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April 8, 2024

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
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

Enclosed please find FortisBC's Application for Approval of a Rate Setting Framework for the years 2025 through 2027.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FEI and FBC 2020-2024 Multi-Year Rate Plan Proceeding; the Pre-Application Rate Setting Framework Workshop Participants and Stakeholders; and the Annual Reviews for 2024 Rates proceedings.

FortisBC Energy Inc.

and

FortisBC Inc.

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

April 8, 2024

Table of Contents

Index of Tables and Figures

List of Appendices

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for 2025 through 2027

Section A:

OVERVIEW

Table of Contents

Index of Tables and Figures

A: OVERVIEW

1. EXECUTIVE SUMMARY

1.1 APPLICATION AND REGULATORY PROCESS

FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (together, FortisBC, the Companies or the Utilities) each seek approval from the British Columbia Utilities Commission (BCUC) of a rate setting framework (Rate Framework or Framework) for the years 2025 through 2027 (Application). More specifically, FortisBC is seeking approval for a Rate Framework that includes, amongst other items, an indexed approach to FEI's and FBC's Operations and Maintenance (O&M) expense and FEI's Growth capital, a forecast cost of service approach to the remainder of FEI's Regular capital and all of FBC's Regular capital, Service Quality Indicators (SQIs) for FEI and FBC, and a refreshed innovation fund for FEI. FortisBC is also seeking approval of deferral accounts, updated depreciation rates and other supporting studies, and other approvals for the term of the Rate Framework. The approvals sought in the Application are set out in detail in Section A2, and draft forms of the final Orders sought are included in Appendix E2.

The Rate Framework builds on the key elements of FEI's and FBC's current multi-year ratemaking plan (Current MRP), while making changes to respond to the energy transition, stakeholder feedback, and other changes in FortisBC's operating environment. Reflecting the nature and scope of the Application and in recognition of the BCUC's desire to improve regulatory timetables, the Companies believe that this Application can be addressed efficiently and effectively by way of a written public hearing process. FortisBC has proposed a regulatory timetable that accounts for the potential for intervener evidence. FortisBC's proposed regulatory process is set out in Section A3 and a draft procedural order is included in Appendix E1.

1.2 RATE SETTING FRAMEWORK CONSIDERATIONS

Section B of this Application provides a review of the key considerations in FortisBC's proposals for its Rate Framework for the coming three years.

The Current MPR has performed well in a rapidly evolving external environment, including unprecedented pressure on rates for both gas and electric operations, driven by factors that are external to FortisBC's historical operations.

Key influences in the operating environment that are becoming increasingly predominant are:

- Policy direction and mandate from all levels of government towards decarbonization;
- Challenges related to energy affordability; and
- Addressing physical and cyber security, climate adaptation, and the ongoing need to invest in FortisBC's energy systems.

FortisBC continues to evolve its rate setting frameworks in response to the rapidly evolving operating environment, which has highlighted the critical interrelationships between the gas and electric systems and the need to provide dependable service to customers during times of peak demand, whether driven by load growth or by shifts in energy use between systems, or between times of the year, week, day, or hour. A key focus of this Application is on proposing flexible rate setting mechanisms that recognize the uncertainty inherent in the energy transition and that manage its impacts on the provision of affordable, reliable, and resilient service to customers in the face of heightened concern around the impacts of climate change, as well as physical and cyber security risks on BC's energy systems.

With this context, FortisBC has proposed a Rate Framework that includes:

1. A term that provides incentive to perform and the capacity to focus on key issues, while acknowledging the current level of uncertainty in the operating environment;
2. Sufficient funding to address emerging requirements and challenges;
3. Flexibility to adapt to the energy transition to manage its costs and impacts; and
4. An efficient annual rate-setting process that allows the Companies to focus on responding to the energy transition operationally and through key regulatory filings focused on the energy transition.

Overall, FortisBC's Rate Framework represents a continued evolution of its approach to rate setting in the midst of a challenging external environment.

1.3 *PROPOSED RATE SETTING FRAMEWORK*

Section C of the Application sets out the details of FortisBC's Rate Framework proposals. To address the energy transition and other influences in FortisBC's operating environment, and in consideration of the existing flexibility and features of its Current MRP and stakeholder feedback received, FortisBC has proposed:

- A shorter (three year) term for its Rate Framework.
- Continuation of the I-Factor, but with the labour and non-labour weightings fixed for the three-year term.
- Returning O&M savings to customers and a continuation of FortisBC's cost control focus through prioritization of spending and a unit cost approach to O&M and FEI growth capital, while proposing incremental O&M funding for key initiatives.
- Providing an opportunity for a detailed review of capital forecasts, base O&M, and productivity factors in this proceeding.
- Maintaining flow-through treatment for key elements such as Clean Growth Initiatives.
- Continued funding for FEI's Clean Growth Innovation Fund.

- Annual reporting on energy transition informational indicators for FEI.
- Continuation of the exogenous factor treatment, the 50:50 earnings sharing mechanism, and the financial off-ramp provisions.
- Continuation of the Annual Review process, providing an opportunity for discussion and review of the Companies' revenue requirements.

1.3.1 Components of the Rate Framework

The Rate Framework will be used to determine natural gas delivery rates and electricity rates over the 2025 to 2027 period. The table below summarizes the Rate Framework components. Most elements of the Rate Framework are identical for the two Companies.

Table A1-1: Summary of 2025-2027 Rate Framework

Item	2025-2027 Rate Framework	Section(s)
Term	A three-year term from 2025 to 2027, with the potential to extend the Rate Framework beyond 2027.	C1.2
Inflation Index (I-Factor)	A weighted average of AWE:BC for labour costs and CPI:BC for other costs will be used to determine the I-Index. FortisBC proposes to return to a fixed labour/non-labour weighting for the term of the Rate Framework.	C1.3
Productivity Factor (X-Factor)	***FEI***: An X-Factor of 0.38 percent, consisting of 0.28 percent industry O&M partial factor productivity (PFP) and 0.10 percent stretch factor for FEI's O&M and Growth capital indexing formulas. ***FBC:*** An X-Factor of 0.20 percent, consisting of 0.20 percent industry PFP and zero percent stretch factor for FBC's O&M indexing formula.	C1.4
Growth Factor	Continue with annual forecast of customer growth for FEI's and FBC's index-based O&M and gross customer additions (GCA) for FEI's Growth capital, both with a true-up to actual when available. In addition, FortisBC is proposing to eliminate the 0.75 discount factor currently applied to the growth factor for the O&M formula.	C1.5
Controllable Expenses – O&M	Continue with an indexed (I – X) unit cost approach for O&M. A 2024 Base O&M is established. O&M will not be rebased during the term of the Rate Framework but will be subject to true-up for actual customers.	C2
Controllable Expenses – Capital	***FEI***: Continue with an indexed (I – X) unit cost approach for Growth capital. The Growth capital formula is tied to the forecast GCA with the base unit cost developed using a regression of three-year actuals and projected results. Growth capital will not be rebased during the term of the Rate Framework but will be subject to true-up for actual GCA. Three-year forecast of Regular Sustainment and Other capital. ***FBC:*** Continue with a forecast of Regular Growth, Sustainment and Other capital expenditures for the term.	C3
Forecast O&M and Capital	Continue with specific O&M and capital items being forecast each year in the Annual Review with variances captured in the Flow-through deferral account or other deferral accounts.	C2 and C3

Item	2025-2027 Rate Framework	Section(s)
Incremental Capital	Continue with annual forecasting of incremental capital approved through CPCNs, OICs, or other Major Project proceedings.	C3
Forecast Revenues and Margins	Continue with annual forecast of revenues. For FEI, variances in revenue will continue to flow to either the RSAM deferral account (for RS 1, 2, 3, and 23) or the Flow-through deferral account. For FBC, variances in both revenue and power supply costs will continue to flow to the Flow-through deferral account.	C4
Deferral Accounts	Continue the use of rate base and non-rate base deferral accounts, with any required changes proposed at each year's Annual Review. Continue the use of a single Flow-through deferral account for each utility to capture all variances that are approved with flow-through treatment, except where a separate deferral account is approved.	C4
Innovation Fund	Continue the funding of innovation for FEI. Return unused funds from the Current MRP in 2025.	C5
Service Quality Indicators (SQIs)	***FEI***: 17 SQIs (8 SQIs with a target benchmark and 9 informational indicators) are proposed as measures of customer service, employee safety and reliability, as well as new informational indicators related to the energy transition. ***FBC***: 12 SQIs (7 SQIs with a target benchmark and 5 informational measures) are proposed as measures of customer service, employee safety, and reliability.	C6
Exogenous Factors (Z-Factor)	Continue with existing criteria (including existing materiality thresholds). Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and BCUC decisions will be flowed through in rates, subject to BCUC approval.	C1.6
Earnings Sharing Mechanism (ESM)	Continue with a 50:50 ESM between customers and the Companies for earnings above and below the allowed ROE.	C1.7
Efficiency Carryover Mechanism (ECM)	Remove the ECM from the Rate Framework.	C1.8
Off-Ramps	Continue with existing off-ramps.	C1.9
Annual Review Process	Retain the Annual Review process but with a more defined scope.	C1.10

1.3.2 Operations and Maintenance (O&M)

During the term of the Current MRP, FortisBC has prioritized and managed its overall O&M expenditures, delivering savings of $28.0 million[1] and $11.8 million[2] to FEI and FBC customers, respectively. The cost benchmark analysis performed by Dr. Kaufmann in Appendix C1-1 demonstrates that both Companies are performing efficiently. Specifically, when comparing average O&M costs per customer against industry peers, FEI performed slightly better than the average (i.e., 0.2 percent better than the average), while FBC performed significantly better than

1 Section B2.2.2.2, Table B2-8.
2 Section B2.2.2.2, Table B2-9.

the average (i.e., 35.0 percent better than the average). Further, when considering FortisBC's productivity under multi-year rate plans since 2014, Dr. Kaufmann's analysis shows that FEI and FBC have exceeded industry norms, generating significant cost savings for customers.

Under the Rate Framework, the amount to be included in rates for FortisBC's O&M expenses will continue to be determined by an index-based formula, supplemented by annual forecasts for categories of costs that are appropriately not subject to a formula. Together, the proposed formula and forecast O&M reflect FortisBC's best estimate of what will be needed to meet the challenges and requirements that will arise over the 2025 to 2027 Rate Framework term. This includes the O&M required to address the impacts of the energy transition and other new requirements, while continuing to meet service quality and reliability requirements, which is a key focus for FortisBC.

For the Rate Framework, both FEI and FBC established the 2024 Base O&M using the same method used to establish the 2019 Base O&M in the Current MRP, which was approved by Orders G-165-20 and G-166-20 (MRP Decision). The majority of FortisBC's O&M expenses will be determined by an indexed-based formula, which uses an O&M per customer amount adjusted for customer growth and inflation, less a productivity improvement factor. The starting point for determining the O&M per customer amount is the 2024 Base O&M, which is the adjusted actual O&M expenditures for 2023 expressed over the average number of customers for 2023, escalated by the approved formula indexing factors for 2024, and includes expected spending for 2024 and incremental funding proposed for the term of the Rate Framework.

Both FEI and FBC are requesting an increase to the 2024 Base O&M upon which the 2025 O&M formula spending envelope will be calculated. The 2024 Base O&M has been determined by returning the 2023 embedded savings from the Current MRP to customers ($4.322 million[3] and $4.235 million[4] to FEI and FBC customers, respectively), adjusting for certain exogenous factors and for the movement of certain items to or from flow-through treatment, adding amounts for required spending that will begin in 2024, and adding required net incremental funding for the term of the Rate Framework ($9.901 million[5] for FEI and $5.681 million[6] for FBC). FEI's 2024 Base O&M is forecast at $302.376 million and FBC's Base O&M is forecast at $76.394 million.

Similar to the Current MRP, FortisBC is proposing an indexing formula with inflation (I), productivity (X) and growth factors. FortisBC proposes to continue the use of a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to Statistics Canada's AWE:BC and non-labour indexed to the All-items Index for CPI:BC.[7] However, in order to improve efficiency, FortisBC proposes to return to fixed labour and non-labour weightings, which FortisBC considers is appropriate and more efficient.

[3] Section C2.2.1, Table C2-1.
[4] Section C2.3.1, Table C2-10.
[5] Section C2.2.1, Table C2-1.
[6] Section C2.3.1, Table C2-10.
[7] In Orders G-164-14 for FEI and G-182-14 for FBC, the BCUC approved the use of Statistics Canada CANSIM Table 326-0020 (now 18-10-0004-01) to determine the CPI:BC and CANSIM Table 281-0063 (now 14-10-0223-01) to determine AWE:BC.

FortisBC's proposed X-Factors are supported by the report of Dr. Kaufmann, who is an expert in the field of productivity studies. Based on productivity studies, benchmarking studies and other analysis, Dr. Kaufmann recommends:

- An X-Factor of 0.38 percent consisting of a 0.28 percent industry O&M partial factor productivity (PFP) and a 0.10 percent stretch factor for FEI's O&M and Growth capital indexing formulas.
- An X-Factor of 0.20 percent consisting of a 0.20 percent industry PFP and zero percent stretch factor for FBC's O&M indexing formula.

Dr. Kaufmann also recommends that there be no discount factor applied to FEI's and FBC's customer growth factors used in the O&M indexing formulas. As explained by Dr. Kaufmann, a discount on the Companies' customer growth factor would not be consistent with the structure and basic design of FortisBC's incentive regulation-based rate frameworks, as economies of scale are already captured in the X-Factor.

In addition to the index-based formula O&M, some items for each of FEI and FBC are forecast on an annual basis, and the variances between forecast and actual amounts are trued up through the Flow-through deferral account or through other deferral accounts.

The Companies propose to continue to treat the following items as Forecast O&M:

- Pension and OPEB expenses (FEI and FBC);
- Insurance premiums (FEI and FBC);
- BCUC levies (FEI and FBC);
- Integrity digs (FEI only); and
- Clean Growth Initiatives (FEI and FBC).

One new item is proposed for FEI and two new items are proposed for FBC for flow-through treatment starting in 2025:

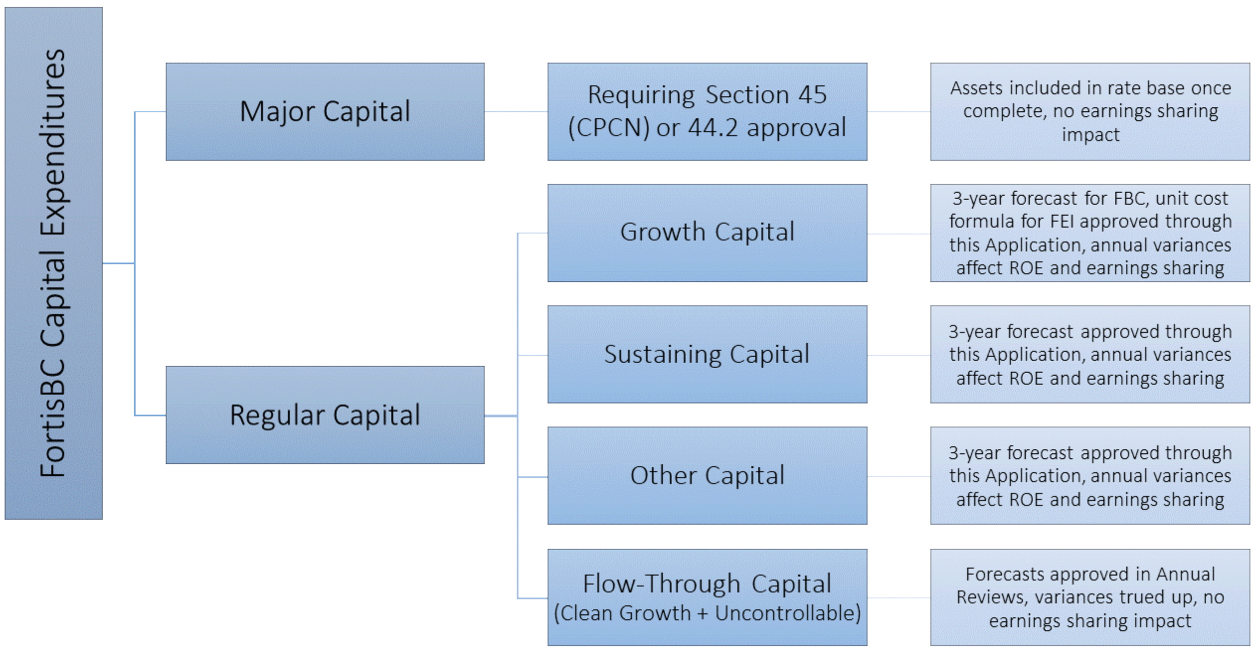
- Meter Reading and Other O&M costs for the Advanced Metering Infrastructure (AMI) project (FEI);
- Costs for the triennial Mandatory Reliability Standards (MRS) Audit (FBC); and
- MRS Assessment Report incremental costs (FBC).

This treatment remains appropriate as these categories of costs are not conducive to being included in an index-based O&M formula because they are either tied to parts of the business that are changing in response to government policy or are otherwise outside the control of management. In the case of the AMI project, this treatment is to ensure that only the actual costs incurred are recovered from customers, which is consistent with the approved treatment of CPCN expenditures.

1.3.3 Capital Expenditures

FortisBC is proposing to determine the majority of its capital expenditures using a three-year forecast of capital expenditures, while retaining a unit cost approach for only those categories of capital that can be suitably managed within a formula. The following diagram illustrates the categories of FortisBC's capital expenditures and their treatment.

Figure A1-1: Categories of Capital Expenditures and Treatment



The Application seeks approval of a forecast of FEI's Sustainment and Other capital and of FBC's Growth, Sustainment and Other capital expenditures from 2025 to 2027 which will be incorporated into FEI's and FBC's rates in those years. FEI is also proposing to continue with a unit cost approach for its Growth capital.

As is the case in the Current MRP, FEI and FBC will seek approval of Major Capital in separate proceedings.

1.3.3.1 FEI Growth Capital

FEI proposes to continue with a unit cost approach to determining Growth capital. The inputs used for calculating Growth capital for the term of the Rate Framework include:

1. **The 2024 Unit Cost Growth Capital Base:** FEI requests approval of a 2024 Base unit cost of $9,300 per Gross Customer Addition. This amount has been determined from a regression of the 2021-2023 actual unit costs of Growth capital, which incorporates the significant cost pressures that were experienced over the Current MRP term, including contractor price increases in 2022, increasing complexity in mains and services

installation, evolving local government restrictions and permitting requirements, and a higher number of system improvements.

2. **A forecast of gross customer additions:** A Gross Customer Addition is a new service to a new customer or customers. FEI proposes to continue to forecast its gross customer additions in each Annual Review, subject to a true-up in each subsequent year. This approach allows for Growth capital spending to reflect any changes in customer additions over the three-year term.

3. **The composite I-Factor value and productivity factor:** As in the Current MRP, a weighted average of AWE:BC for labour costs and CPI:BC for other costs will be recalculated in each Annual Review, less an approved productivity factor.

The following equation illustrates the formula applied to Growth Capital (GC):

$$GC_t = UCGC_{t-1} \times (1 + (I - X)) \times GCA_t + TUp_{t-2}$$

Where: *GCA= Gross Customer Additions*
UCGC = Unit Cost Growth Capital
I = Inflation Factor
X = Productivity Improvement Factor
t = Forecast year
TUp = True-up

The proposed formula and base unit cost for FEI's Growth capital is intended to allow the Company to make the capital investments necessary to add customers that request service while allowing a fair and balanced recovery of the costs. This approach will continue to allow expenditures to vary based on customer growth while maintaining accountability for expenditures to attach new customers based on the unit cost.

1.3.3.2 FEI Sustainment and Other Capital

FEI is seeking approval of the level of Sustainment and Other capital expenditures to be incorporated in rates over the term of the Rate Framework.

Tables A1-2 and A1-3 below summarize the 2025-2027 Forecast expenditures for Sustainment and Other capital, respectively, with 2023 and 2024 Approved amounts provided for comparison. Further details of FEI's forecast Sustainment and Other capital expenditures are provided in Sections C3.3.2 and C3.3.3, respectively.

Table A1-2: FEI Approved and Forecast Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Customer Measurement	30,015	30,494	14,295	13,459	13,422
Transmission System Relilability & Integrity	47,937	49,573	60,065	75,133	66,469
Distribution System Reliability	15,341	17,709	21,245	17,254	9,237
Distribution System Integrity	36,043	32,852	29,993	25,887	36,356
Total Sustainment Capital (Gross)	**129,336**	**130,628**	**125,599**	**131,733**	**125,484**
Sustainment CIAC	(4,342)	(4,342)	(4,436)	(8,443)	(4,615)
Total Sustainment Capital (Net)	**124,994**	**126,286**	**121,163**	**123,290**	**120,869**

Table A1-3: FEI Approved and Forecast Other Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Equipment	12,270	12,240	14,989	16,123	18,421
Facilities	14,686	11,349	18,727	13,053	8,551
Information Systems	24,458	24,563	25,300	25,800	26,500
Corporate Security	3,100	3,100	8,887	7,720	7,741
Total Other Capital	**54,514**	**51,252**	**67,904**	**62,696**	**61,213**

FEI will realize a large reduction in the Customer Measurement portfolio starting in 2025 due to the deployment of the AMI project. Despite this reduction, overall spending on Sustainment capital is forecast to remain at a similar level to that approved for 2023 and 2024. This is because the reduction in Customer Measurement spending is offset by increased spending on pipeline alterations due to the need to address an increased number of regulatory compliance-driven class location upgrades, as well as an increase in pipeline inspection costs to reflect the recently approved ability to conduct in line inspections using electromagnetic acoustic transducer (EMAT) tools.

Other capital is forecast to increase as Equipment and Facilities are entering a large capital replacement cycle due to their age. FEI is also proposing increased investment in physical and cybersecurity, including increased expenditures in patch management, given the need to address the risk environment.

1.3.3.3 FBC Growth, Sustainment and Other Capital

FBC is seeking approval of the level of Growth, Sustainment and Other capital expenditures to be incorporated in rates over the term of the Rate Framework.

Tables A1-4 to A1-6 below summarize the 2025-2027 Forecast expenditures for Growth, Sustainment and Other capital, with 2023 and 2024 Approved amounts provided for comparison. Further details of FBC's forecast Growth, Sustainment and Other capital expenditures are provided in Sections C3.4.1 through C3.4.3 of the Application.

Table A1-4: FBC Approved and Forecast Growth Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Transmission	6,223	1,088	16,418	19,323	20,149
Distribution	1,899	1,716	1,775	1,747	1,814
New Connects	21,951	21,764	23,156	23,965	24,395
Total Growth (Gross)	**30,072**	**24,568**	**41,349**	**45,035**	**46,357**
CIAC (New Connect)	(10,218)	(6,925)	(8,085)	(8,364)	(8,485)
Total Growth (Net)	**19,854**	**17,643**	**33,264**	**36,671**	**37,871**

Table A1-5: FBC Approved and Forecast Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Generation	7,623	7,225	12,823	13,298	15,274
Transmission Sustainment	9,159	12,800	13,604	9,149	8,991
Stations Sustainment	6,841	8,209	20,486	23,627	24,783
Distribution Sustainment	17,480	18,219	22,446	19,014	18,291
Telecommunications	3,606	5,199	6,304	7,028	3,971
Total Sustainment (Gross)	**44,710**	**51,652**	**75,664**	**72,116**	**71,310**
Sustainment CIAC	(1,410)	(614)	(765)	(791)	(816)
Total Sustainment (Net)	**43,300**	**51,038**	**74,899**	**71,326**	**70,494**

Table A1-6: FBC Approved and Forecast Other Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Equipment	4,099	3,717	6,307	6,194	5,842
Facilities	4,305	4,096	6,945	6,792	4,763
Information Systems	8,246	8,372	9,150	9,400	9,550
Corporate Security	1,008	1,028	2,668	2,536	2,544
Total Other Capital	**17,658**	**17,213**	**25,070**	**24,922**	**22,699**

FBC is forecasting increases across all categories of capital expenditures.

The primary drivers for the increase in Growth and Sustainment capital expenditures are increased requirements for system improvements to accommodate load growth, upgrades to aging generation assets to meet current codes and standards, and equipment replacements necessary to address condition, aging infrastructure and improve reliability.

Similar to FEI, Other capital is forecast to increase as fleet, facilities and building equipment are entering a capital replacement cycle due to their age. FBC is also proposing increased investment in physical and cyber security, including increased expenditures in patch management, given the need to address the risk environment.

1.3.4 Annual Calculation of the Revenue Requirement

As in the Current MRP, FEI and FBC will calculate their respective revenue requirements and rates in each Annual Review during the term of the Rate Framework. Section C4 describes the cost and revenue items required to determine the Companies' annual revenue requirements, which will be included in each year's Annual Review materials.

As in the Current MRP, FEI and FBC will forecast each year's delivery revenues (for FEI), revenue and power supply costs (for FBC), depreciation and amortization expense, property taxes, other revenue, interest expense, income tax, return on equity (ROE) and rate base other than those capital expenditures that have been approved in this proceeding.

FortisBC proposes to continue with exogenous factor treatment for events meeting the approved exogenous factor criteria. Subject to BCUC approval, customers' rates will be adjusted either up or down for the cost of service impacts of exogenous events that are beyond the control of the Companies. Exogenous factor treatment of such items will ensure that customers pay only for the actual costs in circumstances where FortisBC does not control the level of expenditures.

As in the Current MRP, FortisBC proposes the continuation of the 50:50 sharing of variances in ROE. Where variances are proposed to be flowed through in future revenue requirements, they will not affect the ROE. Instead, they will be captured in a single Flow-through deferral account, except where a previously approved deferral account already exists.

FortisBC proposes that the structure of the Annual Review process remains the same. However, FortisBC considers that regulatory efficiency can and should be improved in the Annual Review process through a clearer scoping of topics permitted to be explored in IRs (or at the workshop). Therefore, FortisBC proposes that certain topics approved by the BCUC as part of the Rate Framework, including FortisBC's demand/load forecast methods, be out of scope of the Annual Reviews, thus allowing the Companies, the BCUC, and interveners to focus on the in-scope issues and generally improve the efficiency of the process.

1.3.5 FEI Clean Growth Innovation Fund

The importance of the clean energy transition, supported by policy direction from all levels of government, has amplified the urgency for innovation and the adoption of new technologies in the energy sector to advance decarbonization. Recognizing this imperative, FEI is seeking to renew and enhance the Clean Growth Innovation Fund (CGIF) to expedite clean energy innovation. The CGIF supports the CleanBC goal of decarbonization by advancing innovative technologies that will help FEI reduce GHG emissions for its customers and support the transition to a lower carbon economy while optimizing the use of its gaseous energy delivery system for the benefit of its customers.

FEI is proposing to return the unused funds from its 2020 CGIF to customers in 2025, and to continue the CGIF rate rider for the Rate Framework term to support the clean energy transition along the gas value chain with specific enhancements, including a broader focus on cost mitigation and an additional criterion for resilience. In particular, the proposed enhancements to the CGIF will support and advance British Columbia's clean energy transition by investing in solutions that will reduce GHG emissions in the Province while mitigating costs for customers. At the end of the Rate Framework term, FEI proposes to return any unused balance in the CGIF to customers.

1.3.6 Service Quality Indicators

The current suite of Service Quality Indicators (SQIs) for FEI and FBC have been appropriate and useful in monitoring the Companies' performance to ensure that any efficiencies and cost reductions do not result in a degradation of service quality. For the Rate Framework, FortisBC reviewed the current SQIs to assess their continued appropriateness in measuring service quality and for the level of the benchmarks and thresholds for each metric. Based on this review, FEI and FBC are proposing updates and modifications to the existing suite of SQIs in order to build on the experience gained during the Current MRP term.

FortisBC is proposing updates to the benchmarks and/or thresholds for the All Injury Frequency Rate (AIFR) indicator, FEI's Public Contact with Gas Lines indicator, and FBC's System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) indicators. FortisBC is also proposing to make the "Meter Reading Accuracy" metric an informational indicator and rename it "Meter Reading Completion" to better reflect what the metric is measuring.

Reflecting FortisBC's key focus for this Application, FEI is proposing a new category of informational indictors specific to the energy transition.

1.3.6.1 FEI's Proposed Service Quality Indicators

The following table provides a comparison of FEI's current and proposed SQIs. The areas of the table that are shaded green reflect changes to existing indicators as well as new indicators.

Table A1-7: Comparison of FEI Current and Proposed SQIs

Safety Indicators		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	Emergency Response Time	>= 97.7%	96.2%	>=97.7%	96.2%
Annual results	Telephone Service Factor (Emergency)	>= 95%	92.8%	>=95%	92.8%
3 Year rolling average	All Injury Frequency Rate	<= 2.08	2.95	<= 1.64	2.21
Annual results	Public Contacts with Gas Lines	<=8	12	<=6	10
Responsiveness to Customer Needs Indicators					
Annual results	First Contact Resolution	>= 78%	74%	>=78%	74%
Annual results	Billing Index	<= 3	5	<=3	5
Annual results	Meter Reading Completion	>= 95%	92%	Informational	Informational
Annual results	Telephone Service Factor (Non Emergency)	>= 70%	68%	>=70%	68%
Annual results	Meter Exchange Appointment Activity	>=95%	93.8%	>=95%	93.8%
Annual results	Customer Satisfaction Index	Informational	Informational	Informational	Informational
Annual results	Average Speed of Answer	Informational	Informational	Informational	Informational
Reliability Indicators					
Annual results	Transmission Reportable Incidents	Informational	Informational	Informational	Informational
Annual results and 5 Year rolling average	Leaks per KM of Distribution System Mains	Informational	Informational	Informational	Informational
Energy Transition Indicators					
Annual results	Scope 1 Emissions	N/A	N/A	Informational	Informational
Annual results	Renewable and Low Carbon Energy Supply Volume	N/A	N/A	Informational	Informational
Annual results	Natural Gas for Transportation Volume	N/A	N/A	Informational	Informational
Annual results	Demand Side Management Energy Savings	N/A	N/A	Informational	Informational

1.3.6.2 FBC's Proposed Service Quality Indicators

The following table provides a comparison of FBC's current and proposed SQIs. The four metrics with green shaded areas reflect changes from the current SQIs.

Table A1-8: Comparison of FBC Current and Proposed SQIs

		Current		*Proposed*	
Safety Indicators		Benchmark	Threshold	Benchmark	Threshold
Annual results	**Emergency Response Time**	>= 93%	90.6%	>=93%	90.6%
3 Year rolling average	**All Injury Frequency Rate**	<= 1.64	2.39	<=1.31	2.56
Responsiveness to Customer Needs Indicators					
Annual results	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual results	**Billing Index**	<= 3	5	<=3	5
Annual results	**Meter Reading Completion**	>= 98%	96%	Informational	Informational
Annual results	**Telephone Service Factor**	>= 70%	68%	>=70%	68%
Annual results	**Customer Satisfaction Index**	Informational	Informational	Informational	Informational
Annual results	**Average Speed of Answer**	Informational	Informational	Informational	Informational
Reliability Indicators					
Annual results	**System Average Interruption Duration Index - Normalized**	3.22	4.52	3.24	4.71
Annual results	**System Average Interruption Frequency Index - Normalized**	1.57	2.19	1.64	2.25
Annual results	**Generator Forced Outage Rate**	Informational	Informational	Informational	Informational
Annual results	**Interconnection Utilization**	Informational	Informational	Informational	Informational

1.4 *SUPPORTING STUDIES*

This Application seeks approval of updated versions of the various studies that will support the calculation of revenue requirements for the term of the Rate Framework. Specifically, FortisBC has updated studies that will support the calculation of FortisBC's revenue requirements for the term of the Rate Framework. These include Depreciation Studies, Lead/Lag Studies, a Corporate Services Study, and Capitalized Overhead Studies.

In addition to the studies referenced above, FortisBC completed a review of the Cost Driver Approach for shared services between FEI and FBC, which was previously approved for use by the BCUC for the Current MRP. Based on discussions with the departments sharing services and a review of the cost pools for the shared resources, FortisBC confirmed that the Cost Driver Approach, using the four current cost drivers remain appropriate. As part of the Cost Driver Approach, during the Rate Framework term, FortisBC will annually review the allocation basis for each cost driver (e.g., for costs allocating using the number of customers, the numbers of FEI and FBC customers will be updated to determine the allocation percentage used) and update the percentages as required.

1.4.1 Depreciation Studies

FEI and FBC are proposing updates to their respective depreciation rates and net salvage rates based on the results of the depreciation studies in Appendix D2-1 (FEI) and Appendix D2-2 (FBC) (2022 Depreciation Studies).

For FEI, implementation of the 2022 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of Contributions in Aid of Construction (CIAC) rates, results in a net increase of aggregate depreciation and net salvage expense of approximately $2.0 million per year, a 0.02 percent overall increase to the composite depreciation rate compared to the current approved rates.

For FBC, implementation of the 2022 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of CIAC rates, results in a net increase of aggregate depreciation and net salvage expense of approximately $4.3 million per year, an approximate 0.20 percent overall increase to the composite depreciation rate compared to the current approved rates.

1.4.2 Lead-Lag Studies for Cash Working Capital

FortisBC is requesting approval to adopt updated lead-lag days as determined in the 2023 Lead-Lag Studies in Appendix D3-1 for FEI and Appendix D3-2 for FBC.

The results for FEI are as follows:

- When applied to 2024 approved data, the 2023 Lead-Lag Study results in a net lag of 5.1 days, which is consistent with the net lag of 5.1 days that results when using the previous approved Lead-Lag study.
- This difference of 0.0 days is the result of a 1.2 day decrease in expenditure lead days, offset by a 1.2 day decrease in revenue lag days. The decrease in expenditure lead days is primarily attributable to a shorter payment lead for carbon tax and PST remittances as

well as a shorter service lead for O&M expenditures. The decrease in revenue lag days is primarily attributable to a decrease in collection lag for residential customers.

- The updated study has no impact to total cash working requirements.

The results for FBC are as follows:

- When applied to 2024 approved data, the 2023 Lead-Lag Study results in a net lag of 12.7 days as compared to a net lag of 9.6 days that results when using the previous approved Lead-Lag study.
- The difference of 3.1 days is the result of a 4.7 day decrease in expenditure lead days offset by a 1.6 day decrease in revenue lag days. The decrease in expenditure lead days is primarily due to automation of the power purchase payment process resulting in a shorter payment lead. This was offset by a decrease in revenue lag days primarily due to a decrease in service lag days for residential customers due to an increase in customers billed monthly vs bi-monthly.
- When applied to the forecast revenues and operating expenses for 2024, this change in net days would have resulted in an increase of approximately $2.4 million in cash working capital ($3.7 million increase from expenses offset by a $1.3 million decrease from revenues).

1.4.3 Corporate Services Study

FortisBC is requesting approval of the methodologies of allocating common corporate service costs from Fortis Inc. (FI) and FortisBC Holdings Inc. (FHI) to FEI and FBC. The allocation methodologies include a formula that is based on total assets, excluding goodwill, and controllable operating expenses for FI corporate services, and the use of a Massachusetts Formula for FHI corporate service allocations. Both methodologies and the nature of the FI and FHI corporate service costs have been reviewed and endorsed by KPMG in the 2023 Corporate Service Cost Study (2023 CSC Study) included in Appendix D4-1. FortisBC is seeking approval of the allocation methodology, rather than the forecast of corporate service costs. The actual costs and allocation percentages will vary each year of the Rate Framework depending on the size of the eligible corporate cost pool at FI and FHI, as well as the relative size of the FI and FHI allocators.

The allocation of FI and FHI corporate service costs has been reviewed by KPMG in the 2023 CSC Study. In Section 7 of the 2023 CSC Study, KPMG states:

> KPMG evaluated FI's and FHI's corporate service cost allocation methodologies in alignment with evaluation criteria introduced in Section 2.3 of the 2023 CSC Study. Overall, both allocation methodologies appear to be a reasonable mechanism to allocate corporate service costs.

Based on the recommendations from the 2023 CSC Study, FortisBC will continue to apply the methodology of aggregating its common corporate service costs from FI and FHI and allocating them to FEI and FBC using the methodologies described above and in more detail in the 2023 CSC Study.

1.4.4 Capitalized Overhead Studies

For the term of the Rate Framework, FEI is proposing to apply a capitalized overhead rate of 14.5 percent of gross O&M, net of biomethane O&M transferred to the BVA, and FBC is proposing to apply a capitalized overhead rate of 15.5 percent of gross O&M, to regular capital expenditures. This compares to the 16 percent for FEI and 15 percent for FBC used during the term of the Current MRP. The capitalized overhead rates reflect a reasonable basis for capitalization of costs related to capital activities for both FEI and FBC that have not been directly charged to capital projects. The allocation of capitalized overhead costs is consistent with the methodology from prior years' studies and filings, and corroborated with established rate-regulated utility practice, the BCUC's Uniform System of Accounts (USofA), and US GAAP.

FortisBC engaged KPMG to perform a review of its capitalized overhead methodology for the term of the Rate Framework. The 2023 Capitalized Overhead Study for FEI is included in Appendix D5-1 and the 2023 Capitalized Overhead Study for FBC is included in Appendix D5-2.

FEI estimates that the impact on customer delivery rates of a change to the capitalized overhead rate is approximately 0.35 percent for every 1 percent change in the capitalized overhead rate. Therefore, all else equal, decreasing the capitalized overhead rate from 16 percent to 14.5 percent would increase customer delivery rates by approximately 0.52 percent in the year of implementation (2025 in this case).

FBC estimates that the impact on customer rates of a change to the capitalized overhead rate is approximately 0.17 percent for every 1 percent change in the capitalized overhead rate. Therefore, all else equal, increasing the capitalized overhead rate from 15 percent to 15.5 percent would decrease customer rates by approximately 0.09 percent in the year of implementation (2025 in this case).

1.5 CONCLUSION

FortisBC's Rate Framework should be approved by the BCUC. The Rate Framework incorporates flexible rate setting mechanisms that recognize the uncertainty inherent in the energy transition and the need to manage its impacts on the provision of affordable, reliable, and resilient service to customers in the face of heightened concern around the impacts of climate change, as well as physical and cyber security risks on BC's energy systems.

FortisBC believes that the Rate Framework strikes a reasonable balance, by providing the necessary flexibility for FortisBC to manage the impacts of the energy transition (through annual updating of forecasts and costs), while continuing to incent FortisBC to control its ongoing operating and capital costs. FortisBC continues to believe in the fundamental principles behind incentive regulation. The majority of the Companies' O&M costs, and also the unit costs of FEI's growth capital, can still benefit from the discipline imposed by an indexing approach. Similarly, the majority of the Companies' capital costs remain subject to a three-year forecast, providing incentive to control costs during the term of the Rate Framework. The Rate Framework also provides for regulatory efficiency by establishing the parameters for what can and should be reviewed during each Annual Review.

2. APPROVALS SOUGHT

2.1 INTRODUCTION

In this Application, FEI and FBC are respectfully seeking an Order or Orders from the BCUC, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), granting the approvals set out in Sections A2.2 and A2.3, respectively. Draft forms of Order sought for FEI and FBC are included in Appendix E of the Application.

2.2 FEI APPROVALS

Proposed Rate Framework

1. Approval of the rate setting mechanisms set out in Section C1 and in Table C1-1 of this Application for setting delivery rates for the years 2025 through 2027, including:

   a) A three-year term from 2025 to 2027, with the potential to extend the term beyond 2027, subject to review and approval by the BCUC (Section C1.2);

   b) Use of an index-based approach to Base O&M and Growth capital, incorporating:

      i) A 2024 Base O&M per customer, as described in Section C2.4;

      ii) A 2024 Base Unit Cost Growth Capital of $9,300, as described in Section C3.3.1.2.2, Table C3-4;

      iii) An inflation factor as set out in Section C1.3, including a fixed labour weighting of 51 percent and fixed non-labour weighting of 49 percent;

      iv) An X-Factor of 0.38 percent, as set out in Section C1.4.2;

      v) A growth factor set at 100 percent of the growth in average number of customers for O&M and 100 percent of Gross Customer Additions for Growth capital, with a true-up to actual when available, all as set out in Section C1.5;

   c) Approval of the level of forecast Sustainment and Other capital to be incorporated in rates over the term of the Rate Framework, as set out in Section C3.3;

   d) Flow-through treatment for the items described in Section C4.13.2 and Table C4-7;

   e) Exogenous factor treatment as described in Section C1.6;

   f) The Service Quality Indicators listed in Table C6-2 of Section C6.3 and described in Appendix C6-1;

g) Continuation of the Earnings Sharing Mechanism, with half of ROE variances to be shared with customers as set out in Section C1.7;

h) Off ramps as described in Section C1.9; and

i) The Annual Review process, with changes to the scope of the Annual Reviews, as described in Section C1.10, including approval of FEI's demand forecasting methods for the term of the Rate Framework.

Clean Growth Innovation Fund (CGIF)

2. Approval to return to customers the balance in the 2020 CGIF and to establish the 2025 CGIF and rate rider for the term of the Rate Framework as follows:

   a) Establish the non-rate base 2025 CGIF, attracting a WACC return, to record the funding collected through the Innovation Fund rate rider and the expenditures. Any residual balance will be returned to customers at the end of the Rate Framework;

   b) Continue the Innovation Fund basic charge rate rider of $0.40 per month during the term of the Rate Framework; and

   c) Return the ending balance of the 2020 CGIF to customers through amortization of the deferral account over one year in 2025.

Core Market Administration Expense (CMAE)

3. Approval of the following regarding CMAE during the term of the Rate Framework:

   a) To continue to forecast the CMAE budget by cost component using a new, simplified template, as described in Appendix C4-3;

   b) To submit the CMAE forecast for approval as a separate application at or near the same time as FEI's Third Quarter Gas Cost Report;

   c) To review the prior year's forecast to actual CMAE variances within the CMAE forecast application, using the new, simplified template;

   d) To continue to treat CMAE as part of FEI's Cost of Gas, allocating 25 percent of costs to the Commodity Cost Reconciliation Account (CCRA) and 75 percent to the Midstream Cost Reconciliation Account (MCRA); and

   e) To record the variances between forecast and actual CMAE in the CCRA and MCRA using the same allocation as is used to allocate the forecast CMAE.

Supporting Studies

4. Approvals of the following based on supporting studies to be used in the determination of rates for FEI effective January 1, 2025:

   a) Depreciation rates in the amounts set out in Table D2-3 in Section D2.2;

b) Net salvage rates in the amounts set out in Table D2-4 in Section D2.2;

c) Modification to the approved Lead Lag days as set out in Table D3-1, Section D3.2;

d) The methodologies of allocating common corporate service costs from Fortis Inc. and FortisBC Holdings Inc. to FEI, as set out in Section D4; and

e) The capitalized overhead rate of 14.5 percent, as set out in Section D5.4.

Other Approvals

5. Approval to continue the use of the non-rate base Flow-through deferral account, attracting a WACC return, as described in Section C4.13.2 and Table C4-7.

6. Approval of Exogenous Factor treatment for the 2021 Flood costs, as described in Section C1.6.1.

7. Approval to maintain the CPCN threshold for FEI at $15 million during the term of the Rate Framework.

2.3 *FBC APPROVALS*

Proposed Rate Framework

1. Approval of the rate setting mechanisms set out in Section C1 and in Table C1-1 of this Application for setting rates for the years 2025 through 2027, including:

   a) A three-year term from 2025 to 2027, with the potential to extend the term beyond 2027, subject to review and approval by the BCUC (Section C1.2);

   b) Use of an index-based approach to Base O&M, incorporating:

      i) A 2024 Base O&M per customer, as described in Section C2.4;

      ii) An inflation factor as set out in Section C1.3, including a fixed labour weighting of 61 percent and fixed non-labour weighting of 39 percent;

      iii) An X-Factor of 0.20 percent, as set out in Section C1.4.3;

      iv) A growth factor set at 100 percent of the growth in average number of customers, with a true-up to actual when available, as set out in Section C1.5;

   c) Approval of the level of forecast Growth, Sustainment and Other capital to be incorporated in rates over the term of the Rate Framework, as set out in Section C3.4;

   d) Flow-through treatment for the items described in Section C4.13.2 and Table C4-7;

e) Exogenous factor treatment as described in Section C1.6;

f) The Service Quality Indicators listed in Table C6-7 of Section C6.4 and described in Appendix C6-2;

g) Continuation of the Earnings Sharing Mechanism, with half of ROE variances to be shared with customers as set out in Section C1.7;

h) Off ramps as described in Section C1.9; and

i) The Annual Review process, with changes to the scope of the Annual Reviews, as described in Section C1.10, including approval of FBC's load forecasting methods for the term of the Rate Framework.

Supporting Studies

2. Approvals of the following based on supporting studies to be used in the determination of rates for FBC effective January 1, 2025:

   a) Depreciation rates in the amounts set out in Table D2-7 in Section D2.3;

   b) Net salvage rates in the amounts set out in Table D2-8 in Section D2.3;

   c) Modification to the approved Lead Lag days as set out in Table D3-2, Section D3.3;

   d) The methodologies of allocating common corporate service costs from Fortis Inc. and FortisBC Holdings Inc. to FBC, as set out in Section D4; and

   e) The capitalized overhead rate of 15.5 percent, as set out in Section D5.4.

Other Approvals

3. Approval to continue the use of the non-rate base Flow-through deferral account, attracting a WACC return, as described in Section C4.13.2 and Table C4-7.

4. Approval to maintain the CPCN threshold for FBC at $20 million during the term of the Rate Framework.

3. PROPOSED REGULATORY PROCESS

FortisBC considers that this Application can be addressed efficiently and effectively by way of a written public hearing process that includes two rounds of information requests (IRs) and an opportunity for interveners to file evidence.

The draft regulatory timetable proposed below enables ample public participation in the proceeding while aligning with the BCUC's Final List of Efficiencies issued as part of the Regulatory Efficiency Initiative.[8] Consistent with the BCUC's goal to improve regulatory timetables, FortisBC has proposed a draft regulatory timetable for the entire proceeding – thereby establishing a "clear path" towards the completion of the proceeding and greater certainty for participants. Additionally, FortisBC has incorporated additional time after the filing of the Application and after the filing of IR No. 1 responses to allow the BCUC time to provide directions on scoping of issues. In particular, while FortisBC considers two rounds of IRs to be appropriate given the nature and scope of the Application, FortisBC notes the expectation established in the BCUC's Final List of Efficiencies that second round IRs will be used to seek clarification of IRs from the prior round.

The proposed timetable also takes into consideration the following:

- That the BCUC, interveners, and the Companies have five years of experience with the Current MRP on which the Rate Framework is based;
- While this Application is about setting the Rate Framework for the upcoming three-year term, FortisBC is proposing Annual Reviews each year of the Rate Framework to set rates and review applicable revenue requirement items; and
- FortisBC has filed a comprehensive and detailed Application.

FortisBC has provided a draft regulatory timetable below that accounts for the potential for intervener evidence. This timetable contemplates the BCUC issuing a procedural order on or before May 10, 2024.

Table A3-1: Proposed Regulatory Timetable

Action	Dates (2024)
FortisBC publishes notice by	Friday, May 24
FortisBC confirmation of notice	Wednesday, May 29
Intervener registration deadline	Friday, June 7
BCUC Information Request (IR) No. 1	Tuesday, June 11
Intervener IR No. 1	Tuesday, June 18
Companies' Responses to IR No. 1	Tuesday, July 23
Intervener confirmation of intent to file Evidence	Friday, August 9
BCUC and Intervener IR No. 2	Tuesday, August 20

8 https://docs.bcuc.com/documents/other/2023/doc_75555_bcuc-regulatory-efficiency-initiative-final.pdf.

Action	Dates (2024)	
BCUC notice of remaining timetable	Tuesday, August 27	
Companies' responses to IR No. 2	Thursday, September 12	
Action	**Without Evidence**	**With Evidence**
Intervener Evidence		Tuesday, October 1
IRs on Intervener Evidence		Wednesday, October 23
Intervener Responses to IRs on Evidence		Thursday, November 14
Companies Rebuttal Evidence (if required)	Not Applicable	Tuesday, December 3
IRs on Rebuttal Evidence (if required)		Thursday, December 19
		Dates (2025)
Companies' Response to IRs on Rebuttal (if required)		Tuesday, January 14
Letters of comment deadline	Thursday, September 19	Thursday, January 16
FortisBC final argument	Friday, October 4	Tuesday, January 21
Intervener final arguments	Friday, October 25	Tuesday, February 11
FortisBC reply argument	Monday, November 18	Tuesday, March 4

In addition to the procedural steps set out above, FortisBC proposes that it host a targeted workshop on demand/load forecasting to assist the BCUC and interveners in understanding the forecast methods that are currently employed by the Companies in their annual short-term forecasting, and the other forecast methods that can be used to determine longer term trends and impacts of the energy transition. FortisBC proposes that the workshop be held between IR No. 1 and IR No. 2, as parties will have had the opportunity to explore technical details of the load forecasting methods in the first round of IRs, which will help to inform the discussions at the workshop. Additionally, through questions and discussion at the workshop, issues can be explored and resolved prior to the second round of written IRs, thus improving the efficiency of IR No. 2. Accordingly, FortisBC proposes that the workshop be held either the week of August 6th or the week of August 12th. The exact timing of the workshop can be determined once the BCUC has issued its procedural order and after discussion with interveners and the BCUC on a date that accommodates the availability of all parties.

Following a Decision on this Application, which will determine the Rate Framework and specific elements of the annual rate setting process, FEI and FBC will file their respective Annual Review materials for setting 2025 rates. Based on the timetables proposed above, it is unlikely that the Annual Reviews for 2025 rates will be completed in time to have permanent rates effective January 1, 2025. As such, FEI and FBC expect to seek approval of rates, on an interim basis, effective January 1, 2025, some time in the Fall of 2024.

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for 2025 through 2027

Section B:

RATE SETTING FRAMEWORK CONSIDERATIONS

Table of Contents

Index of Tables and Figures

B: RATE SETTING FRAMEWORK CONSIDERATIONS

1. ENERGY TRANSITION INFLUENCES ON THE RATE SETTING FRAMEWORK

1.1 INTRODUCTION

In this Application, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (together, FortisBC, the Companies or the Utilities) sets out their proposed rate setting framework (Rate Framework or Framework) for the three years 2025 to 2027. In developing its proposals in this Application, FortisBC has considered the impacts of the energy transition on its customers and operations and has reflected these impacts in the proposed term and other elements of the Rate Framework.

A key focus of this Application is on proposing flexible rate setting mechanisms that recognize the uncertainty inherent in the energy transition and that manage its impacts on the provision of affordable, reliable and resilient service to customers in the face of heightened concern around the impacts of climate change, as well as physical and cyber security risks on BC's energy systems. For more than a decade, FortisBC has been evolving its rate setting frameworks to help manage the early impacts of the energy transition, and five years have passed since FortisBC filed its 2020-2024 Multi-year Rate Plan (MRP) Application. During this time, many CleanBC policies have advanced to implementation stages, the impacts of the energy transition are now more pervasive in both gas and electric operations, and further adjustments to the rate setting frameworks are needed.

In Sections B1.2 and B1.3, FortisBC provides information on the energy transition and the policies guiding the energy transition. Section B1.4 describes the energy transition impacts on FEI and FBC. Section B1.5 discusses the challenges related to energy affordability, and Section B1.6 addresses physical and cyber security, climate adaptation, and the ongoing need to invest in FortisBC's energy systems.

1.2 THE ENERGY TRANSITION

The energy transition, a pivotal shift in the global energy sector, represents the movement from fossil fuel-based energy to energy based on renewable and low carbon sources. The International Energy Agency (IEA) World Energy Outlook 2023[9] describes this transition as a complex and multifaceted process, involving a substantial overhaul of existing infrastructure and market dynamics. The aim is to meet rising energy demands while simultaneously reducing greenhouse gas emissions to mitigate the impacts of climate change and adapting infrastructure to a changing climate.

[9] https://www.iea.org/reports/world-energy-outlook-2023/executive-summary.

The energy transition is expected to develop differently across jurisdictions such that jurisdiction-specific characteristics will frame available pathways to a lower carbon future.[10] Regardless of the pathway, there is a need for the energy transition to consider affordability, security, and resilience. This is recognized by the IEA which highlights three important issues, including risks in affordability, electricity security, and the resilience of energy supply chains.[11] Echoing this sentiment, the Honourable Josie Osborne, Minister of Energy, Mines and Low Carbon Innovation, emphasizes that affordability should be a cornerstone of British Columbia's energy transition.[12] This commitment to balancing affordability and climate action is reflected in the Premier's mandate letter to Minister Osborne of January 15, 2024, which directs the Minister to "work with the BC Utilities Commission to identify an appropriate role for the Commission in supporting B.C.'s clean energy transition, in alignment with the province's climate goals to achieve net zero by 2050 and affordability objectives".[13]

In light of the energy transition, FortisBC recognizes the need to continue evolving its approach and depart from business as usual over time. This transition, while essential, brings with it significant changes and challenges that require thoughtful and proactive responses. FortisBC has been actively adapting to the changing energy landscape and continues to evolve its approach as the energy transition unfolds.

1.3 *POLICIES GUIDING THE ENERGY TRANSITION IN BRITISH COLUMBIA*

Climate policy at all levels of government is focused on reducing emissions. FortisBC has played a key role in enabling the transition and has been adapting its business so that it can continue to serve its customers in a low carbon future; however, uncertainty over the role of gas and electric infrastructure remains.

