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November 5, 2024

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC)

Application for Approval of a Rate Setting Framework for 2025 through 2027 (Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 2

On April 8, 2024, FortisBC filed the Application referenced above. In accordance with the amended regulatory timetable established in BCUC Order G-255-24 for the review of the Application, FortisBC respectfully submits the attached response to BCUC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners.

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A. PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

45.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-4, BCUC IRs 7.1, 7.2, 7.6, and 7.9

Productivity Improvement Factor (X-Factor)

In response to BCUC IR 7.1, FortisBC stated that companies that have been more successful in realizing cost efficiencies in prior years have less potential to realize incremental cost savings going forward.

In response to BCUC IR 7.2, FortisBC stated that FEI is an “average cost performer” in the gas distribution industry supporting a 0.1 percent stretch factor for FEI’s proposed X-Factor and that FBC is a “superior cost performer” in the electricity distribution industry supporting a zero stretch factor for FBC’s proposed X-Factor.

45.1 Please explain why a 0.1 percent stretch factor differential is sufficient to reflect the differences between FEI as an “average cost performer” and FBC as a “superior cost performer”.

<u>Response:</u>

The following response was provided by Dr. Kaufmann:

As set out in Dr. Kaufmann’s Report in Appendix C1-1 of the Application, the proposed stretch factor differential between FEI and FBC is sufficient based on: (1) the BCUC’s stretch factor precedents; (2) the difficulty of achieving incremental cost savings in additional incentive regulation plans; and (3) assessments of the Companies’ cost performance. In particular, Dr. Kaufmann recommended a higher stretch factor for FEI primarily based on the empirical evidence showing that FBC has displayed superior cost performance while FEI has displayed average cost performance.

Dr. Kaufmann also notes the following three points supporting the sufficiency of the 0.1 percent stretch factor differential.

First, the 0.1 percent stretch factor differential between FEI and FBC is consistent with the 0.1 percent stretch factor differential approved by the BCUC for the 2014-2019 PBR Plans. While the BCUC did not explain the basis for this 0.1 percent differential, regulators generally approve lower stretch factors for relatively more cost-efficient utilities. It is therefore reasonable to infer that the 0.1 percent differential between the FEI and FBC stretch factors in the 2014-2019 PBR Plans reflected the BCUC's judgement that FBC's cost performance relative to its industry was superior to FEI's relative cost performance, consistent with Dr. Kaufmann's evidence. The BCUC decision on the 2014-2019 stretch factors therefore: (1) supports the reasonableness of the proposed stretch factors in its proposed Rate Framework; and (2) supports the view that the proposed 0.1 percent stretch factor differential reflects the difference in cost performance between FEI and FBC.

Second, the proposed 0.1 percent stretch factor differential is approximately double the implicit stretch factor differential in the Current MRPs. As discussed in Dr. Kaufmann's Report, the most reasonable estimates of FEI's and FBC's implicit, current stretch factors are approximately 0.1 percent and 0.05 percent, respectively. The most recently approved stretch factor differential between FEI and FBC is therefore approximately 0.05 percent. The proposed 0.1 percent stretch factor differential therefore is higher than the 0.05 percent implicit stretch factor differential approved by the BCUC for the Current MRPs. This higher proposed differential highlights the consistency of Dr. Kaufmann's assessment that an appropriate stretch factor difference between an average cost performer and superior cost performer should be set at 0.1 percent.

Third, the 0.1 percent stretch factor differential is sufficient given that Dr. Kaufmann's proposal to increase the stretch factor differential from 0.05 percent to 0.1 percent takes place within the context of the proposed Rate Framework, which will be the third consecutive application of incentive regulation for the Companies. The BCUC has found that it is increasingly difficult to achieve incremental cost efficiencies in subsequent applications of incentive regulation. All else equal, this trend tends to reduce approved stretch factors for all companies, regardless of their measured cost performance. Given this context, Dr. Kaufmann's proposal to increase the stretch factor differential from 0.05 percent to 0.1 percent demonstrates the weight that has been placed on the cost benchmarking evidence for FEI and FBC, which shows that FEI exhibits average cost performance and FBC exhibits superior cost performance. The increase in the proposed stretch factor differential therefore indicates that cost benchmarking evidence is playing an important role in the proposed Rate Framework, which in turn supports the reasonableness of each Company's stretch factor.

FortisBC further adds the following response:

Another consideration for assessing the sufficiency of the proposed stretch factor values for FBC and FEI and their differentials relates to the changes in the weighting of the stretch factor value in FEI's and FBC's overall recommended/approved X-Factor values over time.

	Company	Stretch Factor	X-factor Value	Stretch factor as a percentage of X-Factor
Proposed Rate Framework	FEI	0.10%	0.38%	26.3%
	FBC	0%	0.20%	0%
2020-2024 MRPs	FEI	0.1%	0.50%	20%
	FBC	0.05%	0.50%	10%
2014-2019 PBRs	FEI	0.20%	1.10%	18.2%
	FBC	0.10%	1.03%	9.7%

As shown in the table above, proportionally, FEI's proposed stretch factor in the proposed Rate Framework makes up more than 26 percent of the overall recommended X-Factor value (compared with FBC's weighting of zero percent), while weighting for FEI's 0.2 percent approved stretch factor in the PBR Plan was approximately 18 percent of the overall approved X-Factor (compared with FBC's weighting of approximately 10 percent). In other words, compared to the previous rate plans and despite the same 0.1 percent differential between FEI's and FBC's stretch factor, the significance/weighting of the stretch factor value for FEI, as an average cost performer, has increased, while the significance/weighting of the stretch factor value for FBC, as a superior cost performer, has decreased.

45.2 If the methodology used by Dr. Kaufmann to determine the X-Factors in the proposed Rate Framework was applied to the FortisBC 2020—2024 Multi-Year Rate Plan (Current MRP),[1] please estimate what FEI's and FBC's X-Factors would be, and to the extent possible, include a breakdown by partial factor productivity (PFP) and stretch factor for each of FEI and FBC.

<u>Response:</u>

The following response was provided by Dr. Kaufmann:

BCUC IR2 45.2 requests that Dr. Kaufmann access data from an earlier period of time and use these data to undertake analyses that are consistent with "the methodology used by Dr. Kaufmann to determine the X-Factors in the proposed Rate Framework applied to the FortisBC 2020—2024 Multi-Year Rate Plan." It should be recognized, however, that it may not be entirely possible to estimate what X-Factor values Dr. Kaufmann would have recommended if he had applied the

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[1] FortisBC Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024. The current multi-year plan was set by Decision and Orders G-165-20 and G-166-20 dated June 22, 2020 (Current MRP Decision).

same methodology for the Current MRPs as this type of hypothetical, counterfactual analysis is often constrained and/or otherwise impacted by the need to draw on more distant data for electric and gas utilities. The reasons for this include but are not limited to data reporting issues in prior years (incomplete or missing data for some companies) that are resolved in subsequent years and/or mergers and acquisitions that can distort reported data.[2]

With this in mind, Dr. Kaufmann has, to the extent possible, applied the methodology used to estimate the proposed X factors for FEI and FBC to the Company's Current MRPs. This analysis is presented below.

As set out below, Dr. Kaufmann has estimated FEI's O&M PFP growth over the 15-year period between 2004 and 2019, which is the most recent 15-year period before the Current MRP went into effect.[3] Dr. Kaufmann has also developed stretch factor recommendations for FEI and FBC informed by the BCUC's stretch factor precedents for the 2014-2019 PBR Plan, the BCUC's finding that it is increasingly difficult to find cost savings in new iterations of incentive regulation and a consideration of FEI and FBC costs.

Dr. Kaufmann also intended to estimate FBC's O&M PFP over the 2004-2019 period. However, the 2005 O&M expenditure data for the electricity distribution industry was anomalous and almost certainly incorrect. Measured O&M expenditures in 2005 grew by 12.41 percent from the previous 2004 value. This was a far greater rate of change than the industry norm for annual O&M expenditure growth, which averaged 3.39 percent over the 2002-2022 period, excluding 2005. The 2005 change in O&M expenditures did not impact Dr. Kaufmann's earlier O&M PFP estimate for the electricity distribution industry, since that sample period began in 2007 and did not include 2004-2005 data. Extending the sample period to 2004 thereby would have included an anomalous rate of change in O&M between 2004 and 2005. This anomaly would therefore have distorted the estimated, long-run trend in O&M PFP for the electricity distribution industry.

It is often appropriate to modify samples to exclude anomalous variables that distort measured, long-run productivity trends. To provide the BCUC with the most accurate and meaningful analysis of what productivity factors would have been estimated for the Companies if the proposed methodology was applied to the Current MRP, Dr. Kaufmann believes it is appropriate to modify the US electricity distribution industry sample slightly.

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[2] For example, reported data can be distorted by mergers and acquisitions, which lead to sudden spikes in a utility's customer numbers and/or costs. It is sometimes possible to correct for these developments by obtaining detailed data on the merged companies from other sources and allocating costs and customers appropriately across the pre-merged companies. However, this process is time-consuming and not always straightforward. It is also more difficult to control for mergers that happened many years ago rather than in the recent past.

[3] In this hypothetical scenario, it is possible to include all these years in the studies used to estimate O&M PFP growth. In practice, this is normally not possible, because it takes time for data to be reported, collected and published. For example, Dr. Kaufmann's 2024 report used data ending in 2022 to estimate O&M PFP growth rates because these were the most recent data that were available at the time the study was prepared. However, if more recent evidence on 2023 and 2024 had been available, these data would have been used when developing the productivity factor and stretch factor recommendations. Dr. Kaufmann has therefore used 2018-2019 data to calibrate the elements of the 2020-2024 MRP.

