand Charge times the Peak Shaved Load.

MINIMUM MONTHLY BILL:

The minimum monthly bill will be the sum of the Demand Charge and the monthly Fixed Charge, less any applicable Peak Shaving Credit.

PEAK SHAVED LOAD:

Peak Shaved Load in any billing month is the amount by which then nominated Winter Contract Load is less than the Billing Demand for the month.

BILLING DEMAND:

The Billing Demand will be the greater of:

(a) the highest metered kVA demand recorded in the current billing month; or

(b) the highest metered kVA demand recorded in the previous 12-month period including the current billing month, excluding the months April through September; or

(c) the contract minimum demand.

WINTER CONTRACT LOAD:

A customer may, by six month written notice to YEC, nominate a Winter Contract Load at not less than two-thirds of the customer's contract maximum demand subject to the following conditions:

(a) The customer will thereby contract with YEC not to exceed the nominated Winter Contract Load whenever the temperature at Whitehorse is below -30 degrees Centigrade, based on YEC informing the customer by phone, fax or e-

mail as to forecast and actual winter temperatures at Whitehorse as provided for in paragraph (b);

(b) YEC will inform the customer at least one hour in advance, and not more than one day in advance, of a forecast temperature at Whitehorse being below -30 degree Centigrade; thereafter, until YEC informs the customer otherwise, the customer will be responsible for ensuring that its metered kVA demand does not exceed the Winter Contract Load during any hour when the actual temperature at Whitehorse is below -30 degrees Centigrade; YEC will inform the customer forthwith when the temperature at Whitehorse is no longer forecast to be below -30 degree Centigrade within the next 24 hours;

(c) The customer agrees that the contract for the nominated Winter Contract Load will continue until terminated by written notice of not less than 12 months by the customer to YEC;

(d) If during such contract period for the Winter Contract Load the customer's metered kVA demand recorded, after YEC has provided notice as specified in paragraph (b) above, exceeds the Winter Contract Load when the temperature at Whitehorse is less than -30 degrees Centigrade, the Winter Contract Load contract will be terminated forthwith, the customer will forthwith be required to repay to YEC all Peak Shaving Credits determined within the previous 12 billing months, and the customer will also pay for that billing month to YEC as penalty an amount equal to four times the Demand Charge on the metered kVA demand recorded in excess of the Winter Contract Demand; in addition, YEC reserves the right if so required to meet system loads when the temperature at Whitehorse is less than - 30 degrees Centigrade during the then current month and the following 12 months to interrupt electricity supplied to the customer in excess of the previous Winter Contract Load.

BASE LOAD ENERGY:

A Base Load Energy amount per month may be established for a customer at 90% of forecast use when YEC expects to require diesel fuel generation to service use in excess of such a Base Load Energy amount. At such time, Rate Schedule 39 will be submitted to the Yukon Utilities Board for amendment to adjust the Energy rate as required for a two part rate that yields the same overall energy charge at forecast energy use, with all energy consumed in excess of the Base Load being charged at a rate reflecting the

incremental cost of service using diesel fuel generation and all other energy being charged at the reduced rate required to yield the same overall energy charge at forecast energy use.

RATE MODIFICATIONS APPLICABLE:

For fuel adjustment rider, see Rider F. Rider F applied to energy charges only, set to $0.0 for fuel price forecast filed November 20, 2006 and changed as follows:

a) Fixed Rider F of 0.211 cents per kWh charged only to Rate Schedule 39 customers to account for fuel price variance from price forecast filed November 20, 2006 to fuel price forecasts for 2009 as approved by the Board in Order 2009-08 and Order 2009-10 for Yukon Energy; plus

b) Ongoing Rider F per kWh as required to ensure consistency, after consideration of the Fixed Rider F as provided for in (a) herein, with the Rider F applied to all applicable rate schedules to account for fuel price variance from price forecasts as last approved by the Board for Yukon Energy and Yukon Electrical GRAs.

TERMS AND CONDITIONS OF SERVICE :

The Company's Terms and Conditions of Service approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

Table of Contents

Page

PART 1
DEFINITIONS AND INTERPRETATION 1

1.1 Definitions 1
1.2 Schedules 7
1.3 Interpretation 8

PART 2
DURATION 8

2.1 Term 8

PART 3
CONDITIONS PRECEDENT 8

3.1 Conditions 8

PART 4
INITIAL ACTIVITIES 9

4.1 Filing with YUB 9
4.2 McQuesten Substation 9
4.3 Initial YEC System Improvements 9
4.4 Mine Facilities, Mine Facilities Spur, and VGC Group Power Facilities 10
4.5 Transmission Facilities Development 10
4.6 Step Down Transformer 10
4.7 SVC/Statcom 10
4.8 Operating Agreement 10

PART 5
ELECTRICITY 11

5.1 Electricity to be Delivered and Accepted 11
5.2 VGC Group Forecasts 11
5.3 Point of Delivery 11
5.4 Maximum Electric Demand 12
5.5 Increase in Maximum Electric Demand 12
5.6 VGC Group Standards for Usage of Electricity 12
5.7 Terms and Conditions of Service 13
5.8 Commercial Operation Cessation Date 13
5.9 Suspension of Commercial Operation 13
5.10 Planned YEC Maintenance 13

PART 6
YEC CAPITAL COSTS 13

6.1 YEC Capital Costs 13

PART 7
BILLING/PAYMENT 15

7.1 VGC Group Power Bill 15

7.2 Canadian Funds 15
7.3 Failure to Render Invoice 15
7.4 Late Payment 15
7.5 Prepayments 15
7.6 Taxes 15
7.7 Fixed Charge 15

PART 8
METERING 16

8.1 Metering 16
8.2 Testing 16
8.3 Backup Metering 16
8.4 Costs 16

PART 9
FORCE MAJEURE 16

9.1 Force Majeure 16
9.2 Notice of Force Majeure 16
9.3 Exclusions 17

PART 10
REPRESENTATIONS AND WARRANTIES 17

10.1 YEC Representations and Warranties 17
10.2 VGC Group Representations and Warranties 18

PART 11
DEFAULT 18

11.1 Event of Default 18
11.2 Remedies 18

PART 12
DISPUTE RESOLUTION 19

12.1 Confidentiality of Process 19
12.2 Stages 19
12.3 Availability of Argument 20
12.4 No Further Claims 20
12.5 Continued Payment 20

PART 13
INDEMNITY 20

13.1 Limitation of Liability 20
13.2 Indemnification 20
13.3 Assertion of Claims 21
13.4 Defence of Claims 21

PART 14
ASSIGNMENT 22

14.1 Assignment 22

14.2 Sale of the Transmission Facilities 22
14.3 Sale of the Mine 22

PART 15
CONFIDENTIALITY 22

15.1 Confidentiality 22
15.2 Exceptions 22
15.3 Survival 23
15.4 Injunctive Relief 23

PART 16
GENERAL 23

16.1 Notices 23
16.2 Coordination of Communications 24
16.3 Amendment 24
16.4 Governing Law and Language 24
16.5 Submission to Jurisdiction 24
16.6 Severability 25
16.7 Entire Agreement 25
16.8 Further Assurances 25
16.9 Successors and Assigns 25
16.10 Waivers 25
16.11 Time 25
16.12 Counterparts 25
16.13 Joint and Several 25

Schedule B

McQuesten Substation

B.1 **McQuesten Substation Planning to Date.** The McQuesten Substation project to be connected to the existing grid powerline between Mayo and Keno City is designed to accommodate the future Transmission Facilities Development. The McQuesten Substation project and the Transmission Facilities Development have completed Yukon Environmental and Socio-economic Assessment Act screening followed by a decision document issued by the Yukon Government to allow all required construction and operating permits for the Stewart-Keno City Transmission Project (or components thereof) to be issued. YEC can secure access from the Yukon Government to use of the required right of way. Detailed engineering design of the McQuesten Substation project has been largely with funding from the Yukon Government and VGC Group.

B.2 **McQuesten Substation MOU**. A copy of the McQuesten Substation MOU (the "**MOU**") that was signed by VGC and YEC on September 19, 2017 is attached in Appendix B-1 to this Schedule B, setting out a formal relationship between the Parties and commitments to enable the Parties to work together on the successful tendering, procurement, construction, commissioning and turnover of the McQuesten Substation to YEC. The MOU notes that the McQuesten Substation design has been directed and reviewed by YEC, and has been frozen after the 85% design review and the agreement of the Parties to the design. VGC Group is authorized under the MOU to order long lead equipment, and is responsible under the MOU for issuing request for tender proposals, construction management, and pre-commissioning activities. YEC is responsible under the MOU for actual commissioning of the McQuesten Substation. The MOU provides for the Parties to develop an acceptance test or protocol for determining that the McQuesten Substation has been commissioned, and that deficiencies identified during commissioning will be rectified by VGC and approved by YEC before the McQuesten Substation is released to YEC for commercial operation. When the Substation has passed the agreed upon acceptance test or protocol and all deficiencies are rectified by VGC to the satisfaction of YEC, the MOU specifies that VGC will execute and deliver a document agreed to by the Parties transferring legal and beneficial title to the McQuesten Substation to YEC free and clear of all liens, charges, and encumbrances.

B.3 **McQuesten Substation Capital Costs funded by VGC Group:** Except as otherwise specified in this Agreement, VGC Group will fund all of the costs, fees and expenses for development of the McQuesten Substation, including actual final YEC's Owners Costs (see Table B-1 for YEC's estimate of these costs as of the current date). The YEC's Owner's Costs will be recovered from VGC Group after the Commencement of Delivery under Section 6.1(c) of this Agreement.

Table B-1: YEC's Owner's Costs for McQuesten Substation Development

Project Manager	$68,640
Owner's Engineer	$93,600
Site Supervision	$186,000
SCC SCADA	$16,000
Overhead (management, reporting)	$15,000
Commissioning (Internal)	$44,000
Commissioning (External)	$60,000
Total	**$483,240**

B.4 **McQuesten Substation Capital Costs funded by YEC**: YEC is responsible for the YEC McQuesten Substation Costs for incremental fees, costs and expenses associated with the McQuesten Substation being able to operate at 138 kV voltage at such time after the Commencement of Delivery when the Transmission Facilities Development is completed and energized at 138 kV YEC McQuesten Substation Costs are set at **[$930,563]**, as detailed in Table B-2. The YEC McQuesten Substation Costs will be payable by YEC to VGC Group after the Commencement of Delivery under Section 6.1(d) of this Agreement.

Table B-2: YEC McQuesten Substation Costs

5258 McQuesten & 5249 Mayo	YEC	
Construction	**$**	**605,931**
Supervision	$	36,000
Site Prep (Civil works)	$	325,350
Foundations	$	174,081
Structure and Bus Work	$	8,000
Electrical / Telecontrol / Telecom	$	62,500
Material	**$**	**240,036**
Switch Yard	$	132,770
Major Equipment	$	87,266
Delivery	$	20,000
Commissioning	**$**	-
On-site		
Owner's Costs	**$**	-
Overall owner's costs		
Subtotal	$	845,967
Contingency (10%)	$	84,597
TOTAL	**$**	**930,563**

Appendix B-1: McQuesten Substation MOU

Eagle Gold Project – McQuesten Substation

Memorandum of Understanding ("MOU")

BETWEEN

YUKON ENERGY CORPORATION (**"YEC"**)

AND

VICTORIA GOLD CORP. (**"VGC"**)

(collectively the **"Parties"**)

WHEREAS, VGC is a leading gold exploration and development company whose Eagle Gold Project (the "**Project**") is located within proximity to YEC's grid, is fully permitted and under construction to be Yukon's next and largest gold mine;

WHEREAS, YEC is a crown owned, regulated utility with a mandate to plan, generate, transmit, and distribute a continuous and adequate supply of energy in the Yukon;

WHEREAS, VGC and YEC have finalized detailed design of the McQuesten Substation (the "**Substation**"), finalized a system impact study and are actively working on the development of a power purchase agreement which provides the technical and commercial terms for connecting the Project to YEC's grid;

WHEREAS, YEC is currently planning for the replacement and upgrade of the Stewart-Keno Transmission Line; and

WHEREAS, YEC and VGC seek to work together on the successful tendering, procurement, construction, commissioning and turnover of the Substation to YEC.

NOW THEREFORE, YEC and VGC agree to the Eagle Gold Project – McQuesten Substation MOU as outlined below:

Objective

The objective of the Parties is to construct a quality Substation on scope as per the detailed design through quality workmanship in supply and installation, on schedule to meet the Project schedule, and in the most cost-effective manner possible.

Intent

The intent of this MOU is to establish a formal relationship between the Parties and secure commitments to enable the Parties to work together on the successful tendering, procurement, construction, commissioning and turnover of the Substation to YEC by:

- Sharing and exchanging information that is relevant to discussions as outlined in this MOU,
- Committing to the principles of collaboration and time is of the essence,
- Developing a work plan to track and summarize all responsibilities and activities undertaken through this MOU,
- Scheduling regular meetings to ensure ongoing meaningful dialogue, resolution of any issues, formalizing key decisions and reporting on progress,
- Implementing the Substation Construction Execution Plan with the schedule, file No. S258 Construction Schedule R2,
- Developing a genuine atmosphere of collaboration and alliance in the support of an effective and efficient partnership and leadership meant to maintain, safeguard and sustain sound and optimal managerial, financial and administrative commitment with regards to all matters related to the Substation,
- Recognizing that by implementing any contract, license, or other agreement entered into between the Parties subsequent hereto shall supersede any conflicting provision of this MOU.

Workplan

A workplan will be established to detail the implementation of the Substation through the draft Work & Responsibility Matrix attached to this MOU as Schedule 1.

Workplan Assumptions

1. Funding

Except as set out below VGC will fund all the full fees, costs, and expenses, including YEC's non-executive labour costs, external fees, costs, and expenses of the design, engineering, procurement, construction, project management, site supervision, SCADA changes, operations orientation and commissioning of the Substation. Notwithstanding the foregoing YEC will be responsible for all incremental fees, costs, and expenses associated with Substation being able to operate at 138 kV voltage, which amount will be payable by YEC to VGC at the time the Substation is transferred to YEC under Section 7 below.

2. Design Approval

The Substation design has been directed and approved by YEC.

The 85% design review of August 22, 2017, has frozen the design fully meeting YEC's requirements and both Parties agree to the design.

3. Long Lead Equipment Procurement

Orders for long lead equipment are, as of Aug. 22, 2017, being progressed by VGC, which ATCO will issue for tender with ordering prior to year-end 2017. The equipment will be ordered for delivery to ensure the Substation project schedule is maintained.

All of the long lead equipment vendors, save the E-house, have already been approved by YEC and VGC.

4. Preparation of Installation Tender Documents

A tender document for the contract is required. The type of contract (fixed price lump sum, cost plus, unit rate, etc.) to be mutually agreed by the Parties. ATCO will provide a construction work package which includes substation drawings, technical specifications, and tendering documents. YEC may require general and special conditions of contract and evaluation criteria, including provisions which provide for the assignment of all manufacturer warranties to YEC when YEC becomes the owner of the Substation under Section 8 below. YEC will provide VIT with any special conditions prior to VIT ordering any long lead equipment and prior to VGC preparing the tender document. VGC will be responsible for assembly of the document.

5. Tendering & Evaluation of Proposals

VGC, in conjunction with YEC, will be responsible for assembling a list of pre-approved tenderers. Tendering will be on the basis that any or no successful tenderer may be accepted, but in general the principle will be to select a complying proposal that meets all technical and construction requirements, has a competitive price and is by a tenderer with a good utility performance record and is in a solid financial position.

The subject of bid and performance bonds is to be mutually agreed upon by the Parties.

VGC will be responsible for issuing the request for tender proposals (RFPs) and formally answering questions as may arise during tendering.

VGC, with assistance of ATCO, will be responsible for the tender technical and schedule evaluation, with approval from YEC pursuant to the tender document.

VGC will be transparent with YEC for the economic evaluation of the tenders.

6. Permits

The Parties will identify all permits required for the construction and operation of the Substation and allocate responsibility for obtaining such permits.

7. Construction Management & QA/QC

VGC will be responsible for construction management. YEC may review the construction materials and methods and will be kept fully up to date, receive all reports, and make site visits as required and appropriate.

The contractor will be required to retain a pre-approved substation electrical testing contractor. Concrete and similar civil testing will be made available to YEC.

VGC will be responsible for oversight of the QA/QC process, from the results of which will be made available to YEC.

VGC will, in conjunction with the testing subcontractor, be responsible for pre-commissioning and preparation of "punch lists." (See also Section 8, Acceptance & Commissioning below.) This list will be reviewed and approved by YEC.

8. Acceptance & Commissioning

VGC or its designate will complete "pre-commissioning" which consists of all the tests done by the testing subcontractor. These tests will be specified and recorded by VGC, and approved by YEC before proceeding to substation commissioning.

Actual commissioning will be the responsibility of YEC, with assistance from Substation contractor and other parties as involved in Substation installation and testing. The Parties will develop an acceptance test or protocol for determining that the Substation has been commissioned. Deficiencies identified during commissioning will be rectified by VGC and approved by YEC before the Substation is released to YEC for commercial operation. When the Substation has passed the agreed upon acceptance test or protocol and all deficiencies are rectified by VGC to the satisfaction of YEC, VGC will execute and deliver a document agreed to by the Parties transferring legal and beneficial title to the Substation to YEC, free and clear of all liens, charges, and encumbrances.

Duration

The term of this MOU shall extend until March 31, 2019.

Extent of the Agreement

The signing of this MOU doesn't create any legal or financial obligations on the part of either Party. No rights or limitation of rights shall arise or be assumed between the Parties as a result of the terms of this MOU.

Assignment

Neither Party to this MOU may assign or transfer the responsibilities or agreements made herein without the prior written consent of the non-assigning Party, which approval shall not be unreasonably withheld.

Legal and Regulatory Authority

Any future agreements and projects will be subject to any and all legal and regulatory approvals under any applicable legislation.

Acts of Parties and Agents

Each Party shall be responsible for the acts of its own employees, agents and contractors in carryout the provisions of the MOU.

Amendment

Any amendments to the MOU will be made in writing upon the consent of both Parties.

Termination

Either Party may terminate this MOU by providing thirty (30) days written notice to the other Party.

The Parties have executed, and made effective, this MOU as of the ____ day of September, 2017.

VICTORIA GOLD CORP

_____

Mark Ayranto, Executive VP

YUKON ENERGY CORPORATION

_____

Andrew Hall, President & CEO

Schedule 1

Work & Responsibility Matrix

[NTD: Matrix to be reviewed and updated by Parties.]

Item	Description	Responsibility / Approval Milestones
1	Design completion including S258 and by-pass lines. The design is now 85% with all significant items agreed to by all.	VGC and YEC
2	Purchase of long lead "engineered" equipment	VGC
3	Preparation of tender documents	VGC, YEC
4	Pre-qualification of tenderers	VGC and YEC
5	Installation contract: tendering, contractor selection, and award.	VGC and YEC
6	Construction management	VGC
7	Strategy for QA/QC, third party inspection, etc.	VGC, YEC
8	Strategy to meet the recently published schedule	VGC
9	First Nations participation	VGC
10	Coordination with Northwestel and others	VGC (construction manager)
11	Temporary facilities as required	VGC (construction manager)
12	Contractor mobilization to site	VGC (construction manager)
13	Contractor invoicing and payment	VGC (construction manager)
14	Schedule maintenance	VGC
15	Safety plan with zero accidents objective	VGC (construction manager)

Item	Description	Responsibility / Approval Milestones
16	Field material and free issue equipment, control plan	VGC (construction manager)
17	Parties to identify additional permits required for the Substation and allocate responsibility for obtaining permits.	VGC and YEC
18	Environmental including temporary site drainage control, etc.	VGC (construction manager)
19	Contractor detailed schedule, labour (manpower) plan, review and approve	VGC (construction manager)
20	Site security	VGC (construction manager)
21	Testing & pre-commissioning (by approved subcontractor)	VGC (construction manager), YEC
22	Final inspection and turn over	YEC & VGC
23	Commissioning	YEC
24	Transfer of legal title of Substation to YEC	VGC and YEC
24	Keno outage and line change-over	YEC

Schedule C

Initial YEC System Improvements

C.1 The Initial YEC System Improvements that YEC is to design, engineer, procure, construct and commission on YEC's existing power system prior to Commencement of Delivery, to accommodate the sale of Grid Electricity by YEC to VGC Group for the Mine, are as follows:

a) Update YEC Under Frequency Load Shedding (UFLS) Scheme:

UFLS settings changes are to be implemented in certain locations throughout the YEC system, as set out in Table C-1 (the specific settings in this table are subject to ongoing change by YEC at its sole discretion as needed for system impact management). Some changes are required to third party equipment (Minto and ATCO). Mayo F1 and Minto will both require relay installations. Testing and tuning will be completed as required following real life system contingencies.

Table C-1: Under Frequency Load Shedding Settings

Item Tripped	Relay Settings			Simulation Parameters		
	f (hz)	df/dt (hz/s)	T_d (4)	T_m+T_d (s)(3)	T_b (s)(2)	T_t (s)(1)
Minto Block 1 – 50% of Load	59.5	-3.4		.25	.083	0.333
Minto Block 1 – 50% of Load	56	----		.25	.083	0.333
Minto Block 2 – 50% of Load	59.5	-4.2		.1	.083	0.183
Minto Block 2 – 50% of Load	56	----		.75	.083	0.183
Minto Capacitor Bank	59.5	-3.4		.1	.083	0.183
Minto Capacitor Bank	56	----		.25	.083	0.183
S170 S6838	59.5	-1.0		0.6	.083	0.683
S150-52-22, S150-52-21	59.5	-1.8		0.4	.083	0.483
S170 S6837	59.5	-2.6		0.2	.083	0.283
S164 52-7	56.5	----		0.1	.083	0.183
EG F1 Block 1– 50% of F1Load + Caps(5)(6)	59.5	-1.0		0.55	.083	
EG F1 Block 2 – 50% of F1 Load +Caps	59.5	-2.4		0.25	.083	
EG F2 Block 3– 50% of F2 Load + Caps	59.5	-3.2		0.10	.083	
EG F2 Block 4 – 50% of F2 Load + Caps	59.5	-1.8		0.4	.083	.483
Dawson F1	56	----	1.		.083	
Dawson F2	56	----	2.		.083	
Mayo F1	58	----	5.		.083	
Callison (Hunker Creek)	56	----	1.		.083	
Keno/Elsa	59.5	-3.4		0.4	.083	.483
McQuesten Capacitor Stage1 (2 MVAr)	59.5	-1.8		.25	.083	.333
McQuesten Capacitor Stage2 (2 MVAr)	59.5	-2.4		.10	.083	.183

(1) Total clearing time. Includes all intentional and non-intentional delays and breaker interrupting time.
(2) Breaker interrupting time. This may be reduced to observed times.
(3) T m+Td is the relay measurement delay plus the delay set on the relay. Tm will vary with the specific relay and the settings and must be determined.
(4) Td must be determined by the relay engineer to achieve to Tt indicated (TBD).
(5) F1- Crusher & Conveyers, F2 – Process Plant and Pumping.
(6) Capacitors are shed in proportion to the amount of load shed so the resulting load power factor remains close to unity.

b) Confirm timing of Mayo Breaking Resistors:

Timing test to be performed on the breaking resistors for both insertion and removal.

There are two banks of resistors (2 MW each) each with four stages of 250 kW and two stages of 500 kW. They engage and disengage on frequency and have a limited insertion time of 70 and 12 seconds for the 250 and 500 kW units respectively. Once the thermal limit is reached they disconnect and then are precluded from engaging for the next 15 minutes.

Once timing is determined they are to be compared to the desired settings. Settings changes may be required which will require additional modeling. Current estimated settings are as follows (the specific settings provided below are subject to ongoing change by YEC at its sole discretion as needed for system impact management):

- Stage 1 – >61.5 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 2 – >61.8 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 3 – >62.1 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 4 – >62.4 Hz, >+0.2 Hz/s, >0.1 s (250 kW, 60 seconds).
- Stage 5 – >62.7 Hz, >+0.2 Hz/s, >0.1 s (500 kW, 10 seconds).
- Stage 6 – >63.0 Hz, >+0.2 Hz/s, >0.1 s (500 kW, 10 seconds).

c) Commission LV Reactor Insertion/Trip (Minto/Faro):

The purpose of this is to add or remove the reactors from the system during system contingencies. The existing protection relays at Faro and Minto do not have the functionality to accommodate this. They will need to be replaced. There is limited space in the Minto e-house meaning that the panels will need to be reworked. The Minto relay installation will require more than average engineering and installation time. The required scheme is as follows:

- Automatic insertion of the 2.5 MVAr reactors at Minto and Faro on detection of sustained voltages greater than 107% (positive sequence or phase-to-phase) with time delays of not less than 2 seconds and less than the over-voltage trips set on L178 at Carmacks, L173 at Minto and L174 at Stewart (staggered insertions). Initial settings can be 2 and 2.5 seconds.
- With two 2.5 MW reactors in service at Minto a trip of either L173 or the trip of L174 at Minto must also cross-trip one reactor with no intentional delay. One of two reactors should also be tripped upon detection of open breaker contacts opening for L173 or L174 breakers at Minto. With only one 2.5 MVAr reactor in service at Minto no action is taken.

d) Confirm Aishihik/Mayo over-frequency trips:

Over-frequency trips for Mayo-B units and Aishihik units to limit over-frequency in the event of a separation south of Takhini. This work requires settings changes and testing only. Over frequency trips as set are to remain:

- Aishihik1 - >62.7Hz, >0.3 seconds
- Mayo B1 - >66Hz, >0.3 seconds

e) Engage Over frequency trips on WG1,2,3:

As backup and to cover isolations south of Minto where SPS and RAS are not practical due to lack of communications. This is due to the increases in the south to north flow resulting from the Mine development and generation supplied from Whitehorse. This work requires equipment replacement, testing and settings changes as per the following current assessments (the specific settings provided below are subject to ongoing change by YEC at its sole discretion as needed for system impact management):

- LNG1>61.5 Hz, >+1.8Hz/s, >.6s AND Also >63.5 Hz, 0.6s.
- LNG2>61.5 Hz, >+2.4Hz/s, >.4s, AND Also >63.5 Hz, 0.4s.
- LNG3>61.5 Hz, >+3.2Hz/s, >.2s, AND Also >63.5 Hz, 0.2s.

f) Confirm over-voltage trips on MD interconnect and L173:

This work requires settings changes and testing only. Protection settings to be set as follows (the specific settings provided below are subject to ongoing change by YEC at its sole discretion as needed for system impact management):

L174 or L175 at Stewart - 138kV Voltage

- 140% for 0.15s OR
- 127% for 7s OR
- 117% for 40s

L173 at Minto - 138kV Voltage

- 140% for 0.15s OR
- 127% for 6s OR
- 117% for 30s

L178 at Carmacks - 138kV Voltage

- 140% for 0.10s OR
- 127% for 5s OR
- 117% for 30s

g) SPS/RAS1 - Shed Mine load for loss of Mayo:

The loss of units at Mayo can cause unacceptable voltage depressions. SPS/RAS1 executes a high speed load rejection on L250, L180 and the Mine feeders. Operating instructions will need to be written for the YEC System Control Centre. Mayo B and S249 will need some fiber work (fiber already existing but not connected). Programmable Logic Controller (PLC) will need to be

installed at S249. Assuming that no work needed at MH0. Heavy engineering is needed for design and programing of this scheme. SCADA component is also significant.

h) SPS/RAS2 – L172 Riverside Generation Rejection Whitehorse

Ensures that system frequency deviation is limited to within tolerable bounds and can be brought back to 60 Hz. SPS/RAS2 monitors L172 MW at Whitehorse and arms selected units for rejection upon detection of trip or open breakers on the Whitehorse end of L172. Units available for selection are three LNG units (preferred trip - assumes LNG third unit installed) and WH3. This work requires some equipment changes to accommodate fiber communications (fiber is already installed). PLC needed at Riverside substation and engineering is needed for design and programing of this scheme. SCADA component is also significant.

i) SPS/RAS3 – L172 Takhini: Generation Rejection Whitehorse
SPS/RAS4 – L170 Takhini: Generation Rejection Whitehorse

Ensures that system frequency deviation is limited to within tolerable bounds and can be brought back to 60 Hz. SPS/RAS3 and SPS/RAS4 monitors L172 and L170 MW at Takhini and arms selected units for rejection upon detection of trip or open breakers on the Whitehorse end of L172 and L170. Units available for selection are three LNG units (preferred trip) and WH3. This work requires some equipment changes to accommodate fiber communications (fiber from Whitehorse to Takhini is being installed by another YEC project, however if that project is canceled then this project would need to pick up that work). PLC needed at Takhini substation and heavy engineering is needed for design and programing of this scheme. SCADA component is also significant.

j) SPS/RAS5 – MacIntyre: Generation Rejection Whitehorse

Ensures that system frequency deviation is limited to within tolerable bounds and can be brought back to 60 Hz. SPS/RAS5 Monitors load at MacIntyre substation and arms selected units at Whitehorse for rejection upon detection of trip or open breakers that disconnect the load from the system. Rejection would include the three LNG units (preferred trip) and WH3. This work requires some equipment changes to accommodate fiber communications (fiber from Whitehorse to MacIntyre is being installed by another YEC project, however if that project is canceled then this project would need to pick up that work). PLC needed at MacIntyre substation and heavy engineering is needed for design and programing of this scheme. SCADA component is also significant.

k) SPS/RAS6 Loss of Mine Load – Tripping Mayo Generators

The loss of load at the Mine can cause unacceptable voltage spikes. SPS/RAS6 monitors L250 at Mayo substation and arms selected Mayo units for rejection upon detection of trip or open breakers for L250, L180 and the Mine. Operating instruction will need to be written for the YEC SCC. Mayo B and S249 will need some fiber work (fiber already existing but not connected). PLC will need to be installed at S249. Significant programming time. Assuming that no work needed at MH0. Mayo Diesel requires SCADA and Automation systems to be installed along with some fiber work.

l) Verify the Mine SPS design, settings and commissioning

YEC to verify VGC Group design, settings and commissioning of SPS's at the Mine as required pursuant to Schedule D.

m) Out of Step – Protection Review L171

The Mine development increases the speed requirements of protection and backup protection operations for faults near Takhini and in particular L171. Settings, backup clearing times and coordination to be reviewed. This requires system studies, installation of new settings and testing.

n) SPS/RAS7 L172 Riverside Trip: On High Load - Cross Trip Takhini Terminal L172

SPS/RAS7 mitigates lower transient voltages that result for certain contingencies with the reactors in service. Monitors L172 MW at Riverside and Takhini. The setting will depend on the amount of generation on line in the north.

- Arming Parameter = L172 North at Riverside – L172 North at Takhini
- Arm at 0 MW with Aishihik off line
- Arm at the lesser of 4 MW or the regulating reserve at Aihihik when Aishihik is on line
- Requires high-speed communications between Whitehorse and Takhini

o) Dispatch YEC thermal generators to limit MD Import from south <11 MW

Programmed alarms for YEC SCC; minimal effort required.

C.2 The estimated YEC Capital Costs of $1,677,883 for the Initial YEC System Improvements are provided in Table C-2.

Table C-2: Estimated YEC Capital Costs for Initial YEC System Improvements

	Initial YEC System Improvements	Estimated Capital Cost				
		Contractor	Labour	Material	Contingency	Total
a	Update YEC UFLS Scheme	$94,200	$24,880	$7,000	$50,432	$176,512
b	Mayo Breaking Resistors	$19,400	$4,000	$0	$9,360	$32,760
c	Minto/Faro LV Reactor Intersection/Trip	$81,000	$8,880	$2,500	$36,952	$129,332
d	Aishihik/ Mayo Over-frequecy Trips	$11,200	$1,600	$0	$5,120	$17,920
e	Over-frequecy trips on WG 1,2,3	$17,600	$5,600	$10,000	$13,280	$46,480
f	Over-voltage trips on MD interconnect and L173	$17,600	$4,000	$2,500	$9,640	$33,740
g	SPS/RAS1 - Shed EG load for loss of Mayo	$54,025	$12,880	$10,000	$30,762	$107,667
h	SPS/RAS2 - L172 Takhini: Generation Rejection WH	$100,200	$28,400	$40,000	$67,440	$236,040
i,j	SPS/RAS3/4/5 - L172/L170 Takhini & MacIntyre: Generation Rejection WH	$240,000	$78,800	$20,000	$135,520	$474,320
k	SPS/RAS6 - Loss of EG Load - Trip Mayo	$85,000	$40,000	$50,000	$70,000	$245,000
l	Verify EG SPS Design, Settings, Commissioning	$6,400	$6,800	$2,500	$6,280	$21,980
m	Out of Step - Protection Review L171	$48,000	$20,880	$2,500	$28,552	$99,932
n	SPS/RAS7 L172 Riverside Trip: On High Load - Cross Trip Takhini Terminal L172	$0	$30,500	$2,500	$13,200	$46,200
0	Dispatch YEC Thermal Generators to Limit MD Impart from south <11 MW	$0	$10,000	$0	$0	$10,000
	Total	$774,625	$277,220	$149,500	$476,538	$1,677,883

Schedule D

VGC Group Power Facilities

D.1 The VGC Group Power Facilities that VGC Group is to install at the Mine Facilities prior to Commencement of Delivery, and to operate thereafter as set out herein as part of the Mine Facilities in order to manage impacts on the YEC power system from the sale of Grid Electricity by YEC to VGC Group for the Mine, are as follows:

a) Measures in Substitution of McQuesten Capacitor Bank Installation

The following equipment-related measures will be undertaken in substitution of McQuesten Capacitor Bank installation:

- Ensure that Mine UFLS sheds capacitors in proportion to the Mine load.
- Trip Mine load in response to capacitor bank trips. (i.e., loss of capacitor bank trips two main feeders).

b) Coordinate Mine Voltage and Tap Changer Controls

Normally the transformer tap-changers will regulate the 13.8kV bus (presumably to nominal voltage). This approach cannot be applied with the Mine generation online. The following operation will be adopted at the Mine Facilities and can be changed if mutually agreed by YEC and VGC Group:

- Mine capacitor banks are switched to produce a net load power factor of unity measured on the feeders or on the LV side of transformers but netting out the reactive load on the generators.
- Tap-changers control 13.8 kV bus voltage with generation off.
- With the Mine generators on, the tap-changers are moved to nominal taps and further operation blocked.
- The Mine generators regulate the 13.8 kV bus voltage between 100 and 105% of nominal and YEC has control of this set-point. Generators reactive output will be adjusted by YEC in real time, to regulate the 69kV system voltage, by pulsing the AVR voltage set-points. The Mine sets the acceptable range that YEC can adjust voltage within it.
- YEC must have full SCADA visibility of the Mine substation and control of critical elements.

c) Install over-voltage protection

To prevent feeder/load trips at the Mine from creating sustained over-voltages the following protections are required at the Mine Facilities:

- On loss of either of the two main Mine feeders, directly trip a proportionate share of the Mine capacitors with no intentional delay.
- Capacitor stages also must have over-voltage protection set to trip when voltage exceeds threshold on the 69kV bus. The trips are to be staggered with time delays settable, as specified by YEC. The delays are expected to be in the 0.1 to 20 second range. Initial settings are 108% for 1 second and 1.25 and 1.75 seconds assuming shedding in blocks, one allocated to each main feeder.