FortisBC is an industry leader through its development of emissions-reducing programs like Demand-Side Management (DSM), Renewable Natural Gas (RNG), Natural Gas for Transportation (NGT) and Electric Vehicle (EV) Direct Current Fast Charging (DCFC) Infrastructure, efforts it has pursued for more than a decade. FortisBC's most recent response to its policy environment, the "Clean Growth Pathway to 2050"[14], represents an evolution of its innovative programs and outlines how FortisBC's infrastructure can contribute to achieving climate policy objectives at all levels. The pillars for the Clean Growth Pathway to 2050 include

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[10] Low Carbon Resource Initiative: Designs for Net Zero Energy Systems: Meta-Analysis of U.S. Economy-Wide Decarbonization Studies. December 2023. https://www.epri.com/research/products/000000003002028736. "There is no single design for net-zero energy systems. Each of these studies points to a wide array of energy carriers, technologies, and regionally specific solutions to meet the energy demands of an expanding U.S. economy. The range of results across these studies highlights a range of perspectives and possibilities for the design of net-zero systems".

[11] https://www.iea.org/reports/world-energy-outlook-2023/executive-summary.

[12] Minister of Energy, Mines and Low Carbon Innovation, Josie Osborne, 2023. https://twitter.com/Josie_Osborne/status/1709996555431002554.

[13] 2024 Mandate Letter to Energy, Mines and Low Carbon Innovation. https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/premier-cabinet-mlas/minister-letter/emli_-_osborne.pdf.

[14] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/clean-growth-pathway-brochure.pdf.

renewable and low carbon gases, energy efficiency, low and zero carbon transportation, and Liquefied Natural Gas (LNG) for marine fueling. FortisBC believes its infrastructure will play a critical role in the transition toward a lower carbon environment.

As a significant energy provider in British Columbia, the direction of environmental and economic policies is of great importance to FortisBC. FortisBC must align its strategies and adapt to the increasingly complex policy requirements that are being put in place and that will continue to evolve. This must be done, not only from a compliance perspective, but also to seize opportunities that arise from a policy environment that increasingly favours innovative and low carbon energy solutions.

In the following subsections, FortisBC details the policies that are currently having the greatest influence on the Companies, and those that are expected to be significantly impactful over the coming three to five years.

1.3.1 Greenhouse Gas Reduction Standard

As described in the CleanBC Roadmap to 2030[15], the Greenhouse Gas Reduction Standard (GHGRS) will establish an obligation for natural gas utilities to reduce GHG emissions from energy delivered to the buildings and industrial sectors by way of an annual cap of approximately 6 Mt CO2e on gas customer emissions. The GHGRS cap is a significant part of the Province's CleanBC 2030 Roadmap, considering that more than half of the buildings in BC are heated with natural gas. The provincial government has indicated that enabling legislation for the GHGRS will be introduced to the provincial legislature in 2024.

While there is no clarity on the approach utilities are expected to take to comply with the GHGRS, FEI anticipates that the GHGRS may lead to the electrification of gas end uses, with significant implications on electric utilities through increasing the demand for electricity across the Province.

1.3.2 Greenhouse Gas Reduction Regulation

The *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR) authorized under the *Clean Energy Act* (CEA) allows the government to set out prescribed undertakings which utilities may choose to carry out to reduce GHG emissions while recovering the costs in rates. Through the prescribed undertakings, the GGRR enables FortisBC to use specific technologies or renewable or low carbon fuels to reduce emissions. The most recent amendment to the GGRR in 2023 provides FortisBC with incentive amounts of $200 million for low-carbon transportation (vehicle incentives and fueling infrastructure) which includes support for renewable fuels like hydrogen. It also allows for cost recovery of FortisBC's investments in EV charging stations. Each utility in BC is eligible to invest up to $100 million in zero emission vehicle incentives and $100 million in infrastructure, meaning that FEI and FBC may each invest up to $200 million.

15 https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf.

1.3.3 Demand Side Measures Regulation

The Demand-Side Measures Regulation (DSM Regulation) was amended in June 2023. As amended, the DSM Regulation phases out incentives for conventional gas space and water heaters, while allowing for increased incentives for advanced DSM measures such as gas heat pumps, hybrid heating systems and deep energy retrofits. To support advanced DSM, the DSM Regulation now requires the use of the utility cost test to evaluate cost-effectiveness, with the avoided cost of gas being the maximum price under the GGRR for the purchase of RNG, hydrogen, synthesis gas and lignin. The DSM Regulation also provides increased support to address energy efficiency in Indigenous communities and for low-income customers.

In response to the amendments to the DSM Regulation, FEI amended its energy efficiency and rebate programs, pivoting towards advanced DSM measures. This is highlighted in FEI's 2024-2027 DSM Expenditures Plan Application, which was accepted by the BCUC on February 2, 2024. The 2024-2027 DSM Plan also introduced new program areas, including the Indigenous Program Area, which focuses exclusively on Indigenous communities.

While eliminating incentives on conventional gas space and water heating appliances, the updated DSM Regulation does allow for incentives for hybrid heating systems. Although they are not widely adopted today, hybrid heating systems can leverage the gas system in meeting peak demand, ideally shifting towards more flexible and efficient heating solutions that can help mitigate excessive peak demand growth on the electrical grid. FortisBC views its infrastructure as a critical platform for innovation, facilitating the adoption of new, efficient, and low emission technologies.

1.3.4 Carbon Pricing

In 2008, the Province introduced North America's first carbon tax. This tax is levied on the purchase and use of fossil fuels which encompass about 70 percent of the Province's GHG emissions. In alignment with federal carbon pricing requirements, starting April 1, 2023, BC's carbon tax rate is increasing annually by $15 per tonne until it reaches $170 per tonne in 2030. An output-based pricing system (BC OPBS) for large industrial operations will be brought into effect April 1, 2024. The BC OPBS is an industrial carbon pricing system designed specifically for industry in BC and will be mandatory for operations that emit over 10,000 tonnes of carbon dioxide equivalent (tCO2e) per year.

Throughout 2022 and 2023, FEI has actively engaged with provincial authorities to discuss the existing carbon tax structure, highlighting areas that potentially restrict FEI from achieving its GHG reduction plans. One particular risk for FEI is that the GHGRS, as discussed in Section B1.3.1, could effectively introduce an indirect carbon pricing mechanism. If the carbon tax is also added to gas customers' bills, then they will effectively pay a double carbon charge with both the GHGRS and carbon tax. Such an outcome would decrease the availability of low-carbon solutions and affordable energy that the gas system offers.

1.3.5 Clean Electricity Regulations

The federal government issued an initial draft of the Clean Electricity Regulations[16] (CER) under *the Canadian Environmental Protection Act, 1999* with the objective of reaching net-zero emissions from Canada's electricity grid by 2035. The CER is part of Canada's broader strategy to combat climate change and transition to renewable energy sources, aiming for a net-zero economy by 2050. The CER focuses on reducing GHG emissions from fossil-fuel generated electricity by setting performance standards for electricity generation and promoting the shift towards clean energy sources such as wind, solar and hydroelectric power. The CER is expected to have varied impacts across the provinces, particularly those reliant on fossil fuel-generated electricity. The cost for compliance would potentially be incurred when the sector is already dealing with growing demand due to electrification of other sectors, including growth in electric vehicle adoption. These changes in the industry will drive significant investment beyond generation, including major upgrades to distribution networks and deployment of smart grid technology. As these proposed regulations are still in the early consultation stages, the impact to FortisBC is uncertain.

1.3.6 Clean Energy Act Amendments

Objective 2(c) of the CEA was amended and replaced in February 2024. This objective now requires that 100 percent of electricity generated in British Columbia and supplied to the integrated grid is generated from clean or renewable resources, and that the infrastructure necessary to transmit that electricity is built. This amendment further restricts FBC's choices for new electric resource options, particularly when it comes to new capacity resources. Options may include new hydro-electric generation, pump storage, batteries or renewable gas fired combustion. Solar and wind generation are not included in this mix as they are intermittent resources, incapable of providing the dispatchable energy needed to meet energy demand during BC's cold winter peak events.

1.3.7 BC Building Codes

The Province has established regulations aimed at enhancing energy efficiency and reducing GHG emissions through the BC Building codes. These provincial requirements significantly influence local government policies and the buildings sector, setting performance targets for new buildings. These building codes grant local governments the discretion to adopt progressive performance levels over time.

For FortisBC, staying abreast of and responding to these policy shifts is critical, as they can influence requirements ranging from infrastructure development to the choice of energy options offered to customers. FortisBC further discusses the BC Energy Step Code[17], the Zero Carbon

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[16] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html.
[17] https://energystepcode.ca/.

Step Code[18], and the City of Vancouver's building code[19] below. The BC Energy Step Code and the Zero Carbon Step Code work in tandem to produce more efficient, lower emitting homes. The BC Energy Step Code requires progressive advancement in building envelope and mechanical system efficiency whereas the Zero Carbon Step Code sets progressive GHG emissions requirements for new buildings (i.e., new buildings must eventually achieve zero GHG emission performance).

For FEI and FBC, evolving building codes are expected to place some downward pressure on building energy demand as building envelope and mechanical system efficiency increases, helping to offset demand increases due to population growth and fuel switching.[20] The emphasis on emissions performance is expected to lead to decreased demand for natural gas, and increased demand for low carbon energy (such as electricity or renewable and low carbon gas) as new buildings seek to comply with emissions standards. For FEI, an additional challenge is securing a compliance pathway using renewable and low carbon gases to meet emissions performance requirements so that buildings can be connected to its system at higher steps.

The building codes are explained in more detail below.

1.3.7.1 BC Energy Step Code

The BC Energy Step Code (Energy Step Code) is a component of the BC Building Code regulation. It is pivotal in shaping energy efficiency standards for new buildings. The Energy Step Code establishes performance targets that progressively enhance energy efficiency beyond the base building code requirements. The current mandate requires a significant increase in energy efficiency. While a provincial standard, the Energy Step Code grants significant authority to local governments who have the discretion to adopt progressively higher standards.

By 2030, the Energy Step Code will move towards net-zero ready performance for new buildings. Within the Energy Step Code, some local governments have implemented a tiered adoption that favours the use of electricity (i.e., lower efficiency requirements if using electricity). So far, 13 local governments have chosen to adopt the top step of the Energy Step Code. The implementation of tiered systems by local governments poses economic and regulatory challenges for FortisBC. FortisBC will need to navigate a complex landscape of local requirements, which may vary significantly across different jurisdictions.

1.3.7.2 Zero Carbon Step Code

The Zero Carbon Step Code was introduced on May 1, 2023 and it marks a further advancement in building standards, focusing on reducing GHG emissions. So far, 22[21] local governments have adopted the Zero Carbon Step Code. The Zero Carbon Step Code also outlines a stepped

[18] https://energystepcode.ca/zero-carbon/#:~:text=The%20Zero%20Carbon%20Step%20Code%20was%20first%20introduced%20in%20a,space%20and%20water%20heating%20systems.

[19] https://vancouver.ca/home-property-development/large-building-energy-requirements-forms-checklists.aspx.

[20] For example, switching to electricity or gas from other fuels.

[21] https://energystepcode.ca/implementation_updates/?mc_cid=5a98d3b26a&mc_eid=b774263037.

approach, ranging from basic emissions tracking to zero carbon performance. The Zero Carbon Step Code contains four staggered carbon performance tiers:[22]

1. Measure only (Emission level 1) – requires measurement of a building's emissions without reductions.
2. Moderate carbon (Emission level 2) – performance standard effectively means that either space heating <u>or</u> domestic hot water systems must meet zero carbon performance.
3. Strong carbon (Emission level 3) – performance standard effectively means that both space heating <u>and</u> domestic hot water systems are approaching zero carbon performance.
4. Zero carbon ready (Emission level 4) – performance standard means that both space heating and hot water systems must meet zero carbon performance.

Although currently optional, zero carbon performance will be required in new buildings by 2030. Zero carbon performance will eliminate the use of unabated natural gas for heating and hot water and require the use of low carbon resources; however, renewable and low carbon gases have not yet been identified as a compliance pathway within the code.

1.3.7.3 City of Vancouver Building Code

The City of Vancouver (COV), under the Vancouver Charter, possesses unique legislative powers, distinct from other BC local governments that are governed by the *Local Government Act*. The distinctive legal standing offers the COV more autonomy in various areas, including the ability to craft its own building code that can differ from the provincial standards. With its own charter, the COV has established a building code tailored to its sustainability objectives. This allows the COV to implement building requirements that are more stringent than those found in the BC Building Code, such as higher efficiency standards. While the BC Energy Step Code discussed above aims to make buildings net-zero ready by 2032, the COV has the authority to accelerate this timeline within its jurisdiction or implement even more ambitious energy performance requirements.

1.3.8 Low Carbon Fuel Standard

Initiated in 2008, the Low Carbon Fuel Standard (LCFS) seeks to reduce transportation-related emissions by incentivizing the integration of low-carbon alternative fuels into the market. As of January 1, 2024, the legislative basis of the LCFS is the *Low Carbon Fuels Act* and the *Low Carbon Fuels (General) Regulation*. Within the LCFS, low carbon fuels are those with a carbon intensity (CI) below annually determined targets, serving as a replacement for base fuels such as petroleum-derived gasoline or diesel. Suppliers of these fuels receive credits when they provide fuels with a CI below the set of targets and incur debits for supplying fuels exceeding those

[22] The Zero Carbon Step Code includes three GHG emissions compliance options (i.e., maximum GHG emissions by house; maximum GHG intensity plus maximum GHG emission by house; and by energy source) and is calculated using an emissions factor of 0.011kgCO_2e/kWh for electricity and 0.18kgCO_2e/kWh for natural gas. Currently, there is no carbon intensity figure included for RNG. RNG is currently treated the same as natural gas.

targets. Recent changes under the *Low Carbon Fuels Act* are geared towards facilitating greater GHG reductions and expanding the reach of the LCFS. With a move to a 30 percent CI reduction target by 2030, electrification is emerging as a significant compliance pathway. This shift is anticipated to have a notable impact on FBC's operations as fuel providers pivot towards serving electric vehicles to meet compliance obligations.

In early 2023, the Ministry of Energy and Mines and Low Carbon Innovation determined that out-of-province RNG (i.e., RNG that does not physically flow into BC) would not qualify as a compliance pathway within the LCFS framework. The exclusion of out-of-province RNG means that only in-province RNG is recognized and will generate credits under the LCFS framework, leading to two critical issues. First, there is a smaller available supply of in-province RNG compared to out-of-province sources over the near to mid term. Second, in-province RNG projects tend to be smaller in scale. This creates a limitation on the amount of RNG available for natural gas for transportation, which impacts NGT customers who would benefit financially through the LCFS by using out-of-province RNG. Using RNG allows these customers to lower their carbon intensity, thereby increasing the number of credits they can obtain under the LCFS. Given the current high price on LCFS credits, fleets running on RNG expect to recover significant value from the generation and sale of credits. However, the exclusion of out-of-province RNG challenges the viability and scalability of RNG for transportation under the LCFS, as it limits the potential for generation credits by restricting access to a broader RNG supply that could facilitate greater CI reductions.

1.4 *ENERGY TRANSITION IMPACTS ON FEI AND FBC*

1.4.1 Energy Transition Impacts on FEI

FEI's focus continues to be on reducing emissions while also providing safe, affordable, reliable, and resilient service to customers. The development and refinement of climate policy has led to uncertainty over what the future role of the gas system will be. Provincial policy is driving towards reducing emissions by 40 percent by 2030 and 80 percent by 2050, with ambitions to achieve Net Zero emissions across BC's economy. The most direct impacts of this policy environment on FEI are the potential for a decline in customer attachments, lower throughput through energy efficiency requirements, and increased cost pressures for customers due to investments in emissions abatement (e.g., investments in renewable and low carbon gas and energy efficiency initiatives).

To better understand strategies for achieving net zero, a significant amount of research has been conducted across North American jurisdictions. Recently, the Low Carbon Resource Initiative (LCRI) undertook a meta-analysis of leading studies to evaluate and understand their commonalities, including with respect to infrastructure. They found that gas infrastructure can play a key role:

> Pipeline gas infrastructure capacity must be maintained and modernized to support the reliable delivery of gas for peak energy needs, as well as the use of low-carbon

fuels in the gas system. Reduced methane emissions rates from gas production and distribution will be essential to minimize the greenhouse gas impacts of the system.[23]

While the long-term role for gas infrastructure remains somewhat uncertain, FEI agrees with the LCRI's findings that gas infrastructure is a critical element of a decarbonized energy system. In particular, gas infrastructure has unique properties that serve the cold-weather energy demand profile due to its ability to cost-effectively store and deliver significant volumes of energy seasonally.[24] This strength plays a vital role in meeting peak energy demand during cold weather events and may prove even more important in the future given the weather-driven impacts being observed on BC's hydro-electric resources. In addition, gas infrastructure brings renewable and low carbon fuels that are crucial for addressing hard-to-decarbonize sectors such as the high intensity heat required by the industrial sector, or the energy density required by heavy-duty, long-distance transportation. Lastly, gas infrastructure can provide access to scalable supplies of low carbon energy, such as hydrogen, that will be required to meet BC's growing energy needs in a decarbonized future. Maintaining and preparing the gas system for future uses and challenges in the energy transition remains a key priority for FEI as there are over 1.1 million customers that rely on FEI's services for their energy needs.

1.4.2 Energy Transition Impacts on FBC

Although FBC serves a smaller segment of the Province's electrical load than BC Hydro, FBC will nonetheless play a vital role in BC's energy future. To that end, FBC is focused on keeping pace with the growing demand for electricity in a constantly evolving operating environment. Policies are increasingly promoting the use of electricity, including in home heating, light duty transportation and industrial processes. Electrification of heating demand in particular poses a significant challenge to the electric grid which lacks the capacity to shoulder peak heating demand on its own. Electrification demands from all sectors of the economy would therefore exceed what the grid is currently designed for and challenge FBC to maintain reliability, resiliency, and affordability.

FBC sees hybrid heating systems[25] as a potential solution to moderate the growth in peak capacity requirements and the infrastructure needed to support it. Even if FBC is successful in avoiding some or all of the peak heating impacts of electrification, the current policy environment will inevitably drive increased annual demand for electricity. Expanding FBC's infrastructure to keep up with demand, while also managing the impacts of a changing climate, will require significant resources in all areas of the business environment. Being proactive in addressing these challenges is essential for FBC.

[23] Low Carbon Resource Initiative: LCRI Net-Zero 2050: U.S. Economy-Wide Deep Decarbonization Scenario Analysis. December 2022. https://www.epri.com/research/products/000000003002024993.

[24] Today, approximately two-thirds of the energy delivered during the winter peak is provided by the gas system in BC.

[25] A hybrid heating system consists of an electric heat pump, gas furnace and common controls. The electric heat pump is used for shoulder season heating while the gas furnace is used to heat during the colder winter period, thereby avoiding adding significant peak heating demand to the electric system.

1.4.3 Flexibility is Vital to Both FEI and FBC

Despite differing impacts on gas and electric operations from the energy transition, FortisBC has filed one common Rate Framework application. This is because the flexibility inherent in the proposals in this Application are designed to allow for increases and decreases in both cost and demand levels driven by the energy transition. In Section B3.2 of the Application, FortisBC describes how the specific elements of the Rate Framework address the energy transition and other influences in the Companies' operating environments.

FortisBC's priority remains on delivering safe, reliable, and affordable energy in an increasingly low carbon future. The sections below describe the impacts of the energy transition on affordability for the critical energy needs of customers, and how population growth, the energy transition and environmental influences more broadly are requiring increased investments and greater diligence to maintain a safe, reliable, and resilient system.

1.5 *ENERGY AFFORDABILITY INCREASINGLY CHALLENGED*

Energy affordability for FortisBC's customers is top of mind in a period of rising inflation and the impacts of the energy transition on customer energy costs. There are significant costs required to enable the energy transition that negatively impact affordability, such as:

- Increased costs related to investment in emissions reduction, such as the costs of acquiring renewable and low carbon fuels;
- Increased costs related to expanding electrical generation, transmission and distribution infrastructure to meet growing demand, while also maintaining a clean electricity portfolio;
- Increased costs related to investments in climate adaptation and resilience; and
- Rate pressures due to the potential for reduced throughput and a decline in customer additions on the gas system, resulting in increased costs per customer.

Ultimately, the pace of the energy transition must align with customers' ability to afford the increased costs associated with the transition. To help address this challenge, FortisBC's gas and electric operations are seeking to manage costs and invest in the most affordable ways by:

- Continuing with an indexed-based formula approach for the majority of O&M costs and for FEI growth capital, limiting spending in these areas and maintaining a cost-control focus;
- Increasing investment in energy efficiency programs aimed at reducing customers' energy consumption;
- Optimizing energy supply portfolios to reduce customer costs;
- Pursuing a diversified approach to long-term planning to manage affordability and optimize the use of gas and electric infrastructure;

- Carefully considering the need for capital investments and available project alternatives, including considering whether there are smaller incremental investments to increase future optionality as the energy transition evolves;
- Balancing the need to be proactive in building capacity with the expected timing of demand on the system;
- Adding new sources of revenue through serving non-traditional markets, like transportation end uses; and
- Focusing on customer retention and growth.

FortisBC will continue to explore and further develop these avenues, advocating on behalf of customers for lower cost energy transition pathways that utilize existing capacity and minimize the need for new capacity additions, whether for gas or electric.

Understanding where additional customer support is needed, and can be provided, is key to the success of the clean energy transition. The provincial government can play a key role in assisting with the affordability of the energy transition, whether through managing the pace or by assisting utilities or customers directly. In April 2022, the Energy Affordability Working Group, comprised of representatives from the BC Ministries of Energy, Mines and Low Carbon Innovation, Social Development and Poverty Reduction and Indigenous Relations and Reconciliation, as well as BC Hydro, convened a stakeholder discussion on household energy affordability in BC. Stakeholders were asked to provide feedback on the issues specific to each stakeholder group and how the Province could provide energy affordability programs to help customers. FortisBC had the opportunity to respond and emphasized the need for an energy agnostic approach to program design to enable support for customers using both electricity and gas. FortisBC also requested that additional funding be allocated to existing energy affordability programs and emphasized the need for a long-term solution based on customer needs and circumstances. The Companies will continue to advocate for assistance for those customer segments most significantly impacted.

1.6 *CONTINUING TO PROVIDE SAFE, RELIABLE AND RESILIENT SERVICE*

The energy transition has highlighted the critical interrelationships between the gas and electric systems. Both systems need to be able to provide dependable service to customers during times of peak demand, whether driven by load growth or by shifts in energy use between systems, or between times of the year, week, day, or hour. Both systems need to be resilient in the face of heightened physical and cyber security risks and climate change.

The following subsections discuss some of the challenges that FEI and FBC share, followed by specific discussions relevant to each Company.

1.6.1 Physical and Cyber Security and Climate Adaptation

There is an elevated risk to the gas and electric systems related to physical and cyber security as well as extreme weather events. Increased activism and geopolitical instability have increased the potential for bad actors to engage in targeted disruption of energy systems. This increases the need for investment in physical and cyber security for both FEI and FBC to maintain the safety and reliability of the Province's energy systems. Additionally, the increasing frequency of extreme weather events has created additional risk to energy infrastructure, and FEI and FBC must invest to ensure their systems are resilient and adaptable in response. Finally, there are new and increasing obligations around environmental stewardship and sustainability that apply to both utilities.

1.6.1.1 Enhancing Physical and Cyber Security

Protection of assets and the provision of reliable energy services to customers continues to be a top priority for FortisBC. In an environment that is constantly evolving and transforming, it is critical that the Companies' systems be able to respond to new and emerging threats. FortisBC's corporate security risk management program is a risk-based approach that requires continuous improvement and monitoring to address the changing threat landscape.

FortisBC will continue to strengthen its emergency management and business continuity portfolios in response to these threats, as well as to meet the growing regulatory requirements and to support ongoing diligence in preparedness, mitigation, and response to emergencies and continuity events.

To address the anticipated growth in corporate cyber and physical threats affecting energy companies, FortisBC will need to further enhance its security operations, including a focus on technologies that improve monitoring and standardization across sites and security systems.

Further information related to FortisBC's proposed physical and cyber security O&M and capital expenditures is provided in Sections C2.2.4.3 and C2.3.4.3 for O&M and C3.3.3.4 and C3.4.3.4 for Capital.

1.6.1.2 Climate Change Operational Adaptation

The potential impacts of climate change are key drivers behind the energy transition. Changing weather patterns within FortisBC's service territories have the potential to impact the operation of existing and future gas and electric assets, increasing operational risk and, if left unaddressed, leading to safety and reliability consequences. FortisBC's Climate Change Operational Adaptation (CCOA) work aims to improve asset and operational resilience to climate change risks and to maintain safe and reliable energy supply to customers. In 2023 and 2024, as part of its initial CCOA development work, FortisBC is evaluating the risk of climate-related events to its various asset types. These events include wildfires, flooding, sea-level rise, windstorms, snowstorms, extreme temperature, landslides, lightning, and freeze-thaw events. The results of this initial risk assessment, along with additional investigations where required to confirm the impacts of certain climate-related events, will inform FortisBC's next steps as they are applied to specific assets to determine the risk associated with these various events over time. Where unacceptable risk levels exist, mitigation plans can be developed and proposed to address these risks to maintain resilience in the face of changing climate conditions.

A critical component of the Province's long-term transition to cleaner energy is the continued reliability and resilience of both the gas and electricity systems. British Columbians rely significantly on BC's gas systems to deliver energy at peak winter heating times. For instance, on January 12, 2024, one of the coldest days experienced in BC, FEI's gas system delivered approximately twice the energy of BC's electricity system, setting a new peak demand record. Similar peak demand events occurred in December 2021 and 2022, demonstrating that while the climate is warming overall, the need for reliable capacity at peak demand times is a function of weather extremes and is in fact increasing, rather than decreasing.

FBC has also experienced extreme temperatures in its service territory, including new winter peaks and record low temperatures in the extreme winter conditions noted above, but also record peaks in recent summer seasons. In 2021, a warm weather event (known as the heat dome) settled over western Canada, resulting in several days of record high temperatures. Further, in 2023, many areas of the Province, including in FBC's service area, again broke high temperature records contributing to conditions which resulted in wildfires burning the most hectares of forest and land (2.84 million hectares) in a wildfire season in BC's recorded history. In addition, BC has experienced prolonged drought conditions, including during the winter months, which has led to low snow levels and lower hydro-electric storage resources.

These weather conditions present increased challenges for FortisBC's infrastructure and energy resources.

1.6.1.3 Environment and Sustainability

Both FEI and FBC have obligations related to environmental stewardship and sustainable operations that are expected to increase over the coming years. There are also specific requirements for each utility owing to the differences in operating circumstances and locations.

Regulatory requirements contained in legislation such as the *Fisheries Act*, *Species at Risk Act*, *Water Sustainability Act*, *Environmental Management Act*, *Declaration on the Rights of Indigenous Peoples Act*, and *Heritage Conservation Act*, among others, are influencing the way that FortisBC conducts its day-to-day operations. These regulatory requirements impact the planning and execution of work in such areas as environmental management, archaeological permitting, fisheries assessment, and invasive species prevention.

Specific proposals in this area are detailed in Sections C2.2.4.2 and C2.3.4.2 of the Application.

1.6.2 Continued Investment in the Gas System

FEI continues to need to invest in the reliability, integrity, and security of its system, both to serve existing customers and for future growth. While new customer attachments have declined in recent years, replacing conventional natural gas with renewable and low carbon gases requires that FEI's assets continue to remain operational and in good order. An aging system requires investments to continue to provide safe, reliable, and resilient service throughout the ongoing energy transition.

Each of these influences is discussed below.

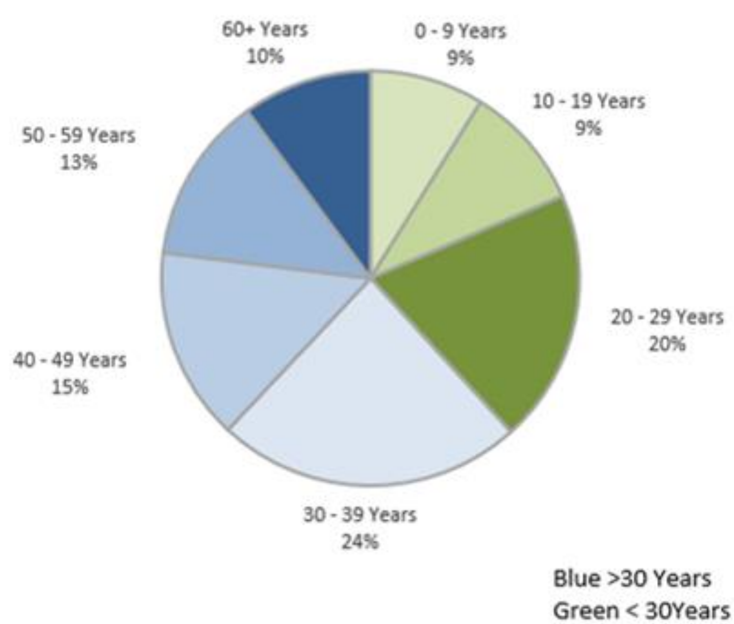
1.6.2.1 Continued Customer Attachments

British Columbia continues to grow in population and FEI continues to experience new customer attachments each year, though over the past three years, the number of new gross customer attachments has been declining, from approximately 20 thousand in 2021 to less than 16 thousand in 2023. FEI expects this trend to continue in 2024, with gross customer attachments projected to be in the range of 11 to 12 thousand. Given the range of future scenarios within the energy sector, construction industry, and municipal and governmental rules and restrictions, the growth trajectory for future years remains unpredictable. This unpredictability, combined with the policies discussed in Section B1.3, will impact gross customer attachments. FEI has proposed a formulaic approach to Growth capital that is responsive to changes in customer attachments to manage this uncertainty.

1.6.2.2 Aging Infrastructure

FEI's existing infrastructure is aging and requires increased (e.g., more frequent) maintenance. Maintaining its assets and optimizing lifecycle costs is particularly important to support affordable, safe, and reliable service to customers. While there is uncertainty about how the energy transition will unfold, FEI's gas assets remain an important part of BC's energy mix. Ensuring the gas system continues to be well-maintained supports the transition towards cleaner energy sources and helps minimize the need to build out new energy assets. As shown in the following figure, 62 percent of FEI's transmission and distribution assets were over 30 years old in 2023, compared to 48 percent in that same age group five years ago. FEI's planned Sustainment capital spending over the Rate Framework term is described in Section C3.3.2.

Figure B1-1: Age of FEI's Transmission and Distribution Assets (Approx. 51,000 km, % Basis)



1.6.2.3 Renewable and Low Carbon Fuel Supply

The integration of RNG and hydrogen supply into FEI's existing gas assets signifies a progressive shift toward cleaner and more sustainable energy sources. These adaptations are fundamental in aligning FEI's infrastructure with the evolving landscape of renewable energy. While this transition provides long-term environmental benefits, it requires additional operations and maintenance resources which include not only the direct expenses linked to integrating new technologies, but also forward-looking investments in training, infrastructure adjustments, and maintenance procedures. These initiatives are essential to ensure a smooth energy transition, supporting safe, reliable, and efficient energy supply while promoting sustainable energy solutions.

1.6.3 Increasing Investment in the Electric System

With the implementation of CleanBC, dependence on FBC's system is expected to increase, particularly at peak demand times. As a result, the entirety of the FBC system, from generation to local distribution infrastructure and the necessary support systems, will require investment to address both the ability to accommodate load growth (through growth capital expenditures), and the ability of the existing infrastructure to support current and increasing levels of demand. FBC discusses the impacts of continued growth and the need to address aging infrastructure below.

1.6.3.1 Continued Growth

FBC will see increasing load over the term covered by the Rate Framework. This growth results from both customer additions and from the movement away from fossil fuels to renewable and low carbon energy, including electricity. FBC expects the addition of approximately 2,400 new customer attachments per year and to grow at an average annual growth rate of 0.8 percent per year over the next 20 years. Along with the increase in the number of customers, FBC expects load to increase as a result of the growth in EV sales in the FBC service area, which is expected to play a significant role in the demand for electricity, and an increase in large load additions and decarbonization through hydrogen and RNG production. The electrification of existing heating load, and an increasing percentage of new heating installations being electricity-based, will also increase demand and place stress on the electric infrastructure.

FBC supports load growth through capital expenditures categorized as either Growth – consisting of new infrastructure required to increase system capacity, or Sustainment – which includes system improvements to the transmission and distribution system to maintain existing equipment to meet forecast load and for the safety, reliability, and quality of the system.

Growth and Sustainment related projects are described in Sections C3.4.1 and C3.4.2, respectively. Growth and Sustainment capital expenditures during the 2025 – 2027 period are forecast to increase markedly relative to recent years due in large part to accommodate increasing loads in the context of a relatively constrained system.

1.6.3.2 Aging Infrastructure

As with FEI, FBC has a number of assets that require upgrades or replacements due to age-related condition. FBC has proposed to address age-related condition issues through a number of capital projects and programs, which are discussed in Section C3.4.2 of the Application. Some elements of the electric system have long service lives and, while they have provided reliable and cost-effective service for decades, require replacement. This is particularly the case for substation transformers, a number of which require attention during the 2025 to 2027 period.

Replacement of aging underground and overhead conductors and aging camera infrastructure is required, and a number of 1980's vintage pad-mount switchers in critical locations are near end of life. The FBC generation plants range in vintage from 92 to 117 years old – and FBC is proposing a number of necessary projects to address the condition of its generation assets.

1.7 *CONCLUSION*

The energy transition and related policies are having a significant impact on FortisBC's operational environment. FortisBC has considered these policies and the impacts of the energy transition on both FEI and FBC in the context of designing its Rate Framework. FortisBC is committed to evolving its operations and strategies to meet the demands of the energy transition, focusing on the Companies' emissions reductions, keeping pace with growing electricity demands, and ensuring affordability and resilience for customers.

2. EVALUATION OF THE CURRENT MULTI-YEAR RATE PLAN, JURISDICTIONAL COMPARISON AND STAKEHOLDER FEEDBACK

2.1 *INTRODUCTION*

In addition to the impacts of the energy transition on the Rate Framework, FortisBC has also considered how its current Multi-year Rate Plan (Current MRP) has performed, developments in other jurisdictions, and the feedback received from stakeholders. This section summarizes these considerations:

- Section B2.2 provides a description and evaluation of FortisBC's Current MRP;
- Section B2.3 summarizes developments in other jurisdictions; and
- Section B2.4 discusses the feedback received from stakeholders.

2.2 *EVALUATION OF THE CURRENT MULTI-YEAR RATE PLAN*

The FortisBC's Current MRP was approved by Orders G-165-20 and G-166-20 on June 22, 2020 (MRP Decision). A summary of the main features of the Current MRP is provided in Table B2-1 below.

Table B2-1: Main Features of the Current MRP

Item		FEI MRP	FBC MRP
Process		Written hearing	
Term		Five years (2020-2024)	
Formula	O&M	$OM_{t} = UCOM_{t-1} * [1 + (I-X)] * [(AC_{t} - AC_{base\ year}) \times 75\% + AC_{base\ year}] + True\ Up_{t-2}$ UCOM = Unit Cost O&M I = I-Factor X = X-Factor Base year = The base year actual for starting UCOM (2019) AC = Average Customer True Up = Actual Average Customer from two years prior	
	Capital	$Growth\ Capital_{t} = UCGC_{t-1} * (1+(I-X)) * (GCA_{t}) + True\ Up_{t-2}$ UCGC = Unit Cost Growth Capital GCA = Gross Customer Additions	N/A

Item	FEI MRP	FBC MRP
Forecast of Regular Capital	Sustainment and Other Capital	Growth, Sustainment and Other Capital
I-Factor	Composite index (consisted of BC-AWE and BC-CPI) with specific weightings to be calculated each year for FEI and FBC	
X-Factor	Fixed at 0.5% for the MRP term	
Flow-through (Y-Factor)	Certain categories of expenses, revenue and capital are forecast annually and the variances between forecast and actual amounts are recorded in the Flow-through deferral account or other deferral accounts	
Z-Factor	Available for prudently incurred costs caused by exogenous factors	
	Materiality threshold: $500 thousand	Materiality threshold: $150 thousand
Earnings Sharing Mechanism (ESM)	50/50 symmetric sharing for variances between achieved ROE and allowed ROE	
Off-ramp	Off ramp triggered if earnings in any one year varies from approved ROE by more than +/- 150 bps (post sharing)	
Earnings Carryover Mechanism (ECM)	FortisBC could apply for approval of an ECM at any time in the last three years of the term, either in advance or following the action/initiative giving rise to savings beyond the term. The annual net savings identified under this ECM would be shared equally for a maximum of three years following the end of the term	
Incremental Capital	CPCNs or other Major Projects are approved separately	
	Materiality threshold of $15 million	Materiality threshold of $20 million
Service Quality Indicators (SQIs)	Nine SQIs and four informational indicators	Eight SQIs and four informational indicators

The Current MRP is in effect until the end of 2024 and actual performance for 2024 is not yet known. However, rates for each year of the Current MRP have been approved, and a summary of those rates is provided below. This is followed by an analysis of how the Current MRP has delivered on the anticipated benefits.

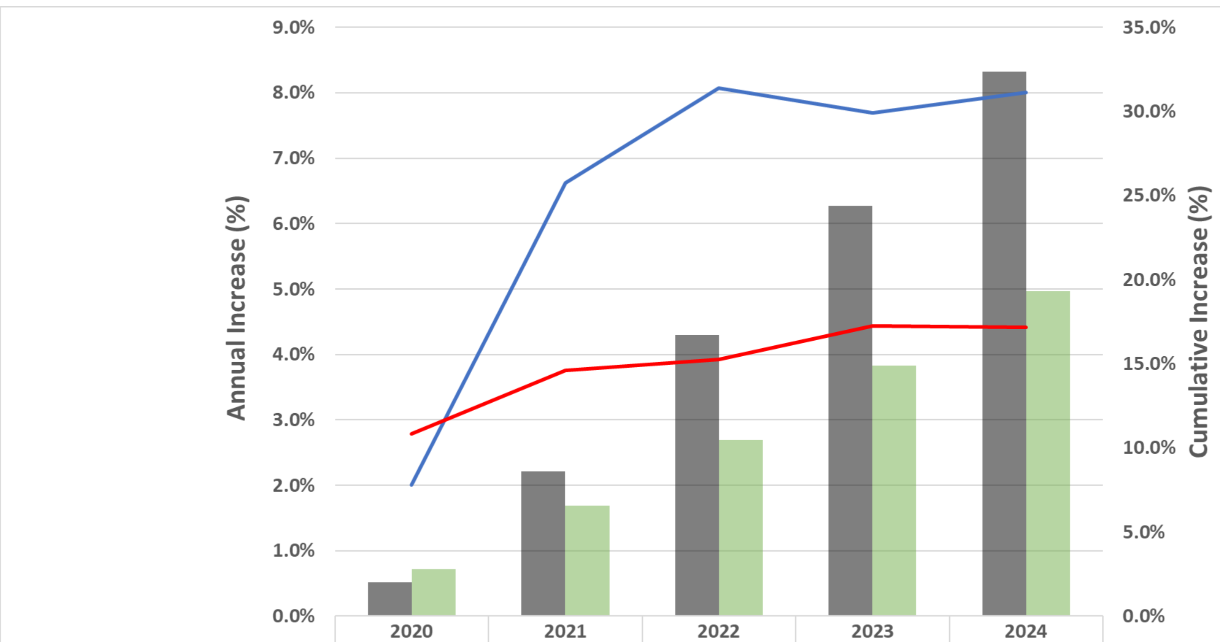
2.2.1 Rate Trend

The growth trend in rates has been a helpful indicator of the performance of FortisBC's multi-year rate plans in the past. The Current MRP, however, has seen unprecedented pressure on rates for both gas and electric operations, driven by factors that are external to FortisBC's operations. These include the energy transition impacts, as discussed in Section B1, and the impacts of the COVID-19 pandemic, which has contributed to a high inflationary environment and supply chain shortages. In addition, both Companies' 2024 rates reflect some impact from the increase in the cost of capital approved by the BCUC which was effective January 1, 2023, but for which rate recovery began in 2024.

2.2.1.1 FEI Delivery Rates

Figure B2-1 below compares FEI's delivery rate trend with the composite Inflation Factor[26] used in the Current MRP formulas. The figure shows that FEI's average annual delivery rate growth from 2020 to 2024 is approximately 6.5 percent, exceeding the average Inflation Factor during the same period which was approximately 3.9 percent. The impact on customer bills is lower since delivery rates comprise approximately 50 to 60 percent of FEI's total annual revenue requirement. For the average residential customer with 90 GJ of annual consumption, the total bill increase was approximately 20.7 percent over the term of the Current MRP, an average annual increase of 4.1 percent when accounting for all of the commodity-related charges as well as all rate riders[27]. This is comparable to the cumulative increase in the Inflation Factor over the same period at 19.3 percent, or an average of 3.9 percent per year. Further, as explained below, the more significant drivers of the delivery rate increases have been the broader inflationary impacts of the COVID-19 pandemic, the impact on rates as approved Major Projects enter rate base, and the increase in FEI's cost of capital.

Figure B2-1: FEI Delivery Rate Changes During the Current MRP Term



	2020	2021	2022	2023	2024
FEI Delivery Rate (Cumulative)	2.0%	8.6%	16.7%	24.4%	32.4%
CPI/AWE (Cumulative)	2.8%	6.5%	10.5%	14.9%	19.3%
FEI Delivery Rate	2.0%	6.6%	8.1%	7.7%	8.0%
CPI/AWE	2.8%	3.8%	3.9%	4.4%	4.4%

[26] The Inflation Factor is weighted for labour (BC AWE) and non-labour (BC CPI). These weightings are adjusted each year for the prior year actual labour and non-labour percentages.

[27] Commodity related charges include Cost of Gas and Storage & Transport charges. Rate riders include the Basic Charge CGIF Rate Rider 2, Biomethane Variance Account (BVA) Rate Rider 3, RSAM Rate Rider 5, and Midstream Cost Reconciliation Account (MCRA) Rate Rider 6. The total bill increase noted does not include carbon tax, municipal operating fees, ICE Levy, or GST.

Table B2-2 below provides a breakdown of the impact of various drivers on FEI's delivery rates from 2020 to 2024, using a grouping that is consistent with that provided during each Annual Review, and including a subtotal before approved rate smoothing impacts.

Table B2-2: FEI's Delivery Rate Increases by Key Driver During the Current MRP Term

Particular	2020	2021	2022	2023	2024	Total
Volume/Revenue Related						
Demand Forecast	(0.64%)	(1.13%)	(0.26%)	(1.67%)	(0.70%)	(4.39%)
Demand Forecast - BCH IG	-	-	-	1.62%	-	1.62%
Other Revenue	0.90%	(0.53%)	0.04%	(0.04%)	(0.04%)	0.32%
O&M Related						
Formula	1.39%	1.09%	1.21%	1.22%	1.05%	5.96%
Forecast (Clean Growth)	0.01%	0.07%	(0.03%)	0.07%	0.23%	0.35%
Forecast (BCUC, Pension/OPEB, Insurance, Integrity)	2.04%	0.36%	(0.97%)	0.36%	(0.10%)	1.69%
Rate Base Growth						
Regular Capital, net of Accumulated Depreciation	1.33%	0.75%	0.64%	0.79%	0.23%	3.74%
Major Projects, incl. Depreciation and Income Tax	3.93%	0.92%	1.06%	2.39%	0.64%	8.95%
Clean Growth (NGT, Biomethane)	0.02%	0.03%	0.02%	0.20%	0.24%	0.52%
Unamortized Deferral	0.37%	(0.15%)	(0.09%)	0.54%	(1.40%)	(0.73%)
Working Capital, CWIP (No AFUDC)	(0.89%)	0.03%	0.12%	0.29%	(0.31%)	(0.76%)
Rebasing (2014-2019 PBR)	0.94%	-	-	-	-	0.94%
Depreciation and Amortization Related						
Depreciation	0.25%	1.07%	0.81%	0.92%	0.64%	3.67%
Deferral Amortization	(0.16%)	4.67%	2.14%	0.63%	1.35%	8.63%
Study Rate Change (Depreciation, CapOH, Salvage)	(1.97%)	-	-	-	-	(1.97%)
Financing and Return on Equity						
Financing Rate and Ratio Change	(1.47%)	(0.02%)	(0.38%)	0.28%	0.04%	(1.55%)
GCOC Stage 1 (G-236-23)	-	-	-	-	6.06%	6.06%
Tax Expense						
Income tax and Property Tax	(2.78%)	2.50%	(0.22%)	0.09%	1.59%	1.16%
Subtotal	**3.27%**	**9.64%**	**4.09%**	**7.69%**	**9.51%**	**34.20%**
Rate Smoothing						
Deferred Revenue/Deficiency	(1.27%)	(3.02%)	3.98%	-	(1.51%)	(1.82%)
Total Delivery Rate Change (w/ Rate Smoothing)	**2.00%**	**6.62%**	**8.07%**	**7.69%**	**8.00%**	**32.39%**

On an annual basis, the significant drivers of the delivery rate increases before considering rate smoothing impacts are described below.

<u>2020 Delivery Rate Increase:</u>

- The completion and capital additions of approximately $304 million related to the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) CPCN project for reliability and integrity in the Lower Mainland area.
- The approved incremental funding in year 1 of the Current MRP related to BCUC levies and integrity digs, along with increases in Pension & Other Post Employment Benefit (OPEB) costs.

2021 Delivery Rate Increase:

- An increase in deferral amortization along with increased income tax expense accounted for most of the increase in 2021. The deferral amortization increase was related to the elimination of the 2020 credit amortization of approximately $36.392 million from the 2014-2019 Flow-through deferral account.[28] Since the credit from the 2014-2019 Flow-through deferral account was fully amortized in 2020, it resulted in an overall increase in 2021. This increase in deferral amortization in 2021 also impacted income tax expense, as the income tax deduction was reduced due to the increase in amortization.

2022 Delivery Rate Increase:

- An increase in deferral amortization contributed approximately half of the increase, with a number of smaller items making up the difference. The deferral amortization increase was primarily related to the DSM deferral account ($6.933 million) and the 2020-2024 Flow-through deferral account ($11.417 million). The increase in amortization from the 2020-2024 Flow-through deferral account, which captures the variances between forecast and actual/projected from 2020 and 2021, was largely due to unfavourable commercial and industrial delivery margins which were impacted by the COVID-19 pandemic.[29]

2023 Delivery Rate Increase:

- Capital additions related to multiple Major Projects, including the Inland Gas Upgrade (IGU) project, Pattullo Gasline Replacement (PGR) project, and the Coastal Transmission System – Transmission Integrity Management Capabilities (CTS-TIMC) project, resulted in a combined capital addition to FEI's rate base in 2023 of approximately $245 million.
- The loss of revenue from FEI's contract with BC Hydro for the Island Generation (IG) facility resulted in a deficiency of approximately $15.7 million.

2024 Delivery Rate Increase:

- The BCUC issued Decision and Order G-236-23 regarding Stage 1 of the Generic Cost of Capital (GCOC) proceeding, resulting in increases in FEI's deemed equity thickness and return on equity (ROE) to 45 percent and 9.65 percent, respectively. The 2024 delivery

[28] As explained in Section 14.3 of FEI's Annual Review for 2020 and 2021 Delivery Rates, the credit amortization in 2020 from the 2014-2019 Flow-through deferral account was related to the variances in 2018 and 2019 between forecast/projected and actuals. The credit variances were primarily due to higher delivery margin revenue, lower income tax, and lower depreciation expense in 2018 and 2019. These credit variances were fully amortized in 2020, thus resulting in an increase in deferral amortization expense in 2021.

[29] The demand forecast for 2020 and 2021 was completed in early 2020 as part of FEI's Annual Review for 2020 and 2021 Delivery Rates, filed with the BCUC in August 2020. At that time, the impact of the COVID-19 pandemic on FEI's recoveries from commercial and industrial customers was not foreseen, resulting in a large variance between forecast and actuals for both 2020 and 2021. These variances were captured in the Flow-through deferral account and recovered through amortization of the Flow-through deferral account in 2022.

rates include only part of the impact, with the remaining impact captured in the 2023-2024 Revenue Deficiency deferral account.[30]

- Increases in income taxes and property taxes, partly due to the phase-out of Canada's Accelerated Investment Incentive starting in 2024, which resulted in reduced income tax deductible through capital cost allowance (CCA).

Table B2-3 below shows that, when excluding items that were approved outside of the Current MRP, the cumulative increase in FEI's delivery rate is equal to approximately 13.2 percent, which is approximately two-thirds of the cumulative inflation at 19.3 percent (i.e., composite CPI/AWE as shown in Figure B2-1 above).

Table B2-3: FEI's 2020-2024 Delivery Rate Increases Excluding Non-MRP Impacts

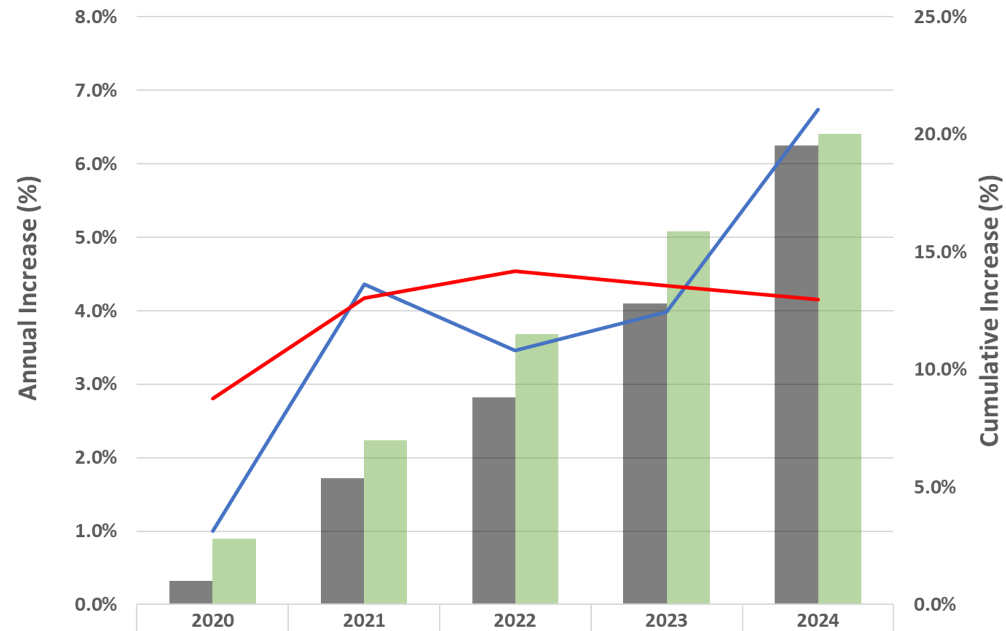
	2020	2021	2022	2023	2024	Total
Delivery Rate Changes (w/o Rate Smoothing)	3.27%	9.64%	4.09%	7.69%	9.51%	34.20%
Less: Non-MRP Related Items/Impacts Identified						
Major Projects (e.g. CPCN)	(3.93%)	(0.92%)	(1.06%)	(2.39%)	(0.64%)	(8.95%)
Elmination of 2014-2019 (PBR) Flow-Through Credit in 2021		(6.04%)				(6.04%)
GCOC Stage 1 (G-236-23)					(6.06%)	(6.06%)
Delivery Rate Changes (MRP Framework Only)	**-0.66%**	**2.68%**	**3.02%**	**5.30%**	**2.81%**	**13.15%**

2.2.1.2 FBC Rates

Figure B2-2 below compares FBC's rate trend[31] with the composite Inflation Factor used in the Current MRP formula. Overall, the rate increases for FBC during the term of the Current MRP were generally in line with the Inflation Factor (composite CPI and AWE). The figure shows that the cumulative increase in FBC's rates for 2020 through 2024 is approximately 19.5 percent, which is equivalent to an average increase of 3.9 percent per year, while the cumulative increase in the Inflation Factor during the same period is approximately 20.0 percent, which is equivalent to an average increase of 4.0 percent per year. Further, as explained below, the more significant drivers of the rate increases have been the broader inflationary impacts of the COVID-19 pandemic, increases in power supply expense, the impact on rates as approved Major Projects enter rate base, and the increase in FBC's cost of capital.

[30] Decision and Order G-236-23, p. 50.
[31] FBC's rates include power supply costs.

Figure B2-2: FBC Rate Changes During the Current MRP Term



	2020	2021	2022	2023	2024
FBC Effective Rate (Cumulative)	1.0%	5.4%	8.8%	12.8%	19.5%
CPI/AWE (Cumulative)	2.8%	7.0%	11.5%	15.9%	20.0%
FBC Effective Rate	1.0%	4.4%	3.5%	4.0%	6.7%
CPI/AWE	2.8%	4.2%	4.5%	4.3%	4.2%

Table B2-4 below provides a breakdown of the impact of various drivers on FBC's rates from 2020 to 2024, using a grouping that is consistent with that provided during each Annual Review, and including a subtotal before approved rate smoothing impacts.