The modification is to use a 14-year, 2005-2019 sample period to estimate O&M PFP trends for FBC, rather than a 15-year, 2004-2019 sample. By moving the first year of the sample from 2004 to 2005, the analysis eliminates the 2004-2005 O&M rate of change outlier from the data used to estimate O&M PFP trends. Eliminating this anomaly will lead to a more accurate and meaningful estimate of long-run O&M PFP trends for the electricity distribution industry.

This adjustment applies only to FBC and not FEI. Using 14-year samples to estimate TFP trends has extensive precedent in North America incentive regulation. For example, the last five PBR plans approved in Massachusetts all used 14 years of industry data to estimate productivity trends. There is also typically little difference between 14-year and 15-year TFP trends, but the large O&M anomaly in this instance is the exception to the rule. If Dr. Kaufmann had faced this situation in his original evidence, he would have responded by using a 15-year sample period to estimate O&M PFP trends for FEI and a 14-year sample period to estimate O&M PFP trends for FBC. Dr. Kaufmann therefore adopts this approach for this response.

FEI Productivity Factor

For the purpose of estimating FEI's productivity factor for the Current MRP, Table 1 below provides the calculation of O&M PFP for the US gas distribution industry. The sample period for all calculations is 2004-2019.

Table 1: Gas Distribution O&M PFP Growth 2004-2019

Customer Growth [1]	Growth in O&M Spending [2]	Growth in Input Prices [3]	Growth in O&M Inputs [4]=[2]-[3]	Growth in O&M PFP [5]=[1]-[4]
0.73%	3.07%	2.53%	0.54%	0.19%

In the 2004-2019 study, the gas industry's customer numbers grew by 0.73 percent per annum. This is slightly above the gas industry's 0.67 percent customer growth in the 2007-2022 period. O&M spending grew by 3.07 percent per annum, while input prices grew by 2.53 percent per annum; both of these values were similar to the industry growth numbers Dr. Kaufmann measured for the 2007-2022 period.

The growth in O&M input quantity is equal to the growth in O&M expenditure minus the growth in O&M input prices. In the 2004-2019 study, this value was therefore equal to 3.07 percent minus 2.53 percent, or 0.54 percent. When this estimate of 0.54 percent O&M input quantity growth is subtracted from the 0.73 percent growth in customer numbers, it yields an estimate of O&M PFP growth of 0.19 percent. This value is nine basis points below the 0.28 percent industry productivity factor Dr. Kaufmann measured for the 2007-2022 period. Therefore, if the same methodology used to determine FEI's recommended productivity factor for the proposed Rate Framework had been applied to FEI's Current MRP, it would have yielded a recommendation of 0.19 percent.

FBC Productivity Factor

As discussed, for the purpose of estimating FBC's productivity factor for the Current MRP, Dr. Kaufmann calculated O&M PFP growth for the electricity distribution industry for the 2005-2019 period. These results are provided below.

Table 2: Electricity Distribution O&M PFP Growth 2005-2019

Customer Growth [1]	Growth in O&M Spending [2]	Growth in Input Prices [3]	Growth in O&M Inputs [4]=[2]-[3]	Growth in O&M PFP [5]=[1]-[4]
0.96%	3.22%	2.24%	0.99%	-0.02%

It can be seen from the table above that the industry's customer numbers grew by 0.96 percent per annum, slightly higher than the 0.91 percent industry customer growth estimated for the 2007-2022 period. O&M spending grew at an average rate of 3.22 percent, input prices grew by 2.24 percent per annum, and O&M quantity accordingly grew by 0.99 percent per annum over the 2005-2019 period. When this 0.99 percent O&M PFP quantity trend is subtracted from the 0.96 percent average industry customer growth, it yields an estimate of O&M PFP growth of negative 0.02 percent. Therefore, if the same methodology used to determine FBC's recommended productivity factor for the proposed Rate Framework had been applied to FBC's Current MRP, it would have yielded a recommendation of -0.02 percent, which is 22 basis points lower than Dr. Kaufmann's recommended 0.20 percent productivity factor for FBC's proposed Rate Framework.

FEI and FBC X Factors

As discussed in response to BCUC IR2 45.1, a careful examination of the BCUC's approved X factors for the Current MRP indicates that the implicit stretch factors for FEI and FBC were informed by assessments of the Companies' relative cost performance. The implicit stretch factors also incorporated the BCUC finding that it is increasingly difficult to identify incremental cost savings in further applications of incentive regulation plans. It is also evident that the BCUC findings in the 2020-2024 MRP Decision considered the BCUC's previous stretch factor determinations when determining appropriate stretch factors for the Companies' Current MRP. Dr. Kaufmann's recommended stretch factors were similarly informed by previous BCUC determinations, the increasing difficulty of achieving cost savings in additional applications of incentive regulation, and a consideration of each Companies' cost performance. Dr Kaufmann believes all three of these elements are present in the implicit stretch factors approved by the BCUC for the Current MRPs.

Based on this understanding of BCUC findings on appropriate stretch factors for FEI and FBC, as well as Dr. Kaufmann's work in recommending appropriate stretch factors in other jurisdictions, Dr. Kaufmann believes the implicit stretch factors in the Current MRPs were reasonable at the time and, after inspection and analysis, remain reasonable. The implicit stretch factor values approved in the Current MRPs are approximately 0.1 percent for FEI and 0.05 percent for FBC. Dr. Kaufmann would therefore have recommended those values in a hypothetical examination.

Overall, Dr. Kaufmann finds that an application of his methodology to the Current MRPs would have yielded the following productivity factors, stretch factors and overall X factors for FEI and FBC.

Table 3: Hypothetical Productivity Factors, Stretch Factors and X Factors for Current MRPs

Company	O&M PFP	Stretch Factor	Hypothetical X-factor Recommendation for the Current MRP	Recommended X-Factor for the Proposed Rate Framework
FEI	0.19%	0.10%	0.29%	0.38%
FBC	- 0.02%	0.05%	0.03%	0.20%

In response to BCUC IR 7.9, FortisBC provided electricity and gas distribution cost rankings, which summarized FEI's and FBC's ranked positions against 54 sampled gas distributer's average operations and maintenance (O&M) costs per customer for FEI and 83 sampled electricity distributer's average O&M costs per customer for FBC, over a three-year period from 2020 to 2022. For FEI, FortisBC stated that FEI ranked 31st amongst the 54 sampled gas distributers and that the ranking is consistent with

Dr. Kaufmann's finding that FEI exhibits average cost performance relative to the US gas distribution industry. For FBC, FortisBC stated that FBC ranked 5th amongst the 83 electricity distributers supporting that FBC's cost performance was well above average.

In response to BCUC IR 7.6, FortisBC stated that a sample period from 2007 to 2022, or 15 years of growth rates, was chosen by Dr. Kaufmann for the FEI and FBC productivity studies because a 15-year sample period minimizes the impact of year-to-year volatility and the experience of a small number of years on estimated productivity growth.

Further in its response to BCUC IR 7.6, FortisBC provided the annual and average growth rates in O&M PFP for the 2017 to 2022 period for both the gas distribution and electricity distribution industries and stated that a sample period of "five years is far too short to estimate reliable, long-run trends for O&M PFP growth." FortisBC also stated that "the average PFP growth between 2017 and 2022 was 0.72 percent per annum for the gas distribution industry and 1.41 percent for the electricity distribution industry."

45.3 Please explain why a three-year sample period was chosen to provide FEI's and FBC's cost rankings and why a 15-year sample period, as used by Dr. Kaufmann in the FEI and FBC productivity studies, was not chosen. As part of the response, please explain whether Dr. Kaufmann considers the three-year sample period to be volatile or unreliable, and if not, why not.

Response:

The following response was provided by Dr. Kaufmann:

To be consistent with the competitive market paradigm described in Section 1 of Dr. Kaufmann's Report, productivity factors should be calculated using industry productivity trends. These industry productivity trends can be measured using either total-factor or partial-factor productivity metrics, depending on whether the incentive regulation formula is applied to total or partial costs. The productivity trends calculated for FEI's and FBC's indexing formulas are O&M PFP indices, which are constructed using data on: (1) customer numbers; (2) O&M costs; and (3) measures of O&M input price indices. Dr. Kaufmann will focus on these items in the response that follows.

In general, industry productivity studies become more accurate when they sample a large cross section of utilities across the industry. Adding companies to the sample naturally increases the coverage of the sample, and ideally the industry sample will comprise the entire industry. In practice, it is rarely possible to sample the entire industry because of data and reporting constraints. Nevertheless, a good rule of thumb for estimating industry productivity is to include as many companies as possible, provided that all sampled companies have high-quality data.

It should be noted, however, that one of the most important ways that utilities differ across the industry is in terms of size. Larger utilities (in terms of both customers served and O&M expenditures) have more of an impact on industry-wide productivity trends than smaller utilities, simply because they represent and serve a larger share of the industry. This, in turn, implies that the data from larger utilities will have an outsized impact on measured industry-wide productivity trends. Relatedly, larger utilities will have a disproportionate impact on O&M PFP volatility.

It is common for industry-wide productivity trends to be volatile on a year-to-year basis. Since O&M PFP is measured using customer numbers, O&M expenditures, and O&M input prices to measure O&M PFP, this volatility will, in turn, reflect volatility in the number of customers served, the amount of O&M expenditures, and/or changes in input price trends. This volatility will exist for every sampled firm in an O&M PFP study.

Customer numbers tend to grow at relatively stable levels over time and therefore have relatively little impact on volatility. Input price inflation also tends to be similar across the industry, and over the last 20 or so years it has been relatively steady, although there are notable exceptions (e.g., the surge in inflation worldwide in 2021-2022).

The primary source of volatility is therefore associated with O&M expenditures. Every utility's O&M expenditures can differ across years for a wide variety of reasons. However, as discussed above, when computing industry PFP trends, larger firms will naturally have an outsized impact on measured industry-wide productivity trends as well as the volatility of productivity trends. In any given year, changes in industry O&M PFP are therefore highly sensitive to the O&M spending patterns of the larger firms in the sample.