- Trip of capacitor bank blocks must also trip associated feeder with no intentional delay.

d) Mine Reactive support

VGC Group will install and operate the following as part of the Mine Facilities:

- Capacitors must be shed with load and load shed with capacitors
- Install SPS and RAS Loss of the Mine capacitors – Trip Mine load
- Install SPS/RAS Loss of the Mine Load – Trip Mine capacitors pro-rata
- Maximum size of switched elements 1.4 MVAr
- Subject to Power Quality requirements, VGC Group may choose to maintain 1MW of load when shedding in order to maintain power supply to critical loads.

e) SPS/RAS6 Loss of Mine Load – Tripping Mayo Generators

The loss of load at the Mine can cause unacceptable voltage spikes. SPS/RAS6 monitors L250 at Mayo substation and arms selected Mayo units for rejection upon detection of trip or open breakers for L250, L180 and the Mine. Equipment with the necessary metering and communication capabilities including high speed communication to be installed at the Mine Site or McQuesten Substation as required.

f) Mine Generators equipped with Utility Grade Speed and Voltage Controls

The Mine Facilities generators must provide the same frequency and voltage ride-through as utility generators. In addition the controls must provide the same operational modes as those found on similar utility generators as follows:

- AVR/Exciters will operate in voltage control mode. This is the mode they will invariably operate in.
- Speed Governor – The governor will operate in speed droop (not kW-droop). Any constant kW mode that is included (for troubleshooting) must have trips to Droop that are set by YEC. The governors must be set up to maximize response to frequency deviation, both loading and unloading. YEC must receive test results and modeling information.

g) Under Frequency Protection

Under Frequency Load Shedding (UFLS) is required at the Mine site to minimize the negative effects of contingency events on the YEC system. The settings will be as per YEC discretion.

h) YEC Inspections

YEC will have access to the Mine equipment for periodic testing and verification of the SPS/RAS functionality.

Schedule E

Operating Agreement

E.1 **Operating Agreement.** Prior to the Commencement of Delivery and throughout the balance of the Term, YEC and VGC Group will maintain an operating agreement (the "**Operating Agreement**") to coordinate electric power operations of YEC and the Mine.

E.2. **Draft Operating Agreement.** Appendix E-1 to this Schedule E provides a draft Operating Agreement that the Parties will finalize prior to the Commencement of Delivery. The following are noted regarding terms used in the Draft Operating Agreement:

- "L251" means the Mine Facilities Spur; and
- "Operational Boundary/Interface Point of Point of Common Coupling (PCC)" means the Point of Delivery

E.3 **Amendments to Operating Agreement**. The Parties will review the provisions of the Operating Agreement on a regular basis, and amend the Operating Agreement form time to time as required to reflect changing conditions and requirements.

Appendix E-1: Draft Operating Agreement

YUKON ENERGY	OPERATING AGREEMENT	DEPARTMENT:	INQUIRIES TO:	TOPIC:
		ISSUED DATE	Review Date	Victoria Gold / Yukon Energy Operating Agreement

1.0 Purpose

1.1 This procedure outlines the steps to take to ensure a reliable and safe supply of power to the Mine through a variety of circumstances.

2.0 General Information

2.1 Breaker Identification
S258 52-1 – Connection between the McQuesten bus and S249 (Mayo) bus
S258 52-2 – Connection between the McQuesten bus and S257 (Keno) bus
S258 52-3 – Connection between the McQuesten bus and L251
VGC 52-T1 – Connection between L251 and the VGC bus
VGC 52-T2 – Connection between L251 and the VGC bus

2.2 Interlocks
Identified break interlocks with sequence information

Operating Authority: The organizational unit assigned responsibility for operating a portion of the electrical system. For YEC the SCC operator is the operating authority. For the VGC Group the ??? is the operating authority.

Operational Boundary/Interface Point or Point of Common Coupling (PCC): The location on the electrical system at which responsibilities between Operating Authorities meet. The breaker S258 52-3 is the interface point between the Mine and YEC.

2.3 Contact Information
SCC – phone 867-393-5355 or 867-393-5324 (recorded lines)

Mike Hannah (Leadhand SCC)	393-5399, cell 334-6759
Myles O'Brien (Operation Coordinator)	393-5352
Ed Peake (Manager Operations)	393-5383, cell 334-6586
Guy Morgan (Director of Operations)	393-5366, cell 334-6904

Mine – Contact Information ########

2.4 Normal Operation
Under normal operating conditions the Mine will be supplied from the YEC grid. The breakers status under normal operating conditions is as follows.

Breaker	**Status**
S258 52-1	Closed
S258 52-2	Closed

S258 52-3	Closed
VGC 52-T1	Closed
VGC 52-T2	Closed

3.0 Operating Procedures

3.1 L### (S258 to the Mine Site) Isolation

L### isolation requires the minimum notification defined in section 4.3, with the exception of emergency repairs. YEC will provide a condition guarantee on breaker S258 52-3. The condition guarantee is used in communications between external parties. It is a formal method of communication that switching has been completed. It ensures the status of the breaker/device will not change until the work is complete, the lock out tag out is surrendered and all workers are clear.

3.2 Voltage Support/Load Reduction

Based on the power quality conditions defined in Schedule F of this Agreement and system security requirements, SCC may request voltage support and/or a mine load reduction. Voltage support and a Mine load reduction can be accomplished by placing the Mine generation on line, or other means such as capacitor banks or transformer tap changing.

- When the Mine has generation online, the generators regulate the 13.8 kV bus voltage between 100 and 105% of nominal and YEC will have control of this set-point. Generators reactive output will be adjusted by YEC in real time, to regulate the 69kV system voltage, by pulsing the AVR voltage set-points. VGC Group sets the acceptable range that YEC can adjust voltage within it.
- YEC must have full SCADA visibility of the Mine substation and control of critical elements.

3.3 SCC Remote Monitoring and Control

SCC will have visual indication of the Mine breakers, generator status, capacitor status and electrical measurement information for the Mine Site Single Line Diagram (SLD) including transformers, feeders and breakers. Control will be limited to approving load step requests from the Mine to SCC. Load step requests will be approved by SCC based on the generation dispatch and system status. Load changes of more than 1000 kW must be communicated and approved by YEC.

YEC will have control (open and close) of incoming 69kV line breakers at the Mine.

If VGC Group exceeds the Maximum Electric Demand load limitations specified in Section 5.1 of this Agreement, the following procedure will be followed.

a) SCC will contact VGC Group to notify them that their load is exceeding the cap.
b) VGC Group has 30 min to reduce load below the cap.
c) If VGC Group does not comply within 30 mins, SCC will contact VGC Group again to provide a final warning.
d) If the Mine still does not comply within 30 mins, SCC operator may exercise the right to disconnect the Mine by opening S258 52-3.

4.0 Operational Notification

4.1 Daily Operating Communications
Under normal operating conditions the Mine will be supplied from the YEC grid. Load changes supplied to the Mine of more than 1000 kW must be communicated and approved by YEC.

4.2 The transition from winter to summer and conversely summer to winter loading needs to be established with SCC with a minimum of 30 days' notice.

4.3 Mine Planned Maintenance and Scheduling
To meet changing operating conditions and coordinate maintenance efforts, maintenance shutdowns by the Mine need to be communicated to SCC at least one week in advance for shutdowns of up to 12 hours and 30 days for shutdowns longer than 12 hours.
Changes in the availability and capacity of the onsite generation needs to be communicated to SCC at least 30 days in advance of such changes.
The Parties will share annual shutdown/maintenance plans in February of each year.

4.4 YEC Transmission and Generation Maintenance and Scheduling
YEC performs annual line maintenance on the transmission lines and generation facilities, during which Grid Electricity to the Mine may be curtailed or suspended. The duration of this annual transmission and generation maintenance can be up to 14 days per calendar year.
YEC will provide a minimum of 30 days' notice of the start date and expected duration of work that will curtain or otherwise interrupt the supply of Grid Electricity to the Mine.

5.0 Loss of Supply Procedures

5.1 Loss of Supply - Short Term
In the event of a disturbance that results in the loss of Grid Electricity to the Mine Site, SCC will make one attempt to re-energize the line to the Mine Site. If successful the following steps apply to resume the Mine operation with Grid Electricity.

a) SCC will confirm the status of the breakers located in the S258 switching station.

Breaker	Expected Status
S258 52-1	Closed
S258 52-2	Closed
S258 52- 3	Closed
VGC 52-T1	Open
VGC 52-T2	Open

b) SCC will request closed breakers VGC 52-T1 and VGC 52-T2.

c) Once complete and with confirmation from SCC the Mine may proceed with the restarting of their operation. VGC Group will communicate to SCC on load pickups greater than 1000 kW. The request to load up may be communicated verbally or via SCADA.

5.2 Loss of Supply - Long Term
In the event of a disturbance that results in the loss of Grid Electricity to the Mine Site and SCC is unsuccessful in re-energizing the line the following steps will apply.

b) SCC will confirm the status of the breakers.

Breaker	Expected Status
S258 52-1	Closed
S258 52-2	Closed
S258 52- 3	Open
S258 52-4	Closed
VGC 52-T1	Open
VGC 52-T2	Open

c) At the direction of SCC the Mine personnel will start and stage their diesels on line supplying power to the Mine.

d) Once the line to the Mine has been re-energized, with confirmation that breaker S258 52-3 is closed.

e) SCC will request the Mine synchronize and close breakers VGC 52-T1 and VGC 52-T2.

f) The Mine is now connected to YEC Grid Electricity. Once complete and with confirmation from SCC the Mine may proceed with the restarting of their operation. VGC Group will communicate to SCC on load pickups greater than 1000 kW. The request to load up may be communicated verbally or via SCADA.

g) At the direction of SCC the Mine personnel will be requested to unload and shutdown some or all Mine Site diesel generation

7.0 Revision and Approval

7.1 This Agreement comes into effect once it is signed by VGC Group and YEC.

7.2 This Agreement will remain in effect unless cancelled upon the mutual agreement of both Parties.

7.3 The Parties will provide 90 days notice in writing of the intention to modify this Agreement.

7.4 The Agreement may be revised upon mutual agreement of both Parties. This agreement will be formally reviewed every two (2) years.

Approved by: _____
Guy Morgan
Yukon Energy Corporation

Approval Date: _____

Approved by: _____
X
Victoria Gold Corporation

Approval Date: _____

Approved by: _____
X
Stratagold Corporation

Approval Date: _____

Schedule F

Power Quality Requirements

F.1 **Power Quality Requirements**. Starting with the Commencement of Delivery and throughout the Term when receiving Grid Electricity from YEC, VGC Group will operate the Mine Facilities in accordance with the power quality requirements of YEC as set out in this Schedule F and in Section 5.6 of this Agreement. In this Schedule F "PCC" means the Point of Delivery.

F.2 **Power Factor**. VGC Group will maintain a 96% leading load power factor for Grid Electricity supplied to the Mine at the PCC, that is computed from real load (total 13.8 kV real load less the power generated) and reactive load (total 13.8 kV reactive load net of the capacitors and ignoring any reactive power produced by on-line generators) and will be controlled, as nearly as possible, by the capacitor bank steps of 1.4MVAR.

F.3 **Frequency Variation.** The continuous or quasi-continuous variations in the Mine load should not create a variation in system frequency by more than 0.25 Hz. This includes jogging and variation in load. Infrequent load pickups and trips should not cause more than a 0.5 Hz deviation. This is set to ensure that variations do not risk under-frequency load shedding operations without the SCC having to operate with frequency above 60 Hz.

F.4 **Perceptible Lamp Flicker**: Lamp flicker results from voltage variations caused by the operation and switching of equipment and load variations. The short-circuit strength of the 69 kV bus at the Mine can be between 50 and 33 MVA. At McQuesten Substation, the PCC, short-circuit levels vary between 65 and 40 MVA. The Mine shall design equipment and manage operations to meet the following requirements for flicker at the PCC:

a) Pst < 0.8, Plt<0.6 at McQuesten Substation with the 65 MVA normal YEC short-circuit conditions.

b) Pst< 0.9, Plt<0.7 at the McQuesten Substation with reduced 40 MVA normal YEC short-circuit conditions.

c) Based on standards IEEE 1546 (adopted from IEC 61000).

d) Based on 120v 60Hz lamps.

e) Should the Mines operation produce unacceptable variations then dynamic voltage control equipment can be installed.

TOPIC: **Sales Forecasts – Residential Sales.**

REFERENCE: **2021 General Rate Application, page 2-7 (PDF page 32 of 441)**

PREAMBLE: YEC provides one paragraph explaining its residential sales forecast.

QUESTION:

a) Please provide the monthly actual and normal sales, monthly actual and normal sales per customer, and monthly customers for each community for 2015, 2016, 2017, 2018, and 2019 in Excel format.

b) Please provide an explanation for changes in use per customer and number of customers in each community.

c) Please provide the forecast sales, sales per customer, and customers for each community for 2020 and 2021 in excel format.

d) Please provide the calculation of historical averages referred to in line 18,

e) Please provide the actual and normal weather (Temperatures and degree days) by month for each community.

f) Please YEC's definition of normal weather, and the calculation of normal weather for each month for each community.

ANSWER:

(a) through **(d)**

Please see CW-YEC-1-6 Attachment 1 for YEC retail sales for 2018 and 2019 actuals, 2020 and 2021 forecasts. The actuals sales for 2015 through 2017 are not included in Table 2.1 for the 2021 GRA.

As illustrated in CW-YEC-1-6 Attachment 1 the annual sales and sales per customer are steady without any notable changes year over year, except for two instances:

- The annual changes for Mayo general service sales are impacted by Alexco sales. As noted on page 2-8, for the years 2018 through 2020 Alexco was a general service customer with 2.4 GW.h sales in 2018, 1.8 GW.h sales in 2019 and 1.6 GW.h sales forecast in 2020. Starting in 2021 Alexco was included as an industrial customer which resulted in a decrease in average sales per customer for general service in this community in 2021.

- The increase in Faro general service sales reflects changes for the largest General Service customer - Faro Mine remediation project. As noted on page 2-7, the sales for this customer are forecast to grow to 14.4 GW.h in 2020 and 2021 resulting in an increase in average sales per customer.

(e) and **(f)**

YEC does not prepare weather normalized level sales for retail and industrial sales. Therefore, the requested information cannot be provided.

Yukon Energy uses the Environment Canada Canadian Climate Normal for Whitehorse Airport for the definition of normal weather as noted in response to YUB-YEC-1-16 (a). See also CW-YEC-1-3(d) which provides YEC's definition of normal weather.

YEC Retail Sales by Community Level

Residential Sales, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	863	2,845	48	291	3,276	8,224	79	15,626
2019	813	2,869	51	258	3,217	8,114	63	15,384
2020	873	3,188	42	297	3,450	8,811	69	16,730
2021	849	3,115	47	293	3,307	8,529	70	16,210

General Service Sales, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	244	9,973	81	62	5,292	11,419	99	27,171
2019	214	11,975	80	36	4,512	12,238	93	29,148
2020	237	14,947	79	44	4,828	12,022	94	32,250
2021	236	16,902	80	47	2,869	12,078	111	32,323

Residential Annual Average Number of Customers

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	101	263	9	29	291	991	6	1,689
2019	100	280	9	29	295	1,012	6	1,730
2020	99	288	9	29	299	1,026	6	1,756
2021	100	289	9	29	301	1,046	6	1,780

General Service Annual Average Number of Customers

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	11	76	3	7	69	333	7	506
2019	11	76	3	7	71	341	8	517
2020	11	75	3	7	72	341	7	516
2021	11	75	3	7	68	341	8	514

Residential Annual Average Usage per Customer, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	9	11	5	10	11	8	14	9
2019	8	10	6	9	11	8	11	9
2020	9	11	5	10	12	9	12	10
2021	8	11	5	10	11	8	12	9

General Service Annual Average Usage per Customer, MW.h

	Champagne	Faro	JC	Braeburn	Mayo	Dawson	N Klondike Hwy	Total
2018	22	131	27	9	77	34	14	54
2019	19	157	27	5	63	36	12	56
2020	22	198	26	7	67	35	13	62
2021	21	224	27	7	42	35	15	63

TOPIC: **Sales Forecasts – General Service Sales**

REFERENCE: **2021 General Rate Application, page 2-7 (PDF page 32 of 441)**

PREAMBLE: YEC provides one paragraph explaining its General Service sales forecast in general and one discussing Faro Mine remediation.

QUESTION:

a) Please provide the monthly actual and normal sales, monthly actual and normal sales per customer, and monthly customers for each community for 2015, 2016, 2017, 2018, and 2019 in Excel format.

b) Please provide an explanation for changes in use per customer and number of customers in each community.

c) Please provide the forecast sales, sales per customer, and customers for each community for 2020 and 2021 in Excel format.

d) Please provide the calculation of historical averages referred to in lines 23-24.

e) If different than residential, please provide the actual and normal weather (Temperatures and degree days) by month for each community.

f) If different than for residential, please YEC's definition of normal weather, and the calculation of normal weather for each month for each community.

ANSWER:

(a) through **(f)**

Please see response to CW-YEC-1-6.

TOPIC: **Sales Forecasts – General Service Sales – Faro Mine remediation**

REFERENCE: **2021 General Rate Application, page 2-7 (PDF page 32 of 441)**

PREAMBLE: YEC provides one paragraph explaining its General Service sales forecast in general and one discussing Faro Mine remediation.

QUESTION:

a) Please provide the referenced "forecasts provided to Yukon Energy by the customer, the Government of Canada". In the response please fully explain any efforts undertaken by YEC to vet or validate the forecasts.

ANSWER:

(a)

The customer provided YEC with forecasts for fiscal 2019 and 2020 (see Attachment 1 to this response). Subsequently by email, the customer provided an update that "our 2021 projection should be in line with what we projected for 2020." YEC reviewed the reasonableness of the forecast and compared it to actual historical results.

Faro Mine Complex | 100 Mine Road | Faro, Yukon, Canada Y0B 1K0
PARSONS
Main: +1 867-994-2600 | www.parsons.com

October 10, 2019
Crown-Indigenous Relations and Northern Affairs Canada Northern Contaminated Sites Branch
Government of Canada Room 415C
300 Main Street Whitehorse, Yukon Y1A 2B2
Email: cam.malloch@canada.ca
Attention: Cam Malloch, P.Eng.
Senior Engineer - Faro Mine Remediation Dear Mr. Malloch:

Re: Draft Electrical Demand Forecast, FY2019 and FY2020
Faro Mine Complex, Faro, Yukon

INTRODUCTION

Pursuant to your request, Parsons Inc. (Parsons) is pleased to provide the following information pertaining to the estimated future demand for electricity at the Faro Mine Complex (FMC). New electrical equipment such as that associated the X13 pumping and conveyance system is now operable and certain other electrical components will be operational over a longer period of time; both activities will increase the amount of electricity consumed at FMC. Although certain older equipment such as the existing IP pumping system will be retired in future years, the demand of the new equipment exceeds the previous demand so the annual cost of the electricity will increase.

This forecast identifies the existing demand and predicts the forecast demand for certain operational scenarios. The forecast is based on actual consumption since April 2016.

EXISTING AND FORECAST DEMAND

The current and future demand is based on the operation of site facilities as summarized in the following tables for FY2019 and FY2020, respectively.

envision more SM
Parsons PLUS

FY2019 FORECAST

Site Facility	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March
Faro Side Facilities												
Faro Water Facilities												
- Cornell Pumping												
- IWTP												
- IP Pumping												
- Miller Skid Pumping												
- X13 Sump Pumping												
- X13 Other Pumping												
CVPTP Operation												
Van Gorda Side Facilities												
Van Gorda Water Facilities												
- VGWTP												
- VG Pumping												
- Grum Pumping												
Construction Camp												
Legend	Active											

Monthly Energy Summary

Actual Consumption, MWh	612	672	720	864	960	-	-	-	-	-	-	-
Total Actual Consumption, MWh	612	1,284	2,004	2,868	3,828							
Forecast Consumption, MWh	583	583	1,069	1,069	1,110	1,483	1,195	1,114	1,075	1,075	1,075	860
Total Forecast Consumption, MWh	583	1,166	2,235	3,304	4,414	5,897	7,091	8,205	9,280	10,354	11,429	12,289

FY2020 FORECAST

Site Facility	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March
Faro Side Facilities												
Faro Water Facilities												
- Faro Pit Pumping												
- IWTP												
- IP Pumping												
- Miller Skid Pumping												
- X13 Pumping												
CVPTP Operation												
Van Gorda Side Facilities												
Van Gorda Water Facilities												
- VGWTP												
- Van Gorda Pit Pumping												
- Grum Pit Pumping												
Construction Camp												
Legend	Active											

Monthly Energy Summary

Forecast Consumption, MWh	1,082	1,082	1,676	1,730	1,500	1,500	996	915	876	876	876	661
Total Forecast Consumption, MWh	1,082	2,164	3,840	5,570	7,070	8,571	9,567	10,482	11,358	12,234	13,110	13,771

Cam Malloch
Crown-Indigenous Relations and Northern Affairs Canada October 10, 2019

Based on the assumed equipment and operation schedule we predict that the FMC will consume approximately 12,300 MWh in FY2019 and approximately 13,800 MWh in FY 2020. At historic rates, the FY2019 and FY2020 annual cost for electricity should be approximately $2.40million and $2.60million, respectively.

CLOSURE

We trust that the information presented herein is satisfactory for your present requirements. If you have any questions, please do not hesitate to contact the undersigned.

Respectfully submitted,
PARSONS INC.
James Carss, P.Eng.
Program Director
PARSONS

TOPIC: **Power Generation**

REFERENCE: **2021 General Rate Application, page 2-9 (PDF page 34 of 441) and Table 2.2**

PREAMBLE: CW notes that there is a pattern of increased thermal generation in 2019 and 2020, but this is forecast to decline in 2021. Further, CW notes that the LTA predicts a higher use of thermal. CW requires information as to how the different forecasts would impact customers.

The following table is taken from data in Table 2.2

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
Actual					
Hydro Generation	411,397	413,052	370,819	436,725	506,483
Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
Thermal Generation	11,109	37,316	69,858	71,199	30,260
Total Actual Generation	422,506	450,368	440,676	507,980	538,726
Total Sales	388,332	412,470	403,492	465,788	495,151
Losses	34,173	37,898	37,185	42,193	43,575
	422,506	450,368	440,676	507,980	538,726
LTA					
LTA Hydro Generation	403,910	418,695	415,377	438,905	452,437
LTA Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
LTA Thermal Generation	16,355	31,391	25,300	69,019	84,306
Total LTA Generation	420,265	450,086	440,676	507,980	538,726
Actual					
Hydro Generation	97.37%	91.71%	84.15%	85.97%	94.01%
Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
Thermal Generation	2.63%	8.29%	15.85%	14.02%	5.62%
Total Actual Generation	100.00%	100.00%	100.00%	100.00%	100.00%
LTA					
LTA Hydro Generation	96.11%	93.03%	94.26%	86.40%	83.98%
LTA Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
LTA Thermal Generation	3.89%	6.97%	5.74%	13.59%	15.65%
Total LTA Generation	100.00%	100.00%	100.00%	100.00%	100.00%

QUESTION:

a) Please fully explain why the LTA forecasts were not used in the preparation of the GRA forecast.

b) Please explain the impact of a scenario where the actual is closer to the LTA, yet the GRA forecast is approved. What will the impact be on the various deferral accounts and on base rates?

c) CW notes that on lines 21-26 of page 2-9, CW [sic] briefly discusses its sourcing strategy. This addresses years with normal water conditions. Please fully explain the YEC strategy for sourcing energy in years that do not have normal water conditions. What assets are engaged first, second, third, etc. Why is this the appropriate strategy?

d) On lines 17-20 of page 2-9, YEC discusses that 2018 and 2019 experienced unfavourable water conditions, and that actual hydro generation is currently forecast to reflect water availability at about LTA in 2020 and above LTA in 2021. Please fully explain the current water levels, and the likelihood that the GRA forecast generation mix will be achieved.

ANSWER:

(a)

The LTA forecasts as provided in Table 2.2 were used to prepare the GRA forecast, as stated in Sections 2.3 and 3.2 of the Application. Section 3 of OIC 2021/16 also now directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average annual renewable resource availability.

(b)

The GRA forecast is based on LTA hydro. The scenario in this question cannot occur.

(c)

Yukon Energy optimizes the hydro system within the license requirements to maximize the hydro system capabilities and minimize thermal energy. The typical dispatch order used by Yukon Energy for the system is: (1) hydro, (2) LNG, and (3) diesel, subject to operational restrictions and reliability limitations. This dispatch order is based on minimizing generation costs for ratepayers while maintaining system reliability.

(d)

As quoted above, YEC currently expects better than LTA hydro generation in 2021. However, the GRA forecast is based on LTA hydro generation. To the extent that actual hydro generation results differ from LTA and are caused by water supply issues, these amounts will be charged to the LWRF in accordance with the rules established for that fund and approved by the YUB. The 2021 GRA rate determination is not affected by the current reservoir conditions.

Please also see responses to CW-YEC-1-43 (c) and YUB-YEC-1-27 (a).

TOPIC: **Resource Plan**

REFERENCE: **2021 General Rate Application, page 2-14 (PDF page 39 of 441)**

PREAMBLE: On lines 5-8. YEC discusses a 2016 resource plan that was used in the 2017-18 GRA. CW requires information regarding how the 2016, or subsequent, resource plan was used in the preparation of this GRA.

QUESTION:

a) Please confirm that there is no newer resource plan that was prepared by YEC subsequent to the referenced 2016 Resource Plan. If not confirmed, please provide the most recent resource plan.

b) Please fully discuss how the 2016 (or more recent) resource plan was used in the preparation of this GRA.

ANSWER:

(a)

The 10 Year Renewable Electricity Plan was developed in 2020 (referenced as "10 Year Renewable Energy Plan" in Appendix 5.4, Section 5.4.3). Please see Attachment 1 to response to CW-YEC-1-36(a) for a copy of this most recent plan.

(b)

The 10-Year Renewable Electricity Plan has guided Yukon Energy in selection of potential new renewable generation and related transmission projects to be pursued over the coming decade. In this regard, it has influenced some of the capital and deferred projects being planned and addressed in Tab 5 of this GRA Application – however, in all important instances (beyond the Plan itself) the relevant capital and deferred costs are forecast to remain in WIP through the 2021 test year and therefore do not affect the forecast 2021 revenue requirement.

TOPIC: **Long-Term Average Hydro Generation (2021)**

REFERENCE: **2021 General Rate Application, Appendix 2.1, Table 2.1-1**

PREAMBLE: In Appendix 2.1, YEC discusses its LTA forecasts. CW requires information to assess the LTA and how it is used.

QUESTION:

a) Please provide the year that each line number in Table 2.1-1 relates to. In the response, please also provide Table 2.1-1 in Excel format.

b) Please confirm that the LTA is a simple average of years. If not confirmed, please fully explain.

c) If (b) above is confirmed, please fully discuss whether any trend or regression analysis was conducted on the LTA data. If any such analysis was conducted, please provide it.

ANSWER:

(a) through **(c)**

Please see CW-YEC-1-11 Attachment 1 for the copy of Table 2.1-1 in MS Excel format. There are no years associated with line numbers. The lines just reflect the loads with 5 GW.h increments. The table is designed to show long-term average hydro and thermal generations at various load ranges. No trend or regression analysis was conducted on the LTA data.

Please see the detailed example included in the notes to the table with steps on how to use the table and identify thermal generation based on long-term average hydro generation to the given load.

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

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

Notes:
1. "YEC Grid Load" is annual YEC generation load on the Integrated Grid net of IPP generation, secondary sales related generation and Fish Lake hydro generation. The load will also be adjusted for WH2 and WH4 uprates as noted in #7 below.
2. The thermal generation and increase for the added load are based on a polynomial equation derived from "YECSIM" - the simulation model developed for the Integrated Grid by KGS Group.
3. The model calculates expected hydro plant generation for each load scenario. It incorporates, on a weekly time step, 38 "water years" on record (1981-2018) and 20 "load years" (each examines a different hypothetical scenario to evaluate generation under different sequences of the recorded water years), of which 13 load years (load years 7-19) are used for the final averaging (this removes results distorted by starting or ending year volumes). "Hydro Generation" is long-term average hydro generation as estimated by YECSIM.
4. The simulation model results used for this table assume the current operation rule in effect at Aishihik Lake (i.e., 10-year rolling average spring elevation no lower than 913.7 m), current Mayo Lake operation rule (no additional storage, impact of sedimentation at the outlet of Mayo Lake) and restricted Mayo GS winter flows (based on new Mayo Ice Protocol Mayo GS outflows are restricted at max 19 cms in November and 15 cms in December, after which restrictions are relaxed by 1.75 cms/week reaching 20 cms by early January and 24 cms by February [compared to 20 cms restriction through winter used in the 2017/18 GRA]. The model aslo assumes Whitehorse GS winter max flows at 170 cms compared to 160 cms in 2017/18 GRA.

5. The simulation model results are based on 2021 forecast load and IPP distributions, and requires modifications when new mines, industrial loads or IPP generation are connected to [or disconnected from] the grid.

6. The table assumes max YEC Grid Load (i.e., excluding IPP generation) at 585 GW.h and minimum YEC Grid Load at 475 GW.h. If the YEC Grid Load exceeds these limits then the table needs to be updated.

7. YEC is undertaking capital projects that will increase hydro generation output in Whitehorse GS [WH2 and WH4 uprates]. The preliminary estimates show that these capital projects will increase generation output by 7.1 GW.h/year [4.2 GW.h for 2021 considering expected in service date effective July 1, 2021 - monthly allocation based on Whitehorse GS monthly generation forecast]. Therefore, the YEC Grid Load is reduced to reflect increased output from these capital projects [not all incremental generation will directly displace LTA thermal].
8. Numbers are subject to rounding.

Example
Expected YEC Thermal Generation for the YEC generation at 536.743 GW.h (net of expected IPP & Fish Lake)

Remove Expected Generation for WH uprates [estimate for 2021 at 4.213 GW.h] to get net load at 532.530 GW.h

Step 1. Find the closest load from Column A that is less than 532.530 GW.h = 530 GW.h (Line 12).

Step 2. Find the thermal generation from Column C = 82.231 GW.h (Line 12).

Step 3. Find the difference between the given load (532.530 GW.h) and load from Step 1 (530 GW.h) = 2.530 GW.h

Step 4. Apply the percentage from Column F (Line 12, 82%) to the difference from Step 3 (2.530 GW.h) = 2.075 GW.h

Step 5. Add numbers from Step 2 (82.231 GW.h) and Step 4 (2.075 GW.h) = 84.306 GW.h

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

TOPIC: **Fuel Costs**

REFERENCE: **2021 General Rate Application, Table 3.2.1 and Table 2.2**

PREAMBLE: In Table 2.2, it appears that the forecast 2021 generation is based on a forecast that is different than the LTA, yet in Table 3.2.1, it appears that the fuel costs are based on LTA thermal generation. The following table taken from Table 2.2 demonstrates the difference between the 2021 forecast and the LTA.

	2018 Approved	2018 Actual	2019 Actual	2020 Forecast	Forecast 2021
Actual					
Hydro Generation	411,397	413,052	370,819	436,725	506,483
Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
Thermal Generation	11,109	37,316	69,858	71,199	30,260
Total Actual Generation	422,506	450,368	440,676	507,980	538,726
Total Sales	388,332	412,470	403,492	465,788	495,151
Losses	34,173	37,898	37,185	42,193	43,575
	422,506	450,368	440,676	507,980	538,726
LTA					
LTA Hydro Generation	403,910	418,695	415,377	438,905	452,437
LTA Wind Generation	0	0	0	0	0
IPP Generation	0	0	0	56	1,983
LTA Thermal Generation	16,355	31,391	25,300	69,019	84,306
Total LTA Generation	420,265	450,086	440,676	507,980	538,726
Actual					
Hydro Generation	97.37%	91.71%	84.15%	85.97%	94.01%
Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
Thermal Generation	2.63%	8.29%	15.85%	14.02%	5.62%
Total Actual Generation	100.00%	100.00%	100.00%	100.00%	100.00%
LTA					
LTA Hydro Generation	96.11%	93.03%	94.26%	86.40%	83.98%
LTA Wind Generation	0.00%	0.00%	0.00%	0.00%	0.00%
IPP Generation	0.00%	0.00%	0.00%	0.01%	0.37%
LTA Thermal Generation	3.89%	6.97%	5.74%	13.59%	15.65%
Total LTA Generation	100.00%	100.00%	100.00%	100.00%	100.00%

QUESTION:

a) Please fully explain and reconcile the apparent discrepancy.

b) Please provide an adjusted fuel cost forecast using the generation mix incorporated in the 2021 forecast in Table 2.2.

ANSWER:

(a) and **(b)**

There is no discrepancy; fuel cost for rate making purposes is based on LTA thermal generation as previously approved by the YUB and consistently applied in this application. Table 2.2 shows hydro and thermal generation levels for 2018-2021 years based on the following:

- **"Actual":** These reflect actual generation for 2018 and 2019 years as well as forecast generation for 2020 and 2021 based on known/expected reservoir conditions for these years at the time of preparation of forecasts.

- **"LTA":** These generation numbers reflect hydro and thermal generations based on long-term average water conditions [1981-2018].

Section 2.3 of the Application provides explanations for actual and LTA generation. The LTA forecasts as provided in Table 2.2 were used to prepare the GRA forecast, as stated in Sections 2.3 and 3.2 of the Application. Section 3 of OIC 2021/16 also now directs that forecast fuel costs to be included in rates for thermal generation to meet forecast customer requirements are to be based on long-term average annual renewable resource availability as stated in response to CW-YEC-1-9 (a).

TOPIC: **Labour**

REFERENCE: **2021 General Rate Application, page 3-8 and 3-9 (PDF pages 54-55) and Table 3.4**

PREAMBLE: On page 3-9 YEC provides a discussion of reasons for increases in labour. In Table 3.4, YEC provides a summary of employment history. On lines 11-13 of page 3-8, YEC discusses overtime, vacancies and capital allocation. CW requires information to analyse the employment levels and verify the assertions of the causes of increases in headcount.

QUESTION:

a) Please fully explain whether the headcount in Table 3.4 is total complement, O&M only, includes vacancies or excludes vacancies, and whether it includes or excludes allocations to capital.

b) Please provide the calculation of total headcount, allocations to capital, and vacancies arriving at total O&M headcount, net of vacancies, in a form similar to Table 3.4, and in Excel format.

c) Please provide an analysis that lists the positions that directly work in:
   i. Reading meters;
   ii. Maintaining and operating assets;
   iii. Customer billing and responding to customer calls;
   iv. Providing customer service in the field;
   v. Transmission;
   vi. Generation; and
   vii. Other administrative functions.

d) For each of the positions listed in the response to (c) above for please provide the headcount for each YEC community in Excel format for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021

Please ensure that the total reconciles to the totals related to O&M as provided in response to (b) above. Where a position provides a number of the functions listed in (c) above, please allocate the headcount between the functions, and provide an explanation of the allocation.

e) Please provide total customers by community and by customer class for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021.

f) Please provide the kilometres of line, number of transformers, number of meters, number of substations, number of poles, number of towers, and number of generation assets by community and/or location of facility for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021

ANSWER:

(a)

The headcount in Table 3.4 is total complement; it includes permanent, casual and temporary employees, regardless of whether their time is spent on admin, O&M or capital. Vacancies are not deducted from this headcount.

(b)

For forecasting purposes, YEC translates the expected vacancy rate into a percentage reduction which is applied to each position's loaded charge out rate. There is no obvious method to apply this rate to the position counts in Table 3.4. Actual vacancies for 2018 and 2019 are noted in Table 1 that follows.