Table B2-4: FBC's Rate Increases by Key Driver During the Current MRP Term

Particular	2020	2021	2022	2023	2024	Total
Volume/Revenue Related						
Demand Forecast	2.07%	(1.29%)	0.96%	(3.05%)	(0.54%)	(1.84%)
Other Revenue	(0.38%)	(0.42%)	0.10%	(0.10%)	0.03%	(0.77%)
Power Supply						
Power Supply Expense	(1.45%)	1.63%	0.07%	4.95%	2.67%	7.87%
O&M Related						
Formula	0.85%	0.57%	0.87%	0.85%	0.50%	3.65%
Forecast (Clean Growth - EV)	-	-	0.04%	0.01%	0.02%	0.07%
Forecast (BCUC, Pension/OPEB, Insurance)	(0.15%)	0.14%	(0.30%)	0.09%	(0.19%)	(0.41%)
Rate Base Growth						
Regular Capital, net of Accumulated Depreciation	0.25%	0.38%	0.73%	0.34%	0.49%	2.19%
Major Projects, incl. Depreciation and Income Tax	0.67%	1.28%	1.32%	1.29%	0.16%	4.71%
Unamortized Deferral	0.11%	0.09%	0.08%	0.15%	0.18%	0.61%
Working Capital, CWIP (No AFUDC)	0.08%	0.00%	0.14%	0.22%	(0.13%)	0.31%
Rebasing (2014-2019 PBR)	0.48%	-	-	-	-	0.48%
Depreciation and Amortization Related						
Depreciation	(0.66%)	0.61%	0.59%	0.42%	0.57%	1.55%
Deferral Amortization	1.44%	2.06%	(1.04%)	(1.25%)	0.39%	1.59%
Study Rate Change (Depreciation, CapOH, Salvage)	0.60%	-	-	-	-	0.60%
Financing and Return on Equity						
Financing Rate and Ratio Change	(0.64%)	(0.01%)	(0.79%)	0.64%	0.07%	(0.74%)
GCOC Stage 1 (G-236-23)	-	-	-	-	1.45%	1.45%
Tax Expense						
Income tax and Property Tax	(0.90%)	0.96%	(0.71%)	(0.60%)	1.08%	(0.16%)
Subtotal	**2.36%**	**6.00%**	**2.06%**	**3.98%**	**6.74%**	**21.15%**
Rate Smoothing						
Deferred Revenue/Deficiency	(1.36%)	(1.64%)	1.41%	-	-	(1.59%)
Total Rate Change (w/ Rate Smoothing)	**1.00%**	**4.36%**	**3.47%**	**3.98%**	**6.74%**	**19.55%**

On an annual basis, the significant drivers of the rate increases, before considering rate smoothing impacts, are described below.

<u>2020 Rate Increase:</u>

- Reduced demand, partly offset by a decrease in power supply expense.
- Reduced credit amortization in 2020 from the 2014-2019 Flow-through deferral account that was approved for the previous PBR term.

<u>2021 Rate Increase:</u>

- Capital additions related to Major Projects totalled approximately $40.4 million, including the Corra Linn Dam Spillway Gates Replacement (Corra Linn) project, the Upper Bonnington Old Units Refurbishment (UBO) project, and the Grand Forks Terminal Station Reliability (GFT) project.

- Deferral amortization resulting from the elimination of the 2020 credit amortization from the 2014-2019 Flow-through deferral account.[32] Since the credit from the 2014-2019 Flow-through deferral account was fully amortized in 2020, it resulted in an overall increase in 2021. This increase in deferral amortization also contributed to an increase in income tax expense.

2022 Rate Increase:

- Capital additions totalling to approximately $32.4 million related to the Corra Linn, UBO, and GFT projects.

2023 Rate Increase:

- Increased power supply costs, primarily due to greater reliance on energy supplied by BC Hydro through the Power Purchase Agreement (PPA) and corresponding reduced market and contracted power purchases.
- Major Project capital additions, including the Kelowna Bulk Transformer Addition (KBTA), Corra Linn, UBO and Playmor Substation Upgrade projects. The total capital additions added to FBC's 2023 rate base were approximately $45.4 million. These capital additions grew FBC's rate base and increased depreciation expense as well as income tax expense.

2024 Rate Increase:

- Increased power supply costs due to the same reasons as in 2023.
- The BCUC issued Decision and Order G-236-23 regarding Stage 1 of the GCOC proceeding, resulting in increases in FBC's deemed equity thickness and ROE to 41 percent and 9.65 percent, respectively.
- Increase in income tax expense, partly due to the phase-out of Canada's Accelerated Investment Incentive starting in 2024, which resulted in reduced income tax deductible through CCA.

Table B2-5 below shows that, when excluding items that were approved outside of the Current MRP, the cumulative rate increase is approximately half of the cumulative inflation at 20.0 percent (i.e., composite CPI/AWE as shown in Figure B2-2 above).

[32] As explained in Section 14.3 of FBC's Annual Review for 2020 and 2021 Rates, the credit amortization in 2020 from the 2014-2019 Flow-through deferral account was related to the variances in 2018 and 2019 between forecast/projected and actuals. The credit variances were primarily due to lower power purchase expense, lower income tax, and higher apparatus rental revenue in 2018 and 2019. These credit variances were fully amortized in 2020, thus resulting in an increase in deferral amortization expense in 2021.

Table B2-5: FBC's 2020-2024 Rate Increases Excluding Non-MRP Impacts

	2020	2021	2022	2023	2024	Total
Rate Changes (w/o Rate Smoothing)	2.36%	6.00%	2.06%	3.98%	6.74%	21.15%
Less: Non-MRP Related Items/Impacts Identified						
Major Projects (e.g. CPCN)	(0.67%)	(1.28%)	(1.32%)	(1.29%)	(0.16%)	(4.71%)
Elmination of Credit from 2014-2019 (PBR) Flow-Through	(1.90%)	(2.86%)				(4.76%)
GCOC Stage 1 (G-236-23)					(1.45%)	(1.45%)
Rate Changes (MRP Framework Only)	**-0.20%**	**1.86%**	**0.75%**	**2.69%**	**5.13%**	**10.23%**

2.2.2 Analysis of the Current MRP

In FortisBC's 2020-2024 MRP Application, the key elements of the rate plan were described as:

- A multi-year plan framework;
- Stable levels of O&M funding;
- Flexibility to innovate and adapt; and
- Incentive to invest in our future.

Below, FortisBC expands on each of these areas, and how the Current MRP has performed.

2.2.2.1 A Multi-year Rate Plan Framework

In the 2020-2024 MRP Application, FortisBC described the benefits of a multi-year rate plan framework as:

- Reduced regulatory costs and internal efficiencies associated with the streamlined regulatory process;
- Increased utility focus on managing the business with a long-term view; and
- Increased operational flexibility to address the increasing pace and growing scope of energy industry transformation.

In this regard, FortisBC believes the benefits over traditional cost of service regulation were largely achieved; however, as shown in Tables B2-6 and B2-7 below, the efficiencies in costs and effort expended in the Annual Review process have started to erode. In fact, the total number of information requests (IRs) combined for FEI and FBC in 2024 marked an increase to almost the same level as the number of IRs that FortisBC received in 2015, which was the first Annual Review of the 2014-2019 PBR Plan term.

Table B2-6: Comparison of Annual Review Proceeding Costs between the 2014-2019 PBR Plan Term and the 2020-2024 MRP Term[33]

Type of Regulatory Costs	FEI Annual Reviews 2020-2024 MRP (Average)	FEI Annual Reviews 2014-2019 PBR (Average)	FBC Annual Reviews 2020-2024 MRP (Average)	FBC Annual Reviews 2014-2019 PBR (Average)
BCUC Costs	16	24	14	23
Intevener PACA	76	40	100	40
Consulting and Legal	90	67	77	62
Other/Misc.	-	1	-	0
Total - Average ($000s)	**$ 182**	**$ 132**	**$ 190**	**$ 125**

Table B2-7: Comparison of Number of Annual Review IRs between the 2014-2019 PBR Plan Term and the 2020-2024 MRP Term

	Annual Reviews	Number of IRs FEI	FBC	Total
2014-2019 PBR	2015	457	343	800
	2016	278	361	639
	2017	352	387	739
	2018	214	375	589
	2019	226	424	650
2020-2024 MRP	2020-2021	224	379	603
	2022	255	339	594
	2023	338	334	672
	2024	380	408	788

As FortisBC discusses further in Section C1.10, the Companies consider that a goal of the Rate Framework should be to find ways to streamline the Annual Review process; in particular, to better define and scope the information requests. Improved regulatory efficiency is important as it will allow the Companies to focus and dedicate the necessary resources to responding to the challenging and complex external environment, as was discussed in Section B1.

As illustrated in the tables above, although some of the regulatory efficiencies gained during the 2014-2019 PBR Plan term and the earlier years of the Current MRP have diminished, the improved regulatory efficiency in the early years of the Current MRP term allowed FortisBC to increase its focus on managing the utility business with a longer-term view.

[33] The first Annual Review for the 2014-2019 PBR Plan occurred for 2015 rates, with 2014 rates being set as part of the 2014-2019 PBR Plan Decision due to the length of the proceeding. The 2020 and 2021 Annual Reviews as part of the Current MRP were combined as one application.

From 2020 through 2023, FEI developed and filed an unprecedented number of regulatory applications and participated in numerous complex BCUC-initiated proceedings, including:

- Six large CPCN applications;
- The Revised Renewable Gas Program application;
- The 2022 Long Term Gas Resource Plan (LTGRP), which included the development of FEI's Diversified Energy Pathway and the Kelowna Electrification Study;
- The 2023 DSM Expenditures Plan and the 2024-2027 DSM Expenditures Plan applications;
- Stage 1 of the BCUC-initiated GCOC proceeding;
- BCUC-initiated inquiries and processes, including the Acquisition of RNG by Public Utilities and the Regulation of Hydrogen Energy Services;
- Annual Contracting Plans (ACPs), including a detailed ACP Compliance Report in 2020 which was directed by the BCUC subsequent to the Enbridge T-South rupture event in 2019;
- Approximately 30 applications for acceptance of biomethane purchase agreements (BPAs); and
- Approximately 70 applications for NGT/CNG fuelling services.

FBC also developed and filed numerous key applications during the 2020 to 2023 timeframe:

- Two CPCN applications;
- The 2021 Long Term Electric Resource Plan (LTERP);
- The rate design and rates for FBC's electric vehicle (EV) direct current fast charging (DCFC) service in 2021 and the application for energy-based rates in 2023;
- Participation in Stage 1 of the BCUC-initiated GCOC proceeding, in which FBC actively participated and filed evidence;
- The 2023-2027 DSM Expenditures Plan application;
- The development and filing of a Large Commercial Interruptible Rate application; and
- Annual Electric Contracting Plans.

These projects together provide a long-term vision for FortisBC, with a continuing focus on providing safe, reliable, and resilient service to customers while addressing the ongoing energy transition through an affordability lens. The efforts and resources required to complete these critical proceedings are supported by an efficient and streamlined rate setting environment.

A multi-year framework has afforded the operational flexibility to prepare and address the growing scope of the energy transition, including expanded effort in areas such as renewable and low carbon gas development, NGT service, energy efficiency and conservation, and FBC's EV DCFC service. Further discussion on the flexibility of FortisBC's Current MRP to address the energy transition is provided in Section B2.2.2.3 below.

2.2.2.2 Stable Levels of O&M Funding

In the 2020-2024 MRP Application, FortisBC stated that, while it will continue to pursue productivity improvements, the rate plan should encourage FortisBC to increase its focus on addressing emerging challenges in its operating environment. To successfully achieve this, stable levels of O&M funding are required that are sufficient to address emerging pressures, provide certainty for plans and initiatives, and encourage utility management to focus on the efficient allocation of resources within the business over the term of the Current MRP.

Tables B2-8 and B2-9 show the formula O&M and the actual/projected savings for FEI and FBC, respectively. Both utilities continued to achieve savings through the productivity improvement factor (PIF) that is part of the formula (all savings benefit customers) as well as through reduced spending from the allowed formula amount (savings shared through the ESM). Furthermore, FortisBC's actual/projected formula-based O&M for both utilities has been relatively stable and consistent throughout the term of the Current MRP. As mentioned above, FortisBC's goal was to achieve an efficient allocation of resources available with stable levels of O&M funding. FortisBC considers this has been largely achieved for both utilities, with no decline in service levels in terms of safety and reliability as evidenced by the SQI results shown in Appendices C6-1 and C6-2.

Table B2-8: FEI Actual Formula O&M and Savings ($ millions)

Year	Actual (a)	Formula with 0.5% PIF (b)	Savings above the Formula (c=b-a)	Formula without 0.5% PIF (d)	Savings related to 0.5% PIF (e = d-b)	Total Savings to customer w/ Sharing (f = 0.5*c + e)
2020	$ 259.5	$ 261.8	$ 2.3	$ 263.1	$ 1.3	$ 2.4
2021	268.3	272.5	4.2	274.9	2.5	4.6
2022	281.7	285.2	3.5	289.1	3.9	5.6
2023	295.0	299.3	4.3	304.3	5.0	7.2
2024P	309.6	312.6	3.0	319.3	6.8	8.3
Total			**$ 17.3**		**$ 19.4**	**$ 28.0**

Table B2-9: FBC Actual Formula O&M and Savings ($ millions)

Year	Actual (a)	Formula with 0.5% PIF (b)	Savings above the Formula (c=b-a)	Formula without 0.5% PIF (d)	Savings related to 0.5% PIF (e = d-b)	Total Savings to customer w/ Sharing (f = 0.5*c + e)
2020	$ 58.2	$ 59.8	$ 1.5	$ 60.0	$ 0.2	$ 1.0
2021	58.9	62.3	3.4	62.9	0.6	2.3
2022	63.6	66.2	2.6	67.1	0.9	2.2
2023	66.1	70.3	4.2	71.7	1.4	3.5
2024P	70.8	72.8	2.0	74.7	1.8	2.8
Total			**$ 13.8**		**$ 4.9**	**$ 11.8**

2.2.2.3 Flexibility to Innovate and Adapt

In the 2020-2024 MRP Application, FortisBC stated that a flexible approach that allows for innovation and adaptation will be key to managing the transition to a lower carbon economy while achieving a balance between affordability and low emissions for current and future customers. The rate plan was intended to provide the opportunity for innovation and the adoption of new technologies.

In the design of the Current MRP, FEI introduced the Clean Growth Innovation Fund (CGIF) and CGIF rate rider in order to invest in innovation for the purpose of adapting its system in the future to the ongoing transition to a lower carbon economy. As discussed in Section C5, the CGIF has been effective in providing funding to important gas decarbonization innovations that can provide customers with lower-carbon gaseous fuels at reasonable costs. FEI is expecting a total commitment of approximately $17 million in approved funding through the CGIF by the end of 2024 to support research and development in low carbon innovation initiatives, including hydrogen production, hydrogen distribution, end-use with hydrogen, hybrid systems, RNG, and carbon capture technologies. This research is expected to continue past the term of the Current MRP.

The Current MRP has demonstrated its flexibility during global events that had a significant impact on the Companies and their customers. The COVID-19 pandemic was a significantly disruptive event that has had broad-reaching impacts, including the subsequent increase in global inflation and major supply chain shortages. Additionally, extreme weather events have impacted both Utilities during the Current MRP term. FBC continues to manage through extreme wildfire seasons, with this most recent summer bringing devastating wildfires to the Kelowna area. The impacts of extreme flooding during the “atmospheric river” event in 2021 caused significant damage to FEI’s assets and greatly impacted customers. Through the design of the Current MRP framework, which included mechanisms for adjusting costs for inflation, utilizing the approved flow-through and exogenous factor mechanisms, and prioritizing and updating forecasts of regular capital projects, FortisBC was able to address these significant disruptive events. The Annual Review process itself also provided an important opportunity, particularly through the workshops, for interveners and the BCUC to engage directly with the Companies on the impacts and the Companies' responses to these significant events.

FortisBC believes that its Current MRP framework has been successful in providing reasonable flexibility to innovate and adapt towards a future lower carbon economy while also including mechanisms for the Utilities to address and recover significant costs resulting from unanticipated and extraordinary events that have impacted FortisBC's operating environment. An important goal of the Rate Framework in this Application is to maintain this flexibility.

2.2.2.4 Incentive to Invest in the Future

In the 2020-2024 MRP Application, FortisBC highlighted that it needed to increase its focus on seeking growth opportunities which help offset the costs associated with climate policy and meeting emissions reduction targets, as well as the costs to meet the growing need for investment in system integrity and reliability. Continued growth also helps expand FortisBC's ability to provide lower-carbon energy solutions to a broader customer base now and in the future. The rate plan should provide incentive for FortisBC to continue to invest in the long-term health of the Companies.

Under the Current MRP, FortisBC has continued to expand its investments in Clean Growth Initiatives, including FEI's NGT fuelling stations and tanker service, FEI's LNG sales through Rate Schedule (RS) 46, FEI's renewable gas service and programs, and FBC's EV DCFC service. By design, under the Current MRP framework, the costs and revenues associated with these Clean Growth Initiatives were approved to be forecast annually, with variances between forecast and actual amounts captured in the Flow-through deferral account. This approach has enabled FortisBC to effectively and proactively expand resources and undertake activities to meet emission targets and government policies. This has included detailed study and planning for the introduction of hydrogen into FEI's system to reduce emissions and enable FEI to continue to play a key role in the energy transition.

FortisBC believes the treatment of these investments under the Current MRP worked well in allowing both Utilities to expand low-carbon energy solutions, ensuring reasonable incentives were available for the Utilities to continue to invest in Clean Growth Initiatives for the transition to a low carbon future.

2.3 *REVIEW OF OTHER JURISDICTIONS*

Regulators in major Canadian provinces continue to employ indexed-based MRPs for the regulation of natural gas and electric utilities within their jurisdictions. In addition to BC, Alberta, Ontario and Quebec currently apply indexed MRPs to their major local distribution companies. Other North American regulators have also been pushing for alternative incentive frameworks to traditional cost of service regulation.

FortisBC observes that all MRPs included in its review share a set of common objectives in seeking to promote a continuous efficiency focus, align utilities' and ratepayers' interests and encourage utilities to achieve government policy objectives, while ensuring service quality requirements are met. Further, all MRPs reviewed aim to create an efficient regulatory process for the period of the MRP, allowing the utilities to focus on effectively managing business priorities and increasing the focus on innovative solutions to utility challenges.

However, within the frameworks of these common objectives, each jurisdiction has tailored the plans to fit its specific circumstances. This supports the popular belief among MRP practitioners that the framework adopted for each utility should be in keeping with their specific circumstances and their history with performance-based rate-setting. In other words, while MRPs in various jurisdictions may share many common features, the overall incentive package is tailored to fit the circumstances of each utility.

2.3.1 Features of Indexed-based MRPs in Canada

This section includes a summary comparison of MRP features and related regulators' decisions in three Canadian jurisdictions. Specifically, Table B2-10 below provides a snapshot of Alberta's third generation PBR plans for natural gas and electric distributors, the Ontario Energy Board's (OEB) renewed regulatory framework for Ontario's electric distributors and the Enbridge Gas Distribution (EGD) incentive rate-setting plan in Ontario, and Energir's multi-year rate plan in Quebec. A more detailed discussion regarding the background information and explanation of MRPs for each jurisdiction is provided in Appendix B2-2 to this Application.

1 **Table B2-10: Jurisdictional Comparison of MRPs**

	Alberta Natural Gas Utilities	Alberta Electric utilities	Enbridge Gas IR plan	Ontario Electric Utilities[34] (Price cap)	Ontario Electric Utilities (Custom IR)	Energir
Proceeding	Limited AUC initiated multi-utility hearing		Phase 1: Partial Negotiated Settlement Phase 2: TBD	OEB initiated multi-utility hearing		Oral hearing
Term	5 years (2024-2028)		5 years (2024-2028), first year is cost of service	5 years		3 year extension (2022/2023 to 2024/2025 fiscal years)
Type	Revenue per Customer Cap	Price Cap	Price Cap (Implied Revenue Cap)	Price Cap	Custom IR	Revenue decoupling with O&M Indexing
Formula	Revenue per customer$_t$ = Revenue per customer $_{t-1}$ * (1 + I – X)	Rates $_t$ = Rates $_{t-1}$ * (1 + I – X)	Rates $_t$ = Rates $_{t-1}$ * (1 + I – X) + AU AU : Avg Use adjustment	Rates $_t$ = Rates $_{t-1}$ * (1 + I – X)	Could be forecast, formula or both. Usually capital is forecast and included in the formula through a capital factor.	O&M $_{t+1}$ = O&M$_t$ * (1 + I + 0.75* G) G: customer growth Capital is forecast.
Inflation	Composite factor of Alberta FWI AHE and Alberta CPI		GDP IPI FDD (EGD is proposing a composite index of Ontario AHE and GDP IPI FDD)	Composite factor of Ontario AWE and GDPPI-FDD	Usually the same as price cap but may change on a case-by-case basis	Composite factor of Quebec AWE (with a 4% ceiling) and Quebec CPI
X-Factor	0.4% (0.1% for calculating incremental capital needs)		0.3% (EGD is proposing a negative X-factor of -1.35%)	0% to 0.6%	0% to 0.6% Can change on a case-by-cases basis	0%
Earnings sharing mechanism	If (actual ROE – allowed ROE) is between 200 and 400 bps then 60% utility and 40% rate payers. If the variance is above 400 bps then 80% sharing in favour of rate payers. No sharing for variances below 200 bps		If normalized actual ROE is 150 bps above approved ROE, excess earnings is shared on a 50/50 basis.	No earnings sharing	To be decided on a case-by-case basis	If (actual ROE – allowed ROE) between 0 bps and 50 bps then 75% Energir and 25% ratepayers. For ROE variance > 50 bps then 50:50 sharing

34 Ontario's electric utilities can choose from a menu of options which include Price Cap IR, Annual Indexing IR and Custom Incentive Rate-setting (Custom IR). The table above includes the information related to Price Cap IR and Custom IR only. See Appendix B2-2 to this Application for more information regarding the annual indexing option.

	Alberta Natural Gas Utilities	Alberta Electric utilities	Enbridge Gas IR plan	Ontario Electric Utilities[34] (Price cap)	Ontario Electric Utilities (Custom IR)	Energir
Off-ramps / re-openers	- 300 bps normalized ROE for two consecutive years or +/- 500 bps in one year		+/- 300 bps normalized ROE for one year	+/- 300 bps normalized ROE for one year		None
Efficiency carry-over mechanism	None		Deferred rebasing for five years	Consolidating utilities can ask for deferred rebasing of benefits for up to ten years		None
Incremental Capital Funding	TYPE 1: Funding for expenditures directly caused by applicable law related to net-zero objectives; TYPE 2: An incremental capital calculated based on capital-related revenue generated under I-X and the total notional capital-related revenue requirement		Incremental capital module (ICM) similar to the one applied to Ontario's electric utilities	ICM and Advanced capital module (ACM). Criteria: prudence, discrete projects, clearly outside the base rates and for expenditures above the materiality threshold	Not Applicable. Forecasted in the 5-year plan (exceptions may exist)	Not applicable. Projects above $4 M may need specific approval.
Energy Transition Impact	Capital tracker treatment to include projects caused by applicable laws related to net-zero objectives Option for O&M remuneration scheme		Phase 1: Reduction to proposed base capital investment; increase to equity thickness and changes to main extension test. Phase 2: TBD	Utilities can use the custom IR plan to forecast their incremental capital needs related to Energy Transition		Regulatory relief in revenue requirement to focus on other strategic proceeding aimed at addressing Energy Transition
Z-Factor	Unforeseen, outside management control, and materiality threshold (dollar value of a 40 bps change in ROE on an after tax basis)		Unforeseen events, outside management control, materiality threshold ($5.5M revenue requirement impact)	Unforeseen events, outside management control, Materiality threshold: $50K for Revenue required (RR) less than $10M; 0.5% of RR if $10M < RR =< $200M, $1M if RR > $200M		Not applicable
Y-Factor	Includes items such as AESO flow-through items, municipal fees, load balancing deferral accounts, weather deferral account, …		Includes items such as cost of gas, DSM expenses, Tax variances, LRAM, …	Includes both commodity and non-commodity related deferral accounts	Similar to the price cap plan plus as needed to track capital variances	Includes both commodity and non-commodity related deferral accounts
Service Quality Indicators	Based on AUC's Rule No.2		Scorecard system	Scorecard system		Yes

FortisBC draws the following high-level conclusions from the review of the above MRPs:

- There has been no significant change in the MRP/PBR plans' overall structure in the studied jurisdictions since FortisBC filed its 2020-2024 MRP Application. Changes are mainly related to specific elements of the plan and are incremental.
- With the exception of Energir's plan, all other jurisdictions have a five-year term. However, the MRP term for both Enbridge Gas and Ontario's electric utilities typically includes a one-year cost of service for establishing the going-in base rates.
- Most plans cover both O&M expenditures and capital expenditures while allowing for recovery of certain costs outside the formula as incremental capital expenditures, flow-through or exogenous cost items. Ontario's custom incentive rate-setting (Custom IR) option, however, is often used by utilities with significantly large and highly variable capital plan profiles not suitable for formulas. Therefore, the capital expenditures under these plans are often forecast and then included in the formula through a capital factor. Hydro One's Custom IR is a recent example of this and is included in the jurisdictional comparison Appendix. Energir's rate plan also excludes capital investments from formula and uses a forecast instead.
- Both revenue cap and price cap type formulas have been used by natural gas and electric utilities; however, all natural gas distributors' price cap plans include a mechanism to adjust the rates for average use variances and mitigate the demand risk (similar to FEI's revenue stabilization adjustment mechanism) which transforms their plans into a form of revenue cap in practice. Energir's plan is similar to FortisBC's plan in the sense that the formula is directly applied to the O&M expenses rather than to revenues or prices.
- All plans' formulas include a composite inflation factor consisting of both labour and non-labour price indexes. Further, the X-Factor value for the electric and natural gas utilities in Alberta, Ontario and Quebec ranges between 0 percent and 0.6 percent, inclusive of any stretch factor. All plans have some form of growth factor (explicitly for revenue per customer cap and O&M per customer indexing and implicitly embedded in the price cap plans). Further, with the exception of Energir's plan, all plans provide for recovery of 100 percent of customer growth (i.e., they do not include a discount to the growth factor).
- Most plans include some form of incremental capital funding mechanism outside the I-X formulas to accommodate utilities' capital needs for lumpy and significant capital projects during the MRP term (unless the capital is forecast).
- Canadian regulators' approaches to addressing the energy transition in revenue requirement proceedings vary. In jurisdictions such as Quebec, the energy transition solutions are largely addressed outside the revenue requirement in separate proceedings (or separate phases of the same proceeding). Indeed, the Regie specifically notes that its approved rate plan for Energir is designed to reduce the regulatory burden so that both the Regie and Energir can focus on other strategic projects/proceedings[35], most of which relate to the energy transition, such as dual-fuel energy solutions for space heating, mandatory RNG connections for new

[35] Dossier R-4076-2018, Decision D-2019-028, para 34.

customers and resource planning. In Alberta, the AUC agreed to change the criteria for capital tracker treatment to include projects directly caused by applicable laws related to net-zero objectives. Additionally, the AUC stated that utilities can file proposals for O&M remuneration schemes for projects that can delay and/or reduce the need for capital intensive system expansion projects. In Ontario, electric distributors can use the Custom IR plan to forecast their lumpy and significant capital needs. Further, the OEB's decision in phase one of EGD's 2024-2028 revenue requirement proceeding included a number of measures to address energy transition risk, such as an increase to EGD's equity thickness, a decrease to the proposed capital investment plan and changes to the main extension test for small volume customers which is under review.[36]

- All plans include safeguard mechanisms to protect the utility and ratepayers against the potential unintended consequences of MRPs (such as windfall surpluses or losses). These can be in the form of earning sharing mechanisms, off-ramps and/or re-opener mechanisms that are triggered when, for example, the variances between achieved and approved ROEs exceed a certain threshold.
- All plans include a series of service quality indicators to monitor the reliability and quality of service during the MRP term and ensure that any cost reduction is not achieved at the expense of service quality.

2.4 *STAKEHOLDER FEEDBACK*

In its efforts to develop this Rate Framework Application in a way that recognizes stakeholder interests and issues of concern, FortisBC engaged in discussion with interveners and BCUC staff as the content for this Application was being conceived and then developed. This took the form of initial informal one-on-one conversations in April 2023 and then a full workshop on November 20, 2023. The following is a summary of these activities.

Participants

FortisBC engaged with the following stakeholders through the Application development process:

- BCUC staff
- BC Municipal Energy Utilities
- BC Public Interest Advocacy Centre
- BC Sustainable Energy Association
- Commercial Energy Consumers of BC

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[36] Subsequent to the OEB decision, the Ontario Minister of Energy tabled a bill, Keeping Energy Costs Down Act, 2024, which seeks to provide the Minister with powers to amend the OEB decision in a number of respects, including reversing changes to the main extension test and prescribing a separate proceeding to consider such changes. At the time of writing, the bill had reached second reading. https://www.ola.org/en/legislative-business/bills/parliament-43/session-1/bill-165.

- Industrial Customers Group
- Movement of United Professionals (MoveUP)
- Residential Consumer Intervener Association

2.4.1 April 2023 Preliminary Meetings

FortisBC representatives met with BCUC staff to gather feedback and perspective on its upcoming rate setting framework application. Specifically, FortisBC sought feedback on what has worked well with the Current MRP, what could be improved, the top issues in relation to the rate plan, and any other advice in relation to the next rate plan.

Key areas of feedback included the need to find and maintain regulatory process efficiencies. This included discussion of efficiencies flowing from a joint application between FEI and FBC as well as seeking to streamline the Annual Review process. Staff supported the need to consult with stakeholders to ensure their voices are heard. Staff also suggested that the application would benefit from clear articulation of the themes of the application, including how FortisBC has balanced the impacts of the energy transition and affordability. Finally, it was suggested that greater clarity and consistency in how capital is described would be beneficial.

FortisBC representatives also met with interveners individually in one-hour meetings to probe their thoughts on what has worked well with the Current MRP, what could be improved, the top issues facing their constituents in relation to the rate plan, and any other advice they had in relation to the next rate plan.

Common areas of feedback received from these meetings included support for regulatory efficiencies where possible while still enabling transparency given the evolving environment. There was skepticism from some interveners on whether the cost efficiencies were realized due to the Current MRP mechanisms or if they would have happened anyway under a non-incentive model. Interest was expressed in reshaping the ratemaking model to adapt to current times. Interveners wanted to see the utilities adapt as part of the energy transition but still expected affordability. A couple of interveners shared concerns around future renewable gas supply and the overall viability of the gas utility given existing and anticipated government policy direction.

2.4.2 November 2023 Workshop

On November 20, 2023, FortisBC representatives met with BCUC staff and interveners in a full day workshop held at the FortisBC Vancouver office and virtually. Topics included on the agenda for this workshop were:

- FortisBC's Operating Context
- Adapting the Framework to the Operating Context
- Proposed Service Quality Indicators

Material used by FortisBC to facilitate the discussion was provided and is included in Appendix B2-3. A summary of the feedback received and how it has been addressed in this Application is provided in Table B2-11 below.

Table B2-11: Summary of Intervener Feedback

No.	Intervener Feedback	How FortisBC Has Addressed in Application	Application Reference
EVOLVING WITH THE ENERGY TRANSITION			
1.	Adapt with the energy transition while maintaining affordability.	FortisBC proposes to address this challenge by maintaining a cost-control focus, supporting customers in reducing their energy consumption, optimizing existing infrastructure and investments, and adding new sources of revenue serving non-traditional markets. Further, FortisBC has proposed mechanisms that, over the three-year term, will provide flexibility to adapt to the changing environment, including formula-based growth capital for FEI (see item 6 below).	Section B1.4; Section B3.2; Section C3.3.1
2.	Concerns about the viability of the gas utility given existing and anticipated government policy direction.	While the long-term role for gas infrastructure is uncertain from a policy perspective, FortisBC views gas infrastructure as a critical element of the energy system in BC, meeting peak energy demand during cold weather events, providing access to scalable supplies of low carbon energy, and bringing low carbon fuels to hard-to-decarbonize sectors. Further, there are many filings that deal with the impacts of the energy transition beyond the rate setting framework. FortisBC continues to manage the impacts across all of its filings.	Section B1.4.1; Section B3.1
3.	Utilize innovation, renewable gases, gas and electric integration, and new lines of business to help keep the gas utility viable.	FEI proposes to continue the Clean Growth Innovation Fund, continue investments in clean growth initiatives, to focus on more integrated planning for gas and electric systems, and to continue to pursue growth in non-traditional markets.	Sections C2.2.3.3 and C2.3.3.2; Section C2.5; Section C5
PURSUING REGULATORY EFFICIENCIES AND TRANSPARENCY			
4.	Pursue regulatory efficiencies where possible while enabling collaboration and ensuring transparency.	FortisBC has filed a joint application between FEI and FBC given the overlap in common rate framework elements. Reviewing those elements in the same regulatory proceeding enhances the efficiency of the review process. FortisBC is also proposing to continue the Annual Review process while gaining efficiencies by removing from the scope of the Annual Review process those components of the Framework that are approved by the BCUC in this Proceeding and that remain unchanged each year.	Section B3.2; Section C1.10
5.	Comfortable with the Application incorporating both FEI and FBC.	As noted above, this Application incorporates both FEI and FBC with distinctions between the two utilities noted throughout as applicable. FortisBC believes that this approach optimizes regulatory efficiency.	Throughout Application

No.	Intervener Feedback	How FortisBC Has Addressed in Application	Application Reference
INVESTING IN SAFE, RELIABLE AND RESILIENT SERVICE			
6.	FEI will be experiencing a drop off in customer growth and this should be considered for the growth capital formula and depreciation moving forward.	FEI considers the formula approach based on unit costs and a forecast of gross customer additions with true-up for variances remains the most appropriate approach for establishing FEI's growth capital. Since this approach will continue to be dependent on the number of gross customer additions, it will also provide flexibility when establishing the amount of growth capital each year during the transitional period to lower carbon emission energy. For example, if the number of gross customer additions is reduced during the three-year term due to the energy transition, the formula approach will also reduce the amount of growth capital calculated but still enable FEI to meet the obligation to connect any new customers if requested to do so.	Section C3.3.1; Section D2
7.	Investment is needed for emergency event preparedness and cyber related risks.	FortisBC concurs and has suggested in this Application that this increases the need for investment in physical and cyber security for both FEI and FBC to maintain the safety and reliability of the Province's energy system. Additionally, the increasing frequency of extreme weather events has created additional risk to energy infrastructure and FEI and FBC must invest to ensure their systems are resilient and adaptable in response.	Section B1.6; Sections C2.2.4.3, C2.3.4.3 and C2.3.4.5; Sections C3.3.3.4 and C3.4.3.4
ADAPTING SERVICE QUALITY INDICATORS			
8.	Adapt and report on the energy transition and general support for exploring possible leading indicators to establish a means of more effectively measuring overall employee safety. Question over the need to report meter reading completion with AMI in place. (Further specific SQI feedback is noted in the SQI appendices)	FortisBC has considered all feedback received from interveners on the proposed SQIs, including proposing a new FEI category of Informational Indictors specific to the energy transition and proposing a new employee safety leading informational indicator for both FEI and FBC. FEI and FBC have proposed to rename and transition meter reading completion to an informational indicator given the implementation of advanced metering. FEI has also considered feedback on the threshold for TSF (non-emergency) and has maintained the threshold at 68 percent.	Section C6; Appendices C6-1 and C6-2

A more detailed summary of the feedback received was provided and is included in Appendix B2-3. A summary of the feedback received in the Service Quality Indicators portion of the workshop is included in Section C6.2 and in Appendices C6-1 and C6-2.

2.5 CONCLUSION

The Current MRP has performed well in a rapidly evolving external environment, including unprecedented pressure on rates for both gas and electric operations, driven by factors that are external to FortisBC's historical operations. These include the energy transition impacts and the impacts of the COVID-19 pandemic, which have contributed to the high inflationary environment and supply chain shortages. FEI's and FBC's total effective rate increases have tracked close to composite inflation on a cumulative basis and, when excluding rate impacts from items approved outside of the Current MRP, have tracked below the composite inflation rate.

Looking across Canada, there have been no significant changes to the structure of rate plans for gas and electric utilities that have been implemented; however, regulators have increasingly recognized the need to account for the energy transition, but have maintained consistency with the requirements of rate plans and managed many of the impacts of the energy transition outside of rate framework proceedings.

Finally, FEI and FBC have met with BCUC staff and interveners to discuss the operating context and how it shapes the rate-setting framework. The Companies took away valuable feedback, which was used to inform the design of the Rate Framework.

3. IMPLICATIONS FOR THE RATE FRAMEWORK

The purpose of this Application is to establish a flexible and efficient rate setting framework that supports FortisBC's ability to adapt to the energy transition and manage its impacts on the provision of affordable, reliable, and resilient service to customers as the Province works toward a more integrated and sustainable energy future. In developing its Rate Framework proposals, FortisBC considered how the energy transition and other key influences in its external operating environment impact the components of its revenue requirement.

FortisBC believes that its Rate Framework proposals set out in Section B3.2 below strikes a reasonable balance by providing for necessary flexibility (through annual updating of certain forecasts and costs) and incenting FortisBC to continue to control its costs. Over FortisBC's long history with PBRs and MRPs, different components of the revenue requirement have been included in the indexing approach. FortisBC continues to believe in the fundamental principles behind incentive regulation and has proposed that the majority of the Companies' O&M costs, and also the unit costs of FEI's Growth capital, continue to benefit from the discipline imposed by an indexing approach. Similarly, the majority of the Companies' capital costs remain subject to a three-year forecast, providing incentive to control costs during the term of the Rate Framework. The Rate Framework also provides for regulatory efficiency by establishing the parameters for what can and should be reviewed during each Annual Review.

While there are key differences in the challenges facing FEI and FBC, there are common rate framework solutions that can help mitigate those challenges. This joint Application proposes similar, although not identical, rate-setting frameworks that account for the different challenges facing each utility. FortisBC believes that the flexibility provided by the Rate Framework can accommodate the types of energy transition impacts that face both the gas and electric utilities.

3.1 *THE ENERGY TRANSITION IMPACTS REACH ACROSS MANY REGULATORY PROCEEDINGS*

As stated above, FortisBC is proposing a rate-setting framework that is flexible enough to accommodate the impacts of the energy transition. Detailed and iterative analyses, engagement, and regulatory policy will be needed to effectively navigate the future role of gas and electricity, and how these energy sources can work together to provide an efficient and effective energy system in BC. A key focus for FortisBC and its customers is to implement a rate-setting framework that recognizes the uncertainty inherent in the energy transition and that can incrementally adapt to the complex changes that happen primarily over the medium to long term. The energy transition will occur over time, through various policy enactments that will be reflected in key regulatory filings and proceedings. This Application is about setting a rate framework that is flexible enough to accommodate those impacts, but this rate framework is not where the majority of those determinations are made. Below, FortisBC describes the major regulatory proceedings where the energy transition impacts will be addressed, and how impacts of the decisions on these processes will be reflected through the Annual Reviews provided through the Rate Framework.

3.1.1 Long Term Resource Plans

In FortisBC's gas and electric long term resource plans (LTGRP and LTERP, respectively), the Companies provide a longer term (20 year) view of how the various energy policies and other external influences will impact the businesses. It is in these proceedings that the BCUC accepts a future planning scenario that is used to inform FortisBC's capital plans and that supports FortisBC's views of the future demand scenarios that could develop. It is in the LTGRP/LTERP proceedings where the various aspects of FEI's and FBC's responses to the energy transition are pulled together.

FEI filed its most recent LTGRP on May 9, 2022 and received a decision from the BCUC on March 20, 2024. While the 2022 LTGRP examined a range of future potential demand scenarios, including the potential for both increasing and decreasing gas demand over the next 20 years, FEI has based its capital forecasts in this Application on the Diversified Energy (Planning) (DEP) scenario. The DEP scenario envisions a high level of DSM activities, a role for some electrification of gas loads in buildings, and an important and growing role for renewable and low carbon gases to replace conventionally sourced natural gas over the next 20 years to address the transition to a decarbonized energy future. The combination of these resources is shown to meet the Province's GHG emission reductions targets in the *Clean Energy Act* and the *Climate Change Accountability Act*. The 2022 LTGRP and numerous other studies cited in the LTGRP have shown that there remains an important role for the gas system in a decarbonized energy future. While it is likely that the actual combination of resources will unfold somewhat differently than the amounts modelled in the 2022 LTGRP DEP Scenario, none of the scenarios filed differ significantly over the term of this proposed three-year Rate Framework. Finally, the various components of the Rate Framework provide sufficient flexibility to accommodate changes in the external environment, such as through the forecast/flow-through treatment of demand and of certain O&M and capital expenditures.

FBC filed its LTERP on July 4, 2021 and received a decision from the BCUC on December 21, 2022. FBC's long-term vision also aligns with a diversified energy future as the key pathway to a decarbonized energy future. The BCUC decision on the 2021 LTERP has been fully reflected in the proposals set out in this Application. FBC's next LTERP is expected to be filed in 2025, with any decision likely to be received in late 2026. Although the timing of the LTERP decision will likely occur after rates are proposed for 2027, the various components of the Rate Framework provide sufficient flexibility to accommodate changes.

3.1.2 Major Projects

FortisBC typically files separate applications for its Major Projects, which are primarily CPCNs but can include other significant projects. The decisions in these separate proceedings determine whether the projects are approved to proceed, and in some cases, can influence future levels of O&M and Sustainment capital, as well as energy demand assumptions.

A number of CPCNs were approved during the Current MRP term, and the impacts of those CPCNs were incorporated into the applicable rate-setting years through the mechanisms approved within the Current MRP. For instance, the approval of the IGU project and the CTS TIMC project resulted in incremental O&M requirements. These incremental O&M amounts were included as forecast (flow-though) integrity O&M during the Current MRP term. These amounts will be incorporated into Base O&M for the proposed Rate Framework as discussed in Section C2.2.2.2.2.

In 2023, FEI received approval for the Advanced Metering Infrastructure (AMI) CPCN project. This project has a range of impacts on the Company during the term of the Rate Framework, as AMI will be in the process of deployment throughout the three-year period. FEI has proposed how to accommodate the deployment of the AMI project in Sections C2.2.2.2.1 (O&M) and C6.3.3 (SQIs) of this Application, demonstrating that the Rate Framework is sufficiently flexible to adapt to changes in operational circumstances. As new Major Projects are reviewed and approved during the term of the Rate Framework, such as the recently filed FBC Fruitvale Substation CPCN project, the flexibility contained within the Rate Framework will allow for the impacts to be incorporated into rates, similar to the Current MRP.

3.1.3 FEI Gas Filings

FEI files an Annual Contracting Plan (ACP) with the BCUC in the spring of each year. The ACP focuses on FEI's short- to mid-term contracting strategies for storage, supply, and pipeline transportation resources to meet the peak day, winter design, and annual load requirements for not only the upcoming gas years (November to October) but future gas years as well.[37] The ACP includes increasing amounts of renewable and low carbon gas over time.

The transition from conventional gas to renewable and low carbon gas is an important component in the overall strategic planning of the ACPs. Over the past several years, FEI has incorporated RNG supply into its gas supply portfolio and expects the amount of supply will continue to grow. In order to properly manage any adjustments to FEI's contracting strategies for conventional gas, storage, and pipelines, there are several considerations that FEI must assess. FEI monitors whether the supply is directly connected to FEI's system (on-system) or delivered to FEI's system through displacement (off-system). FEI also assesses the firm amount of supply delivered on its system, or at the regional market hubs. RNG purchases have different contractual obligations than FEI's conventional natural gas purchases. This is because contracted RNG projects can have either an annual or monthly supply requirement to FEI, or a minimum daily firm amount, whereas FEI's firm conventional natural gas purchases are for a fixed GJ/day delivery for each day of the term of the transaction. Therefore, the volumes delivered to FEI can fluctuate during the month, based on whether the RNG plant(s) are running and other market conditions. From a security of supply perspective, FEI needs to maintain a portion of conventional natural gas within the portfolio to manage the risk of any supply variability.

In the short-term, FEI anticipates that the majority of its RNG supply will be secured outside of FEI's service areas (i.e., off-system supply). Therefore, FEI will still require contracts with third parties for transportation services to deliver gas (whether conventional or RNG) to FEI's

[37] These requirements are for RS 1 to 7 and RS 46 sales service customers (Core customers).

customers. As RNG volumes continue to increase each year, FEI will monitor and make any adjustments that are required to the remainder of the gas supply portfolio through each ACP. Additionally, as FEI begins to integrate other low-carbon gas supply, it will assess annually the impact to the portfolio in each ACP.

The ACP that is accepted by the BCUC is then reflected in rates through a series of quarterly gas cost filings and periodic renewable gas supply filings.

FEI filed an Application for a Revised Renewable Gas Program in 2021 and received a decision from the BCUC on March 20, 2024. Although the decision made in that regulatory proceeding will directly impact FEI's energy transition plans, the impacts will primarily be reflected in future renewable gas plans and applications, and in commodity and midstream rates. The effects on the delivery rates will be limited to the pace of future customer attachments, the balances in certain deferral accounts, and the requirements for employees and systems to support the renewable gas program. Although these impacts can be significant, they are expected to be more impactful over a longer term than the three-year term proposed for this Rate Framework. Further, the mechanisms that FEI already has in place, and that it proposes to continue in the Rate Framework, provide flexibility to accommodate these changes. These mechanisms include annual reforecasting of customer attachments, annual updating of deferral account balances, flow through of renewable gas acquisition costs and renewable gas O&M and capital.

3.1.4 Demand Side Management (DSM)

FEI's 2024-2027 DSM Expenditures Plan was accepted on February 2, 2024, and FBC's 2023-2027 DSM Expenditures Plan was accepted on December 16, 2022. These filings are focused on energy efficiency programs, with an emphasis on cost-effective measures that contribute to the long-term success of the energy transition, including opportunities for gas system optimization such as hybrid heating. The Rate Framework allows for annual updating of the deferral accounts where the DSM Expenditures are captured (including the costs of the employees that support the programs), and the forecasting methodologies are designed to reflect changes in use rates, whether caused by DSM activities or otherwise, over time. There are no direct O&M impacts from the Companies' DSM programs.

3.1.5 Summary of Energy Transition Regulatory Impacts

FortisBC has made significant efforts over the past decade to evolve its rate-setting frameworks, as well as the projects, plans and programs in the above noted proceedings, to manage the early impacts of the energy transition. As discussed in Section B1, the impacts of the energy transition on FortisBC's gas and electric operations are growing and FortisBC must continue to evolve its rate-setting framework to help manage the impacts. While many of these impacts will ultimately have an effect on FortisBC's rates, the majority of the related projects, plans and programs are reviewed and determined outside of the Rate Framework and outside of the annual rate-setting process (i.e., Annual Reviews).

FortisBC's goal with this Rate Framework is to ensure that it continues to be flexible enough to accommodate those impacts while also providing the necessary certainty and efficiency that will help it manage the growing requirements to diversify revenue streams, invest in capacity and resiliency projects as approved, and elevate its focus on integrating gas and electric planning across the Province for an efficient and effective use of resources. The Rate Framework will also support the need to continue to secure resources and invest in necessary energy infrastructure.

The proposed three-year term may reduce the incentive properties of the Rate Framework compared to a longer term, but FortisBC has a strong track record of cost control and savings while operating under successive plans, and this will continue to be a major focus of the Companies. Additionally, to respond to rate pressures, FortisBC will continue to focus on rate smoothing approaches, and on the affordability strategies discussed in Section B1.5.

3.2 *KEY FEATURES OF THIS RATE FRAMEWORK THAT ADDRESS THE ENERGY TRANSITION*

To address the energy transition and other influences in FortisBC's operating environment, and in consideration of the existing flexibility and features of its Current MRP and stakeholder feedback received, FortisBC's key proposals for the Rate Framework are as follows:

1. A term that provides incentive to perform and the capacity to focus on key issues, while acknowledging the current level of uncertainty in the operating environment;
2. Sufficient funding to address emerging requirements and challenges;
3. Flexibility to adapt to the energy transition to manage its costs and impacts; and
4. An efficient annual rate-setting process that allows the Companies to focus on responding to the energy transition operationally and through key regulatory filings focused on the energy transition.

Below, FortisBC describes the various elements of its Rate Framework at a high level.

3.2.1 Elements Common to FEI and FBC

3.2.1.1 Term

FortisBC is proposing a three-year term for its Rate Framework, with an option to extend beyond three years subject to a review of the operating environment at that time. Three years is a shorter term compared to the Current MRP and the previous 2014-2019 PBR Plan, and it reflects the uncertainty inherent in the operating environment due to the energy transition. Three years provides a balance between a long enough time frame to find some efficiencies in the regulatory process and provide certainty on the rate mechanisms in place, while recognizing that the energy transition will have transformational impacts and that the timing and quantum of these impacts is uncertain.

The option to extend this Rate Framework beyond 2027 has the potential to provide for additional efficiencies. FortisBC believes that in three years (in 2027), further policy development will likely have occurred, with further clarity provided on what roles the gas and electric utilities play in the future, and on how gas and electric utilities can work together to accommodate the energy transition. In 2027, FortisBC will carefully review the implications of policy developments and its overall operating environment and consider the externalities present at that time. Based on these considerations, FortisBC may propose to extend the Rate Framework for one or both of the Companies. Overall, a three-year term with the possibility to extend will allow for efficiency and allow FortisBC to continue to focus on the fundamental impacts of the energy transition.

3.2.1.2 Base O&M Formula

FortisBC proposes to continue with its existing formula-based approach to Base O&M. This has provided for an efficient rate-setting process over the past decade and continues to provide incentive for FortisBC to control and prioritize spending. FEI and FBC have re-set their starting Base O&M levels considering both current actual spending levels and incremental requirements over the upcoming three years. The Companies have also reviewed the inflation factor, productivity factor and growth factor, and provide recommendations on each of these items in Section C1. The specifics of the Companies' O&M proposals are included in Section C2.

3.2.1.3 Three Year Regular Capital Forecast

In the 2020-2024 MRP Application, FortisBC had proposed to establish its Regular capital forecasts (Sustainment and Other capital for FEI; Growth, Sustainment and Other capital for FBC) for the entire five-year term. However, in the MRP Decision, the BCUC approved only the first three years of the Companies' five-year capital forecasts. The BCUC stated the following (page 131):

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecasts in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.

FortisBC considers these concerns to be just as valid today, particularly in light of potential energy transition impacts on longer term capital plans. This was a key consideration in FortisBC's three-year forecast of Regular capital expenditures, as set out in Section C3, and was a key consideration in proposing a three-year term for this Rate Framework.

3.2.1.4 Flow-through and Exogenous Items

FortisBC proposes to continue with the majority of its existing flow-through items and resulting deferral accounts. The flow-through items are discussed in Section C2.5 (O&M), Section C3.3.4 (FEI Capital) and Section C3.4.4 (FBC Capital), and a listing of the deferral accounts is provided in Appendices C4-4 and C4-5. A key category of existing flow-through items for both FEI and FBC is Clean Growth Initiatives, and both Companies propose to continue to treat these initiatives as flow-through. Clean Growth Initiatives are vital to supporting the energy transition, but the pace at which they may scale up is uncertain and difficult to anticipate. Therefore, flow-through treatment benefits both the Companies and customers because it allows for the Companies to invest the amounts needed to support the energy transition while ensuring that customers only pay for the actual expenditures incurred. Further, by forecasting these items annually, the BCUC and interveners have the opportunity to review the forecasts in each Annual Review.

An area of significant focus in the Current MRP has been FEI's and FBC's load forecasts. In response, the Companies have provided an explanation of the load forecasts in Appendices C4-1 and C4-2 and have proposed a workshop specific to reviewing the load forecast methods in this proceeding. FortisBC proposes to continue to treat revenue (with the exception of some aspects of Other Revenue) as flow-through. This treatment ensures that annual variances between forecast and actual amounts are trued-up in the subsequent year. Therefore, should the Companies experience notable fluctuations in load in a specific year that are not captured by the forecast, these fluctuations will be captured in the Flow-through deferral account, and the forecasts will be adjusted in subsequent years to account for changes in demand, whether as a result of the energy transition or other factors.

FortisBC sees value in continuing with the existing exogenous factor criteria and thresholds as discussed in Section C1.6. This mechanism has served both customers and the Utilities well in flowing through both costs and savings that were unforeseen at the time the rate plans were approved. In particular, with the continuing occurrence of extreme weather events, it is important that the Companies have the opportunity to recover significant costs resulting from these events.

3.2.1.5 Earnings Sharing Mechanism, Efficiency Carryover Mechanism and Off-Ramp

FortisBC continues to believe that a symmetrical 50/50 earnings sharing mechanism (ESM) is the most beneficial in aligning the interests of customers and the Utilities. The ESM provides the Companies with an incentive to perform and ensures that customers are sharing in any savings achieved each year.

Given the limited time frame for the proposed Rate Framework (three years), FortisBC does not consider it necessary to include an efficiency carryover mechanism (ECM) in the proposed Rate Framework.

FortisBC proposes to continue with the existing off-ramps that were approved for the Current MRP. The off-ramps provide a safeguard to the Companies and customers, and while they have not been required thus far in the Companies' rate plan history, given the uncertainties in the timing and pace of impacts of the energy transition, FortisBC considers it worthwhile to continue the off-ramp mechanism during the term of the Rate Framework.

Further discussion of these items is provided in Sections C1.7 through C1.9.