Over a longer period, however, years with especially high O&M expenditures are balanced out against years with much lower O&M spending, and the volatility of the industry's expenditures diminishes. Longer-run trends thereby become apparent in the data. The best practical solution for mitigating volatility in O&M is therefore to increase the number of years used to measure productivity. As discussed, the sample used to estimate productivity should already include all the available utilities with high quality data, so volatility cannot therefore be mitigated by further expanding the cross section of sampled utilities.

At the same time, there are limits to how long the time series of utility data should be expanded. Samples can potentially reach back too far into the past and thereby reflect conditions, technologies and related factors that are obsolete and not representative of the current utility industry. As discussed in the response to BCUC IR1 7.6, although the appropriate length of time for the sample depends on judgment, many researchers have recently used a period of about 15 years to measure productivity trends.

The situation is different in several respects with respect to benchmarking company costs. First, cost benchmarking analysis is not designed to compute a long-term trend for an entire industry. Instead, the purpose of benchmarking is to assess the recent cost performance and potential of an individual company to make incremental cost performance gains under a proposed incentive regulation plan. The focus is therefore on that company's current cost performance, and its potential to achieve performance gains going forward. This objective requires more of a short-run "snapshot" of a company's current cost performance, not a longer-term trend. Examining the company's costs from 15 years ago is unlikely to provide an accurate assessment of its current operations or potential to achieve cost savings.

Another difference is that cost benchmarking typically compares unit costs or similar metrics on a company-by-company basis, rather than against a single, industry-wide trend. Larger companies in the sample therefore do not have an outsized impact on measured volatility, which can only be practically mitigated by extending the time series of sampled companies. Reducing the need to expand samples across time facilitates the use of shorter benchmarking periods that are focused more directly on current cost performance and its implications for the immediate future.

It is true that some amount of volatility will be present in a utility's average three-year unit cost, but it is noteworthy that it is the company's own volatility, rather than volatility largely created by other firms in the industry. Further, averaging unit cost over three years controls for this volatility to an extent.

Expanding the sample period beyond three years may reduce volatility, but it does so by pushing the analysis back further into the past, which is less relevant for assessing the company's current cost conditions. This concern is more pronounced for cost benchmarking than for estimating industry O&M PFP growth, because benchmarking is expressly designed to measure a company's current cost performance and its potential to achieve incremental cost performance.

In Dr. Kaufmann's opinion, a three-year period strikes a reasonable balance between mitigating the company's own cost volatility and developing timely and accurate measures of the utility's current unit costs. Because productivity trends measure long-term industry trends, it is reasonable to balance these objectives using longer time series data.

45.4 Please provide FEI's and FBC's relative cost rankings and classifications (i.e. inferior, average, superior) if a 15-year sample period from 2007 to 2022 was used instead of three years.

Response:

The following response was provided by Dr. Kaufmann:

Table 1 below provides the rankings of FEI and the sampled US gas distributors, as ranked by their average unit costs over the 2007-2022 period. FEI ranks 26th in this ranking, which is similar to its previous ranking when gas distributors were ranked by their average unit costs over the 2020-2022 period. Unit O&M costs over the 2007-2022 period averaged US$234.16 for the sampled US gas distributors. FEI's average unit costs over the 2007-2022 period were US$224.36, which was 4.2 percent below the US average. When similar comparisons were made for unit costs over the 2020-2022 period, FEI's costs were 0.2 percent below the US average. In both instances, Dr. Kaufmann believes FEI's unit costs are consistent with average cost performance.

Table 1: Ranking of O&M Unit Costs for US Gas Distributors and FEI, 2007-2022

Rank	Company	Fifteen Year 2007-2022 Avg. Unit Cost
1	Atlanta Gas Light Company	$99.87
2	The East Ohio Gas Company	$109.05
3	Northern Illinois Gas Company	$110.01
4	Questar Gas Company	$117.10
5	Wisconsin Gas LLC	$121.72
6	Ohio Gas Company	$136.41
7	Public Service Electric and Gas Company	$142.39
8	Public Service Company of North Carolina, Incorporated	$142.97
9	Virginia Natural Gas, Inc.	$153.00
10	Consumers Energy Company	$155.08
11	Colonial Gas Company	$156.43
12	Northern States Power Company	$157.90
13	Puget Sound Energy, Inc.	$160.22
14	Southern California Gas Company	$162.42

Rank	Company	Fifteen Year 2007-2022 Avg. Unit Cost
15	Black Hills Energy Arkansas, Inc.	$169.49
16	Cascade Natural Gas Corporation	$170.18
17	Avista Corporation	$172.57
18	South Jersey Gas Company	$178.83
19	Pacific Gas and Electric Company	$179.86
20	Wisconsin Power and Light Company	$188.82
21	Louisville Gas and Electric Company	$195.70
22	Duke Energy Ohio, Inc.	$197.84
23	Northern Indiana Public Service Company	$208.39
24	Southern Indiana Gas and Electric Company	$209.31
25	Rochester Gas and Electric Co	$218.55
26	FortisBC Energy Inc.	$224.36
27	Washington Gas Light Company	$227.29
28	Peoples Gas System	$231.87
29	Madison Gas and Electric Company	$236.50
30	Niagara Mohawk Power Corporation	$236.53
31	Delta Natural Gas Company, Inc.	$239.57
32	DTE Gas Company	$245.52
33	New Jersey Natural Gas Company	$248.56
34	Bluefield Gas Company	$252.14
35	Boston Gas Company	$265.72
36	National Fuel Gas Distribution Corporation	$266.52
37	Baltimore Gas and Electric Company	$267.71
38	North Shore Gas Company	$272.61
39	Mountaineer Gas Company	$279.63
40	The Berkshire Gas Company	$286.37
41	Columbia Gas of Kentucky, Incorporated	$287.44
42	Consolidated Edison Company of New York, Inc.	$287.69
43	Brooklyn Union Gas Company	$299.28
44	Superior Water, Light and Power Company	$301.23
45	The Southern Connecticut Gas Company	$302.03
46	St. Joe Natural Gas Co, Inc.	$308.18
47	New York State Electric & Gas Corporation	$313.44
48	Connecticut Natural Gas Corporation	$348.47
49	Columbia Gas of Maryland, Incorporated	$353.28
50	Yankee Gas Services Company	$353.47

Rank	Company	Fifteen Year 2007-2022 Avg. Unit Cost
51	The Peoples Gas Light and Coke Company	$361.87
52	Central Hudson Gas & Electric Corporation	$424.77
53	Corning Natural Gas Corporation	$429.81
54	Orange and Rockland Utilities, Inc.	$439.18
55	St. Lawrence Gas Company, Inc.	$473.27

Table 2 below provides the rankings of FBC and the sampled US electricity distributors, as ranked by their average unit costs over the 2007-2022 period. FBC ranks 20th among the US sample of 81 electricity distributors, which is consistent with first quartile and superior cost performance.

Table 2: Ranking of O&M Unit Costs for US Electricity Distributors and FBC, 2007-2022

Rank	Company	Average Unit Cost, 2007-2022
1	Versant Power	$140.95
2	Florida Power & Light Company	$179.26
3	Kingsport Power Company	$182.61
4	NextEra Energy, Inc.	$183.39
5	Pennsylvania Power Company	$236.24
6	The Potomac Edison Company	$238.65
7	Nevada Power Company	$249.85
8	West Penn Power Company	$261.66
9	Northwestern Wisconsin Electric Co Inc	$277.27
10	Virginia Electric and Power Company	$285.35
11	Duquesne Light Company	$290.12
12	Pennsylvania Electric Company	$295.60
13	Duke Energy Carolinas, LLC	$301.01
14	Ohio Edison Company	$303.27
15	Jersey Central Power & Light Company	$303.95
16	The Cleveland Electric Illuminating Company	$304.98
17	Tampa Electric Company	$312.33
18	Duke Energy Florida, LLC	$312.82
19	Duke Energy Progress, LLC	$327.98
20	FortisBC Inc.	$330.64
21	Commonwealth Edison Company	$335.98
22	Arizona Public Service Company	$337.87

Rank	Company	Average Unit Cost, 2007-2022
23	Entergy Mississippi, LLC	$345.59
24	Black Hills Colorado Electric, Inc.	$351.80
25	PacifiCorp	$355.55
26	Kentucky Utilities Company	$357.64
27	Tucson Electric Power Company	$360.08
28	Metropolitan Edison Company	$363.67
29	Public Service Company of New Mexico	$364.47
30	El Paso Electric Company	$365.42
31	Georgia Power Company	$366.30
32	AES Indiana	$370.66
33	The Toledo Edison Company	$373.94
34	PPL Electric Utilities Corporation	$379.63
35	Atlantic City Electric Company	$384.87
36	Appalachian Power Company	$388.84
37	OGE Energy Corp.	$389.01
38	Duke Energy Indiana, LLC	$401.63
39	Ohio Power Company	$410.89
40	Potomac Electric Power Company	$411.01
41	Public Service Company of New Hampshire	$413.17
42	Cleco Power LLC	$418.22
43	The Dayton Power and Light Company	$419.26
44	Public Service Company of Oklahoma	$423.63
45	Portland General Electric Company	$424.15
46	Southwestern Electric Power Company	$425.73
47	Indiana Michigan Power Company	$429.76
48	Entergy Arkansas, LLC	$442.10
49	Idaho Power Company	$443.05
50	Alaska Electric Light and Power Company	$444.79
51	Alabama Power Company	$452.05
52	Evergy Missouri West, Inc.	$453.61
53	Maui Electric Company, Ltd.	$463.95
54	Evergy Metro, Inc.	$467.90
55	Central Maine Power Company	$477.80
56	DTE Electric Company	$479.52
57	The Connecticut Light and Power Company	$482.95
58	The Empire District Electric Company	$490.22
59	Kentucky Power Company	$490.78

Rank	Company	Average Unit Cost, 2007-2022
60	Monongahela Power Company	$507.11
61	Unitil Energy Systems, Inc.	$507.31
62	Southern California Edison Company	$535.05
63	Lockhart Power Company	$540.36
64	Hawaiian Electric Company, Inc.	$543.92
65	Green Mountain Power Corporation	$567.05
66	NSTAR Electric Company	$594.49
67	Rockland Electric Company	$603.63
68	Upper Peninsula Power Company	$610.45
69	Southwestern Public Service Company	$620.02
70	Evergy Kansas Central, Inc.	$627.20
71	Otter Tail Corporation	$642.77
72	Liberty Utilities (Granite State Electric) Corp.	$648.70
73	Evergy Kansas South, Inc.	$667.11
74	Wheeling Power Company	$681.37
75	Mississippi Power Company	$681.60
76	Massachusetts Electric Company	$682.99
77	Black Hills Power, Inc.	$767.22
78	The United Illuminating Company	$807.80
79	Minnesota Power Enterprises, Inc.	$966.26
80	Hawaii Electric Light Company, Inc.	$5,809.97
81	Consolidated Water Power Company	$21,054.98

45.5 Please explain why long-run productivity trends are more reliable in estimating PFP growth compared to short-run productivity trends given that the proposed term of the Rate Framework is only three years.