Table 1: Actual Vacancies for 2018 and 2019

	Actual 2018	Vacancy Allocation 2018	Net 2018 Allocation	Actual 2019	Vacancy Allocation 2019	Net 2019 Allocation
President	5.14	(0.25)	4.89	4.82	(0.45)	4.37
First Nations Relations	-	-	0.00	-	-	-
Communications & Customer Acct.	1.00	-	1.00	1.00	(0.04)	0.96
Human Resources & Info. Mgmt.	5.27	(0.64)	4.63	5.34	(0.07)	5.27
Resource Planning & Environment	5.00	(0.41)	4.59	5.75	(2.04)	3.71
Finance & Purchasing	16.89	(0.47)	16.42	17.24	(0.57)	16.67
Operations	46.58	(2.07)	44.51	47.12	(3.86)	43.26
Engineering Services	13.03	(2.21)	10.82	15.16	(2.88)	12.28
Health, Safety & Environment	2.00	-	2.00	2.00	-	2.00
Total	**94.91**	**(6.05)**	**88.86**	**98.44**	**(9.91)**	**88.53**

Capital allocation is forecast on an employee by employee basis based on the supervisors' assessment of hours worked in O&M v. Capital. As such, YEC is not able to provide an employee complement with adjustments for capital allocation on a departmental basis. However, YEC can provide the capital allocation on a company wide basis (see Table 2 below):

Table 2: Capital Allocation

	Capital	Maintenance
2018 Approved	17.0%	83.0%
2018 Actual	14.7%	85.3%
2019 Actual	16.0%	84.0%
2020 Actual	18.2%	81.8%
2020 Forecast	17.5%	82.5%
2021 Forecast	17.6%	82.4%

(c)

A position analysis is provided as Attachment 1 to this response.

(d)

As the table requested in part (b) is not possible, it is not possible to provide a Table in part (d) that reconciles to it. However, a headcount per community is provided as Attachment 1 to this response.

(e)

The sales and number of customers are not approved by community level. Please see response to CW-YEC-1-6 for actual and forecast sales and number of customer by community.

(f)

Please see the tables that follow which provide a list where feasible of the different equipment requested by location as of December 31, 2020. The data provided is for equipment commissioned by end 2020. No historical trend or growth data exists for previous years.

The following information is available on number of meters by community[1]:

- Dawson = 1501
- Faro = 402
- Mayo = 398
- Johnson's Crossing = 12
- Mendenhall = 76
- Braeburn = 39
- Other = 39

Separate tables have not been provided for 2018 approved or actual, 2019 actual, 2020 forecast, or 2021 forecast. Adjustments to reflect 2018 and 2019 actual are as follows:

- In 2018 LNG unit #3 was added
- In 2019 the McQuesten Substation was added
- In 2020 the Faro Substation to connect rental diesel units was added
- In 2020 the Van Gorda Substation was added
- In each year a number of distribution poles and transformers were added

[1] A number of customers disconnect power on a seasonal basis. The total of 2736 in the attached table includes all meters (including seasonally disconnected) whereas the count by community of 2467 meters only includes "active" meters.

Forecasted changes to equipment list for 2021 are as follows:

- Commission new Mayo-McQuesten Transmission line and decommission old line.
- Net addition of poles for L177 re-route

YUKON ENERGY - Count of customer meters
2736

1

YUKON ENERGY - TRANSMISSION LINES					
Name	From	To	Tower Count	Pole Count	Length (m)
L127	WH4 - Unit 4	S150 - Whse Hydro Sub	8 (steel)	0	794
L150	S150 - Whse Hydro Sub	S171 - Riverside Sub	0	0	200
L151	WG0 (S151)	S150 - Whse Hydro Sub	8	8	384
L169	tap from L172 (str. 48)	S170 - McIntyre Sub	30	74	6543
L170	S164 - Takhini Sub	870S - Faro Sub	724	1480	152000
L171	S164 - Takhini Sub	S167 - Aishihik Sub	591	1222	129862
L172	S171 - Riverside Sub	S164 - Takhini Sub	112	236	25355
L173	S255 - Carmacks Airport Sub	S253 - Minto Landing Sub	387	1104	70891
L174	S253 - Minto Landing Sub	S252 - Pelly Crossing Sub	165	330	30044
L174	S252 - Pelly Crossing Sub	S251 - Stewart Crossing South Sub	371	842	64823
L175	S251 - Stewart Crossing South Sub	S256 - Stewart Crossing North Sub	32	64	5704
L176	S249 - Mayo Hydro Sub	S256 - Stewart Crossing North Sub	353	363	52000
L177	S256 - Stewart Crossing North Sub	S250 - Callison Sub	1375	1389	172000
L178	S255 - Carmacks Airport Sub	870S - Faro Sub	748	1288	190000
L248	S248 - Mayo B Substation	S249 - Mayo Hydro Substation	55	55	3505
L250 (Old Line)	S249 - Mayo Hydro Sub	S257 - Keno Sub	?	752	52000

2 Note: L250 Mayo to McQuesten is being replaced and the new line will be commissioned in 2021. Count of poles and structures is for the
3 old line.

1

YUKON ENERGY -Substations		
Name	Location	Count
S167	Aishihik	1
S163	Carmacks	2
S255	Carmacks	
S250	Dawson	1
870S	Faro	5
S146	Faro	
S162	Faro	
S140	Faro	
S178	Faro	
S248	Mayo	4
S249	Mayo	
S257	Mayo	
S258	Mayo	
S253	Minto	2
S254	Minto	
S252	Pelly	1
S251	Stewart	2
S256	Stewart	
S150	Whitehorse	5
S151	Whitehorse	
S164	Whitehorse	
S170	Whitehorse	
S171	Whitehorse	

YUKON ENERGY - Distribution assets Note: length of distribution line assets is not available.		
Distribution District	Pole Count	Distribution Transformers Count
Haines Junct	62	3
Johnsons Crossing	40	21
Champagne	136	17
South Fox Lake	117	23
Mendenhall	482	71
Braeburn	80	12
Faro area	515	99
Drury Creek	47	9
Mayo	849	161
Dawson	1762	320
Small Taps	323	Unknown
L355 Feeder	500	0

YUKON ENERGY - Count of Generators by Location	
Location	Count
Aishihik	3
Dawson	6
Faro	2
Mayo	7
Whitehorse	12
Grand Total	**34**

CW-1-13 (c)- Position Analysis

Position Name	i. Reading Meters	ii. Maintaing & Oper. Assets	iii. Cust. Billing/Service	iv. Providing Cust. Service in field	v. Transimission	vi. Generation	vii. Other Admin. Functions
Manager, Communications & Customer Service			✓				✓
Sr. Office Administrator			✓				
Customer Service Rep.			✓				
Meter Reader/Admin. Asst.	✓		✓				
Communication Coordinator			✓				✓
VP, Finance & Chief Financial Officer							✓
Manager, Procurement							✓
Procurement Specialist							✓
Sr. Procurement Specialist							✓
Warehouse Administrator							✓
Warehouse Assistant							✓
Controller							✓
Sr. Regulatory Analyst							✓
Financial Administrator							✓
Accounts Payable Clerk							✓
Assistant Controller							✓
Financial Administrator							✓
Payroll Analyst							✓
Financial Administrator							✓
Procurement Specialist							✓
Manager, Health & Safety							✓
Safety Coordinator							✓
Manager, Human Resources							✓
Manager, IT							✓
Network Administrator							✓
Web Developer & Systems Administrator							✓
Web Developer & Systems Administrator							✓
VP, Operations	✓	✓		✓	✓	✓	✓
Operations Coordinator					✓	✓	✓
CMMS/Operations Administrator							✓
Distribution Coordinator				✓			
Leadhand, SCC					✓	✓	✓
SCC Operator I					✓	✓	
SCC Operator II					✓	✓	
SCC Operator I					✓	✓	
SCC Operator I					✓	✓	
SCC Operator I					✓	✓	
Manager, Operations	✓	✓		✓	✓	✓	✓
Leadhand, T&D		✓			✓		✓
Powerline Technician		✓			✓		
Sr. Powerline Technician		✓			✓		
Sr. Powerline Technician		✓			✓		
Sr. Powerline Technician	✓	✓			✓		
Powerline Technician	✓	✓			✓		
Sr. Powerline Technician		✓			✓		
Powerline Technician	✓	✓			✓		
Lead hand, Electrical Maintenance		✓			✓		✓
Maintenance Electrician		✓			✓		
Electrical Instrumentation Coordinator		✓			✓		
Metering Coordinator Mntce Electrician		✓		✓	✓		
Electrical Protection & Control Coordinator		✓			✓		
Maintenance Electrician		✓			✓		
Maintenance Electrician		✓			✓		
Maintenance Electrician		✓			✓		
Electrical Protection & Control Coordinator		✓			✓		
Leadhand, Mechanical Maintenance		✓				✓	✓
Sr. Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Maintenance Mechanic		✓				✓	
Apprentice Trades Person		✓				✓	
Maintenance Mechanic		✓				✓	
Sr. Plant Operator		✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator-Aishihik		✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator	✓	✓				✓	
Plant Operator-Mayo		✓				✓	
Plant Operator-Mayo		✓				✓	
Manager, Property & Projects		✓					✓

Position Name	i. Reading Meters	ii. Maintaing & Oper. Assets	iii. Cust. Billing/Service	iv. Providing Cust. Service in field	v. Transimission	vi. Generation	vii. Other Admin. Functions
President & CEO							✓
VP, Business and Corporate Development							✓
Corporate Secretary							✓
Records Management Analyst							✓
VP, First Nations Relations							✓
VP, Resource Planning & Regulatory Affairs							✓
Manager, Environment							✓
Environment Coordinator							✓
Resource Planner							✓
Resource Planning Engineer							✓
Project Manager – Planning & Regulatory Affairs							✓
Project Manager – Moon Lake							✓
VP, Engineering & Capital Projects		✓			✓	✓	✓
Asset Manager		✓					
Job Planner		✓					
Administrative Assistant- Eng.							✓
Manager, Civil Engineering & Projects		✓			✓	✓	✓
Program Manager		✓			✓	✓	✓
Coordinator, Mechanical Projects		✓				✓	✓
Mechanical Engineer		✓				✓	✓
Draftsperson/ Land Use Administrator							✓
Draftsperson/ Land Use Administrator							✓
Capital Program Manager		✓			✓	✓	✓
Electrical Engineer		✓			✓	✓	✓
Electrical Engineer		✓			✓	✓	✓
Mech. Engineer-Engineer in Training		✓			✓	✓	✓
Protection & Systems Engineer		✓			✓	✓	✓
Coordinator, Electrical Projects		✓			✓	✓	✓
Casual Admin.							✓
Casual Warehouse Worker							✓
Casual IT Help Desk							✓
Casual IT							✓
Temp Plant Operator		✓				✓	
Temp Plant Operator		✓				✓	
Casual LNG Off Loader						✓	
Casual LNG Off Loader						✓	
Casual Plant Operators		✓				✓	
Casual Plant Operators		✓				✓	
Casual Diesel Plant Operator		✓				✓	
Diesel Plant Operator-Casual		✓				✓	
Casual Labourer		✓					
Yard Worker		✓					
Student Labourer		✓					
Student Labourer		✓					

CW1-13(d)- Employee Complement by Community

	2018 Approved				
	Whitehorse	**Dawson**	**Mayo**	**Faro**	**Total**
President	4.16				4.16
First Nations Relations					-
Communications & Customer Acct.	1.00				1.00
Human Resources & Info. Mgmt.	5.25				5.25
Resource Planning & Environment	5.00				5.00
Finance, Cust. Acctg. & Purchasing	14.69	2.10			16.79
Operations	36.00	3.00	5.00	0.50	44.50
Engineering Services	15.00				15.00
Health, Safety & Environment	2.00				2.00
Totals	**83.10**	**5.10**	**5.00**	**0.50**	**93.70**

2018 Actual					2019 Actual				
Whitehorse	**Dawson**	**Mayo**	**Faro**	**Total**	**Whitehorse**	**Dawson**	**Mayo**	**Faro**	**Total**
5.14				5.14	4.82				4.82
				-					-
1.00				1.00	1.00				1.00
5.27				5.27	5.34				5.34
5.00				5.00	5.75				5.75
14.79	2.10			16.89	15.14	2.10			17.24
38.70	2.77	5.00	0.11	46.58	39.19	2.54	5.00	0.40	47.13
13.03				13.03	15.16				15.16
2.00				2.00	2.00				2.00
84.93	**4.87**	**5.00**	**0.11**	**94.91**	**88.40**	**4.64**	**5.00**	**0.40**	**98.44**

2020 Forecast					2021 Proposed				
Whitehorse	**Dawson**	**Mayo**	**Faro**	**Total**	**Whitehorse**	**Dawson**	**Mayo**	**Faro**	**Total**
4.01				4.01	4.16				4.16
				-	1.00				1.00
1.00	2.10			3.10	2.00	2.60			4.60
5.32				5.32	5.25				5.25
5.51				5.51	7.05				7.05
13.54				13.54	14.79				14.79
40.25	3.00	5.00	0.50	48.75	40.75	3.00	5.00	0.50	49.25
15.63				15.63	15.50				15.50
2.00				2.00	2.00				2.00
87.26	**5.10**	**5.00**	**0.50**	**97.86**	**92.50**	**5.60**	**5.00**	**0.50**	**103.60**

TOPIC: **Labour**

REFERENCE: **2021 General Rate Application, page 3-8 (PDF page 54) and Table 3.4**

PREAMBLE: On page 3-8 YEC provides a discussion of reasons for increases in labour. On lines 11-13 of page 3-8, YEC mentions overtime, vacancies and capital allocation. In Table 3.4, YEC provides total labour. CW requires information to analyse the employment levels and verify the assertions of the causes of increases in headcount.

QUESTION:

a) Please provide the total Labour provided in Table 3.4 separating base labour, overtime, benefit costs and incentive compensation.

b) For each new position where YEC asserts that the increased position is needed as a result of overtime, please provide an analysis that clearly demonstrates that there was a pattern of overtime, and that there is a reduction in overtime that is included in the forecast for 2021 to offset that new position.

ANSWER:

(a)

Table 3.4 Employee Complement History as defined is total position count (number of employees). Table 1 below provides the Employee Complement with Total Labour by Department. Please note that it is not possible to provide Table 3.4 broken out by employee base labour, benefits and overtime, as YEC does not track employee actual benefits at the employee level. The cost of benefits are pooled and spread across all departments; and each employee base labour rate is multiplied by a F&B (fringe and burden) rate to get the labour expense. The F&B rate is determined by forecasting all employee's annual benefits in Business Planning process.

Also, as some departments have one or a few employees providing the level of detail requested may raise privacy concerns.

Table 1: Employee Complement with Total Labour by Department

	Approved 2018	Actual 2018	Actual 2019	Forecast 2020	Proposed 2021
President	$ 964	$ 936	$ 952	$ 959	$ 953
First Nations Relations	$ -	$ -	$ -	$ -	$ 248
Communications & Customer Acct.	$ 177	$ 185	$ 181	$ 382	$ 522
Human Resources & Info. Mgmt.	$ 811	$ 687	$ 825	$ 815	$ 858
Resource Planning & Environment	$ 918	$ 840	$ 667	$ 932	$ 1,266
Finance & Purchasing & Customer Acct. & Property Mang.	$ 2,355	$ 2,299	$ 2,459	$ 1,760	$ 1,942
Operations & Property Mang.	$ 6,443	$ 6,643	$ 6,659	$ 7,415	$ 7,528
Engineering Services	$ 2,417	$ 2,011	$ 2,071	$ 2,627	$ 2,517
Health, Safety & Environment	$ 310	$ 311	$ 325	$ 325	$ 317
Total	**$ 14,394**	**$ 13,912**	**$ 14,139**	**$ 15,215**	**$ 16,152**

(b)

As stated in the Application, none of the new positions are created solely to reduce overtime. YEC noted there were increases in positions in an effort to reduce overtime per employee for the Operations department (Maintenance Mechanic and Plant Operators), as well as in the Engineering department (Electrical Engineer). Below is a table of actual overtime cost for the last three years.

Table 2: Actual Overtime Costs: 2018-2020

	Overtime $
2018	$ 901,416
2019	$ 938,858
2020	$ 992,155

Notwithstanding wage rate increases, overall overtime is forecast to reduce in 2021 to a cost of $761,000.

TOPIC: **Labour**

REFERENCE: **2021 General Rate Application, page 3-10 (PDF page 56)**

PREAMBLE: On line 21, YEC discusses an increase related to a meter reader. CW requires information to assess efforts to improve productivity.

QUESTION:

a) Please fully discuss all research, analysis or other investigations that YEC has done in the areas of Automated Meter Reading (AMR) or Advanced Metering Infrastructure (AMI). In the response please fully discuss any plans YEC has to implement AMR or AMI, and the timeframes for any implementation. If YEC is not planning on implementing any AMR or AMI technology please fully explain why not, and provide all economic analysis that YEC has performed related to AMR or AMI.

ANSWER:

(a)

YEC has no plans at the current time to implement AMI or AMR and no current analysis of this technology. The request for additional staffing in this area reflects current need; any technology implementation would be several years away in Yukon. YEC notes that previous utility applications to implement AMR in Yukon have been denied by the YUB.

In the future, YEC expects that, as greater understanding of grid modernization unfolds, including progress on YG's "Our Clean Future" strategy actions and a broader deployment of demand-side management programs, YEC will continue to assess AMR/AMI and its potential to provide a cost-effective alternative for ratepayers, its benefits and potential barriers.

TOPIC: **Labour Rates**

REFERENCE: **2021 General Rate Application, page 3-8 (PDF page 54)**

PREAMBLE: In lines 2-8, YEC states:

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

QUESTION:

a) Please provide a working paper that identifies the cost of living adjustment, performance increments and any other adjustments for each of:
   i. 2018 Approved;
   ii. 2018 Actual;
   iii. 2019 Actual;
   iv. 2020 Forecast; and
   v. Proposed 2021.

b) Please fully discuss the increases awarded to employees not subject to the CBA.

ANSWER:

(a)

Cost of Living and Performance Increments are rolled up in overall wage costing.

Regarding performance increments, employees subject to the Collective Bargaining Agreement can have up to two increments per year (every six months) if they are not capped at their maximum salary level. With many new hires recently this means a lot of performance increments. Management and Professional employees are eligible for performance increments annually if they are not capped at their maximum salary level. As union employees can have different dates for increments based on their start dates throughout the year, YEC forecasts performance increments by using an average wage for that position for the year. Additionally, due to the timing of the performance increase being dependent on the timing of the performance review, we also get into situations were increments are late and run between different years, but the retro ends up in year it is paid. As such, a calculation of cost of performance increments would be extremely difficult.

For GRA forecast purposes, performance increments are similar to cost of living as they are buried in the overall costs, which are referred to as economic increments. For 2018, the cost of living increase was 1.50%, equal to the 2018 approved amount. The 2019 cost of living increase was 2.00%, equal to the rate required in the collective bargaining process. YEC has forecast an economic increase (cost of living and performance increment) of 2.00% for 2020 and 2021.

(b)

For the 2017 to 2019 CBA, increases awarded to employees not subject to the CBA were consistent with increases awarded to employees subject to the CBA. For the 2021 forecast, the assumption is the same.

TOPIC: **Production**

REFERENCE: **2021 General Rate Application, Section 3.3.2, and Table 3.5**

PREAMBLE: On lines 4-8 of page 3-14, YEC discusses diesel rentals, and an increase of $3.834 million.

QUESTION:

a) Please provide copies of all analysis or business cases that YEC has done or prepared comparing the cost of owning diesel generation compared to rentals. If no such analysis or business cases have been prepared, please fully explain why not.

b) Please provide the number of diesel generation units that would be rented, and the amount of use each would experience (Months per year).

c) Please describe the rental terms. As an example, are the units rented on a month to month basis or on an annual basis? In the response, please provide an analysis that clearly identifies the number of months of rental payments YEC has forecast for each unit it is renting in 2021. Also, are the rentals under long term leases, or can the rental be cancelled with 30 days notice or no notice at all?

d) Please provide the capacity of each unit.

e) Please explain what operating costs YEC is responsible for, compared to the costs the lessor is responsible for.

f) Please describe the characteristics of each unit, for example, are the all the units mobile or are any fixed in place?

g) Please provide YEC's estimated cost of purchasing each rental unit that is forecast to be rented in 2021.

ANSWER:

(a)

Yukon Energy's 2016 Resource Plan included action plans focusing on short and long-term options to reduce the capacity shortfalls, including building a new 20 MW diesel plant.

However, based on feedback received from Yukoners as well as to address impacts of the Yukon government Climate Change Strategy Yukon Energy's Board of Directors decided not to pursue a new 20 MW thermal plant at this time and look at options to replace capacity at Yukon Energy's existing generation facilities as diesel engines reach end-of-life.

Yukon Energy is pursuing the new renewable generation capacity options as outlined in the 10-Year Renewable Electricity Plan [please see CW-YEC-1-36 (a) Attachment 1 for the copy of the Plan], including battery energy storage system, Atlin Hydro Expansion Project, and the potential development of pumped storage at Moon Lake. Until the new renewable resource options are developed, diesel rentals are continuing to be the best available option at this time to address capacity shortfalls.

Please also see YUB-YEC-1-40 (a).

(b)

For the 2021/22 winter YEC forecast to rent 17 diesel units, including a spare unit in each location [Faro and Whitehorse]. The usage of the units will depend on peak in the system and condition of the existing generation capacities. The diesel rentals are primarily in place to provide for the N-1 contingency event and would not normally be called upon to use fuel in order to generate electricity.

(c)

The diesel units are rented through an annual contract for the winter heating season period, from December through April. The rental rates are based on a 28 day cycle.

(d)

Each diesel unit has a capacity of 1.8 MW.

(e)

Per the supply contract, YEC is responsible for periodic operations checks including monitoring and maintaining consumables (fuel, oil, antifreeze, etc.). YEC is not charged maintenance if the individual units are run less than 100 hours per 28 day rental cycle. At the end of the contract, YEC pays a maintenance charge based on the pro rata hours run. CAT is responsible for the cost of any breakdowns.

(f)

The units are installed at the beginning of rental period [November/December] in two locations with rental unit infrastructure [Faro and Whitehorse] and decommissioned at the end of rental period [April].

(g)

YEC is not planning to purchase the rental diesel units and, as far as YEC is aware, the vendor is not offering these units for sale.

TOPIC: **Brushing Costs**

REFERENCE: **2021 General Rate Application, page 3-15 (PDF page 61) Table 3.6.1 and following paragraph**

PREAMBLE: CW notes that YEC discusses brushing and its related policy. Also, CW notes that there appears to be a marked reduction in costs in 2019 for distribution. CW is concerned that there be no arbitrary reductions in brushing to maintain corporate profits.

QUESTION:

a) Please fully explain the YEC brushing policy, and how the 2019 actual Distribution brushing expenditure was consistent with the policy.

b) CW notes that the 2019 actual Distribution brushing was only $28,000. Please fully explain why the 2019 Distribution Brushing was so low. In the response please also confirm that YEC follows its brushing policy, and does not reduce brushing to avoid costs and maintain returns. If not confirmed, please fully explain.

ANSWER:

(a) and **(b)**

The YEC brushing policy was developed at the direction of the YUB (Order 2013-01) and was reviewed as part of the 2017/18 GRA (Order 2018-10).

The policy was developed as follows: utilizing the information gathered in aerial and ground surveys and supplemented with line maintenance history provided by YEC, ECI (contractor) developed a recommended cyclic maintenance schedule based on 10 year cycle guideline for each line. The growth rates vary per line and per year so the priorities are adjusted based on line patrols.

ECI recommended the following:

1. Remove trees under the conductors in locations designated as Critical as soon as possible.

2. Remove trees under the conductors in locations designated as Priority before the next growing season (June 2011).

3. Remove all trees designated as Hazard over the next two years.

4. Establish a schedule of cyclic maintenance by right-of-way including separate schedules for Critical, Priority and Hazard tree locations.

5. Budget funds to address Critical locations as they are identified. This will be reduced each subsequent year of the maintenance cycle.

6. Establish a list or database of danger and hazard tree locations and develop a priority program to determine which trees should be removed first.

7. Develop vegetation maintenance clearance specifications for transmission and sub-transmission voltages and policy and standards specific to YEC needs and conditions. ECI has developed a draft TVMP for YEC"s consideration.

8. Consider contracting alternatives to reduce maintenance cost as well as developing additional qualified vendors to perform vegetation maintenance on the YEC system (including herbicide application).

9. Implement Integrated Vegetation Management (IVM) as the guiding maintenance principle on the YEC system.

10. Establish an herbicide test plot area. Develop specification and guidelines on the use of herbicides on the YEC system. After an initial test period of various products and application methods and upon development of specification/procedures for herbicide use, (2012-2013), integrate the use of herbicides as a major component of the YEC vegetation maintenance program.

Distribution brushing priorities are identified using ground patrol data.

The vegetation management budget is typically about 80/20 split transmission/distribution. In 2019, the distribution portion was less due to the TLR work and the requirement to prioritize the brushing on the transmission system where the work was to take place.

TOPIC: **Distribution Costs**

REFERENCE: **2021 General Rate Application, page 3-16 (PDF page 62) Table 3.7 and following paragraph.**

PREAMBLE: CW notes that YEC has forecast "Other Non-Labour" to increase from $204,000 in the 2018 approved forecast to $279,000 in 2021. This is an increase of approximately 37%.

QUESTION:

a) Please fully explain why "Other Non-Labour" reduced to $80,000 in 2019. In the response, please fully explain why that level of costs could not be maintained in 2021.

b) Please fully explain what costs are included in "Other Non-Labour" and why the forecast increased by 37% from 2018 to 2021.

ANSWER:

(a)

There was an error in the table that affected the 2019 actuals. The corrected table is below.

	2018 Approved	Actual 2018	Actual 2019	Forecast 2020	Forecast Existing 2021	Forecast Proposed 2021
Labour	$ 856	$ 801	$ 625	$ 617	$ 629	$ 629
Brushing Cost	331	212	28	249	212	212
Other Non-Labour	204	236	265	287	279	279
Total Distribution	$ 1,391	$ 1,250	$ 918	$ 1,154	$ 1,120	$ 1,120

With this correction, the 2019 actual cost of Other Non-Labour is in line with previous and subsequent results. The low brushing total for 2019 is explained in CW-YEC-1-18.

(b)

Costs included in 'Other Non-Labour' include the following:

- Response to distribution events (i.e., trees on lines, distribution transformer/pole replacement);

- Call outs (i.e., customer complaints, refusing, house fires, power quality);

- High loads; and

- Outage response.

This work is forecast to be higher in 2021 as compared to 2018 as we expect 2021 to be fairly similar to costs in 2020.

TOPIC: **General Operating and Maintenance**

REFERENCE: **2021 General Rate Application, pages 3-16 and 3-17 (PDF pages 62 and 63) Table 3.8 and following paragraph.**

PREAMBLE: In the paragraph following Table 3.8, YEC explains what areas the cost increases are in, but now why the costs increase.

QUESTION:

a) Please fully explain why costs related to Transportation, Maintenance of Company Owned Properties, and Scada Communication are forecast to increase by 10%, 18%, and 15% respectively.

ANSWER:

(a)

See response to YUB-YEC-1-42.

TOPIC: **Administration**

REFERENCE: **2021 General Rate Application, pages 3-17 and 3-18 (PDF pages 63 and 64) Table 3.9 and following paragraph.**

PREAMBLE: YEC discusses changes in Administration costs.

QUESTION:

a) On lines 1-5 of page 3-18, YEC discusses cost increases due to a 3 year water license. Please provide the term of the referenced license (i.e. what years are covered by the license).

ANSWER:

(a)

The term of Aishihik Generating Station Water Use License HY19-016 is from March 1, 2020 to December 31, 2022.[1]

[1] Water Use Licence HY19-057 was effective January 1, 2020 to February 29, 2020.

TOPIC: **LWRF Stabilization Mechanism**

REFERENCE: **2021 General Rate Application, page 3-31 (PDF page 77)**

PREAMBLE: On lines 11-19, YEC discusses why it has not updated its LWRF Term Sheet.

QUESTION:

a) Please fully explain what COVID conditions prevented the completion of an updated term sheet.

b) Please fully explain what other factors prevented the completion of the updated term sheet.

c) Please fully explain when YEC expects to complete an updated term sheet.

d) Please fully explain why YEC did not file to be given relief from filing an updated term sheet.

ANSWER:

(a) through **(d)**

As reviewed in Section 1.1 of the Application, Yukon Energy faced ongoing difficulties in proceeding with the next GRA required as soon as feasible after final approvals for the 2017-18 GRA. After having to cancel a 2019/20 GRA, the effort to implement any rate change in 2020 had to be suspended in response to COVID-19 conditions.

Late in 2020, Yukon Energy was able to develop and proceed with the proposed approach for the 2021 GRA as set out in the Application. As stated at the referenced lines on page 3-31, in order to get the Application filed in November, Yukon Energy was required to focus first on completion and filing of its 2021 forecast revenue requirement and rates Application.

The Application recognizes the need to file an updated LWRF Term Sheet to assess the reasonableness of the LWRF for addressing transactions or amounts with respect to the LWRF deferral account following the end of the 2021 test year. The LWRF Term Sheet,

however, does not have any impact on review and assessment of the 2021 GRA revenue requirement forecasts.

Yukon Energy is working to provide an updated LWRF Term Sheet in March 2021, along with related LWRF Annual Reports for 2019 and 2020.

TOPIC: **Timing of Rate Increases**

REFERENCE: **2021 General Rate Application Introduction, page 2 (PDF page 3)**

PREAMBLE: YEC states that it proposes to implement interim rates on July 1, to coincide with the expected reduction in Rider F. Further, YEC proposes to implement final rates on December 1 to coincide with the removal of Rider J1.

QUESTION:

a) Please provide a detailed analysis of Rider F, and the expected rate for July 1, 2021.

b) Please provide the current Rider F.

c) Please fully explain why Rider J1 is still being used in 2021, some 3 years after the last test period.

d) Please confirm that Rider F could increase in the future, depending on fuel prices. If not confirmed, please fully explain.

ANSWER:

(a) and **(b)**

The current Rider F rate is at 1.371 cents/kW.h.

Please see CW-YEC-1-23 Attachment 1 and Attachment 2 for the copies of the Advisory of Rate Change filed with the Board on September 23, 2020. Although, the actual balance of the Fuel Price Variance Account will depend on volume of actual thermal generation and fuel prices for YEC and AEY, the advisory filed by the companies on September 23, 2020 was the best information available for the companies at the time of filing which aimed to get Fuel Price Variance Account balance to zero by July 1, 2021.

(c)

A true-up rider Rider J1 relates to the 2017-18 GRA shortfalls which is in effect until November 30, 2021, or such earlier month end when the $12.557 million 2017-18 GRA shortfall has been recovered. In the 2017/18 GRA Compliance Filing YEC proposed to collect the shortfall over 24 months period to reduce bill impact to customers which was accepted by the Board.

(d)

Confirmed - Rider F will increase or decrease in future in response to change in actual fuel prices relative to approved forecast fuel prices.

ATCO Electric
YUKON

yukon energy

September 22, 2020

Bonnie King, Vice Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Ms. King:

RE: Rate Change- Rider F, Fuel Adjustment Rider

On January 1, 2020, ATCO Electric Yukon and Yukon Energy Corporation (the "Companies") adjusted the Diesel Fuel Price Variance Rider ("Rider F') from a refund of 0.011 cents per kWh to a charge of 0.970 cents per kWh.

Pursuant to the Rider F Policy, if the Companies' Fuel Price Variance Account ("FPVA") is fluctuating over a broad range, the Companies must refine the forecast to reflect changing economic conditions to arrive at a new Rider F rate.

Accordingly, the Companies have determined that Rider F rate is required to change from a charge of 0.970 cents per kWh to a charge of 1.371 cents per kWh, effective November 1, 2020.

The Companies have enclosed an Excel spreadsheet to provide further detail regarding this rate change. We trust that if the Board or any interested party has questions regarding this Rider F rate change, they will contact one of the undersigned.

Sincerely,

ATCO ELECTRIC YUKON

Jaspreet Kaur

Digitally signed by Jaspreet Kaur
DN: cn=Jaspreet Kaur, o, ou, email=jaspreet.kaur@atco.com, c=CA
Date: 2020.09.22 11:49:59 -06'00'

Jaspreet Kaur Senghera
Manager, Accounting
jaspreet.kaur@atco.com

YUKON ENERGY CORPORATION

Ed Mollard
Chief Financial Officer
Ed.Mollard@yec.yk.ca

ATCO Electric Yukon and
Yukon Energy Corporation
Rider F Calculation

		Combined Company Balance				
		Total Monthly Fuel Price Variance, $	RS 32 Secondary Sales Adjustment, $	Rider F Surcharge at current rate 0.97 cents/kW.h, $	Cumulative Balance, $	Monthly Change, $
	Due (From)/To Customers - as at June 30, 2020				(5,060,713)	
2020	July	23,237	-	303,002	(4,734,474)	326,239
	August	63,894	-	287,992	(4,382,589)	351,886
	September	27,494	-	322,782	(4,032,313)	350,276
	October	13,895	-	372,336	(3,646,082)	386,231
	November	(337,255)	-	405,550	(3,577,787)	68,295
	December	(563,338)	-	450,647	(3,690,478)	(112,691)
2021	January	(43,625)	-	506,496	(3,227,606)	462,872
	February	(35,485)	-	437,549	(2,825,543)	402,063
	March	(35,256)	-	451,954	(2,408,845)	416,698
	April	(29,844)	-	396,008	(2,042,681)	366,164
	May	(26,485)	-	362,603	(1,706,562)	336,119
	June	(25,173)	-	343,537	(1,388,198)	318,364
	Estimated Combined YEC/AEY Ending Balance				**(1,388,198)**	
	Nov 2020-June 2021 Forecast Retail Sales (MWh)				345,809	
	Incremental Rider F Rate (¢/kWh)				**0.401**	
	Existing Rider F Rate (¢/kWh)				0.970	
	New Rider F Rate (¢/kWh) effective November 1, 2020				**1.371**	

Notes:
1. Positive balances represent amounts to the benefit of ratepayers.
2. Negative balances are amounts owing to the utilities.

TOPIC: **Depreciation**

REFERENCE: **2021 General Rate Application, page 3-22 (PDF page 68), Alliance Consulting Group Depreciation Study, PDF pages 241, 249, and 250.**

PREAMBLE: On lines 18-21 of page 3-22, YEC states:

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

On PDF page 241, Alliance Consulting Group states:

> The term "depreciation" as used in this study is considered in the accounting sense, that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

On PDF page 249, Alliance Consulting Group states no net salvage analysis was performed.

On PDF page 250, Alliance Consulting Group provides a flowchart of the process.

QUESTION:

a) Please fully explain why no net salvage analysis was performed. In the response please fully explain how any actual net salvage is treated in YEC asset accounts, and how it was dealt with in the Alliance Consulting Group study.

b) Please confirm that the difference between $12.945 million in 2021 based on existing rates and $13.581 million on proposed rates is solely due to the impact of the Alliance Consulting Group depreciation study. If not confirmed, please fully explain.

c) Please provide an analysis that separates the impact of (i) changes in lives, (ii) amortization of reserve differences, (iii) any consideration of net salvage, and (iv) other. For any other, please fully explain what it is.

d) Please fully discuss all life extension efforts or initiatives that YEC:
   i. Is considering;
   ii. Is planning on implementing after the test period;
   iii. Is planning on implementing in the test period; or
   iv. Has implemented prior to 2021.