3.2.1.6 Incremental Capital

As discussed above in Section B3.1.2, a provision to allow for the inclusion of incremental capital approved through CPCNs or other Major Project proceedings has been instrumental in having a rate setting framework that can accommodate energy transition impacts and allow for safe, reliable, and resilient energy systems. FortisBC believes this process has worked well and should be continued.

3.2.1.7 SQIs

FortisBC has reviewed its suite of SQIs for continued applicability for those metrics that are reflective of service expectations, and in consideration of providing information on its progress through the energy transition. FEI is proposing a new suite of Energy Transition informational indicators. These new indicators are described in detail in Section C6.3.4 and in Appendix C6-1.

3.2.1.8 Annual Reviews

As explained above, a key feature of the Rate Framework is to provide an efficient annual rate-setting process that allows the Companies to focus on responding to the energy transition operationally and through key regulatory filings focused on the energy transition. In Section B2.2.2.1, FortisBC discussed how the regulatory efficiency of the Annual Review process has diminished, and why an efficient rate-setting process is vital so that the Companies can focus their attention and resources on the many significant operational and regulatory processes that are and will be required for the Companies to respond to the energy transition and changes in the external environment.

FortisBC considers that the Annual Review process should be continued during the Rate Framework term. However, FortisBC considers that increased regulatory efficiency can be achieved, and has accordingly proposed some clarifications and adjustments to the process in Section C1.10.

3.2.2 Elements Specific to FEI

As explained in Section B1.4, the energy transition has specific and unique implications for FEI as compared to FBC. FEI has reviewed the features of the Current MRP and has assessed whether certain components require modification to respond to the energy transition and other external factors.

3.2.2.1 Forecast/Flow-through Items

With regard to forecast/flow-through items, as explained in Section B3.2.1.4, FEI and FBC both propose to continue treating Clean Growth Initiatives as flow-through during the Rate Framework term. This treatment is especially vital for FEI, as FEI addresses emissions and continues to develop its low carbon energy solutions, including the existing categories of renewable gas, which has expanded from just biomethane initiatives to now include hydrogen initiatives, as well as CNG and LNG fuelling and LNG production. For this Rate Framework, FEI discusses the addition of methane emission mitigation as a new category of Clean Growth Initiatives. Please refer to Section C3.3.4.1 for further details.

3.2.2.2 Regular Growth and Sustainment Capital

In the Current MRP, unlike FBC, FEI has utilized a formula approach to Growth capital. FEI reviewed this treatment in consideration of the energy transition's expected impact on new customer additions and believes that for the three-year term of the Rate Framework, a formula approach continues to be appropriate for managing the uncertainty associated with customer connections. FEI's Growth capital needs are directly related to annual new customer attachments; therefore, a formula approach is well suited to this category of capital. Accordingly, FEI proposes to continue the formula approach and to continue with the existing method of forecasting gross customer attachments annually, with the variances between forecast and actual connections trued up and Growth capital adjusted for this true-up. This forecasting and true-up approach provides the flexibility needed to adjust Growth capital annually for changes in customer attachments, whether due to the energy transition or otherwise. FEI has an obligation to connect customers if requested to do so; this remains a valid external driver of Growth capital additions. For further discussion of Growth capital, please refer to Section C3.3.1.

FEI has taken steps to rationalize its Sustainment capital planning, while recognizing the importance of continuing to provide safe and reliable service to customers. FEI has accordingly focused on prioritizing the necessary reliability and integrity projects and programs over the three years of the Rate Framework, and on planning new load driven infrastructure with optionality to account for the scope and timing uncertainty of the energy transition from gas to electric. The specific details of FEI's capital planning are discussed in Section C3.2.

3.2.2.3 Energy Transition Informational Indicators

As referenced in Section B3.2.1.7 and described in detail in Section C6.3.4 and Appendix C6-1, FEI is proposing to add a new suite of informational indicators related to the energy transition.

3.2.2.4 Earlier Recovery of Gas System Assets

One response to the energy transition that has been discussed in other FEI regulatory proceedings and has been raised for future consideration in other jurisdictions is a change in approach to depreciation expense, from the long-established useful life approach to an economic planning horizon recovery method. This approach has the goal of reducing the potential for stranded assets over the long term. However, this change would result in an accelerated recovery of depreciation expense, which would increase rates for customers. Although this is an approach that can have some value in the future, the energy transition will be a long-term transition and will unfold over an extended time horizon; FEI firmly believes that now is not the time to accelerate depreciation and increase costs for customers.

A better approach at this time, which FEI has been pursuing to date, is to develop alternative energy products and services that leverage existing assets while also reducing emissions. The early retirement of assets is conceptually at odds with the development of alternative products and services using those assets. It will also increase costs and crowd out investments in emissions reduction, and projects a negative signal about the future use of gas infrastructure and its ability to successfully navigate the energy transition. This would be misleading, as FEI's assets can play a critical role in the transition towards a lower carbon future. Because of this, developing alternative energy products and services that leverage existing assets while also reducing emissions is the reasonable and appropriate pathway.

Further discussion of this topic in the context of FEI's depreciation study is provided in Section D2.1.

3.2.3 Elements Specific to FBC

FBC is affected by the energy transition differently than FEI. FBC is focused on investing in capacity to accommodate increases in load, whether coming from electric vehicles or from customers moving to electricity from other fuels. In addition, the need to respond to climate impacts through investments in climate adaptation is more acute for FBC compared to FEI due to FBC's above-ground grid. As such, FBC has provided further discussion on the expected O&M and capital impacts of these influences over the coming three years in Section C2.3.4.5.3 for O&M and in Sections C3.4.1 and C3.4.2 for capital.

3.3 *CONCLUSION*

FortisBC has considered the fundamental impacts of the energy transition on its customers and gas and electric operations and concluded that it needs an efficient rate setting framework that supports its ability to adapt to the energy transition without compromising the reliability and resilience of its energy systems as it works toward a more integrated and sustainable energy future.

In developing its Rate Framework proposals, FortisBC therefore considered the significant uncertainty caused by the energy transition against a backdrop of increasing challenges related to climate impacts on energy infrastructure, physical and cyber security, aging assets, and customer affordability. To manage these impacts, FortisBC has proposed a Rate Framework that includes:

1. A term that provides incentive to perform and the capacity to focus on key issues, while acknowledging the current level of uncertainty in the operating environment;
2. Sufficient funding to address emerging requirements and challenges;
3. Flexibility to adapt to the energy transition to manage its costs and impacts; and
4. An efficient annual rate-setting process that allows the Companies to focus on responding to the energy transition operationally and through key regulatory filings focused on the energy transition.

Overall, FortisBC's Rate Framework represents a continued evolution of its approach to rate setting in the midst of a challenging external environment.

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for 2025 through 2027

Section C:

PROPOSED RATE SETTING FRAMEWORK

Table of Contents

Index of Tables and Figures

C: PROPOSED RATE SETTING FRAMEWORK

FortisBC's Rate Framework will be used to determine natural gas delivery rates and electricity rates over the 2025-2027 period for FEI and FBC, respectively. As discussed in Section B2 of the Application, the Current MRP has demonstrated its inherent flexibility which has helped the Companies manage the uncertainty caused by the energy transition and extreme weather events, as well as the substantial inflationary pressures impacting costs. Although inflationary pressures are expected to lessen, the risks related to the energy transition and extreme weather events remain over the proposed three-year term of the Rate Framework.

The material in Section C of this Application, along with the information contained in the referenced Appendices, provides a comprehensive description of FEI's and FBC's proposed Rate Framework for the period from 2025 to 2027:

Section C1 – Components of the Rate Framework: Sets out the components of the Rate Framework and provides a summary of each. Further details on significant components are provided in Sections C2 through C6.

Section C2 – O&M: Describes the proposed 2024 Base O&M and discusses how O&M funding, including both formula and forecast, will be determined during the term of the Rate Framework.

Section C3 – Capital Expenditures: Discusses FEI's 2024 Base Growth capital and funding over the term of the Rate Framework. It also provides FEI's and FBC's forecasts of all other capital expenditures from 2025 to 2027, and an update on anticipated Major Projects.

Section C4 – Annual Calculation of the Revenue Requirement: Discusses the items that will be included in the revenue requirement at each Annual Review, and the proposed treatment of variances from forecast for each item.

Section C5 – Innovation Funding: Describes FEI's updated proposal for innovation funding for accelerating investment in innovative technologies.

Section C6 – Service Quality Indicators: Describes FEI's and FBC's proposed suite of SQIs to monitor performance during the term of the Rate Framework, including the new Energy Transition informational indicators proposed for FEI.

Section C7 – 2025 Indicative Rates: Provides the Companies' indicative 2025 rates incorporating all of the proposals, including those set out in Section D.

1. COMPONENTS OF THE RATE FRAMEWORK

1.1 INTRODUCTION

This section describes the components of the Rate Framework from 2025 to 2027 for FEI and FBC. Table C1-1 below summarizes the Rate Framework components and references the section where the details can be found. Most elements of the Rate Framework are identical for the two Companies.

Table C1-1: Summary of 2025-2027 Rate Framework

Item	2025-2027 Rate Framework	Section(s)
Term	A three-year term from 2025 to 2027, with the potential to extend the Rate Framework beyond 2027.	C1.2
Inflation Index (I-Factor)	A weighted average of AWE:BC for labour costs and CPI:BC for other costs will be used to determine the I-Index. FortisBC proposes to return to a fixed labour/non-labour weighting for the term of the Rate Framework.	C1.3
Productivity Factor (X-Factor)	***FEI***: An X-Factor of 0.38 percent, consisting of 0.28 percent industry O&M partial factor productivity (PFP) and 0.10 percent stretch factor for FEI's O&M and Growth capital indexing formulas. ***FBC:*** An X-Factor of 0.20 percent, consisting of 0.20 percent industry PFP and zero percent stretch factor for FBC's O&M indexing formula.	C1.4
Growth Factor	Continue with annual forecast of customer growth for FEI's and FBC's index-based O&M and gross customer additions (GCA) for FEI's Growth capital, both with a true-up to actual when available. In addition, FortisBC is proposing to eliminate the 0.75 discount factor currently applied to the growth factor for the O&M formula.	C1.5
Controllable Expenses – O&M	Continue with an indexed (I – X) unit cost approach for O&M. A 2024 Base O&M is established. O&M will not be rebased during the term of the Rate Framework but will be subject to true-up for actual customers.	C2
Controllable Expenses – Capital	***FEI***: Continue with an indexed (I – X) unit cost approach for Growth capital. The Growth capital formula is tied to the forecast GCA with the base unit cost developed using a regression of three-year actuals and projected results. Growth capital will not be rebased during the term of the Rate Framework but will be subject to true-up for actual GCA. Three-year forecast of Regular Sustainment and Other capital. ***FBC:*** Continue with a forecast of Regular Growth, Sustainment and Other capital expenditures for the term.	C3
Forecast O&M and Capital	Continue with specific O&M and capital items being forecast each year in the Annual Review with variances captured in the Flow-through deferral account or other deferral accounts.	C2 and C3
Incremental Capital	Continue with annual forecasting of incremental capital approved through CPCNs, OICs, or other Major Project proceedings.	C3

Item	2025-2027 Rate Framework	Section(s)
Forecast Revenues and Margins	Continue with annual forecast of revenues. For FEI, variances in revenue will continue to flow to either the RSAM deferral account (for RS 1, 2, 3, and 23) or the Flow-through deferral account. For FBC, variances in both revenue and power supply costs will continue to flow to the Flow-through deferral account.	C4
Deferral Accounts	Continue the use of rate base and non-rate base deferral accounts, with any required changes proposed at each year's Annual Review. Continue the use of a single Flow-through deferral account for each utility to capture all variances that are approved with flow-through treatment, except where a separate deferral account is approved.	C4
Innovation Fund	Continue the funding of innovation for FEI. Return unused funds from the Current MRP in 2025.	C5
Service Quality Indicators (SQIs)	***FEI***: 17 SQIs (8 SQIs with a target benchmark and 9 informational indicators) are proposed as measures of customer service, employee safety and reliability, as well as new informational indicators related to the energy transition. ***FBC***: 12 SQIs (7 SQIs with a target benchmark and 5 informational measures) are proposed as measures of customer service, employee safety, and reliability.	C6
Exogenous Factors (Z-Factor)	Continue with existing criteria (including existing materiality thresholds). Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and BCUC decisions will be flowed through in rates, subject to BCUC approval.	C1.6
Earnings Sharing Mechanism (ESM)	Continue with a 50:50 ESM between customers and the Companies for earnings above and below the allowed ROE.	C1.7
Efficiency Carryover Mechanism (ECM)	Remove the ECM from the Rate Framework.	C1.8
Off-Ramps	Continue with existing off-ramps.	C1.9
Annual Review Process	Retain the Annual Review process but with a more defined scope.	C1.10

1.2 *TERM*

As discussed in Section B3.2.1.1, FortisBC is proposing a three-year term for the Rate Framework for the years 2025 to 2027, with the potential to extend beyond 2027 if appropriate. FortisBC considers that a three-year term will provide a long enough timeframe to allow for some efficiencies in the regulatory process while being short enough that nearer term impacts from the energy transition can be accommodated. FortisBC notes a three-year term to 2027 will also be the midway point to 2030, with 2030 being a significant milestone for many climate goals set out by government.

Towards the end of the three-year term, FortisBC will review and assess the Rate Framework and submit a proposal to either extend the Rate Framework or propose a new rate-setting framework if necessary. The review will consider whether the index-based O&M (FEI and FBC) and Growth capital (FEI) formulas are providing reasonable funding levels, whether adjustments need to be made to flow-through items and/or other components of the Rate Framework, and will assess overall whether the Rate Framework continues to be flexible enough to accommodate the impacts of the energy transition as understood at that time.

1.3 *INFLATION (I) FACTOR*

The use of an inflation or I-Factor in a rate-setting framework provides recognition that utility costs are subject to the general inflationary pressures occurring in the economy, although the specific pressures or weightings of the various inflationary influences may be different than for the economy in general. As in the Current MRP, FortisBC proposes to continue the use of a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to Statistics Canada's AWE:BC and non-labour indexed to the All-items Index for CPI:BC.[38] However, FortisBC proposes to return to fixed labour and non-labour weightings. Fixed weightings were approved for FortisBC's 2014-2019 PBR Plans and were proposed for its Current MRP.

In proposing the weightings, FortisBC reviewed the recent history (2019 to 2023) of the labour and non-labour splits that were approved during the term of the Current MRP as shown in Table C1-2 below.

Table C1-2: History of Labour and Non-labour Split for FEI and FBC

	FEI		FBC	
	Labour	Non-Labour	Labour	Non-Labour
2019	52%	48%	62%	38%
2020	52%	48%	62%	38%
2021	51%	49%	63%	37%
2022	51%	49%	60%	40%
2023	49%	51%	57%	43%
Average	51%	49%	61%	39%

FortisBC is proposing a fixed 51 percent labour weighting for FEI and a fixed 61 percent labour weighting for FBC, based on the average of the 2019 to 2023 actual labour weightings. This is a departure from past filings where the same percentages were applied to both FEI and FBC. Using the proposed weightings, the I-Factor determination for the Rate Framework is expressed as follows:

38 In Orders G-164-14 for FEI and G-182-14 for FBC, the BCUC approved the use of Statistics Canada CANSIM Table 326-0020 (now 18-10-0004-01) to determine the CPI:BC and CANSIM Table 281-0063 (now 14-10-0223-01) to determine AWE:BC.

$$I_t = L\% \ x \ AWE{:}BC_{t-1} \ + N\% \ \ x \ CPI{:}BC_{t-1}$$

Where: *I = inflation factor*
L = labour weighting
AWE:BC = labour index
N = non-labour weighting
CPI:BC = non-labour index
t-1 = most recent July to June values

In proposing to move back to a fixed labour and non-labour weighting approach as was approved in the 2014-2019 PBR Plans, FortisBC considered its objective of increasing regulatory efficiency during the Rate Framework against the potential for decreased accuracy of the annual labour and non-labour weightings. As explained below, FortisBC considers the benefits of regulatory efficiency outweigh the potential for decreased accuracy.

The BCUC stated in the MRP Decision that "to attain a higher degree of accuracy, the Panel finds that it is more appropriate to set the labour to non-labour ratio annually and to base it on the most recently completed year."[39] Although accuracy is a valid consideration, it should be balanced against other equally important considerations such as regulatory efficiency. As with the other components of the indexing formulas, it is only necessary for the inflation factor to be reasonable, not exact. For example, if FEI's labour weighting had been fixed at 51 percent for the term of the Current MRP, the actual labour weightings would have ranged from 1 percent higher to 2 percent lower than a fixed 51 percent. The impact would then have been that in some years (assuming that the AWE:BC increased more than CPI:BC each year, as was generally experienced during the Current MRP), FEI's formula O&M funding would have been slightly lower or slightly higher (or equal). Ultimately, however, the impact to FEI's overall O&M funding envelope would have been minor, and consistent with the intent of the formula-based approach to O&M funding, FEI would manage these annual variations through re-allocation of resources as needed. The same would also be true for FBC.

FortisBC has observed during the Current MRP term that there may be less acceptance of the approach directed in the MRP Decision of recalculating the labour and non-labour ratios annually based on the number and types of information requests received during the Annual Reviews. While FortisBC appreciates that the intent is generally to understand how the weightings are being calculated and why they are changing annually, the requests ultimately result in additional time and effort for the Companies to prepare these responses and do not have a bearing on the approvals being sought in the Annual Reviews, because the method for calculating the weightings was established in the MRP Decision and is not subject to change during the term of the Current MRP. FortisBC therefore considers that moving back to fixed labour and non-labour weightings is appropriate and more efficient.

[39] MRP Decision, pp. 47-48.

A fixed weighting is also appropriate because of the relatively short term of the Rate Framework (three years) which limits the potential for significant variations, and because the impact of the weighting changes on a year-to-year basis on the O&M and Growth capital envelopes is not material. FortisBC also notes that the AUC[40] adopted fixed labour to non-labour ratios in the most recent PBR plans for the utilities in Alberta, even though there are a number of utilities, and each has a different weighting from year to year.

FortisBC accordingly proposes that the weightings for AWE:BC and CPI:BC rates be fixed at 51 percent labour and 49 percent non-labour for FEI, and at 61 percent labour and 39 percent non-labour for FBC for the term of the Rate Framework.

1.4 *X-FACTOR VALUES FOR FEI'S AND FBC'S INDEXING FORMULAS*

Another feature of FEI's and FBC's indexing formulas pertains to the X-Factor values which, along with industry input price changes (the inflation factor), are two industry-specific data that are used to decouple the link between the utility's allowed costs and its actual costs.

The X-Factor, also referred to as the productivity improvement factor (PIF), is typically computed as the sum of the industry productivity growth trend and a company-specific stretch factor (if appropriate). FortisBC retained the services of Dr. Lawrence Kaufmann, an expert in the field of productivity studies, to conduct two separate productivity studies for FEI's and FBC's respective industries and recommend an appropriate, evidenced based X-Factor (including any stretch factor, if appropriate) for their indexing formulas. Based on his analysis, Dr. Kaufmann recommends the following X-Factor values for FEI and FBC:

- An X-Factor of 0.38 percent, consisting of a 0.28 percent industry O&M partial factor productivity (PFP) and a 0.10 percent stretch factor for FEI's O&M and Growth capital indexing formulas.
- An X-Factor of 0.20 percent, consisting of a 0.20 percent industry PFP and zero percent stretch factor for FBC's O&M indexing formula.

In the following sections, FortisBC discusses each of these recommendations. Dr. Kaufmann's Report (Appendix C1-1 to this Application) provides more detailed analysis and explanation of the methodology, model inputs and the results.

1.4.1 The Appropriate Measure for Estimating FortisBC's X-Factors is O&M Productivity

In the 2020-2024 MRP Application, FortisBC did not conduct a productivity study to support its proposed X-Factor. Rather, FortisBC's proposed X-Factor value was based on the Total Factor Productivity (TFP) studies conducted by experts in other North American jurisdictions. However, considering that FortisBC's indexing formulas are mainly focused on O&M expenses, the BCUC

[40] In their decision on Alberta's PBR3, the AUC's rationale for choosing a fixed ratio was to "ensure that the distribution utilities' incentives will not be influenced by the relative rates of inflation between the components in the I factor".

determined that the results of the TFP studies, which consider both O&M and capital costs, cannot be directly applied to FortisBC's formulas.[41]

In his Report, Dr. Kaufmann agrees with the BCUC and states that an O&M PFP factor, which focuses on the industry O&M productivity growth, is a more appropriate measure for calibrating FEI's and FBC's O&M formulas, as well as FEI's Growth capital formula, since FortisBC's indexing formulas overwhelmingly apply to O&M costs.

Regarding FEI's Growth capital formula, Dr. Kaufmann explains that, due to data constraints, it is not possible to calculate a Growth capital specific productivity value.

1.4.2 X-Factor Recommendation for FEI's O&M and Growth Factor Formulas

Dr. Kaufmann's Report for FEI includes the following main sections:

- An industry O&M PFP analysis for US natural gas distribution utilities; and
- A comparison of FEI's O&M unit cost with the US natural gas distribution utilities as well as an analysis of the BCUC's previous decisions and FEI's own O&M PFP to inform his proposal for an appropriate stretch factor.

Each of these items is discussed further below.

1.4.2.1 Industry O&M PFP Analysis for Natural Gas Distribution Utilities

As explained in Dr. Kaufmann's Report, the industry O&M PFP analysis for FEI is estimated based on a sample of 54 US natural gas distributors over the 2007-2022 period.

Table C1-3: O&M PFP Trend for US Natural Gas Distributors 2007-2022

Sample	Period	Customer Growth	O&M Growth	Industry Input Price	O&M Quantity Growth	O&M PFP Growth
54 US NG distributors (excluding gas cost)	2007-2022	0.67%	2.98%	2.59%	0.39%	0.28%

As shown above, the industry O&M PFP growth for the US natural gas distributors is computed at 0.28 percent which, along with the stretch factor value, is used to determine FEI's X-Factor value.

1.4.2.2 Stretch Factor Analysis

As defined in Dr. Kaufmann's Report, a stretch factor represents a commitment by the utility to achieve incremental cost performance above the industry's average productivity during the plan's term. Ordinarily, stretch factor values are set based on a regulator's best judgement informed by:

41 MRP Decision, p. 59.

(1) a utility's relative efficiency at the outset of the plan's term; and (2) the number of times the utility has been subject to cost efficiency improvement plans.[42]

Dr. Kaufmann conducts an O&M unit cost benchmarking analysis for FEI to measure its relative efficiency and inform its stretch factor recommendation. FEI's O&M unit costs were benchmarked against the US gas distributors used to estimate O&M PFP trends. These results are presented in Table C1-4 below.

Table C1-4: FEI's O&M Unit Cost vs. US Proxy Group (2020-2022)

FEI Avg. Cost/Customer (USD)	US NG distributors Avg. Cost/Customer (USD)	Percent Difference
$257.20	$262.18	-0.2%

As demonstrated above, FEI's average O&M cost per customer is similar to the US gas distribution average. As such, Dr. Kaufmann would consider FEI to be an average cost performer.

In addition, Dr. Kaufmann estimates that FEI's own internal O&M PFP growth averaged 1.26 percent and 0.34 percent over the 2014-2022 and 2007-2022 periods, respectively. FEI's performance during the 2014-2022 period (when its O&M costs were subject to an indexing formula), greatly exceeds the industry's O&M PFP trend of 0.28 percent, and out-performs industry norms. As Dr. Kaufmann concludes, FEI has likely generated significant cost savings for customers that have since been rebased into customer rates. This experience should be taken into account when considering an appropriate stretch factor for FEI.

In conclusion, considering the BCUC's previous stretch factor determinations, FEI's own O&M PFP growth rate, and the results of the unit cost benchmarking analysis, Dr. Kaufmann recommends a 0.10 percent stretch factor which, when added to the industry O&M PFP growth of 0.28 percent, results in a 0.38 percent X-Factor recommendation for FEI.

1.4.3 X-Factor Recommendation for FBC's O&M formula

Dr. Kaufmann's Report for FBC consists of the following main sections:

- An O&M PFP analysis for both the US electric utility industry and small electric utility peer groups; and
- A comparison of FBC's O&M unit cost (excluding generation O&M) with the two US proxy groups as well as an analysis of the BCUC's previous decisions and FBC's own O&M PFP to inform his proposal for an appropriate stretch factor.

42 As acknowledged by the BCUC in the MRP Decision, utilities that have been continuously subject to an incentive ratemaking framework may have less potential for incremental productivity gains.

1.4.3.1 Industry O&M PFP Analysis

As explained in Dr. Kaufmann's Report, while FBC is a vertically integrated electric utility (VIEU), its electricity transmission and distribution and related customer care operations account for the bulk of its O&M costs.[43] Further, generation O&M can vary significantly based on the generation type and it may not be possible to construct a sufficient industry proxy group that has similar characteristics to FBC when including generation. As such, Dr. Kaufmann determined that it would be reasonable to exclude generation O&M expenses from FBC's O&M PFP analysis used to establish an appropriate industry-based productivity factor for the Rate Framework.

To account for FBC's small size and dispersed operations, Dr. Kaufmann's analysis for FBC considered two separate samples of electric utilities. The first sample was a broad-based, 82 company sample that comprises nearly the entire US electric utility industry. This broader sample is therefore consistent with the competitive market paradigm, wherein industry-wide productivity trends are used to set productivity factors. The second sample was a sub-set of the first proxy group comprising 20 relatively small US VIEUs. The table below provides the computation of the O&M PFP growth studies of these two samples for the 2007-2022 period.

Table C1-5: O&M PFP Trend for US Electric Utility Industry 2007-2022

Sample	Period	Customer Growth	O&M Growth	Industry Input Price	O&M Quantity Growth	O&M PFP Growth
82 US Electric Utilities	2007-2022	0.91%	3.26%	2.55%	0.71%	0.20%
20 Small US VIEUs	2007-2022	0.42%	3.39%	2.55%	0.84%	-0.42%

Dr. Kaufmann concludes the O&M PFP trend that uses the entire 82 company sample is a more appropriate basis for FBC's productivity factor than the small company alternative. While FBC's cost structure may in theory be more similar to its small company peers, the differences in output growth between FBC and the small company sample are stark.[44] Given this disparity, and the theoretical and precedential support for using the largest possible sample to calibrate productivity factors, Dr. Kaufmann recommends that FBC's productivity factor be equal to the industry-wide, long-run estimate of 0.20 percent O&M PFP growth.

1.4.3.2 Stretch Factor Analysis

As explained above, ordinarily stretch factor values are not based directly on any specific calculation but are rather set based on a regulator's best judgement informed by: (1) a utility's relative cost efficiency at the outset of the plan; and (2) the number of times the utility has been consecutively subject to cost efficiency improvement plans.

To measure FBC's relative cost efficiency and inform his stretch factor recommendation, Dr. Kaufmann conducted a unit cost benchmarking analysis where FBC's O&M expense (excluding generation O&M) per customer is compared with the equivalent O&M unit cost of the sampled

[43] Over the 2007-2022 period, generation accounted for just 5.2 percent of FBC's O&M costs.
[44] FBC's average annual output growth during the 2007-2022 period is 0.9 percent higher than the small peer group.

proxy groups. As shown in the tables below, this analysis indicates that FBC is an efficient cost performer relative to both proxy groups.

Table C1-6: Electric Utility Industry O&M Unit Cost vs FBC (Excluding Generation) (2020-2022)

FBC Avg. Cost/Customer (USD)	US VIEU Avg. Cost/Customer (USD)	Percent Difference
$340.15	$523.33	-35.0%

Table C1-7: Small VIEU Sample O&M Unit Cost vs FBC (Excluding Generation) (2020-2022)

FBC Avg. Cost/Customer (USD)	US VIEU Avg. Cost/Customer (USD)	Percent Difference
$340.15	$947.88	-64.1%

In addition, Dr. Kaufmann estimates that FBC's own internal, O&M PFP growth averaged 3.68 percent and 1.08 percent over the 2014-2022 and 2007-2022 periods respectively. FBC's performance during the 2014-2022 period (when its O&M cost were subject to an indexing formula), greatly exceeds the O&M PFP trend typical of small utilities, as well as the O&M PFP trend of the larger electric utility industry. As Dr. Kaufmann concludes, this exceptional performance has almost certainly generated cost savings that have since been rebased into rates and thereby benefited customers.

In conclusion, considering the BCUC's previous stretch factor determinations, FBC's own internal O&M PFP growth rate, and the results of the unit cost benchmarking analysis, Dr. Kaufmann recommends a zero percent stretch factor which, when added to the industry O&M PFP growth of 0.20 percent, results in a 0.20 percent X-Factor recommendation for FBC.

1.5 *GROWTH FACTOR FOR FEI'S AND FBC'S INDEXING FORMULAS*

FortisBC proposes to maintain the average number of customers as the growth factor for FEI's and FBC's O&M indexing formulas and to continue to use the Gross Customer Additions (GCA) as the growth factor for FEI's Growth capital formula. Further, similar to the approach approved in the MRP Decision,[45] FortisBC proposes to continue to use a forecast with subsequent true-up mechanism for the growth factor.

FortisBC is proposing to eliminate the 0.75 discount factor currently applied to the growth factor for the O&M formulas.

FortisBC discusses the rationale for the continuation of the proposed growth factors and the forecast and true-up mechanism, as well as discontinuation of the 0.75 discount factor to the O&M formulas' growth factors, below.

45 MRP Decision, pp. 36-37.

1.5.1 Average Number of Customers Remains the Main Cost Driver for O&M Costs

FortisBC is proposing to maintain the average number of customers as the growth factor for FEI's and FBC's O&M indexing formulas. It is widely accepted that the number of customers is one of the primary cost drivers for a utility's operations.

Experts commonly use the number of customers to measure the output trends and to calculate the productivity growth trends of utilities. This includes FortisBC's expert, Dr. Kaufmann, who uses the number of customers for his O&M productivity calculations, as shown in Appendix C1-1. As explained in Dr. Kaufmann's report, "because the Companies' indexing formulas are applied on a per customer basis, the appropriate output measure for both Companies is the number of customers."[46] Using a different growth factor in the indexing formulas would therefore require a change in the choice of the output measure used in calculating the Companies' productivity growth trends.

1.5.2 Gross Customer Additions Continues to be the Appropriate Growth Factor for FEI's Growth Capital Formula

In the MRP Decision, the BCUC agreed with FEI's reasoning that Gross Customer Additions is the primary cost driver for FEI's Growth capital, and FEI was approved to change the growth factor from service line additions to GCA:[47]

> **The Panel approves Gross Customer Additions as the primary growth factor element to be used for the FEI Growth capital formula**. As noted above, the evidence establishes a clear connection between the number of new attachments and actual Growth capital expenditures.
>
> The Panel also finds it reasonable that the increasing trend towards multi-family developments makes the use of Gross Customer Additions more reflective of costs compared to the use of service line additions because of the need for multiple meters and larger headers. This is supported by the correlation between expenditures on meters and Gross Customer Additions (0.94) being higher than service line additions (0.88).[97] This is also consistent with FortisBC's explanation that use of service line additions in the Growth capital formula in the Current PBR Plan was one of the causes of the variance between actual and formula Growth capital.
>
> Further, the Panel is persuaded by FortisBC's argument that it is the addition of customers, not the average number of customers, that drives cost. This is supported by the high correlation of FEI Growth capital with Gross Customer Additions and by the fact that the average number of customers includes

[46] Appendix C1-1, p. 9.
[47] MRP Decision, p. 30.

customers that move in and out of premises, which typically does not require capital additions.

FEI submits that the BCUC's reasoning in the excerpt above for approving the GCA as the growth factor for Growth capital continues to hold true and that GCA continues to be the appropriate growth factor for FEI's Growth capital formula.

1.5.3 Forecast and True-up Mechanism Remains Appropriate

In the 2020-2024 MRP Application, FortisBC explained that a forecast growth factor with a subsequent true-up mechanism is the appropriate approach for updating the indexing formulas as follows:

- Costs and revenues are both driven by the actual growth experienced in the year for which rates are being set. Using a forecast ensures the Companies have the necessary funds to connect customers and operate the business in the year the funds are required to be spent.
- FortisBC recognizes that by using a forecast, a forecast variance will result in either an under recovery or over recovery of costs. FortisBC's proposed forecast and true-up mechanism will adjust the Companies' O&M expenditures and FEI's Growth capital for the forecast variance and removes any concerns of forecasting bias.
- The use of a forecast growth factor is consistent with: (1) the approach under traditional cost of service ratemaking; (2) the approved approach in other jurisdictions; and (3) how FortisBC internally forecasts its costs.

In the MRP Decision, the BCUC agreed with FEI's reasoning and approved the proposed forecast and true-up mechanism:[48]

> **The Panel approves the use of forecast average number of customers and the related true-up mechanism for calculating the FEI and FBC growth factor.** The Panel notes that none of the interveners raised concerns with FortisBC's request to eliminate the use of lagged actual customer growth and agrees with its reasons for an adopting forecast/true-up approach as a preferable methodology …
>
> … **The Panel approves FortisBC's proposal to eliminate the lagged actual customer approach for FEI Growth capital used in FEI's Current PBR Plan. The Panel also approves FortisBC's proposal to use forecast Gross Customer Additions with true-up to actual amounts in each test year for the previous year's forecasts.**

[48] MRP Decision, pp. 37, 41.

FortisBC submits that the forecast and true-up mechanism has worked as anticipated and that there is no compelling reason to change the current approach.

1.5.4 Discount Factor to the Growth Factor is Not Warranted

In the 2020-2024 MRP Application and proceeding, FortisBC explained that the application of a discount factor to the growth factor used in the indexing formulas is not warranted and amounts to double counting of the effects of economies of scale on costs' growth trends since the economies of scale are already reflected in the productivity growth factors calculated as part of the TFP or PFP studies conducted by experts.

In the MRP Decision, the BCUC accepted FEI's proposal to set the growth factor for FEI's Growth capital formula at 100 percent of the GCA. However, the BCUC determined that the growth factor for the O&M formulas should be reduced by 25 percent, using a 0.75 discount factor to the growth in average number of customers. The BCUC explained its Decision as follows:[49]

> The Panel continues to support the commentary in the BCUC's Decisions on the Current PBR Plans and notes that there is a not a 1:1 relationship between fixed and variable costs. However, using FortisBC's index-based O&M formula would result in forecast O&M (including fixed and variable costs) increasing or decreasing in a 1:1 relationship with the average number of customers. FortisBC explains that a 1:1 relationship is characterized by the expectation that the per customer O&M cost increase arising from adding new customers is the same as the average O&M per customer embedded in the Base O&M. In the Panel's judgement, it is not intuitively reasonable that the O&M cost impact of adding an additional customer is 100 percent.
>
> In determining the appropriate growth factor multiplier, in addition to considering the factors noted above, the Panel is also persuaded by the CEC's argument that an increase from 50 to 100 percent when the Current PBR Plans did not result in underfunding is not warranted. Accordingly, the Panel uses its best judgement to set a 75 percent growth factor multiplier for the Proposed MRPs.
>
> Regarding FortisBC's argument that the growth factor multiplier is duplicative of the productivity factor, in the Panel's view the multiplier is an adjustment to arrive at an index-based proxy to calculate the relationship between costs and number of customers and is unrelated to the purpose of a productivity factor.

FortisBC continues to believe that applying a discount factor to the growth factor used in the indexing formulas equates to double counting the effects of economies of scale on costs' growth trends. In other words, it is incorrect to state that FortisBC's position is that the "O&M cost impact of adding an additional customer is 100 percent." Rather, FortisBC's position is that the O&M costs are already reduced by the calculated productivity factor which considers the relationship

[49] MRP Decision, p. 37.

between the growth in average number of customers and O&M costs for the industry as a whole; therefore, re-discounting this factor amounts to a clear double counting of its effect in O&M costs.

Dr. Kaufmann confirms FortisBC's views and provides a deeper analysis and explanation in his report. As explained in Dr. Kaufmann's Report (Appendix C1-1), economies of scale (or lack of a 1:1 relationship between the growth in O&M costs and average number of customers) are reflected in the productivity factor calculations, not in the growth factor. Dr. Kaufmann states:[50]

> In other words, an important element of a "consistent cost-based treatment of output growth" is recognizing that changes in output (i.e. customer numbers) do not measure or reflect "the effect of output growth on cost." Instead, "these are captured in the productivity trend."
>
> … Cost theory shows that economies of scale is one of several sources of productivity growth. A rigorous mathematical derivation of this fact is presented (along with similar findings) in Appendix Two of this report. Since economies of scale is a component of productivity change, a properly constructed productivity index will by definition capture the impact of scale economies.
>
> There is also a more commonplace explanation: claiming that scale economies are reflected in the growth factor puts the cart before the horse. The logical sequence of events is that customer growth occurs, and scale economies follow. The phenomenon instigating the change will not measure the consequences.
>
> Another way to look at this is that, in a well-designed cost recovery mechanism, the productivity factor and customer growth factor have two distinct purposes. The productivity factor is designed to capture all the factors contributing to achieved cost efficiencies. The customer growth factor has a different purpose: to scale revenues upward or downward in response to changes in the scale of output, as measured by customer growth. There should accordingly be a one-to-one relationship between the number of customers served and the value of revenues received.

Dr. Kaufmann emphasizes in particular that a discount on the growth factor would not be reasonable given his recommended productivity factors:[51]

> The Companies' proposed indexing formula uses properly constructed O&M productivity indices. This change is responsive to BCUC concerns regarding the use of TFP metrics. It will also better align the MRP formulas with the costs recovered by the formulas.
>
> In light of this more rigorous and carefully focused framework, it is also more important for other elements of the indexing formula to be properly aligned.

[50] Appendix C1-1, p. 29.
[51] Appendix C1-1, p. 30.

> Indexing logic, basic cost theory, and common sense all support the conclusion that economies of scale are captured in the O&M PFP trend and not the customer growth factor. For all components of the Companies' indexing formulas to be internally consistent, no discounts of the customer growth factor should be applied to the Companies' allowed O&M adjustment formulas. Any discount of the customer growth factor would be unwarranted and tantamount to a "double counting" of scale economies, which are in fact fully recovered in the productivity factors. Accordingly, LKC recommends that no discounts should be applied to the customer growth factors for FEI and FBC's proposed indexing formulas.

Dr. Kaufmann also noted that other experts have acknowledged that a discount on the growth factor is mathematically incorrect:[52]

> While this analytical approach may have intuitive appeal, the customer growth issue ultimately does not hinge on statistical data or tests. Instead, the appropriate value of the customer growth factor should be determined by a proper application of indexing logic and cost theory.
>
> One illustration of this point is provided in a May 2021 Electricity Journal article titled *Escalating Power Distributor O&M Revenue*. The paper was written by Dr. Mark Lowry and David Hovde. The name of the article is itself an indicator of its relevance to the Companies' MRPs, which are focused on adjusting (aka "escalating") O&M revenue.
>
> … The general framework described by Lowry and Hovde has been applied in FortisBC's MRPs. The FEI and FBC applications of this framework use customer numbers as the sole "scale escalator," or output measure, for each plan. The Companies' MRPs also use an established and approved measure of industry input price inflation. Going forward, the X-factor proposals use measures of O&M partial factor productivity trends as the basis for their productivity factors, consistent with the Lowry/Hovde model. The basic design of the Companies' proposed indexing formulas is therefore identical with the framework developed by Lowry and Hovde.
>
> However, the article does more than identify the components of an appropriate index-based mechanism for adjusting allowed O&M costs; it also explains what those components do, and do not, measure. For example, after emphasizing that "a consistent cost-based treatment of output growth should be used in the productivity research," Lowry and Hovde write (in footnote 5), that the "growth of OutputsC Utility *is not the effect of output growth on cost because economies of scale are part of this effect and these are captured in the productivity trend* (emphasis added) [Footnote omitted]."[53]

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[52] Appendix C1-1, p. 28.
[53] Lowry, M.N., *op cit*.

Based on the above, FortisBC respectfully requests that the growth factor used in the O&M formulas be set at 100 percent of the growth in the average number of customers.

1.6 *EXOGENOUS (Z) FACTOR*

FortisBC proposes to retain the existing exogenous factor (Z-factor) treatment from the Current MRP for events that are non-controllable and unforeseeable in nature. Subject to BCUC approval, customers' rates will be adjusted either up or down for the cost-of-service impacts of exogenous factors that are beyond the control of the Companies. Exogenous factor treatment of such items will ensure that customers pay only for the actual costs in circumstances where FEI or FBC does not control the level of expenditures.

In general, events that would qualify for exogenous factor treatment include:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;
- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to BCUC decisions (examples include rate design issues, depreciation rate changes, changes to cost of capital).

During the Current MRP term, there were a number of events for which exogenous factor treatment was approved for FortisBC, including:

- the COVID-19 pandemic net incremental cost reductions for both FEI and FBC from 2020 to 2021;[54]
- the incremental one-time and ongoing costs for FBC related to Mandatory Reliability Standards (MRS) Assessment Report (AR) No. 13;[55] and
- the 2021 Nk'Mip Creek wildfire for FBC in 2021.[56]

In addition, in the Annual Reviews for 2023 and 2024 Delivery Rates, FEI discussed the 2021 flooding related damage and remediation costs and stated that it would apply for exogenous factor treatment once the related insurance claim had been settled. The claim has now been settled and FEI is seeking exogenous factor treatment as part of this Application. As the flooding event has previously been discussed in detail in the 2023 and 2024 Annual Reviews, the discussion in the

54 FEI and FBC Annual Reviews for 2023 Rates Decisions and Orders G-352-22 and G-382-22.
55 FBC Annual Review for 2022 Rates Decision and Order G-374-21.
56 FBC Annual Review for 2022 Rates Decision and Order G-374-21.

subsection below is primarily focused on the calculation of the amount of costs that FEI is seeking recovery of.

FortisBC will continue to identify exogenous factor events in its Annual Reviews and will also continue to follow the criteria established as part of the MRP Decision for evaluating whether the impact of an event qualifies for exogenous factor treatment:[57]

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

Regarding the materiality threshold, FortisBC proposes to maintain the existing materiality thresholds of $0.500 million for FEI and $0.150 million for FBC that were directed as part of the MRP Decision.[58] The established materiality thresholds have enabled the Companies to recover costs (or return savings) for significant events without resulting in an excessive number of requests for exogenous factor treatment. As discussed above, during the Current MRP term, FEI sought exogenous factor treatment for one event and discussed the potential for a second event, and FBC sought exogenous factor treatment for three events.

1.6.1 2021 Flooding Damage and Remediation

FEI is requesting exogenous factor treatment in this Application for the recovery of the incremental costs that were not recovered through its insurance claim related to the 2021 flooding event. FEI provides the following details on the remediation costs incurred, the exogenous amount FEI is seeking recovery of, and the implications of the proposed exogenous factor on the Base O&M for the Rate Framework.

Remediation Costs Incurred to Repair the Damages

From 2021 to 2022, FEI incurred in total approximately $3.734 million of incremental O&M and capital costs and billing credits provided to customers to remediate the damages due to the floods. In 2023, insurance proceeds of $2.013 million (net of the $1 million deductible), were received from FEI's insurance provider. These amounts are detailed in the table below.

[57] MRP Decision, page 62.
[58] MRP Decision, page 65.

Table C1-8: Summary of Remediation Costs and Insurance Proceeds Received

Items	2021 to 2022	2023	2024
	costs incurred ($)	*recovered with insurance ($)*	*exogenous treatment ($)*
O&M	1,641,509	(1,576,242)	65,267
Capital	1,266,012	(1,262,947)	3,064
Bill Credits	826,135	(173,924)	n/a
Total	3,733,656	(3,013,113)	68,331
Deductible		1,000,000	1,000,000
Net insurance proceeds		(2,013,113)	1,068,331

Amount Eligible for Exogenous Factor Treatment

FEI proposes exogenous factor treatment for the total incremental costs incurred that were not recovered through insurance, as the amount exceeds the materiality threshold of $0.500 million.

As shown in Table C1-8 above, $3.013 million of the total incremental costs of $3.734 million were recovered, with a remaining unrecovered balance, excluding the bill credits,[59] of $0.068 million. Additionally, FEI had a $1 million deductible on this insurance claim that was not recovered. The sum of the unrecovered remaining balance of $0.068 million plus the $1 million deductible totals to $1.068 million and represents FEI's out-of-pocket costs related to the flood remediation and the basis for the proposed exogenous factor amount.

Subject to receiving approval as part of this Application for exogenous factor treatment, FEI will record the O&M and the cost of service impacts of the capital in the existing Flow-through deferral account in 2024, consistent with the accounting treatment used in the past for other exogenous factors, with recovery in rates in 2025.

Implications for the Rate Framework Base O&M

In 2023, to account for the receipt of the net insurance proceeds received of $2.013 million, FEI credited formula O&M, capital and revenues. Please refer to the amounts in the column labelled "2023, recovered with insurance" in Table C1-8 above for the allocation of the proceeds between the categories. The $1 million deductible was recorded as an offset in formula O&M.

As a result of the above accounting, formula O&M actuals in 2023 include a one-time credit of $0.576 million, representing the net insurance proceeds received of $1.576 million less the $1

[59] The unrecovered portion of Bill Credits ($652,211) claimed for insurance is not subject to the exogenous factor treatment and is accounted for in the Flow-through deferral account used to capture the annual variances between the actual and approved amounts for costs and revenues.

million deductible. As this is a one-time credit in the 2023 formula O&M and will not re-occur, it should not form part of the 2024 Base O&M. FEI has therefore adjusted the 2024 Base O&M for this one-time credit, as explained in Section C2.2.2.1. The adjustment is captured in the line item "Adjustment for exogenous factor and flow through items" in Table C2-1 of Section C2.2.1.

1.7 *EARNING SHARING MECHANISM*

FortisBC is proposing to continue the symmetrical 50/50 earnings sharing mechanism (ESM) under the Rate Framework. An ESM is a regulatory tool in a rate-setting plan that is designed to enhance the alignment between customer and company interests and share the risks and benefits of the plan. An ESM is normally also put in place to mitigate against unintended results of a new plan, such as excessive utility gains or losses. An ESM is typically a backward-looking sharing mechanism in which a rate adjustment is provided if the actual earnings fall below or exceed a certain threshold.

Through the ESM (which is calculated as 50 percent of the ROE variance from allowed) FortisBC will continue to have incentive during the three-year term of the proposed Rate Framework to:

- Contain annual index-based O&M expenditures to a level at or below that calculated under the gross O&M per customer amount; and
- Contain Regular capital spending[60] at or below the approved level or, in the case of FEI's Growth capital, at or below the amount set through the index-based unit cost.[61]

FortisBC will also continue to calculate the earnings sharing using the widely-accepted method of a straight-forward 50 percent of the variances from the allowed rate of return on equity as approved in the Current MRP. This method is easy to understand and provides greater transparency, maintains the simplified approach adopted in the Current MRP, and enables incentive and flexibility to implement O&M and capital plans efficiently.

1.8 *EFFICIENCY CARRY-OVER MECHANISM*

FortisBC is not proposing an efficiency carryover mechanism (ECM) for the Rate Framework.

The purpose of an ECM is to provide incentive for the utility to continue to pursue efficiency gains toward the end of a multi-year rate plan, since the amount of time remaining to achieve a return on efficiency investments becomes successively shorter. Given a more limited (three-year) term for this Rate Framework, the focus in the coming three years on managing through the energy transition, and the complexities involved in designing an ECM tailored to its specific Rate Framework elements, FortisBC does not believe that an ECM is required at this time.

[60] Regular capital refers to capital that is part of the three-year forecast and/or part of FEI Growth capital. It excludes forecast/flow-through capital and incremental capital as part of Major Projects that is subject to flow-through treatment.

[61] The ROE impact of variances in Regular capital expenditures will be reflected in variances in depreciation, interest, taxes and ROE.

FortisBC will continue to evaluate the design of any future ECM and may propose to re-instate an ECM in the future, with the goal of proposing an ECM that is both simple to understand and provides incremental incentives.

1.9 *FINANCIAL OFF-RAMP PROVISIONS*

FortisBC considered whether the existing financial off-ramp provision should be retained in the Rate Framework. The off-ramp provision under the Current MRP is triggered if earnings in any one year vary from the approved ROE by more than +/- 150 basis points (post-sharing).

FortisBC believes the likelihood of triggering an off-ramp is low, for the following reasons:

- FortisBC is proposing only a three-year term for the Rate Framework;
- Both FEI's and FBC's actual ROE (post-sharing) have been well within the +/- basis point trigger during the Current MRP term;[62] and
- The Rate Framework continues with mitigations such as flow-through treatment for Clean Growth Initiatives, revenues and power supply costs, and the continuation of the existing 50:50 ESM.

Nevertheless, FortisBC believes there is value in continuing with the existing off-ramp provision, in particular due to the potential for a more rapid acceleration in climate change policy than what is currently anticipated over the term of the Rate Framework.

1.10 *ANNUAL REVIEW PROCESS*

The Annual Review process, which provides the BCUC and interveners with an opportunity to review the Companies' performance during the prior year and understand plans for the coming year, has now been in place for both the Current MRP term and the previous PBR Plan term. The scope and process for the Annual Reviews has largely remained the same, and FortisBC considers that the Annual Reviews have provided a successful forum for the Companies to communicate, and the BCUC and interveners to review, annual performance, new or changed requirements, and successes and challenges experienced by the Companies.

Accordingly, FortisBC proposes that the structure of the Annual Review process remains the same, (i.e., that the process continues to include one round of written IRs, a workshop, and written final and reply submissions). One written round of IRs allows for the issues, particularly technical issues, to be explored in detail, with any follow-up questions occurring at the workshop. FortisBC continues to believe that the workshop is a valuable opportunity for the Companies to interact directly with the BCUC and with interveners, and that parties continue to see value in this approach. Overall, the process has provided for a more streamlined rate-setting process while

[62] The maximum post-sharing variance to date in the Current MRP (to the end of 2022) is 22 basis points for FEI and 28 basis points for FBC.

still allowing for issues to be explored and evidence gathered so that the BCUC Panel is able to make informed decisions on the approvals sought.

However, and as discussed in Section B2.2.2.1, some efficiencies within the Annual Review process have diminished, and this is particularly evident in the expanded scope and number of IRs being asked. When assessing whether and how the Annual Review process could be improved, FortisBC considered the BCUC's Final List of Efficiencies (List), which was issued on December 22, 2023 as part of the BCUC's Regulatory Efficiency Initiative process. Notably, the Annual Review process already addresses many of the items in the List, including providing an established deadline for filing the Annual Review applications, having an established format for the applications and for the regulatory process, establishing the regulatory timetable upfront, and providing some scoping of topics to be addressed by the Companies in the Annual Review applications.

The primary area where FortisBC considers that regulatory efficiency can and should be improved in the Annual Review process is in clearer scoping of topics permitted to be explored in IRs (or at the workshop). For example, the BCUC stated in its decision on FBC's Annual Review for 2020-2021 Rates:[63]

> The purpose of the Annual Review is not to unravel or revisit the MRP Decision, rather, as the BCUC stated in that decision, the Annual Review process is designed to provide the BCUC, interveners and interested parties the opportunity to review the performance of [FBC] over the prior year.

This was further confirmed by the BCUC on a number of occasions, including in the decision on FBC's Annual Review for 2022 Rates[64] and 2023 Rates:[65]

> Once an MRP is approved, it should be given the opportunity to work as intended and should not be adjusted due to annual fluctuations in certain individual components of the plan. The Panel agrees with the BCUC's statement in FBC's Annual Review for 2020-2021 Rates that adjusting individual components of the formula O&M is outside the scope of any Annual Review. The purpose of the Annual Review is not to unravel or revisit the MRP Decision but to provide the BCUC, interveners and interested parties the opportunity to review the performance of FBC over the prior year and to assess the reasonableness of proposed rates for the following test period. [*Footnote omitted*]

The BCUC Panel's findings in the Annual Review decisions quoted above are instructive. Consistent with these findings, FortisBC is seeking clearer parameters at the outset of this Rate Framework on topics that are out of scope in the Annual Reviews, thus allowing the Companies,

[63] Decision and Order G-42-21, p. 14.
[64] Decision and Order G-374-21, pp. 20-21.
[65] Decision and Order G-382-22, p. 9.

the BCUC and interveners to focus on the in-scope issues and generally improve the efficiency of the process.

FortisBC considers that the following components, once approved by the BCUC as part of the Rate Framework, should remain out of scope for the Annual Review process and not be the subject of IRs or argument during the three-year term:

- **Inflation Index (I-Factor) and Productivity Factor (X-Factor):** The approved methodology for calculating each factor as well as any chosen economic indexes for labour and non-labour.
- **Growth Factor:** The methodology for calculating the growth factor (average number of customers for O&M and gross customer additions for FEI Growth capital).
- **Demand/Load Forecast Method:** The methods used to forecast demand and load each year for FEI and FBC, as described in Section C4.2. For clarity, FortisBC considers the demand/load forecast (e.g., the drivers of each year's demand increase or decrease) is within the scope of the Annual Review process, but the methods used to develop each forecast should remain out of scope as they will not change during the term of the Rate Framework.
- **Index-based O&M (FEI and FBC) and Growth Capital (FEI):** The methodology to calculate each year's index-based O&M and Growth capital, including the use of the growth factor, should remain out of scope as it will not change during the term of the Rate Framework. Additionally, requests for detailed comparisons of actual versus formula components of the index-based O&M should be out of scope in the Annual Reviews.
- **Forecast Capital:** For Regular capital (i.e., three-year Growth capital for FBC, and three-year Sustainment and Other capital for both FEI and FBC as discussed in Section C3), once the total amount is approved as part of this Application, it should not be subject to further review. Requests for detailed comparisons of actual versus approved forecast components of the approved Regular capital expenditures should be out of scope in the Annual Reviews.
- **Major Projects or Other Approved Projects or Initiatives:** Projects or Initiatives that are approved by the BCUC through a CPCN or other separate application process, or by government OIC should not be subject to review again during the Annual Review process.
- **FEI Biomethane Program and FBC RS 96 EV DCFC Service:** The cost and revenues that are forecast each year are within the scope of the Annual Review process; however, the merits of the program, the program design, and the rate design as approved by the BCUC through other proceedings should be out of scope of the Annual Review process.