Response:

The following response was provided by Dr. Kaufmann:

Please refer to the response to BCUC IR2 45.3. As discussed in that response, industry-wide productivity trends are best computed using long-run samples of approximately 15 years. In contrast, relatively short-run "snapshots" of a company's cost performance and potential to achieve incremental cost savings are best computed over approximately three years. The reasons provided in the response to BCUC IR2 45.3 are not impacted by whether the term of the incentive regulation plan is five years or three years.

45.6 Please confirm, or explain otherwise, that if the most recent five years of data were used instead of a 15-year sample, the PFP for FEI and FBC would be 0.72 percent and 1.41 percent, respectively.

Response:

The following response was provided by Dr. Kaufmann:

Confirmed. However, the 2017-2022 period is clearly not representative of conditions going forward. The 2017-2022 period included a worldwide pandemic, which in short order initiated a worldwide recession. When the pandemic abated in late 2021, it sparked the worst worldwide price inflation in more than 40 years. Therefore, it would not be reasonable to calculate the PFP for FEI and FBC based on the most recent five years of data.

B. PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

46.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-4, BCUC IRs 14.1 and 2.1

FBC – Adjustments to 2024 Base O&M for Required 2024 Spending

In response to BCUC IR 14.1, FBC stated: “Managing added complexity is a cost driver for all of the requested incremental spending, as FBC not only requires more resources to manage and optimize its existing supply portfolio given the increasingly tight power market, but also requires resources to plan and model future supply options.” FBC also provided a detailed breakdown of the $1.200 million in incremental funding requested, which includes $0.335 million for two energy supply positions (Energy Supply Data Analysis Manager and Energy Supply Resource Specialist).

46.1 Please provide a brief description of the responsibilities for the Energy Supply Data Analysis Manager and the Energy Supply Resource Specialist. As part of the response, please confirm, or explain otherwise, that these two positions do not have any overlapping duties and responsibilities.

Response:

FBC confirms that there are no overlapping duties and responsibilities between these two positions. The Energy Supply Resource Specialist reports to the Energy Supply Data Analysis Manager.

The Energy Supply Data Analysis Manager is responsible for leading a technical team responsible for modeling, analysis, research, and recommendations in support of the Energy Supply group, with an emphasis on the Power Supply and Resource Planning teams. This position acts as the senior technical lead on the FBC Long Term Electric Resource Plan and manages the detailed analysis of how individual potential resources integrate into FBC’s power supply portfolio. The position also manages the analysis of Advanced Metering Infrastructure (AMI) data within the Power Supply group.

The Energy Supply Resource Specialist position is responsible for developing analysis, reports and studies, and delivering presentations to internal and external stakeholders, including researching methodologies and topics related to long term electric resource planning.

46.2 Please discuss how these two roles are expected to support and/or optimize FBC’s power supply portfolio and plan future supply options.

Response:

These two roles are focused on the medium to long-term power supply portfolio and help ensure that FBC has the information and analysis required to make strategic and cost-effective decisions regarding the resources needed to meet FBC's load.

In response to BCUC IR 2.1, FortisBC stated:

> The [Climate Change Operational Adaptation] CCOA development work described [on page B-12 of the Application] is referring to FBC. However, FEI also considers the need to improve asset and operational resilience to climate change risks to be of high importance and is undertaking similar CCOA development work. FEI is funding its work on climate change operational adaptation through formula O&M.

46.3 Please confirm, or explain otherwise, that FBC's CCOA costs for 2025 to 2027 will be included in FBC's formula O&M.

Response:

To the extent the activities are O&M related, FBC confirms that CCOA-related costs will be managed within FBC's formula O&M during the proposed Rate Framework term.

C. PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

47.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-4, BCUC IRs 18.2 and 33.7.1

FEI – Capital Planning Process – Energy Transition

In response to BCUC IR 18.2, FEI stated:

> FEI is currently undertaking the British Columbia Gas System Blending Study and Technical Assessment project to better understand how hydrogen integration will affect FEI's legacy system. The results of this study will inform how FEI's system can accommodate hydrogen. Until this work is done, FEI does not have the required information to incorporate the impacts of hydrogen integration at the project level. However, FEI utilizes modern materials for all new gas infrastructure installations, so the compatibility of new gas infrastructure with hydrogen is inherently improved.

In response to BCUC IR 33.7.1, FEI stated that it expects the British Columbia Gas System Blending Study and Technical Assessment project to be complete in 2027.

47.1 Please discuss the impact, if any, that FEI anticipates the British Columbia Gas System Blending Study and Technical Assessment project will have on (i) the proposed Rate Framework for 2025 to 2027 and (ii) FEI's next rates application for beyond 2027. Please explain whether the impact would differ if the next rates application were an application to continue the proposed Rate Framework or a new rate plan.

<u>Response:</u>

FEI does not anticipate any impact on the proposed Rate Framework for 2025 to 2027 from the British Columbia Gas System Blending Study and Technical Assessment project (Study), as the anticipated completion date of this study is in 2027. Further, since the results of the Study are not yet known, FEI is unable to speculate what the Study's impact might be beyond 2027.

FEI expects the results from the Study to be implemented over several years and its approach to implementation would not change or be affected by the type of rate-setting process in place at the time, including whether FEI proposes to extend the Rate Framework or establish a new plan subsequent to 2027. At that time, FEI will need to seek approval of new Sustainment capital forecasts, as FEI is only seeking approval of three-year Sustainment capital forecasts in this Application. Accordingly, if there were any impacts from the Study, FEI would incorporate those impacts into its new capital forecasts. Similarly, if FEI had the necessary information based on the Study results, it could consider proposing a new informational indicator, regardless of whether FEI proposed to extend the Rate Framework or establish a new rate-setting plan at the conclusion of the 2025-2027 Rate Framework.

48.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-4, BCUC IRs 21.1 and 21.2

FEI – Other Capital – Expenditures Related to Corporate Security

In response to BCUC IR 21.1, FortisBC stated: "The Patch Management costs of $5.589 million are made up of $2.799 million in Labour and $2.790 million in Managed Services for each year of the Rate Framework term."

48.1 Please provide a high-level overview of the activities performed as Patch Management work associated with the $2.799 million in Labour costs and the $2.790 million in Managed Services. As part of the response, please indicate whether activities are one-time or recurring in nature.

Response:

Before implementing each patch and update released by vendors to production environments, Patch Management activities are required, which include completing a patch implementation plan, completing and documenting implementation trials, and performing an impact analysis developed from the testing. These activities (and costs) are split between internal labour and third party managed services in accordance with FEI's IT services model.

All of the Patch Management activities are recurring and as stated on page C-98 of the Application, these activities are expected to increase in frequency:

> The increased frequency of these vendor released updates requires FEI to increase the cadence of the patch review and installation. In many cases, required patching will increase from quarterly to monthly, essentially quadrupling the patching workload for those systems…

In response to BCUC IR 21.2, FortisBC stated:

> The patch management costs included as capital expenditures […] are for the installation and testing of upgrades that would extend the life of hardware and software assets in FEI's and FBC's systems, thus making them eligible to be capitalized. This treatment is consistent with the Current MRP.

48.2 Please describe the types of hardware and software that will be upgraded, the nature of the upgrades, how these upgrades will extend the asset lives, and for how long the asset lives will be extended as a result of the upgrades.

Response:

The hardware and software that typically require upgrades include servers, desktops, mobile devices, firewalls, switches, virtualization hardware, virtual machines, appliances, and storage infrastructure. These upgrades often involve updating operating systems, firmware, and business applications.

Investment in these sustainment upgrades, including patching, extends the life and enhances the value of FortisBC's technology assets by enabling potential new functionality, as well as ensuring reliability, resilience, and security of the assets. Without these investments, the assets may need to be decommissioned or replaced due to functionality or security issues. The amount of time that the life is extended for each asset due to patching and upgrades varies based on the type and function of the asset. As an example, a firewall may have its life extended by two or more years by applying patches and upgrades. Enterprise software assets, such as Enterprise Resource Planning (ERP) solutions and Geographic Information Systems (GIS), require upgrades and patches to remain in service for 10 or more years.

49.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1 (Application), Section 3.4.1.1, Table C3-30, pp. C-106 and C-108, Exhibit B-4, BCUC IR 23.10; FBC Kelowna Bulk Transformer Addition Project Certificate of Public Convenience and Necessity (KBTA Project), Exhibit B-1 (KBTA Application) dated April 24, 2020, pp. 1 and 18, Exhibit B-2, BCUC IR 6.4

FBC – Capital Expenditures Forecasts

Table C3-30 on page C-106 of the Application shows FBC's forecast transmission growth capital projects from 2025 through 2027.