   In the response please fully explain the costs of each initiative, and the expected impact, including lengthening service lives, and impact on reduced depreciation.

e) If there are no life extension efforts or initiatives, please fully explain why not.

ANSWER:

(a)

YEC does not accrue or book net salvage in their accumulated provision for depreciation and no provision for net salvage is incorporated in the Company's current depreciation rates. As such, Alliance did not include net salvage in its depreciation rate calculations so no net salvage analysis was necessary or performed. In YEC actual accounts, when an item is disposed of that has salvage value, that salvage value becomes part of the calculation of net gain or loss on disposal.

(b)

Confirmed

(c)

The details of (i) changes in lives and (ii) amortization of reserve differences are shown in the Application in Tab 7, Schedule 3A, on a Class line item basis and can be calculated by comparing the '2021 Existing Forecast Depreciation' column with the '2021 Proposed Forecast Depreciation' column. The summation of the impact of changes in lives is $0.458 million and the impact of depreciation study differences is $0.178 million.

(d) and **(e)**

As part of YEC's annual capital budgeting process, a portion of the budget is set aside for Maintenance Capital, which overall has the purpose of maintaining assets in healthy operating conditions. In addition, as discussed in the Application at section 5.4.1.1 on page 5-28, YEC details its Enterprise Asset Management System Purchase and Implementation which will also assist in this initiative.

TOPIC: **Rate Relief**

REFERENCE: https://globalnews.ca/news/7584771/altalink-alberta-refund

PREAMBLE: In Alberta, AltaLink has proposed to refund over collected depreciation and future income taxes in an effort to provide rate relief to customers. CW understands that YEC, as a crown corporation will not have any income taxes. Having said that, CW is interested in understanding what efforts YEC has undertaken to identify and implement measures that would provide rate relief to customers.

QUESTION:

a) Please fully discuss and provide copies of any and all research YEC has conducted into ways to provide rate relief to customers, including, but not limited to extending service lives for utility assets.

ANSWER:

(a)

YEC has not conducted research specifically into ways to provide rate relief to customers. However, YEC has completed depreciation update studies for this and prior GRAs to assess (among other matters) opportunities to extend service lives for utility assets (see Tab 9 of GRA Application). YEC also continues to assess least cost resource options for future development of required generation and transmission - including options to secure federal and other government funding that will reduce ratepayer costs, e.g., as demonstrated for the proposed Battery Energy Storage Project and the Atlin Hydro Expansion Project.

TOPIC: **LNG Third Engine/ Critical Spares**

REFERENCE: **2021 General Rate Application, page 5-8 (PDF page 121)**

PREAMBLE: On lines 5-6 of page 5-8, YEC states, with respect to the Faro Thermal Rental Site Infrastructure project, "[t]he project is expected to be completed in 2020 at an estimated budget of $2.037 million. The project is on track for a mid-November 2020 in service date."

QUESTION:

a) Please confirm that the project is complete. If not please provide the estimated completion date.

b) Please provide the actual cost of the project, and an explanation of any variances.

ANSWER:

(a)

Confirmed.

(b)

Please see response to YUB-YEC-1-49 for project cost breakdown.

Actual project costs totaled $2.446 million, compared to the estimated budget of $2.037 million included in the application (approximately $0.408 million increase in costs). Major variances are noted as follows:

- Additional materials were needed after completion of the detailed design, including: power and control cables, cold shrink cable terminations, rigid bus bar connectors, PTs for ground fault protection, lightening arrester and materials for line and gantry construction.

- Higher market prices were also a factor, the cost to procure of a 138kV disconnect switch, 25kV breaker and the refurbishment of the spare transformer were higher than budgeted, the lowest prices were selected through RFQ process.

- The added scope was due to a safety requirement to install a ground grid in the generator area, and an environmental requirement to install generator berms for the purpose of containing fuel and/or oil spill from the generators.

- The added scope of work included: relocation of warehouse materials at the substation and generator bay area, cost to install ground grid in generator area, rental generator prep, pulling and termination of cables to rental generators, and unit transformers and installation of generator berms.

- Construction and installation were also impacted by higher market prices, the budget for crane rental and SCADA commissioning were higher than budget.

- A rented crane was needed on site for an additional day due to the delayed arrival of the rental tanks. Furthermore, 3.5 additional days were needed to establish communication with the Finning units.

- Overage for internal cost is because more internal manpower for construction, testing and commissioning was required than initially envisioned at the beginning of the project.

- Project management overage is because more responsibility was assigned to an external consultant during a 4 week absence of the YEC Project Manager, due to unforeseen circumstances.

While the actual costs exceeded the estimate included in the application, it is important to note that the final project costs of $2.446 million were lower than the lowest bid received from the EPC RFP process ($3.335 million).

TOPIC: **Mayo – McQuesten Transmission Line Upgrade**

REFERENCE: **2021 General Rate Application, Section 5.2.1.3**

PREAMBLE: On line 11 of page 5-9 (Pdf page 122), YEC indicates this project was reviewed in the 2017/18 GRA. In Table 5.2.1-2, YEC provides project costs and contributions.

QUESTION:

a) Please provide specific reference to where this project was approved in the 2017/18 GRA.

b) Please provide the cost estimates that were reviewed and approved in the 2017/18 GRA.

c) Please provide a variance analysis comparing the cost estimates approved in the 2017/18 GRA to the forecast costs included in Table 5.2.1-2. In the response please provide explanations for all material variances.

ANSWER:

(a) and **(b)**

The reference provided notes that the project details have previously been subject to review by the Board as part of two separate proceedings: the 2017 VGC Group Power Purchase Agreement proceeding; and as part of the 2017/18 General Rate Application. As the project was not complete and in service during the 2017/18 GRA, project costs were not approved as part of that proceeding.

(c)

Detailed cost estimates were not reviewed as part of the 2017/18 GRA. The 2017 VGC Group PPA proceeding estimated costs for the L180 Mayo to McQuesten 138 kV line

(assumed to be operated at 69 kV) at $32.2 million, including costs that VGC Group and/or YEC will have funded for the McQuesten Substation pursuant to the PPA.[1]

Tab 5, page 5-8 notes a total project cost for the Mayo – McQuesten Transmission Line Upgrade of $31.701 million, offset by contributions of $23.674 million.

[1] See response provided in the VGS Group PPA proceeding to YUB-YEC-1-14.

TOPIC: **Transmission Line Refurbishment**

REFERENCE: **2021 General Rate Application, Section 5.2.1.5**

PREAMBLE: On lines 2-4 of page 5-15 (PDF page 128), YEC states "[t]he Transmission and Distribution Line replacement project was initially reviewed as part of the 2017/18 GRA; and project components were capitalized as completed and placed into service, with approved costs forecast to the end of 2018 included in ratebase." CW requires information to understand the prudence of the investment.

QUESTION:

a) Please provide an analysis that compares approved costs and actual costs with explanations of significant variances.

b) Please provide an analysis that compares the approved assets and components to be replaced with the actual assets and components that were replaced.

ANSWER:

(a)

Actual 2018 costs were materially higher than approved costs. The quantity of work accomplished in 2018 was significantly more than was forecasted, as a large portion of the overall 5 year planned work was completed in one year. The increase in work scope and 2018 spending was justified due to lower unit costs; the reduced customer impact of the transmission outage number and duration; and reduced mobilization and demobilization costs for the contractor.

Table 1: Approved and Actual Transmission Line Refurbishment Costs

	Cost
2018 Approved	$ 2,000,000
2018 Actual	$ 6,280,165

(b)

Table 2 below compares the approved assets and components to be replaced with the actual assets and components that were replaced.

Table 2: Approved and Actual Scope of Work (2018)

	Full structure replacement	Crossarm replacement	Insulator replacement
2018 Approved	21	112	251
2018 Actual	61	254	489
Change (Actual vs Approved)	40	142	238

TOPIC: **Transmission Line Refurbishment – L178**

REFERENCE: **2021 General Rate Application, Section 5.2.1.6**

PREAMBLE: On line 12 of page 5-15 (PDF page 128), YEC states "[t]he final phase of the Transmission Line Refurbishment Project will commence in 2021."

QUESTION:

a) Please provide evidence from the 2017/18 GRA that clearly demonstrates that this component of the line was NOT included in the costs approved in the 2017/18 GRA.

ANSWER:

(a)

Section 5.2.1.8 of the YEC's 2017/18 GRA noted that the T&D Line Replacement project would address replacement of key components of the following YEC transmission lines which are approaching the end of their economic life:

Line #	Route	Install Date
L170	Takhini Sub to Carmacks	1968
L171	Aishihik plant to Takhini Sub	1975
L178	Carmacks to Faro	1968

In that section, YEC also noted that the required replacements would be carried out over five years beginning in 2018 at an estimated total cost of $11.5 million. YEC forecast spending in the 2018 test year at $2.0 million [the remaining estimated $9.5 million spending was forecast after 2018].

On page 5-15 of the 2021 GRA Application, YEC provides an update to the project noting that remaining components requiring replacement on lines L170, L171 and L172 were completed by the end of 2019 with total cost of $4.272 million and included refurbishment of 255 structures (58 full structures, 80 crossarms, and 117 insulators) and the final phase

of the Transmission Line Refurbishment Project will commence in 2021 for the Carmacks to Faro Transmission Line (L178).

As reviewed above, Transmission Line Refurbishment – L178 project is part of $11.5 million Transmission and Distribution Line Replacement Project noted in the 2017/18 GRA section 5.2.1.8, however, the cost for this project was not included in the 2017 or 2018 test year revenue requirements as the 2018 test year included only $2 million out of $11.5 million total project cost estimate at that time.

TOPIC: **Breaker Replacement Program**

REFERENCE: **2021 General Rate Application, Section 5.2.1.7**

PREAMBLE: On line 12 of page 5-16 (PDF page 129), YEC states the project "was reviewed as part of the 2017/18 GRA".

QUESTION:

a) Please provide an analysis that compares approved costs and actual costs with explanations of significant variances.

ANSWER:

(a)

The approved 2017 and 2018 budgets were $110,519.61 and $1,250,000, respectively. The actual expenditures for 2017 and 2018 were $110,519.61 and $1,167,329.46 respectively. No significant variances for this project are noted.

TOPIC: **Replacement of P125 Head Gate**

REFERENCE: **2021 General Rate Application, Section 5.2.1.8**

PREAMBLE: On page 5-18 (PDF page 131), YEC states "[i]t is expected that the WH2 headgate will be completed in 2020 at a forecast cost of $2.3 million; and that the WH1 and WH3 headgates will be completed in 2021 at a forecast cost of $3.5 million."

QUESTION:

a) Please provide the status of the WH2 headgate. Is the project complete, and what is the actual cost?

b) Please provide the status of the 2021 project.

ANSWER:

(a)

The project to replace the WH2 headgate (1 of 3) is complete and the total cost was $1,958,118.

(b)

The 2021 project has been delayed. YEC is in the early planning and design stages for the WH1 and WH3 Headgate Replacements which will commence in 2022.

TOPIC: **WH2 Uprate**

REFERENCE: **2021 General Rate Application, Section 5.2.1.9**

PREAMBLE: On line 19 of page 5-18, YEC refers to the 2016 Resource Plan. On lines 23-27 of page 5-18 (PDF page 131), YEC states:

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

CW requires information to understand what was approved compared to what was actually implemented.

QUESTION:

a) Please provide the evidence from the 2017/18 GRA, and related decision sections, that clearly indicate what was requested and approved in the 2017/18 GRA.

b) Please provide an analysis of the forecast and approved costs from the 2017/18 GRA compared to the actual costs incurred for 2017, 2018, and 2019 with variances explained.

ANSWER:

(a) and **(b)**

The 2017/18 GRA included $0.450 million forecast spending in 2018 for the Whitehorse Hydro Uprate [see page 5.4-4 of Appendix 5.4 of the 2017/18 GRA]. The following was noted:

> As part of the Resource Plan, a preliminary assessment of the Whitehorse hydro units was completed which identified a number of potential uprating (or re-runnering) scenarios. An uprate project was identified to provide both additional

firm energy and dependable capacity. Additional benefits of the project could potentially include an improved efficiency curve allowing increased operational flexibility.

Spending of $0.450 million in 2018 will be used for a detailed investigation of which alternative to proceed with as well as selecting an owner's engineer to represent YEC throughout the project. A scope of work will be created and the construction contract could possibly be awarded by the end of the year. This project is expected to be complete and in service by 2020.

In Tab 5, Table 5.8 of the 2017/18 GRA notes the forecast cost of $0.450 million remained in WIP, i.e., it was not part of the requested 2017/18 revenue requirement. The project was forecast to be complete and come into service in 2020 (Appendix 5.4 of 2017/18 GRA). In paragraph 527 of Appendix A to Board Order 2018-10, the Board stated that it denied YEC's proposed Whitehorse hydro uprate project and directed YEC to remove any forecast expenditures and cost recovery related to this project in its compliance filing. As YEC had not applied to include these costs in rates, this Order had no effect on final approved recoveries.

The actual spending for this preliminary assessment in 2018 was at $0.208 million as shown in Tab 5, Table 5.3 of the current GRA [see "WH2 Uprate Assessment"] compared to $0.450 million forecast in the 2017/18 GRA. The 2018 actual costs covered procurement of an Owner's Engineer and the issuance of an RFP for the turbine & generator contractor.

By end of 2019, the cost incurred for this project is $3.297 million [$3.044 million as shown in Table 5.2-1 plus $0.252 million in Table 5.4].

TOPIC: **WH2 Uprate**

REFERENCE: **2021 General Rate Application, Section 5.2.1.9**

PREAMBLE: In lines 28-30 of page 5-18 (PDF page 131), YEC states:

> The project is planned to be implemented over a three year period (2019-21), and is expected to add 6.4 GWh/yr additional hydraulic generation to the grid [starting in the third quarter of 2021]. The project is also expected to increase dependable capacity of WH2 by 0.94 MW.
>
> CW requires information to understand how distributed energy was factored into the need for a capacity increase.

QUESTION:

a) Please provide a copy of the business case for the project. In the response please provide specific references to how YEC considered the implementation and use of distributed and micro generation over the life of the asset.

ANSWER:

(a)

The 2016 Yukon Energy Resource Plan (YEC, 2017) identified hydro uprate projects as an economically attractive option to help address YEC's existing and forecast capacity shortfall, as well as providing a cost effective incremental source of firm renewable energy. As such, uprating of the Whitehorse hydro units were included in the recommended near-term action plan under the 'base case' load scenario. Table 1 below summarizes WH2 Uprating economics and alternatives reviewed. Distributed generation and microgeneration were not considered in the assessment.

The economics of the WH2 uprating project were calculated for a number of scenarios in order to assess the sensitivity of the project economics to the following factors:

1. **Unit Output:** incremental energy production of 6.4, 6.2 and 3.2 GWh/year were assessed as 'High', 'Expected' and 'Low' output scenarios. The 'Expected' unit

output 6.2 GWh/year was based on the performance of the new turbine guaranteed by Litostroj Power.

2. **Deferred Maintenance Costs:** Since the WH2 Uprating project has a benefit of deferring planned maintenance on the WH2 unit to a later time, the economics of this benefit was also assessed.

A summary of the WH2 Uprating economics when compared to near thermal and renewable generation is provided below. The 'Base Case' scenario is shaded in blue. The calculated increases in annual energy and capacity for the project under the base case assumptions are 5.6 GWh and 0.94 MW respectively. The data shows that the WH2 Uprating project is an economic option to add firm energy and dependable capacity to YEC's portfolio in the near term. This is favourable when compared with other options presented in the 2016 Resource Plan.

See also Hatch study provided as YUB-YEC-1-57 (d) Attachment 1.

Table 1: WH2 Uprating Economics and Summary of Alternatives

WH2 uprating economics and summary of alternatives available

Source	Increase in Dependable Capacity	Increase in Firm Energy	LCOE ($/kWh)	LCOC ($/kW.yr)
WH-2 Uprate 2016 Resource Plan	0.3 MW	1.4 GWh/yr	0.04	361
WH2 Uprate 2017 Hatch Study	0.4 MW	1.9 GWh/yr	N/A	N/A
WH2 Uprate Case 1: High Output With Contingency With Deferred Maintenance Benefit OEM Quoted Performance[1]	0.94 MW	6.4 GWh/yr	0.052	387.49
WH2 Uprate Case 2: Expected Output With Contingency Without Deferred Maintenance Benefit OEM Quoted Performance[1]	0.94 MW	6.2 GWh/yr	0.072	482.60
WH2 Uprate Case 3: Expected Output With Contingency With Deferred Maintenance Benefit OEM Quoted Performance[1,2]	0.94 MW	6.2 GWh/yr	0.059	387.49
WH2 Uprate Case 4: Low Output With Contingency With Deferred Maintenance Benefit OEM Quoted Performance[1]	0.94 MW	3.2 GWh/yr	0.109	387.49
Takhini LNG Plant – Incremental Capacity 2016 Resource Plan	5 MW	41.6 GWh/yr	0.26	812
Takhini Diesel Permanent Installation – Midgard 2019 Thermal Generation Planning Report	20 MW	5 GWh/yr	0.83	138
Drury Small Hydro	8.1 MW	31.7 GWh/yr	0.19	700
Atlin/Pine Creek Small Hydro	5 MW	22.3 GWh/yr	0.13	806

Notes:

[1] Based on total project budget including contingency

[2]Based on post uprate performance guarantees from Litostroj Power.

TOPIC: **Demand Side Management (DSM)**

REFERENCE: **2021 General Rate Application, Section 5.3.1.2**

PREAMBLE: On lines 1-2 of page 5-23 (PDF page 136), YEC states "[t]he 2016 Resource Plan determined that DSM programs are a cost-effective way to meet energy and capacity demand that should be included in the proposed future portfolio of energy supply projects." Pursuant to government direction, YEC has included DSM costs. CW requires information to assess how DSM benefits have been factored into YEC cost forecasts.

QUESTION:

a) Please provide a copy of all research, studies, business cases, and other analysis that YEC has conducted that demonstrates DSM is "a cost-effective way to meet energy and capacity demand."

b) Please provide an analysis that demonstrates how DSM will reduce the need for incremental assets and capacity over the next 40 years.

c) Please fully explain how YEC has factored the potential benefits of DSM into each capital project that results in increased capacity of the asset or system.

ANSWER:

(a)

Please see response to YUB-YEC-1-47(a) and (b).

(b) and **(c)**

Yukon Energy's 10-Year Renewable Electricity Plan provides updated analysis as to forecast DSM impacts on reducing the need for incremental assets and capacity over the next decade, demonstrating that YEC has factored the potential benefits of DSM into each major capital project that is being considered to provide increased capacity.

Please see response to CW-YEC-1-36 (a) [Attachment 1] and (b).

TOPIC: **Investments to Ensure Dependable Capacity**

REFERENCE: **2021 General Rate Application, Appendix 5-1, Section 5.1-2**

PREAMBLE: YEC proposes to spend $25,000,000 in 2021 (with a $16,500,000 contribution) on a Battery Energy Storage System.

QUESTION:

a) Please provide a full business case for the Battery Energy Storage System.

b) Please provide a detailed analysis that clearly demonstrates how the inclusion of a Battery Energy Storage System was considered in determining the need for each capital project that results in increased capacity of the asset or system.

ANSWER:

(a)

Please see the response to YUB-YEC-1-71.

(b)

The Battery Energy Storage System project has been designated by OIC 2020/180 as a "regulated project" under Part 3 of the *Public Utilities Act.* Based on this requirement, Yukon Energy has filed an application for an energy project certificate and an energy operation certificate with the Minister of Justice.

Section 4.2.1 of the Part 3 Application reviews "Alternatives to the Project". Table 4-1 from the Application summarizes Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (MW) and is excerpted below.

Table 1: Forecast Non-Industrial Peak and Dependable Capacity under N-1 Capacity Planning Criterion: 2021/22-2030/31 Winter (MW)

	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Non-industrial Peak	**104,102**	**107,372**	**110,546**	**113,952**	**117,030**	**120,515**	**124,517**	**129,214**	**133,769**	**138,676**
Non-industrial Peak	*103,284*	*106,277*	*109,078*	*111,985*	*114,393*	*116,982*	*119,783*	*122,870*	*125,268*	*127,285*
EV Peak	*818*	*1,096*	*1,468*	*1,968*	*2,637*	*3,533*	*4,734*	*6,344*	*8,501*	*11,391*
Existing Resource Dependable Capacity	**112,100**	**112,100**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**	**106,900**
YEC Hydro	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*	*70,500*
YEC Thermal	*36,050*	*36,050*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*	*30,850*
AEY Thermal	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*	*5,550*
N-1 Event [Lost of AH GS or L171]	**-37,195**	**-37,194**	**-37,193**	**-37,192**	**-37,191**	**-37,190**	**-37,189**	**-37,188**	**-37,187**	**-37,186**
Loss of AH GS	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*	*-37,000*
Loss of AEY Haines Junction diesel	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*	*-1,500*
Haines Junction peak	*1,305*	*1,306*	*1,307*	*1,308*	*1,309*	*1,310*	*1,311*	*1,312*	*1,313*	*1,314*
Capacity Shortfall/Surplus under N-1	**-29,197**	**-32,466**	**-40,839**	**-44,244**	**-47,321**	**-50,805**	**-54,806**	**-59,502**	**-64,056**	**-68,962**
Committed and Planned Supply Options	**2,843**	**12,047**	**26,752**	**35,318**	**35,385**	**35,452**	**35,521**	**70,589**	**70,659**	**70,729**
Diesel Replacements	*0*	*0*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*	*12,500*
Whitehorse #2 Uprate	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*	*638*
BESS	*0*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*	*7,000*
Atlin Hydro EPA	*0*	*0*	*0*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*	*8,500*
DSM	*2,205*	*4,409*	*6,614*	*6,680*	*6,747*	*6,814*	*6,883*	*6,951*	*7,021*	*7,091*
Moon Lake Pump Storage Phase 1	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*35,000*	*35,000*	*35,000*
Capacity Shortfall/Surplus under N-1	**-26,355**	**-20,419**	**-14,087**	**-8,926**	**-11,936**	**-15,352**	**-19,285**	**11,087**	**6,603**	**1,767**

The discussion in Section 4.2.1 of the Part 3 Application notes, “Many of these options do not provide dependable capacity; and the new resources that will provide dependable capacity would generally not displace what the BESS option can provide, i.e., the identified permanent resource capacity options are generally all needed to remove reliance on rented diesels for addressing the forecast capacity shortfall reviewed in Table 4-1. Moon Lake pumped storage, when developed, is the only identified resource option aside from default new thermal fossil fuel generation that has the capability to remove the forecast N-1 dependable capacity shortfall.”

Further, Section 4.2.1 of the Part 3 Application notes: “aside from the potential Moon Lake pumped storage project in the future, the temporary rental diesel option or permanent new diesel development remain the only feasible alternatives that would provide dependable capacity required to address the N-1 shortfall.”

TOPIC: **Investments to Ensure Dependable Capacity**

REFERENCE: **2021 General Rate Application, Appendix 5.1, Section 5.1-2, page 5.1-7 (PDF page 164)**

PREAMBLE: YEC proposes to spend $3,000,000 on a "Whitehorse Interconnection." In the explanation YEC discusses a 10-year Renewable Energy Plan and a number of new projects being planned over the next decade.

QUESTION:

a) Please provide a copy of the 10-year Renewable Energy Plan.

b) Please provide a list of the "number of new projects being planned over the next decade." In the response, please provide YEC's assessment of the probability of each project proceeding.

ANSWER:

(a)

See Attachment 1 to this response.

(b)

The quote references the 10-Year Renewable Electricity Plan's outline of "a number of potential new projects being planned over the next decade to meet Yukon's growing electricity needs." The potential future resources for the Plan portfolio include the following:

- Atlin Hydro Expansion (6 MW) – for 2024/25.
- A potential 20 MW wind resource for 2025/26 under only the High Case.
- Tutshi-Moon Pumped Storage Project – Phase 1 – 2028/29 (this includes upgrade and expansion of transmission in the Southern Lakes region).

The Action Plan includes the following:

- **Stage 1: Committed resources –** Includes Whitehorse Hydro #2 and #4 (WH2 and WH4) Uprate projects, Battery Storage System, SOP IPP and Micro-Generation projects.

- **Stage 2: Completion of planned work and final decisions to proceed with planned resources –** Includes SLESP (Southern Lakes Enhanced Storage Project), MLESP (Mayo Lake Enhanced Storage Project), the Incremental Diesel Replacement, and DSM (Demand Side Management).

- **Stage 3: Development and implementation of the Future Potential Projects –** Includes the three future potential projects outlined above (Atlin Hydro Expansion, Moon-Tutshi Pumped Storage, and (for the High Case only) a potential 20 MW Wind Project. The Plan highlights that these projects are dependent on securing significant federal funding in order to proceed. Other risks are also identified for these projects. YEC at this time has no specific assessment of the probability of each project proceeding – the Atlin Hydro Expansion is the first of these potential projects, and YEC during 2021 is in active discussions and planning to address the requirements that would enable this project to be committed prior to the end of 2021.

TOPIC: **Diesel Retirement Replacement**

REFERENCE: **2021 General Rate Application, Appendix 5-3, Section 5.3-1**

PREAMBLE: On page 5.3-3 (PDF page 181), YEC discusses diesel replacement.

QUESTION:

a) Please provide the business case that identifies all the options or alternatives considered and a detailed analysis of the costs of replacement compared to each of the options considered. In the response, please provide the costs of each unit included in the proposal, and the total cost or the project.

b) Please fully discuss how YEC considers total life cycle cost of the alternatives in its business case.

c) Please provide the expected life of each unit.

ANSWER:

(a)

The project is currently in the planning phase, and will remain in WIP in 2021 and therefore not affect the 2021 GRA forecast revenue requirement. Please see response to YUB - YEC-1-92(c) for an update on planning assessments to date.

(b)

When assessing thermal generation capacity development options focused on addressing the N-1 dependable capacity shortfall, business case assessments examine the levelized cost of capacity (LCOC) for each option over the expected life of the facility.

(c)

The expected life of the planed diesel retirements are:

- Faro Diesel 1 (FD1) is March 2022;

- Dawson Diesel 2 (DD2) is March 2023; and

- Dawson Diesel 5 (DD5) is March 2023.

The remaining diesel plant retirements are beyond the 10 year period.

TOPIC: **Southern Lakes Enhanced Storage**

REFERENCE: **2021 General Rate Application, Appendix 5-3, Section 5.3-1**

PREAMBLE: On page 5.3-4 (PDF page 182), YEC discusses Southern Lakes Enhanced Storage.

QUESTION:

a) Please provide a detailed analysis that clearly demonstrates how the Southern Lakes Enhanced Storage project was considered in determining the need for each capital project that results in increased capacity of the asset or system.

ANSWER:

(a)

The Southern Lakes Enhanced Storage Project was selected in all scenarios of YEC's 2016 Resource Plan, and was also included in YEC's 10-Year Renewable Electricity Plan. Accordingly, the project has been inherently included in the analysis of all YEC projects needed for the future.

TOPIC: **EV Infrastructure Project**

REFERENCE: **2021 General Rate Application, Appendix 5-5**

PREAMBLE: On PDF page 194, YEC discusses an EV Infrastructure Project.

QUESTION:

a) Please fully discuss and explain who (shareholder or customer) would bear the risk if there is not sufficient EV usage to warrant EV stations.

b) Please fully explain YEC's position as to whether EV stations should be owned and operated by independent competitive entities or by regulated utilities.

ANSWER:

(a) and **(b)**

Please see response to YUB-YEC-1-101. Subsequent to the submission of the Application, YEC has chosen to defer this project to a future year, as it is expected to take several years for the rollout of electric vehicles to take place at a larger scale in Yukon. This change has no impact on the forecast revenue requirement for the 2021 test year, i.e., Appendix 5.5 includes only projects forecast to remain in WIP.

The potential impact of electric vehicles on the Yukon electrical system will need to be assessed along with any requirements for YEC to meet these challenges. As noted in the Application, not addressing this could result in unforeseen costs and reactionary programs.

TOPIC: **Board Directions**

REFERENCE: **2021 General Rate Application, Tab 6.0**

PREAMBLE: On PDF page 198, YEC discusses Cost of Service (COS) studies and rate design. On lines 15-19, YEC states:

> The latest Order in Council (OIC) direction provided in December 2018 (OIC 2018/220) provides that material rate design changes that would result in rebalancing of rates between different customer classes cannot be undertaken at this time. The remaining outstanding directives in Order 2010-13 will be addressed in the next joint cost of service and rate design application. This includes directives #1 to #12 and #19 (as summarized in Tab 6 of the 2012/13 GRA filing).

QUESTION:

a) Please fully discuss and explain all conversations, communications, and correspondence YEC has had with its Shareholder, about why a COS proceeding and rate rebalancing may in fact be appropriate.

ANSWER:

(a)

This question is outside the scope of the current proceeding.

TOPIC: **Directive #463 – Battery Project**

REFERENCE: **2021 General Rate Application, Tab 6.1.5**

PREAMBLE: On PDF page 207, YEC notes that the Board did not approve a battery project, yet YEC proceeded with a project, based on receiving grants for the project.

QUESTION:

a) Please fully explain YEC's position on who bears the risk if the project does not produce benefits or proves to be unviable. Would that be written off to the shareholder or included in future rates?

ANSWER:

(a)

It is noted that the Battery Energy Storage System project has been designated by OIC 2020/180 as a "regulated project" under Part 3 of *the Public Utilities Act*. Based on this requirement, on January 20, 2021 Yukon Energy filed an application for an energy project certificate and an energy operation certificate with the Minister of Justice of Yukon; and the need and justification for the project will be subject to a review by the YUB prior to the issuance of a project energy certification and operation certification by the Yukon Government. This process will include a review of the project business case and risks.

The project will also be subject to a prudence review by the YUB prior to it being included in rates. Costs determined to be prudently incurred by the YUB would be included in rates.

TOPIC: **Depreciation Study**

REFERENCE: **2021 General Rate Application, Tab 9 Depreciation Study**

PREAMBLE: On PDF page 246, The Alliance Consulting Group states:

> At the request of Yukon Energy, this study continues to use the ALG depreciation procedure to group the assets within each account. In its last depreciation study, Yukon Energy was authorized to use the average life group, whole life ("ALG-WL") depreciation procedure. This study continues to use the ALG depreciation procedure to group the assets within each account.

QUESTION:

a) Please fully explain all methods that are accepted by depreciation experts, including the ELG method. In the response, please provide the advantages and disadvantages of each.

b) Please fully explain the impact on depreciation rates if the ELG were used. Would lives tend to lengthen or shorten?

c) Please provide a full discussion of The Alliance Consulting Group's experience as to which depreciation method is most commonly used.

d) Does The Alliance Consulting Group support the ALG method or would it prefer some other method like the ELG method?

e) Please fully explain whether The Alliance Consulting Group recommended a different method to YEC. Please fully explain the process for the selection of the ALG.

f) Please provide the retainer letter or other engagement documents that govern the relationship between YEC and The Alliance Consulting Group.

g) Please fully explain any ways that The Alliance Consulting Group could support that would lengthen lives and reduce customer rates.

ANSWER:

(a)

ALG or ELG are depreciation procedures. See Attachment 1 to this response which is an extract from Depreciation Systems, an authoritative treatise on the subject. ALG and ELG are defined by how assets are grouped.

As stated in the attachment:

> "Both procedures are "systematic and rational" as required by the definition of depreciation accounting. Use of the average life procedure matches the depreciation charges to the service provided by the average lived unit. That is, the shorter-lived units contribute fewer units of service than the longer-lived units, and therefore, the total accrual associated with a short-lived unit is less than that associated with a long-lived unit. The ALG procedure treats each unit as though its life is equal to the average life of the group. The ELG procedure treats each unit in the group as though its life was known. This is the basis for the argument that the equal life group procedure better matches depreciation charges with the life of the units in the group."

(b)

Alliance Consulting Group has not made the computation to quantify impact of using ELG to determine depreciation rates. In general, with growing plant (such as the case with YEC), ELG will produce higher depreciation accrual rates than ALG. The life choices would remain the same, but the deprecation accrual rates would change and increase if ELG was adopted. If lives are lengthened, both ALG and ELG depreciation rates decrease. If lives are shortened, both ALG and ELG depreciation rates increase.

(c)

Alliance Consulting Group supports the uses of the ALG method, which has been used in the majority of our cases. We have also recommended ELG in certain jurisdictions where ELG is the precedent accepted by the regulatory body.

(d)

Yes, although ELG will provide a more precise pattern for recovering the cost of varying-live assets within a group, both ALG and ELG are accepted in various jurisdictions. YEC's existing depreciation rates are derived using the ALG procedure. Therefore, Alliance Consulting Group supports the uses of the ALG method for YEC.

(e)

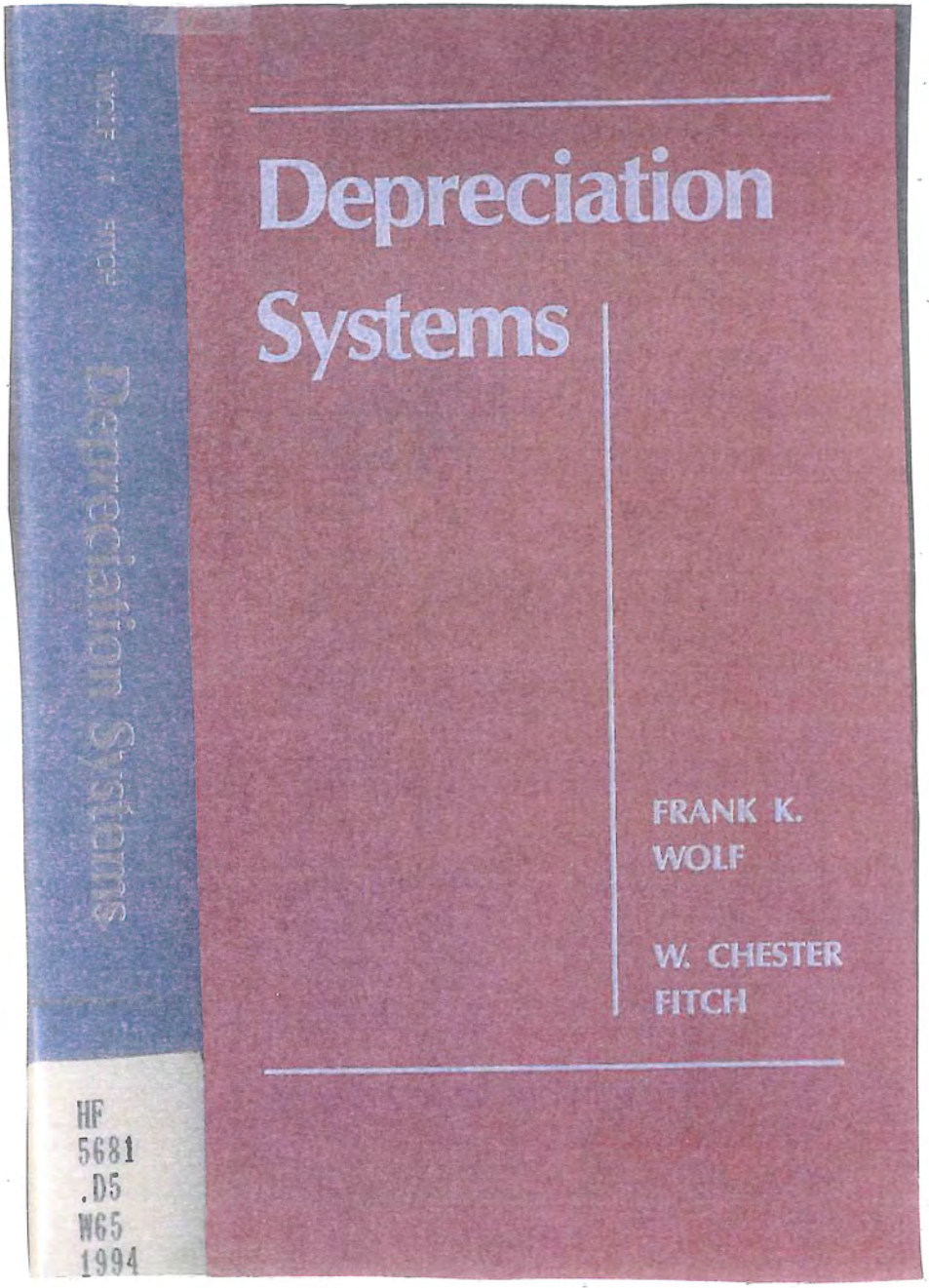
Alliance Consulting Group did not recommend any other method to YEC. ALG is the procedure used in YEC's currently approved depreciation rates and ALG is used by many companies across the utility industry.