1.11 *CONCLUSION*

To address the energy transition and other influences in FortisBC's operating environment, and in consideration of the existing flexibility and features of its Current MRP and stakeholder feedback received, FortisBC's key proposals for the Rate Framework are as follows:

1. A term that provides incentive to perform and the capacity to focus on key issues, while acknowledging the current level of uncertainty in the operating environment;
2. Sufficient funding to address emerging requirements and challenges;
3. Flexibility to adapt to the energy transition to manage its costs and impacts; and
4. An efficient annual rate-setting process that allows the Companies to focus on responding to the energy transition operationally and through key regulatory filings focused on the energy transition.

FortisBC has reviewed the elements of its Current MRP and retained those that have worked well. In recognition of the themes noted above, FortisBC has proposed:

- A shorter (three-year) term for its Rate Framework.
- Continuation of the I-Factor, but with the labour and non-labour weightings fixed for the three-year term.
- Returning O&M savings to customers and a continuation of FortisBC's cost control focus through prioritization of spending and a unit cost approach to O&M and FEI Growth capital, while proposing incremental O&M funding for key initiatives.
- Providing an opportunity for a detailed review of capital forecasts, Base O&M, and productivity factors in this proceeding.
- Maintaining flow-through treatment for key elements such as Clean Growth Initiatives.
- Continued funding for FEI's Clean Growth Innovation Fund.
- Annual reporting on energy transition informational indicators for FEI.
- Continuation of the exogenous factor treatment, the 50:50 ESM, and the financial off-ramp provisions.
- Continuation of the Annual Review process, providing an opportunity for discussion and review of the Companies' annual revenue requirements.

2. OPERATIONS AND MAINTENANCE (O&M)

2.1 INTRODUCTION TO O&M

Under the Rate Framework, the amount to be included in rates for FortisBC's O&M expenses will continue to be determined by an index-based formula, supplemented by annual forecasts for categories of costs that are appropriately not subject to a formula. Together, the proposed formula and forecast O&M reflect FortisBC's best estimate of what will be needed to meet the challenges and requirements that will arise over the 2025 to 2027 Rate Framework term. This includes the O&M required to address the impacts of the energy transition and other new requirements, while continuing to meet service quality and reliability requirements, which is a key focus for FortisBC.

The majority of FortisBC's O&M expenses will be determined by an indexed-based formula, which uses an O&M per customer amount adjusted for customer growth and inflation less an approved productivity improvement factor. The starting point for determining the O&M per customer amount is the 2024 Base O&M, which is the adjusted actual O&M expenditures for 2023 expressed over the average number of customers for 2023, escalated by the approved formula indexing factors for 2024, and includes expected spending for 2024 and incremental funding proposed for the term of the Rate Framework. The process for determining FEI's and FBC's 2024 Base O&M and the proposed adjustments are described in Sections C2.2 and C2.3, respectively. Over the term of the Rate Framework, the 2024 Base O&M will be escalated by the approved customer growth and inflation net of the productivity improvement factor[66] as described in Section C2.4.

In addition to the index-based formula O&M, some items for each of FEI and FBC are forecast on an annual basis, and the variances between forecast and actual amounts are trued up through the Flow-through deferral account or through other deferral accounts. FortisBC's forecast O&M is discussed in Section C2.5.

Overall, FortisBC's O&M proposals reflect the Companies' continued focus on efficiency, including the optimization and prioritization of available resources, while also responding to the changes in the operating environment. Please refer to Appendices C2-1 through C2-3 for the details of the actual O&M by department during the Current MRP term.

2.2 FEI 2024 BASE O&M

2.2.1 FEI 2024 Base O&M Calculation

FEI established the 2024 Base O&M for the Rate Framework using the same method that it used to establish the 2019 Base O&M in the Current MRP, which was approved by the MRP Decision and Order G-165-20.

[66] The approved 2025 growth and inflation factors will be determined in a separate proceeding to set 2025 rates. The approved X-Factor will be determined in this proceeding.

Consistent with past practice, FEI has used 2023 Actual expenditures (2023 Approved Base O&M less savings) as the starting point for the 2024 O&M Base, as 2023 is the latest year for which actual expenditures are available, and therefore, the most recent historical representation of the level of O&M funding required to operate FEI's system safely and reliably and to maintain its overall service quality level.

By starting with the 2023 Actual expenditures, the savings achieved in 2023 (i.e., $4.322 million) are accounted for in the calculation of the 2024 Base O&M. With the starting point (i.e., 2023 Actuals) established, the 2024 Base O&M is then developed by incorporating various adjustments, including the removal or addition of exogenous and flow-through items, application of the 2024 formula inflator, the inclusion of amounts to reflect the new activities that are occurring in 2024 that would not be reflected in the 2023 Actual amounts, and incremental net funding which FEI requires during the Rate Framework term.

The process to calculate the 2024 Base O&M is therefore as follows:

1. Start with 2023 Actual Base O&M, which is the 2023 Approved Base O&M reduced by the 2023 savings achieved.

2. Adjust for previously approved exogenous factors and items currently in formula O&M that will be re-classified as Forecast (flow-through) O&M during the term of the Rate Framework. This adjustment is required to align the 2023 Actual Base O&M with the scope of the formula O&M for the term of the Rate Framework.

3. Multiply by the 2024 formula inflator[67] as approved in the Annual Review for 2024 Delivery Rates. This adjustment is required to state the 2023 Actual Base O&M in 2024 dollars.

4. Add amounts for required spending that will begin in 2024. As FEI started with 2023 Actual expenditures, this adjustment is required to derive a projection of FEI's 2024 Base O&M requirements.

5. Add net incremental funding required beginning in 2025 and over the term of the Rate Framework. This is the final adjustment, which increases the projected 2024 Base O&M to the amount that will be required over the term of the Rate Framework, but stated in 2024 dollars.

Table C2-1 shows how the 2024 Base O&M is calculated using the above adjustments. Each adjustment is discussed in the sections that follow.

[67] 2024 Formula inflator includes inflation less productivity, and customer growth.

Table C2-1: FEI 2024 Base O&M ($ millions)

2023 Approved Base O&M	299.302
2023 Savings - Base O&M	(4.322)
2023 Actual Base O&M	**294.980**
Adjustment for exogenous factor and flow through items (in 2023 dollars)	(18.007)
2024 Base O&M (in 2023 dollars)	**276.973**
2024 Inflator	1.0443
2024 Base O&M (in 2024 dollars)	**289.243**
Adjustments for Required 2024 Spending (in 2024 dollars)	3.232
2024 Projected Base O&M	**292.475**
Net incremental funding for Rate Framework (in 2024 dollars)	9.901
2024 Base O&M for Rate Framework	**302.376**

2.2.2 Adjustments for Exogenous Factor and Flow-through Items

As discussed below, there is one exogenous factor adjustment required for 2021 flooding and remediation activities, and there are two adjustments proposed related to flow-through expenditures.

2.2.2.1 Exogenous Factor

It is necessary to make an adjustment of $0.576 million to add back a one-time credit recorded in the 2023 Actual formula O&M related to the 2021 flooding and remediation exogenous factor event. Please refer to Section C1.6.1 for details of this exogenous factor event and the calculation of the one-time credit.

2.2.2.2 Flow-Through Items

In addition to the exogenous factor discussed above, there are two flow-through adjustments included in the "Adjustments for exogenous factor and flow through items" line in Table C2-1 above. The first adjustment is to remove the O&M costs that will be impacted by FEI's Advanced Metering Infrastructure (AMI) project from formula O&M, and the second adjustment is to include the O&M costs for the Inland Gas Upgrade (IGU) and Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) projects in formula O&M.

2.2.2.2.1 ADVANCED METERING INFRASTRUCTURE PROJECT

In response to the BCUC's approval of FEI's AMI Project CPCN Application in May 2023,[68] FEI is proposing to reclassify certain costs currently in formula O&M to forecast (flow-through) O&M during the Rate Framework term. The reason for the proposed reclassification is that FEI will be in the process of deploying AMI during this period and the related O&M costs currently included

[68] Decision and Order C-2-23 dated May 15, 2023.

in the formula are expected to decline as manual metering reading activities decrease. To properly track and report on the annual costs and savings, FEI proposes to forecast these costs in each Annual Review and provide a discussion of its expectations for the costs for the coming year, with variances between forecast and actual costs recorded in the Flow-through deferral account and returned to or recovered from customers in subsequent years. This treatment will result in customers paying only the actual costs incurred, which is consistent with the approved treatment of CPCN expenditures.

This treatment was discussed in the response to BCUC IR1 20.2 in the FEI AMI Project CPCN proceeding, provided below for reference.

> **BCUC IR1 20.2**
>
> Please discuss how the O&M savings from the proposed AMI project will be treated under FEI's current Multi-Year Rate (MRP) Plan and whether the financial analyses account for this treatment.
>
> <u>Response:</u>
>
> Consistent with the BCUC's past recommendation to FEI, "if capital associated with a particular CPCN is excluded from the formula, the CPCN review of that project should include an assessment by the Commission of any potential impact of the project on O&M. If appropriate, an adjustment to the formula based O&M spending envelope should then be made."
>
> FEI considers that, if approved, the net O&M impact of the AMI Project warrants an adjustment to the formula O&M. FEI plans to adjust the Base O&M unit cost under the formula O&M to remove the existing meter reading costs and forecast the new AMI O&M costs as flow-through O&M costs/savings until the end of the MRP term (2024). FEI will provide the amounts for this adjustment (and for any regular capital expenditure changes) in the Annual Review following approval of this CPCN.
>
> Post MRP, the O&M treatment for the AMI O&M will depend on the regulatory framework at that time.

In order to treat O&M costs impacted by the AMI project as a flow-through item, FEI has removed the 2023 Actual Meter Installation, Meter Reading, Operations, Customer Service and Meter Shop O&M costs from the Base O&M unit cost.[69]

[69] Formula O&M costs expected to be impacted by the AMI project were outlined in Section 6.2.2 (page 105) of the FEI AMI Project CPCN Application.

Table C2-2: Adjustments to FEI Base O&M for Approved AMI Project[70]

Item	2023 Actuals ($ millions)
Meter Installation O&M	0.733
Meter Reading O&M	15.142
Operations O&M	2.122
Customer Service O&M	1.480
Meter Shop O&M	0.306
Total Gross O&M	**19.783**

The following is a brief description of each of the O&M items noted in the table above:

- Meter Installation O&M: This is the portion of meter installation costs currently recorded in O&M. The majority of meter installation costs are capitalized and included in Sustainment capital.
- Meter Reading O&M: This consists of the manual costs of reading meters and the cellular costs for current large commercial and industrial meters.
- Operations O&M: This is the cost for activities completed by field crews that are impacted by the AMI project, specifically meter trouble calls, meter reads, meter identifications, disconnects, unlocks, cathodic protection data gathering, and odour measurement.
- Customer Service O&M: This is the cost for the customer service activities impacted, include billing investigation and exceptions, meter reading coordinator workload, vacant premises processing, and meter switching identification and validation.
- Meter Shop O&M: This is the cost for activities related to the volume of meter exchanges and specifically, the meter sampling recall program. FEI will temporarily halt the meter sampling program during AMI deployment. While the program will resume after deployment, there will be a significant decrease in the volume of meters included in the sample as a result of the entire meter fleet being replaced.

Treating these O&M costs as forecast (flow-through) O&M during the AMI project implementation recognizes the uncertainties in the deployment schedule, and ultimately enables the O&M savings caused by the AMI project to be fully passed on to customers.

[70] The numbers presented in this table are on a Gross O&M basis, instead of Net O&M after capitalized overheads, as presented in the AMI Project CPCN Application.

2.2.2.2.2 INCREMENTAL INTEGRITY ACTIVITIES RELATED TO THE IGU AND CTS TIMC PROJECTS

During the Current MRP term (and subsequent to the establishment of the 2019 Base O&M for the Current MRP term), the BCUC granted CPCNs for the IGU project[71] and the CTS TIMC project.[72]

Consistent with the treatment approved in the MRP Decision[73] for incremental expenditures which occur as a result of CPCN projects during the term of the Current MRP, FEI applied for flow-through treatment of incremental O&M expenditures resulting from the IGU and CTS TIMC projects in the Annual Review for 2023 Delivery Rates. These incremental O&M expenditures, forecast to be $0.300 million for the IGU project and $0.700 million for the CTS TIMC project, were approved to be treated as flow-through O&M as part of the Annual Review for 2023 Delivery Rates Decision and Order G-352-22.

As FEI is now establishing the 2024 Base O&M for the Rate Framework, FEI proposes to re-classify the incremental IGU and CTS TIMC project O&M expenses from flow-through to formula.

In both the 2023 and 2024 Annual Reviews, FEI forecast $0.300 million for incremental O&M resources associated with the IGU project. FEI considers $0.300 million to be an appropriate amount to add to 2024 Base O&M. The costs, as explained in the 2023 and 2024 Annual Reviews, are for engineering analysis of In Line Inspection (ILI) data as well as planning and implementing operational responses, such as identifying future integrity digs or other monitoring activities. The 2023 Actual O&M spending was consistent with the 2023 Approved amount of $0.300 million.

In both the 2023 and 2024 Annual Reviews, FEI forecast $0.700 million for incremental resources associated with the CTS TIMC project. In assessing its resourcing needs starting in 2025 (i.e., the start of the Rate Framework), FEI considers $0.900 million to be an appropriate amount to add to 2024 Base O&M. With the additional $0.200 million, FEI will be hiring a fourth senior technical resource from approximately mid-2024 onward. This resource is associated primarily with incremental ILI analysis activities. The CTS TIMC project resources are similarly associated with incremental ILI activities, as well as performing Quantitative Risk Assessments (QRAs). The 2023 Actual O&M spending was consistent with the 2023 Approved amount of $0.700 million.

For the incremental O&M expenditures associated with the recently approved[74] Interior Transmission System (ITS) TIMC project, FEI is currently in the process of evaluating requirements and may request incremental O&M funding at a later date through the Flow-through mechanism, similar to the approach in the Current MRP for the IGU and CTS TIMC projects.

2.2.3 Adjustments for Required 2024 Spending

Since FEI used 2023 Actual expenditures as the starting point for determining its 2024 Base O&M, any new O&M expenditures that will begin in 2024 are not yet reflected in the Base O&M and

[71] Approved by Order G-12-20.
[72] Approved by Order C-3-22.
[73] MRP Decision, pp. 132-133.
[74] Approved by Order C-1-24 on January 15, 2024.

therefore need to be added. There are four items, totalling to $3.232 million, that will commence in 2024 and are not reflected in 2023 Actual expenditures. These are: (1) new facility lease costs of $1.450 million; (2) incremental costs to support LNG Operations of $0.600 million; (3) incremental costs to support the Long-Term Gas Resource Plan (LTGRP) of $0.382 million; and (4) incremental costs for decarbonization and sustainability of $0.800 million.

2.2.3.1 New Facility Lease Costs

As part of the Kelowna Space Project that was reviewed in detail in FEI's and FBC's Annual Reviews for 2023 Rates, FortisBC will be occupying new facilities in the Kelowna region to meet its space capacity needs starting in 2024. In the 2023 Annual Reviews, FEI and FBC received approval for updated Other capital expenditure forecasts for 2023 and 2024, including capital expenditures for the Kelowna Space Project.[75] As part of this project, both FEI's and FBC's Shared Services Departments (Support Services) located in Kelowna relocated to a new leased office facility in early 2024. The incremental leasing (O&M) cost for the site to be added to Base O&M is $0.900 million, shared between FEI and FBC based on the number of employees for each Company. FEI's allocation is approximately $0.600 million.

Additionally, FEI has entered into a lease for a new contact centre facility in Prince George and is in the process of relocating its employees to this new facility. The incremental leasing (O&M) cost to be added to Base O&M is $0.850 million. FEI is currently evaluating options for the existing facility, including selling or leasing the property.

These two items total to $1.450 million in 2024 dollars and have been added to the 2024 Base O&M as shown in Table C2-1 above.

2.2.3.2 LNG Operations

Additional costs are required for operational support at both the Tilbury and Mt. Hayes facilities in 2024. At Mt. Hayes, two operator positions are being added to ensure working alone requirements are met for emergency situations as well as to provide adequate staffing for increased liquefaction requirements experienced at the facility over the past five years. Two operator positions are also required at Tilbury to ensure full vacation and sick coverage and full 24/7 coverage for the operation of that facility. The total cost of these four positions is $0.600 million.

2.2.3.3 Long-Term Resource Planning

Long-term resource planning is a critical function for FortisBC as it assesses the future energy requirements of customers and options to meet them over the long-term, providing the context and framework for future regulatory applications, including CPCNs. The requirement to submit long-term resource plans to the BCUC is set out in section 44.1 of the UCA. During the ongoing energy transition and the rapidly changing external environment, FortisBC's resource planning activities are becoming less cyclical and more ongoing, with long-term resource plans being

[75] Approved by Orders G-352-22 (FEI) and G-382-22 (FBC).

developed and filed with the BCUC on a more frequent basis. With new sources of supply, such as RNG and hydrogen, and less certainty in future gas demand, resource planning has increased in complexity.

The BCUC recently issued its decision on FEI's 2022 LTGRP.[76] As part of the decision, the BCUC directed FEI to address a number of matters in the next LTGRP and to undertake a variety of detailed analyses, including making changes to its modelling. Further, the BCUC directed FEI to file its next LTGRP on or before March 31, 2026 which, given the time needed to develop and consult on the plan, means that FEI must commence work immediately.

In consideration of the recent decision on FEI's 2022 LTGRP, the increasing complexity of resource planning for both gas and electric utilities, and the need to continue to advance the integration of gas and electric resource plans, the Companies have identified an immediate need for three additional positions in 2024 to support their long-term resource planning activities. The new roles will provide analysis and research and manage internal and external stakeholder engagement. Examples of these activities include:

- Analysis related to and forecasting of load duration curves;
- Integrating renewable gases, including hydrogen, into the supply portfolio;
- Analysis related to an integrated (i.e., diversified) gas and electric system;
- Increasing stakeholder and Indigenous engagement related to resource planning; and
- More collaboration with BC Hydro on load forecasting and scenarios.

The total cost of these three positions, including supporting costs, is $0.552 million, with the costs being allocated approximately two-thirds to FEI and one-third to FBC (FEI's share of the costs is equal to $0.382 million).

2.2.3.4 Decarbonization and Sustainability

To comply with growing requirements related to GHG emissions and sustainability reporting and disclosures, FortisBC created the Decarbonization and Sustainability department in Q4 2023. Policy makers, regulators, customers, capital markets, and other key stakeholders have broadened their requirements for reporting, compliance and disclosure of FortisBC's progress towards decarbonization and other sustainability goals. The legal and reputational risks associated with compliance are also growing, and FortisBC, like many other companies, is responding by developing frameworks to advance sustainable practices and report on progress towards sustainability commitments, which requires analytical resources, systems, and controls.

For example, BC Energy Regulator (BCER) methane reporting requires increased measurement and reporting with documented leak detection and repair (LDAR) programs. In addition, GHG quantification for reporting has become more complex, with less reliance on asset-based emission factors and an increasing requirement for measurement. There are also reporting requirements

[76] Decision and Order G-78-24 dated March 20, 2024.

associated with three carbon trading systems that FEI is expecting to report under, including the BC Low Carbon Fuels Standard, Environment and Climate Change Canada's Clean Fuel Regulation, and the BC Output Based Pricing System.

In addition, Canadian regulators have enhanced the requirements for environmental disclosure related to GHG emissions and climate risk. Guidance for Environmental, Social, and Governance (ESG) reporting continues to evolve with a shift away from voluntary reporting to proposed required reporting from regulators and standard setters globally, including:

- Proposed National Instrument 51-107, Disclosure of Climate-related Matters by the Canadian Securities Administrators (CSA);
- Proposed Rule Release No. 33-11042, The Enhancement and Standardization of Climate-Related Disclosures for Investors by the Securities Exchange Commission (SEC); and
- General Requirements for Disclosure of Sustainability-related Financial Information and Climate-related Disclosures by the Canadian Sustainability Standards Board (CSSB) through the recently published exposure drafts of CSDS 1 and 2. While the standards will be voluntary, they will inform Canadian regulators in deciding on mandatory rules for sustainability and climate-related disclosure. The CSSB is suggesting that its standards apply on or after January 1, 2025.

Consistent with the increased need for data accumulation, analysis, validation, verification, and controls to support climate-related disclosures, FEI requires additional resources to administer and support its participation.

To support these reporting and compliance requirements, FEI requires $0.800 million starting in 2024 for two new positions, as well as costs related to membership dues, external audit fees and consulting costs.

2.2.4 Net Incremental Funding for the Term of the Rate Framework

To address key issues and changes in its operating environment, FEI requires net incremental O&M funding to be added to its 2024 Base O&M. The following table and discussion describe the net incremental O&M funding required over the term of the Rate Framework, organized by the respective business drivers.

Table C2-3: FEI Net Incremental Funding for the Term of the Rate Framework

Business Driver	$ millions
Government, Indigenous and Community Engagement	2.748
Environment and Sustainability	1.800
Corporate Security	1.607
Technology	2.946
System Operations and Adaptation	0.800
Total	**9.901**

2.2.4.1 Government, Indigenous and Community Engagement

As discussed in Section B1 and further below, there continue to be substantial shifts within the policy environment that are significantly influencing FortisBC and its customers, particularly now that policies are reaching implementation and are affecting FortisBC's operations. At the same time, requirements for Indigenous engagement are increasing and becoming more complex, requiring additional resources and funding to build and maintain relationships.

Table C2-4 below provides the net incremental funding requests for this area, followed by a discussion and rationale for the requests. For context, FEI has also provided the historical actual expenditures since the start of the Current MRP and the projected base funding for 2024.

Table C2-4: FEI Government, Indigenous and Community Engagement Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Government Relations and Public Policy	2.041	2.202	2.246	2.510	2.621	0.234
Community and Indigenous Relations	4.624	4.279	4.810	5.455	5.697	2.240
Customer Engagement	6.878	5.730	6.424	6.942	7.250	0.275
Total	**13.543**	**12.211**	**13.480**	**14.907**	**15.567**	**2.748**

Each of the three identified areas are discussed further below.

2.2.4.1.1 GOVERNMENT RELATIONS AND PUBLIC POLICY

Climate policy at the local, Indigenous, provincial and federal levels of government are both a significant challenge and opportunity for FortisBC. Since the beginning of the Current MRP, FortisBC has faced a rapidly evolving policy environment, significantly influenced by government responses to climate change. These policy changes, aimed at reducing GHG emissions and promoting cleaner energy solutions, have created a challenging and complex operating landscape for utilities. FortisBC must navigate a combination of government climate plans, targets, legislation, and regulation to enable its Clean Growth Pathway. Examples of government policy initiatives are highlighted in Section B1. These policies collectively demand an increase in FortisBC's efforts to contribute to policy development, advocate for positive policy outcomes for customers, and support the implementation of new policies.

To support policy development and advocate on behalf of customers, FortisBC is challenged to undertake increased analysis to identify positive policy outcomes, respond to consultation requests at various levels of government and engage in detailed policy development with government staff. For example, in 2020, the Companies helped develop the analysis and related

Pathways for British Columbia to Achieve its GHG Reduction Goals report (Pathways Report)[77] to inform optimal ways to achieve government GHG and economic targets. The Companies then used the Pathways Report to guide their participation in government policy discussions on behalf of customers.

Accordingly, FortisBC is requesting new funding of $0.300 million, which will be allocated between FEI ($0.234 million) and FBC ($0.066 million). The new funding consists of two new positions. These positions will be responsible for conducting analyses to identify policy outcomes and ensuring new or amended policies align with FortisBC's objectives to provide safe, affordable, reliable, and resilient service while also supporting provincial GHG reduction targets.

2.2.4.1.2 COMMUNITY AND INDIGENOUS RELATIONS

Table C2-5 below provides the breakdown of the funding request for Community and Indigenous Relations.

Table C2-5: Breakdown of Community and Indigenous Relations Net Incremental Funding ($ millions)

Breakdown of Net Incremental Funding	Net Incremental Funding
Community Engagement	0.480
Community Investment	0.500
Total Community	**0.980**
Indigenous Relations Engagement	0.560
Advancing Reconciliation	0.700
Total Indigenous	**1.260**

Community Engagement and Investment

Community Engagement

In addition to the resources identified above for engagement with federal and provincial governments, FEI requires incremental resources within its Community Relations team to support the engagement required for capital projects, ongoing operations, and the implementation of climate policy at the local level.

Increasingly restrictive municipal climate policies, uncertainty around FEI's role in supporting provincial and municipal decarbonization goals, and a political environment that favours electrification, are just a few of the challenges in FEI's municipal operating environment.

[77] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf.

To ensure FEI's customers' needs are heard and to support an orderly transition to a lower carbon future, there is a need to engage in systematic, structured, and frequent dialogue at multiple levels within a municipality, including elected officials, senior city staff, and departmental leads (planning, permitting, etc.). For example, with the increasing number of municipalities implementing stringent climate policies, particularly in the Metro Vancouver Regional District and Vancouver Island areas (where a significant portion of FEI's customers reside), dedicated resources are required for one-on-one engagement to address the challenges of the accelerated adoption of polices such as the Zero Carbon Step Code. A low level of awareness around energy implications and solutions requires multiple iterations of engagement.

Additionally, an increasing number of organized voices opposing low carbon gaseous energy solutions requires continued engagement in the community with a broad range of stakeholders, including chambers, boards of trade, and business associations. Increased effort is required to ensure that the interests of gas customers are raised and considered.

Other priorities in the next few years include renegotiation of operating agreements that will be expiring with municipalities in the Interior, and building capacity to field requests for new or updated operating agreements in the Lower Mainland. Over the term of the Current MRP, FEI renegotiated an average of one to two Interior operating agreements per year. FEI now has 14 operating agreements coming due for renewal at approximately the same time, and will see a significant increase in negotiation activity over the upcoming three years.

Further, engagement with municipalities around FEI's operations and sustainment work has increased significantly over the past few years and there is increased need for the Community Relations team to be involved to help coordinate and provide resolution for high-risk operations and sustainment work.

The total $0.480 million requirement is for three Community Relations/Public Policy Manager positions focused on Municipal and Climate Policy, along with supporting costs (non-labour) to cover increased associated travel and administration.

Community Investment

Increased funding is required to expand the Community Investment program for the communities that FortisBC serves and operates in. Creating community partnerships improves both the ability to work in these communities and the effectiveness of those activities. These investments also improve the pride that FortisBC employees take in their work and help to attract and retain top talent while maintaining the trust that customers have in FortisBC's business through knowing that the Companies are actively engaged with the communities they serve. The Companies invest in four key areas to help contribute to the well-being of BC's communities:

- **Safety:** these are projects that promote natural gas and electrical safety, personal safety and accident avoidance;
- **Education:** these are projects that promote natural gas and electrical trades, literacy and leadership;

- **Indigenous Initiatives:** these are projects that meet the unique needs of Indigenous organizations or communities; and
- **Environment:** these are projects that directly benefit the environment.

Through this program, FortisBC currently provides $1.100 million in donation funding to support grassroots initiatives to more than 126 municipalities and regional districts and 58 First Nations communities, of which $0.750 million is allocated to FEI and the remaining $0.350 million is allocated to FBC. Consistent with FortisBC's efforts to increase engagement with local and Indigenous communities across the Province, FortisBC has experienced an increase in funding requests. Funding requests from Indigenous communities in particular have increased, with this segment making up nearly 30 percent of the overall Community Investment spending in 2023.

Along with these grassroots initiatives, the Community Investment program also provides funding for business development such as conferences, forums and workshops. These include conferences for local governments, Indigenous economic development, climate change and Net Zero collaboration, and local chambers. There has been an increase in these business development requests to connect with local politicians and business leaders, which accounts for approximately 25 percent of the overall Community Investment spending.

FEI requires incremental funding of $0.500 million to extend the support for the communities it serves. The increase to FBC's funding amount is discussed in Section C2.3.4.1.2.

Indigenous Relations and Reconciliation

Indigenous Relations and Reconciliation is an increasingly predominant activity and continues to require enhanced engagement, relationship building, capacity support, economic inclusion and community investment.

There have been significant changes in the policy landscape as it relates to Indigenous rights and reconciliation in recent years. This includes policy changes, legal decisions, and discoveries in communities – all of which have increased the need for and expectations around engagement with Indigenous Nations since the filing of the 2020-2024 MRP Application. In November 2019 and June 2021 respectively, the Province and Government of Canada enacted laws to affirm the application of the UN Declaration for the Rights of Indigenous Peoples (the Declaration) to provincial and federal laws.[78] Both levels of government have also developed action plans to implement the Declaration and align legislation with their respective Declaration Acts. The Declaration is a foundational document which provides a framework for reconciliation and cooperative relations founded on principles of justice, democracy, and human rights. The adoption of the Declaration, both federally and provincially, marked a significant step towards reconciliation and has significant impacts on FortisBC.

[78] Declaration on the Rights of Indigenous Peoples Act, SBC 2019 c. 44 and United Nations Declaration on the Rights of Indigenous Peoples Act, SC 2021 c. 14.

In 2019, a new British Columbia *Environmental Assessment Act* (EAA) came into force, which introduced changes to the environmental assessment process to incorporate the concept of Free, Prior and Informed Consent (FPIC) and significantly broadens engagement requirements. The increased engagement requirements in the new EAA include a focus on seeking consensus and consent of Indigenous communities at stages throughout the process, (as well as a risk of litigation in the absence of consent), and also offers a mechanism for Indigenous Nations to opt into the EAA process, which can increase the number of Nations requiring engagement.

In response to the increased need for engagement and consensus seeking regarding FortisBC's operations, FortisBC must continue to enhance its engagement practices with Indigenous communities. This involves learning the Indigenous communities' protocols, governance structures, and community engagement systems. FortisBC is committed to learning and working with communities so that operations and project development on traditional territories is undertaken in a way that respects Indigenous rights and title. As more and more proponents and companies approach Indigenous communities to engage, many communities are facing capacity constraints and competing priorities, which can create delays for timelines to review and work through issues.

There have been several recent decisions which are shaping the legal landscape with respect to the rights and claims of Indigenous nations in BC. In June 2021, the BC Supreme Court found that the cumulative impacts of industrial development in Treaty 8 territory infringed the Blueberry River First Nation's treaty rights. This decision required the Province to establish mechanisms to assess and manage cumulative impacts of industrial development. In the February 2024 case of *Thomas and Saik'uz First Nation v. Rio Tinto Alcan Inc.*, the BC Court of Appeal confirmed that Indigenous nations have the ability to pursue tort claims against private parties based on impacts to proven Aboriginal rights when those Aboriginal rights are sufficiently connected to lands relied on by Indigenous nations. In order to establish such a claim against a private party, Indigenous nations must first establish their Aboriginal rights against the Crown, and where a private party's conduct has been statutorily authorized, this can be a full defence against the claim. Importantly, this decision confirms a broader set of circumstances in which Indigenous nations may seek to bring claims against private parties, including owners of new energy projects and existing facilities, based on impacts to Aboriginal rights and title.

Furthermore, Indigenous communities increasingly expect that Indigenous-led policy documents are considered and actioned, including the Truth and Reconciliation Commission's (TRC's) Calls to Action and the National Inquiry into Missing and Murdered Indigenous Women and Girls. The former outlines the impact of the Residential School System in Canada and provides recommendations (calls to action) for government and the private sector. The recent discoveries of remains at former Residential School sites in British Columbia and across Canada in the last two years have put a bigger spotlight on this period of Canadian history, and the action that is needed and expected from communities. Further, Indigenous communities are increasingly interested in participating in discussions regarding energy planning and have greater expectations for economic opportunities – including supply chain, workforce development and hiring, and partnership opportunities.

In light of the above changes in the Indigenous relations and reconciliation landscape and the law, engagement with Indigenous communities has become an important and growing component of FortisBC's business, requiring additional staff and resources. Furthermore, engagement is increasingly an ongoing process that takes place over an extended, multi-year period. Maintaining positive relationships and continuing to build relationships with Indigenous leaders involves a focus on listening as well as demonstrating community benefit from FortisBC operations and/or projects, such as through employment, training, and business opportunities. Much of FEI's infrastructure was developed and constructed when laws around consultation and engagement with Indigenous communities were different than they are today. This creates some unique challenges and requires increased engagement with Indigenous communities, particularly where resolving historical grievances is part of moving new projects forward. For example, FEI is working with the Okanagan Indian Band to modernize a right of way agreement through reserve lands that have been in place since the 1950s. This requires enhanced engagement and will impact all future projects.

FortisBC's increasing focus on renewing and strengthening its relationships with Indigenous peoples, communities, and Nations is consistent with the increased commitment at the provincial and federal levels. The Company recently achieved Progressive Aboriginal Relations (PAR) Silver Certification and will continue to enhance its engagement practices, including advancing Indigenous inclusion and committing additional staff and resources to building capacity in Indigenous communities. This will assist in gaining vital support for required projects. Maintaining and building positive relationships is key to securing broad support for FortisBC's future projects, business operations and commitment to the PAR Certification.

The following section outlines the initiatives and resources required by FEI to meet the expectations of Indigenous communities and to continue to enhance engagement, Truth and Reconciliation efforts, and capacity building.

Indigenous Relations Engagement

To support enhanced engagement activities, as described above, FEI's Community and Indigenous relations department requires net incremental funding of $0.560 million for four new Community & Indigenous Relations/Initiatives Manager positions. These roles will support key activities related to engagement, Indigenous initiatives, and advancing reconciliation efforts. Building relationships takes time and resources. This can only be done with human capacity to build authentic and meaningful relationships with Indigenous communities.

Advancing Reconciliation

In addition to the resources required to implement enhanced engagement activities, there are several initiatives that need additional funding to support Truth and Reconciliation efforts. FEI requires $0.700 million for initiatives and administration associated with the following:

- Advancement of Indigenous agreements for operational certainty and building mutually beneficial relationships.

- Advancement of relations with key Indigenous organizations, including working with Indigenous consultants to continue to support many internal and external initiatives such as Indigenous awareness training, communications, engagement strategies, and archaeological and environmental assessments.
- Implementing FortisBC's socio-economic impact program that strives for an inclusive process, and further develop mechanisms to support Indigenous-owned businesses in becoming suppliers, contractors, and business partners on FortisBC's projects.
- Further developing and implementing Indigenous procurement supply chain initiatives to reduce barriers for Indigenous businesses to access opportunities, including networking opportunities such as business-to-business career fairs and supply chain workshops.
- Engagement on the role of the gas system in decarbonization and advancement of renewable gas partnership opportunities with First Nations.
- Supporting Indigenous Initiatives such as Indigenous Awareness training for employees that are an important part of TRC's Call to Action 92 for advancing reconciliation, as well as participating in cultural events and celebrating and honouring Indigenous days of significance broadly across the organization.

2.2.4.1.3 CUSTOMER ENGAGEMENT

FEI proposes to increase its communication resources starting in 2025 to support the increasing need and expectations that customers, and the public, have around receiving the information they need when they need it, which can occur in several ways (from in person to written or digital).

The incremental funding of $0.275 million is requested for two positions, an Events and Outreach position and a Digital Content Designer.

FEI requires an additional Events and Outreach position to ensure it can meet the increased expectations of the public to actively engage with them in person in their community. The public and customers interact with FEI on several areas of interest, including questions about rates, energy safety, energy efficiency programs and curiosity about how the energy transition may impact them. These opportunities are convenient for customers and provide an additional channel for contact with the organization.

FEI requires a Digital Content Designer to ensure that it delivers digital content that is easy for customers to find and understand. This position responds to customers increasingly seeking information in a "digital first" way.

2.2.4.2 Environment and Sustainability

Table C2-6 below provides the actual expenditures for environment and sustainability from 2020 to 2023, the projected base funding for 2024, and the net incremental funding to be added to the 2024 Base O&M.

Table C2-6: FEI Environment and Sustainability Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Environment and Sustainability	1.955	2.300	2.697	2.910	3.839	1.800
Total	1.955	2.300	2.697	2.910	3.839	1.800

As discussed in Section C2.2.3.4 above, FortisBC's Decarbonization and Sustainability department was created in response to increased reporting and compliance requirements related to GHG emissions and sustainability, which are driving the need to add additional resources, both in 2024 and 2025. In addition, environmental and archaeological regulatory requirements continue to increase through new legislation or through changes to existing legislation.

There are numerous environmental and archaeological regulatory requirements and risks associated with FortisBC's operations, and a multitude of federal, provincial, regional, and municipal permits and approvals that are typically required. FortisBC's work involves development in urban, rural, and natural areas with potential environmental impacts on watercourses, sensitive ecosystems (including riparian areas), at risk species, agricultural areas, and archaeological sites which need to be adequately assessed and managed. There are often significant regulatory triggers under the *Fisheries Act*, *Species at Risk Act*, *Water Sustainability Act*, *Environmental Management Act*, *Declaration on the Rights of Indigenous Peoples Act (DRIPA)*, and *Heritage Conservation Act* (HCA). The federal and provincial regulatory requirements are anticipated to continue to increase over the next five years with recent new and pending regulatory requirements.

Furthermore, changes to the Contaminated Sites Regulation (CSR) under the *Environmental Management Act* in 2021 and 2023 have triggered more Stage 1 & 2 Preliminary Site Investigations (PSIs) requiring significant environmental support. Any municipal permit required for a site with commercial/industrial activities (Schedule 2 activities) can trigger full PSIs unless an exemption applies. In addition, as of March 2023, soil relocation (>30m^3) from Schedule 2 sites also triggers PSIs and soil receiving sites are requiring environmental data from all sites (including roadways), regardless of any Schedule 2 activity. The PSIs and soil testing require significant environmental support for the duration of the work, from initial screening, managing consultants, reviewing reports, and providing direction to business units for a multitude of activities ranging from day-to-day service installations to multi-year main extensions.

Ongoing process improvements at FortisBC's facilities are required to ensure proper storage and disposal of hazardous and non-hazardous waste (including soils), such as improved waste categorization and segregation practices and increased waste pick-ups to avoid accumulation and meet increasing regulatory requirements.

New requirements are also proposed to come into force in 2024 under the *Transportation of Dangerous Goods Act* (TDGA) and associated regulations related to the creation of a job specific

TDGA training course and registration of all sites with dangerous goods. FortisBC must ensure training is developed to comply with the new requirements and support Operations with the logistics of dangerous goods movement to ensure that all affected sites are registered.

The implementation of DRIPA has resulted in increased regulatory requirements for Indigenous review and consultation. As many of the concerns expressed by Indigenous communities are related to the protection of environmental and archaeological resources, an increased workload will result to ensure Indigenous communities' concerns are addressed through project planning, assessment, permitting and execution. For example, the HCA is currently being revised to incorporate the UNDRIP/DRIPA principles. FortisBC anticipates increased assessment and permitting requirements for heritage/archaeological resource management. It is anticipated that changes to the HCA will be passed into legislation in the Fall of 2024.

FEI requires net incremental funding for environment and sustainability of $1.800 million related to the following areas:

- Increased scope/scale of activities/projects requiring environmental review and environmental management during implementation;
- Increased regulatory/compliance requirements;
- Increased GHG management and reporting requirements;
- Increased carbon accounting and management;
- Archaeological permitting costs;
- Increased environmental (non-regulatory) reporting; and
- Increased consulting costs for environmental risk management.

Of the total $1.800 million required, $0.700 million is estimated for ongoing requirements, with the remaining $1.100 million estimated to be attributable to implementing new codes and regulations required or anticipated in the following areas:

- Labour: Environmental Program Lead (Contaminated Sites Regulation) to support increased requirements/activities;
- Labour: Environmental Program Lead (Transportation of Dangerous Goods/Hazardous Waste Regulation) to support increased requirements/activities;
- Labour: Archaeologist to support increased requirements/activities;
- Labour: Carbon Accounting Lead (GHG) to support new compliance reporting requirements;
- Labour: Carbon Accounting Technician (GHG) to support new compliance reporting requirements;

- Labour: Additional Sustainability Program Manager to support increased sustainability reporting;
- Non-labour: Increased archaeology permits/compliance costs;
- Non-labour: Increased Contaminated Sites Regulation compliance costs/consulting; and
- Non-labour: Increased GHG emissions/carbon accounting costs.

FBC's funding request in this area is discussed in Section C2.3.4.2.

2.2.4.3 Corporate Security

The Corporate Security department manages cybersecurity, physical security, business continuity programs, and emergency management programs for all of FortisBC's business areas. The group is responsible for the security of corporate and operational technologies and assets, the development and maintenance of business continuity plans, and the development, maintenance and exercising of emergency management and response plans.

FortisBC is investing more in cybersecurity, physical security, business continuity and emergency management to manage the increasing and evolving risks. FortisBC requires additional resources to deploy and sustain technologies that detect and mitigate the growing cyber and physical threats, enable swift response to security incidents, improve the security of FortisBC's assets, and enhance emergency response and business continuity capabilities to respond to increasing climate related events.

Table C2-7 below provides FEI's actual expenditures for corporate security and business continuity from 2020 to 2023, the projected base funding for 2024, and the net incremental funding to be added to the 2024 Base O&M. FBC's funding request in this area is discussed in Section C2.3.4.3.

Table C2-7: FEI Corporate Security Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Corporate Security	3.640	3.055	3.465	4.068	4.248	1.607
Total	3.640	3.055	3.465	4.068	4.248	1.607

Additional cybersecurity resources are required to enhance FortisBC's ability to discover and monitor for security threats, perform threat hunting (i.e., the practice of searching for cyber threats that may have evaded detection tools), and expand the cybersecurity operations centre to enable additional alert monitoring and threat responses, and to improve visibility and coordination between information systems, operation technology and cybersecurity. Cyber threats have changed and become more sophisticated. Phishing scams are on the rise, not just online but also through texts and voice calls. These scams may aim to access customer funds or information by impersonating FortisBC. Additional security efforts are needed to protect customers and employees from these evolving threats.

The net incremental funding for physical security is for additional resources needed to enhance FortisBC's security operations and expand its security operations centre. These funds will enable additional monitoring of alerts, allow for improved responses to security events, and will provide resources for additional physical security audits and assessments. Further, the additional funding will support the continued standardization of physical security practices and equipment across FortisBC.

Additional resources for Emergency Management are primarily required in response to the increase in climate related events that have been experienced over the past five years. There have been more demands on the emergency operations centre (EOC) and the team that operates it. This requires additional training and resources to ensure FortisBC can continue to respond to emergency events of any kind.

Net incremental funding required for FortisBC (FEI and FBC) is approximately $2.060 million. This is comprised of $0.420 million for three positions: one cybersecurity analyst, one physical security advisor, and one Emergency Program manager, with the remaining costs of $1.640 million for external contracted services across cybersecurity, physical security, and emergency management.

The total funding of $2.060 million will be allocated between FEI and FBC using the approximate number of employees as the cost driver, which results in a 78 percent allocation to FEI and a 22 percent allocation to FBC. FEI's and FBC's allocations are therefore $1.607 million and $0.453 million, respectively.

2.2.4.4 Technology

Technology services are responsible for identifying, designing, operating, and maintaining technology solutions to improve the delivery of service. Information Systems (IS) enable FortisBC's operations to provide responsive, secure, and simple access to information anywhere at any time. IS applications and delivery services manage the application portfolio and project delivery and execution, along with providing quality assurance of the systems landscape. IS enterprise and technology services manage IS business planning, enterprise and technology services, and enterprise data and analytics practices.

Table C2-8 below provides the actual expenditures for FEI software licensing fees and patching from 2020 to 2023, the projected base funding for 2024, and the net incremental funding to be added to the Base O&M. FBC's funding request in this area is discussed in Section C2.3.4.4.

Table C2-8: FEI Technology Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Software Licensing Fees	6.213	6.816	7.699	9.059	9.460	1.600
Patching[79]	-	-	-	-	-	1.346
Total	6.213	6.816	7.699	9.059	9.460	2.946

2.2.4.4.1 SOFTWARE LICENSING FEES

A software licensing fee is charged for the right to use, or maintain a copy of, software for operating and maintaining technology solutions in FortisBC's IS application portfolio.

Additional software licensing fees are needed for new systems software, along with renewal of existing software licenses, and for new licenses to support the addition of new users or expanded use of existing software. As older systems are replaced, the ongoing licensing costs of the new systems can be double or triple that of the older systems due to higher costs for the software.

Another contributing factor to the higher forecast of software licensing fees is that for the renewal and purchase of software, the trend in ownership of software application solution(s) is moving away from the current "on-premises" model to a different model of SaaS (Software as a service – Cloud). Some vendors are withdrawing the option of an "on-premise" solution that FortisBC currently owns, necessitating the transition to SaaS. As SaaS is a different ownership and support model, its ongoing costs are higher than the traditional "on-premise" model. On-premise licensing typically involves a higher initial capital cost with a lower O&M cost for ongoing maintenance licenses. This expected trend towards SaaS is forecast to increase software licensing costs for FortisBC.

For these reasons, FEI requires net incremental funding of $1.600 million. This estimate for the 2025 to 2027 timeframe is based on the current project list and incorporates recent pricing information available. The pricing information used includes actual licensing costs over the last four years as a guide (i.e., SaaS, on-premise) and/or recent budgetary estimates provided by vendors to determine the required licensing costs. Software support agreements currently have a one-to-three-year term, and most software agreements have been renewed during the Current MRP term, providing recent pricing information for forecasting costs for the Rate Framework. For renewal of software licenses that came due in 2023, FortisBC experienced annual increases in the 5 to 10 percent range. FortisBC is expecting this trend to continue for software license fees that come due during the period of the Rate Framework.

[79] No historical O&M expenditures are shown for years prior to 2024 as the costs were capitalized through the current managed service agreement and spread amongst the existing employee resources. There are currently no dedicated resources to patch systems.

2.2.4.4.2 PATCHING

Security patch management is the process of applying updates to hardware and software to fix security vulnerabilities. Patching is a key aspect of cybersecurity and information technology maintenance as it helps prevent attackers from exploiting known flaws in software or devices which could lead to the compromise of system reliability, including data integrity, confidentiality, or availability.

In recent years, both FEI and FBC have increased their expenditures for cybersecurity as the Companies respond to evolving cyber risks. Further increased sophistication in cyber threats has forced hardware and software companies to release updated code and operating system patches to counteract these threats. An increased frequency of these updates requires FortisBC to increase the cadence of the patch review and deployment process.

In addition to increased frequency, FortisBC's patch process must increase in scope to include all critical and non-critical applications. This includes review and assessment of available patches, testing, and deployment.

The frequency of off-cycle and zero-day[80] patches from hardware and software vendors has also increased and FortisBC needs to apply these patches to remediate the serious vulnerabilities that cannot wait for the next scheduled patch implementation cycle. Security patch management is completed by IS personnel with third party support.

FortisBC has a robust patching process to mitigate risk in the current threat landscape; however, patching must increase in frequency in response to expanded cybersecurity demands due to the increase in sophistication and frequency of cyber threats, which is broadening the threat landscape. FortisBC pushes patches to end-points via automation, but critical servers are patched manually. This involves extensive testing to ensure the systems perform as expected when returning to service.

FEI has over 300 applications, 5,200 end-points (computers and mobile devices), 1,100 servers, and 550 appliances.

FEI requires net incremental O&M funding of $1.346 million to support an increased cadence for security patching of hardware and software. This net incremental funding is comprised of $0.596 million, which is the non-capitalized portion of 12 technical and 2 management employees, and $0.750 million for managed services.[81] The total patch management program of $4.935 million is split between O&M and capital work, with the majority being capital. The associated increase in capital expenditures is discussed in Section C3.3.3.4.

FBC's O&M funding request in this area is discussed in Section C2.3.4.4 and the associated increase in capital expenditures is discussed in Section C3.4.3.4.

[80] An off-cycle and zero-day patch is a security fix that is released by a vendor outside of their regular patch release schedule and is required to be applied to address a recently discovered vulnerability to reduce risk of exploitation.
[81] A managed service is the practice of allowing a third-party company to support information technology operations.

2.2.4.5 System Operations and Adaptation

FortisBC's operations are focused on meeting customer expectations by improving processes that positively impact the efficiency and effectiveness of work completed. Table C2-9 below is a summary of the proposed funding requests. FEI's historical actual expenditures since the beginning of the Current MRP are provided for context along with the projected base funding for 2024. The net incremental funding represents the additional funds to be added to FEI's 2024 Base O&M.

Table C2-9: FEI System Operations and Adaptation Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Operate and Maintain LNG Plants	11.889	13.117	14.013	13.385	14.578	0.400
Workforce Development	8.148	8.628	8.501	8.879	9.272	0.400
Total	20.037	21.745	22.514	22.264	23.850	0.800

2.2.4.5.1 OPERATE AND MAINTAIN LNG PLANTS

In the Current MRP, FEI's LNG O&M costs are allocated between formula and forecast (flow-through) O&M based on whether they are fixed or variable costs. The portion of the total O&M costs allocated to formula O&M represents the fixed costs to operate the LNG plants, regardless of use. The remaining portion of total O&M costs are treated as flow-through outside the formula O&M. These costs represent the variable costs for the production of LNG (the liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers with LNG, etc.) where the costs fluctuate and are dependent on sales volumes. Accounting for these costs as forecast (flow-through) recognizes that these costs are dependent on sales volumes which are difficult to predict.

Table C2-9 above provides the combined recent historical expenditures to operate and maintain the Tilbury Base Plant, the T1A facility, and the Mt. Hayes facility. FEI requires additional resources to undertake incremental activities required to operate the facilities safely and reliably to meet ongoing operational and regulatory requirements as well as address incremental costs associated with higher run times at the Mt. Hayes facility.

Net incremental funding of $0.400 million is required for the following reasons:

- FEI plans to add a warehouse position to manage the flow of spare parts and consumables required for the ongoing operation of the Tilbury 1A facility.
- FEI requires funding to manage ongoing maintenance requirements over the term of the Rate Framework, including regulatory requirements to complete pressure safety valve

(PSV) recertifications, funding for increased material and facility costs related to increased Mt. Hayes production, and work to complete major equipment maintenance.

2.2.4.5.2 WORKFORCE DEVELOPMENT

As operational needs and the demographics of the workforce evolve, it is necessary to support the business by recruiting talent as well as investing in current employees to prepare for the future while continuing to address immediate business needs. The evolution of workforce skills and capabilities is also required to keep up with the evolving energy landscape, and to focus on emerging areas such as Indigenous employment contracts, diversity, equity and inclusion (DEI), and expectations of the labour market.

The $0.400 million net incremental funding provides for three additional positions focused on recruitment, corporate employee skills, and competencies development for all employees. Of the three positions, two are for recruitment and corporate employee training/development program(s), with the remaining position for supporting multi-year employment contracts with Indigenous communities.

The two positions for recruitment and employee training and development are required to provide support for the projected retirements over the upcoming three years. Since 2020, there has been a steady increase in total attrition, particularly regarding retirements and voluntary terminations. There has been increased turnover of voluntary exits from 2.9 percent in 2020 to 8 percent in 2023, as well as increased retirements from 2.0 percent in 2020 to 3.1 percent in 2023 which requires knowledge transfer to build up successors. Additionally, the two positions will support the increasing volume of recruitment and employee movements. Recruitment volumes have steadily increased since 2018, increasing by 25 percent as of 2023 compared to when the Current MRP was developed. Recruitments include new jobs and replacements. Although new jobs remained consistent over the Current MRP term, replacements increased by 29 percent, while the staffing for Talent Acquisition has remained the same over the Current MRP term. Current Talent Acquisition staffing levels restrict FortisBC's ability to be proactive, build relationships with educational institutions, Indigenous communities, employment and immigration service providers, and limit capacity to proactively engage hiring managers, external agencies, and resources to attract candidates. Furthermore, FortisBC is modernizing its tools and platforms to support future workforce development and growth. These tool modernization activities require additional resources.

The remaining position is to support multi-year employment contracts with Indigenous nations to strengthen partnerships with Indigenous communities. Programs will be established to meet PAR targets through a proactive implementation plan to engage underrepresented groups with respect to career opportunities at FortisBC. Examples include creating a summer student program, job shadowing, site tours, and an Indigenous Management Training program.

2.3 *FBC 2024 BASE O&M*

2.3.1 FBC 2024 Base O&M Calculation

FBC established the 2024 Base O&M for the Rate Framework using the same method that it used to establish the 2019 Base O&M in the Current MRP, which was approved by the MRP Decision and Order G-166-20.

Consistent with past practice, FBC has used 2023 Actual expenditures (2023 Approved Base O&M less savings) as the starting point for the 2024 Base O&M, as 2023 is the latest year for which actual expenditures are available, and therefore, the most recent historical representation of the level of O&M funding required to operate FBC's system safely and reliably and to maintain its overall service quality level.