Further on page C-106 of the Application, FBC states that the Reconductor 52L & 53L project is required to resolve the N-1 condition, which constitutes a violation of BC Mandatory Reliability Standard TPL-001-5.1.[4]

On page C-108 of the Application, FBC states that the Princeton 138 kV Capacitor Bank Addition project is required to provide acceptable voltage during an N-1 condition, which constitutes a violation of BC Mandatory Reliability Standard TPL-001-5.1.[5]

49.1 Please expand Table C3-30 of the Application to include an additional column for references to any applicable federal and provincial regulations, mandatory standards, local laws, and codes that inform the requirement for additional capacity and redundancy over the proposed term of the Rate Framework. As part of the response, please identify projects that are not subject to any standards or regulations but are necessary for compliance only with FBC's own planning criteria.

<u>Response:</u>

As requested, Expanded Table C3-30 below includes an additional column indicating the laws/regulations/codes informing the requirement for additional capacity and redundancy. As indicated in the table, for all projects, the need for additional capacity and redundancy is informed by FBC's obligation to serve as set out in the *Utilities Commission Act* (UCA), as well as FBC's planning criteria, which are informed by CSA standards and good utility practice. In addition, where applicable, the need for the additional capacity and redundancy is based on ensuring compliance with Mandatory Reliability Standards (MRS).

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[4] This statement was removed in the Errata to the Application (Exhibit B-1-1).

[5] This statement was removed in the Errata to the Application (Exhibit B-1-1).

Expanded Table C3-30: FBC Forecast Transmission Growth Capital Projects 2025-2027 ($000s)

Project	2025 Forecast	2026 Forecast	2027 Forecast	Law/regulations/codes informing the requirement for additional capacity and redundancy
Reconductor 52L & 53L	3,067	3,000		UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Glenmore Low Voltage Bus Capacity and Equipment Upgrades	1,421	174		UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Duck Lake Second Distribution Transformer Addition	4,683	681		UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Christina Lake Station Upgrade	1,567	3,962	2,322	UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Saucier Second Distribution Transformer Addition	5,269	7,294	2,757	UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
DG Bell Second Distribution Transformer Addition	411	2,724	7,511	UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Princeton 138 kV Capacitor Bank		414	1,766	TPL Mandatory Reliability Standards, UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Reconductor 51L & 60L		1,075	5,000	UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice
Glenmore Station Capacity Upgrade			791	UCA (obligation to serve), FBC Planning Criteria, including CSA standards and good utility practice

49.2 Please identify any applicable standards, codes, and regulations that will come into effect for the FBC service area during the proposed term of the Rate Framework but were not applicable over the Current MRP term.

Response:

FBC is not aware of any new applicable standards, codes and regulations that will come into effect in its service area during the proposed term of the Rate Framework that were not applicable over the Current MRP term.

In response to BCUC IR 23.10, FortisBC stated:

> While the new Spare Parts program is required to maintain compliance with TPL-001-4 2.1.5, FBC confirms that the 138 kV Kelowna system, which includes 51L and 60L, is <u>not</u> subject to Mandatory Reliability Standards, including TPL-001-4 2.1.5, at this time due to the Local Network exclusion.
>
> […]
>
> The reconductoring of 60L and 10 51L must be completed to re-configure the Kelowna 138 kV network to prevent exceeding line and transformer emergency ratings to satisfy this N-1-1 requirement and to satisfy FBC's Transmission System Planning Criteria.

On page 1 of the KBTA Application, FBC summarizes the need for the KBTA Project stating that "FBC will not be able to meet the N-1 system reliability planning criteria in order to reliably maintain service to the area load during peak periods in the event of an outage or failure of one of the two existing 230/138 kV transformers at LEE [F.A. Lee Terminal Station on McCurdy Road in Kelowna, BC]."

On page 18 of the KBTA Application, FBC states: "Typical industry transmission planning standards require the system to be planned such that all projected customer loads are served during both normal (N-0) operation and single contingency (N-1) operation."

In response to BCUC IR 6.4 of Exhibit B-2 for the KBTA Project proceeding, FBC provided the following list of power system elements to which FBC applies N-1 planning criteria:

> FBC applies N-1 planning criteria to transmission lines, transformers, generating units, and power-conditioning units. A power-conditioning unit includes a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, a synchronous condenser, a static VAR compensating device, a filter bank, or other similar device that can be removed from the system by protection equipment.

49.3 Please confirm, or explain otherwise, that FBC applies its system planning criteria to prioritize capital investments for local networks that are not subject to any other applicable standards and regulations.

<u>Response:</u>

Not confirmed.

FBC uses its asset-investment planning (AIP) process set out in Section C3.2 of the Application to prioritize its capital investments. Amongst other factors, the AIP process considers reliability and regulatory risks, which would include consideration of system planning criteria and applicable standards and regulations.

FBC uses its system planning criteria to identify the need for capital investments for local networks that are not otherwise required by applicable standards and regulations.

49.3.1 Please discuss how FBC determines the level of redundancy required for local networks to be appropriate and consistent with industry practice. Please identify any reliability studies or relevant industry standards, if applicable, used by FBC in making that determination.

Response:

FBC applies N-1 planning criteria to all power system elements (transmission lines, transformers, generating units, and power-conditioning units) for all Bulk Electric System (BES) and non-BES elements within the FBC system. BES elements are planned to N-1-1 criteria as detailed and required by the MRS TPL-001-4 2.1.5.

Local networks, such as the Kelowna area, are not currently subject to MRS, including TPL-001-4 2.1.5, due to the Local Network exclusion and are instead governed by FBC's planning criteria. Consistent with industry practice, FBC may provide redundancy beyond N-1 (i.e., N-1-1) to a local network on a case-by-case basis based on several factors, such as an area's unique reliability risks, size (impact of an outage) and/or growth rate.

For example, the BCUC has previously found that an N-1-1 contingency level is appropriate in the Kelowna Area:[6]

> With respect to the appropriate reliability levels for the City of Kelowna, the Commission Panel notes that the criteria of N-1 is a minimum standard set by the WECC for bulk transmission systems and adopted by most utilities. The Commission Panel acknowledges that there are situations (particularly in large urban centers) where the consequence of a lower probability occurrence of an N-1-1 or N-2 event requires the N-1 standards to be exceeded. Each case is a judgment call and must be evaluated on its own merits. However it is common practice to have N-2 contingency levels for certain load centers in large urban centers (e.g. Vancouver and Victoria). **The Commission Panel accepts that an N-1-1 contingency level for Kelowna is appropriate at this time.**

However, in the case of the City of Kelowna, FBC clarifies that the 51L and 60L reconductoring project is primarily required to provide capacity to address the unprecedented load growth in the

[6] Order G-52-05, p. 59.

City of Kelowna, including large developments being constructed and additional load factors, such as gas to electric fuel switching and new electric loads (e.g., the Step 4 Energy code). The project has secondary benefits which include enhancing operational flexibility during maintenance outages and addressing the capacity constraints during N-1-1 contingencies.

49.4 Please identify and discuss any key updates to the planning criteria that FBC applies to its service area during the proposed term of the Rate Framework since the Current MRP term and provide any impacts as a result of these updates on system planning and development of capital expenditure forecasts for the proposed term of the Rate Framework.

Response:

FBC has not made updates to its planning criteria for the proposed term of the Rate Framework.

49.4.1 Please clarify whether FBC's reliability planning requirement for the F.A. Lee terminal substation transformers has changed from N-1 operation to N-1-1 operation since the KBTA project.

Response:

FBC confirms that its planning criteria has not changed since the KBTA Project.

49.4.2 Please confirm, or explain otherwise, that FBC's list of power system elements to which it applies the N-1 planning requirement remains unchanged for the purposes of system planning and development of capital expenditure forecasts during the proposed term of the Rate Framework. If not confirmed, please discuss any updates to the list of power system elements provided for the KBTA project and explain the key drivers for these updates.

Response:

Confirmed. FBC still applies N-1 planning criteria to the power system elements (transmission lines, transformers, generating units, and power-conditioning units).

D. PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

50.0 Reference: PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section 3.4, p. C-104, Appendix C4-2 (FBC's Load Forecast Methods), p. 7, Exhibit B-4, BCUC IRs 27.1 and 27.1.2

FBC – Energy and Demand Forecasts

In Table 1 of the response to BCUC IR 27.1, FBC provided the aggregate gross load (before and after savings), after-savings peak summer and winter demands, and year-end aggregate customer counts for 2024F, 2024S, and 2025 to 2027F.

In response to BCUC IR 27.1.2, FBC stated:

> The increase in 2024S aggregate gross load from 2024F is predominantly due to a forecast increase in industrial loads, which are interruptible and therefore do not impact peak demand. The difference in 2024S and 2024F is also impacted by small increases in residential and commercial loads.
>
> […]
>
> The actual average annual customer growth from years 2020 through 2023 was 1.7 percent while the forecast average annual customer growth from 2024 through 2027 is 1.3 percent.

On page C-104 of the Application, FBC states that it is forecasting increases in Growth, Sustainment and Other capital expenditures for each year of the proposed term of the Rate Framework.