(f)

See Attachment 1 to this response.

(g)

Alliance Consulting Group does not agree with the concept propounded in the question. Depreciation provides cost recovery of the investment in capital equipment. Regulatory principles incorporate the matching principle where customers utilizing assets should be charged for the recovery of those costs over the assets' lives, rather than shift the burden to ratepayers who do not have use of the assets. The proposed depreciation rates by Alliance Consulting Group achieve that objective.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FRANK K. WOLF

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Frank K. Wolf, Ph.D., P.E., is professor and past chair of the Department of Industrial Engineering at Western Michigan University where he teaches courses in operations research and statistics. He is vice president of Depreciation Programs, Inc., and has developed and presented specialized training programs and seminars in depreciation since 1971.

W. Chester Fitch, Ph.D., P.E., is dean of engineering, emeritus, Western Michigan University. He is retired after more than 40 years of conducting depreciation studies and educating and training depreciation staff. He founded a series of programs providing specialized training in depreciation in 1969 and is currently president of Depreciation Programs, Inc.

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Contents

PREFACE, vii

1 Financial Aspects of Accounting for Depreciation, 3

2 Data, 14

3 Survivor Curves, 21

4 Salvage Concepts, 51

5 Depreciation Systems, 69

6 Continuous Property Groups, 139

7 Defining Depreciation Systems, 175

8 Actuarial Methods of Developing Life Tables, 179

9 Renewals, 200

10 Pricing Retirements, 210

11 Analysis of Unaged Data, 217

12 Aging Balances, 251

Table 4.10. Conversion of salvage in Table 4.9 to 1982 dollars.

	Experience year						
	82	83	84	85	86	87	88
Gross salvage	94	337	418	645	834	890	720
Cost of retiring	27	106	163	276	437	539	553
Annual retirements	157	627	941	1568	2508	3135	3292
Gross salvage ratio	.60	.54	.44	.41	.33	.28	.22
Cost of retiring ratio	.17	.17	.17	.18	.17	.17	.17
Net salvage ratio	.43	.37	.27	.23	.16	.11	.05

5 Depreciation Systems

THE recovery of capital through depreciation accruals may be thought of as a dynamic system. A system is an arrangement of things that are connected to form a complete organization of integrated parts. The state of the system at any time is defined by current values of the characteristics that define the system. A dynamic system is one where the state of the system depends on the history of the input variables. To define and study a system is to better understand the system so that more efficient methods of control can be designed to accomplish the desired ends.

There are two methods of controlling a system. One is to select an input and wait for the result or final output. If a different output is desired, the input is changed and the new output is obtained. The other method of control is to select an initial input, monitor the process, and when necessary, alter the input to achieve the desired goal. The first method is called an open control loop and the second a closed control loop. A necessary feature of the closed control loop is the feedback resulting from the monitoring of the system. A home heating system is a common and simple example of a dynamic system with a closed feedback loop. The parts of the system are a furnace and a thermostat. The thermostat monitors the room temperature and creates feedback, in the form of electrical signals, when the room temperature rises above or falls below the desired temperature. The electrical signals turn the furnace off or on to achieve the desired goal, a constant, predetermined room temperature.

Think of a depreciation accounting system as a dynamic system controlled with a closed feedback loop. Estimates of life and salvage and the

amount of plant in service are inputs to the system, and the accumulated provision for depreciation is a measure of the state of the system at any time. The process of calculating the accumulated provision for depreciation is determined by the factors needed to define the system. The initial input to the system is estimates of the life and salvage, which are combined in an accrual rate. Dynamic forces affect the life and salvage, and revision of the original life and salvage estimates are the result of the monitoring process. These revisions to the initial input initiate feedback in the form of adjustments to the accumulated provision for depreciation. The goal of the system is recovery of capital in a timely manner.

One consideration that complicates this discussion is that many options can be combined to form many different depreciation systems. Whether the depreciation is for book, tax, valuation, or other purposes, each of these factors must be considered when discussing and defining a depreciation system.

DEFINING A DEPRECIATION SYSTEM

Below is a list of the factors needed to define a depreciation system. Each factor contains two or three options, and the complete definition of a system requires the selection of one option from each factor. The order of the list is arbitrary, but the last four factors are those whose options are varied when discussing depreciation systems commonly used to calculate book depreciation.

1. The depreciation concept, including (a) physical condition, (b) decrease in value, or (c) cost of operation
2. Depreciation over (a) time or (b) units of production
3. Depreciation of (a) a unit of property or (b) a group of property
4. Methods of allocation, including (a) the straight line method, (b) an accelerated method, or (c) a decelerated method
5. Procedures for applying the method of allocation including (a) the average life procedure, (b) the equal life group procedure, or (c) the probable life procedure
6. Adjustment using (a) the amortization method or (b) the remaining life method
7. Use of (a) the broad group model or (b) the vintage group model

The mathematically astute reader who multiplies the number of options in each factor will find that there are 432 combinations of options, each of which is a potential depreciation system. However, not all of these combinations are feasible, and some are unimportant. Only a few of these

combinations are of major interest when considering systems of book depreciation currently being used.

Concepts of Depreciation

Three options are available when defining the concept of depreciation. These include (a) physical condition, (b) decrease in value, or (c) cost of operation. Though all have been used by utilities to determine book value, the cost of operation is, with few exceptions, the concept in current use.

Physical condition is, perhaps, the first option a lay person would think of if asked to define depreciation. An early reference to the relationship between depreciation and physical condition is from the 1588 textbook by John Mellis who referred to a debit to the profit and loss account because "implements of householde I doe find at this day to be consumed and worn." A later reference is in the 1833 annual report of the Baltimore and Ohio Railroad, which reported that an annuity was established "to provide for the replacement of oak sills and sleepers and yellow pine stringpieces."

Two problems arise when using the concept of physical condition as a measure of depreciation. First, wear and tear do not account for all retirements; in fact, they are often a minor reason for the retirement of property. Second, physical condition can be difficult to measure. Though it is possible to measure directly the wear of railroad track and the corrosion of cast iron pipe, easily measurable wear is not characteristic of most industrial property.

The concept of loss of value is also a common depreciation concept, and the lay person often uses it to explain the difference between the purchase price and the current market value of an automobile or major household appliance. The definition from the Supreme Court case *Lindheimer v. Illinois Bell Telephone* (1934) is often quoted: "Broadly speaking, depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence."

In contrast to the concept of physical depreciation, the Lindheimer definition recognizes that factors other than wear and tear cause or contribute to the retirement of property. The definition refers to the "loss" but does not clearly state what is "lost" or how the "loss" should be measured. A 1935 definition by the Federal Communications Commission was similar to the Lindheimer definition but referred to "loss in service value," where service value is equated to the original cost less salvage.

Use of the concept of loss of value to determine annual depreciation charges might imply the need for an annual valuation of the property owned by the organization, particularly if the rate of loss in value was not

uniform or readily defined. The process of determining a value is complex, depending on the purpose of the valuation and type of property. Thus, an annual valuation of a utility could be such an expensive and time-consuming process that it would not be a practical approach to use in determining annual depreciation.

Many types of property provide a constant level of service until they are retired. The intrinsic physical value of this type of property is only that it functions. A gas meter is a common example of a type of property that may provide a constant level of service throughout its life. If value is measured by the level of service provided, the meter would retain full value until retirement because its value to the utility would depend on its function rather than its age. This concept ignores the consumption of future service and would result in an annual depreciation charge that would be zero until the final year of service. Then the charge would equal the full value and would result in deferring all depreciation charges until the final year of service. A concept that better matches depreciation to service rendered and weighs it in relation to the total service potential might be preferable for purposes of both book and valuation depreciation. That is, a quantitative measure of value, such as service-years, is generally preferable to a functional measure.

The third concept is that depreciation represents an allocated cost of capital to operation. This concept recognizes that depreciation is a cost of providing service and that an organization should recover the capital invested in equipment and other property needed to provide the required service. In fact, the term *capital recovery* is often used in connection with depreciation. An early reference to depreciation is by the Roman Marcus Vitrurius Pollio, who in 27 B.C. wrote of "walls which are built of soft and smooth-looking stone, that will not last long." He calculated that the walls would not last more than eighty years and suggested that, for purposes of valuation, one-eightieth part of their original cost be deducted each year. Pollio not only raised several issues concerning depreciation but seemed to be equating depreciation to a cost of operation.

The definition of *depreciation accounting* by the American Institute of Certified Public Accountants (1961, par. 56) reflects the concept of depreciation as a cost: "Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation." This definition does not use the term *loss of service value* because it is defining depreciation accounting rather than depreciation itself. The definition emphasizes that the purpose of depreciation accounting is a means of distributing cost in a rational manner during the service life, in turn providing for the systematic recovery of capital. By use of the term *useful life,* the definition encompasses all causes of retirement. By referring to the distribution of cost less salvage, this definition recognizes that salvage should be considered when developing depreciation charges.

Historically, all three concepts of depreciation have been used by utilities to determine the book value of industrial property. Of these, the concept of depreciation as the allocation of cost has proven to be the most useful and most widely used concept.

Time versus Unit of Production

Useful life can be measured in units of time or units of production (also called units of service). Measurement of life in years is a common and familiar concept. Measurement of life in units of production can be applied to some types of property such as a truck, whose life can be measured in miles (e.g., a useful life of 100,000 miles). A feeder pipeline connecting an oil field to a transmission line will be in service until the field is no longer productive. If the only function of the feeder line is to transport oil from the field to the transmission line, the life of the feeder line is determined by the reserves of the oil field that must eventually pass through the pipeline. Annual depreciation could be measured in units of production, such as barrels of oil. A railroad might depreciate rail as a function of the accumulated weight that the rail has carried.

Suppose a truck is to be depreciated over its life as measured in miles. First, the life must be estimated, say 100,000 miles. Second, the number of miles the truck will be driven during the next year, say 27,000 miles, must be forecast to have sufficient information to budget the annual depreciation charge. Third, at the end of the year when the budgeted annual depreciation becomes an accounting entry, the amount would be calculated to reflect the actual miles driven.

The most common measure of life is in units of time rather than units of production. Most types of property (e.g., poles, buildings, wire) do not have a measure of production associated with them. If the life can be measured in some unit of production and the rate of production is constant from year to year, measurement of life in either units of time or production will result in the same annual accruals. The unit of production has strong appeal in situations where use varies significantly over time and the life can be measured in units of production. But these two conditions are not often met, and usually life is measured over time.

Depreciation of an Individual Unit versus a Group

Accounting records of transactions relating to depreciable property can be kept on either a unit or a group basis. An individual unit of property has a single life, while the units in a group of property display a range, or

dispersion, of lives. Grouping many units of property into a single account simplifies the accounting system but also creates a complexity not encountered in the depreciation of an individual unit. The resulting complications provide a major challenge to the depreciation analyst.

A vintage group refers to a group of property placed in service during the same year. The plant in service decreases until all units are retired from service. The individual unit and the vintage group are similar because each has well-defined life characteristics. The life of an individual unit is described by a single number and the life of a vintage group is described by a survivor curve, which is a statistical description of the lives of the units of property in the group.

Methods of Allocation

To fully recover capital invested in plant and equipment, the total depreciation charge must equal the depreciation base. When using the allocation of cost concept, the depreciation base is the initial, or original, cost less net salvage. The annual depreciation accrual rate for a unit of property can be (a) constant over life (straight line), (b) high during early years and low in later years (accelerated), or (c) low in early years and high in later years (decelerated). Most methods of allocation fall into one of these three classifications, although it would be possible to develop a method that is a combination of them. The straight line method of allocation is the method of allocation most often used when calculating book depreciation. Accelerated methods of allocation are commonly used for tax purposes. Decelerated methods of allocation are not in common use for book or tax purposes, but they are of historical interest and are used in valuation problems.

Average Life, Equal Life Group, or Probable Life Procedures

The average life and equal life group procedures are two ways of applying a method of allocation to determine the annual accrual. The probable life procedure is similar to the average life procedure, but is not appropriate for depreciation accounting.

A group of property displays a wide range of lives, and the life characteristics of the group must be described statistically. This is in contrast to a unit of property, whose life can be described as a single number. When depreciating a group of property, rather than a unit of property, a major decision must be made whether to base the depreciation accrual rate on the average life of the group (the average life procedure) or whether to divide the group into subgroups of equal life (the equal life group procedure).

In the average life procedure, a constant annual accrual rate based on the average life of all property in the group is applied to the surviving

property. Most retirements occur either before or after, rather than at, the average life, but both short- and long-lived property are depreciated at the same rate. Property having a shorter life than the average will not be fully depreciated by the time of its retirement. Because the accrual rate is based on the average life of the group, the difference between accruals for early retirements and the full cost of the early retirements will be balanced during the life of the property having lives longer than the average. The result is that the group will be fully depreciated by the time of the final retirement.

In the equal life group procedure the property is divided into subgroups that each have a common life. Each subgroup is then depreciated as a unit using an accrual rate based on the common life of the group. Each unit is fully depreciated by the time it is retired. Application of the equal life group procedure is generally considered to better match the consumption of capital with service provided than does application of the average life procedure.

Any of the three methods of allocation (i.e., straight line, accelerated, or decelerated) can be applied to an individual unit or to group property. When the average life procedure is applied, the straight line method of allocation is easily used; application of either an accelerated or a decelerated method becomes more complicated. When the equal life group procedure is used, any of the three methods of allocation can be easily used.

The probable life procedure is a variation of the average life procedure. It is not valid for depreciation accounting or capital recovery because it does not fully depreciate the group. The depreciation charges are allocated over the average life of the property remaining in service (i.e., over the probable life), so that the continually decreasing rate is inadequate to fully recover the depreciable base. Use of this procedure should be restricted to those special situations where it is applicable; for example, it may used in the valuation process.

Methods of Adjustment

Depreciation accrual rates are calculated using estimates of the service life and salvage. Over time, new events that provide additional information occur, and the existing estimates are revised. A revision of the estimates of life and salvage results in the recognition that the accumulated provision for depreciation may now be either higher or lower than necessary, depending upon the magnitude and direction of the revised estimates. This recognition may justify an adjustment to the accumulated provision for depreciation, an adjustment to the annual depreciation rate, or both.

Adjustments to the accumulated provision for depreciation[1] can be made using either a fixed amortization period or the remaining life basis. The term *amortization method of adjustment* is used to describe a general

approach in which the first step is the estimation of the required adjustment to the accumulated provision for depreciation and the second step is the determination of the timing and amount of the adjustment. In the remaining life method of adjustment, adjustments to the accumulated provision for depreciation are amortized over the remaining life of the property and are automatically included in the annual accrual.

The amortization method of adjustment uses the revised estimates of life and salvage characteristics to compute the calculated accumulated depreciation (CAD) to serve as a guide when determining the appropriate adjustment. The CAD is compared to the accumulated provision for depreciation; a significant difference between the two shows that an adjustment to the accumulated provision for depreciation may be advisable. The adjustment can be allocated in several ways, which might include (1) a lump sum equal to the adjustment made immediately, (2) amortization of the adjustment over a fixed period (e.g., over 5 years), or (3) amortization of the adjustment over the remaining life of the property. A lump sum adjustment is not an amortization but will be considered an option in the amortization method of adjustment (i.e., the amortization method could be more accurately called the amortization or lump sum method of adjustment). The difference between the CAD and the accumulated provision for depreciation is only an estimate of the required adjustment. The need for, the magnitude of, and the timing of the actual adjustment should be based upon the recommendation of the depreciation professional. This recommendation requires professional judgment and should consider several factors: the characteristics of the account; the cause of the difference; estimates of future events that will affect the property; the year-to-year volatility of the accumulated provision for depreciation; and the depreciation policies of the organization. A revised forecast of life or salvage normally leads to a revised depreciation rate even when an adjustment to the accumulated provision for depreciation is not considered necessary.

When using the remaining life method of adjustment, emphasis is placed upon forecasting the remaining life of the property in service. A change in the estimate of either life or salvage characteristics automatically triggers an adjustment to the accumulated provision for depreciation, and the adjustment will be spread over the remaining life of the property.

Broad Group or Vintage Group Model

Typically, property depreciated as a group provides a service to the organization over a long period of time. Each year property in the group is retired from service, but new property is added to the group to replace that retired or to increase the capacity of the group. Thus, over time vintage groups are continually being retired from and added to the group. A group

such as this is called a *continuous property group,* though the term *open-ended group* is also used. The life and salvage characteristics of the vintages in the continuous property group must be specified in some systematic manner. The broad group model views each vintage in the continuous group as having identical life and salvage characteristics. The vintage group model views each vintage as having different life and salvage characteristics.

UNIT DEPRECIATION

Depreciation of a unit of property is a concept more readily understood than depreciation of a group of property. This section will present a brief discussion of the three methods of allocating the depreciable cost of a unit of property among accounting periods. An understanding of unit depreciation, particularly the straight line method of allocation, is necessary when considering depreciation for a group of property. In all examples, the cost of operation depreciation concept will be used, and depreciation will be over time (i.e., years). The depreciation base will equal the original cost less net salvage. This base represents the amount of capital to be consumed and, therefore, the amount of capital to be recovered through depreciation accruals.

Methods of Allocation

The three general methods of allocation are straight line, accelerated, and decelerated. An example of each will be applied to a unit of property that has an initial cost of $4000, a life of 4 years, and a net salvage value of $800 at retirement. The net salvage is commonly expressed in terms of the *salvage ratio* (SR), $800/$4000 or 0.20 or 20%.

Straight Line Method of Allocation

The straight line method of allocation is used almost exclusively by regulated, capital-intensive companies when calculating depreciation accruals for book accounting purposes. The straight line method applies a constant annual accrual rate to the cost of the unit, thus yielding a constant annual depreciation charge. The net book value (i.e., the original cost less the accumulated provision for depreciation) plotted versus time is a straight line.

The straight line rate is (1 – SR)/life. The factor (1 – SR) = (1 – 0.20) = 0.80, or 80%, represents the fraction of the original investment consumed during the life of the property, or the depreciable base. In this example that amount is 0.80 × $4000, or $3200. The accrual rate is 0.80/4

or 20%. The equal annual accruals are obtained by multiplying the original cost by the accrual rate. The figures in Table 5.1 (see end of chapter) are based on the assumption that this property was installed on January 1, 1974, and show the resulting accumulated provision for depreciation by year for this system. In the final year, the credit to the accumulated provision for depreciation equals the annual depreciation charge of $800 plus the net salvage of $800 for a total credit of $1600.

A major reason for the popularity of the straight line method is its simplicity. In addition, it occupies a middle ground between the accelerated and decelerated methods. Implicit in the use of the straight line method is the suggestion that the level of service provided by industrial property is independent of its age, and therefore the annual depreciation rate also should be independent of age (i.e., constant). Examples can be given where property such as poles, pipelines, cable, and meters provides a constant level of service throughout its life, but examples where the service provided by these types of property varies with age also can be given.

Accelerated Methods of Allocation

Any method that results in annual accruals that are higher early in life than late in life is called an accelerated method of allocation. Accelerated methods are allowed for calculating depreciation for tax purposes and are often used because of the rapid recovery of capital that they provide. Sometimes industrial property provides more service during early years than later years. An electrical generating unit begins its life as a base load generator operating continuously except for scheduled maintenance. As more efficient generators are installed, the base load generator becomes a peak load generator and operates only several hours each day. Eventually the generator is not used regularly but is used on a standby basis. Thus the service it provides changes significantly with age.

One accelerated method is the sum-of-years–digits method. Applying it to the $4000, 4 years, 20% salvage ratio example leaves the depreciable base unaffected at $3200, but the annual accruals vary with age rather than staying constant. To calculate the annual rate during year i, first sum the digits from 1 through the maximum life. In the example the sum is $1 + 2 + 3 + 4 = 10$. (A useful equation is that the sum of digits from 1 to n is $[(n)(n + 1)/2]$ or in the example $[(4) \times (5)/2] = 10$.) The rate during year i is $(1 - SR)(\text{life} - i + 1)/(\text{sum-of-years–digits})$. Applied to the example, the annual accrual rates are calculated as follows:

			Annual Rate	
Year	Sum	Life − Year + 1	No Salvage	With Salvage
1	10	4 − 1 + 1 = 4	40%	32%
2	10	4 − 2 + 1 = 3	30%	24%
3	10	4 − 3 + 1 = 2	20%	16%
4	10	4 − 4 + 1 = 1	10%	8%
			100%	80%

Note that with no salvage the accrual rates sum to 100% and that with salvage the accrual rates sum to 100%(1 − SR) or 80%, so that the depreciable base is recovered. Table 5.2 (see end of chapter) shows the application of the sum-of-years–digits method to the example.

The annual accruals of $1280 and $960 during the first two years are larger than the $800 annual accrual when using the straight line method of allocation, but the $640 and $320 for the final two years are less. When matching depreciation to service, an accelerated method of allocation would be appropriate if the property yields significantly more service early in life than it does later in life.

The declining balance method is another example of an accelerated method of allocation and it is widely used for tax depreciation. This method applies a constant rate to the declining balance of the book value, so that the annual accruals decrease even though the rate is constant. The rate is equal to a constant/life; if the constant is two, the rate is double the straight line rate and results in the double declining balance method. Rather than double declining balance, we will use 1.5 declining balance, so that the rate is 1.5/4 or 37.5%. Table 5.3 (see end of chapter) shows the calculations using the 1.5 declining balance method and illustrates a complexity inherent in the method. Because salvage was not included in the rate, it is necessary to switch to a straight line rate late in life so that the final value of the accumulated provision for depreciation is zero. In this example, the book value is $976 at the beginning of the fourth year; continuation of the 37.5% rate will result in a fourth-year accrual of $366 and total accruals of $3390, which is $190 more than the $3200 capital that has been consumed. We will switch to a straight line rate that will yield a final accrual of $976 − $800 or $176 during the final year as shown in Table 5.3. Details on switching rules should be obtained from the IRS if using this method for tax depreciation.

The equation $1 - (SR)^{1/N}$ calculates the declining balance rate that will yield a final book value equal to a nonzero salvage. In our example that rate is $1 - 0.2^{1/4}$ or 1 − 0.67 or 33%. Applying that rate to the book balance yields total annual accruals of $3200 without resorting to switching rules at the end of the life.

Decelerated Methods of Allocation

Any method that results in annual accruals that are lower early in life than later in life is called a decelerated method of allocation. The sinking fund method is an example of a decelerated method. To apply it to our example, the sinking fund factor (also called the A/F factor) must be calculated; the sinking fund factor is $\{r/[(1 + r)^n - 1]\}$, where r is an interest rate and n is the life. Tables of this factor as a function of r and n are included in most books on business finance and engineering economics. If r = 10% and n = 4, the sinking fund factor is $\{0.10/[(1.10)^4 - 1]\}$ or 0.2155. This means that if \$100 × 0.2155 or \$21.55 is invested at the end of each year for four years and returns an annual effective return of 10% compounded annually, the value of the sinking fund at the end of the fourth year will be \$100. But in order for the four annual payments of \$21.55 to total \$100, each payment must be compounded by (1 + r), or 1.10 in the example, each year. The accrual rate without salvage is 21.55% the first year, 1.1 × 21.55% or 23.70% the second year, 1.1 × 23.70% or 26.07% the third year, and 1.1 × 26.07% or 28.68% the fourth year. The annual accrual rates without and with 20% salvage are summarized as follows:

	Annual Rate	
Year	No Salvage	With Salvage
1	21.55%	17.24%
2	23.70%	18.96%
3	26.07%	20.85%
4	28.68%	22.95%
	100.00%	80.00%

The accrual rates with salvage are used in Table 5.4 (see end of chapter).

The annual accruals of \$690 and \$758 during the first two years are less than the \$800 annual accrual resulting from the straight line method of allocation, and the \$834 and \$918 during the final two years are more. A larger rate of interest results in a larger difference between annual accruals. A negative interest rate will result in accelerated depreciation. A zero interest rate results in a straight line rate.

Another decelerated method of allocation is the present worth method. It results in annual accruals that are identical with the sinking fund method, although the rationale leading to the calculation of the annual accruals is different. The present worth method is often used in the economic valuation and comparison of capital investments.

GROUP DEPRECIATION SYSTEMS WITH NO SALVAGE

The remainder of this chapter is devoted to the depreciation of a vintage group of property. First, the systems described and examples presented will assume zero salvage. Then the modifications to these systems when salvage is not zero will be introduced and discussed.

Four of the seven factors of depreciation listed at the beginning of the chapter will be limited to one option during the following discussion. Only the cost of operation concept of depreciation will be considered. Depreciation will be over time. Depreciation will be of a group, not a unit. Only the straight line method of allocation will be used. Both the average life and equal life group procedures, and the amortization and remaining life methods of adjustments will be examined. A discussion of the broad group and vintage group models will be deferred to a following chapter.

The Average Life Procedure Applied to a Vintage Group

Calculation of the Annual Accrual

One system of calculating the annual accrual incorporates the straight line method of allocation (SL) and applies the average life procedure (AL) to a vintage group. It is denoted by the initials SL-AL. As defined, this system lacks a feedback loop to control the system. A method of adjustment must be added to design a controlled, closed loop depreciation system.

The average life procedure applies the constant rate of 1/AL to the average plant in service during the year. Note that because the balance is averaged over a year, the AL must be measured in years. If the estimate of the average life is accurate, the vintage will be fully depreciated (i.e., the accumulated provision for depreciation will equal zero) after the final retirement.

It may not be immediately clear that this system will work (i.e., that the sum of the accruals will equal the original cost of the initial installations). The left side of the equation below equals the sum of the annual accruals when a rate of 1/AL is used and is set equal to the amount to be recovered (i.e., the original cost or initial balance).

$$\Sigma \text{ (average plant in service during age interval j)/AL} = \text{original cost}$$
$$\text{summed for j} = 0, 1, 2, \ldots, \text{ML (the maximum life)}$$

The average plant in service during the age interval times the one-year width of the age interval equals the dollar-years service provided during the year. The sum of the values (average plant in service during age interval j) is

equal to the area under the survivor curve and may be written (area under the survivor curve)/AL = original cost, or by rearranging this equation, AL = (the area under the survivor curve)/(original cost). The average life has been shown to equal the area under the survivor curve divided by the original cost (true whether the survivor curve is measured in dollars or units), so the original equality is true. We can conclude that this system will fully recover the initial investment regardless of the shape of the survivor curve.

This equation also shows that if the AL used in the accrual rate is not equal to the actual average life, the sum of the accruals will not equal the original cost. Suppose that the actual life was 8 years, but a life of 6 years was forecast and used in the depreciation rate. The total accruals would equal 8/6 or 133% of the original cost, and the accumulated provision for depreciation would show an overaccrual equal to 133% − 100% or 33% of the original cost at the time of the final retirement. Similarly, a forecast of a life of 10 years would result in total accruals of 8/10 or 80% of the original cost. At the time of the final retirement the accumulated provision for depreciation would show an underaccrual equal to 100% − 80% or 20% of the original cost.

Consider a property group having the survivor curve shown in Figure 5.1. This curve could result from the grouping of two units, one with a cost of $4000 and a 4-year life and the second with a cost of $6000 and an 8-year life. The average life (AL) is the area under the survivor curve divided by the original cost or the AL = [(4000 × 4) + (6000 × 8)]/10000 or 6.4 years. The straight line, average life annual accrual rate is 1/6.4 or 15.625%.

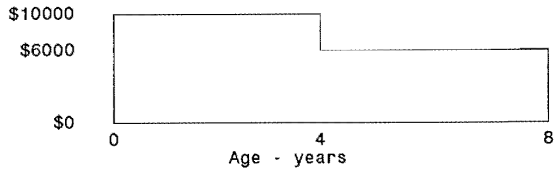

Figure 5.1. A survivor curve with an average life of 6.4 years.

NOTE: To simplify calculations in this section, age intervals will be 0–1, 1–2, 2–3, etc., installations will be assumed to occur at the start of the age interval, and retirements will be assumed to occur at the end of the age interval. The average plant in service during the age interval will then equal the balance at the start of the interval, so that applying the annual accrual rate to the plant in service at the start of the interval is equivalent to applying it to the average balance. In all tables in this section, the balance, accumulated provision for depreciation, and calculated accumulated depreciation are calculated at the beginning of the year. Note that the accumulated provision for depreciation is zero at the beginning of the initial year. Examples using the half-year convention will be shown later.

Table 5.5 (see end of chapter) shows the annual accruals and accumulated provision for depreciation that result from the SL-AL system. Column (b) shows beginning of year balances of $10,000 for the four years 1974 to 1977, and balances of $6000 for the next four years, 1978 to 1981. This follows the survivor curve shown in Figure 5.1. Column (c) shows a $4000 retirement at the end of 1977 and a $6000 retirement at the end of 1981. The annual accrual, column (e), is the product of the rate, column (d), and the plant balance at the start of the year, column (b). As described in the preceding note, retirements are assumed to take place at the end of the year, so that the plant balance at the start of the year is also the average balance during the year. The accumulated provision for depreciation, column (f), is zero at the start of the first year and is then increased by the annual accruals and reduced by the annual retirements. At the time of the final retirement, the accumulated provision for depreciation is zero, showing that the sum of the annual accruals and the annual retirements equals zero and that the property is fully depreciated.

Suppose that at the time of the initial installation of the property, the estimate of the average life was 7.4 years. If the rate 1/7.4 is used throughout the life of the property but the actual life is 6.4 years, then only (6.4/7.4)($10000) or $8649 will be depreciated and $10000 − $8649 or $1351 of invested capital will not be recovered. This is verified by the calculations shown in Table 5.6 (see end of chapter).

An Adjustment Problem—AL Procedure

Now suppose that in January 1977, because of events and activities occurring since 1974, the original forecast of 7.4 years average life is revised to 6.4 years. Table 5.7 (see end of chapter) shows the accumulated provision for depreciation at the start of 1977 is $4054. Unless some corrective action is taken, the annual accruals will not equal the $10,000 original cost, and at the time of the final retirement a total of $1351 will remain unrecovered. The SL-AL system of calculating the annual accruals must be augmented to include a method of adjustment to define a depreciation system that will adapt to the almost certain circumstance that forecasts are revised from time to time.

When there is a revision of the original forecast of service life, it

becomes necessary to consider a method of augmenting the SL-AL system of calculating annual accruals. Either of two methods of adjustment, the amortization method (AM) or the remaining life method (RL), can be added to the system of calculating annual accruals to construct a depreciation system with a closed feedback loop.

Amortization Method of Adjustment (SL-AL-AM)

Use of the amortization method of adjustment does not result in the prescription of an adjustment, but places the responsibility of recommending the magnitude and timing of the adjustment in the hands of the depreciation professional. Control focuses on the calculated accumulated depreciation (CAD). The CAD is normally a reasonable and valid estimate of an adequate level of the accumulated provision for depreciation. The depreciation professional will examine the variation between the CAD and the accumulated provision for depreciation to determine if adjustments to the annual accrual are necessary.

DEVELOPMENT OF THE CALCULATED ACCUMULATED DEPRECIATION. Two approaches can be used to develop the calculated accumulated depreciation. One, a retrospective approach, is to reconstruct the past accruals and retirements to determine what the accumulated provision for depreciation would have been given the current estimate of the life characteristics. The other, a prospective approach, is to estimate the sum of the future additions to and subtractions from the accumulated provision for depreciation. The sum of these additions and subtractions also is an estimate of the accumulated provision for depreciation that would be desirable to have on the books.

The retrospective approach appears to be straightforward. In fact, Table 5.5 shows that if property had the service life characteristics shown in Figure 5.1, the accumulated provision for depreciation at the start of the fourth year would be $4688. Comparison of this figure to the accumulated provision for depreciation of $4054 shown in Table 5.7 shows that an adjustment of $634 is necessary. In practice, however, the retrospective approach has a major shortcoming. The history of the account may go back many years and include accounting transactions, such as transfers, sales, acquisitions, and adjustments, which have been recorded in the accumulated provision for depreciation account. Use of the retrospective approach requires complete knowledge of these transactions as they must be considered for inclusion in the construction of the CAD. Because of the difficulties likely to be encountered in reconstructing the accumulated provision for depreciation, the retrospective approach is usually discarded in favor of the prospective approach.

The prospective approach to the CAD is based on estimates of the

future accruals and retirements. Estimates of future accruals and retirements can be made if the survivor characteristics of the property have been estimated. The following relationship states that the calculated accumulated depreciation plus all future accruals, less all future retirements, equals zero. If this relationship holds, the cost of the property will be fully allocated at the time of the final retirement.

$$\text{CAD(i)} + \text{future accruals} - \text{future retirements} = 0$$

or

$$\text{CAD(i)} = \text{future retirements} - \text{future accruals}$$

The future retirements equal the current balance of the plant in service, because all property currently in service must eventually be retired. The future accruals is the sum of the annual future accruals when the SL-AL system of calculating the annual accruals is used. Thus, CAD(i) = current balance $-$ Σ (average balance during year j)(1/AL) = current balance $-$ (1/AL)Σ (average balance during year j) summed for j from year i to year of final retirement, where CAD(i) = calculated accumulated depreciation at the start of year i.

The average balance during each year is determined by the survivor curve used to describe the life characteristics of the vintage. The sum of the average balances during the year, starting with the current year and continuing through all years until the year of the final retirement, is equal to the area under the survivor curve and to the right of the current age. This area represents the remaining service and is measured, in this case, in dollar-years. The remaining service divided by the plant in service is defined as the average remaining life (also called the expectancy). Dividing both sides of the equation above by the current balance yields the following definition and equation for the calculated accumulated depreciation ratio, which will be abbreviated as CADR[2]:

CAD(i)/current balance = current balance/current balance $-$ (area under the survivor curve/current balance)/AL

CAD(i)/current balance = CADR(i) = 1 $-$ RL(i)/AL, where CADR(i) = calculated accumulated depreciation ratio at age i and RL(i) = remaining life at age i

Tables of the Iowa survivor curves contain values of the calculated accumulated depreciation ratios.