By starting with the 2023 Actual expenditures, the savings achieved in 2023 (i.e., $4.235 million) are accounted for in the calculation of the 2024 Base O&M. With the starting point (i.e., 2023 Actuals) established, the 2024 Base O&M is then developed by incorporating various adjustments, including the addition of a previously approved exogenous item, application of the 2024 formula inflator, the inclusion of amounts to reflect the new activities that are occurring in 2024 that would not be reflected in the 2023 Actual amounts, and incremental net funding which FBC requires during the Rate Framework term.

The process to calculate the 2024 Base O&M is therefore as follows:

1. Start with the 2023 Actual Base O&M, which is the 2023 Approved Base O&M reduced by the 2023 savings achieved.
2. Adjust for a previously approved exogenous factor. This adjustment is required to align the 2023 Actual Base O&M with the scope of the formula O&M for the term of the Rate Framework.
3. Multiply by the 2024 formula inflator[82] as approved in the Annual Review for 2024 Rates. This adjustment is required to state the 2023 Actual Base O&M in 2024 dollars.
4. Add amounts for required spending that will begin in 2024. As FBC started with 2023 Actual expenditures, this adjustment is required to derive a projection of FBC's 2024 Base O&M requirements.
5. Add net incremental funding required beginning in 2025 and over the term of the Rate Framework. This is the final adjustment, which increases the projected 2024 Base O&M to the amount that will be required over the term of the Rate Framework, but stated in 2024 dollars.

[82] 2024 Formula inflator includes inflation less productivity, and customer growth.

Table C2-10 shows how the 2024 Base O&M is calculated using the above adjustments. Each adjustment is discussed in the sections that follow.

Table C2-10: FBC 2024 Base O&M ($ millions)

2023 Approved Base O&M	70.318
2023 Savings - Base O&M	(4.235)
2023 Actual Base O&M	**66.083**
Adjustment for exogenous factor (in 2023 dollars)	0.585
2024 Base O&M (in 2023 dollars)	**66.668**
2024 Inflator	1.0356
2024 Base O&M (in 2024 dollars)	**69.043**
Adjustments for Required 2024 Spending (in 2024 dollars)	1.670
2024 Projected Base O&M	**70.713**
Net incremental funding for Rate Framework (in 2024 dollars)	5.681
2024 Base O&M for Rate Framework	**76.394**

2.3.2 Adjustment for Exogenous Factor

FBC has adjusted the 2023 Actual Base O&M to incorporate the ongoing O&M associated with a previously approved exogenous factor.

2.3.2.1 Mandatory Reliability Standards (MRS) Assessment Report (AR) 13

As part of the Annual Review for 2022 Rates Decision,[83] the BCUC approved exogenous factor treatment for FBC's incremental costs of MRS compliance associated with MRS AR 13, as these costs were not included in the Current MRP's Base O&M. As explained in the Annual Review for 2024 Rates Application,[84] FBC projects $0.585 million of O&M spending in 2024, which is consistent with the 2023 Projected amount and is the amount of O&M that is expected to be incurred annually to maintain compliance with AR 13. This spending is related to ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance with AR 13. As these costs will continue through the term of the Rate Framework, they are included as an adjustment to the Base O&M for the purpose of setting the 2024 Base O&M. This treatment is consistent with how FBC incorporated exogenous factor impacts into Base O&M when establishing the 2019 Base O&M in the Current MRP.

2.3.3 Adjustments for Required 2024 Spending

Since FBC used 2023 Actual expenditures as the starting point for determining its 2024 Base O&M, any new O&M expenditures that will begin in 2024 are not yet reflected in the Base O&M

[83] Decision and Order G-374-21, p. 21.
[84] Section 6.3.5, p. 52.

and therefore need to be added. There are three items, totalling to $1.670 million, that will commence in 2024 and are not reflected in 2023 Actual expenditures. These items are new facility lease costs of $0.300 million, incremental costs to support the Long-Term Electric Resource Plan (LTERP) of $0.170 million, and incremental costs to support the power supply function and development of supply resource options of $1.200 million.

2.3.3.1 New Facility Lease Costs

As part of the Kelowna Space Project that was reviewed in detail in FEI's and FBC's Annual Reviews for 2023 Rates, FortisBC will be occupying new facilities in the Kelowna region to meet its space capacity needs starting in 2024. In the 2023 Annual Reviews, FEI and FBC received approval for updated Other capital expenditure forecasts for 2023 and 2024, including capital expenditures for the Kelowna Space Project.[85] As part of this project, both FEI's and FBC's Shared Services Departments (Support Services) located in Kelowna relocated to a new office lease facility in early 2024. The incremental leasing (O&M) cost for the site to be added to Base O&M is $0.900 million, shared between FEI and FBC based on the number of employees for each Company. FBC's allocation is approximately $0.300 million.

2.3.3.2 Long-Term Resource Planning

Long-term resource planning is a critical function for FortisBC as it assesses the future energy requirements of customers and options to meet them over the long-term, providing the context and framework for future regulatory applications, including CPCNs. The requirement to submit long-term resource plans to the BCUC is set out in section 44.1 of the UCA. During the ongoing energy transition and the rapidly changing external environment, FortisBC's resource planning activities are becoming less cyclical and more ongoing, with long-term resource plans being developed and filed with the BCUC on a more frequent basis. With new sources of supply such as wind and solar, and new types of customer demand such as EV charging and hydrogen production, resource planning has increased in complexity.

The Companies are staffing three additional positions in 2024 to support the increasing frequency and complexity of resource planning as well as the need to continue advancing the integration of gas and electric resource planning. The new roles will provide analysis and research and will manage internal and external stakeholder engagement. Examples of these activities include:

- Assessment of resiliency for resource portfolios in future resource plans;
- Regional load forecasting, and transmission and distribution (T&D) impacts analysis;
- Analysis related to an integrated (i.e., diversified) gas and electric system;
- Increasing stakeholder and Indigenous engagement related to resource planning; and
- More collaboration with BC Hydro on load forecasting and scenarios.

[85] Approved by Orders G-352-22 (FEI) and G-382-22 (FBC).

The total cost of these three positions, including supporting costs, is $0.552 million, with the costs being allocated approximately two-thirds to FEI and one-third to FBC. FBC's share of the costs is therefore $0.170 million.

2.3.3.3 Power Supply and Development of Supply Resource Options

As highlighted at the Annual Review for 2024 Rates workshop, the power supply market is changing and has become more complex and dynamic as the region experiences higher wholesale prices and tighter market conditions. The region is impacted by several factors, including policy and customer-driven demand increases, impacts of climate change on traditional supply resources (e.g., multi-year drought impacts on hydro-electric resources), and a shift towards renewable energy generation. Amidst this changing environment, FBC continues to optimize its costs and ensure security of supply through its management of the power supply portfolio. However, with the added complexity, FBC is adding resources to manage and optimize its power supply portfolio.

In addition to the changing power supply market, FBC must also begin development of new power supply resources. Further to the BCUC Decision and Order G-380-22 regarding FBC's 2021 LTERP (2021 LTERP Decision), FBC is exploring the development of supply side opportunities. In the 2021 LTERP Decision (page 47), the Panel noted the need for FBC to make progress on developing new resources:

> FBC notes that it may take some time to fully define the available resources, particularly given the long development timelines of major projects in BC. The Panel disagrees with ICG that FBC should be limited in its ability to move forward on development plans for new resources. It is not clear to this Panel how FBC could make meaningful progress on the development of new resources without pursuing the predevelopment activities and consultation needed to advance these new initiatives.

FBC has initiated planning and pre-development activities within its service territory as it seeks to optimize the energy resources and infrastructure.

To support the management of its power supply portfolio and the development of new supply side resources, four additional positions, as well as funding for external consultants are being added in 2024 at a total cost of $1.200 million. These expenditures will support the following activities:

- Ongoing power supply portfolio management and optimization;
- Enhanced modelling and data analytics to determine electric supply resources and what those new electric resources will be;
- Pre-project planning related to a number of new electric generation opportunities; and
- Contract design to update the Canal Plant Agreement and related agreements as well as other power supply contracts to account for new electric generation resources.

This work is critical to both identify and further explore the best resource options as well as to develop the new framework under which FBC operations will be coordinated with BC Hydro, as the existing framework does not cover additional FBC generation resources not envisioned in the Canal Plant Agreement. As noted above, this work is aligned with the 2021 LTERP.

2.3.4 Net Incremental Funding for the Term of the Rate Framework

To address key issues and changes in its operating environment, FBC requires net incremental O&M funding to be added to its 2024 Base O&M. The following table and discussion describe the net incremental O&M funding required over the term of the Rate Framework, organized by the respective business drivers.

Table C2-11: FBC Net Incremental Funding for the Term of the Rate Framework

Business Driver	$ millions
Government, Indigenous and Community Engagement	1.356
Environment and Sustainability	0.500
Corporate Security	0.453
Technology	1.099
System Operations and Adaptation	2.273
Total	**5.681**

2.3.4.1 Government, Indigenous and Community Engagement

As discussed in Section B1 and further below, there continues to be substantial shifts within the policy environment that are significantly influencing FortisBC and its customers, particularly now that policies are reaching implementation and are affecting FortisBC's operations. At the same time, requirements for Indigenous engagement are increasing and becoming more complex, requiring additional resources and funding to build and maintain relationships.

Table C2-12 below provides the related net incremental funding requests for this area, followed by a discussion and rationale for the requests. For context, FBC has also provided the historical expenditures since the start of the Current MRP and the projected base funding for 2024.

Table C2-12: FBC Government, Indigenous and Community Engagement Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Government Relations and Public Policy[86]	-	-	-	-	-	0.066
Community and Indigenous Relations	0.501	0.468	0.652	0.654	0.677	1.140
Customer Engagement	1.227	1.065	1.045	0.991	1.027	0.150
Total	1.728	1.533	1.697	1.645	1.704	1.356

Each of these three areas is discussed further below.

2.3.4.1.1 GOVERNMENT RELATIONS AND PUBLIC POLICY

As discussed in Section B1.4.2, policies are increasingly promoting the use of electricity, including in home heating, light duty transportation and industrial processes. FBC is focused on keeping pace with the growing demand for electricity in a constantly evolving operating environment and requires additional resources to engage with government on policy development impacting the electric system. For example, on February 15, 2024, the Province deposited Order in Council (OIC) No. 60 which amended the *Clean Energy Act* (CEA). The CEA now includes an objective to, by 2030, ensure that 100 percent of the electricity generated in British Columbia and supplied to the integrated grid is generated from clean or renewable resources, and to ensure that the infrastructure necessary to transmit that electricity is built. FBC will need to engage with government regarding how this objective is defined, including on the compliance pathways and technologies that are considered “clean”. Further, FBC expects to engage with government on behalf of its customers to promote public policies related to the decarbonization of buildings that minimize impacts on peak demand in its service territory.

Please refer to Section C2.2.4.1.1 for a discussion of FortisBC’s Government Relations and Public Policy requirements. FBC’s share of the net incremental funding of $0.300 million for the two new positions described in that section is $0.066 million.

2.3.4.1.2 COMMUNITY AND INDIGENOUS RELATIONS

Table C2-13 below provides the breakdown of the funding request for Community and Indigenous Relations.

[86] Historically, FBC has engaged with government periodically on public policy matters. These engagements occurred infrequently and were supported by other departments within the Company, as applicable. Funding is required to support the increased and more frequent need for engagement.

Table C2-13: Breakdown of Community and Indigenous Relations Net Incremental Funding ($ millions)

Breakdown of Net Incremental Funding	Net Incremental Funding
Community Investment	0.250
Total Community	**0.250**
Indigenous Relations Engagement	0.580
Advancing Reconciliation	0.310
Total Indigenous	**0.890**

Community Investment

Please refer to the Section C2.2.4.1.2 for details of FortisBC's community investment program. Similar to the need identified for FEI, FBC requires new community investment funding of $0.250 million to support to the communities that FBC serves and operates in.

Indigenous Relations and Reconciliation

Please refer to Section C2.2.4.1.2 for details of some of the significant changes in the public policy landscape regarding Indigenous rights and reconciliation over the last few years.

Similar to FEI, FBC is increasing its focus on strengthening relationships with Indigenous peoples, communities, and First Nations consistent with an increased commitment for engagement and consensus seeking at the provincial and federal levels. Much of FBC infrastructure was developed and constructed in the earlier part of the 20th century when laws around consultation and engagement with Indigenous communities were different than they are today. This creates some unique challenges and requires increased engagement with Indigenous communities, particularly where resolving historical grievances is part of moving new projects forward. For example, before the FBC Oliver office and substation were built, the land used was removed from the Osoyoos Indian Band Indian (OIB) Reserve No. 1, which the OIB is seeking to be returned. These challenges require enhanced engagement and will impact future projects.

Indigenous Relations Engagement

To support enhanced engagement activities, FBC requires net incremental funding of $0.580 million, which is comprised of $0.480 million for three new Community & Indigenous/Initiatives Relations Manager positions and $0.100 million in non-labour costs. These roles will support key activities related to engagement, Indigenous initiatives and advancing reconciliation efforts, including, among other activities:

- Supporting engagement related to FBC's infrastructure growth; and
- Supporting engagement related to the replacement or upgrade of aging assets.

Building relationships takes time and resources. This can only be done with human capacity to build authentic and meaningful relationships with Indigenous communities.

Advancing Reconciliation

In addition to the resources required to implement enhanced engagement activities, there are several initiatives that need additional funding to support Truth and Reconciliation efforts. FBC estimates $0.310 million is required to advance the initiatives described in Section C2.2.4.1.2.

2.3.4.1.3 CUSTOMER ENGAGEMENT

FBC is requesting funding of $0.150 million for an additional Communications Manager to complement the existing two positions and meet growing daily communications needs from customers and the public. This position will manage media relations, customer and public communications related to issues management (i.e., wildfires, public safety, vegetation management, etc.), and increased communications support for community and Indigenous relations initiatives.

2.3.4.2 Environment and Sustainability

Table C2-14 below provides FBC's actual expenditures for environment and sustainability from 2020 to 2023, the projected base funding for 2024, and the net incremental funding to be added to the 2024 Base O&M.

Table C2-14: FBC Environment and Sustainability Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Environment and Sustainability	0.283	0.238	0.596	0.732	0.758	0.500
Total	0.283	0.238	0.596	0.732	0.758	0.500

Environmental and archaeological regulatory requirements continue to increase through new legislation or through changes to existing legislation for both FEI and FBC. FBC is required to comply with the environmental, archaeological, and regulatory requirements and sustainability reporting that are applicable to FEI. Please refer to Section C2.2.4.2 for a description of these increasing requirements.

Furthermore, strengthened fish and fish habitat protection provisions were introduced in 2019 under the modernized *Fisheries Act*, as well as regulations that support these provisions. FBC is responsible for ensuring that the ongoing operation, modification, maintenance, or other works and undertakings associated with its generation facilities are in compliance with the modernized *Fisheries Act*. Additional fisheries assessment work is required to support the evaluation and potential application for an authorization for FBC's river plants under the modernized act. This work involves the identification of operational impacts, mitigation opportunities, and residual impacts including but not limited to stranding, ramping, entrainment, and dam safety work.

There are numerous federal and provincial regulatory requirements to protect species at risk, including aquatic species at risk and migratory birds. Environmental protection and permitting requirements are increasing due to newly listed species at risk and identification of critical habitat. For example, the 2022 updates to the Migratory Birds Regulation (MBR) under the *Migratory Birds Convention Act* increased the protection of pileated woodpecker nesting cavities, requiring them to be protected and monitored for three breeding seasons prior to being removed, to ensure they are not being used (by any species). FBC now requires Damage/Danger permits to allow removal of poles with identified pileated woodpecker nesting cavities once the breeding season is over if the pole had no occupants during the breeding season. As a result, additional assessment and monitoring of poles are now required to identify pileated woodpecker nesting cavities for the permit application and record activity throughout the nesting season.

While the *Migratory Birds Convention Act* and *Fisheries Act* came into force in 2022 and 2019, respectively, it has taken time for the requirements to be clarified. FBC has been engaging with government representatives and expects its engagement and planning phases to conclude in 2024. Accordingly, commencing in 2025, FBC will require additional resources to implement and comply with these new requirements.

Additionally, aquatic invasive species (zebra/quagga mussels) pose a growing threat to FBC's hydro-electric generation stations. As a result, FBC requires additional funding to support aquatic invasive species prevention initiatives.

The increases in resources, labour and non-labour for the proposed net incremental funding of $0.500 million are related to the following areas:

- Increased scope/scale of activities/projects requiring environmental review and environmental management during implementation;
- Increased regulatory/compliance requirements;
- Archaeological permitting costs;
- Increased environmental (non-regulatory) reporting; and
- Increased consulting costs for environmental risk management.

Of the total $0.500 million required, $0.200 million is estimated for increasing regulatory requirements, with the remaining $0.300 million estimated for implementing new codes and regulations required or anticipated in the following areas:

- Labour: Environmental Technician to support increased activities;
- Labour: Environmental Program Lead to support increased activities;
- Non-labour: Increased fisheries assessment work (*Fisheries Act*);
- Non-labour: Additional invasive species (mussel) prevention;

- Non-labour: Additional terrestrial resource management (migratory birds/species at risk; invasive plants); and
- Non-labour: Increased archaeology permits/compliance costs.

2.3.4.3 Corporate Security

Table C2-15 below provides FBC's actual expenditures for corporate security from 2020 to 2023, the projected base funding for 2024, and the net incremental funding to be added to FBC's 2024 Base O&M.

Table C2-15: FBC Corporate Security Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Corporate Security	0.875	0.806	0.967	0.960	0.994	0.453
Total	0.875	0.806	0.967	0.960	0.994	0.453

Please refer to Section C2.2.4.3 for a discussion of FortisBC's Corporate Security activities and focus. As explained in Section C2.2.4.3, the total net incremental funding of $2.060 million will be allocated between FEI and FBC using the approximate number of employees as the cost driver, which results in a 78 percent allocation to FEI and a 22 percent allocation to FBC. FBC's allocation is therefore $0.453 million.

2.3.4.4 Technology

Table C2-16 below provides the actual expenditures for software licensing fees and patching for FBC from 2020 to 2023, the projected base funding for 2024, and the net incremental amount to be added to FBC's 2024 Base O&M.

Table C2-16: FBC Technology Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Software Licensing fees	1.929	2.148	2.286	2.570	2.662	0.650
Patching[87]	-	-	-	-	-	0.449
Total	1.929	2.148	2.286	2.570	2.662	1.099

[87] No historical O&M expenditures are shown as the costs were capitalized through the current managed service agreement and spread amongst the existing employee resources. There are currently no dedicated resources to patch systems.

For the reasons described in Section C2.2.4.4.1, FBC requires net incremental funding of $0.650 million to fund the year-over-year increases expected in its software licensing fees.

For the reasons described in Section C2.2.4.4.2, FBC requires net incremental funding of $0.449 million to support an increased cadence for security patching of hardware and software. The funding includes $0.199 million for the non-capitalized portion of seven technical employees and $0.250 million for managed services.[88] FBC has more than 300 applications, 1,750 end-points (computers and mobile devices), 430 servers, and 330 appliances. The total patch management program of $1.645 million is split between O&M and capital work, with the majority being capital. The associated increase in capital expenditures is discussed in Section C3.4.3.4.

2.3.4.5 System Operations and Adaptation

FortisBC's operations are focused on meeting customer expectations by improving processes that improve efficiency and effectiveness of the work completed. Table C2-17 below is a summary of the proposed funding requests. FBC's historical actual expenditures since the beginning of the Current MRP are provided for context along with the projected base funding for 2024. The net incremental funding represents the additional funds to be added to FBC's 2024 Base O&M.

Table C2-17: FBC System Operations and Adaptation Net Incremental Funding ($ millions)

	Historical Actual Expenditures				Projected Base	Proposed Incremental
	2020	2021	2022	2023	2024	
Engineering	5.900	6.056	6.700	6.328	6.553	0.535
Generation and System Control	7.000	6.400	6.200	7.100	7.353	1.000
Vegetation Management	5.665	5.538	5.937	5.465	5.660	0.478
Workforce Development	1.724	2.076	1.667	1.600	1.657	0.260
Total	20.289	20.070	20.504	20.493	21.223	2.273

Each of the four identified areas are discussed further below.

2.3.4.5.1 ENGINEERING

FBC requires net incremental funding of $0.535 million in Engineering, consisting of $0.345 million for seven additional positions and $0.190 million in other related support costs.

FBC requires an additional seven positions and related costs to support its capital plan (discussed in Section C3.4) and asset maintenance strategy, which will ensure that the electric network has sufficient capacity to meet increasing customer demand and ensure the reliability of energy supply. The new positions include two engineers, three technologists, one data integrity coordinator and one asset assistant, and they are spread across the different teams within Engineering. These teams deal with both asset management and the planning and execution of

[88] A managed service is the practice of allowing a third-party company to support information technology operations.

capital projects. While two of these positions are associated with asset management and have significant O&M allocations, the majority of the positions' salaries are to support the proposed growth in FBC's capital over the upcoming period, with most of the salaries charged to capital activities and the remaining 10 to 15 percent allocated to O&M. The O&M activities include tasks such as training, meeting regulatory requirements, and support for operations and standards. The related support expenses are for travel expenses for training and operations support, course fees, personal protective equipment, communications costs, and professional membership dues.

Other support activities requiring net incremental funding of $0.190 million include:

- **Telecommunications Fees:** $0.050 million for increasing telecommunications fees for existing communication devices (such as smart meters and recloser controllers) and new fees for additional communications devices needed for a communication system that is redundant and resilient to withstand increasing threats to infrastructure from wildfires and other climate change impacts and increased cybersecurity threats.
- **Support the MRS Process:** $0.140 million will fund expected increases for license fees for the software used to meet Mandatory Reliability Standards. As explained in Section C2.2.4.4.1, vendors are changing their software solutions and support models (i.e., SaaS), resulting in increased licensing costs.

2.3.4.5.2 GENERATION AND SYSTEM CONTROL

FBC requires $1.000 million of net incremental funding for Generation and System Control. These funds will be used for compliance with codes and regulations (due to implementation of new processes or timing of activities) and increases in maintenance activities. Table C2-18 below outlines the net incremental funding for Generation and System Control. Each of the incremental expenditures is discussed below the table.

Table C2-18: Breakdown of Generation and System Control Net Incremental Funding ($ millions)

Breakdown of Net Incremental Funding	Net Incremental Funding
BC Dam Safety Regulations	0.260
WorkSafe BC	0.070
Increased Maintenance	0.420
Major Unit Inspections	0.250
Total	**1.000**

FBC must comply with regulatory requirements under the BC Dam Safety Regulation and WorkSafe BC, resulting in net incremental funding of $0.330 million, as further described below.

- **BC Dam Safety Regulations:** $0.260 million is related to compliance activities that include dam safety capacity assessments required by recently completed dam safety reviews, dam monitoring, dam drainage and spillway gate testing.

- **WorkSafe BC:** $0.070 million related to addressing evolving compliance activities such as regulations around equipment identification and labelling. Further, the annual crane inspection and certification activities will be upgraded based on operational learnings, with a crane runway span and elevation surveys.

FBC requires net incremental funding of $0.670 million for increases in maintenance tasks and major unit inspections, as described below.

- **Increased Maintenance Work:** $0.420 million related to an increase in dam and plant maintenance activities due to the condition of assets. Dam maintenance activities include vegetation removal, concrete sealing, intake gate testing and debris boom cleaning. Plant maintenance activities include condition assessments, auxiliary systems maintenance, plant air cooling system and a dewatering systems overhaul.
- **Major Unit Inspections**: $0.250 million related to additional inspection and maintenance tasks as required for units that have reached 20 years since their original upgrades under the Unit Life Extension (ULE) program.

2.3.4.5.3 VEGETATION MANAGEMENT

Tree and vegetation management activities relate to reducing the incidents of damage and related outages to the system resulting from trees and tree debris falling on the power lines and consist of costs to define the right of way perimeters, clear and maintain the right of ways and protect the system from danger trees by removing them. FBC performs these activities systematically to address vegetation that has the potential to grow into or fall and strike FBC's powerlines.

Tree contacts are one of the main causes of outages on FBC's system and can pose a risk to the public, resulting in injury or death. In some cases, tree contacts can result in the ignition of a wildfire. Tree related outages often occur in areas that are difficult to access, which means it can be challenging and time consuming to remove the tree and/or repair the damage. This causes increased outage hours, as well as increased costs to react to the unplanned outage.

The required activities are critical to the safe and reliable operation of FBC's system and have a direct impact on FBC's service quality (i.e., SAIDI and SAIFI). Following is a discussion of the requested net incremental funding for Vegetation Management activities.

- **Trimming and Clearing:** Trimming refers to a person, typically in an aerial lift device or climbing the tree itself, cutting a tree back from the powerline. Clearing typically refers to clearing vegetation under the powerlines from the ground. With a changing climate, there is unpredictable growth in trees and ground vegetation around the distribution and transmission power lines, such as additional growth in areas with increased rainfall. This has increased the number of tree contacts with power lines, causing customer outages and increasing the risk of possible subsequent fires. To mitigate this risk and ensure safety and reliability, FBC has recently changed its trimming standards, resulting in FBC increasing the horizontal and vertical clearance requirements to the powerlines. This has increased the number of trimming and clearing activities and their related costs, and FBC therefore requires $0.320 million in net incremental funding.

- **Hazard Tree Removal:** A hazard tree is a tree that is dead or in decline and as a result, poses a risk to the powerline. Climate change is increasing wildfire risk. Longer, drier spells combined with rapid climate changes have increased the numbers of trees in distress, which increases the risk of trees falling on powerlines, resulting in fires and outages. Climate change is also negatively affecting tree growth rates, mortality rates and overall tree health with higher instances of root rot. All these factors have increased the number of tree contacts with powerlines, thus requiring FBC to remove more hazard trees resulting in higher costs. FBC accordingly requires $0.158 million in net incremental funding for these activities.

2.3.4.5.4 WORKFORCE DEVELOPMENT

For the same reasons described in Section C2.2.4.5.2, FBC requires net incremental funding to support the development of its workforce.

The $0.260 million net incremental funding will provide two additional positions for recruitment and employee training, and support employment contracts with Indigenous Nations. This includes establishing corporate employee training and leadership development program(s) to support business areas across the organization with skills development to meet changing business needs and talent and succession planning requirements. Additionally, programs will be established to meet FBC multi-year workforce agreements with Indigenous communities and the PAR targets through a proactive implementation plan to engage underrepresented groups with respect to career opportunities at FBC. Examples include creating a summer student program, job shadowing, site tours, and an Indigenous Management Training program.

Additionally, FBC requires the net incremental funding to provide support for the continued increases in retirements and staffing for projects. Since 2020, there has been a steady increase in total attrition, particularly regarding retirements and voluntary terminations. There has been increased turnover of FBC voluntary exits, from 2.4 percent in 2020 to 6 percent in 2023, and increasing retirements from 1.7 percent in 2020 to 3.1 percent in 2023. The increased retirements require knowledge transfer to build up successors.

Also, the net incremental funding supports the increasing volume of recruitment and employee movements. Recruitment volumes have steadily increased since 2018, a 15 percent increase in 2023 compared to when the 2020-2024 MRP Application was developed. Recruitments include new jobs and replacements. Although new jobs remained consistent over the Current MRP term, replacements have increased by 23 percent, while the staffing for Talent Acquisition has remained the same over the same period.

2.4 FORMULA O&M DETERMINATION DURING THE TERM OF THE RATE FRAMEWORK

Similar to the Current MRP, the rates for both FEI and FBC in each year during the term of the Rate Framework will reflect the recovery of both index-based O&M and forecast O&M. The annual index-based O&M will be calculated based on the previous year's Unit Cost O&M (UCOM), which is defined as the Base O&M per customer count, escalated by the inflation factor less the productivity factor, and multiplied by a forecast of the average number of customers for the test year. For forecast/flow-through O&M, the Companies will continue to forecast certain O&M expenditures annually, with variances between forecast and actual amounts recorded in deferral accounts. Please refer to Section C2.5 for further discussion of the proposed forecast O&M items.

The starting UCOM (i.e., 2024 UCOM) for FEI and FBC will be calculated using the 2024 Base O&M as set out in Sections C2.2.1 and Section C2.3.1, respectively, and divided by the 2024 average number of customers (calculated as the 12-month average of the number of customers) of FEI and FBC at the time of the Annual Reviews for setting 2025 rates. As an example, using the 2024 Approved average number of customers for FEI[89] and FBC,[90] the 2024 UCOM would be $279 per customer and $503 per customer for FEI and FBC, respectively.

The UCOM is then escalated using the I – X indexing approach (inflation less productivity) in each year during the term of the Rate Framework. The inflation factors that FortisBC proposes to use are described in Section C1.3 and the productivity or X factors that FortisBC proposes to use are described in Section C1.4.

In summary, each year's indexed-based O&M is determined by applying an indexing factor to the previous year's UCOM and then multiplying by a forecast of the average number of customers, expressed as follows:

$$\mathrm{OM}_t = UCOM_{t-1} \times (1 + (I - \mathrm{X})) \times \mathrm{AC}_t + TUp_{t-2}$$

Where: *OM = Indexed-based Operating and Maintenance Expense*
UCOM = Unit Cost O&M
t = Forecast Year
I = Inflation Factor
X = Productivity Factor
AC = Average Number of Customers
TUp = True-up

Consistent with the Current MRP, FEI and FBC will each forecast the average number of customers for the rate-making year as part of the Annual Review process and will continue to include a true-up to the indexed-based O&M based on the actual average number of customers

[89] 2024 Forecast provided in the FEI Annual Review for 2024 Delivery Rates, approved by Order G-334-23. The 2024 Forecast average number of customers was 1,089,371.

[90] 2024 Forecast provided in the FBC Annual Review for 2024 Rates, approved by Order G-340-23. The 2024 Forecast average number of customers was 152,006.

from two years prior. This growth factor true-up process, as discussed in Section C1.5.3, will recover from or return to customers any O&M variance caused by a difference between the forecast and actual average number of customers, thus mitigating any forecast variances during the Rate Framework term.

2.5 FORECAST O&M

During the Current MRP term, FEI and FBC were approved to forecast certain O&M expenses annually, with the variances between forecast and actual amounts recorded in deferral accounts. These expenses are not included in the index-based O&M and the forecasts are updated as part of the Annual Reviews.

The Companies have reviewed the existing forecast O&M items and believe that the currently approved treatment continues to be appropriate. As stated by the BCUC in the MRP Decision, these categories of costs are not conducive to being included in an index-based O&M formula because they are either tied to parts of the business that are changing in response to government policy or are otherwise outside the control of management.[91] Accordingly, the Companies propose to continue to treat the following items as forecast/flow-through O&M:

- Pension and OPEB expenses (FEI and FBC);
- Insurance premiums (FEI and FBC);
- BCUC levies (FEI and FBC);
- Integrity digs (FEI only); and
- Clean Growth Initiatives (FEI and FBC): This category of O&M expenditures supports the Companies' investments in a clean growth future, and currently include initiatives in FEI's NGT stations and tankers, FEI's renewable and low carbon gas initiatives (biomethane service and renewable gas development), FEI's variable LNG production, and FBC's EV DCFC service. Over the term of the Rate Framework, either FEI or FBC may propose to include other new Clean Growth Initiatives in alignment with government policy (e.g., costs related to methane emission mitigation, as further described in Section C3.3.4.1).

Over the term of the Rate Framework, the Companies may propose that new items that are not included in Base O&M should be forecast and subject to approval through the Annual Review process, such as new Clean Growth Initiatives or incremental O&M arising from approved Major Projects.

In addition to the currently approved items described above, FEI and FBC are each proposing one new item to be treated as forecast/flow-through O&M during the Rate Framework term. These are discussed in the following subsections.

[91] MRP Decision, p. 119.

2.5.1 Meter Reading and Other O&M Costs for the AMI Project (FEI)

As discussed in Section B2.2.2.2.1, FEI is proposing that its O&M costs impacted by the AMI project be removed from formula O&M and instead be treated as flow-through O&M. These costs include Meter Installation, Meter Reading, Operations, Customer Service, and Meter Shop O&M costs. FEI proposes to forecast these costs in each Annual Review and provide a discussion of its expectations for the costs for the coming year, with variances between forecast and actual costs recorded in the Flow-through deferral account and returned to or recovered from customers in subsequent years. This treatment will result in customers paying only the actual costs incurred, which is consistent with the approved treatment of CPCN expenditures.

2.5.2 MRS Audit and Assessment Report Costs (FBC)

FBC is proposing to treat two specific types of MRS costs as forecast (flow-through) O&M starting in 2025: (1) costs associated with the triennial MRS audit; and (2) incremental costs associated with MRS Assessment Reports.

2.5.2.1 MRS Audits

Every three years, the administrator of the BC MRS Program – the Western Electricity Coordinating Council (WECC) performs an audit on FBC. The audits include a review, at minimum, of all applicable reliability standards identified in the Actively Monitored List. In the past, FBC has requested a new deferral account at the time of each MRS audit and has been approved to record the audit costs in this deferral account. These costs are then amortized over three years into customer rates.

For example, the triennial MRS audit is occurring in 2024, and FBC was approved as part of the Annual Review for 2024 Rates Decision to record the audit costs in a new deferral account. As part of the decision, the BCUC stated the following:[92]

> The Panel notes that the 2024 MRS audit will be the fifth audit since the introduction of the MRS audit process in 2021, and since these costs are now recurring in nature, it is timely for FBC to now review its forecasting methodology for MRS costs. Accordingly, we encourage FBC to consider whether flow-through treatment of these costs continues to be appropriate as part of its next rates application.

FBC clarifies that while the MRS audit costs have historically been trued up to actuals through the use of deferral accounts, they have not been treated as forecast (flow-through) expenses, which is why FBC has been applying for a new deferral account to record these costs every three years.

FBC considered alternative treatments for the MRS audit costs, including potentially including the costs in the index-based O&M, which would require an adjustment to the 2024 Base O&M.

[92] FBC Annual Review for 2024 Rates Decision and Order G-340-23, p. 19.

However, as the MRS audit costs are expected to occur only once over the term of the three-year Rate Framework (i.e., in 2027), FBC did not consider that setting an annualized amount to include in the Base O&M would be the best approach, as the costs would be included in O&M prior to when they would occur and would be subsequently escalated by inflation and customer growth each year. Therefore, the timing of when the costs are incurred and when they are recovered from customers would not be well matched.

However, FBC acknowledges that applying for a new deferral account every three years is somewhat inefficient, particularly given the regularity and predictability of the timing of the audits. FBC therefore proposes to forecast the MRS audit costs in the year they are expected to be incurred and include the forecast in the Annual Review (i.e., the Annual Review for 2027 Rates). This will allow for the costs to be reviewed by the BCUC and interveners, will increase efficiency by avoiding the creation of a new deferral account, and will allow the costs to be matched with the expected timing of the audit. Similar to other flow-through costs, FBC proposes that the variances between forecast and actual costs be recorded in the Flow-through deferral account.

2.5.2.2 MRS Assessment Report Costs

During both the 2014-2019 PBR Plan and the Current MRP terms, incremental O&M and capital costs related to MRS Assessment Reports (ARs) have been treated as exogenous factors. The most recent MRS AR which was approved for exogenous factor treatment was AR13, which was approved in the FBC Annual Review for 2022 Rates Decision and Order G-374-21. Once exogenous factor treatment is approved, FBC records the actual incremental costs in the Flow-through deferral account. For ongoing incremental costs resulting from the MRS ARs, FBC has historically been approved to continue to forecast those costs outside of indexed-based O&M (or Regular capital) until the conclusion of the multi-year rate plan term. FBC has then applied to include the ongoing incremental costs into the new Base O&M (or the Regular capital forecasts).

In the 2020-2024 MRP Application, FBC applied to change the treatment of the MRS AR costs from exogenous factor to flow-through (forecast); however, the BCUC denied this request, stating that continuing with exogenous factor treatment would still allow FBC to recover costs that have been reviewed and approved by the BCUC.[93]

While FBC agrees that the exogenous factor provides the Company with the ability to seek recovery of the MRS AR costs, FBC considers this approach to be somewhat inefficient and to result in essentially the same treatment of the costs that would occur if they were approved to be forecast in O&M when new assessment reports are issued. Ultimately, whether treated as exogenous or as forecast (flow-through), the costs will be forecast outside of index-based O&M and will be trued up through the Flow-through deferral account. Given that new assessment reports will continue to occur, it is more appropriate and efficient to treat the related costs along with other regularly occurring forecast/flow-through O&M (or capital). While FBC appreciates that if treated as exogenous factors, the costs will be subject to the materiality threshold, due to the impact of the requirements resulting from the MRS assessment reports, the incremental costs

[93] MRP Decision, page 75.

typically exceed the materiality threshold. Moreover, these are mandatory costs for FBC that are outside management's control and, therefore, in principle these MRS costs should be recovered in rates and not subject to a materiality threshold.

Therefore, FBC proposes to treat the incremental MRS assessment report costs as forecast (flow-through) O&M (or capital) during the term of the Rate Framework. Given that the assessment reports occur at varying intervals, FBC notes that none or multiple reports may be issued during the term of the Rate Framework.

2.6 *CONCLUSION*

During the term of the Current MRP, FortisBC has prioritized and managed its overall O&M expenditures, delivering savings of $28.0 million[94] and $11.8 million[95] to FEI and FBC customers, respectively. The cost benchmark analysis performed by Dr. Kaufmann in Appendix C1-1 demonstrates that both Companies are performing efficiently. Specifically, when comparing average O&M costs per customer against industry peers, FEI performed slightly better than the average (i.e., 0.2 percent better than the average), while FBC performed significantly better than the average (i.e., 35.0 percent better than the average). Further, when considering FortisBC's productivity under multi-year rate plans since 2014, Dr. Kaufmann's analysis shows that FEI and FBC have exceeded industry norms, generating significant cost savings for customers.

For the Rate Framework, both FEI and FBC established the 2024 Base O&M using the same method used to establish the 2019 Base O&M in the Current MRP, which was approved by Orders G-165-20 and G-166-20. Starting with 2023 Actual expenditures passes savings onto customers ($4.322 million and $4.235 million to FEI and FBC customers, respectively) before considering necessary adjustments and net incremental funding necessary to address new and incremental requirements over the term of the Rate Framework.

Both FEI and FBC require incremental funding to meet new and incremental requirements, particularly in the areas driven by the energy transition, increasing physical and cyber security risks, and Indigenous relations and reconciliation. FEI and FBC propose net incremental funding of $9.901 million and $5.681 million, respectively, to meet these requirements.

Finally, FEI and FBC propose to continue with an annual forecast of certain O&M expenses, with the variances between forecast and actual amounts recorded in deferral accounts. This treatment remains appropriate as this category of costs is not conducive to being included in an index-based O&M formula because they are either tied to parts of the business that are changing in response to government policy or are otherwise outside the control of management.

[94] Section B2.2.2.2, Table B2-8.
[95] Section B2.2.2.2, Table B2-9.

3. CAPITAL EXPENDITURES

3.1 *INTRODUCTION*

The Companies' capital expenditures are required to maintain the safety, reliability and integrity of the gas and electric facilities used to provide service to customers, respond to the information needs and inquiries of customers, and to provide the information and systems necessary to support the business.

FortisBC's capital expenditures fall under two main categories: (1) Major Projects; and (2) Regular capital.

Major Projects are capital expenditures that do not form part of the Regular capital spending and are typically reviewed by the BCUC through a separate process, such as through applications for a certificate of public convenience and necessity (CPCN) under section 45 of the UCA, or through applications for acceptance of expenditure schedules under section 44.2 of the UCA. FEI's and FBC's Major Projects are discussed further in Sections C3.3.6 and C3.4.6, respectively.

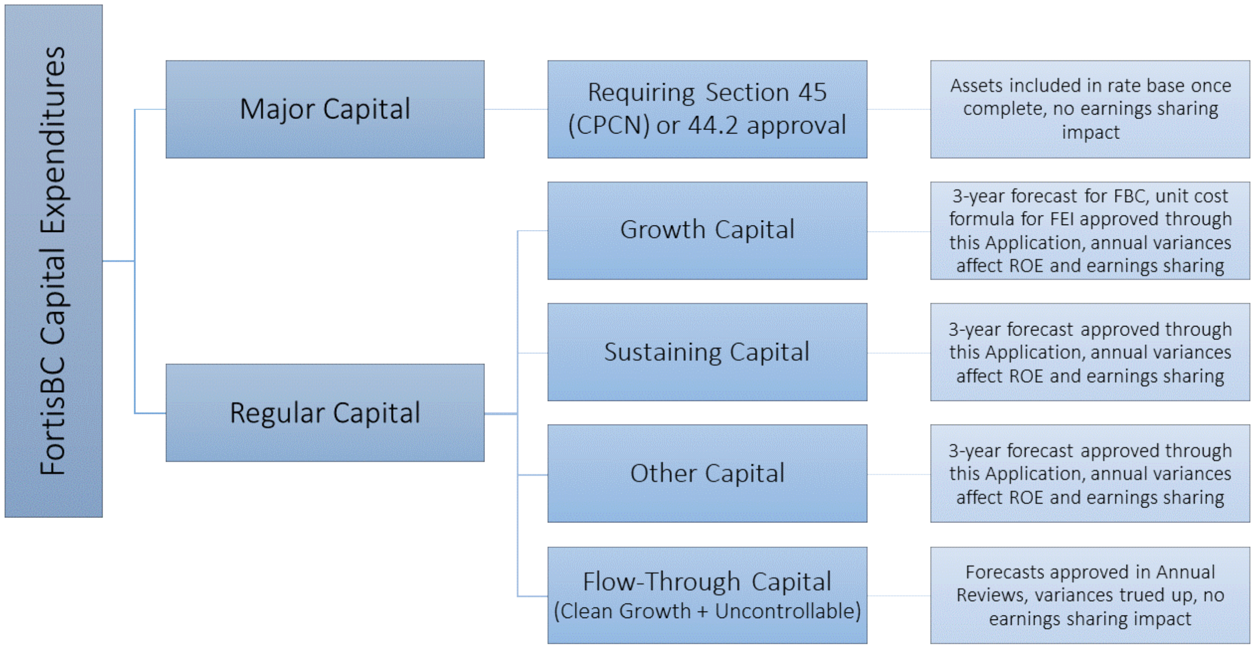
Regular capital expenditures include Growth, Sustainment and Other capital, as well as Flow-through capital.

Consistent with the Current MRP, FEI's and FBC's Regular capital expenditures are divided into the following categories:

- **Growth capital:** For FEI, this consists of expenditures for the installation of new mains, services, meters, and distribution system improvements to support customer additions. For FBC, this consists of expenditures for infrastructure required to meet demand for new customers and/or load growth.
- **Sustainment capital:** For FEI, this consists of expenditures for meter exchange programs, replacements and upgrades to the distribution and transmission systems related to safety, integrity and reliability, and expenditures for mains and service renewals and alterations. For FBC, this consists of expenditures for system reinforcements, asset replacements, and upgrades to the generation, transmission, stations, and distribution assets, to ensure safety, integrity and reliability.
- **Other capital:** For both FEI and FBC, this consists of expenditures for IS, equipment (including fleet vehicles), and facilities.
- **Flow-through capital:** For both FEI and FBC, this consists of expenditures that are forecast annually as part of the Annual Review process, such as Clean Growth Initiatives.

The following diagram illustrates the categories of FortisBC's capital expenditures and their treatment.

Figure C3-1: Categories of Capital Expenditures and Treatment



In the sections below, FortisBC outlines its capital planning processes, discusses the Companies' capital expenditures during the Current MRP term, and provides forecasts of capital expenditures over the 2025-2027 period and the proposed formula for FEI's Growth capital portfolio. FortisBC also provides a discussion of anticipated Flow-through capital expenditures and anticipated Major Projects.

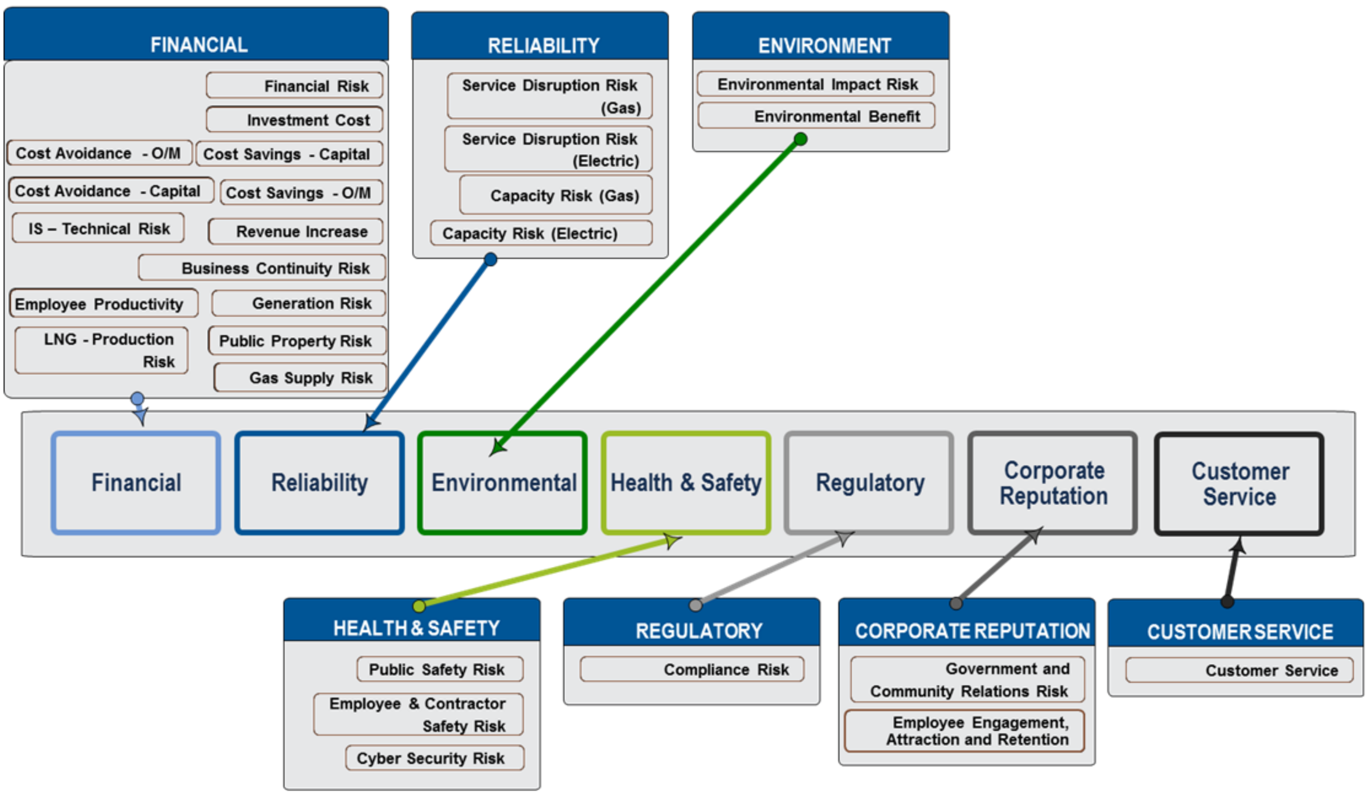
3.2 *CAPITAL PLANNING PROCESS*

FortisBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and provide value to its customers. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some flexibility in timing. This is done with the understanding that conditions change, and the plan must be capable of adapting. This plan flexibility allows FortisBC to manage and execute normal levels of unforeseen urgent work that come up throughout the year within the resource and budget constraints of the capital plan. This planning process applies to FEI and FBC Sustainment and FBC Growth capital planning, whereas Growth capital planning specific to FEI is addressed through a separate process further discussed in Section C3.3.1.

FortisBC has continued to use its asset investment planning (AIP) process which allows it to transparently communicate its decision-making to stakeholders and contributes to the goal of consistent decisions across asset classes. As part of the AIP process, FortisBC optimizes its capital portfolio using Copperleaf C55 software along with methodologies and processes that support the consistent quantification of benefits and risk mitigation associated with each proposed investment. To assign consistent values and weights to individual projects, FortisBC has developed standardized value framework guidelines for each type of project.

The foundation of the AIP tool is the value framework that is used to quantify the value of potential investments. The value framework is made up of seven overarching values: (1) financial; (2) reliability; (3) environmental; (4) health & safety; (5) regulatory; (6) corporate reputation; and (7) customer service. Under each value, there are measures that contribute to and impact each value. These measures, and which value they impact, are shown in Figure C3-2 and further described below.

Figure C3-2: Asset Investment Planning Value Framework Overview



The value that a capital investment contributes to each of these areas is calculated, taking into account the number of customers, employees or other stakeholders impacted, the magnitude of a potential event, the likelihood that an event will occur, the mitigating factors that are present and the impacts of time on risks and benefits. Once projects are evaluated using the value framework, the tool provides the ability to optimize the capital planning portfolio for a given period of time to achieve the greatest benefit within a set of financial and/or resource constraints.

The AIP process and tool supports risk-informed decision-making in capital planning by quantitatively valuing investments through a value framework that is common to all asset classes. FortisBC actively manages the planning and execution of its capital plan to achieve value for customers. For example:

- During the planning stages of capital projects, FortisBC bundles work that is at a common location or that is similar in nature to save on mobilization costs and material purchasing costs;
- Where possible, FortisBC develops standardized designs to save on material purchases, spare parts, and to reduce training needs and improve efficiency of the workforce;
- FortisBC uses a contracting strategy that reduces overall costs by leveraging a flexible workforce that is scalable and able to move to where the work is needed and when it is needed;
- FortisBC prioritizes projects and programs to allow for early engineering and design, procurement of materials and equipment, and comprehensive pre-job planning; and
- FortisBC works closely with municipalities in its operating territories to coordinate planned capital work to minimize project costs and disruption to the public, including (in some cases) negotiating municipal operating agreements to bring cost certainty and improve working relationships.

While efficiencies and cost savings continue to be a focus, FortisBC can experience pressures due to a variety of factors which are outside the Company's control, recent examples being the COVID-19 pandemic, supply chain issues and inflationary increases, among others.

3.2.1 Additional Capital Planning Considerations

The AIP process discussed above remains the foundation for FortisBC's capital planning process. In recent years, additional factors have had an increasing impact on the development of capital plans in the utility landscape, including:

- Specific considerations that the energy transition brings to growth and capacity projects;
- The influence of climate change on climate adaptation planning; and
- Increasing challenges in securing land for project siting.

Each of these is described further below.

3.2.1.1 Energy Transition

The energy transition impacts on capital planning differ for FEI and FBC. For FEI, given the uncertainty over future gas demand levels driven by climate policy, capacity driven projects have been reviewed to ensure they meet the needs of the shorter-term system demand forecast. While the need for an upgrade is determined through normal capacity planning processes, FEI has reviewed the size of the upgrade (length/size of system improvement or capacity of station) with a view to shorter timelines. Typically, a longer-term capacity forecast (20 years) is utilized to ensure any upgrades can address the requirements of the system without having to upgrade again in the near future, with the goal of ensuring investments are as efficient as possible and costs are minimized. With the development of this capital plan, and with the recent pressures of decarbonization and electrification in local communities, FEI has reviewed the proposed capacity driven projects to assess if they can be re-scoped into multiple smaller capacity upgrades so that FEI can proceed with only the portions that meet the underlying need for the near term. FEI expects this process to be iterative over the coming years.

For FBC, the energy transition is expected to increase demand across the service territory. With growth driven by electrification and building code changes as well as the growing adoption of electric vehicles, FBC is working to better understand the potential impacts on its existing system and is in the process of identifying and planning for investments to support the continued growth in demand for new load.

3.2.1.2 Climate Change Adaptation

The environment and the changing climate are important considerations for FortisBC in evaluating necessary investments for new and existing assets. As discussed in Section B1, FortisBC is developing a Climate Change Operational Adaptation Plan to ensure the appropriate consideration is given to the increased risk of natural hazards in each of its service territories. Compliance with regulations concerning the environment has also driven necessary climate change related investments across FEI's system. Further, the need for improved measurement of GHG emissions in advance of any future regulation changes to ensure there is sufficient planning for any asset modifications has resulted in necessary capital expenditures.

3.2.1.3 Land Acquisition

Land acquisition has proven to be a larger challenge and consideration for FortisBC. When new land is required as part of an investment, alternative property locations are reviewed as part of the normal planning process. However, it has become increasingly difficult to procure land in a timely manner to support the execution of projects based on their forecast need. In some cases, FortisBC is needing to complete detailed reviews for dozens of property locations for single investments and it is taking years to engage with property owners, Indigenous communities, municipalities, and regional districts as well as negotiate agreements. Detailed design for these investments cannot be finalized in the meantime as they are dependent on specific property locations. This is creating inflationary pressures and increasing durations to allow for sufficient project planning.

As one of the fastest growing cities in Canada, Kelowna (and/or the surrounding area) requires new substations to accommodate this growth. Land acquisition in the City of Kelowna is becoming a significant challenge for FBC, making it difficult to procure land in a timely manner to support the execution of projects. Accordingly, during the Rate Framework term, FBC will begin the early evaluation of alternative property locations as part of the planning process for new substations and to support the timely acquisition of land.