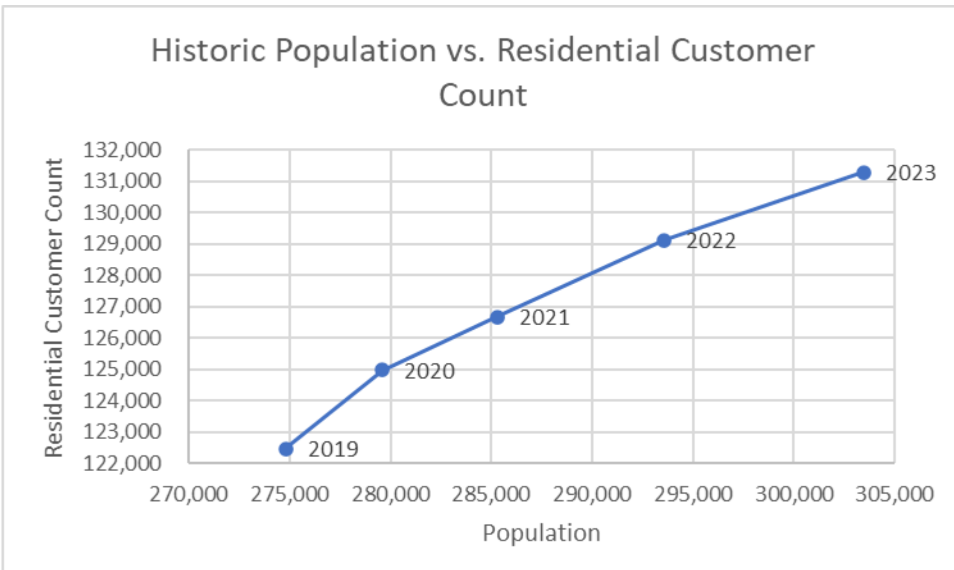
50.1 Please discuss the rationale for the reduction in forecast average annual customer growth from 2024 through 2027 (i.e. 1.3 percent) compared to the actual average customer growth for years 2020 through 2023 (i.e. 1.7 percent).

Response:

The customer count forecasts for both residential and commercial rate classes rely on econometric forecasts which are independent of historical customer growth rates (i.e., they are not based on time series regression forecasts of historical customer growth). As stated in Section 3.1 of Appendix C4-2 to the Application, the residential year-end customer count forecast is based on a least squares regression model using population data provided by BC Stats for FBC's direct service area, while the commercial year-end customer count forecast is based on a least squares regression model using BC provincial GDP data provided by the Conference Board of Canada (CBOC).

The residential and commercial customer counts make up 98.3 percent of FBC's customer count in 2023, with residential customers alone accounting for 87 percent. Given their high proportion, residential customers are largely responsible for any changes in customer count trends observed over time. Figure 1 below shows the trend between the historical residential customer counts and population from 2019 through 2023. Although both the number of residential customers and the overall population are growing, the curve of residential customer growth over population growth is flattening, indicating that the number of persons per dwelling is increasing in recent years compared to prior years. Given the increasing densities per household in recent years, it is expected that for a given population increase, there would be relatively fewer customers added, resulting in the reduced customer count growth rate.

Figure 1: Historic FBC Service Territory Population Vs. Residential Customer Count



50.2 Please calculate the forecast growth rate (percent) for before-savings gross load from 2024 through 2027 and compare it to the actual before-savings gross load growth rate (percent) from 2020 through 2023. Please explain the difference between the actual and forecast load growth rates.

50.2.1 Based on the calculation of the forecast before-savings gross load growth rate from 2024 through 2027 in the preceding IR, please explain if FBC anticipates greater rate pressures during each year of the proposed term of the Rate Framework due to the forecast increase in capital expenditures and reduced annual customer growth.

Response:

The forecast growth rate for before-savings gross load from 2024 to 2027 is 2.6 percent, while the growth rate for normalized actual before-savings gross load from 2020 to 2023 is 1.8 percent. The increase of 0.8 percent is primarily due to increased industrial load. Therefore, while the increased expenditures for Growth, Sustainment and Other capital will increase FBC's rates during the proposed term of the Rate Framework, the expected increase in revenue due to the increasing growth of overall load (and the continued increased in the growth of customers, albeit at a slower rate than 2020 to 2023 as discussed in the response to BCUC IR2 50.1) will help to offset the increase, all else equal.

As discussed in the Application and in the response to BCUC Panel Supplemental IR1, the energy transition is putting pressure on FBC's rates due to the increased need to invest in generation, transmission and distribution infrastructure.

On page 7 of FBC's Load Forecast Methods, it states:

> FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have committed contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group.

50.3 Please clarify which types of industrial load are included in FBC's peak load forecast and explain why this approach is reasonable.

Response:

FBC includes all industrial loads in the peak demand forecast except for customers in rate schedule (RS) 37 Stand-by Service and RS 38 Interruptible Service:

- RS 37 Stand-by Service is a back-up and maintenance service intended for use when a customer's own generating equipment is not in operation. FBC does not plan infrastructure upgrades or power purchase expenses for back-up given the infrequent nature of when a customer's own generating equipment is not in operation. Further, customers under the RS 37 Stand-by Service must also be a customer contracted under RS 31 Large Transmission Service, and RS 31 customer peak demand is included in the peak demand forecast. As such, the RS 37 Stand-by Service is similar to an interruptible service.
- RS 38 Interruptible Service is not included in the peak demand forecast as FBC does not plan infrastructure upgrades or power purchase expenses for interruptible load.

FBC notes that for both RS 37 and RS 38, the power purchase costs (demand and energy) would be flow-through market purchases which are borne by the individual customer, not the general customer group.

50.4 Please provide the actual after-savings summer and winter peak demand (megawatt) for the year 2023 and compare to forecast after-savings summer and winter peak demand respectively for the year 2027. Please include an explanation of variances in the summer and winter peak demand.

Response:

Please refer to Table 1 below for the Actual 2023 and Forecast 2027 winter and summer peaks. FBC notes that actual peak values reflect actual temperatures, whereas forecast peak values are based on average temperatures.

Table 1: 2023 Actual and 2027 Forecast Winter and Summer Peak Demand (MW)

	Winter (MW)	Summer (MW)
Actual 2023 Peak	801	673
Forecast 2027 Peak	802	712
Variance	1	39

The relatively small difference of 1 MW between the 2023 Actual and 2027 Forecast winter peak demand is due to the 2023 winter being colder than normal, while the 2027 Forecast of winter peak demand is based on the average temperature plus four years of normal load growth from 2023.

Similarly, the relatively large difference of 39 MW between 2023 Actual and 2027 Forecast summer peak demand is due to the 2023 summer being cooler than normal, while the 2027 Forecast is based on average temperatures plus normal load growth from 2023.

E. POLICIES AND SUPPORTING STUDIES

51.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-4, BCUC IRs 40.1, 40.2, and 40.4

Change in Service Life of Assets and Impact on Depreciation Rate

In response to BCUC IR 40.1 regarding the relationship between service life and depreciation expense for LNG Gas Structures – Tilbury and LNG Gas Equipment - Tilbury for FEI, Concentric stated:

> An increase in the estimated service life from a prior depreciation study to a newer depreciation study does not always produce a lower depreciation rate. […]
>
> Specifically for the two accounts […] the life rates decreased as a result of increasing the service lives; however, <u>the true up related to the amortization of reserve differences</u> is the main driver of the increase in the overall life rate. [*Emphasis added*]

In response to BCUC IR 40.2, Concentric provided a table showing a breakdown of the increase in the depreciation rate in LNG Gas Structures – Tilbury and LNG Gas Equipment - Tilbury for FEI from the 2017 FEI Depreciation Study. Concentric stated that the primary reason for the increase in the depreciation rate from the last study is the change in the true up related to the amortization of reserve differences, with changes of this magnitude expected between depreciation studies.

In response to BCUC IR 40.4 regarding the increase in the depreciation rate for Light Duty Vehicles for FBC despite no change in service life, Concentric provided a table showing a breakdown of the increase in the depreciation rate from the 2017 FBC Depreciation Study. Concentric stated that the primary reason for the increase in the depreciation rate related to life from the last study is the change in the true up related to the change in the Amortization of Reserve Differences rate.

51.1 Please discuss how changes in the true up related to amortization of reserve differences impact FEI's and FBC's assets. Please use numerical examples, as necessary.

<u>Response:</u>

The following response has been provided by Concentric:

Changes in the true up related to the amortization of reserve differences (ARD) impact the overall depreciation rate but do not impact the physical assets of FEI and FBC. The ARD true up is determined by first calculating the theoretical accumulated depreciation balance by asset account using the proposed Iowa curve and net salvage estimate. The difference between the actual accumulated depreciation and the calculated theoretical accumulated depreciation represents the true up to be amortized over the remaining life of the asset account. The true up enables the amount of accumulated depreciation expected for an asset account to be corrected over its remaining life, thereby decreasing the risk that the original cost of the asset will be under- or over-recovered during its service life.

The true up mechanism is described in the foundational textbook "Depreciation Systems" in the section titled "Methods of Adjustment". It should be noted that authors Frank K. Wolf and W. Chester Fitch use the term "adjustment" to refer to the true up of the accumulated depreciation variance. In this section, the true up (or adjustment) is explained as follows: [7]

> 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 on 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.

The following paragraph further explains:[8]

> 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.

A full description of the remaining life method of adjustment, including detailed examples and explanations, from "Depreciation Systems" is attached as Attachment 51.1 to this response. Attachment 51.1 describes the depreciation accrual calculation for a hypothetical account, as well as when and why the adjustment (or true up) is necessary in order to ensure full recovery of the investment. PDF Page 4 of Attachment 51.1, under the heading "Remaining Life Method of Adjustment (SL-AL-RL)", describes the Remaining Life Method used by FEI and FBC. Detailed calculations are included in Tables 5.5 through 5.11.

Please also refer to the response to BCUC IR1 51.2 for further discussion of the true up related to the ARD in FEI's and FBC's asset classes.

51.2 Please explain why there has been a change in the true up related to the amortization of reserve differences in the asset classes referenced above for FEI and FBC.

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7 Wolf, Frank K. and Fitch, W. Chester, "Depreciation Systems" Iowa State University Press, 1994, page 75.