Table 5.8 (see end of chapter) shows the calculation of the RL, the

CADR, and the CAD for the survivor curve shown in Figure 5.1. The 64,000 dollar-years of remaining service at age zero, column (d), is equal to the sum of the annual balances shown in column (c) and also equal to the area under the survivor curve. (Remember that the width of each interval is one year, so that the balance at the start of the year multiplied by the width of the interval, one year, is the area under the survivor curve attributable to that year.) The amount in column (d) represents the remaining service contained in the existing plant. Each year the amount in column (d) is reduced by the average plant balance during that year times the one-year period (i.e., the service provided during the year) to calculate the service, measured in dollar-years, remaining at the beginning of the next year. The remaining life, column (e), is the remaining service divided by the balance or column (d)/column (c). The CADR, column (f), is 1 – remaining life/average life. The CAD, column (g), equals the CADR multiplied by the plant in service. This calculation shows that the CADR is sensitive to both the average life *and* the shape of the survivor curve.

AN AMORTIZATION SOLUTION TO THE AL ADJUSTMENT PROBLEM. Now return to the problem raised in the scenario shown in Table 5.7. Table 5.8 shows that if the estimate of a 6.4-year average life is accurate, the current value of the accumulated provision for depreciation would be $4688 rather than the recorded $4054, and this results in an apparent deficit of $634. If the depreciation professional believes this variation is significant, then an adjustment to the accumulated provision for depreciation should be made.

The adjustment to the accumulated provision for depreciation can be made in several ways, ranging from a lump sum adjustment of $634 to amortizing the $634 over a period less than the remaining life, equal the remaining life, or longer than the remaining life. For example, suppose it is decided to amortize the $634 over two years; then the accumulated provision for depreciation would be credited an additional $317 in 1978 and 1979. In addition, the annual rate would be changed to 1/6.4 to reflect the revised forecast. Table 5.9 (see end of chapter) shows that these adjustments will result in a recovery of the $10,000 initial investment as reflected by the final zero balance of the accumulated provision for depreciation.

The CAD is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.

Remaining Life Method of Adjustment (SL-AL-RL)

In 1953 the California Public Utilities Commission issued *Determination of Straight-line Remaining Life Depreciation Accruals,* also called *Standard Practice U-4.* This document, which was revised in 1961, presents the steps required in determining the annual accrual when using the straight line method of allocation, the average life procedure, and the remaining life method of adjustment.

Though the term *remaining life* is often thought of as a basis for calculating the annual accrual, it is more appropriately considered a method of adjustment used with a system of calculating annual accruals. As discussed in the preceding paragraphs, a revision of the forecast of average life may lead to an adjustment to the accumulated provision for depreciation. When the remaining life method of adjustment is used, the variation between the CAD and the accumulated provision for depreciation is amortized over the remaining life of the plant in service. This adjustment is automatic in the sense that it is built into the remaining life calculations.

Table 5.5 shows the calculation of annual accruals using the SL-AL system applied to property described by the survivor curve of Figure 5.1. Remember that the annual accrual is the average balance during the year times the straight line rate 1/AL. Use of the remaining life method of adjustment requires different calculations even though the same annual accruals will result. Before calculating the accruals, the remaining life rates for the survivor curve used to estimate the life characteristics must be determined, and these calculations are shown in Table 5.10 (see end of chapter).

The remaining life calculations can be viewed in two ways. One is that the rate 1/RL is applied to the future accrual, which is the current plant in service less the accumulated provision for depreciation. The future accrual (i.e., the amount remaining to be accrued) is allocated over the remaining life of the vintage group using the straight line method. The procedure used to apply the straight line method assumes each unit in service has a remaining life equal to the average remaining life. Thus the AL procedure is used. Table 5.11 (see end of chapter) shows the remaining life calculations using the survivor curve in Figure 5.1. Column (d), the future accruals, is the balance less the accumulated provision for depreciation, column (b) – column (g). The remaining life rates, taken from Table 5.10, are shown in column (e). The annual accruals, the product of columns (d) and column (e), are in column (f). Note that the annual accruals resulting from the remaining life calculations are identical with those obtained by applying the rate 1/AL to the average plant in service and shown in Table 5.5.

A second way of viewing the remaining life calculation is to consider the annual accrual as the SL-AL accrual plus an adjustment to reduce the variation between the CAD and the accumulated provision for depreciation. The following calculations show that the amortization method, SL-AL-AM, and the remaining life method, SL-AL-RL, yield identical annual accruals when the variation between the CAD and the accumulated provi-

sion for depreciation is either (a) zero or (b) amortized over the remaining life.[3]

Let:[4] B = plant balance
AL = average life
RL = remaining life
APD = the accumulated provision for depreciation
APDR = the ratio APD/B
CAD = the calculated accumulated depreciation
CADR = the ratio CAD/B
AARL = the annual accrual using the RL method of adjustment
AAAM = the annual accrual using the AM method of adjustment

The annual accrual will be calculated for both methods of adjustment, and the two annual accruals will then be compared. First, the annual accrual using the remaining life method of adjustment (the AARL) is the total amount remaining to be depreciated (i.e., the future accrual) divided by the remaining life or AARL = (B − APD)/RL = B[(1 − APDR)/RL].

Next, the annual accrual using the amortization method of adjustment (the AAAM) will be written as the sum of the straight line, average life accrual plus the annual adjustment of the variation between the CAD and the accumulated provision for depreciation. The following calculations assume the variation is amortized over the remaining life and make use of the fact that the CADR = 1 − RL/AL.

$$\begin{aligned} \text{AAAM} &= \text{annual accrual} + \text{adjustment} \\ &= \text{annual accrual} + \text{variation/remaining life} \\ &= B/AL + (CAD - APD)/RL \\ &= B/AL + [B(CADR) - B(APDR)]/RL \\ &= B[1/AL + CADR/RL - APDR/RL] \\ &= B[1/AL + (1 - RL/AL)/RL - APDR/RL] \\ &= B[1/AL + 1/RL - 1/AL - APDR/RL] \\ \text{AAAM} &= B[(1 - APDR)/RL] \end{aligned}$$

but this is the same as the annual accrual using the RL method of adjustment so AARL = B[(1 − APDR)/RL] = AAAM.

If the variation is zero, then the accumulated provision for depreciation (APDR) equals the CAD. Because the CAD equals 1 − RL/AL, the annual accruals using the remaining life method of adjustment can be written

$$\begin{aligned} \text{AARL} &= B[(1 - APDR)/RL] \\ &= B[(1 - CADR)/RL] \\ &= B[(1 - 1 + RL/AL)/RL] \\ &= B[1/AL] \\ &= \text{AAAM} \end{aligned}$$

Thus, when the variation is zero, the remaining life accrual can be expressed as the balance divided by the AL.

EFFECTS OF USING AN IMPROPER REMAINING LIFE. Calculation of the remaining life requires knowledge of the survivor curve; survivor curves with the same average life but different shapes will have different remaining lives. This raises the question of the result of applying the remaining life method of adjustment when the average life is correct but the shape of the survivor curve used to calculate the remaining lives differs from the actual retirement pattern. To examine this question, suppose the survivor curve shown in Table 5.12 (see end of chapter) is used to estimate the life characteristics of the property to be depreciated. Though the average life of this curve is 6.4 years, the same as the survivor curve shown in Figure 5.1, its retirement pattern is significantly different from the pattern shown in Figure 5.1.

Note that, as shown during 1981 in Table 5.12, calculation of the remaining life can be puzzling. Confusion arises because the final retirement takes place not at the end of the year, but 1/3 of the way through the year. At the start of the year, the remaining life is 2000/6000 or 1/3 year. However, a remaining life of 1 is needed to obtain a final rate of 100%. An explanation is the choice of one-year intervals to calculate accruals. Suppose that accruals were calculated every 1/3 year, so that a unit of time is 1/3 year rather than 1 year. The average life would then be 6.4 × 3 or 19.2 units (i.e., 19.2 one/third years). These calculations would show the sum of the three 1/3-year accruals equal the annual accruals shown in Table 5.12. However, at the start of 1981, the remaining life is 1 unit, and the corresponding rate is 100%.

Table 5.13 (see end of chapter) shows the result of applying the accrual rates from Table 5.12 to property whose survivor curve is described in Figure 5.1. That is, we will use the correct average life but the incorrect remaining lives. Though the total accruals equal the $10,000 original cost, the annual accruals are not identical with those of Table 5.11. In this example, the maximum life of the survivor curve used to calculate the remaining life rates (7.33 years) is less than the maximum life of the property (8 years), so the final, 100% accrual rate of Table 5.12 assures the accruals will total $10,000.

Now suppose that the survivor curve used to describe the life characteristics of the property being depreciated still has an average life of 6.4 years but the maximum life is greater than 8 years, as shown in Table 5.14

(see end of chapter). When the accrual rates shown in Table 5.14 are applied to property whose life characteristics are shown in Figure 5.1, an underaccrual of $1875 results, because the final retirement was forecast to occur in 1983 but actually occurred in 1981. This emphasizes the fact that when using the remaining life method of adjustment, estimates of the shape of the survivor curve may need to be revised, even though estimates of the average life are unchanged. See Table 5.15 at the end of this chapter.

How does the remaining life adjustment behave when life estimates are revised? Again, the scenario shown in Table 5.7 can be used to observe the results of applying the remaining life method of adjustment. Let the initial forecast of service life be the survivor curve shown in Table 5.16 (see end of chapter); it has an average life of 7.4 years, the same life used to generate the accrual rate shown in Table 5.6.

The remaining life rates of Table 5.16 are used to calculate annual accruals and the accumulated provision for depreciation shown in Table 5.17 (see end of chapter). Because the actual average life is 6.4 years but the forecast life is 7.4 years, the total accruals are $1351 less than the required $10,000.

A REMAINING LIFE SOLUTION TO THE AL ADJUSTMENT PROBLEM. Table 5.7 presented a scenario where accrual rates based on a forecast life of 7.4 years were used for the years 1974, 1975, and 1976. Then in January 1977, the forecast was revised to an average life of 6.4 years. From our discussion of the amortization method of adjustment, we know that in 1977 the accumulated provision for depreciation is $634 less than it would be had the revised forecast been used during 1974, 1975, and 1976. Unless some adjustment is made, that difference will grow to $1351.

The remaining life method of adjustment shown in Table 5.18 (see end of chapter) will amortize the $634 in the following manner. At the start of 1977 the remaining life is 3.4 years, so the adjustment during that year is $634/3.4 or $186. This amount is the difference between the $1749 accrual shown in Table 5.18 and the $1563 accrual (i.e., the average life accrual $10000/6.4) shown in Table 5.5. It reduces the adjustment to $643 − $186 or $448 at the start of 1978. Then the remaining life is 4 years, so the adjustment during 1978 is $448/4 or $112, which is again the difference between the accruals for 1978 as shown in Tables 5.17 and 5.5. In this manner the adjustments for 1979, 1980, and 1981 can be shown to be $112, $112, and $112. Thus, the $1634 variation is amortized over the remaining life. The adjustments are "automatic"; that is, they result automatically when the remaining life calculations are used to determine the annual accruals.

Summary

When comparing the amortization and remaining life methods of adjustment, remember that the magnitude and timing of the annual accruals depend upon the method of allocation and the procedure for applying the method of allocation. The difference between the two methods of adjustment only becomes apparent when the forecast is revised. The remaining life method amortizes the variation between the CAD and the accumulated provision for depreciation over the remaining life and the adjustment is included in the annual accrual. The amortization method allows the variation to be amortized over any period, but requires that the annual amount to be amortized be calculated separately and then added to the calculated accrual. If the depreciation professional chooses to amortize the variation over the remaining life, the two methods result in equal annual accruals.

Neither method of adjustment will properly recover the depreciable base unless accurate forecasts are made. It could be argued that the remaining life method requires only an estimate of the remaining life, while the amortization method requires an estimate of the average life. Remember that at age zero the remaining life is also the average life, and that at any time, the average life can be partitioned into the realized life and the remaining life. The realized life can be obtained from historical records while the remaining life must be forecast. From that point of view, there is no difference between the difficulty of forecasting the remaining life and the average life, because the average life depends on the realized life (which is known) and the remaining life (which must be forecast).

Both methods of adjustment require a forecast of the survivor curve describing the property. The amortization method requires only the average life when calculating the annual accruals, but requires the shape of the survivor curve to calculate the CAD. The remaining life method requires the average life and the shape of the curve to calculate the remaining life and the annual accruals.

The Equal Life Group Procedure Applied to a Vintage Group

The next system of calculating the annual accrual uses the straight line method of allocation and applies the equal life group procedure to a vintage group (SL-ELG). Both the AM and RL methods of adjustment are combined with the ELG procedure.

History of the Equal Life Group Procedure

Allocation using the equal life group procedure was discussed as early as March, 1928, during an ICC hearing (*Telephone Engineer and Management,* 1967, p. 55). Robley Winfrey studied it during the 1930s and in 1942

published a detailed discussion of the procedure in *Depreciation of Group Properties, Bulletin 155.* Winfrey considered it "the only mathematically correct procedure" (p. 71) and called it the unit summation procedure. The procedure was primarily of academic interest until the 1970s.

The major objection to the everyday use of the equal life group procedure was the large number of computations necessary to calculate the annual depreciation. When done manually, these calculations consumed enough time to make the equal life group procedure impractical. As computers became more common and computer time less expensive, this objection gradually disappeared. Another objection focused on the fact that in a growing account, the change from the average life to the equal life group procedure typically was accompanied by a significant increase in annual accruals. Though this increase was coupled with a similar decrease as the account matured, the increase created a bias against the procedure. In the early 1970s, the Bell System began to espouse the equal life group procedure in both the United States and Canada. Bell's informational campaign speeded acceptance first by regulators in Canada and then in the United States. The major argument for equal life group procedure is that it more closely matches depreciation charges with the service rendered during the life of the property than does the average life procedure.

The ELG Procedure

To find the accrual rate when using the equal life group procedure, the life characteristics (the average service life and the shape of the survivor curve) must be estimated. Then the original cost is subdivided into equal life groups. Typically, the equal life groups are formed by specifying the life of each group in one-year increments, and the survivor curve is used to find the proportion of the original cost assigned to each equal life group. Though it is not possible to physically identify the individual units in each ELG, it is possible to statistically identify the fraction of the plant in service in each ELG. Each equal life group is treated as a unit of property and is depreciated using the straight line method of allocation. Note that any method of allocation that can be applied to an individual unit can be applied in the same manner to an equal life group. The total annual accrual for the vintage is found by summing the annual accruals for each equal life group remaining in service. The ELG accrual rate is the total annual accrual divided by the average plant in service during the year.

The $10,000 original cost of the survivor curve shown in Figure 5.1 can be divided into two groups. The first group has a life of 4 years and contains $4000 of the original cost. The second group has a life of 8 years and contains $6000 of the original cost. These will be identified as group A and group B respectively. Note that each dollar in group A has a life of 4 years, therefore the name *equal life group.* Each group will be depreciated using the straight line method of allocation, so that the first group will be depreciated at a rate of 1/4 for 4 years and the second group at a rate of 1/8 for 8 years. Table 5.19 (see end of chapter) shows the calculation of the annual accruals for each equal life group and then sums them to obtain the total accruals and accrual rates. For the year 1974, the annual accruals of $1000 and $750 total $1750, which results in a composite annual rate of $1750/$10000 or 17.50%. For this survivor curve, the ELG rates are constant during the first 4 years (17.50%) and during the last 4 years (12.50%).

The annual accrual rates developed in Table 5.19 are used in Table 5.20 (see end of chapter), which shows the SL-ELG method of calculating the annual accruals and accumulated provision for depreciation for property described by the survivor curve shown in Figure 5.1.

Comparison of the AL and ELG Procedure

Compare the annual accruals and the accumulated provision for depreciation resulting from the use of the SL-ELG system, which are shown in Table 5.20, with the annual accruals and accumulated provision for depreciation resulting from the use of the SL-AL system, which are shown in Table 5.5. When contrasted with the average life procedure, the equal life group procedure results in annual accruals that are higher during the early years and lower in the later years. After the first retirement, which reduces the 1977 balance by $4000, the accumulated provision for depreciation using the average life procedure is $2250 as contrasted with $3000 using the equal life group procedure. With the equal life group procedure, the first unit has been fully depreciated and retired, and $3000 has been accumulated against the eventual (in 4 years) retirement of the $6000 life group, which has a life of 8 years. The $6000 life group is halfway through its life and is half depreciated. The accumulated provision for depreciation with the average life procedure is only $2250, so the $4000 unit was not fully depreciated at the time of its retirement. The $750 difference in the accumulated provision for depreciation between the two procedures will be made up over the life of the longer-lived unit. This is not to imply that the average life procedure is incorrect, only that it is different.

Both procedures are "systematic and rational" as required by the definition of depreciation accounting. Use of the average life procedure matches the depreciation charges to the service provided by the average-lived unit. That is, the shorter-lived units contribute fewer units of service than the longer-lived units, and therefore, the total accrual associated with a short-lived unit is less than that associated with a long-lived unit.

The AL procedure treats each unit as though its life is equal to the average life of the group. The ELG procedure treats each unit in the group as though its life was known. This is the basis for the argument that the equal life group procedure better matches depreciation charges with the life of the units in the group.

Effect of Improper Forecast of Curve Shape

What happens if the shape of the curve used to calculate the equal life group rates differs from the shape of the curve describing the property, even though the estimate of the average service life is correct? Table 5.14 shows a survivor curve with an average life of 6.4 years and with units of $4000 and $6000 but with a different shape than the survivor curve shown in Figure 5.1. Table 5.21 (see end of chapter) shows the application of the ELG rates (see Table 5.19) for the survivor curve shown in Figure 5.1 to property whose survivor curve is shown in Table 5.14. The accruals total only $9400, leaving $600 of the original cost unrecovered. This shows that the shape of the survivor curve affects the capital recovery when using the ELG procedure.

Effect of Improper Average Life Forecast

Now recall the survivor curve with an average life of 7.4 years that was used to show the result of overestimating the service life when using the SL-AL system. The annual accrual rates for this curve when using the SL-ELG system are shown in Table 5.22 and these accrual rates are applied to property with an average life of 6.4 years to obtain the annual accruals shown in Table 5.23. (See end of chapter for both tables.) The results are similar to those shown in Table 5.6. The property lacks $1034 of being fully recovered; this is a smaller deficit than if the average life procedure had been used because of the higher early accrual rates resulting from the use of the equal life group procedure.

An Adjustment Problem—The ELG Procedure

As before, suppose that during 1974, 1975, and 1976 annual accruals were obtained from rates based on a 7.4 year life and shown in Table 5.22. In January 1977, the original forecast is revised to the survivor curve shown in Figure 5.1. Table 5.24 (see end of chapter) shows the accumulated depreciation at the time of the revised forecast to be $4863. The SL-ELG system must be augmented to include a method of adjusting the accumulated provision for depreciation to correct for the accruals made during 1974, 1975, and 1976.

Either the amortization or the remaining life method of adjustment can be used to add a feedback loop to the SL-ELG system of calculating annual accruals. Much of the previous discussion of adjustments to the SL-AL system is applicable to the SL-ELG system, and this section will address only the additional information needed when the equal life group procedure is substituted for the average life procedure.

Amortization Method of Adjustment (SL-ELG-AM)

The discussion of the purpose of, approach to, and estimation of the accumulated provision for depreciation in a preceding section is germane to the CAD calculation when using the SL-ELG-AM system. The calculation of the calculated accumulated depreciation ratio at age i using the equation CADR(i) = 1 − RL(i)/AL is still correct, but the terms RL(i) and the AL now apply to each equal life group rather than the total vintage group. As such, the RL and the AL are no longer averages but are simply the remaining life and the life of a single ELG. The CADR is calculated for each equal life group and is then multiplied by the number of dollars in that equal life group to find the CAD for that equal life group. The CAD for the vintage group is then obtained by summing the CAD for each equal life group remaining in service.

Calculation of the CADR(i) is simplified because the remaining life of an equal life group is the life of the equal life group minus its age. This is true because the survivor curve of a unit is the square survivor curve. If the life of an equal life group is 8 years and its age is 3 years, the remaining life is 5 years, and the calculated accumulated depreciation ratio is CADR(3) = 1 − 5/8 or 3/8, which simplifies to the age/AL.

Table 5.25 (see end of chapter) shows the CAD calculations for the survivor curve shown in Figure 5.1. At the end of the third year, both equal life groups remain in service and their age is 3 years. The $4000 equal life group has an age of 3 years, a CADR of 3/4 or 0.75, and the CAD for this unit is $4000 × 0.75, or $3000. The $6000 equal life group has an age of 3 years, a calculated accumulated depreciation ratio of 3/8 or 0.375, and the CAD for this unit is $6000 × 0.375 or $2250. The CAD of the vintage is $3000 + $2250 or $5250. Because the balance at that time is $10,000, the calculated accumulated depreciation ratio for the vintage is 0.525.

AN AMORTIZATION SOLUTION TO THE ELG ADJUSTMENT PROBLEM. Now return to the scenario summarized in Table 5.24. The accumulated provision for depreciation is $4863 and it is now the start of 1977; the original forecast has been revised and the CAD, based on the revised forecast, calculated. Had the revised forecast been used starting in 1974, the current amount of the accumulated provision for depreciation would be $5250. An adjustment of $5250 − $4863 or $387 is needed to fully recover the initial $10,000 investment.

The amortization method of adjustment allows the $387 to be amortized over a period recommended by the depreciation professional. Suppose that it is decided to make the entire adjustment as a lump sum during 1977. An argument for an immediate adjustment of $387 is that this timing places the increase in the cost of service nearest to the customers who benefitted

by the under-accruals during 1974, 1975, and 1976. Deferral of this adjustment until later in the life of the property may be more likely to assess customers who had not benefitted by the service provided by the property during 1974, 1975, and 1976.

Table 5.26 (see end of chapter) shows the resulting accruals if an immediate, lump sum adjustment is made and the revised rates adopted. As anticipated, the accumulated provision for depreciation is zero at the time of the final retirement.

Remaining Life Method of Adjustment (SL-ELG-RL)

The remaining life method of adjustment can be used with the ELG procedure to form the SL-ELG-RL system of depreciation. The general comments concerning the SL-AL-RL system of depreciation apply when using the ELG procedure, rather than the AL procedure. This section will discuss the differences between the two systems and will focus on the equal life groups formed from the vintage group.

When using the SL-ELG-RL system of depreciation, the annual accruals, as shown in Table 5.20, are determined by the SL-ELG system. But the remaining life method of adjustment requires that the annual accruals be calculated by dividing the future accrual by the remaining life. Application of the remaining life method of adjustment to the ELG procedure requires calculations be made for each ELG. The accruals for each ELG are obtained by dividing the future accrual of the ELG by the remaining life of the ELG and summing over all ELGs to obtain the annual accrual for the vintage. These calculations are shown in Table 5.27 (see end of chapter), where the first section of the table shows the calculations for the $4000 and the $6000 units, and the second portion of the table totals the accruals from each ELG to obtain the vintage accrual. As expected, the annual accruals and the accumulated provision for depreciation are equal to those shown in Table 5.20.

Note that column (e) of the final section of Table 5.27, labeled 1/RL and equaling the composite rate, was calculated by dividing the annual accruals by the future accrual (i.e., the vintage accrual rate was calculated after the annual accrual was calculated).

These accrual rates also can be viewed as a weighted average, where the remaining life for an ELG is weighted by the balance/life of the ELG. In 1976 both unit A and B are in service and their remaining lives are 2 and 6 years respectively. The weight for A is $4000/4 (the balance/life of the ELG) or $1000; for B it is $6000/8 or $750. The remaining life using the average service life weighting is then [$1000(2) + $750(6)]/$1750 or 3.71 years. Note that the numerator ($6500) equals the future accrual and the denominator equals the annual accrual, so that these calculations are equivalent to those shown in Table 5.27.

ALLOCATION OF THE ACCUMULATED PROVISION FOR DEPRECIATION. The calculation of the annual accruals when there is a variation between the CAD and the accumulated provision for depreciation raises the question of how the accumulated provision for depreciation should be allocated among the equal life groups. Any accrual rate used to calculate the annual accrual either explicitly or implicitly allocates the accumulated provision for depreciation (and the variation) among the ELGs. Suppose that at the start of 1976 the accumulated provision for depreciation is $2500, resulting in a variation between the CAD and the accumulated provision for depreciation of $3500 − $2500 or $1000, so that future accrual must include adjustments that will total $1000.

Any method that allocates the accumulated provision for depreciation to each ELG could be used (e.g., the accumulated provision for depreciation could be spread equally among the ELGs, or $1250 to unit A and $1250 to unit B). Logically, the method used should be based on a rational scheme that is consistent with the goals of the depreciation system.

Two methods of allocation will be considered: (a) allocation proportional to the CAD and (b) allocation proportional to the balance less the CAD, which will be called the calculated future accrual (CFA). In either case, we must divide the $2500 accumulated provision for depreciation into two parts and assign one part to unit A and the other to unit B.

The first method considered will be an allocation proportional to the CAD. The calculations are shown below, with columns (b) and (c) taken from Table 5.27. Column (d) shows that ratio of the CAD associated with unit A to the total CAD is 2000/3500 or 57.14%, so that portion of the accumulated provision for depreciation will be allocated to unit A and the remaining 1500/3500 or 42.86% to unit B. Column (e) shows the results of using these percentages to allocate the $2500 accumulated provision for depreciation to the two units. Column (f) is obtained by subtracting the accumulated provision for depreciation allocated to the unit, column (e), from the balance, column (b), and is divided by the remaining life to obtain the annual accrual, column (h), for the ELG. These calculations are equivalent to allocating the $1000 variation proportionally to the CAD; note that 57.14% of $1000 is $571 and that the CAD for unit A, $2000 less $571 is $1429. The total annual accrual is $2107, the resulting composite rate is 2107/7500 or 28.09%, and the composite remaining life is 1/0.2809 or 3.56 years.

Unit (a)	Bal (b)	CAD (c)	% CAD (d)	Accum depr (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	2000	57.14	1429	2571	2	1286
B	6000	1500	42.86	1071	4929	6	821
		3500		2500	7500		2107

The preceding example assumed a variation of +$1000. Now suppose the accumulated provision for depreciation is $4500 as shown below. The resulting variation is $3500 − $4500 or −$1000; the future accrual will be reduced by $1000. The calculations below show allocation of this variation proportional to the CAD. The annual accrual is now only $1393, the composite rate is 25.32%, and the composite remaining life is 1/0.2532 or 3.95 years. Note that when using this method of allocation, the composite rate varies with the variation. The larger the variation the larger the rate (and the smaller the composite remaining life), while the smaller the variation the smaller the rate (and the larger the composite remaining life).

Unit (a)	Bal (b)	CAD (c)	% CAD (d)	Accum depr (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	2000	57.14	2571	1429	2	714
B	6000	1500	42.86	1929	4071	6	679
		3500		4500	5500		1393

The second method allocates the variation proportional to the CFA. The calculations are shown below. Column (d) shows the balance less the CAD and column (e) shows these figures as a percentage of the total. The $7500 actual future accrual is then allocated to each unit using these percentages and the results are shown in column (f). This is equivalent to allocating the $1000 variation by assigning 30.77% to unit A and 69.23% to unit B. The total accrual is $2019, the composite rate is 2019/7500 or 26.92%, and the composite remaining life is 3.71 years. Note that the composite rate is the same as that used when there was a zero variation and is shown in Table 5.27. If this example was carried out assuming an accumulated provision for depreciation of $4500 resulting in a variation of −$1000, the composite rate would remain at 26.92% and the composite remaining life would remain at 3.71 years.

Unit (a)	Bal (b)	CAD (c)	CFA (d)	% CFA (e)	Future Accrual (f)	RL (g)	Accrual (h)
A	4000	2000	2000	30.77	2308	2	1154
B	6000	1500	4500	69.23	5192	6	865
			6500		7500		2019

An important insight into the difference between the two methods is gained by observing the contribution of each ELG to the total annual accrual. The variation can be expressed as $1000/6500 or 15.38% of the CFA; the future accrual is 15.38% more than it should be if the most recent forecast is correct. Had the accumulated provision for depreciation been $6500, the annual accrual would have been $1750. If the accumulated provision for depreciation is allocated proportionally to the CAD (i.e., the first method), the total annual accrual is increased by (2107 − 1750)/1750 or 20.40%; also, the accrual due to unit A is increased by (1286 − 1000)/1000 or 28.60%, and the accrual due to unit B is increased by (821 − 750)/750 or 9.5%. In contrast, allocation proportional to the CFA (i.e., the second method) yields an increase in the annual accrual of (2019 − 1750)/1750 or 15.38%; also, the accrual due to unit A and unit B are both increased by 15.38%. Allocation proportional to the CAD results in accruals associated with units with a smaller remaining life receiving a proportionally larger share of the variation. Allocation proportional to the CFA yields accruals that are uniformly proportional to the variation.

Use of the method of allocation in which the variance is proportional to the CAD is supported by these arguments.

1. Each ELG will be fully depreciated by the end of its service life.
2. Adjustments (either positive or negative) to past accruals are more rapid, thus placing the added costs or savings on the rate payers closest to the past.
3. The composite rate will increase or decrease as the size of the variation increases or decreases. The larger the variation, the more rapid the rate of adjustment.
4. Typically the allocation of the accumulated provision for depreciation among accounts is proportional to the CAD, and this method extends that concept to the vintage group.

Arguments for allocation proportional to the CFA are listed below:

1. The accrual for each ELG is increased (or decreased) by the same proportion.
2. Adjustments to past accruals are spread over a longer period, thus the magnitude of change in the annual accrual is minimized.
3. The composite rate remains constant despite the size of the variation, thus simplifying both the concept and the calculations.
4. This method is currently widely used when allocating the accumulated provision for depreciation among ELGs within a vintage group.

Strong arguments exist for both methods of allocation. In all future examples, the variation within a vintage group will be allocated proportionally to the CFA, thus allowing use of a constant composite rate despite the

magnitude of the variation. This does not imply that this method is better, only that in this case it is more convenient because the composite rate can be calculated without knowledge of the variation.

Again, return to the problem raised in the scenario shown in Table 5.24. First, duplicate the results of Table 5.23 using the remaining life calculations. This requires calculation of the composite remaining life of the survivor curve shown in Table 5.16, which had an average life of 7.4 years; these calculations are shown in Table 5.28 (see end of chapter).

A REMAINING LIFE SOLUTION TO THE ELG ADJUSTMENT PROBLEM. Next, apply these accrual rates to the example problem, as shown in Table 5.29 (see end of chapter). Note that the annual accruals and accumulated provision for depreciation are the same as in Table 5.23 because both use the same forecast. If the forecast is not revised, $1034 of the initial investment will not be recovered.

Now apply the remaining life method of adjustment to the problem presented in Table 5.24. Starting in 1977, use the accrual rates shown in Table 5.27. The results, shown in Table 5.30 (see end of chapter), are that the −$387 difference between the accumulated provision for depreciation and the CAD at the start of 1977 is amortized over the remaining life of the property, and the accumulated provision for depreciation, after the final retirement, is $0.

How does the remaining life method of adjustment allocate the $387 deficit? Table 5.27 shows that the CFA, at the start of 1977, is $1000 for unit A and $3750 for unit B, for a total of $4750, and that the remaining lives are 1 and 5 years respectively. Unit A accounts for 1000/4750 or 21% of the total while unit B accounts for 3750/4750 or 79%. The method of calculating the composite rate shown in Table 5.27 prorates the $387 deficit so that 21% or 0.21 × $387 or $82 is added to the future accrual of unit A and 79% or 0.79 × $387 or $305 is added to the future accrual of unit B. The $82 is amortized over the remaining life of 1 year, so that the 1977 accrual includes ($1000 + $82)/1 or $1082 for unit A. The $305 is amortized over the remaining life of 5 years, so that the 1977 accrual includes 750 + $305/5 or $811 for unit B. The total 1977 accrual is then $1082 + $811 or $1893. The annual accruals from 1978 through 1981 include the $750 and a $305/5 or $61 adjustment.

GROUP DEPRECIATION SYSTEMS WITH SALVAGE

The preceding discussion of systems of depreciation of a vintage group of property assumed there was no salvage (i.e., the net salvage was zero). These systems can be modified to include salvage so that the annual accruals are a function of the estimates of both life and salvage. In this section the term *salvage* will always refer to salvage used in the accrual rate, which is the net salvage (i.e., the gross salvage less the cost of retiring). An important concept is that a depreciation system should consider the change in salvage as the property ages.

Aged Salvage

Examine the salvage schedule shown in Table 5.31 (see end of chapter) as it will be used in the examples that follow. The salvage ratios of units A and B are 30% and 10% respectively so the salvage is 0.30 × $4000 or $1200 for unit A and 0.10 × $6000 or $600 for unit B. The average salvage ratio (ASR) is (1200 + 600)/10000 or 18%. Column (b) shows the age at the start of the year and reminds us that the salvage ratio changes with age. The term *aged salvage* is used to express this concept. Column (c) is the survivor curve and column (e) shows the salvage ratio for each year in which the plant is retired. Column (f) is the salvage ratio times the retirement frequency. The salvage ratio during the fourth year is 30% and the retirement frequency is 4000/10000 or 0.40, yielding a weighted ratio of 30% × 0.40 or 12% to show that salvage during that year equals 12% of the original investment. The sum of column (f), 18%, is the total salvage expressed as a percentage of the initial cost and is called the average salvage ratio (ASR). The product of the average salvage ratio and the original cost equals the total salvage dollars for the vintage group. Column (g) is the total salvage to that time divided by the total retirements to that time and equals the (average) realized salvage ratio[5] at that age. At age 4, the total salvage realized thus far is $1200 and retirements have totaled $4000; the ratio 1200/4000 yields the realized salvage ratio of 30%. Column (h) is the total salvage remaining to be collected divided by plant remaining to be retired and equals the (average) future salvage ratio. At age 4, the remaining salvage is $600 and the plant remaining to be retired is the $6000 plant in service; the ratio 600/6000 yields the future salvage ratio of 10%. Column (i) is the average salvage ratio. It is the sum of the product of the realized salvage ratio, column (g), times the percent of the plant that has been retired, plus the product of the future salvage ratio, column (h), times the percent of the plant in service. At age 5, 40% of the plant has been retired with a realized salvage ratio of 30%, while 60% remains in service with a future salvage ratio of 10%; the average salvage ratio is 30% × 0.4 + 10% × 0.6 or 18%. Though the realized and future salvage ratios vary with time, the average salvage ratio for the salvage schedule is constant.

It is important to remember that the future salvage ratio changes with the age of the plant. At the time of the initial installation, the future salvage ratio and the average salvage ratio are both 18%. But after unit A is retired,

the future salvage depends only on the remaining plant in service, unit B, and that salvage ratio is 10%. A positive salvage was used in the example, but negative salvage could have been selected just as easily. This schedule also reflects salvage that decreases with age, but an example where salvage increases with age could have been used.

The Average Life Procedure Applied to a Vintage Group

Calculation of the Annual Accrual

When applying the SL-AL system of calculating annual accruals, the rate 1/AL is applied to the plant in service to recover the initial investment. Only the original cost less salvage, or 1 − ASR, may be recovered through annual accruals. In our example the original cost is $10,000 and the ASR is 18%, so $10000 × 1.00 − 0.18 or $8200 is recovered through annual accruals and the remaining 18% or $1800 is recovered as salvage at the time of the retirement.