3.3 FEI CAPITAL EXPENDITURES

Table C3-1 below provides FEI's gross capital expenditures (before Contributions in Aid of Construction or CIAC) for the term of the Current MRP. The 2020 through 2023 expenditures are actual; the 2024 expenditures are projected.

Table C3-1: FEI Actual and Projected Regular Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Growth Capital	85,336	91,505	106,848	117,538	114,826
Sustainment Capital	112,405	115,763	124,653	129,588	130,628
Other Capital	50,745	50,246	46,560	54,312	53,194
Total Regular Capital (Gross)	**248,486**	**257,514**	**278,060**	**301,438**	**298,648**

In this Application, FEI is seeking approval of the level of Regular Sustainment and Other capital expenditures to be incorporated in rates over the years 2025 to 2027, and approval of the method to be used to incorporate Growth capital expenditures into rates over the same time period.

Table C3-2 below summarizes the Approved and Forecast expenditures for gross Regular capital for FEI. The amounts shown in the years 2025 through 2027 for Growth capital have been calculated under the Growth capital formula using the Approved 2024 net inflation factor and an illustrative forecast of Gross Customer Additions for each year.

Table C3-2: FEI Approved and Forecast Regular Capital Expenditures 2020-2024 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Growth Capital	87,531	54,686	86,567	67,763	59,883
Sustainment Capital	129,336	130,628	125,599	131,733	125,484
Other Capital	54,514	51,252	67,904	62,696	61,213
Total Regular Capital (Gross)	**271,381**	**236,566**	**280,069**	**262,192**	**246,580**

The Regular capital expenditures are discussed below in terms of Growth (Section C3.3.1), Sustainment (Section C3.3.2), and Other capital (Section C3.3.3), with explanation provided for any project that is forecast to exceed $2 million. The Regular Flow-through capital categories are also discussed in Section C3.3.4.

3.3.1 FEI Growth Capital

FEI's Growth capital expenditures consist of the installation of new mains, services and meters necessary to attach new customers to the gas distribution system, as well as distribution pressure (DP) system improvements required when the capacity of the gas distribution system at a specific service location is insufficient to meet an adequate level of inlet pressure to ensure reliable service to customers.

Under the Current MRP, FEI's Growth capital expenditures are set based on an indexing formula using a unit cost approach escalated each year by the inflation factor less the approved productivity improvement factor (X-Factor), as discussed in Sections C1.3 and C1.4 respectively, and multiplied by a forecast of gross customer additions plus a true-up for the variances between prior years' forecast and actual gross customer additions. The following equation illustrates the formula used to determine Growth capital (GC):

$$GC_t = UCGC_{t-1} \times (1 + (I - X)) \times GCA_t + TUp_{t-2}$$

Where: GCA= Gross Customer Additions
UCGC = Unit Cost Growth Capital
I = Inflation Factor
X = Productivity Improvement Factor
t = Forecast year
TUp = True-up

3.3.1.1 FEI Growth Capital During the Current MRP Term

Growth capital expenditures, both in total and on a per customer basis, for mains, services, meters, DP system improvements, and growth-related CIAC for 2020 to 2024 are summarized in the table below.

Table C3-3: FEI Growth Capital Expenditures and UCGC 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
New Customer Mains	29,699	25,637	39,301	38,398	35,611
New Customer Services	49,794	58,291	58,819	60,376	54,127
New Customer Meters	4,690	4,125	4,011	4,287	2,840
System Improvements (DP)	1,153	3,452	4,718	14,477	22,248
Total Growth Capital (Gross)	**85,336**	**91,505**	**106,848**	**117,538**	**114,826**
CIAC	(1,791)	(1,719)	(1,850)	(1,688)	(1,252)
Total Growth Capital (Net)	**83,545**	**89,786**	**104,998**	**115,850**	**113,574**
Gross Customer Additions	18,890	20,344	16,589	15,608	11,765
Acrtual Unit Costs, Net (UCGC)	**4,423**	**4,413**	**6,329**	**7,422**	**9,654**

As shown in the above table, although the number of Gross Customer Additions has declined since 2021, the unit costs have been increasing. The key drivers of the increase in Growth capital unit costs include:

- Unprecedented inflationary increases;
- Increased complexity of mains installations, primarily associated with higher density dwellings and in developing areas;

- Increased municipal restrictions and permitting requirements for installation of mains; and
- A higher number of DP system improvements.

Each of these cost drivers, as well as mitigation efforts that FEI has undertaken during the Current MRP term, are described below.

3.3.1.1.1 SIGNIFICANT INFLATIONARY PRESSURES

Table C3-3 above shows that the unit cost growth capital (UCGC) was relatively stable in 2020 and 2021 but started to increase significantly in 2022 and 2023. This trend coincided with significant global market events that occurred, including the recovery from the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events significantly increased market prices of many commodities and services that make up FEI's supply chain and did so in a sustained way, such that these inflated prices for commodities and services remained at this high level into 2024. The impact on FEI's Growth capital has been similar to what has been experienced in FEI's Sustainment capital portfolio and by other utilities in North America over the same period. As discussed in FEI's Annual Review for 2023 Delivery Rates, gas utilities across North America saw an average escalation of 31.2 percent in capital costs between the first quarter of 2020 and the first quarter of 2022. As part of the Annual Review for 2023 Delivery Rates Decision and Order G-352-22, FEI received approval of increases to its Sustainment capital forecasts for 2023 and 2024 to reflect these cost pressures.

As also identified in FEI's Annual Review for 2023 Delivery Rates,[96] one contributor to the inflationary increases for Growth capital, and to a lesser extent Sustainment capital, was that FEI's Mains and Services (M&S) construction contracts expired at the end of 2021. As a result of the contracts expiring, FEI engaged in a competitive bidding process for new contractors and implemented a new contracting strategy utilizing more contractors, increasing the total number of contractors from two in 2019 to five in 2022. Despite a competitive bidding process and this new contracting strategy, all new contracts put in place in 2022 had higher rates than the previous contracts, reflecting the significant inflationary pressures being experienced in the industry. The higher rates in the new M&S construction contracts contributed to the significant increase in the unit costs for FEI's capital. FEI notes that the contracts put in place in 2022 will expire by the end of 2024. FEI is currently working on renewing these contracts with the goal of renewing them to 2027, coinciding with the end of the Rate Framework term. This should provide a more stable contractor environment for FEI's capital program for the coming three years.

3.3.1.1.2 INCREASE IN COMPLEXITY OF MAINS INSTALLATIONS

Another factor that contributed to the higher unit cost of Growth capital is the increasing complexity of mains installations.

There are many factors that led to increased complexity in main installations, including evolving government policy and the continuing market shift towards high density dwellings such as

[96] Pages 59-60 and Footnote 43.

townhomes and high-rises in place of single-family dwellings, which led to more challenging permit requirements and more complex installations. For example, main installations for high-density dwellings require a larger main pipe size diameter to service a much more diverse load profile. In addition, FEI has been experiencing an increasing trend of mains requiring narrower and more challenging running lines during installation, as well as increasing underground utility congestion which requires additional coordination between utilities vying for limited space in smaller areas. All of these factors have increased the complexity of the work, resulting in higher unit costs.

3.3.1.1.3 INCREASE IN MUNICIPAL RESTRICTIONS AND PERMITTING REQUIREMENTS

During the Current MRP term, more road use permits have been required with increasing restrictions on working hours. This is due to local traffic impacts in densely populated areas, especially for high-density developments.

For example, it is now more common for FEI to incur additional costs due to night shift work imposed by a municipality with restrictions on day shift hours, or additional costs for redesigning alignment due to local municipality requests to reserve space for future possible city utilities. There are also additional costs due to requirements by the local municipality for full lane paving (as opposed to re-paving trench widths), greater asphalt thicknesses, and additional soil contamination testing and disposal.

Despite the increasing restrictions and permitting requirements, FEI continues to seek out cost-effective solutions and/or negotiate workaround solutions to minimize the additional costs.

3.3.1.1.4 INCREASE IN NUMBER OF DP SYSTEM IMPROVEMENTS

As more customers connect to FEI's system over time, especially large volume customers such as multi-family and high-density dwellings, DP system improvements in the localized area are required to ensure sufficient capacity is available for customers. The timing of each individual DP system improvement does not always fall in the same year as new customers attaching to FEI's system as it depends on the available system capacity in the localized region and the number of new customers attachments. FEI is experiencing an increased need for DP system improvements to support customer demand as the system has become more constrained over time.

3.3.1.2 FEI Growth Capital for the Rate Framework Term

With this Application, FEI proposes to continue with a unit cost approach to determining Growth capital, with re-basing of the starting UCGC amount.

FEI believes that the impact of significant global events, like the COVID-19 pandemic and supply chain issues that occurred during the term of the Current MRP, are now fully embedded in the cost structure. Given the shorter length of the Rate Framework, FEI considers that the formula approach based on unit costs and a forecast of gross customer additions with true-up for variances remains the most appropriate method to establish FEI's Growth capital spending envelope. Furthermore, since this approach will continue to be dependent on the number of gross customer additions, it will provide flexibility when establishing the amount of Growth capital funding each year during the ongoing energy transition. For example, if the number of gross customer additions remains stable, the formula approach will continue to provide a consistent level of Growth capital funding; however, if the number of gross customer additions declines during the three-year term, the formula approach will also reduce the Growth capital spending envelope while still allowing FEI to meet its obligation to connect new customers when requested to do so.

Any variances between actual Growth capital and the spending envelope provided by the Growth capital formula will result in variances in rate base, depreciation, financing, and taxes, which will all affect the Company's ROE and be subject to earnings sharing. As such, the formula approach will continue to incent FEI to improve on efficiency and identify potential savings in Growth capital related work.

The following subsections discuss re-basing of the starting unit cost of Growth capital for 2025.

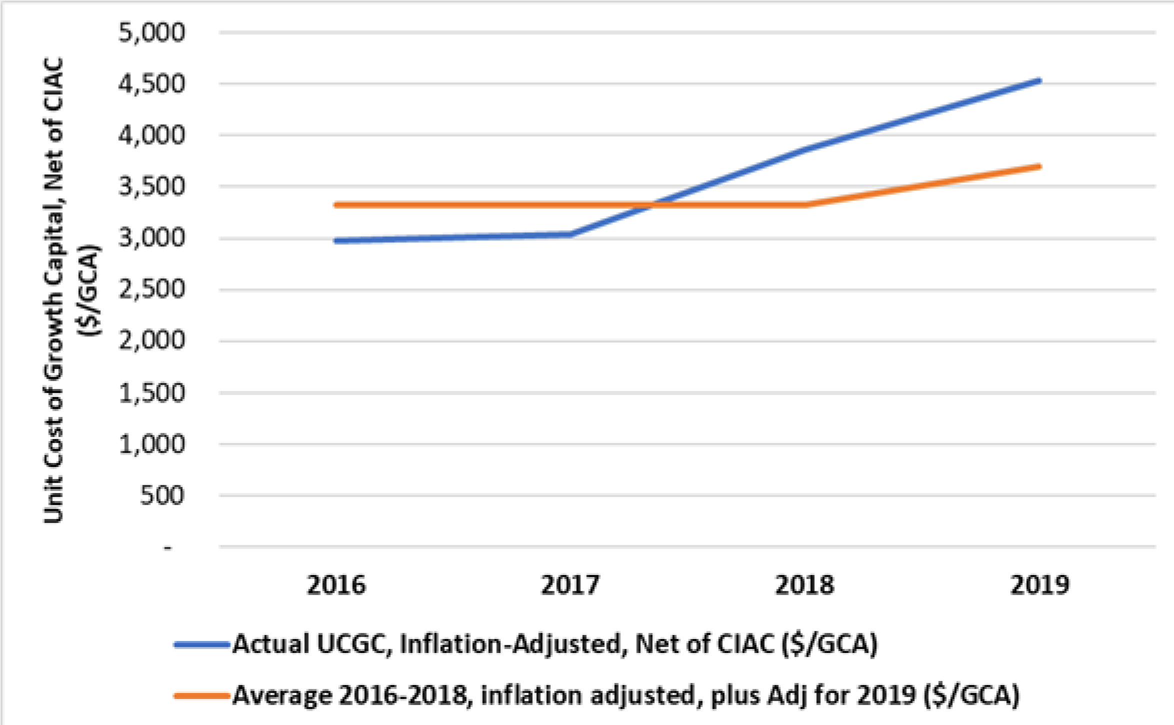
3.3.1.2.1 GROWTH CAPITAL BASE UNIT COST

Under the Current MRP, the starting base unit cost (i.e., 2019) was set based on the average of actual unit costs from 2016 to 2018 (inflation-adjusted to 2019 dollars) plus adjustments for 2019. However, the approved UCGC (net of CIAC) in the first year of the Current MRP (i.e., $3,789 in 2020) was already significantly less than the first year's actual UCGC (net of CIAC) of $4,423. Given that the formula for Growth capital is based on the approved prior year's unit cost, this shortfall in the first year carried on throughout the term of the Current MRP. Establishing a reasonable and sufficient starting base unit cost is critical to having a well-functioning Growth capital formula.

The main reason for the discrepancy in the UCGC at the beginning of the Current MRP term was because the starting base UCGC in 2019 was set using an average from 2016 to 2018 (inflation-adjusted to 2019 dollars) plus forecast adjustments for 2019. Using an average of the three years rather than an approach more closely aligned with the most recent unit cost (2019) significantly understated the starting UCGC. In fact, as shown in Figure C3-3 below, even with the forecast adjustment for 2019, the starting base UCGC in 2019 was already approximately 22 percent less than the actual UCGC in 2019 before the Current MRP term even started.[97]

[97] 2019 Actual UCGC = $4,530, whereas 2019 Base UCGC = $3,704 ($4,530 / $3,704 – 1 = 22%).

Figure C3-3: Comparison of FEI's 2016 to 2019 UCGC Actuals and Average



To avoid understating the starting base UCGC for the years 2025 to 2027, FEI proposes in this Rate Framework to calculate the starting Base 2024 UCGC by extrapolating from a linear regression of Actual UCGC between 2021 and 2023 (inflation-adjusted to 2024 dollars). Figure C3-4 below provides a comparison between the three-year regression approach and the previously used three-year average approach for setting the starting UCGC. The three-year regression approach allows for the growth trend in the UCGC over the recent years to be recognized. If FEI were to continue using the previous approach of a three-year average, the starting UCGC for 2024 would be $6,551 per GCA, which is significantly less than the actual UCGC in 2023. Given the recent increases in construction costs due to inflation and other factors as discussed above, FEI does not believe it is reasonable to assume that a starting UCGC that is less than the current level by approximately 15 percent[98] would provide a sufficient level of capital for attaching new customers. As previously explained, using a starting UCGC that already carries a significant shortfall even before the start of the Rate Framework will provide an insufficient level of Growth capital throughout the term.

Using the regression approach shown in Figure C3-4 below, the starting base UCGC for the Rate Framework would be $9,300 per GCA, which is comparable to the current 2024 Projected UCGC of $9,654 per GCA as shown in Table C3-3 above and would better account for the increase in construction costs in recent years.

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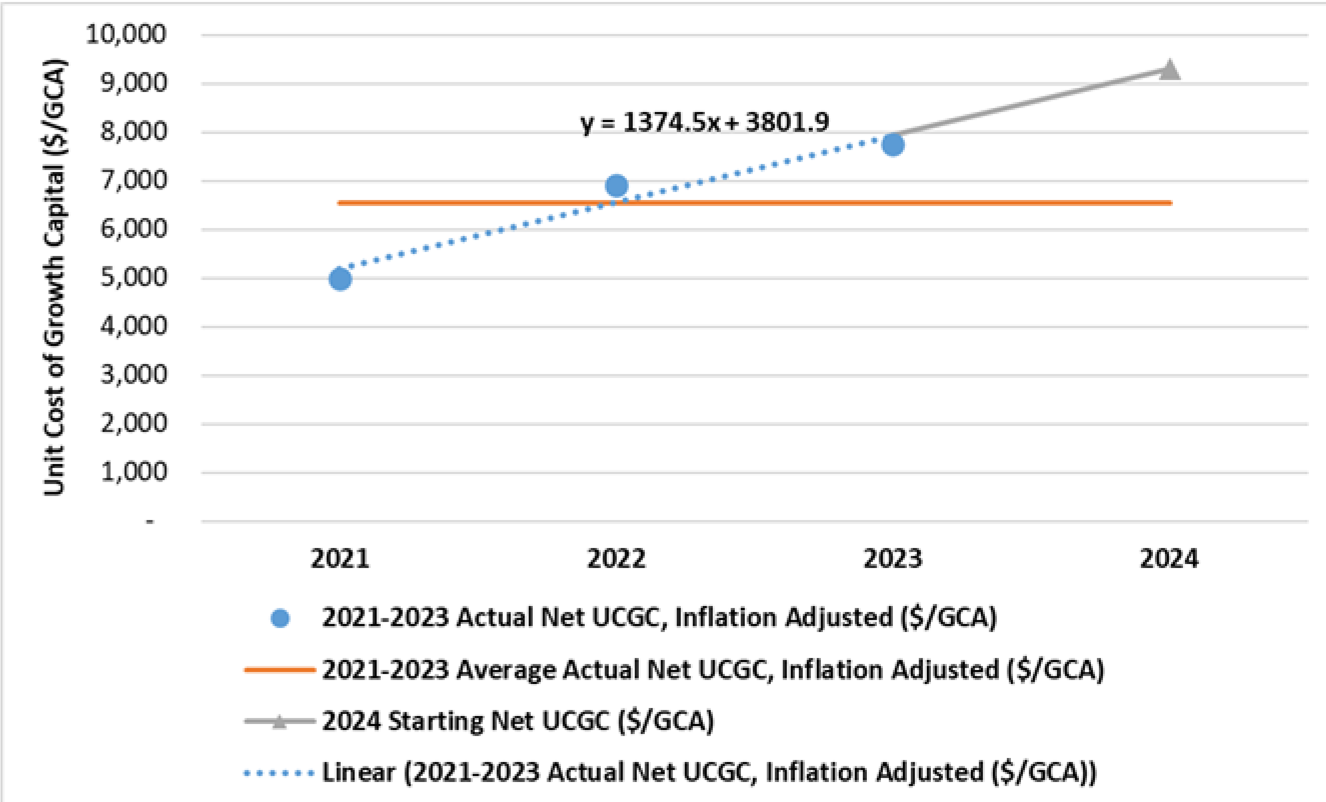
98 2023 Actual UCGC = $7,422 x (1 + 4.41%) = $7,750 in 2024 dollars, whereas the average of the Actual UCGC from 2021 to 2023 = $6,551 in 2024 dollars ($6,551 / $7,750 – 1 = -15%).

Figure C3-4: Comparison between Three-year Linear Regression Approach and Three-year Average Approach for Setting FEI's Starting Base UCGC



3.3.1.2.2 ILLUSTRATION OF 2025 TO 2027 GROWTH CAPITAL SPENDING ENVELOPE

Based on the proposed 2024 starting base UCGC of $9,300, Table C3-4 below provides an example of the calculation of FEI's formula-based Growth capital from 2025 to 2027 using the Approved 2024 net inflation factor and an illustrative forecast of Gross Customer Additions over the term of the Rate Framework. The forecast of Gross Customer Additions from 2025 to 2027 shown in Table C3-4 below assumes a decline in customer attachments from the 2024 Projected level given the current policy environment as discussed in Section B1 of this Application. FEI notes that these estimates are for illustration purposes only and not for the purpose of determining the Growth capital for 2025 to 2027, which will be determined in each year's Annual Review.

For comparison, FEI also provides an illustration of the Growth capital spending if the number of Gross Customer Additions remains at the 2024 Projected Gross Customer Additions of 11,765 shown in Table C3-3 above.

Table C3-4: Illustration of Range of FEI Growth Capital Expenditures 2025 to 2027

	2024	2025	2026	2027
Total Unit Cost Growth Capital $/GCA (Net of CIAC)	9,300	9,664	10,042	10,435
Net Inflation Factor		3.914%	3.914%	3.914%
GCA Forecast		8,700	6,500	5,500
Inflation Indexed Growth Capital ($000s)		84,077	65,273	57,393
Growth CIAC (2024 Approved)		2,490	2,490	2,490
Total Inflation Indexed Gross Growth Capital		**86,567**	**67,763**	**59,883**
GCA Forecast @ Current 2024 Projected Level		11,765	11,765	11,765
Inflation Indexed Growth Capital - GCA @ Current Level ($000s)		113,697	118,144	122,768
Growth CIAC (2024 Approved)		2,490	2,490	2,490
Total Inflation Indexed Gross Growth Capital - GCA @ Current Level		**116,187**	**120,634**	**125,258**

The formula approach provides FEI the flexibility needed to adjust Growth capital annually for changes in customer attachments, whether due to the energy transition or other factors.

3.3.1.3 FEI Growth Capital Summary

The proposed formula and base unit cost for FEI's Growth capital is intended to provide funding for the Company to make the capital investments necessary to add customers that request service, while allowing a fair and balanced recovery of the costs.

During the Current MRP term, FEI experienced significant cost pressures in Growth capital, primarily due to unanticipated inflationary pressures since 2021 which also included contractor price increases in 2022, increasing complexity in mains and services installation, evolving local government restrictions and permitting requirements, and a higher number of system improvements. However, FEI expects the Growth capital cost increases will track more closely to general inflation over the three-year term of the Rate Framework.

With the expectation of a more stable Growth capital environment, FEI proposes to continue with the existing formula-based, unit cost approach to determining Growth capital. The formula approach will continue to allow expenditures to vary based on customer growth while maintaining accountability for expenditures to attach new customers based on the unit cost.

3.3.2 FEI Sustainment Capital

The expenditures within Sustainment capital include gas system improvements to transmission and distribution assets to ensure the continued safety, reliability, and integrity of the system. Sustainment capital includes expenditures for meter recall programs, replacements and upgrades to the distribution and transmission systems, and expenditures for mains and service renewals and alterations.

Sustainment capital is further classified into four categories of expenditures. Table C3-5 below summarizes the actual expenditures from 2020 to 2023 and the projected 2024 expenditures.

Table C3-5: FEI Actual and Projected Sustainment Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Customer Measurement	30,398	32,182	29,006	27,671	30,494
Transmission System Relilability & Integrity	34,963	38,251	47,168	50,534	49,573
Distribution System Reliability	14,022	13,464	15,848	19,660	17,709
Distribution System Integrity	33,023	31,866	32,630	31,723	32,852
Total Sustainment Capital (Gross)	**112,405**	**115,763**	**124,653**	**129,588**	**130,628**
Sustainment CIAC	(4,879)	(4,771)	(4,547)	(8,139)	(5,065)
Total Sustainment Capital (Net)	**107,527**	**110,992**	**120,106**	**121,449**	**125,563**

As discussed during the Annual Review for 2023 Delivery Rates and in Section C3.3.1.1 above, FEI has experienced pressures during the Current MRP term due to a variety of external factors, including the COVID-19 pandemic, supply chain issues, significant inflationary increases, and the war in Ukraine, among others.

The drivers of the increases in the Sustainment capital portfolios discussed in the Annual Review for 2023 Delivery Rates are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel; and
- Alteration activities driven by various large third-party infrastructure upgrade projects that have received funding from various levels of government as part of the COVID-19 pandemic economic recovery efforts.

FEI successfully implemented a number of mitigation strategies to limit the impact of cost pressures, thus allowing FEI to manage the overall cost increases. These mitigation strategies included:

- Reprioritizing projects, or components of a project (e.g., final paving) that could be safely re-scheduled to accommodate other project cost increases that could not be deferred. While FEI has delayed some work with flexible timing to accommodate the increased capital demands, this has only mitigated part of the capital pressures due to the magnitude of market and other pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, due to the magnitude of the overall inflationary pressure experienced by the North American gas utility industry, FEI was not able to fully mitigate the cost increases.

Table C3-6 below summarizes FEI's forecast Sustainment capital expenditures required over the 2025 to 2027 Rate Framework term, along with the 2023 and 2024 Approved amounts for comparison. FEI notes that it will realize a large reduction in the Customer Measurement portfolio starting in 2025 due to the deployment of the AMI project.

Table C3-6: FEI Approved and Forecast Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Customer Measurement	30,015	30,494	14,295	13,459	13,422
Transmission System Relilability & Integrity	47,937	49,573	60,065	75,133	66,469
Distribution System Reliability	15,341	17,709	21,245	17,254	9,237
Distribution System Integrity	36,043	32,852	29,993	25,887	36,356
Total Sustainment Capital (Gross)	**129,336**	**130,628**	**125,599**	**131,733**	**125,484**
Sustainment CIAC	(4,342)	(4,342)	(4,436)	(8,443)	(4,615)
Total Sustainment Capital (Net)	**124,994**	**126,286**	**121,163**	**123,290**	**120,869**

The forecast capital expenditures for each of the categories shown in the table above are described in more detail in the following sections, along with a description of projects forecast to exceed $2 million that are expected to proceed within the 2025 to 2027 timeframe.

3.3.2.1 Customer Measurement

Customer Measurement includes expenditures related to meter exchanges and meter set upgrades. Customer Measurement is further broken down into the four broad categories shown in the table below. Details of the Customer Measurement capital expenditures from Table C3-6 above are provided in Table C3-7 below.

Table C3-7: FEI Approved and Forecast Customer Measurement Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Meter Materials	20,589	20,854	9,642	10,849	10,055
Residential Meter Alteration & Exchange	6,856	7,029	36	37	38
Small Commercial / Industrial Meter Alteration & Exchange	1,086	1,064	1,062	1,073	1,083
Large Commercial / Industrial Meter Alteration & Exchange	1,484	1,547	3,555	1,500	2,247
Total Customer Measurement	**30,015**	**30,494**	**14,295**	**13,459**	**13,422**

The Customer Measurement spending in the Meter Materials and Residential Meter Alteration & Exchange categories decreases starting in 2025 in comparison to recent years due to the AMI project. The AMI project is replacing the residential diaphragm style meters that would have needed to be replaced/altered with new ultrasonic style meters. The AMI project capital will be added to FEI's rate base in multiple phases as the project progresses, consistent with the treatment of FEI's other approved Major Project capital. Accordingly, the AMI project capital is not included in the Regular Sustainment capital expenditure forecasts.

The forecast capital in the remaining two categories (Small Commercial/Industrial and Large Commercial/Industrial Meter Alteration & Exchange) is relatively consistent with the currently approved levels of spending, other than an increase in the Large Commercial/Industrial Meter Alteration & Exchange expenditures category in 2025 and again in 2027. The increase in 2025 is due to a number of smaller projects with similar timing. The increase in 2027 is for a project that is forecast to cost more than $2 million, described further below.

- **CS Fording Greenhills Mine Station Upgrade**: This project will replace and relocate the customer station to a higher elevation, approximately 20 m to the west, along the FEI pipeline Right-of-Way. A number of operational issues have been reported at the Customer TP/DP pressure control station in Elk Valley, BC. The identified operational issues include access concerns, undersized station bypass inhibiting maintenance activities, station heater inefficiency, and seasonal flooding in the Spring due to the low elevation of the building. The estimated cost of this project is $2.1 million, with forecast spending of $0.429 million in 2026 and $1.660 million in 2027.

3.3.2.2 Transmission System Reliability & Integrity

The Transmission System Reliability & Integrity capital category includes activities related to the ongoing safe and reliable operation of the transmission system. The main areas of expenditure under this category include:

- Pipeline alterations to mitigate the threat of natural hazards, comply with regulatory codes and standards, and facilitate maintenance and inspections;
- Alterations to transmission facilities, including pressure control, compression, and LNG to ensure safe, reliable, and efficient operation; and
- Pipeline major inspections, including in-line inspections and marine crossing inspections.

Details of the Transmission System Reliability & Integrity capital expenditures from Table C3-6 above are provided in Table C3-8 below.

Table C3-8: FEI Approved and Forecast Transmission System Reliability & Integrity Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Pipeline Alterations	16,667	14,479	23,186	28,563	31,165
Pipeline Capacity Improvements	-	-	-	-	335
Pipeline Station Alterations	2,014	3,835	3,127	6,151	1,965
Transmission System Telemetry Alterations	353	303	1,487	667	594
Compressor Station Alterations	9,140	13,096	7,899	11,710	8,850
Compressor Unit Overhauls	2,128	2,343	-	216	2,447
LNG Plant Alterations	6,579	7,322	7,200	7,200	7,200
Transmission System Cathodic Protection	356	395	425	409	417
Pipeline Inspection	10,635	7,767	16,100	20,197	13,497
Pipeline SRW Acquisition	65	33	641	21	-
Total Transmission System Reliability & Integrity	**47,937**	**49,573**	**60,065**	**75,133**	**66,469**

The primary categories of forecast increased capital spending during the Rate Framework term are Pipeline Alterations, Transmission System Telemetry Alterations, and Pipeline Inspection. There is also increased variability in the Pipeline Station Alterations category. Each of these areas is discussed further below.

- **Pipeline Alterations:** The 2025-2027 Forecasts are higher than the 2023 and 2024 Approved levels due to the need to address an increased number of regulatory compliance-driven, class location upgrades. These investments consist of pipeline upgrades to account for more stringent design parameters and safety factors due to population growth in areas adjacent to FEI pipelines. Class location assessments are completed for all pipeline assets on an annual basis, with additional expenditures required during the Rate Framework term due to continued population growth within FEI's service territory.

- **Pipeline Station Alterations:** Forecast spending for Pipeline Station Alterations is on average consistent with the 2023 and 2024 Approved amounts, with the exception of one larger project forecast for 2026. This project involves adding a new control station on the Roebuck Valve Assembly site on the Livingston Patullo 457 (LIV PAT 457) pipeline to support maintenance activities requiring lower pressures. Other larger projects under this portfolio include remote control valve upgrades on the ITS, bypass piping modifications at control stations, and Established Operating Pressure (EOP) control projects.

- **Transmission System Telemetry Alterations:** There is a larger expenditure forecast in 2025 due to necessary hardware upgrades of gas control systems, specifically for the supervisory control and data acquisition system (SCADA).

- **Pipeline Inspection:** ILI programs are developed by FEI's System Integrity department based on various factors such as age, attributes, and condition of the pipeline. Recognizing the susceptibility of its coastal and interior transmission pipelines to time-dependent cracking threats, the BCUC has approved alterations to FEI's CTS and ITS to facilitate the adoption of Electromagnetic Acoustic Transducer (EMAT) ILI tools as the most technically and financially feasible method to monitor these threats. Alterations to existing pipeline systems were necessary to facilitate successful EMAT ILI runs. FEI established the EMAT program for the CTS following BCUC Decision and Order C-3-22, with a pilot program initiated in 2019. FEI has updated the 2025-2027 ILI portfolio to incorporate EMAT ILI for the ITS, as approved by BCUC Decision and Order C-1-24. The first EMAT run for the ITS is scheduled to begin as early as 2025.

The inclusion of EMAT in the 2025-2027 portfolio results in a 60 percent increase in inspection costs compared to not employing this technology. Considering the time-dependent nature of cracking threats (i.e., crack growth over time) and the likelihood of rupture as its failure mode, EMAT will become an integral part of the ILI program. EMAT run frequency will align with the condition of the pipeline and FEI's integrity management program standards.

Table C3-9 shows the anticipated spend profile of the projects greater than $2 million in the Transmission System Reliability & Integrity category from 2025 to 2027.

Table C3-9: FEI Forecast Transmission System Reliability & Integrity Capital Expenditures on Projects Greater than $2 million 2025-2027 ($000s)

Project	Portfolio	2025 Forecast	2026 Forecast	2027 Forecast
Shallow Depth of Cover Site 24 – Grand Forks Trail Lateral 273	Pipeline Alterations	62	449	3,806
Livingston Pattullo 457 – Relocate Pig Receiver to Roebuck	Pipeline Alterations	500	2,000	25
Kingsvale Princeton 323 kP9.55 Voght Creek (Hazard ID547)	Pipeline Alterations	310	1,671	19
Merritt Lateral 114 – Coldwater River Erosion (Hazard ID60)	Pipeline Alterations	134	2,000	22
Shoreacres Lateral 114 – kP0.18 Slocan River (Hazard ID2168)	Pipeline Alterations	-	616	2,609
Princeton Oliver 323 – 530m @ kP95.3 Class 3 Upgrade	Pipeline Alterations	88	394	2,196
Vancouver Mainland 273 788m @KP34 Class 3 Upgrade	Pipeline Alterations	125	1,906	29
Highland Valley Lateral 114 – kP13.3 to 16.7	Pipeline Alterations	582	3,865	52
Roebuck TP – New Control Station	Pipeline Station Alterations	500	2,500	248
PLC & HMI Upgrades – Kitchener and Langley Compressor Stations	Compressor Station Alterations	3,576	5,412	68
Tilbury LNG – 2027 Pressure Vessel Inspections	LNG Plant Alterations	-	150	3,700
Fording Lateral 219 – ILI	Pipeline Inspection	1,331	1,000	-

Each of these projects is described further below.

- **Shallow Depth of Cover Site 24 – Grand Forks Trail Lateral 273:** The pipeline at this location has been found to have insufficient depth of cover due to farming activities and ground settlement in the area. The existing pipeline will need to be removed and replaced with a new pipeline installed at a minimum depth of cover of 1.2 metres. The estimated cost of this project is $4.4 million in total, with the majority of the costs expected to be incurred in 2027.
- **Livingston Pattullo 457 – Relocate Pig Receiver to Roebuck:** This project involves relocating the existing pig receiving barrel for the LIV PAT 457 pipeline from its current location at the Pattullo Gate Station to the Roebuck Valve Assembly. FEI needs to relocate this receiving barrel because, due to the Pattullo Gas Line Replacement (PGR) project, there is not enough flow through the pipeline at the current location to run the in-line inspection tools. The barrel will also be upgraded to meet the requirements of new ILI tool technology. This project is anticipated to cost $2.6 million, with most of the costs incurred in 2026.
- **Kingsvale Princeton 323 kP9.55 Voght Creek (Hazard ID 547):** The KIN PRI 323 and PRI LTL 88 transmission pressure pipelines have been identified as having a shallow depth of cover due to scouring in the creek. Replacement of the two pipeline crossings is needed to restore adequate depth of cover to these two pipelines. The estimated cost of this project is $2.5 million, with the majority of the costs forecast to be incurred in 2026.
- **Merritt Lateral 114 – Coldwater River Erosion (Hazard ID60):** The City of Merritt is planning to remove the temporary dike that was installed in 2021 due to the flood in the Coldwater River. FEI expects that the pipeline will not have sufficient cover to serve as a permanent water crossing when the temporary dike is removed. The estimated cost of this project is $2.1 million and will be undertaken in 2026.
- **Shoreacres Lateral 114 – kP0.18 Slocan River (Hazard ID2168):** The depth of cover of the underwater pipeline crossing the Slocan River needs to be re-established as the pipe located near the left bank is exposed. Grade control and erosion protection will also be considered in the design, as well as backwater effects from the Kootenay River. The estimated cost of this project is $3.8 million, with the majority of the costs incurred in 2027.
- **Princeton Oliver 323 – 530m @ kP95.3 Class 3 Upgrade:** Due to development growth in the Oliver area, a section of the existing pipe needs to be upgraded to meet Class 3 location requirements as defined by CSA Z662. The estimated cost of this project is $3.1 million, with the majority of the costs incurred in 2027.
- **Vancouver Mainland 273 788m @KP34 Class 3 Upgrade:** This segment of pipe's class location designation changed due to development in the area. The pipe is now required to be designed to a Class 3 location and therefore needs to be upgraded to meet CSA Z662 requirements. The estimated cost of this project is $2.0 million and is expected to be undertaken in 2026.

- **Highland Valley Lateral 114 – kP13.3 to 16.7:** The current location of the transmission pipeline is in conflict with the expansion proposed by the Highland Valley Copper mine. This is a customer driven project and will be fully funded by Highland, with the offsetting contribution included as a CIAC. There is also potential for load increase during the expansion. The estimated cost of this project is $4.8 million, with the majority of spending forecast for 2026. Since the customer will be providing a CIAC for the project, if the project scope or schedule shifts, there will be no impact to the net Sustainment capital expenditures.

- **Roebuck TP – New Control Station:** This project is related to the Livingston Patullo 457 – Relocate Pig Receiver to Roebuck project described above. As a result of the PGR project, there is not enough flow through the pipeline to run the ILI tools. Therefore, to manage any integrity threats, a new pressure control station is required to reduce pressure on a segment of the LIV PAT 457 transmission pressure pipeline between Roebuck and Sandell from a Maximum Operating Pressure (MOP) of 4020 kPa to an MOP of 1900 kPa. Pressure control equipment will also be installed to control pressure on the TP pipelines west of Roebuck. The estimated cost of this project is $3.2 million, with the majority of the costs forecast to be incurred in 2026.

- **Compressor Unit Control Upgrades:** Programmable Logic Controller (PLC), Human Machine Interface (HMI) and Control System upgrades are required at the Kitchener and Langley Compressor Stations as are end-of-life and need to be replaced. FEI will identify, supply, and install the latest version of PLC software and HMI to bring the units up to current standards and serviceability. The total estimated cost of these projects is $9.2 million.

- **Tilbury LNG – 2027 Pressure Vessel Inspections:** The Tilbury 1A LNG facility has 147 pressure vessels requiring a major inspection every five years in accordance with Technical Safety BC. These inspections check for internal damage and corrosion to ensure the integrity of the vessels and to estimate remaining life. The inspection commencing in 2027 will include a review of the process history of each vessel during the previous five years of operation and any necessary changes to isolation plans, hazard analysis or focus areas based on findings from the last inspection. The total estimated capital cost of this project is $3.8 million, with the majority of spending occurring in 2027. During these inspections, other maintenance work is completed that is not capitalized, currently estimated at $400 thousand. FEI will forecast this portion as Flow-through O&M for the LNG Facilities in its Annual Review for 2027 Delivery Rates.

- **Fording Lateral 219 – ILI:** In accordance with FEI's ILI program requirements, the ILI runs on the 219 mm Fording Lateral will be completed to provide critical pipeline condition information required to manage the integrity of the pipeline. The ILI runs will be completed over a two-year period from 2025 to 2026. The estimated cost for this project is $2.4 million.

3.3.2.3 Distribution System Reliability

Distribution System Reliability expenditures consist primarily of new pressure control stations or improvements to existing pressure control stations due to condition, load change, obsolescence, and regulatory compliance. Also included in this category are alterations or improvements to distribution telemetry installations and distribution sectioning valves.

Details of the Distribution System Reliability capital expenditures from Table C3-6 above are provided in Table C3-10 below.

Table C3-10: FEI Approved and Forecast Distribution System Reliability Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Distribution Stations Alterations	11,485	13,633	12,520	11,372	7,150
Distribution System Telemetry Alterations	1,656	329	582	377	125
Distribution System Capacity Alterations	64	476	3,539	180	956
Distribution Stations New	1,326	3,159	3,539	5,238	41
Revelstoke Propane Plant Alterations	252	92	437	32	964
Distribution Sectioning Valves	558	20	629	55	-
Total Distribution System Reliability	**15,341**	**17,709**	**21,245**	**17,254**	**9,237**

Overall, on average, Distribution System Reliability capital expenditures from 2025 to 2027 are decreasing relative to the 2023 and 2024 Approved amounts. Areas that have significant variances are Distribution Stations Alterations, Distribution System Capacity Alterations, Distribution Stations New, and Revelstoke Propane Plant Alterations. Each of these areas are discussed further below.

- **Distribution Stations Alterations:** Expenditures in 2027 are forecast to be lower than prior years due to the timing of specific projects. These station upgrades are typically required to address capacity shortfalls and operational risks.
- **Distribution System Capacity Alterations:** There is a larger expenditure scheduled in 2025 to address a large load coming online in Mission. This project is approximately $3.1 million and is further described below.
- **Distribution Stations New:** The Distribution Stations New portfolio does not follow a particular trend, as the number of projects is fewer, and their timing is dependent on several factors including growth in specific regions/municipalities. There are two projects over $2 million in this category which are described below.
- **Revelstoke Propane Plant Alterations:** The existing Revelstoke propane plant experiences capacity shortfalls during winter cold weather periods. FEI plans to add tank capacity at the existing plant to be able to serve a longer duration during the cold weather. The upgrade is expected to occur in 2028, with planning work such as design and procurement commencing in 2027.

Table C3-11 below shows the anticipated spend profile of the projects in this category greater than $2 million from 2025 to 2027.

Table C3-11: FEI Forecast Distribution System Reliability Capital Expenditures on Projects Greater than $2 million 2025-2027 ($000s)

Project	Portfolio	2025 Forecast	2026 Forecast	2027 Forecast
Kinchant Street and Bowron Avenue - Station Upgrade	Distribution Stations Alterations	175	1,938	17
6 Ave & Cumberland – Station Rebuild	Distribution Stations Alterations	815	1,191	-
SI – 1050m x 323 IP/ST Riverside St, Abb	Distribution System Capacity Alterations	3,140	-	-
Colwood New IPDP Stn	Distribution Stations NEW	690	4,515	41
New Stn – 1900/420 Downes/Bradner	Distribution Stations NEW	2,472	40	-

Each of these projects is described further below.

- **Kinchant Street and Bowron Avenue – Station Upgrade:** The Kinchant Street pit station serving downtown and West Quesnel is currently operating at 90 percent capacity. In addition to capacity issues, the station has poor access to complete maintenance and safety checks. A new location is proposed for an above ground station. The estimated cost of this project is $2.5 million with spending primarily in 2026.
- **6 Ave & Cumberland – Station Rebuild:** A new pit station is required to replace the existing 6th Ave and Cumberland Street District Station in New Westminster. The proposed upgrades include relocating the existing station as it is currently located at a busy road posing a risk of injury for the public and FEI personnel, and there is limited space for access. A suitable location near 7th Ave and Cumberland Street has been identified for the new pit station. The estimated cost for this project is $2.1 million with spending primarily in 2026.
- **System Improvement – 1050m x 323 IP/ST Riverside St, Abb:** This upgrade is required due to a large commercial load coming online in north Mission. The 1050 m of 323 mm IP pipeline is required to be online by 2025 and will be required to provide adequate station inlet pressure for two stations in Mission. The estimated cost for this project is $3.1 million.
- **Colwood New IPDP Station:** The population and natural gas demand in the Colwood area on Vancouver Island is growing significantly. A new IP/DP station is proposed to address growth in demand and capacity constraints in Colwood. Potential location options are currently being evaluated. The estimated cost of this project is $5.8 million.
- **New Stn – 1900/420 Downes/Bradner:** Residential and commercial growth in the Townline area of Abbotsford has significantly impacted the DP network in the area. Delivery of minimum service pressure will become more challenging as commercial loads

are set to come online in 2026. FEI will install a new IP/DP station in the vicinity of the intersection of Downes Rd and Bradner Rd to increase flow to the downstream DP network. This project will commence in 2024, with approximately $1.2 million projected to be incurred in 2024 and the remainder of the costs forecast to be incurred in 2025 and 2026.

3.3.2.4 Distribution System Integrity

Distribution System Integrity expenditures consist primarily of main and service alterations and replacements due to condition or at the request of third parties.

Details of the Distribution System Integrity capital expenditures from Table C3-6 above are provided in Table C3-12 below.

Table C3-12: FEI Approved and Forecast Distribution System Integrity Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Main and Service Alterations	21,817	20,669	18,104	15,577	20,042
Main and Service Renewals	10,605	9,488	9,130	7,498	13,446
Service Hazards Mitigation	2,154	1,223	1,259	1,284	1,310
Distribution System Cathodic Protection	1,467	1,472	1,500	1,527	1,558
Total Distribution System Integrity	**36,043**	**32,852**	**29,993**	**25,887**	**36,356**

Overall, the average Distribution System Integrity spending for the years 2025 to 2027 is lower than the 2023 and 2024 Approved amounts. Areas that have variances are Main and Service Alterations, and Main and Service Renewals. Each of these areas is discussed further below.

- **Main and Service Alterations:** The forecast for this portfolio is lower in 2025 and 2026 in comparison to 2023 and 2024, but then increases in 2027 due to two projects over $2 million, discussed below.
- **Main and Service Renewals:** This category encompasses planned replacements of FEI's mains and services which are identified based on asset integrity, condition, and age. The forecasts for this portfolio in 2025 and 2026 are relatively consistent with the 2023 and 2024 Approved amounts. However, FEI is forecasting higher expenditures in 2027 due to a higher volume of planned main renewals based on the specific timing of replacement determined through FEI's mains renewal program.

Table C3-13 below shows the anticipated spend profile of the projects in this category with forecast spending greater than $2 million during the 2025 to 2027 timeframe.

Table C3-13: FEI Forecast Distribution System Integrity Capital Expenditures on Projects Greater than $2 million 2025-2027 ($000s)

Project	Portfolio	2025 Forecast	2026 Forecast	2027 Forecast
Hwy 97 Quesnel River Bridge - Crossing Replacement	Main and Service Alterations	-	113	2,983
RICH IP – 8" Capstan Way to Cambie Rd Relocate	Main and Service Alterations	50	416	2,500

Each of these projects is described further below.

- **Hwy 97 Quesnel River Bridge – Crossing Replacement:** This project involves replacing the IP pipeline crossing on the Quesnel River Bridge due to the pipeline and pipe hangers' deteriorating conditions. This project is currently in development to review options to replace the pipe and hangers or to install a new crossing via horizontal directional drilling (HDD). The estimated cost of this project is $3.0 million, with spending primarily in 2027.
- **RICH IP – 8" Capstan Way to Cambie Rd Relocate:** This project is for an IP pipeline to supply the Cambie Rd & River Rd Station, which requires a capacity upgrade. Due to future plans by the City of Richmond at the current location, the upgraded station will have to be built in a new location and FEI may need to relocate a longer section of IP pipeline. The estimated cost of the project is $3.4 million, with spending primarily in 2027.

3.3.2.5 Contributions in Aid of Construction

The recoveries in this category are forecast based on the anticipated customer contributions for work for third party alterations and the historical level of contributions for Transmission crossing replacements and identified recoverable projects.

The two tables below provide the realized and projected CIAC over the Current MRP term, and the forecasts for 2025 to 2027, with 2023 and 2024 Approved amounts provided for comparison.

Table C3-14: FEI Actual and Projected Sustainment CIAC 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Sustainment CIAC	(4,879)	(4,771)	(4,547)	(8,139)	(5,065)

Table C3-15: FEI Approved and Forecast Sustainment CIAC 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Sustainment CIAC	(4,342)	(4,342)	(4,436)	(8,443)	(4,615)

With the exception of 2026, the forecasts generally reflect an anticipated stable level of contributions compared to recent years. The higher forecast CIAC in 2026 is for the Highland

Valley Lateral 114 project discussed above in Section C3.3.2.2 (Transmission System Reliability & Integrity).

3.3.3 FEI Other Capital

Other capital includes Equipment, Facilities, and IS expenditures, as well as a new category for Corporate Security expenditures.

Table C3-16 below summarizes the actual and projected Other capital expenditures from 2020 to 2024.

Table C3-16: FEI Actual and Projected Other Capital Expenditures 2020-2024 ($000s)[99]

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Equipment	16,024	14,025	11,186	12,169	14,240
Facilities	6,675	8,447	7,031	14,846	11,349
Information Systems	24,217	24,074	24,475	23,381	23,835
Corporate Security	3,829	3,700	3,868	3,917	3,770
Total Other Capital	**50,745**	**50,246**	**46,560**	**54,312**	**53,194**

Table C3-17 below provides the 2025-2027 Forecast Other capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-17: FEI Approved and Forecast Other Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Equipment	12,270	12,240	14,989	16,123	18,421
Facilities	14,686	11,349	18,727	13,053	8,551
Information Systems	24,458	24,563	25,300	25,800	26,500
Corporate Security	3,100	3,100	8,887	7,720	7,741
Total Other Capital	**54,514**	**51,252**	**67,904**	**62,696**	**61,213**

Each of the categories is discussed further below.

3.3.3.1 Equipment

Equipment capital expenditures include the acquisition of vehicles and equipment, telecommunication infrastructure, specialized tools and equipment, and radio system upgrades. Expenditures for the Equipment category are driven by obsolescence, excessive wear, and regulatory compliance.

[99] During the Current MRP, Corporate Security was included in the IS portfolio under Cybersecurity and in the Sustainment capital portfolio under Physical Security. Actuals for Corporate Security are now shown separately to allow for comparison with the 2025-2027 Forecast amounts.

Table C3-18 below summarizes the actual and projected Equipment capital expenditures from 2020 to 2024.

Table C3-18: FEI Actual and Projected Equipment Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Tools and Equipment	5,319	4,699	2,512	3,273	3,300
Fleet Services	8,845	7,905	7,213	7,309	9,400
Measurement Services	338	276	460	506	507
Radio Communications	1,155	787	671	749	700
Supply Chain	367	358	330	332	333
Total Equipment	**16,025**	**14,025**	**11,186**	**12,169**	**14,240**

Table C3-19 below provides the 2025-2027 Forecast Equipment capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-19: FEI Approved and Forecast Equipment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Tools and Equipment	3,300	3,300	3,537	3,608	4,092
Fleet Services	7,380	7,400	9,753	10,782	12,562
Measurement Services	507	507	531	541	552
Radio Communications	750	700	780	796	812
Supply Chain	333	333	388	396	404
Total Equipment	**12,270**	**12,240**	**14,989**	**16,123**	**18,421**

With the exception of Fleet Services, which is discussed further below, the 2025-2027 Forecasts for Equipment are generally consistent with 2023 and 2024 Approved amounts.

- **Fleet Services:** This category includes the replacement and/or acquisition of specialized heavy fleet vehicles, specialty equipment, mid-duty service vehicles, light duty passenger vehicles, and off-road vehicles necessary to meet FEI's operational requirements. Over the next few years, FEI has a substantial capital replacement requirement based on replacement triggers identified by age, engine hours, and utilization to maintain safe and reliable vehicles and equipment able to respond to customer calls and provide emergency response. FEI plans to replace 123, 84 and 95 vehicles in 2025, 2026 and 2027, respectively. These replacements encompass light duty, medium duty and heavy-duty trucks and vans, trailers, and other equipment.

  FEI considers many factors when determining the need for vehicle replacements. These include suitability to meet current and future business requirements and the ability to maintain adequate safety, as well as age, condition, and compliance with regulations and sustainability. Each replacement decision is evaluated on a unit-by-unit basis.

3.3.3.2 Facilities

Facilities capital expenditures include the acquisition or leasing of land, non-plant buildings such as offices, field musters and warehouses, and office furniture and equipment. The expenditures focus primarily on capacity planning, upgrading, and replacement of end-of-life assets.

Table C3-20 below provides the actual and projected Facilities capital expenditures from 2020 to 2024.

Table C3-20: FEI Actual and Projected Facilities Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Facilities	6,675	8,447	7,030	14,846	11,349

Table C3-21 below provides the 2025-2027 Forecast Facilities capital expenditures as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-21: FEI Approved and Forecast Facilities Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Facilities	14,686	11,349	18,727	13,053	8,551

Overall, on average over the Rate Framework term, FEI's forecast for Facilities capital expenditures is in line with the 2023 and 2024 Approved average amount. FEI is forecasting a large increase in 2025, with the forecast spending trending downwards for the remainder of the Rate Framework term. The key projects included within the 2025-2027 timeframe are discussed below.

Trail Operations Centre Replacement

The FEI Trail Operations Centre is nearing end-of-life and requires replacement. The property was purchased in 1960 by FEI's predecessor, Inland Natural Gas, and converted to the Trail Operations Centre. The building is circa 1950.

In addition to the building nearing end-of-life, there are capacity and other challenges with the space, including:

- The building does not meet accessibility requirements for corridors and washrooms;
- There are no change rooms for the crew;
- There is no meeting room space, so meetings must take place in the kitchen, which poses challenges for presenting and for people accessing water, coffee and food;
- The crew rooms are too small to accommodate all crew team members at once; thus, crew members are "split" up into different areas for collaboration;

- There is no space available for general training due to limited space in the office and bays;
- All workspaces are occupied so there is no capacity for growth;
- There is insufficient material storage capacity; and
- There is no room for a welding bay.

FEI has completed an assessment of the Trail Operations Centre to determine the required size of the replacement property and has developed a project plan. The required size of the building is determined by itemizing the needed base building and common rooms, individual workspaces (based on current and future headcount identified by the departments) and by calculating by the predetermined space standards that are aligned with industry standards. Warehousing and truck bay sizes have been developed by measuring linear storage and vehicle size.

Based on FEI's assessment, the current property size is too small to re-build. Accordingly, FEI plans to relocate and construct a new facility. The project is expected to be completed over three years, from 2024 through 2026, and the forecast cost is approximately $13 million. FEI forecasts capital expenditures of $1.6 million in 2024, $7.5 million in 2025, and $3.9 million 2026. FEI will seek BCUC approval to dispose of the existing site once the project is complete.

Heated Storage Building for Pipeline Operations

FEI's Pipeline Operations department is in the process of replacing high pressure equipment to double block and bleed (i.e., blocking flow on the upstream and downstream sides so that bleeding can occur between them). Previously, the single block equipment had a much smaller footprint for storage. As the high-pressure equipment needs to be stored inside in a heated space to ensure no rusting as it is used on transmission pipelines, a new heated storage bay needs to be added in the Kootenay area. This project is estimated at $2.7 million, with $2 million forecast to be incurred in 2025 and $0.7 million in 2026.

Maintenance of Existing Facilities

FEI needs to maintain its existing facilities. Over the next decade, FEI's buildings and building equipment are entering a large capital replacement cycle due to their age. To sustain aging assets, FEI needs to increase its Facilities capital renewal project expenditures, ultimately impacting the upcoming three-year period.