8 Ibid, page 76.

Response:

The following response has been provided by Concentric:

The change in the ARD true up from FEI's and FBC's last depreciation study to the current depreciation study can be primarily attributed to the addition of significant investment in the time since the last depreciation study. There was over $88 million invested in Account 442.00 LNG Gas Structures-Tilbury in 2018, which represents 87 percent of the total cost of plant in service as of December 31, 2022. In the time since the 2017 depreciation study, this amount has been depreciated at a rate of 2.20 percent, which includes a reduction in total life depreciation expense of 1.80 percent due to the ARD rate true up embedded in the total life depreciation rate. The five years of accruals with this reduction have eliminated the need for a reduction in the total depreciation expense due to the true up, and this account is now in a slightly under-accrued position. As such, there is a small increase in the depreciation expense related to the true up of 0.13 percent in the current depreciation rate.

Account 443.00 LNG Gas Equipment-Tilbury has undergone a similar shift in the years since the 2017 depreciation study. There was an investment of $161 million made in 2018, representing 88 percent of the total cost of plant in service as of December 31, 2022. This investment was depreciated at a rate of 1.23 percent, which includes a reduction of 1.27 percent due to the ARD rate true up embedded in in the total life depreciation rate. The five years of accruals with this reduction have nearly eliminated the need for a reduction in the total depreciation expense, with this account now only requiring a reduction for true up of 0.04 percent.

FBC Account 392.10 Light Duty Vehicles has also seen a large increase in original cost since the previous depreciation study. There have been additions of over $3 million since 2017, representing 64 percent of the total plant in service as of December 31, 2022. These additions have been depreciated at a rate of 4.79 percent, which includes a reduction of 3.54 percent due to the ARD rate true up embedded in the total life depreciation rate. The accruals at this reduced rate have eliminated the need for a true up, and this account is now under accrued. As such, there is an increase in the depreciation expense related to the true up of 2.84 percent in the current depreciation rate.

51.3 In the context of FEI's LNG Gas Structures and LNG Gas Equipment, please explain Concentric's statement that changes of this magnitude are expected between depreciation studies.

Response:

The following response has been provided by Concentric:

Any utility utilizing remaining life depreciation, or whole life with a remaining life true up method, will have shifts in total depreciation expense between studies. This is particularly apparent when large investments are made soon after a depreciation study is completed. The depreciation study process expects these true ups to be required as it is assumed that life and net salvage estimates will be revised over time as more information becomes available. It is for this reason that depreciation studies need to be carried out regularly.

52.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D2.2.2, Table D2-4, pp. D-14 to D-16, Section 2.2.2.1, Section 2.2.2.2, p. D-17, Exhibit B-4, BCUC IRs 41.1 and 41.3

Increase in Negative Net Salvage Percent Rate

On page D-17 of the Application, regarding the change in net salvage expense for FEI, FortisBC states that for Services (473-00), Concentric recommends a negative net salvage percent rate of 85 percent (an increase from negative 70 percent) and for Distribution Mains (475-00), Concentric recommends a negative salvage percent rate of 30 percent (an increase from negative 25 percent).

On pages D-14 to D-16 of the Application, FortisBC provides Table D2-4 showing the impact of implementing recommended net salvage percent rates for FEI. The impact of implementing recommended net salvage percent rates for Services (473-00) and Distribution Mains (475-00) amounts to increases of $5.8 million and $1.4 million, respectively.

In response to BCUC IR 41.1 regarding the net salvage activity in these accounts in the past five years, FortisBC stated: "In the past five years, the cost of removal for both accounts 473-00 DS Services and 475-00 DS Mains shows a general increase due to higher inflation in the last few years, as well as an increase in third-party requests to relocate and remove existing assets to accommodate their proposed infrastructure."

52.1 Please provide a detailed description of the net salvage activity that occurred in accounts 473-00 and 475-00 within FEI from 2018 to 2022. As part of the response, please describe the nature of assets involved, asset locations, quantities salvaged (as applicable), and the net salvage amount (i.e. salvage value less cost of removal) for each activity.

<u>Response:</u>

The net salvage activity in accounts 473-00 DS Services and 475-00 DS Mains relates to the abandonment costs of Distribution Mains and Distribution Services, comprised of both steel and polyethylene, that were retired from active service across the entire FEI service territory.

When a main or service is retired, there is no salvage value. In most cases, the main or service is removed from service, but left in the ground, and thus there is no salvage and no salvage value. In cases where FEI is required to physically remove the pipe from the ground, the mains and services removed have zero salvage value.

The tables below provide the net salvage activity that occurred in accounts 473-00 DS Services and 475-00 DS Mains from 2018 to 2022.

Table 1: 473-00 DS Services Net Salvage Activity from 2018-2022 ($)

Net salvage activity	2018	2019	2020	2021	2022
Company driven	1,349,729	2,105,869	1,921,799	2,203,883	1,692,556
Customer driven	9,224,603	7,814,615	7,735,213	10,915,971	13,348,669
Total	**10,574,332**	**9,920,485**	**9,657,013**	**13,119,854**	**15,041,226**

Table 2: 473-00 DS Services Net Salvage Activity by Location from 2018-2022 ($)

	Net salvage activity				
Location	2018	2019	2020	2021	2022
100 Mile House	8,361	5,489	12,634	23,673	14,355
Abbotsford/Matsqui	246,964	264,868	318,223	548,009	471,682
Armstrong	7,600	14,592	120,103	46,922	18,466
Ashcroft				1,684	
Burnaby	886,708	878,825	618,493	879,377	1,354,398
Cache Creek		798	23,077	130	14,383
Campbell River	18,856	25,308	14,249	3,499	25,738
Campbell River Regional	3,692	5,229	3,273	91	4,617
Castlegar	29,978	75,221	45,370	13,827	46,685
Central Saanich	5,656	7,964	5,503	9,988	7,951
Chase	445	4,250	7,076	1,458	37,713
Chemainus	5,359	2,334	2,332	199	4,915
Chetwynd	16,473	5,841	5,691	4,679	2,767
Chilliwack	232,313	217,205	264,140	286,591	277,171
Christina Lake	1,663	9,390	6,976	3,405	7,104
Clinton	2,548			816	2,331
Coldstream	2,456	16,273	18,377	24,337	8,914
Colwood	507	4,755	5,259	13,884	13,251
Comox	3,602	3,776	7,803	7,304	12,487
Coquitlam	477,406	395,003	316,498	584,869	656,780
Courtenay	6,616	8,792	8,042	14,233	40,927
Courtenay District	2,320	2,442	5,426		5,542
Cowichan Valley Regional	3,938	13,070	7,866	5,368	13,630
Cranbrook	78,495	75,127	109,507	187,392	83,699
Creston	59,773	24,916	82,084	171,195	35,879
Crofton			4,240	1,547	2,428
Cultus Lake	14,456	18,338	8,546	25,130	11,650
Cumberland	2,199	2,619	695		4,117
Delta	331,392	306,692	310,817	597,298	556,333
Duncan	633	1,995	4,297	4,740	7,253

	Net salvage activity				
Location	2018	2019	2020	2021	2022
Enderby	440	2,293	2,196	7,594	5,981
Esquimalt	10,722	15,683	16,358	21,539	31,587
Falkland		214	2,370	3,501	2,488
Fernie	9,815	44,464	45,266	20,083	52,451
Fort Nelson	39,881	26,563	37,879	28,796	38,025
Fruitvale	5,884	13,773	22,842	8,623	2,566
Gibsons	11,673	2,032		3,274	4,499
Grand Forks	44,456	8,081	32,705	20,524	119,926
Greenwood		4,563	8,903	17,137	
Grindrod	2,901		4,603	909	4,826
Highlands		858			
Hixon	1,769		1,965		
Hope	10,580	8,856	16,862	31,176	44,036
Hudson Hope	1,013	4,477	11,935	3,195	1,691
Kamloops	128,069	125,507	95,356	159,726	158,113
Kelowna	232,877	260,334	214,650	388,941	606,691
Kent	31,529	15,545	21,054	34,263	7,520
Keremeos	4,099	2,623	665	9,487	9,963
Kersley					938
Kimberley	55,332	28,804	37,515	31,332	37,554
Lac La Hache	289			7,850	2,750
Ladysmith	2,443	2,752	4,836	2,412	5,003
Lakeview Heights	13,127	17,840	17,272	43,650	57,378
Langford	15,537	14,131	6,798	26,785	32,093
Langley City	168,962	133,135	115,503	189,677	281,364
Langley District	234,800	258,147	236,108	316,334	327,882
Lantzville	3,367	1,167	599	1,670	11,219
Logan Lake	825				3,649
Lumby	6,795	1,963	1,708	8,860	6,456
Mackenzie	10,012	3,028	3,926	1,918	7,652
Maple Ridge	103,133	114,137	205,761	180,327	146,186
Merritt	20,478	11,738	7,363	6,946	97,795
Metchosin				2,076	2,925
Midway		1,815	11,632	4,434	65
Mission	90,616	53,487	58,369	72,533	96,845
Nanaimo	77,677	52,394	49,654	39,661	102,034
Nanaimo Regional		1,406			1,614