In the section that assumed no salvage, it was shown that original cost = Σ (average plant in service during age interval j)/AL, when summed over j = 0,1,2, . . ., ML. The equation below shows both sides multiplied by the fraction of the original cost to be recovered, (1 − ASR), so that the rate, on the righthand side, will now be (1 − ASR)/AL. The total accruals, the lefthand side, will be the original cost times (1 − ASR), which equals the capital consumed. This shows that application of the rate (1 − ASR)/AL will fully recover the original cost less the salvage.

(original cost)(1 − ASR) = Σ (average plant in service during age interval j)(1 − ASR)/AL when summed over j = 0,1,2, . . ., ML

Table 5.32 (see end of chapter) shows the result of applying this rate to the example used in the previous section to obtain the annual accruals.

The accumulated provision for depreciation is $2325 after the first retirement. The accumulated provision for depreciation at the start of the previous year, $3844, is increased by the annual accrual of $1281, decreased by the $4000 original cost, and increased by the $1200 salvage to yield the accumulated provision for depreciation of $2325 at the start of 1978.

Note that any other salvage schedule with an average salvage ratio of 18% will yield the same annual rate and result in the same annual accruals shown in Table 5.32. However, the accumulated provision for depreciation will vary from Table 5.32 because the timing of the salvage between the two schedules will differ. If, for example, the salvage ratio is 18% for *both* units (so that the average salvage remains at 18%), the annual accruals will remain at $1281 for the first 4 years and $769 for the last 4 years. But, the accumulated provision for depreciation at the start of 1978 will equal $3844 + $1281 − $4000 × (1.00 − 0.18) or $1845 rather than $2325. This difference would continue until the final retirement, when the accumulated provision for depreciation becomes zero.

Modifying the annual accrual rate (1/AL) by the factor (1 − ASR) is an extension of the average life procedure to include salvage. The factor (1 − ASR) in the accrual rate is a constant used throughout the life of the property regardless of the actual salvage ratio at each age. All units are treated as though their salvage ratio was equal to the average salvage ratio even though the actual salvage for that year is, depending on the salvage schedule, above or below the average.

Effect of Error in the Estimate of Average Salvage

If the estimate of average salvage is wrong, then the total accruals will not equal the capital consumed. Suppose the estimate of average salvage is $0; then $10,000 rather than $8200 is recovered and the accumulated provision for depreciation will equal $1800 after the final retirement. Or suppose the original estimate is a salvage ratio of 40% for unit A and 15% for unit B, resulting in an average salvage ratio of [(40% × 4000) + (15% × 6000)]/10000 or 25%, as shown in Table 5.33 (see end of chapter).

If a correct life estimate of 6.4 years is assumed, the resulting rate using this schedule is (100% − 25%)/6.4 or 11.719%. Table 5.34 (see end of chapter) shows that the total accruals will equal only $7500, leaving $7500 − $8200 or −$700 in the accumulated provision for depreciation after the final retirement because an ASR of 25% rather than 18% was used.

An Adjustment Problem—The AL Procedure

Assume that our initial estimate of the salvage schedule is that shown in Table 5.33 and that the annual accruals for 1974 through 1977 were based on the 11.719% rate. Now suppose that in January 1978, because of events and activities occurring since 1974, the original salvage forecast of 25% average salvage is revised to 18% as shown in the salvage schedule in Table 5.31, which will turn out to be a correct estimate. Table 5.35 (see end of chapter) shows the accumulated provision for depreciation at the start of 1978 is $1888 and presents the problem of adjusting the future accruals in light of the revised forecast.

When you use either the amortization (AM) or remaining life (RL) method of adjustment, the distinction between the average salvage and future salvage plays an important role in the calculation of the adjustment to the accumulated provision for depreciation. Since both the CAD and remaining life calculations are based on future events, they require estimates of future, rather than average, salvage. Though at age zero the average and future salvage ratios are equal, the difference between these two

averages typically increases as the property ages.

Amortization Method of Adjustment **(SL-AL-AM)**

The underlying relationship used to develop the CAD when there was no salvage was CAD = future retirements − future accruals. Future salvage will affect the future value of the accumulated provision for depreciation. The relationship should be modified to read CAD = future retirements − future gross salvage + future cost of retiring − future accrual, or CAD = future retirements − future net salvage − future accrual. This shows that positive future salvage reduces the required accumulated provision for depreciation, because a portion of the original cost is recovered through salvage. Future retirements equal the current balance, the future salvage can be expressed as the future salvage ratio times the current balance, and the straight line rate (1 − ASR)/AL is used to calculate future accruals so that

CAD(i) = B(i) − B(i)[(FSR(i)] − [(1 − ASR)/AL] Σ (average balance during year j) when summed over j from year i to final year of retirement

where B(i) = balance at age i (i.e., the current balance)
CAD(i) = calculated accumulated depreciation at age i
CADR(i) = calculated accumulated depreciation ratio at age i, CAD(i)/B(i)
FSR(i) = future salvage ratio at age i
RL(i) = remaining life at age i
AL = average life

The term Σ (average balance during year j)/B(i) has been shown to equal the remaining life, RL(i), so RL(i) × B(i) = Σ (average balance during year i). Making this substitution and dividing both sides of the equation by B(i) yields the equation CADR(i) = [1 − FSR(i)] − (1 − ASR)[RL(i)/AL]. The first term is the fraction of the plant in service to be recovered and the second is the future accruals expressed as a fraction of the plant in service. Another form of this equation is CADR(i) = (1 − ASR)[1 − RL(i)/AL] + ASR − FSR(i). This form emphasizes the sensitivity of the CADR(i) to the difference between the average and future salvage. If the average and future salvages are equal, or if they are assumed to be equal, the above equation reduces to CADR(i) = (1 − ASR) − (1 − ASR)[RL(i)/AL] = (1 − ASR)[1 − RL(i)/AL].

Table 5.36 (see end of chapter) shows the CAD for the example problem when the salvage schedule shown in Table 5.31 is used. Column (e) is 1 − FSR(i), which represents the percentage of the current plant in service that must be recovered through annual accruals. Initially this is 82%, but

after the first retirement it changes to reflect the fact that 90% of plant now in service must be recovered via depreciation. Column (f) is the straight line rate (100% − 18%)/6.4 or 12.81%. Column (g) is the remaining life, which was obtained from Table 5.8. These factors are combined using the equation [1 − FSR(i)] − (1 − ASR)[RL(i)/AL] to compute the calculated accumulated depreciation ratios shown in column (h). At the end of 1978, the remaining life is 4 years and the future salvage ratio is 10%. If the first form of the equation for the CADR(4)—note that at this time both the age and the remaining life happen to be 4 years—is used, the calculation is (1 − 0.10) − (1 − 0.18)(4/6.4) or 38.75%. If the second form is used, the calculation is (1 − 0.18)(1 − 4/6.4) + (0.18 − 0.10), which also equals 38.75%. Finally, the CADR(4) is multiplied by the current balance, B(4), to obtain the CAD(4), which is shown in column (i).

AN AMORTIZATION SOLUTION TO THE AL ADJUSTMENT PROBLEM. A comparison of the CAD shown in Table 5.36 with the accumulated provision for depreciation shown in Table 5.35 shows that at the start of 1978 the plant is underaccrued by $2325 − $1888 or $437. With the amortization method of adjustment, this deficit is amortized over a period recommended by the depreciation professional. Suppose it was decided to amortize the deficit over the remaining 4 years of life, or $437/4 or $109 each year. The results are shown in Table 5.37 (see end of chapter).

Remaining Life Method of Adjustment **(SL-AL-RL)**

The remaining life method of adjustment requires an estimate of future salvage to calculate the future accrual. When the salvage is not zero, the future accrual (i.e., the total amount remaining to be recovered) equals the current balance less the *future* salvage less the accumulated provision for depreciation. As before, the annual accrual is the future accrual divided by the remaining life or

AARL(i) = [B(i) − FS(i) − APD(i)]/RL(i)
= B(i)[1 − FSR(i) − APDR(i)]/RL(i)

where: B(i) = balance at age i
FS(i) = future salvage at age i
FSR(i) = future salvage ratio at age i
APD(i) = the accumulated provision for depreciation at age i
APDR(i) = the ratio APD(i)/B(i)
RL(i) = remaining life at age i
AARL(i) = the annual accrual at age i using the RL method of adjustment

When there is no salvage, the annual accrual resulting from use of the RL method of adjustment equals the annual accrual resulting from use of the AM method of adjustment if the variation between the CAD and the accumulated provision for depreciation is zero or if the variation is amortized over the remaining life. This is also true when the salvage is not zero and can be proven using the arguments presented in the preceding section. Remember both methods of adjustment require use of the future salvage; the RL method requires it to calculate the future accrual and the amortization method requires it to calculate the CAD.

Table 5.38 (see end of chapter) shows the remaining life calculations for the example problem; the future accrual, column (d), is calculated by subtracting the future salvage and the accumulated provision for depreciation from the balance. At the start of 1978 this calculation is \$6000 − \$600 − \$2325 or \$3075. Because the variation between the CAD and the accumulated provision for depreciation is zero, the annual accruals equal those calculated using the SL-AL method and shown in Table 5.32.

Table 5.39 (see end of chapter) shows the remaining life calculations when the salvage schedule shown in Table 5.33 is used as a forecast. Because the salvage forecast is incorrect, the original cost is not fully recovered. When using the remaining life method of adjustment, the actual salvage for unit A, \$1200, was reflected in the accumulated provision for depreciation at the start of 1978. The difference between the actual and forecast salvage for unit A, (0.40 − 0.30) × \$4000 or \$400, was amortized over the remaining four years, accounting for the \$100 a year difference between annual accruals shown in Table 5.34 and those shown in Table 5.39 during the years 1978 to 1981. Because the final salvage is misestimated by \$300, total accruals in Table 5.39 are \$300 less than the required \$8200.

A REMAINING LIFE SOLUTION TO THE AL ADJUSTMENT PROBLEM. Now return to the problem presented in Table 5.35 and use the revised forecast of future salvage to calculate annual accruals starting in 1978. The remaining life calculations will amortize the \$437 deficit over the remaining 4 years. The 1978 annual accrual of \$878 shown in Table 5.40 (see end of chapter) is composed of a \$769 accrual and a \$437/4 or \$109 adjustment. The annual adjustment for the next year is the variation, which is now \$437 − \$109, divided by the remaining life of 3 years, which again yields an adjustment of (\$437 − \$109)/3 or \$109. In the same manner the adjustments for the next 2 years can each be shown to be \$109. Table 5.37 shows the results of using the amortization method of adjustment to distribute the \$437 variation over 4 years. The annual accruals for both methods of adjustment are the same (see Tables 5.37 and 5.40) because the 4-year amortization period chosen for the AM method of adjustment equals the remaining life (4 years).

The Equal Life Group Procedure Applied to a Vintage Group

Calculation of the Annual Accrual

A previous section illustrated the division of the survivor curve shown in Figure 5.1 into ELGs, each of which had zero salvage and were depreciated as a unit using the annual rate of 1/AL. When salvage is not zero, the annual rate (1 − ASR)/AL is applied to each ELG. The average salvage ratio (ASR) and the average life (AL) both refer to a specific ELG rather than to the average of the vintage group. Table 5.41 (see end of chapter) shows the calculation of annual accrual rates using the SL-ELG system of calculating annual accruals. The rate of (100% − 30%)/4 or 17.5% is applied to unit A and results in annual accruals of \$700 for 4 years; the rate of (100% − 10%)/8 or 11.25% applied to unit B results in annual accruals of \$625 for 8 years. The ELG rate for the vintage group is 13.75% for the first 4 years and 11.25% for the final 4 years.

Table 5.42 (see end of chapter) shows the application of the rates developed in Table 5.41 to obtain the annual accruals and the accumulated provision for depreciation.

Now compare the accruals using the ELG procedure with those obtained using the AL procedure and shown in Table 5.32. The ELG procedure again results in higher annual accruals early in life and lower accruals later in life. The ELG procedure with zero salvage was shown to yield the same accruals that would result if each equal life group was depreciated as an individual unit, so that each unit is fully depreciated at the time of its retirement. The same principle applies with nonzero salvage; each equal life group is assigned the salvage ratio associated with that particular group, thus assuring that the dollars in each ELG will be fully depreciated at retirement. In contrast, the AL procedure uses the average salvage ratio in the accrual rate. The salvage ratio during any year may be above or below the average ratio used in the accrual rate. Retirements with a large salvage ratio are averaged with those with a small ratio so that the depreciation for a particular retirement is averaged over the life of the vintage group.

Table 5.33 is a schedule with an average salvage ratio of 25% and was used to show the results of misestimating salvage when using the AL procedure. Table 5.43 (see end of chapter) shows the ELG rates that result from using that same salvage schedule.

The higher average salvage ratio yields lower accrual rates. When these rates are applied, as shown in Table 5.44, the original cost is not fully recovered. After the final retirement the accumulated provision for depreciation is −\$700, which is the difference between the actual salvage of \$1600 and forecast salvage of \$2500. This is the same deficit that resulted when using the AL procedure (see Table 5.34). In both procedures, the depreciable base was underestimated by \$700, so the total annual accruals were \$700

less than required to fully recover the original cost.

An Adjustment Problem—ELG Procedure

Again suppose that the rates shown in Table 5.43 are used from 1974 through 1977. Then in January 1978, the original salvage ratio estimate of 40% for unit A and 15% for unit B is revised to 30% for unit A and 10% for unit B. Table 5.45 (see end of chapter) shows the current accumulated provision for depreciation at the start of 1978 is $2150. The future accrual must be adjusted to ensure recovery of the $8200 of capital used to provide service during the years 1974 to 1982.

Both the amortization (AM) and remaining life (RL) methods of adjustment used with the ELG procedure and with no salvage were discussed in a previous section. That discussion will now be extended to include salvage.

Amortization Method of Adjustment (SL-ELG-AM)

The first step when using the amortization method of adjustment is to calculate the current value of the CAD as shown in Table 5.46 (see end of chapter). Unit A has a life of 4 years and a salvage of 30% so that (1.00 − 0.30) × $4000 or $2800 must be recovered through the annual accruals. The first row shows the accumulated provision for depreciation for unit A at the start of years 1, 2, 3, and 4. At the start of year 5, the sum of the previous accruals equals the original cost less salvage ($2800), so the retirement of unit A reduces the CAD to zero. In a similar manner, the (1.00 − 0.10) × $6000 or $5400 depreciable cost associated with unit B is recovered over 8 years as shown in the second row. The annual CAD is the sum of the CAD over all ELGs, 2 in this case, and the calculated accumulated depreciation ratio is, by definition, the CAD/plant in service.

The CAD at age 4 is $2700, but the accumulated provision for depreciation at the start of 1977 and shown in Table 5.45 is $2150, which results in a variation of $550. The depreciation professional must decide if this is a significant variation and, if so, how an adjustment should be made.

Note that at the start of 1978 unit A has been retired and is no longer an element in the calculation of the CAD. Any estimates relating to the age or salvage of unit A do not affect the calculation of the CAD from 1978 on. In general, equal life groups that have been retired do not affect the CAD. When calculating the CAD for a system using the ELG procedure, future, rather than past or average, estimates of life and salvage are needed.

AN AMORTIZATION SOLUTION TO THE ELG ADJUSTMENT PROBLEM. At the start of 1978 only unit B remains in service and the estimate of its life remains at 8 years, while its salvage ratio is now estimated to be 10% rather than 15%. Even if the annual accrual rate is immediately revised to 11.25% (see Table 5.41) to reflect this change in the salvage forecast, the existing deficit of $550 will remain in the accumulated provision for depreciation. By amortizing this variation over 3 years, $550/3 or $183 per year will be added to the annual accruals during the next 3 years, as shown in Table 5.47 (see end of chapter).

Remaining Life Method of Adjustment (SL-ELG-RL)

The remaining life method of adjustment requires the future salvage and the life of each ELG to calculate the annual accrual. Each ELG has a single life and a single salvage, so the average and future salvage for each ELG are the same. Table 5.48 (see end of chapter) shows the calculation of the annual accruals for each ELG using the salvage schedule shown in Table 5.31. The future accrual equals the plant in service less the future salvage less the accumulated provision for depreciation and must be calculated for each ELG remaining in service. The initial value of the future accrual for unit A is (1.00 − 0.30) × $4000 or $2800, the remaining life is 4 years, and the annual accrual is $700. For unit B the future accrual is (1.00 − 0.10) × $6000 or $5400, the remaining life is 8 years, and the annual accrual is $675.

The future accrual and the annual accrual for each ELG are combined in the bottom portion of the table to obtain the totals shown in columns (d) and (f). The annual accrual rate shown in column (e) of Table 5.48 was obtained by dividing the annual accrual shown in column (f) by the future accrual shown in column (d) (i.e., the annual accruals were calculated first and then divided by the future accrual to find the annual rate). As mentioned previously, the reciprocal of the rate is called the composite remaining life.

The annual rate also can be calculated using the weighted average referred to in the discussion of depreciation systems with no salvage. Calculation of this average when there is salvage requires calculating the weighted average of the remaining life times (1 − ASR). In 1976, both units A and B are in service and their remaining lives are 2 and 6 years respectively, while their salvage ratios are 30% and 10% respectively. The numerator of the weight for A is the balance over the average life, $4000/4 years, and this weight is independent of salvage. The numerator of the weight for B is $6000/8. The composite remaining life is {[$4000 × (1 − 0.30)/4] × 2 + [$6000 × (1 − 0.10)/8] × 6} divided by the sum of the weights, [$4000 × (1 − 0.30)/4 + $6000 × (1 − 0.10)/8] or [($700 × 2) + ($675 × 6)]/$1375 or 3.964 or 25.229%, which agrees with the rate shown in Table 5.48.

ALLOCATION OF THE VARIATION. In the section on depreciation systems with no salvage, we discussed the calculation of annual accruals when there is a variation between the CAD and the accumulated provision for

depreciation. That discussion will now be expanded to include salvage.

In the section with no salvage we assumed a $1000 variation and then calculated the 1976 accrual. We will now repeat that calculation with salvage. Assume the accumulated provision for depreciation at start of 1976 is $1750 (i.e., from Table 5.46 we see the CAD at the start of 1976 is $2750, the variation is $2750 − $1750 or $1000). First allocate the variation in proportion to the CAD as shown below. Column (e) uses the percentages in column (d) to allocate the $1750 accumulated provision for depreciation to units A and B. The future accrual, column (f), is obtained by subtracting the accumulated provision for depreciation and the salvage ($1200 and $600 for units A and B respectively) from the balance, column (b). Dividing the future accrual by the remaining life yields the annual accrual for each ELG, column (h). The accruals total $1712. This results in a composite rate of $1712/$6450 or 26.54% and a composite remaining life of 3.77 years.

Unit (a)	Bal (b)	CAD (c)	% CAD (d)	Accum depr (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	1400	50.91	891	1909	2	955
B	6000	1350	49.09	859	4541	6	757
		2750		1750	6450		1712

Now consider the same circumstances but make the allocation in proportion to the calculated future accrual, as shown in the following calculations. For unit A the calculated future accrual (CFA), column (d), is the balance less the CAD less the salvage or $4000 − $1400 − $1200 or $1400. Column (f) is obtained by first calculating the total future accrual, which is $10000 − ($1200 + $600) − $1750 or $6450; this amount is then prorated to units A and B using the percentages shown in column (e). Totaling the accruals for each ELG yields $1627 and a composite rate of $1627/$6450 or 25.229% and a composite remaining life of 3.96 years. This is the same as the composite rate when the variation is zero (see Table 5.48).

Unit (a)	Bal (b)	CAD (c)	CFA (d)	% CFA (e)	Future accrual (f)	RL (g)	Accrual (h)
A	4000	1400	1400	25.69	1657	2	829
B	6000	1350	4050	74.31	4793	6	798
			5450		6450		1627

Now the composite rates shown in Table 5.48 are applied to the example problem and the results are shown in Table 5.49 (see end of chapter). At

the start of 1979, the estimated future salvage is $600, so the future accrual is $6000 − $600 − $3375 or $2025, and applying the composite annual remaining life rate of 33.33% results in an annual accrual of $675. Because the life and salvage estimates used in Table 5.48 were correct, no adjustments are required and the remaining life accruals are equal those obtained using the SL-ELG system of calculating annual accruals and shown in Table 5.42.

Table 5.50 (see end of chapter) shows the calculation of the composite annual rates when the estimated salvage ratios are 40% and 15% for units A and B respectively. The balance to be depreciated for unit A is (1.00 − 0.40) × $4000 or $2400; the balance for unit B is (1.00 − 0.15) × $6000 or $5100. Composite rates are shown in the bottom portion of the table. Note that the rates during ages 5 through 8 are identical with those in Table 5.48 although the salvage ratios differ. To explain this, remember that the composite rate is the sum of the balance less salvage divided by the annual accrual. During the final 4 years of the example problem, only one ELG survives. The numerator and the denominator of the composite rate both contain the factor (1 − ASR); these cancel, so in this example the composite rates for the final 4 years are independent of the salvage ratios.

Table 5.51 (see end of chapter) shows application of these rates to the example problem. Future salvage ratio estimates of 25% from 1974 to 1977 and 15% from 1978 to 1981 are used to calculate the future accrual. As with the SL-AL-RL system (see Table 5.39), the misestimation of future salvage results in an under-accrual of $300.

A REMAINING LIFE SOLUTION TO THE ADJUSTMENT PROBLEM. Return to the ELG adjustment problem presented in Table 5.45. When the 1978 forecast of future salvage is changed from 15% to 10% and the depreciation process is carried forward, the entire $8200 is, as shown in Table 5.52 (see end of chapter), fully recovered.

A COMMENT. Hypothetical examples of survivor curves and salvage schedules have been used to show basic concepts of depreciation. Be careful when making generalizations based on these examples. The only generalization that can be drawn from the preceding examples is that incorrect forecasts can result in improper capital recovery. The magnitude and direction of the error depends on the particular example. Estimates of life can be too short or too long and the shape of the curve can vary while keeping the average life constant. The shape of the curve determines the remaining life and therefore affects the CAD calculations and the remaining life rates. The salvage ratio can be positive or negative, though only positive salvage was used in the preceding examples. When considering aged salvage, the ratios can increase or decrease with age, and the consequences of using average

rather than aged salvage depend on the pattern of the salvage. Any generalizations concerning the variation between the calculated accumulated depreciation and the accumulated provision for depreciation because of errors in estimation of parameters should carefully state the assumptions made.

Use of Average, Rather than Aged, Salvage

Salvage is sometimes viewed as though it remains constant as the property ages, as opposed to the more realistic view that the salvage varies with age. The former view equates average and future salvage, while the latter view recognizes that the salvage ratio may change each year and that it is necessary to estimate the salvage schedule. This section will examine the results of not recognizing that salvage varies with age by illustrating the use of the average salvage ratio rather than a salvage schedule.

The Average Life Procedure

The average life procedure requires estimates of future salvage to assure proper adjustments. When using the amortization method of adjustment, the future salvage enters the CAD calculation; when using the remaining life method of adjustment, the future salvage is needed to calculate the future accrual.

First consider the amortization method of adjustment. The CAD equation CADR(i) = (1 − ASR)[1 − RL(i)/AL] + ASR − FSR(i) reduces to CADR(i) = (1 − ASR)[1 − RL(i)/AL] when the future salvage ratio, FSR(i), is set equal to the average salvage ratio, ASR. The annual values of the CAD using the second equation are shown in Table 5.53 (see end of chapter), and these values should be compared to those in Table 5.36, which were calculated using the correct future salvage. Though the CAD starts and ends at zero in both tables, there is a significant difference between the two after the first retirement. In Table 5.53 the calculations for the CAD at the start of year 5 anticipate a salvage ratio of 18%, which is \$4000 × 0.18 or \$720 for unit A, rather than the actual salvage of \$1200. This difference of \$1200 − \$720 or \$480 equals the difference between the CAD at the start of year 5 in the two tables.

If the CAD shown in Table 5.53 is used as a guide in analyzing the problem posed in Table 5.35, the variation between the calculated accumulated depreciation and the accumulated provision for depreciation is \$1845 − \$1888 or −\$43. This suggests that the future accrual should be *reduced* by a total of \$43. The potential \$437 deficit is concealed by the failure of the depreciation professional to forecast the salvage schedule. The salvage of the final retirement is estimated to be \$6000 × 0.18 or \$1080 rather than the actual \$600, and this difference of \$480 is the difference between the CAD calculated using the salvage schedule and the CAD calculated using

the average salvage during the final 4 years.

The net impact of not distinguishing between average and future salvage depends on the amount of the change in salvage ratios as the account matures. Forecasters may tend to associate realized salvage with average salvage, thus presupposing that future salvage ratios will be close to those observed early in the life of the vintage. The result may be a poor forecast of the average salvage ratio used in the accrual rate.

Results of using the average salvage rather than the future salvage with the remaining life method of adjustment are shown in Table 5.54 (see end of chapter). The annual accruals during the first 4 years are the same as in Table 5.38 (which uses the correct value of future salvage), because the future and average salvage are equal until the time of the first retirement. During the remaining 4 years, the system assumes that only 82% of the plant in service must be recovered. Actually 90% is needed, so a deficit of (82% − 90%) × \$6000 or −\$480 results.

When using the AL procedure and either method of adjustment, accurate estimates of the salvage schedule are needed to fully recover invested capital in a timely manner. Use of the average, rather than aged salvage, will result in incorrect estimates of the CAD and may result in accruals that do not equal the capital consumed.

The Equal Life Group Procedure

The equal life group procedure requires the salvage ratio for each life group in order to calculate the annual accrual. The future salvage is the weighted average of all ELGs remaining in service. Table 5.55 (see end of chapter) shows the calculation of annual accrual rates using the 18% average salvage ratio for both ELGs. Unit A is assigned a rate of (100% − 18%)/4 or 20.5% and unit B a rate of (100% − 18%)/8 or 10.25%.

Table 5.56 (see end of chapter) shows the application of these rates. Note that the accruals total \$8200, as they should, but the timing of the accruals differs from those shown in Table 5.42, which use the correct aged salvage. Because the first retirement had a higher than average salvage ratio, the total annual accruals generated by unit A, 4 × \$820 or \$3280, are \$480 greater than the \$4000 − \$1200 or \$2800 to be depreciated, while the total annual accruals for unit B, 8 × \$615 or \$4920, are \$480 less than the \$6000 − \$600 or \$5400 to be depreciated. The fact that the two differences cancel each other is not coincidence, but the result of using the average salvage ratio.

In this example, use of the average salvage resulted in higher early rates than would have resulted if the salvage schedule had been used. If the salvage schedule had reflected salvage ratios that increased with age, the early rates would have been lower than those resulting from using the average.

Use of the average salvage rather than the aged salvage associated with

each ELG results in the use of the AL procedure for the salvage portion of the annual accrual rate. This combination of the ELG procedure for life and the AL procedure for salvage fully recovers the initial investment less salvage, but it partially negates the major attribute of the ELG procedure. Use of the average salvage in the ELG accrual rate will not match the annual depreciation charges with the consumption of capital. When the ELG procedure is used with a salvage schedule, the units comprising the ELG are fully accrued at the time of their retirement. This is not true if the average salvage is used. The magnitude of the difference in timing resulting from using the average salvage rather than the salvage schedule depends on two factors. First, if the salvage ratio is zero or near zero, then the difference is also zero or near zero. Second, if the salvage ratio is constant, or nearly constant, the annual retirement ratios will be close to the average salvage ratio and the difference will be small. These two factors interact to determine the magnitude of the difference.

Suppose the average salvage ratio of 18%, rather than the aged salvage, had been applied to each ELG when calculating the CAD. The resulting CADs and CADRs are shown in Table 5.57 (see end of chapter).

The CAD at the start of 1978 calculated using the average salvage is $2460 as compared to the CAD of $2700 obtained using the salvage schedule. If the average salvage is used, the variation between the CAD and the accumulated provision for depreciation of $2150 shown in Table 5.45 would be $310 rather than the correct value of $550. If the adjustment was based on the CAD calculated using the average salvage, a deficit of $240 would result. This shows that when the salvage varies with age, use of the average salvage with the ELG procedure will affect the accuracy of the CAD.

Now examine the effects of using the average salvage rather than the aged salvage when the remaining life method of adjustment is used. Table 5.58 at the end of the chapter (which is constructed in the same manner as Table 5.48) shows the calculation of the composite rates using average salvage. The balances for both units A and B are calculated by multiplying the initial cost by (100% − 18%) or 82%, yielding balances of $3280 and $4920 respectively.

Table 5.59 (see end of chapter) shows the results of using average rather than aged salvage with the remaining life method of adjustment. Note that the total accruals were $480 less than necessary to recover the $8200 of capital consumed. After the first retirement, the system expected a future salvage of 0.18 × $6000 or $1080 and accruals were based on that assumption. When only $600 was received, a deficit in accumulated provision for depreciation of $480 resulted.

SUMMARY

The two preceding sections discussed depreciation systems for group property. All the systems discussed applied the straight line method of allocation to a vintage group. First it was assumed that there was no salvage, and then the consideration of salvage was added.

Two procedures for applying the straight line method of depreciation were used. The average life procedure treats each member of the group as though it will have a life and salvage equal to the group average. Though we know that each member of the group will not behave as the average member, our assumption works because the variation between members brings us back to the average. The equal life group procedure statistically divides the vintage group into smaller, equal life groups so that each member of the equal life group will have the same life and salvage. Each equal life group is then depreciated as a unit using the life and salvage associated with the ELG. This yields two systems of calculating annual accruals, the SL-AL system and the SL-ELG system.

These systems are incomplete until a method of control is included in the system. There are two methods of creating a closed loop feedback system. One method is labeled the amortization (AM) method of adjustment. This term describes a system in which the calculated accumulated depreciation (CAD) is used as a measure against which the (book) accumulated provision for depreciation is compared. The depreciation analyst uses this feedback as a guide in determining the necessary adjustment to the annual accruals or, if necessary, to the accumulated provision for depreciation. The remaining life (RL) method of adjustment automatically amortizes the variation between the CAD and the accumulated provision for depreciation over the remaining life of the property.

Combining both methods of allocation with both methods of adjustment yields four depreciation systems. Two use the average life procedure, SL-AL-AM and SL-AL-RL, and two use the equal life group procedure, SL-ELG-AM and SL-ELG-RL. Because the methods of allocation for purpose of book depreciation are almost exclusively limited to the straight line method, these four choices represent the systems available for the depreciation of a vintage group.

Table 5.1. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the straight line method of allocation. The unit has a life of 4 years and a 20% salvage ratio.

Year	Balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		20.0	$800	$0	$0	$800
1975	4000		20.0	800	800	0	800
1976	4000		20.0	800	1600	0	800
1977	4000	$4000	20.0	800	2400	4000	1600
1978	0				0		
				$3200		$4000	$4000

Table 5.2. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the sum-of-years-digits (accelerated) method of allocation. The unit has a life of 4 years and a 20% salvage ratio.

Year	Balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		32.0	$1280	$0	$0	$1280
1975	4000		24.0	960	1280	0	960
1976	4000		16.0	640	2240	0	640
1977	4000	$4000	8.0	320	2880	$4000	1120
1978	0				0		
				$3200		$4000	$4000

Table 5.3. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the declining balanbe (accelerated) method of allocation. The unit has a life of 4 years and a 20% salvage ratio. The rate is 1.5/4 or 37.5%.

Year	Declining balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		37.5	$1500	$0	$0	$1500
1975	2500		37.5	938	1500	0	938
1976	1562		37.5	586	2438	0	586
1977	976	$4000	*	176	3024	4000	976
1978	0				0		
				$3200		4000	$4000

* Switch to straight line rate. This yields a final accrual of $176.

Table 5.4. Calculation of the annual accruals and the accumulated provision for depreciation for a unit of property using the sinking fund (decelerated) method of allocation with i=10%. The unit has a life of 4 years and a 20% salvage ratio.

Year	Balance Jan 1	Retired	Rate%	Annual accrual	* Accumulated depreciation * Net Jan 1	Debit	Credit
1974	$4000		17.24	$690	$0	$0	$690
1975	4000		18.96	758	690	0	758
1976	4000		20.86	834	1448	0	834
1977	4000	$4000	22.95	918	2282	4000	1718
1978	0				0		
				$3200		4000	$4000

Table 5.5. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system and a rate of 1/6.4 or 15.625%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		15.625	$1563	$0
1975	10000		15.625	1563	1563
1976	10000		15.625	1563	3125
1977	10000	$4000	15.625	1563	4688
1978	6000		15.625	938	2250
1979	6000		15.625	938	3188
1980	6000		15.625	938	4125
1981	6000	6000	15.625	938	5063
1982	0				0

Table 5.6. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system and a rate of 1/7.4 or 13.514%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		13.514	$1351	$0
1975	10000		13.514	1351	1351
1976	10000		13.514	1351	2703
1977	10000	$4000	13.514	1351	4054
1978	6000		13.514	811	1405
1979	6000		13.514	811	2216
1980	6000		13.514	811	3027
1981	6000	6000	13.514	811	3838
1982	0				-1351

Table 5.7. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system. A rate of 1/7.4 or 13.514% was used during the first three years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		13.514	$1351	$0
A	1975	10000		13.514	1351	1351
S	1976	10000		13.514	1351	2703
T						4054
F	1977	0000	$4000			
U	1978	6000				
T	1979	6000				
U	1980	6000				
R	1981	6000	6000			
E	1982	0				

Table 5.8. Calculation of the CAD for the survivor curve shown in Figure 5.1.

Year (a)	Age (b)	Balance (c)	Service in $-yrs (d)	Remaining life (e)	CADR (f)	CAD (g)
1974	0	$10000	64000	6.40	.0000	$0
1975	1	10000	54000	5.40	.1563	1563
1976	2	10000	44000	4.40	.3125	3125
1977	3	10000	34000	3.40	.4688	4688
1978	4	6000	24000	4.00	.3750	2250
1979	5	6000	18000	3.00	.5313	3188
1980	6	6000	12000	2.00	.6875	4125
1981	7	6000	6000	1.00	.8438	5063
1982	8	0	0		1.0000	0

Table 5.9. Application of the amortization method of adjustment to the problem presented in Table 5.7. The $634 deficit is amortized over two years and the rate is increased to 15.63%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		13.51	$1351	$0
1975	10000		13.51	1351	1351
1976	10000		13.51	1351	2702
1977	10000	$4000	15.63	1880*	4054
1978	6000		15.63	1255**	1933
1979	6000		15.63	938	3187
1980	6000		15.63	938	4125
1981	6000	6000	15.63	938	5062
1982	0				0

* Includes a $1563 annual accrual plus a $317 adjustment.

** Includes a $938 annual accrual plus a $317 adjustment.

Table 5.10. Calculation of the remaining life and the rate for the survivor curve shown in Figure 5.1.

Year (a)	Age (b)	Balance (c)	Retired (d)	Remaining service $-yrs (e)	Remaining life (f)	Rate % 1/RL (g)
1974	0	$10000		$64000	6.40	15.63
1975	1	10000		54000	5.40	18.52
1976	2	10000		44000	4.40	22.73
1977	3	10000	$4000	34000	3.40	29.41
1978	4	6000		24000	4.00	25.00
1979	5	6000		18000	3.00	33.33
1980	6	6000		12000	2.00	50.00
1981	7	6000	6000	6000	1.00	100.00
1982	8	0				

Table 5.11. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system of depreciation and the accrual rates shown in Table 5.10.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	15.625	$1563	$0
1975	10000		8438	18.519	1563	1563
1976	10000		6875	22.727	1563	3125
1977	10000	$4000	5313	29.412	1563	4688
1978	6000		3750	25.000	938	2250
1979	6000		2813	33.333	938	3188
1980	6000		1875	50.000	938	4125
1981	6000	6000	938	100.000	938	5063
1982	0					0

Table 5.12. Remaining life of a survivor curve in which $4000 is retired after 5 years and $6000 after 7.33 years, resulting in an average life of 6.4 years.

Year (a)	Age (b)	Balance (b)	Retired (c)	Remaining service $-yrs (e)	Remaining life (f)	Rate % (g)
1974	0	$10000		$64000	6.40	15.63
1975	1	10000		54000	5.40	18.52
1976	2	10000		44000	4.40	22.73
1977	3	10000		34000	3.40	29.41
1978	4	10000	$4000	24000	2.40	41.67
1979	5	6000		14000	2.33	42.86
1980	6	6000		8000	1.33	75.00
1981	7	6000	6000	2000*	1.00*	100.00
1982	8	0				

* $6000 is retired 1/3 of the way through the final year so the average balance during 1981 is $2000 and the remaining life at the start of the year is 1.00 year.

Table 5.13. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system and accrual rates developed in Table 5.12.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	15.625	$1563	$0
1975	10000		8438	18.519	1563	1563
1976	10000		6875	22.727	1563	3125
1977	10000	$4000	5313	29.412	1563	4688
1978	6000		3750	41.667	1563	2250
1979	6000		2188	42.857	938	3813
1980	6000		1250	75.000	938	4750
1981	6000	6000	313	100.000	313	5688
1982	0					0

Table 5.14. Remaining life for a survivor curve in which $4000 is retired after 1 year and $6000 after 10 years, resulting in an average life of 6.4 years.

Year (a)	Age (b)	Balance (c)	Retired (d)	Remaining service $-yrs (e)	Remaining life (f)	Rate % (g)
1974	0	$10000	$4000	$64000	6.40	15.63
1975	1	6000		54000	9.00	11.11
1976	2	6000		48000	8.00	12.50
1977	3	6000		42000	7.00	14.29
1978	4	6000		36000	6.00	16.67
1979	5	6000		30000	5.00	20.00
1980	6	6000		24000	4.00	25.00
1981	7	6000		18000	3.00	33.33
1982	8	6000		12000	2.00	50.00
1983	9	6000	6000	6000	1.00	100.00
1984	10	0				

Table 5.15. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system and accrual rates developed in Table 5.14.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	15.625	$1563	$0
1975	10000		8438	11.111	938	1563
1976	10000		7500	12.500	938	2500
1977	10000	$4000	6563	14.286	938	3438
1978	6000		5625	16.667	938	375
1979	6000		4688	20.000	938	1313
1980	6000		3750	25.000	938	2250
1981	6000	6000	2813	33.333	938	3188
1982	0			50.000		-1875
1983				100.000		

Table 5.16. Remaining life for a survivor curve in which $4000 is retired after 4 years, $6000 after 9.67 years, with an average life of 7.4 years.

Year (a)	Age (b)	Balance (b)	Retired (c)	Remaining service $-yrs (e)	Remaining life (f)	Rate % (g)
1974	0	$10000		$74000	7.40	13.51
1975	1	10000		64000	6.40	15.63
1976	2	10000		54000	5.40	18.52
1977	3	10000	$4000	44000	4.40	22.73
1978	4	6000		34000	5.67	17.65
1979	5	6000		28000	4.67	21.43
1980	6	6000		22000	3.67	27.27
1981	7	6000		16000	2.67	37.50
1982	8	6000		10000	1.67	60.00
1983	9	6000*	6000	$4000*	1.00*	100.00
1984	10	0				

* $6000 is retired two-thirds of the way through the final year, so the average balance during 1983 is $4000 and the remaining life is 1.00 year.

Table 5.17. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system and accrual rates developed in Table 5.16.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	13.514	$1351	$0
1975	10000		8649	15.625	1351	1351
1976	10000		7297	18.519	1351	2703
1977	10000	$4000	5946	22.727	1351	4054
1978	6000		4595	17.647	811	1405
1979	6000		3784	21.429	811	2216
1980	6000		2973	27.273	811	3027
1981	6000	6000	2162	37.500	811	3838
1982	0			60.000		-1351
1983				100.000		

Table 5.18. Application of the remaining life method of adjustment to the problem presented in Table 5.7.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate% 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	13.514	$1351	$0
1975	10000		8649	15.625	1351	1351
1976	10000		7297	18.519	1351	2703
1977	10000	$4000	5946	29.410*	1749	4054
1978	6000		4197	25.000*	1049	1803
1979	6000		3148	33.333*	1049	2852
1980	6000		2099	50.000*	1049	3901
1981	6000	6000	1049	100.000*	1049	4951
1982	0					0

* Accrual rates from Table 5.10.

Table 5.19. Calculation of the annual accrual rates for the survivor curve shown in Figure 5.1 using the SL-ELG system.

Group (a)	Group amount (b)	Group life (c)	Group rate % (d)	Annual accrual 1974-77 (e)	Annual accrual 1978-81 (f)
A	$4000	4	25.00	$1000.00	
B	6000	8	12.50	$750.00	$750.00
Annual accruals				$1750.00	$750.00
Balance during interval				$10000	$6000
Annual accrual rate %				17.50	12.50

Table 5.20. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system using the rates calculated in Table 5.19.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		17.50	$1750	$0
1975	10000		17.50	1750	1750
1976	10000		17.50	1750	3500
1977	10000	$4000	17.50	1750	5250
1978	6000		12.50	750	3000
1979	6000		12.50	750	3750
1980	6000		12.50	750	4500
1981	6000	6000	12.50	750	5250
1982	0				0

Table 5.21. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system and the accrual rates calculated in Table 5.19. The survivor curve for the property is shown in Table 5.14.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000	$4000	17.50	$1750	$0
1975	6000		17.50	1050	-2250
1976	6000		17.50	1050	-1200
1977	6000		17.50	1050	-150
1978	6000		12.50	750	900
1979	6000		12.50	750	1650
1980	6000		12.50	750	2400
1981	6000		12.50	750	3150
1982	6000		12.50	750	3900
1983	6000	6000	12.50	750	4650
1984	0				-600

Table 5.22. Calculation of the annual accrual rates for the survivor curve shown in Table 5.16 using the SL-ELG system.

Group (a)	Group amount (b)	Group life (c)	Group rate % (d)	Annual accrual 1974-78 (e)	Annual accrual 1979-81 (f)
A	$4000	4	25.00	$1000.00	
B	6000	9.67	10.34	620.69	$620.69
Annual accruals				$1621.00	$621.00
Balance during interval				$10000	$6000
Annual accrual rate %				16.21	10.34

Table 5.23. Calculation of annual accruals and accumulated depreciation using the SL-ELG system and the accrual rates calculated in Table 5.22.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		16.21	$1621	$0
1975	10000		16.21	1621	1621
1976	10000		16.21	1621	3242
1977	10000	$4000	16.21	1621	4863
1978	6000		10.34	620	2484
1979	6000		10.34	620	3104
1980	6000		10.34	620	3725
1981	6000	6000	10.34	620	4345
1982	0				-1034

Table 5.24. Calculation of annual accruals and accumcumulated depreciation using the SL-ELG system. The accrual rates shown in Table 5.22 are used for the first three years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		16.21	$1621	$0
A	1975	10000		16.21	1621	1621
S	1976	10000		16.21	1621	3242
T						4863
F	1977	10000	$4000			
U	1978	6000				
T	1979	6000				
U	1980	6000				
R	1981	6000	6000			
E	1982	0				

Table 5.25. Calculation of the calculated accumulated depreciation and the calculated accumulated depreciation ratios for the survivor curve shown in Figure 5.1.

		CAD At Start of Year								
Life	Amount	1	2	3	4	5	6	7	8	9
4	4000	0	1000	2000	3000	0				
8	6000	0	750	1500	2250	3000	3750	4500	5250	0
Annual CAD		0	1750	3500	5250	3000	3750	4500	5250	0
Start of year balance		10000	10000	10000	10000	6000	6000	6000	6000	0
CADR		.000	.1750	.3500	.5250	.5000	.6250	.7500	.8750	1.000

Table 5.26. Application of the amortization method of adjustment to the problem presented in Table 5.24. The $387 deficit is amortized over a 1-year period and the accrual rates are changed to those shown in Table 5.19.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		16.21	$1621	$0
1975	10000		16.21	1621	1621
1976	10000		16.21	1621	3242
1977	10000	$4000	17.50	2137*	4863
1978	6000		12.50	750	3000
1979	6000		12.50	750	3750
1980	6000		12.50	750	4500
1981	6000	6000	12.50	750	5250
1982	0				0

* Includes a $1750 accrual and a $387 adjustment.

Table 5.27. Calculation of the annual accruals and accumulated provision for depreciation using the SL-ELG-RL system of depreciation and the survivor curve shown in Figure 5.1.

Accruals by ELG

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$4000	25.000	$1000	$0
1975	4000		3000	33.333	1000	1000
1976	4000		2000	50.000	1000	2000
1977	4000	$4000	1000	100.000	1000	3000
						0
Unit B						
1974	$6000		$6000	12.500	$750	$0
1975	6000		5250	14.286	750	750
1976	6000		4500	16.667	750	1500
1977	6000		3750	20.000	750	2250
1978	6000		3000	25.000	750	3000
1979	6000		2250	33.333	750	3750
1980	6000		1500	50.000	750	4500
1981	6000	$6000	750	100.000	750	5250
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	17.50	$1750	$0
1975	10000		8250	21.21	1750	1750
1976	10000		6500	26.92	1750	3500
1977	10000	$4000	4750	36.84	1750	5250
1978	6000		3000	25.00	750	3000
1979	6000		2250	33.33	750	3750
1980	6000		1500	50.00	750	4500
1981	6000	6000	750	100.00	750	5250
1982	0					0

Table 5.28. Calculation of the composite annual accrual rates using the SL-ELG-RL system of depreciation and the survivor curve shown in Table 5.16.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$4000	25.000	$1000	$0
1975	4000		3000	33.333	1000	1000
1976	4000		2000	50.000	1000	2000
1977	4000	$4000	1000	100.000	1000	3000
						0
Unit B						
1974	$6000		$6000	10.341	$620	$0
1975	6000		5380	11.534	620	620
1976	6000		4759	13.037	620	1240
1977	6000		4139	14.992	620	1860
1978	6000		3518	17.637	620	2480
1979	6000		2898	21.413	620	3100
1980	6000		2277	27.248	620	3720
1981	6000		1657	37.453	620	4340
1982	6000		1036	59.880	620	4960
1982	6000	$6000	416	100.000	416	5580
1983	0					0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$10000	16.205	$1621
1975	10000		8379	19.339	1621
1976	10000		6758	23.975	1621
1977	10000	$4000	5137	31.536	1621
1978	6000		3516	17.637	620
1979	6000		2816	21.413	620
1980	6000		2276	27.248	620
1981	6000		1656	37.453	620
1982	6000	6000	1036	59.880	620
1983	0		416	100.000	416

Table 5.29. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-ELG-RL system of depreciation and the accrual rates shown in Table 5.28.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	16.205	$1621	$0
1975	10000		8379	19.339	1621	1621
1976	10000		6758	23.975	1621	3242
1977	10000	$4000	5137	31.536	1621	4863
1978	6000		3516	17.637	620	2484
1979	6000		2896	21.413	620	3104
1980	6000		2276	27.248	620	3724
1981	6000	6000	1656	37.453	620	4344
1982	0			59.880		-1034
1983				100.000		

Table 5.30. Application of the remaining life method of adjustment to the problem presented in Table 5.24.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$10000	16.205	$1621	$0
1975	10000		8379	19.339	1621	1621
1976	10000		6758	23.975	1621	3242
1977	10000	$4000	5137	36.842*	1893	4863
1978	6000		3244	25.000*	811	2756
1979	6000		2433	33.333*	811	3567
1980	6000		1622	50.000*	811	4378
1981	6000	6000	811	100.000*	811	5189
1982	0					0

* Accrual rates from Table 5.27.

Table 5.31. The salvage schedule for the survivor curve shown in Figure 5.1 and having an average salvage ratio of 18%.

Year (a)	Age (b)	Balance (c)	Retired (d)	SR % (e)	% of orig cost (f)	Realized salvage ratio % (g)	Future salvage ratio % (h)	Average salvage ratio % (i)
1974	0	$10000				.00	18.00	18.00
1975	1	10000				.00	18.00	18.00
1976	2	10000				.00	18.00	18.00
1977	3	10000	$4000*	30.00	12.00	.00	18.00	18.00
1978	4	6000				30.00	10.00	18.00
1979	5	6000				30.00	10.00	18.00
1980	6	6000				30.00	10.00	18.00
1981	7	6000	6000*	10.00	6.00	30.00	10.00	18.00
1982	8	0				18.00		18.00
					18.00			

* Salvage for these units is $1200 and $600 respectively.

Table 5.32. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system and a rate of (100%-18%)/6.4 or 12.813%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		12.813	$1281	$0
1975	10000		12.813	1281	1281
1976	10000		12.813	1281	2563
1977	10000	$4000*	12.813	1281	3844
1978	6000		12.813	769	**2325
1979	6000		12.813	769	3094
1980	6000		12.813	769	3863
1981	6000	6000*	12.813	769	4631
1982	0				***0

* Salvage for these units is $1200 and $600 respectively.

** 2325 = 3844 + 1281 - 4000 + 1200

*** 0 = 4631 + 769 - 6000 + 600

Table 5.33. Salvage schedule for survivor curve shown in Figure 5.1 and having an average salvage ratio of 25%.

Year (a)	Age (b)	Balance (c)	Retired (d)	SR % (e)	% of orig cost (f)	Realized salvage ratio % (g)	Future salvage ratio % (h)	Average salvage ratio % (i)
1974	1	$10000				.00	25.00	25.00
1975	2	10000				.00	25.00	25.00
1976	3	10000				.00	25.00	25.00
1977	4	10000	$4000*	40.00	16.00	.00	25.00	25.00
1978	5	6000				40.00	15.00	25.00
1979	6	6000				40.00	15.00	25.00
1980	7	6000				40.00	15.00	25.00
1981	8	6000	6000*	15.00	9.00	40.00	15.00	25.00
1982	9	0				25.00		25.00
					25.00			

* Salvage for these units is $1600 and $900 respectively.

Table 5.34. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system using a rate of (100%-25%)/6.4 or 11.719%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		11.719	$1172	$0
1975	10000		11.719	1172	1172
1976	10000		11.719	1172	2344
1977	10000	$4000*	11.719	1172	3516
1978	6000		11.719	703	1888
1979	6000		11.719	703	2591
1980	6000		11.719	703	3294
1981	6000	6000*	11.719	703	3997
1982	0				-700

* Salvage for these units is $1200 and $600 respectively.

Table 5.35. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL system. A rate of (100%-25%)/6.4 or 11.719% was used during the first four years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		11.719	$1172	$0
A	1975	10000		11.719	1172	1172
S	1976	10000		11.719	1172	2344
T	1977	10000	$4000*	11.719	1172	3516
						1888
F	1978	6000				
U	1979	6000				
T	1980	6000				
U	1981	6000	6000			
R	1982	0				
E						

* Salvage for this unit is $1200.

Table 5.36. Calculation of the CAD for the SL-AL system using the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.31.

Year (a)	Age (b)	Balance (c)	Retired (d)	1-FSR (e)	Rate % (f)	RL (g)	CADR (h)	CAD (i)
1974	0	$10000		82.00	12.81	6.40	.00	$0
1975	1	10000		82.00	12.81	5.40	12.81	1281
1976	2	10000		82.00	12.81	4.40	25.63	2563
1977	3	10000	$4000*	82.00	12.81	3.40	38.44	3844
1978	4	6000		90.00	12.81	4.00	38.75	2325
1979	5	6000		90.00	12.81	3.00	51.56	3094
1980	6	6000		90.00	12.81	2.00	64.38	3863
1981	7	6000	6000*	90.00	12.81	1.00	77.19	4631
1982	8	0						0

* Salvage for these units is $1200 and $600 respectively.

Table 5.37. Application of the amortization method of adjustment to the problem presented in Table 5.35. The $437 deficit is amortized over 4 years and the rate is increased to 12.813%.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		11.719	$1172	$0
1975	10000		11.719	1172	1172
1976	10000		11.719	1172	2344
1977	10000	$4000*	11.719	1172	3516
1978	6000		12.813	878**	1888
1979	6000		12.813	878**	2766
1980	6000		12.813	878**	3644
1981	6000	6000*	12.813	878**	4522
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

** Includes a $769 accrual and a $109 adjustment.

Table 5.38. Calculation of the annual accruals and the accumulated provision for depreciation using the SL-AL-RL system of depreciation. The rates are shown in Table 5.10 and the future salvage is shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	15.625	$1281	$0
1975	10000		6919	18.519	1281	1281
1976	10000		5638	22.727	1281	2563
1977	10000	$4000*	4356	29.412	1281	3844
1978	6000		3075	25.000	769	2325
1979	6000		2306	33.333	769	3094
1980	6000		1538	50.000	769	3863
1981	6000	6000*	769	100.000	769	4631
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

Table 5.39. Calculation of the annual accrual and the accumulated provision for depreciation using the SL-AL-RL system of depreciation with the rates shown in Table 5.10 and the salvage schedule shown in Table 5.33.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	15.625	$1172	$0
1975	10000		6328	18.519	1172	1172
1976	10000		5156	22.727	1172	2344
1977	10000	$4000*	3984	29.412	1172	3516
1978	6000		3213	25.000	803	1888
1979	6000		2409	33.333	803	2691
1980	6000		1606	50.000	803	3494
1981	6000	6000*	803	100.000	803	4297
1982	0					-300

* Salvage for these units is $1200 and $600 respectively.

Table 5.40. Application of the SL-AL-RL system of depreciation to the problem presented in Table 5.35.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	15.625	$1172	$0
1975	10000		6328	18.519	1172	1172
1976	10000		5156	22.727	1172	2344
1977	10000	$4000*	3984	29.412	1172	3516
1978	6000		3513**	25.000	878	1888
1979	6000		2634**	33.333	878	2766
1980	6000		1756**	50.000	878	3644
1981	6000	6000*	878**	100.000	878	4522
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

** A future salvage of 10% ratio is used.

Table 5.41. Calculation of the annual rates for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.31 using the SL-ELG system of calculating annual accruals.

Group (a)	Group amount (b)	Group life (c)	Group salvage % (d)	Group rate % (e)	Annual accrual 1974-77 (f)	Annual accrual 1978-81 (g)
A	$4000	4	30.00	17.50	$700.00	
B	6000	8	10.00	11.25	675.00	$675.00
Annual accruals					$1375.00	$675.00
Balance during interval					$10000	$6000
Annual accrual rate %					13.75	11.25

Table 5.42. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system of calculating annual accruals and the rates shown in Table 5.41.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		13.750	$1375	$0
1975	10000		13.750	1375	1375
1976	10000		13.750	1375	2750
1977	10000	$4000*	13.750	1375	4125
1978	6000		11.250	675	2700
1979	6000		11.250	675	3375
1980	6000		11.250	675	4050
1981	6000	6000*	11.250	675	4725
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

Table 5.43. Calculation of the annual rates for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.33 using the SL-ELG system.

Group (a)	Group amount (b)	Group life (c)	Group salvage % (d)	Group rate % (e)	Annual accrual 1974-77 (f)	Annual accrual 1978-81 (g)
A	$4000	4	40.00	15.00	$600.00	
B	6000	8	15.00	10.63	638.00	$638.00
Annual accruals					$1238.00	$638.00
Balance during interval					$10000	$6000
Annual accrual rate %					12.38	10.63

Table 5.44. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system and the rates shown in Table 5.43.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		12.375	$1238	$0
1975	10000		12.375	1238	1238
1976	10000		12.375	1238	2475
1977	10000	$4000*	12.375	1238	3713
1978	6000		10.625	638	2150
1979	6000		10.625	638	2788
1980	6000		10.625	638	3425
1981	6000	6000*	10.625	638	4063
1982	0				-700

* Salvage for these units is $1200 and $600 respectively.

Table 5.45. Calculation of annual accruals and accumulated provision for depreciation using the SL-ELG system. Rates shown in Table 5.43 were used during the first 4 years.

	Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
P	1974	$10000		12.375	$1238	$0
A	1975	10000		12.375	1238	1238
S	1976	10000		12.375	1238	2475
T	1977	10000	$4000*	12.375	1238	3713
						2150
F	1978	6000				
U	1979	6000				
T	1980	6000				
U	1981	6000	6000			
R	1982	0				
E						

* Salvage for this unit is $1200.

Table 5.46. Calculation of the calculated accumulated depreciation and the calculated accumulated depreciation ratios for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.31.

		CAD at start of year								
Life	Amount	1	2	3	4	5	6	7	8	9
4	2800	0	700	1400	2100	0				
8	5400	0	675	1350	2025	2700	3375	4050	4725	0
Annual CAD		0	1375	2750	4125	2700	3375	4050	4725	0
Start of year balance		10000	10000	10000	10000	6000	6000	6000	6000	0
CADR		.000	.1375	.2750	.4125	.4500	.5625	.6750	.7875	1.000

Table 5.47. Application of the amortization method of adjustment to the problem presented in Table 5.45. The $550 variation is amortized over a 3-year period and rates are changed to those shown in Table 5.41.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		12.375	$1238	$0
1975	10000		12.375	1238	1238
1976	10000		12.375	1238	2475
1977	10000	$4000*	12.375	1238	3713
1978	6000		11.250	858**	2150
1979	6000		11.250	858**	3008
1980	6000		11.250	858**	3867
1981	6000	6000*	11.250	675	4725
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

** Includes $675 annual accrual and $183 adjustment.

Table 5.48. Calculation of the composite annual accrual rates using the SL-ELG-RL system of depreciation, the survivor curve shown in Figure 5.1, and the future salvage shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$2800	25.000	$700	$0
1975	4000		2100	33.333	700	700
1976	4000		1400	50.000	700	1400
1977	4000	$4000	700	100.000	700	2100
						0
Unit B						
1974	$6000		$5400	12.500	$675	$0
1975	6000		4725	14.286	675	675
1976	6000		4050	16.667	675	1350
1977	6000		3375	20.000	675	2025
1978	6000		2700	25.000	675	2700
1979	6000		2025	33.333	675	3375
1980	6000		1350	50.000	675	4050
1981	6000	$6000	675	100.000	675	4725
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$8200	16.768	$1375
1975	10000		6825	20.147	1375
1976	10000		5450	25.229	1375
1977	10000	$4000*	4075	33.742	1375
1978	6000		2700	25.000	675
1979	6000		2025	33.333	675
1980	6000		1350	50.000	675
1981	6000	6000*	675	100.000	675
1982	0				

* Salvage for these units is $1200 and $600 respectively.

Table 5.49. Calculation of the annual accruals and accumulated provision for depreciation using the SL-ELG-RL system of depreciation and the rates shown in Table 5.48 and the future salvage shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	16.768	$1375	$0
1975	10000		6825	20.147	1375	1375
1976	10000		5450	25.229	1375	2750
1977	10000	$4000*	4075	33.742	1375	4125
1978	6000		2700	25.000	675	2700
1979	6000		2025	33.333	675	3375
1980	6000		1350	50.000	675	4050
1981	6000	6000*	675	100.000	675	4725
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

Table 5.50. Calculation of the composite rates for the survivor curve shown in Figure 5.1 and the salvage schedule shown in Table 5.33.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$2400	25.000	$600	$0
1975	4000		1800	33.333	600	600
1976	4000		1200	50.000	600	1200
1977	4000	$4000	600	100.000	600	1800
						0
Unit B						
1974	$6000		$5100	12.500	$638	$0
1975	6000		4463	14.286	638	638
1976	6000		3825	16.667	638	1275
1977	6000		3188	20.000	638	1913
1978	6000		2550	25.000	638	2550
1979	6000		1913	33.333	638	3188
1980	6000		1275	50.000	638	3825
1981	6000	$6000	638	100.000	638	4463
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$7500	16.500	$1238
1975	10000		6263	19.760	1238
1976	10000		5025	24.627	1238
1977	10000	$4000	3788	32.673	1238
1978	6000		2550	25.000	638
1979	6000		1913	33.333	638
1980	6000		1275	50.000	638
1981	6000	6000	638	100.000	638
1982	0				

Table 5.51. Calculation of annual accruals and accumulated provision for depreciation using the SL-AL-RL system of depreciation with the rates shown in Table 5.50 and future salvage shown in Table 5.33.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	16.500	$1238	$0
1975	10000		6263	19.760	1238	1238
1976	10000		5025	24.627	1238	2475
1977	10000	$4000*	3788	32.673	1238	3713
1978	6000		2950	25.000	738	2150
1979	6000		2213	33.333	738	2888
1980	6000		1475	50.000	738	3625
1981	6000	6000*	738	100.000	738	4363
1982	0					-300

* Salvage for these units is $1200 and $600 respectively.

Table 5.52. Application of the SL-ELG-RL depreciation system to the problem presented in Table 5.45.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$7500	16.500	$1238	$0
1975	10000		6263	19.760	1238	1238
1976	10000		5025	24.627	1238	2475
1977	10000	$4000*	3788	32.673	1238	3713
1978	6000		3250**	25.000***	813	2150
1979	6000		2438**	33.333***	813	2963
1980	6000		1625**	50.000***	813	3775
1981	6000	6000*	813**	100.000***	813	4588
1982	0					0

* Salvage for these units is $1200 and $600 respectively.

** A future salvage of 10% is used.

*** Accrual rates from Table 5.48.

Table 5.53. Calculation of CAD for the SL-AL system using the survivor curve shown in Figure 5.1 and a future and average salvage ratio of 18%.

Year (a)	Age (b)	Balance (c)	Retired (d)	1-ASR (e)	RL (f)	CADR (g)	CAD (h)
1974	0	$10000		82.00	6.40	00.00	$0
1975	1	10000		82.00	5.40	12.81	1281
1976	2	10000		82.00	4.40	25.63	2563
1977	3	10000	$4000*	82.00	3.40	38.44	3844
1978	4	6000		82.00	4.00	30.75	1845
1979	5	6000		82.00	3.00	43.56	2614
1980	6	6000		82.00	2.00	56.38	3383
1981	7	6000	6000*	82.00	1.00	69.19	4151
1982	8	0					0

* Salvage for these units is $1200 and $600 respectively.

Table 5.54. Application of the SL-AL-RL system of depreciation using the average salvage ratio of 18% rather than the future salvage ratio.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	15.625	$1281	$0
1975	10000		6919	18.519	1281	1281
1976	10000		5638	22.727	1281	2563
1977	10000	$4000*	4356	29.412	1281	3844
1978	6000		2595	25.000	649	2325
1979	6000		1946	33.333	649	2974
1980	6000		1298	50.000	649	3623
1981	6000	6000*	649	100.000	649	4271
1982	0					-480

* Salvage for these units is $1200 and $600 respectively.

Table 5.55. Calculation of the annual accrual rates for the survivor curve shown in Figure 5.1 and an average salvage ratio of 18% using the SL-ELG system of calculating annual accruals.

Group (a)	Group amount (b)	Group life (c)	Group salvage % (d)	Group rate % (e)	Annual accrual 1974-77 (f)	Annual accrual 1978-81 (g)
A	$4000	4	18.00	20.50	$820.00	
B	6000	8	18.00	10.25	$615.00	$615.00
Annual accruals					$1435.00	$615.00
Balance during interval					$10000	$6000
Annual accrual rate %					14.35	10.25

Table 5.56. Calculation of annual accrual rates and accumulated provision for depreciation using the SL-ELG system with rates based on average salvage and shown in Table 5.55.

Year (a)	Balance (b)	Retired (c)	Rate % (d)	Annual accrual (e)	Accum depr (f)
1974	$10000		14.350	$1435	$0
1975	10000		14.350	1435	1435
1976	10000		14.350	1435	2870
1977	10000	$4000*	14.350	1435	4305
1978	6000		10.250	615	2940
1979	6000		10.250	615	3555
1980	6000		10.250	615	4170
1981	6000	6000*	10.250	615	4785
1982	0				0

* Salvage for these units is $1200 and $600 respectively.

Table 5.57. Calculation of the calculated accumulated depreciation and calculated accumulated depreciation ratios using the SL-ELG-AM depreciation and an average salvage ratio of 18% for all ELGs.

		CAD at start of year								
Life	Amount	1	2	3	4	5	6	7	8	9
4	3280	0	820	1640	2460	0				
8	4920	0	615	1230	1845	2460	3075	3690	4305	0
Annual CAD		0	1435	2870	4305	2460	3075	3690	4305	0
Start of year balance		10000	10000	10000	10000	6000	6000	6000	6000	0
CADR		.000	.1445	.2870	.4305	.4100	.5125	.6150	.7175	1.000

Table 5.58. Calculation of composite rates using the survivor curve shown in Figure 5.1 and letting the salvage ratio for all retirements equal the average salvage ratio of 18%.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
Unit A						
1974	$4000		$3280	25.000	$820	$0
1975	4000		2460	33.333	820	820
1976	4000		1640	50.000	820	1640
1977	4000	$4000	820	100.000	820	2460
						0
Unit B						
1974	$6000		$4920	12.500	$615	$0
1975	6000		4305	14.286	615	615
1976	6000		3690	16.667	615	1230
1977	6000		3075	20.000	615	1845
1978	6000		2460	25.000	615	2460
1979	6000		1845	33.333	615	3075
1980	6000		1230	50.000	615	3690
1981	6000	$6000	615	100.000	615	4305
						0

Total accruals

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Composite rate % (e)	Annual accrual (f)
1974	$10000		$8200	17.500	$1435
1975	10000		6765	21.212	1435
1976	10000		5330	26.923	1435
1977	10000	$4000	3895	36.842	1435
1978	6000		2460	25.000	615
1979	6000		1845	33.333	615
1980	6000		1230	50.000	615
1981	6000	6000	615	100.000	615
1982	0				

Table 5.59. Application of the SL-AL-ELG-RL system of depreciation using the rates shown in Table 5.58 and a future salvage ratio of 18% rather than the future salvage shown in Table 5.31.

Year (a)	Balance (b)	Retired (c)	Future accrual (d)	Rate % 1/RL (e)	Annual accrual (f)	Accum depr (g)
1974	$10000		$8200	17.500	$1435	$0
1975	10000		6765	21.212	1435	1435
1976	10000		5330	26.923	1435	2870
1977	10000	$4000*	3895	36.842	1435	4305
1978	6000		1980	25.000	495	2940
1979	6000		1485	33.333	495	3435
1980	6000		990	50.000	495	3930
1981	6000	6000*	495	100.000	315	4425
1982	0					-480

* Salvage for these units is $1200 and $600 respectively.

NOTES

1. Gas (FERC), electric (FERC), and water companies (NARUC) use the title Accumulated Provision for Depreciation, while telecommunications (FCC) and railroads (ICC) use the title Accumulated Depreciation. Telecommunications used the title Depreciation Reserve until 1986. We will use the term *Accumulated Provision for Depreciation*. It refers to the net balance of either of these accounts.

2. The CADR is also called reserve ratio or the accrued ratio.

3. The balance, usually shown in column (b) of the tables at the end of this chapter, can be defined as the balance at the start of the year or the average balance during the year. The convention used in this chapter results in the start-of-year balance equaling the average balance. When other conventions are used, a small difference between the two annual accruals may result because the remaining life calculation typically applies the rate to the beginning-year balance while the amortization calculation typically applies the rate to the average balance during the year.

4. All of these variables except AL are a function of the age of the property, and a complete notation would include an index for the age. For example, rather than RL, use RL(i) = the remaining life at age i. The following calculations all refer to the same year so the index i is dropped.

5. Remember that both the realized and future salvage ratios are averages. Both the survivor curve and the salvage ratio at each age from zero to the maximum life are required to calculate these average ratios. For convenience, we will use the terms realized or future salvage ratio rather than *average* realized or *average* future salvage ratio.

6 Continuous Property Groups

CHAPTER 5 used elementary survivor curves, a single vintage group, and a simplified format to illustrate the calculation of the annual accrual for depreciation for several systems of depreciation. This chapter will use Iowa survivor curves and formats characteristic of those found in industrial practice to illustrate the application of these systems of depreciation to continuous property groups. The illustrations will include the use of both average salvage and salvage that varies with age.

A continuous property group[1] is created when vintage groups are combined to form a common group. Each year property is removed from service for many reasons and, at the same time, property may be added either to replace property that was retired or to increase service capacity. Over time the operating and physical characteristics of the property change, but the continuous property group continues as long as the service it provides is needed. If new vintages are no longer added, the continuous property group becomes closed, or bounded, and over time becomes smaller and finally vanishes. The continuous property group, which is usually recorded as a plant account or subaccount, is of interest because it represents the most common method of grouping assets for depreciation.

The method of allocation, the procedure for applying the method of allocation, and the method of adjustment (e.g., SL-AL-AM) specify the factors that define a depreciation system for a vintage group. The terms broad group and vintage group describe two ways of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group for purposes of depreciation. One approach is to view the continuous property group as a collection of vintage

TOPIC: **Secondary Sales**

REFERENCE: **2021 General Rate Application, Table 2.1, 2.2 and Section 2.2.4 and Section 2.3.1**

PREAMBLE: In Tables 2.1 and 2.2, YEC forecasts 0 for secondary sales related to Generation for 2021. On page 2-8 (PDF page 33 of 441), lines 9-14, YEC states:

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

On page 2-9 (PDF page 34 of 441) at line 19, YEC states "[a]ctual hydro generation is currently forecast to reflect water availability at about LTA in 2020, and water availability above LTA in 2021."

CW would like to understand the correlation between surplus water and secondary sales.

QUESTION:

a) Please provide an analysis that compares water levels and secondary sales for each of the last 10 years.

b) Please fully explain the relationship between water levels and secondary sales.

c) Please explain what YEC means by stating that 2021 water levels will be above LTA.

ANSWER:

(a)

Table 1 below provides a comparison of Whitehorse yearly inflows (percent of average) to secondary sales from 2011 to 2020.

Table 1: Summary of Secondary Sales vs Whitehorse Yearly Inflow

	Secondary Sales (KWh)	Whitehorse Yearly Inflow %
2011	552,300	93%
2012	1,992,620	103%
2013	3,959,400	114%
2014	5,414,580	110%
2015	7,030,020	110%
2016	4,835,100	105%
2017	8,385,030	99%
2018	257,955	97%
2019	480	94%
2020	173,841	97%

(b)

Secondary sales typically occur when Yukon Energy is spilling water at one of the hydro facilities and the facility is not operating at a 100% capacity factor. The relationship of secondary sales to water condition is that during higher water (inflows) periods there is a higher potential for spill, and therefore a higher potential for secondary sales. However, secondary sales also relate to the timing and volume of potential secondary sales loads – which tend to focus on winter heating time periods when the potential for spill is reduced.

(c)

Table 2.2 in the Application shows forecast ST 2021 hydro generation at 506.5 GWh, and shows LTA hydro generation for 2021 at the lower level of 452.4 GWh. The ST forecast reflects conditions in the fall of 2020, following high inflows to Aishihik and Mayo during the preceding summer that reversed the prior year's low water conditions.

As shown in prior years, water availability forecasts provided in the fall for the following year are subject to review in following spring and again during the following summer – and can display material changes as actual conditions unfold.