	Net salvage activity				
Location	2018	2019	2020	2021	2022
Naramata		3,674	1,398		1,641
Nelson	28,565	16,431	29,758	35,633	145,078
New Westminster	142,107	186,752	115,756	112,159	104,944
North Cowichan	14,424	2,000	1,083	14,275	1,744
North Saanich	4,360	5,500	5,071	1,359	13,170
North Vancouver City	457,551	512,223	404,164	613,756	561,098
Oak Bay	23,673	24,973	25,726	28,002	27,240
Okanagan Falls	3,366	4,143	884	4,123	764
Oliver	7,805	16,635	3,510	26,308	21,270
Osoyoos	2,824	10,274	4,838	17,617	14,069
Parksville	10,449	9,826	7,788	3,109	9,533
Parksville / Qualicum Regional	5,270	4,364	1,817	832	6,462
Peachland	9,067	4,914	2,885	334	13,557
Penticton	66,233	76,965	53,017	117,508	179,417
Pitt Meadows	29,913	29,298	27,436	37,469	53,909
Port Alberni	13,959	12,566	3,244	5,708	7,770
Port Alberni Regional	4,483	1,201	2,291	1,876	
Port Alberni District		734			2,200
Port Coquitlam	51,818	57,519	40,590	55,164	82,979
Port Moody	124,547	69,370	55,759	63,073	109,832
Powell River	3,512	10,131	3,554	4,093	8,442
Powell River District			1,989		3,098
Prince George	88,182	71,618	80,845	100,102	142,015
Princeton	4,341	8,157	3,418	19,405	18,996
Qualicum	2,022	3,561	8,752	10,172	5,464
Quesnel	20,653	20,495	38,289	37,682	47,000
Revelstoke	1,153	6,284	2,938	6,154	8,331
Richmond	734,682	665,908	654,264	838,876	501,234
Roberts Creek	17,503	1,444			1,224
Rossland	17,193	9,040	3,956	22,208	21,659
Saanich	50,395	56,372	49,349	77,776	51,219
Salmo			3,238	1,238	1,090
Salmon Arm	28,882	15,544	75,127	45,197	64,814
Savona	1,235	3,626	1,626	2,245	2,021
Sechelt	19,109	23,013	6,879	5,685	7,370
Sechelt Band Land		766		1,357	1,854
Sidney	14,340	14,059	8,639	7,603	11,366

	Net salvage activity				
Location	**2018**	**2019**	**2020**	**2021**	**2022**
Sooke			997	320	2,559
Sorrento	5,198	1,382	6,512	7,609	5,703
Sparwood	28,182	41,720	42,202	32,054	10,675
Squamish	8,606	9,770	10,856	12,688	31,404
Summerland	12,435	15,873	28,096	17,285	26,795
Sunshine Coast Regional	4,431	7,079	5,038	3,476	9,245
Surrey	1,584,871	1,429,065	1,314,120	1,890,622	2,069,243
Trail	32,102	20,952	35,044	18,820	37,851
University Endowment Lands	13,560	10,623	11,981	19,424	19,501
Vancouver	2,340,989	2,137,499	2,029,746	2,456,854	3,420,085
Vernon	57,664	61,035	96,734	60,763	65,752
Victoria	80,748	98,689	142,618	173,435	137,184
View Royal	307		2,800	8,506	
West Vancouver	253,297	211,358	229,408	348,195	332,159
Westbank	3,129	22,537	24,357	13,643	15,325
Whistler	11,318	3,590	8,755	16,681	18,997
White Rock	324,593	228,669	277,475	532,960	480,981
Williams Lake	8,650	14,036	19,796	18,614	37,984
Winfield	11,125	24,310	11,347	12,930	10,979
Total	**10,574,332**	**9,920,485**	**9,657,013**	**13,119,854**	**15,041,226**

1 **Table 3: 475-00 DS Mains Net Salvage Activity from 2018-2022 ($)**

Net salvage activity	**2018**	**2019**	**2020**	**2021**	**2022**
Company driven	1,029,985	1,342,531	853,393	1,507,798	1,364,982
Customer driven	135,788	174,033	204,623	516,637	447,758
Total	**1,165,773**	**1,516,563**	**1,058,016**	**2,024,435**	**1,812,740**

2 **Table 4: 475-00 DS Mains Net Salvage Activity by Location from 2018-2022 ($)**

	Net salvage activity				
Location	**2018**	**2019**	**2020**	**2021**	**2022**
100 Mile House	14,130	27			
Abbotsford/Matsqui	1,941	16,848	15,117	1,937	53,379
Armstrong	62	4,027		2,098	
Ashcroft			10,255		
Burnaby	164,120	171,319	29,656	145,056	72,438
Cache Creek	9,619	82	2,735	1,725	
Campbell River	795	6,853	5,263	5,732	
Campbell River Regional		2,055			

	Net salvage activity				
Location	2018	2019	2020	2021	2022
Castlegar		1,539	9,809	115,150	
Central Saanich		2,025			4,858
Chase			3,476	2,610	
Chemainus	436		16,238		
Chilliwack	10,382	8,103	55,712	24,950	19,758
Christina Lake					595
Coldstream	3,287	1,554			
Colwood	80	7,707	1,299	7,652	267
Comox				830	
Coquitlam	21,192	21,192	49,722	212,019	33,669
Courtenay		13,654	1,268	505	655
Courtenay District	10,984	123		5,317	
Cowichan Valley Regional	1,283		8,370	1,285	
Cranbrook	6,993	23,223	1,930	7,168	12,014
Creston	2,667		11,564	4,198	1,292
Cultus Lake		826			
Delta	8,877	69,284	48	32,849	32,191
Duncan				2,414	
Esquimalt	1,929		1,318	276	301
Fernie		2,720	7,135	1,050	12,033
Fort Nelson	19,585	16,498	22,320	35,729	8,132
Gibsons	598	4,167			
Grand Forks			42	8,385	85,229
Highlands				141	
Hope				427	88
Hudson Hope			620	9,862	
Kamloops	9,120	114,194	55,246	23,303	69,091
Kelowna	6,421	41,957	12,999	32,047	16,549
Kent	6,271	3,157		7,656	262
Kimberley		4,038	9,465		
Lac La Hache					2,081
Ladysmith	65	1,088		1,688	1,040
Lakeview Heights	2,939	8,447		6,226	21,623
Langford	7,883	4,562	59,859	15,253	48,935
Langley City	1,714	12,525	65	7,149	11,726
Langley District	18,707	92,223	59,413	88,923	26,945
Lantzville			1,364		5,800

	Net salvage activity				
Location	2018	2019	2020	2021	2022
Lumby			2,425	150	
Mackenzie					3,311
Maple Ridge	14,151	47,216	4,888	5,575	19,135
Merritt	5,989	2,628	-	4,877	2,621
Mission	99,833	19,646	924	94,378	69,704
Nanaimo	12,775	52,339	13,084	12,021	123,442
New Westminster	10,193	14,885		1,125	18,242
North Cowichan	5,008	130			
North Vancouver City	133,919	41,156	174,099	176,844	103,539
Oak Bay	3,982		3,876	6,925	
Okanagan Falls					8,117
Oliver	57	12,474		4,917	4,418
Osoyoos	2,105	12,616		2,719	
Parksville	273	1,042	14,841	2,299	1,537
Parksville / Qualicum Regional	296		303	1,522	
Penticton	10,725	82	5,763	946	16,444
Pitt Meadows	18,862	457	9,758	2,120	
Port Alberni	1,284	3,141			
Port Alberni Regional	1,032				
Port Coquitlam	2,997		867	6,043	3,996
Port Moody	26,817		255	98,135	50,928
Powell River	786	54	4,942		
Prince George	34,793	40,700	18,279	42,964	73,669
Princeton					8,654
Qualicum		984			
Quesnel	1,995	774	207	7,126	21,565
Revelstoke				2,078	
Richmond	49,064	170,916	72,432	90,409	44,377
Roberts Creek	354	98	248		7,764
Rossland		11,562			
Saanich	5,377	2,490	7,930	3,369	43,545
Salmon Arm	1,677		6,750	12,443	17,147
Savona	8,971				
Sechelt		4,910			4,264
Sidney	591				
Sooke	4,529		2,370	5,589	143
Sorrento				7,494	

	Net salvage activity				
Location	**2018**	**2019**	**2020**	**2021**	**2022**
Sparwood		1,250		14,812	664
Squamish		6,226	856	16,840	12,640
Summerland				3,688	360
Surrey	44,942	102,658	29,658	241,188	110,151
Trail		3,575			
University Endowment Lands	109,369	55,315	41	7,617	34
Vancouver	24,933	136,728	152,172	124,326	332,655
Vernon	25,003	1,983	10,886	1,868	7,326
Victoria	26,168	37,282	31,622	99,945	112,891
View Royal	717				
West Vancouver	39,615	34,444	14,385	68,022	9,140
Westbank	3,913	961	1,058		
Whistler	17,441	68	274		35,207
White Rock	3,333	34,913	3,386	35,433	3,586
Williams Lake	78,223	93	2,681	876	575
Winfield	1,598	4,747	14,451	6,145	
Total	**1,165,773**	**1,516,563**	**1,058,016**	**2,024,435**	**1,812,740**

In response to BCUC IR 41.3, Concentric stated that it is appropriate to increase the net salvage estimate to "minimize intergenerational equities and also give consideration to moderation and gradualism."

52.2 Please explain how increasing the net salvage estimate would "minimize intergenerational equities and also give consideration to moderation and gradualism."

Response:

The following response has been provided by Concentric:

Increasing the net salvage estimate to more closely align with FBC's actual cost of removal minimizes intergenerational inequities between customers using the assets today and those that will use the assets in the future. Allocating net salvage costs during the life of the related plant ensures that customers that are using the asset are also paying for the removal of that asset sometime in the future. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage in the future.

Moderation and gradualism are considered when changing net salvage estimates to ensure that indications of historical net salvage are sufficiently established before making large changes.

Attachment 51.1

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%.

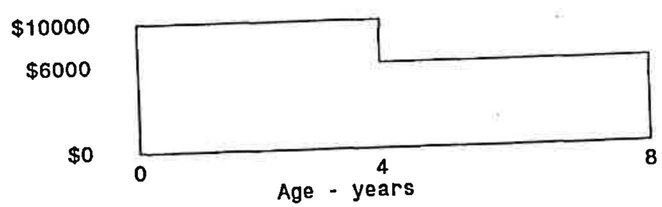

Figure 5.1. A survivor curve with an average life of 6.4 years.

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 provision 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

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 balance (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 ad-

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.