FEI forecasts approximately $2.7 million in 2025 and 2026 and $3.5 million in 2027 for building equipment, including conveying (elevators, cranes), HVAC and fire protection, as well as roofing and paving. A plan has been developed to systematically replace targeted assets over a three-year period, prioritizing asset condition and criticality. With this proactive approach, FEI can better distribute expenditures over the three-year Rate Framework term without compromising critical downtime.

3.3.3.3 Information Systems

FEI's IS expenditures focus on sustaining, enhancing, replacing, and upgrading existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

Table C3-22 below summarizes the actual and projected IS capital expenditures from 2020 to 2024.

Table C3-22: FEI Actual and Projected IS Capital Expenditures 2020-2024 ($000s)[100]

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
IS Sustainment	14,756	14,207	13,864	16,981	14,735
Application Enhancements	2,080	1,488	1,343	957	2,200
Business Technology Applications	7,381	8,379	9,268	5,443	6,900
Total Information Systems	**24,217**	**24,074**	**24,475**	**23,381**	**23,835**

Table C3-23 below provides the 2025-2027 Forecast IS capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-23: FEI Approved and Forecast IS Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
IS Sustainment	10,808	10,913	14,800	15,200	15,800
Application Enhancements	2,850	2,850	2,000	2,100	2,200
Business Technology Applications	10,800	10,800	8,500	8,500	8,500
Total Information Systems	**24,458**	**24,563**	**25,300**	**25,800**	**26,500**

Overall, on average, FEI's actual/projected IS capital spending has been consistent with the approved amounts during the Current MRP term. While the overall spending has been consistent with approved, spending at the individual category level varies from year to year. This is because FEI manages the IS capital portfolio as a whole, with variations in spending amongst the categories due to a degree of overlap in the business drivers for each of the categories and annual prioritization of requests for IS capital work.

For the term of the Rate Framework, FEI is forecasting a level of IS Sustainment capital that is consistent with the level of capital spending that FEI actually incurred in 2023 and projects to incur in 2024. Although the 2025-2027 Forecast IS Sustainment capital expenditures are higher than the 2023 and 2024 Approved amounts, this is partially offset by decreases in Application

[100] Cybersecurity was included within IS Capital Expenditures in the Current MRP; however, it is now included in a new portfolio called Corporate Security, as discussed in Section C3.3.3.4 below. As such, capital expenditures related to cybersecurity are not included in Tables C3-22 and C3-23.

Enhancements and Business Technology Applications compared to the 2023 and 2024 Approved amounts.

The changes in each category are described in the subsections below.

3.3.3.3.1 INFORMATION SYSTEMS SUSTAINMENT

IS Sustainment capital includes infrastructure sustainment, end-user device sustainment, and application sustainment:

- **Infrastructure sustainment:** the capital funding required to replace or upgrade outdated or end-of-life hardware and server software in the data centres. This includes, among other things, servers, operating systems, local area network (LAN) and wide area network (WAN) equipment.
- **End-user device sustainment:** the capital funding required to replace or upgrade end user equipment and software. This includes, among other things, PCs, operating systems, desktop applications, printing equipment and all mobile devices.
- **Application sustainment:** the capital funding required to sustain existing software applications. This includes required upgrades to maintain support, reliability, and performance of existing applications.

As shown in Tables C3-22 and C3-23 above, IS Sustainment capital is the largest area of IS capital spending. Actual IS Sustainment capital spending was higher than the approved amounts during the Current MRP term due to the addition of sustainment costs to support new business tools and devices (e.g., connecting internal systems and data to mobile field users). FEI expects that the IS Sustainment capital spending during the 2025-2027 term of the Rate Framework will be similar to the levels of actual spending experienced during the Current MRP term.

3.3.3.3.2 APPLICATION ENHANCEMENTS

Application Enhancements capital funding is used to modify the functionality or enable capabilities of existing applications to meet annual business requirements.

While actual spending on Application Enhancements can fluctuate from year-to-year based on higher/lower business requests for enhancements to current systems, this category of IS capital spending has been relatively consistent (and small relative to FEI's overall IS Capital expenditures) during the term of the Current MRP.

FEI has slightly reduced the 2025-2027 Forecast expenditures for Application Enhancements compared to the 2023 and 2024 Approved amounts. Overall, the forecasts for the Rate Framework term are generally consistent with the Current MRP term.

3.3.3.3.3 BUSINESS TECHNOLOGY APPLICATIONS

Business Technology Applications (Transform) include capital funding for initiatives that impact the way business is conducted and that support business unit priorities. This includes the introduction of new technologies to meet business requirements, system integration that changes business processes and/or the introduction of new business processes, and harmonization of systems that benefit both FEI and FBC. The prioritization and selection of projects for each year are completed by the Fall of the previous year. This process is designed to ensure that projects with higher value will be considered first when allocating finite resources. In addition, the rapid pace of technology changes necessitates more frequent replacement of systems due to obsolescence, loss of technical support and maintenance, risk of cyber threats, or to leverage the benefits of new functionality.

FEI has reduced its 2025-2027 Forecast expenditures compared to the 2023 and 2024 Approved levels to reflect the actual/projected spending levels during the Current MRP term.

3.3.3.4 Corporate Security

Expenditures related to Corporate Security have historically been split between Sustainment capital and Other capital. In the Current MRP, Cybersecurity was included as a category within IS capital, and Physical Security was included within Sustainment capital. Starting in 2025, FEI is now tracking these costs as a new portfolio in Other capital and has included the historical actuals in Table C3-24 for reference.

Table C3-24: FEI Actual and Projected Corporate Security Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Corporate Security	3,829	3,700	3,868	3,917	3,770

Table C3-25 below provides the 2025-2027 Forecast capital expenditures for Corporate Security as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-25: FEI Approved and Forecast Corporate Security Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Corporate Security	3,100	3,100	8,887	7,720	7,741

As shown in Table C3-25 above, FEI is forecasting a large increase in Corporate Security capital expenditures during the Rate Framework term.

As companies respond to the ever changing cyber and physical security threat landscape due to elements such as state sponsored groups, special interest hacktivists and commercially available hacking tools, additional spending is required to enhance FortisBC's Corporate Security risk management programs. These programs are based on a responsive model that adapts to an evolving threat landscape.

Starting in 2025, FEI is forecasting an increase in capital costs for its patch management program of $3.589 million (please refer to Section C2.2.4.4.2 for a discussion of the O&M component of the patch management program). In recent years, FEI has increased expenditures for patching to respond to evolving security risks and to reduce the threat landscape and vulnerabilities. Increased sophistication in attacker techniques has forced hardware and software companies to release updated code and operating system patches on a more frequent basis to counteract these threats and vulnerabilities. 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. Additionally, the patching program must increase scope to include all critical and non-critical applications. This prevents attackers from exploiting known flaws in software or devices which could potentially lead to compromised system reliability, including data integrity, confidentiality, or availability.

Additionally, FEI is continuing to strengthen the physical protection of its facilities by enhancing its ability to implement and maintain technologies and strategies that manage the threat landscape. This includes improving the physical security of its operations centres and updating its aging camera infrastructure to address end of life/end of support technology for its video management systems. This work is required to address identified cybersecurity vulnerabilities in legacy systems, as well as camera performance issues pertaining to outdated versions and hardware across many locations, which impacts site monitoring and response at these locations.

British Columbia has been experiencing increases in the frequency and severity of emergencies and disaster events which have significant impacts and durations that exceed those of previous years, and it is expected that this trend will continue. FEI requires the ability to establish incident command support bases to serve areas where facilities and infrastructure do not exist, or where space to respond to emergencies is an issue. To address this, in 2025, two mobile incident command units will be purchased and strategically positioned in areas where they can be easily deployed to support an event(s). These mobile command units operate as a central office, equipped with a range of communications technology, including satellite, cellular and Wi-Fi connections to ensure connectivity. The mobile command units are typically used as a central hub for communication between teams of emergency responders to manage on-site emergencies. Responding quickly to situations while also keeping communications flowing is critical whenever public safety, the safety of employees, and restoration of services to customers are at stake, and especially in rapidly changing emergencies. Mobile command centres support more timely and effective response to emergencies by being located as close to the event as safely possible.

3.3.4 FEI Regular Flow-through Capital Expenditures

Flow-through capital expenditures are Regular capital expenditures that are forecast each year in the Annual Reviews, with variances captured in the Flow-through deferral account. FEI is approved to treat certain capital items as flow-through due to a variety of factors, including their uncontrollable nature or uncertainty in scope, costs, and timing. FEI is also approved to treat capital expenditures related to Clean Growth Initiatives as flow-through.

For the Rate Framework, FEI will continue to forecast Regular flow-through capital for both its Pension/OPEB (Growth capital portion) and Clean Growth Initiatives. Currently, FEI includes Biomethane capital and NGT capital under its Clean Growth Initiatives. Over the term of the Rate Framework, FEI also anticipates bringing forward costs related to Methane Emission Mitigation under the same category, and will provide further discussion and forecasts in its upcoming Annual Reviews. Methane Emission Mitigation is discussed further below.

3.3.4.1 Methane Emission Mitigation

Consistent with FEI's other Clean Growth Initiatives, investments in Methane Emission Mitigation reduces greenhouse gas emissions. Methane emissions are a key point of focus for the provincial and federal government, and additional regulations will continue to be considered to further reduce climate change impacts related to methane emissions. For example, in October 2021, the federal government confirmed support for the Global Methane Pledge, which aims to reduce global methane emissions by 30 percent below 2020 levels by 2030 and 75 percent below 2012 levels by 2030.[101] In December 2023, the federal government issued an amendment to increase the stringency of regulations to ensure these reduction goals can be met.[102]

The Province has developed its own methane regulations and has signed an equivalency agreement with the federal government that extends to 2025;[103] however, further review is underway by the BCER, and updates to regulations may be implemented to ensure targets are being met.

The timing and scope of new federal or provincial regulations is uncertain; therefore, FEI is not able to properly forecast capital expenditures at this time. FEI accordingly anticipates that it will be seeking flow-through treatment for capital expenditures related to Methane Emission Mitigation at some point during the Rate Framework term. Although no expenditures have been identified, further review and project development related to measurement of emissions at FEI's station assets is expected to start in 2025. When specific expenditures are identified, they will be brought forward in FEI's Annual Reviews.

3.3.5 FEI Regular Capital Summary

Based on FEI's system requirements and industry drivers, FEI is forecasting decreased levels of Regular capital spending over the term of the Rate Framework relative to recent actual and projected expenditures.

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101 https://www.canada.ca/en/environment-climate-change/news/2021/10/canada-confirms-its-support-for-the-global-methane-pledge-and-announces-ambitious-domestic-actions-to-slash-methane-emissions.html.

102 https://www.gazette.gc.ca/rp-pr/p1/2023/2023-12-16/html/reg3-eng.html.

103 https://www.bc-er.ca/news-publications/trending-topics/methane-emissions/#:~:text=New%20methane%20regulations%20came%20into,off%20the%20road%20each%20year.

FEI proposes to continue with a unit cost approach to Growth capital expenditures with a revised methodology for setting the initial unit cost, taking into account recent trends in the costs to attach new customers. FEI's Growth capital is expected to decrease relative to recent actual and projected expenditures as customer attachments decrease.

FEI will realize a large reduction in the Customer Measurement portfolio starting in 2025 due to the deployment of the AMI project. Despite this reduction, overall spending on Sustainment capital is forecast to remain at a similar level to that approved for 2023 and 2024. This is because the reduction in Customer Measurement spending is offset by increased spending on pipeline alterations due to the need to address an increased number of regulatory compliance-driven, class location upgrades, as well as an increase in pipeline inspection costs to reflect the recently approved ability to conduct in line inspections using EMAT tools.

Other capital is forecast to increase as Equipment and Facilities are entering a large capital replacement cycle due to their age. FEI is also proposing increased investment in corporate security, including increased expenditures in patch management, given the need to address the risk environment.

Finally, FEI proposes to continue its flow-through treatment for Regular capital related to Pension/OPEB (Growth capital portion) and Clean Growth Initiatives, which includes future expenditures in Methane Emission Mitigation to align with policy directives.

3.3.6 FEI Major Capital Projects

Major Projects are capital expenditures that do not form part of Regular capital spending as they are approved through a CPCN or other application. In the MRP Decision, the BCUC determined that FEI's CPCN threshold for the Current MRP term would be $15 million.[104] FEI proposes to maintain the currently approved CPCN threshold of $15 million for the Rate Framework term.

The following are examples of the Major Project applications that may arise during the course of the Rate Framework term:

- FortisBC Enterprise Resource Planning (ERP) Modernization and Electric Customer Information System (CIS+) Replacement
- FEI Surrey Operations Centre Skytrain Impact Mitigation
- FEI Vancouver Island Subsea Pipeline Integrity Mitigation
- FEI Pennyfarthing Dr – 323 DPST Trespass
- FEI Lower Mainland Stores and Muster Replacement
- FEI Sun Peaks Acquisition

Each of these projects is described in more detail below.

[104] MRP Decision, p. 133.

FortisBC ERP Modernization and Electric CIS+ Replacement

Forecast Implementation Timeline: *2025 to 2027*

SAP was initially installed in 1998 and is the ERP system used extensively across FortisBC. FortisBC has been informed that SAP will no longer provide support for the current platform beyond 2027 and, as such, the ERP Modernization project will transition the existing FortisBC system to the new SAP S/4 HANA version. Additionally, FBC will be replacing CIS+, which is a system deployed in 1999 that FBC uses to house the meter to cash process and information for all electric customers. At nearly 25 years old, this system is no longer supported by the software manufacturer and requires ongoing customized support to ensure the continued accuracy and security of customer billing information. FBC intends to align the customer billing system with FEI's system. As such, FBC will be seeking to replace the current CIS+ system with SAP S/4 HANA at the same time as FortisBC transitions to SAP S/4 HANA.

In summary, the ERP Modernization and Electric CIS+ Replacement scope is to upgrade to a newer, more advanced version of the current ERP system used by both FEI and FBC, and to replace the current FBC CIS+. Costs for the project will be allocated between FEI and FBC. Further discussion on the project and the cost allocation will be provided in the upcoming application.

FEI Surrey Operations Centre Skytrain Impact Mitigation

Forecast Implementation Timeline: *2026 to 2028*

The Surrey Skytrain Expo Line extension from the existing King George station to the City of Langley will run along Fraser Highway in Surrey and pass through FEI's Surrey Operations Centre. Construction is expected to commence in 2026 with the extension in-service by 2028.

FEI has been informed that the Skytrain guideway rail will enter FEI's Surrey Operations lot from the southwest corner to the east side, passing closely by the Surrey Operations building. The closest point from the guideway rail to the building is approximately 5 metres (15 feet). This new above ground rail is expected to negatively impact FEI's Surrey Operations, both during and post construction and operation. The impacts include:

- Increased noise from the current reading of 65 decibels to 95 decibels;
- Loss of landscaping;
- Loss of parking; and
- Security impacts that come with Skytrain corridors.

FEI has engaged multiple Subject Matter Experts (SME) to complete a vulnerability assessment. The findings from the assessment as well as the estimated costs to remedy the expected negative impacts are intended to help inform and assist in negotiation with TransLink for cost recovery. While FEI anticipates that capital costs to address the above-noted issues will exceed its CPCN threshold, FEI is only at the early stages of this process and the capital expenditures and potential recoveries from TransLink required for the remediation are uncertain at this time.

FEI Vancouver Island Subsea Pipeline Integrity Mitigation

Forecast Construction Timeline: *2027-2032*

In 2019, the Vancouver Island Transmission System (VITS) marine pipeline network underwent a routinely scheduled inspection by a remotely operated vehicle (ROV). Analysis of the ROV results and subsequent analysis has indicated a non-emergency integrity issue warranting mitigation, related to a failed pipe support (known as a span corrector). This lack of support can result in increased pipe movement in the water and an increased potential for fatigue failure. FEI is currently working to refine its analysis, including further data collection, to better define the priority and urgency of mitigation and to develop an optimized mitigation scope. Due to expected high mobilization costs of specialized resources to perform marine crossing construction activities, FEI expects that the cost of any mitigation scope will exceed the current CPCN threshold of $15 million.

FEI Pennyfarthing Dr – 323 DPST Trespass

Forecast Construction Timeline: *2025-2027*

Approximately 425 m of 323 mm distribution pipeline main on Pennyfarthing Drive in Vancouver, located on the Kitsilano Indian Reserve No. 6 land, is currently in trespass. This main is a major feed providing natural gas from the 6th and Quebec Station across the Burrard Street Bridge and into the downtown Vancouver core. Squamish First Nation and its partners are constructing a phased residential and commercial project known as Seńáḵw (the Development) on the lands. Squamish Nation has requested FEI to relocate the gas main off of their land to make room for the Development. FEI and Squamish Nation are investigating three routing options for the gas main relocation, which are expected to be finalized in mid 2024. FEI will then work with Squamish Nation to select an option and negotiate an agreement for the relocation of the pipeline.

FEI Lower Mainland Stores and Muster Replacement

Forecast Implementation Timeline: *2026 to 2029*

FEI is investigating the relocation of the Lower Mainland Stores building, currently located in Burnaby, to the Fraser Valley area, as well as the replacement of five field musters. All of these buildings support field operation functions, and they are nearing end-of-life.

FEI Sun Peaks Acquisition

Forecast Timeline: *2025-2028*

FEI is considering acquiring the Sun Peaks propane distribution system and the propane storage and vaporization plant which supplies the distribution system. FEI is currently undertaking due diligence activities to inform the acquisition decision.

3.4 *FBC CAPITAL EXPENDITURES*

Table C3-26 below provides FBC's gross capital expenditures (before CIAC) for the term of the Current MRP. The 2020 through 2023 expenditures are actual; the 2024 expenditures are projected.

Table C3-26: FBC Actual and Projected Regular Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Growth Capital	28,799	21,865	30,013	28,445	26,076
Sustainment Capital	47,325	49,601	41,632	48,590	51,653
Other Capital	16,036	15,349	16,921	18,139	18,748
Total Regular Capital (Gross)	**92,160**	**86,815**	**88,565**	**95,174**	**96,477**

As discussed during the Annual Review for 2023 Rates, FBC has experienced pressures during the Current MRP term due to a variety of external factors, including the COVID-19 pandemic, supply chain issues, significant inflationary increases, and the war in Ukraine, among others.

The drivers of the increases in the Growth and Sustainment capital portfolios discussed in the Annual Review for 2023 Rates are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Increased cost and complexity in permitting and land acquisition;
- Increased growth; and
- Additional reliability and safety projects being required that were not anticipated at the time that the 2020-2024 MRP Application was developed.

FBC successfully implemented a number of mitigation strategies to limit the impact of cost pressures, thus allowing FBC to manage the overall cost increases. These mitigation strategies included:

- Reprioritizing projects, or components of a project that could be safely re-scheduled to accommodate other project cost increases that could not be deferred. While FBC has delayed some work with flexible timing to accommodate the increased capital demands, this has only mitigated part of the capital pressures due to the magnitude of market and other pressures;

- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants and construction contractors); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, due to the magnitude of the overall inflationary pressure experienced by the North American electric utility industry, FBC was not able to fully mitigate the cost increases.

In this Application, FBC is seeking approval of the level of Regular Growth, Sustainment and Other capital expenditures to be incorporated in rates over the years 2025 to 2027. The requested levels incorporate the inflationary impacts discussed above.

Table C3-27 below summarizes the 2023 and 2024 Approved and the 2025-2027 Forecast Regular gross capital expenditures for FBC.

Table C3-27: FBC Approved and Forecast Regular Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Growth Capital	30,072	24,568	41,349	45,035	46,357
Sustainment Capital	44,710	51,652	75,664	72,116	71,310
Other Capital	17,658	17,213	25,070	24,922	22,699
Total Regular Capital (Gross)	**92,440**	**93,434**	**142,082**	**142,074**	**140,365**

As explained in Section B1.6.3, with the increased provincial focus on electrification, the entirety of FBC's system, from generation to local distribution infrastructure and the necessary support systems, requires investment to address both the ability to accommodate load growth (through Growth capital expenditures), and the ability of the existing infrastructure to support current and increasing levels of demand.

FBC is forecasting increases in Growth, Sustainment and Other capital expenditures for each year of the Rate Framework term. The annual increases are due to the following key drivers:

- Increased requirements for system improvements to the Transmission and Distribution systems to accommodate load growth;
- Upgrades to aging assets, particularly Generation and Stations assets, to meet current codes and standards, to address the condition and age of infrastructure, and to improve reliability; and
- Increased spending in Corporate Security to respond to the evolving threat landscape as well as the frequency and severity of emergencies and disaster events.

As discussed in Section C2.3.4.5.1, FBC is seeking incremental O&M funding to increase its engineering and support staff to execute on the higher number of projects.

The Regular capital expenditures are discussed below in terms of Growth (Section C3.4.1), Sustainment (Section C3.4.2), and Other capital (Section C3.4.3), with explanation provided for any project that is forecast to exceed $1 million. The Regular Flow-through capital categories are also discussed in Section C3.4.4, and FBC's anticipated Major Projects are discussed in Section C3.4.6.

3.4.1 FBC Growth Capital

FBC's Growth capital expenditures include transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

Table C3-28 below summarizes the actual Growth capital expenditures from 2020-2023 and the projected 2024 expenditures.

Table C3-28: FBC Actual and Projected Growth Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Transmission	7,109	744	5,587	3,838	2,977
Distribution	1,926	1,965	2,814	1,353	1,664
New Connects	19,764	19,156	21,613	23,253	21,436
Total Growth (Gross)	**28,799**	**21,865**	**30,013**	**28,445**	**26,076**
CIAC (New Connect)	(6,301)	(7,600)	(7,348)	(8,169)	(6,925)
Total Growth (Net)	**22,499**	**14,265**	**22,665**	**20,276**	**19,151**

Table C3-29 below summarizes FBC's forecast Growth capital expenditures required over the 2025 to 2027 Rate Framework term, along with the 2023 and 2024 Approved amounts for comparison.

Table C3-29: FBC Approved and Forecast Growth Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Transmission	6,223	1,088	16,418	19,323	20,149
Distribution	1,899	1,716	1,775	1,747	1,814
New Connects	21,951	21,764	23,156	23,965	24,395
Total Growth (Gross)	**30,072**	**24,568**	**41,349**	**45,035**	**46,357**
CIAC (New Connect)	(10,218)	(6,925)	(8,085)	(8,364)	(8,485)
Total Growth (Net)	**19,854**	**17,643**	**33,264**	**36,671**	**37,871**

FBC describes the forecast capital expenditures for each of the categories shown in the table above in more detail in the following sections, along with a description of projects forecast to exceed $1 million that are expected to proceed within the 2025 to 2027 Rate Framework term.

3.4.1.1 Transmission Growth Capital

Transmission Growth capital consists of discrete projects that are determined by transmission system capacity requirements, based on forecast load, for adequate supply during periods of peak demand and adverse weather conditions.

FBC is forecasting an increase in Transmission Growth capital expenditures over the Rate Framework term. To continue providing reliable supply to its customers, FBC is planning to reconductor four transmission lines and to upgrade or rebuild seven stations to accommodate load growth, the energy transition, and increasing electrical loads. In particular, several of the Transmission Growth projects are required to address the resulting increase in demand in the City of Kelowna, which is one of the fastest growing cities in Canada.

Table C3-30 below provides the Transmission Growth capital projects planned to be undertaken during the term of the Rate Framework.

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

Project	2025 Forecast	2026 Forecast	2027 Forecast
Reconductor 52L & 53L	3,067	3,000	-
Glenmore Low Voltage Bus Capacity and Equipment Upgrades	1,421	174	-
Duck Lake Second Distribution Transformer Addition	4,683	681	-
Christina Lake Station Upgrade	1,567	3,962	2,322
Saucier Second Distribution Transformer Addition	5,269	7,294	2,757
DG Bell Second Distribution Transformer Addition	411	2,724	7,511
Princeton 138 kV Capacitor Bank Addition	-	414	1,766
Reconductor 51L & 60L	-	1,075	5,000
Glenmore Station Capacity Upgrade	-	-	791
Total Transmission Growth	**16,418**	**19,323**	**20,149**

Projects over $1 million that are planned to be undertaken over the 2025-2027 timeframe are described as follows:

- **Reconductor 52L & 53L:** This project is required to provide a reliable transmission supply to the Penticton and Oliver regions. An outage of the 63 kV transmission lines 52L or 53L will cause the remaining line to become overloaded beyond its emergency rating when the Penticton area summer peak load is approximately 135 MW, which is forecast to occur during the Rate Framework term. This N-1 condition constitutes a violation of BC Mandatory Reliability Standard TPL-001-5.1. To provide adequate capacity during this N-1 event and allow for future load growth in the Penticton and Oliver regions, this project will reconductor the 52L and 53L transmission lines to a higher ampacity conductor. FBC plans to commence work on this project in 2024, with the majority of expenditures forecast to be incurred in 2025 and 2026. The estimated total cost of this project is $6.6 million.

- **Glenmore Low Voltage Bus Capacity and Equipment Upgrades:** This project is required to accommodate load growth in central Kelowna. Although the Glenmore Transformer T3 (GLE T3) has a nameplate rating of 40 MVA, its capacity is currently being restricted to approximately 32 MVA due to the low voltage (LV) cross bus 1200 A rating. The most recent load forecast indicates GLE T3 summer peak load will exceed the 32 MVA limit during the Rate Framework term. This project involves upgrading the LV cross bus and bus tie switches to a minimum of 2000 A. FBC plans to commence work on this project in 2024, with the majority of expenditures forecast to be incurred in 2025. The estimated total cost of this project is $1.8 million.

- **Duck Lake Second Distribution Transformer Addition:** This project is required to provide a reliable supply to the southern area of Lake Country. FBC's planning criteria are not currently met during a Duck Lake Transformer T1 (DUC T1) outage. This project will install a second transformer at the Duck Lack substation. FBC identified this project in the Annual Review for 2023 Rates. At that time, FBC forecast that $1.1 million would be spent in 2024 and that the forecast total project cost of approximately $5.3 million could increase due to material cost escalation. FBC still intends to commence this project in 2024, but the project cost has increased due to the cost escalation of materials, resulting in an updated total forecast project cost of $6.5 million.

- **Christina Lake Station Upgrade**: This project is required to accommodate load growth and to address aging infrastructure and equipment condition issues to provide a reliable supply to the Christina Lake area. The most recent load forecast indicates the Christina Lake Transformer T1 (CHR T1) summer peak load will exceed its 5 MVA nameplate rating during the Rate Framework term. CHR T1 was manufactured in 1975 and is now 49 years old. The unit has advanced aging of its paper insulation, and a cooling issue which may lead to overheating. The station voltage regulators and capacitor bank switch are also aging and have equipment condition issues. Given the growth and condition issues at the existing CHR substation, this project will rebuild the CHR substation. The existing CHR substation property may be too small to accommodate the rebuild, and FBC may need to acquire land to either expand or relocate the substation. FBC plans to commence work on this project in 2024. The estimated total cost of this project is $8.2 million, with costs forecast to be incurred from 2024 to 2027.

- **Saucier Second Distribution Transformer Addition:** This project is required to accommodate load growth and provide a reliable supply in the downtown area of Kelowna. The Saucier (SAU) substation capacity is currently restricted to approximately 26 MVA due to the 1200 A rating of the SAU LV main bus, Saucier Transformer T1 (SAU T1) main breaker, and the metal-clad switchgear. The most recent load forecast indicates SAU T1 will exceed the 26 MVA limit during the Rate Framework term. To increase station capacity, this project will install a second transformer at the SAU substation and replace the metal-clad switchgear, LV main bus, and the transformer main circuit breakers with a minimum 3000 A rating. This project also involves replacing the high voltage circuit breakers and switches, a building expansion to house the new gas-insulated switchgear, and distribution line upgrades. FBC plans to commence work on this project in 2024. The estimated total cost of this project is $15.9 million, with expenditures forecast to be incurred from 2024 to 2027.

- **DG Bell Second Distribution Transformer Addition**: This project is required to accommodate load growth and provide a reliable supply to the Upper Mission area of Kelowna. During a DG Bell Transformer T1 (DGB T1) outage, the most recent load forecast indicates FBC planning criteria will not be met during the Rate Framework term. This project will install a second transformer at the DG Bell (DGB) distribution substation. This project also involves the addition of new circuit breakers and a voltage transformer on the high voltage side of the existing DGB T1, which will complete the 138 kV ring bus. Completing the ring bus will improve and simplify the protection scheme at the DGB terminal station and increase operational reliability in the Kelowna area. As FBC explained in the Annual Review for 2023 Rates, this project was deferred from the original 2024-2025 construction schedule to accommodate the Duck Lake Second Transformer Addition. The estimated total cost of the DG Bell Second Distribution Transformer Addition project is $11.4 million, with expenditures forecast to be incurred from 2025 to 2028.

- **Princeton 138 kV Capacitor Bank Addition:** An outage of the 230 kV 40L transmission line or Bentley Transformer T1 (BEN T1) results in low voltage near the Princeton area given forecast load levels during the Rate Framework term. This N-1 condition constitutes a violation of BC Mandatory Reliability Standard TPL-001-5.1. To mitigate the low voltage, this project will install a minimum of 10 MVAR additional reactive compensation at the Princeton (PRI) substation to provide acceptable voltage during an N-1 event. The estimated total cost of this project is $2.2 million, with expenditures forecast to be incurred in 2026 and 2027.

- **Reconductor 51L & 60L:** This project is required to provide a reliable transmission supply to Kelowna and its surrounding area. In the event of an outage to one of the F.A. Lee (LEE) terminal substation transformers (LEE T2, LEE T3 or LEE T4), followed by an outage to another LEE transformer, the flow on the remaining LEE transformer exceeds the emergency rating. Re-configuring the Kelowna loop to reduce the post contingency transformer flow results in exceeding the emergency rating of the 138 kV transmission lines 51L and 60L based on forecast load levels during the Rate Framework term. This N-1-1 condition constitutes a violation of BC Mandatory Reliability Standard TPL-001-5.1. To provide adequate capacity during this N-1-1 event and allow for future load growth in the Kelowna area, this project will reconductor 51L and 60L to a higher ampacity conductor. The estimated total cost of this project is $11.2 million, with expenditures forecast to be incurred from 2026 to 2028.

- **Glenmore Station Capacity Upgrade:** This project is required to accommodate load growth and provide a reliable supply to central Kelowna. The most recent load forecast indicates the Glenmore Transformer T2 (GLE T2) summer peak load will exceed its 31.5 MVA nameplate rating during the Rate Framework term. To increase station capacity, this project will replace GLE T2 with a new larger unit. The estimated total cost of this project is $8.0 million, with expenditures forecast to be incurred from 2027 to 2030. Project costs identified in 2027 are primarily for engineering and milestone payments for large equipment.

3.4.1.2 Distribution Growth Capital

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis based on the projected loads. Distribution Growth capital is broken down into two ongoing programs: Small Growth and Unplanned Growth. The forecast capital expenditures for these two programs are provided in Table C3-31.

Table C3-31: FBC Approved and Forecast Distribution Growth Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Small Growth Projects	1,122	1,130	1,085	1,140	1,137
Unplanned Growth Projects	777	586	690	607	676
Total Distribution Growth	**1,899**	**1,716**	**1,775**	**1,747**	**1,814**

Projects included under these ongoing programs include service upgrades, voltage regulation, ties to accommodate load splitting, single to three phase upgrades, and conductor upgrades that are necessary due to load growth. The Small Growth program consists of planned projects less than $0.5 million in size. The Unplanned Growth program consists of unforeseen projects typically less than $0.2 million in size. The forecast expenditures are based on historical expenditures. None of the planned projects under these programs are forecast to exceed $1 million.

3.4.1.3 Distribution New Connects

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service that are not recovered from customers under the terms of FBC's tariff. Consistent with past practice, the forecast expenditures for New Connects are based on historical expenditures adjusted for anomalous years and inflation. None of the planned projects are forecast to exceed $1 million.

3.4.2 FBC Sustainment Capital

The expenditures within Sustainment capital include system improvements to the generation, transmission, and distribution systems to maintain existing equipment to meet forecast load and for the safety, reliability, and integrity of the system. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects.

Sustainment capital is further classified into five categories of expenditures. Table C3-32 below summarizes the actual expenditures from 2020 to 2023 and the projected 2024 expenditures.

Table C3-32: FBC Actual and Projected Sustainment Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Generation	5,884	6,949	6,432	7,941	7,225
Transmission Sustainment	12,506	10,667	8,097	9,158	12,800
Stations Sustainment	4,821	12,083	7,342	6,734	8,209
Distribution Sustainment	21,530	17,479	17,011	21,953	18,219
Telecommunications	2,584	2,423	2,750	2,804	5,199
Total Sustainment (Gross)	**47,325**	**49,601**	**41,632**	**48,590**	**51,653**
Sustainment CIAC	(391)	(689)	(1,150)	(596)	(614)
Total Sustainment (Net)	**46,934**	**48,912**	**40,482**	**47,994**	**51,039**

Table C3-33 below summarizes FBC's forecast Sustainment capital expenditures required over the 2025 to 2027 Rate Framework term, along with the 2023 and 2024 Approved amounts for comparison.

Table C3-33: FBC Approved and Forecast Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Generation	7,623	7,225	12,823	13,298	15,274
Transmission Sustainment	9,159	12,800	13,604	9,149	8,991
Stations Sustainment	6,841	8,209	20,486	23,627	24,783
Distribution Sustainment	17,480	18,219	22,446	19,014	18,291
Telecommunications	3,606	5,199	6,304	7,028	3,971
Total Sustainment (Gross)	**44,710**	**51,652**	**75,664**	**72,116**	**71,310**
Sustainment CIAC	(1,410)	(614)	(765)	(791)	(816)
Total Sustainment (Net)	**43,300**	**51,038**	**74,899**	**71,326**	**70,494**

The forecast capital expenditures for each of the categories shown in the table above are described in more detail in the following sections, along with a description of projects forecast to exceed $1 million that are expected to proceed within the 2025 to 2027 Rate Framework term.

3.4.2.1 Generation Sustainment Capital

FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public, environment, and employees.

FBC's generation facilities consist of 15 hydroelectric generating units in four plants located on the Kootenay River: (1) the Lower Bonnington Dam (LBO) which was constructed in 1897 and upgraded in 1924; (2) the Upper Bonnington Dam (UBO) which was constructed in 1907 and extended to incorporate an additional two units in 1940; (3) the South Slocan Dam (SLC) which was constructed in 1924; and the (4) Corra Linn Dam (COR) which was constructed in 1932.

Since their initial construction, these hydroelectric generating plants have undergone only three major refurbishments or replacements, including:

- the Upgrade and Life Extension (ULE) program, which focused on upgrading the generating units and was undertaken from 1998 through 2011;
- the UBO Old Units Refurbishment project which was completed in 2021; and
- the Corra Linn Spillway Gates Replacement project which is in the final close-out stages.

FBC conducts ongoing condition assessments, engineering analysis and dam safety reviews on Generation infrastructure and equipment. Based on these assessments, FBC has identified critical path items that need to be addressed during the Rate Framework term related to condition, structural capacity, operational requirements, and safety.

FBC's Generation Sustainment capital is grouped into four categories. Table C3-34 below provides the 2025-2027 Forecast capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-34: FBC Approved and Forecast Generation Capital Expenditures Forecast 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Hydraulic Dam Structures	2,248	2,510	6,661	8,531	3,230
Generating Equipment	2,497	1,358	1,759	1,643	7,581
Generation Auxiliary Equipment	2,069	1,087	796	996	2,137
Buildings and Structures	809	2,270	3,607	2,128	2,326
Total Generation	**7,623**	**7,225**	**12,823**	**13,298**	**15,274**

FBC is forecasting an increase in Generation Sustainment capital during the Rate Framework term, primarily in the categories of Hydraulic Dam Structures and Generating Equipment. As explained above, FBC must undertake necessary upgrades to equipment due to condition, obsolescence, and compliance with dam safety that have been identified in the Dam Safety Reviews. Each of the categories is discussed below, with further details provided for projects over $1 million.

3.4.2.1.1 HYDRAULIC DAM STRUCTURES

This category includes capital projects that are related to water flow control equipment, including concrete structures, gates and stop logs, superstructures, lifting equipment (hoists and gantries), and dam safety. The projects are addressing deficiencies to meet the regulatory requirements of the BC Dam Safety Regulation and WorkSafe BC, to protect the condition of critical dam safety equipment and to remediate the condition of aging infrastructure. FBC is planning to undertake a number of projects over $1 million in 2025 and 2026. Each project is described below.

LBO Concrete and Structural Rehabilitation Project

The FBC generation plants range in vintage from 92 to 117 years old. This project is a continuation of the program started in 2012 and involves the correction of deficiencies and degradation in concrete related to normal deterioration that has occurred over time.

A comprehensive third-party engineering inspection of the plants has identified locations that require repair of deteriorated concrete, including resurfacing of waterway structures such as spillway piers, forebay piers, forebay walls, spillway walls, and tailrace piers. The repairs are prioritized based on a deterioration ranking system. The dam safety reviews have identified the concrete condition as a deficiency which poses employee safety hazards and potential risks to the structural integrity of the dams. If not proactively addressed, the deterioration will continue to accelerate over time through exposure to environmental conditions, resulting in increased expenditures in future years to address the issues.

FBC plans to address the locations that require concrete rehabilitation at the LBO tailrace piers during the Rate Framework term. The forecast cost is $2.342 million.

COR Dam Safety Instrumentation Project

This project includes the installation of dam instrumentation systems. The project addresses the requirement in Section 19 of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. As explained in the FBC Annual Review for 2023 Rates (2023 Annual Review),[105] FBC has completed the installation of dam safety instrumentation at LBO, UBO and SLC, while the COR portion of the project was delayed. FBC will be undertaking the installation of dam safety monitoring equipment at COR in 2025, with forecast expenditures of $1.507 million.

COR Dam Safety Stability Anchors Upgrade Project

This project was included in the Other Hydraulic Dam Structures Projects category in the Current MRP and includes the upgrade of the corrosion protection system of all anchors and load testing of select post-tensioned dam stability anchors. FBC initially planned to complete this project between 2022 and 2025. However, in 2023, FBC upgraded the anchors in the west, middle, and east gravity dams at COR and, based on the learnings from that stage of the project, FBC updated the costs and the schedule for upgrading the remaining anchors located in the middle gravity dam piers, middle gravity dam ogee spillways and the east gravity dam log sluice. FBC is now planning to execute the project over four years in order to address construction complexities at the anchor locations. The forecast cost of the project is $2.817 million. FBC plans to complete the project in 2027.

[105] Appendix C2, p. 6.

LBO Spillway Gates Refurbishment Project

The LBO spillway gates were fabricated in 1963 and require refurbishment following engineering inspections for condition and suitability to current dam safety standards. The inspections identified that corrosion on the skin plates, girders, and lifting screws, among other items, require repair and/or re-coating. In addition, a structural analysis to current standards and Dam Safety Guidelines determined that localized areas are overstressed and require re-strengthening. The refurbishment of the first spillway gate to address these concerns was completed during the Current MRP term. The refurbishment of the second gate is planned for completion in 2027 with forecast expenditures of $3.421 million.

UBO Intake Superstructure Upgrade Project

This project includes the refurbishment and upgrade of the intake installed at UBO to address age-related condition issues, increase structural capacity to meet the BC Building Code, and minimize the risks to public and employee safety. An engineering review identified that the intake superstructure at UBO does not meet the safety factors required for the hoist, seismic, wind and other load combinations. To address this issue, the project will strengthen the UBO intake superstructure by reinforcing the angle columns and the bracing-to-column connections, replacing the diagonal braces, and partial recoating. FBC plans to complete this project in 2026, with forecast expenditures of $1.351 million.

3.4.2.1.2 GENERATING EQUIPMENT

The Generating Equipment category includes projects that are related to turbines, generators, governor systems, excitation systems, unit control systems, lubrication systems, cooling water systems and generator switchgear.

FBC is forecasting an increase in capital expenditures in 2027 as a result of a number of planned projects over $1 million. These projects are described below.

LBO Generator Excitation System and Control System Replacement Project

This project includes the replacement of three unit control systems, one plant control system, and the replacement of one of the generator excitation systems at LBO due to obsolescence. The forecast cost of the project is $1.171 million, with the majority of the expenditures forecast to occur in 2027. FBC plans to complete the project in 2028.

UBO Unit 6 Turbine Runner Replacement Project

This project will replace the UBO Unit 6 turbine runner that has reached the end of its service life. The runner is original and will be approximately 89 years old at its proposed date of replacement.

This project was identified in the 2023 Annual Review.[106] At that time, the estimated cost was approximately $4 million and the expected in-service date was December 2024. However, based on new information provided during the procurement process from the quotes received from qualified vendors, FBC discovered that the project cost would be higher than originally estimated. FBC then took steps to validate the updated cost estimate and schedule, and the project was accordingly delayed. FBC now plans to continue with the project in 2025, with expenditures of $1.719 million forecast to be incurred during the Rate Framework term. FBC plans to complete the project in 2029 and the estimated total cost is $6.076 million.

UBO U3 Distributor Upgrade Project

This project will replace the original 1907 distributor components on Unit 3 at UBO to allow unit stopping under water flow. Each unit at the UBO Old Plant has three turbines with a set of wicket gates and the only method of stopping a unit is by closing the three sets of wicket gates because the units do not have intake gates. The turbine distributor components are comprised of a turbine head cover, three sets of wicket gates, and many linkages, including rods, pins, bushings, and operating rings that transmit the mechanical force from the unit governor to the wicket gates of the three turbines. In 2013, the wicket gates were replaced and the turbine shafts and bearing journals were refurbished. The remaining distributor components were not refurbished at that time. Based on FBC's assessment of the distributor components in 2023, refurbishment is now necessary as their deteriorated condition does not allow the wicket gates to close properly and thus the unit can no longer be stopped reliably and safely. The forecast cost of this project is $5.043 million, with the majority of costs forecast to be incurred in 2027.

3.4.2.1.3 GENERATION AUXILIARY EQUIPMENT

The Generation Auxiliary Equipment category includes capital projects that are related to upgrades to station service systems, cranes, elevators, dewatering system, heating and cooling systems, compressed air systems, and communication, network, and security systems.

3.4.2.1.4 BUILDINGS AND STRUCTURES

The Buildings and Structures category includes capital projects that are related to the following Generation assets: buildings and building components (walls, doors, windows, roofs, etc.), heating and ventilation systems, fences, and access roads.

FBC is forecasting the following Buildings and Structures capital projects over $1 million over the 2025 to 2027 Rate Framework term.

COR Annex Building Replacement

The COR annex houses critical systems for the operation of the COR generation facility, including battery banks, control systems and fire protection. The existing building's structure has visible signs of structural cracking and movement. The primary cause of this deterioration is foundation

[106] Appendix C2, p. 7.

settlement of the structure, which is causing the annex building to pull away from the powerhouse. To prevent collapse, temporary lateral bracing has been supporting the structure since 2015.

A collapse of the COR Annex Building due to further foundation settling or a seismic event would affect the operation of the COR generating units by compromising the operation of the battery banks, the fire pump system, and the water treatment equipment, as well as creating safety risks for FBC personnel.

This project was discussed in the 2023 Annual Review.[107] At that time, FBC planned to complete the project in 2024 at an estimated cost of $1.880 million. However, through the engineering detailed design process, FBC determined that additional work was required to strengthen the foundation and that the plant sanitary water system needed to be upgraded to meet current environmental requirements. These changes in the overall project scope identified in the detailed design phase resulted in delays to the start of the project and an increase in costs. FBC has accordingly updated the costs and timing for this project. FBC started this project in 2022 and plans to complete it in 2025 at a total forecast cost of $4.228 million, of which $1.628 million is forecast for 2025.

COR Powerhouse Window Replacement Project

This project involves the replacement of deficient and broken windows at COR. FBC has previously completed the replacement and refurbishment of the LBO, SLC and UBO powerhouse windows. This project was originally contemplated to be undertaken during the Current MRP, but due to other priorities and cost pressures, FBC deferred the project. FBC plans to start this project in 2025 and complete it in 2028 for a total cost of $2.425 million. The forecast expenditures during the Rate Framework term are $1.792 million.

3.4.2.2 Transmission Sustainment Capital

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's existing transmission line facilities, manage the safety risk to employees and the public, and maintain an acceptable level of service for customers. The forecast expenditures for this category are developed based on condition assessments.

Transmission Sustainment capital is further broken down into four programs. Table C3-35 below provides the 2025-2027 Forecast capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

[107] Appendix C2, p. 7.

Table C3-35: FBC Approved and Forecast Transmission Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Transmission Line Condition Assessment	1,058	681	1,485	1,112	1,623
Transmission Line Rehabilitation	6,519	10,447	10,269	6,250	6,263
Transmission Urgent Repairs	505	569	625	541	648
Transmission Rights of Way	1,077	1,103	1,226	1,246	456
Total Transmission Sustainment	**9,159**	**12,800**	**13,604**	**9,149**	**8,991**

3.4.2.2.1 TRANSMISSION LINE CONDITION ASSESSMENT

The Transmission Line Condition Assessment program is based on an eight-year cycle of inspecting and testing all FBC transmission line facilities. The program consists of a pole test and treat component and an above ground visual condition inspection. The test and treat component of the program is aimed at the section of pole at the ground level and below. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying, telecommunications, apparatus, and grounding) attached to the pole. If an issue is detected during the condition assessment, the deficiency is documented and corrected under the following year's transmission line rehabilitation program. The program is managed on an eight-year cycle to levelize both the budget and the resources required. Expenditures vary from year to year based on the length of the lines and number of structures in each line.

3.4.2.2.2 TRANSMISSION LINE REHABILITATION

The specific rehabilitation projects for various transmission facilities involve expenditures for stubbing poles, grounding and bonding, insulators replacements, fibre or telecommunications replacements, replacing poles, cross-arms, guy wires, as well as correcting other defects identified in previous years' assessments. Specific planned expenditures for each transmission line are identified after completion of the condition assessment in the previous years.

FBC is planning to undertake the following two projects during the Rate Framework term that exceed $1 million.

27 Line Rehabilitation

This project includes expenditures for structural stabilization of the transmission line between the Corra Linn (COR) and Salmo (SAL) substations based on the 2023 condition assessment. This includes stubbing poles, structure replacement, replacing cross-arms including defected insulators, tightening hardware, and installing grounding and bonding. The estimated total cost of this project is $4.0 million with expenditures forecast to be incurred from 2024 to 2026.

32 Line Rehabilitation

This project includes expenditures for structural stabilization of the transmission line between the Crawford Bay (CRA) and the Lambert Terminal (AAL) substations based on the 2021 condition assessment, including stubbing poles and installing grounding and bonding. Additionally, the project involves structure replacement, including Transmission or Distribution framing of the structure, insulators and cross-arms and fixing the clearance violations. The estimated total cost of this project is $1.6 million with expenditures forecast to be incurred in 2026.

3.4.2.2.3 TRANSMISSION URGENT REPAIRS

The Transmission Urgent Repairs program is required to repair or replace components that are in poor condition and in danger of immediate failure on the transmission system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions, or other unexpected events or conditions that can cause outages or present risks and must be addressed in an expedient manner. FBC forecasts expenditures based on historical costs, with actual expenditures varying from year to year due to the severity and number of structure failures.

3.4.2.2.4 TRANSMISSION RIGHTS OF WAY

The Transmission Rights of Way program is required for acquiring rights of way and easements for existing transmission facilities that are in trespass on private property. Expenditures for this category will also address access issues with respect to existing rights of way. Many of the transmission lines when initially constructed did not have formal road access to sections of the right of way. Access is required for ongoing operation and maintenance of these lines.

3.4.2.3 Stations Sustainment Capital

Stations Sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently, FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks. Increases in expenditures for the Rate Framework term are mainly due to larger discrete projects required to address transformer and/or equipment condition.

Stations Sustainment capital is further broken down into five categories. Table C3-36 below provides the 2025-2027 Forecast capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-36: FBC Approved and Forecast Stations Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Station Urgent Repairs	617	653	680	759	701
Station Assessment/Minor Planned Projects	1,196	1,059	1,454	1,498	1,549
Spare Parts	-	-	1,940	3,484	8,164
Station Sustainment Programs	4,485	3,796	7,354	6,743	6,859
Station Upgrade/Replacement Projects	543	2,701	9,060	11,143	7,509
Total Station Sustainment	**6,841**	**8,209**	**20,486**	**23,627**	**24,783**

FBC is forecasting increases in the Station Sustainment Programs and the Station/Upgrade Replacement Projects. Additionally, FBC has added a new category titled "Spare Parts". The descriptions of each category and the drivers of the increased expenditures are described below.

3.4.2.3.1 STATION URGENT REPAIRS

Station Urgent Repairs are required to address unexpected failures of in-service equipment. Factors that can result in component failures in substation systems include inclement weather, defective equipment, animal intrusions, and vandalism. These failures can cause outages, or present safety or equipment risks that must be addressed in an expedient manner to maintain safe and reliable service. FBC forecasts Station Urgent Repairs based on historical costs, with actual expenditures varying from year to year due to the severity and number of equipment failures.

3.4.2.3.2 STATION ASSESSMENT/MINOR PLANNED PROJECTS

This category involves ongoing condition assessments of FBC's 68 transmission and distribution substations for environmental, safety and reliability issues on a six-year cycle, and the completion of the required work identified from these assessments. This includes the entire substation system, including equipment such as transformers, breakers, and batteries. FBC plans and executes the work resulting from the condition assessments in subsequent years.

3.4.2.3.3 SPARE PARTS

Due to the increased pressure created by supply chain issues which began to materialize during the Current MRP term, and the resulting increased lead times for receiving necessary equipment, FBC is undertaking a new Spare Parts program commencing in 2025 to comply with Transmission System Planning Performance Requirements (TPL-001-4).

TPL-001-4 became effective in BC on July 1, 2020, and contains the following requirement:

> 2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Where studies identify issues with the equipment being unavailable, spares need to be available within a year, or other system upgrades need to be planned to correct the issues.

FBC completed studies in 2019 to be compliant with the July 1, 2020, effective date to evaluate FBC spare equipment availability, supplier delivery times, and system impacts for equipment with delivery times longer than one year. FBC identified 500/230 kV, 250 MVA transformers as having a delivery time longer than one year and that a spare 500/230 kV, 250 MVA transformer would be needed to correct system issues in 2029. In 2019, all other equipment had a manufacturer delivery time that was less than one year, which meant that no other spare equipment was needed to meet the TPL-001-4 requirements.

As manufacturer delivery and repair times were historically very short, FBC has previously been able to operate its system without in-stock transmission equipment spares with limited system or customer load risk. However, supply chain issues have resulted in current manufacturers' delivery times for high voltage equipment now significantly exceeding one year, and FBC does not have internal spares available. FBC has studied the impact of this potential unavailability on system performance and considers it unacceptable. As such, FBC requires additional spare equipment for TPL-001-4 compliance. The impact of increasing forecast load has also resulted in FBC now requiring the 500/230 kV, 250 MVA spare transformer within the Rate Framework term.

Given the current market constraints outlined above, and in order to comply with TPL-001-4 compliance requirements, FBC is planning to purchase the following equipment as spares during the Rate Framework term:

- 500/230 kV, 250 MVA transformer;
- 230/161/138/63 kV, 200 MVA transformer;
- 245 kV, 2000 A circuit breaker;
- 145 kV, 30 MVAR capacitor bank; and
- 145 kV, 2000 A Point-On-Wave (POW) circuit breaker.

3.4.2.3.4 STATION SUSTAINMENT PROGRAMS

This category includes all programs that fell under the previously titled "Station Equipment" and "Transformer Replacements" categories in the 2020-2024 MRP Application. FBC combined these programs under the title "Station Sustainment Programs" to better reflect the nature of this category of expenditures.

Station Sustainment Programs include new and existing programs required to replace or refurbish obsolete or aging equipment, maintain or improve reliability of the substations, and/or improve legacy designs. Specific planned expenditures for each substation are identified through the CMMS and condition assessments. Existing programs will continue to address refurbishment or replacement work related to power transformers, breakers, disconnect switches, metal-clad switchgear, ground grids, station oil containment, etc.

The forecast increase in expenditures during the Rate Framework term is the result of FBC implementing certain new programs which will support an all-inclusive approach to station condition assessment. The new programs will upgrade legacy distribution transformer high voltage protection, replace porcelain fused cut-outs at legacy stations, implement station security upgrades, and enhance station transformer monitoring.

3.4.2.3.5 STATION UPGRADE/REPLACEMENT PROJECTS

This category includes a number of discrete projects that involve the replacement of key substation equipment, such as power transformers and/or medium voltage switchgear. These projects generally have higher total project costs and may involve multiple years of design and construction. Replacement of this equipment often requires station expansions or upgrades to physical infrastructure to accommodate the new equipment, such as earthworks, foundations, structures, bus work, ground grids, oil containment, transformer sound/blast walls, and associated protection & control and ancillary equipment (lighting, monitoring, alarms, etc.).

To maintain adequate levels of reliability, FBC will replace transmission and distribution station transformers and/or associated equipment based on condition assessments, which consider asset health, reliability, age, risk of failure, loading, outdated load tap changers, and the impact to the FBC system.

Table C3-37 below provides the breakdown of the projects forecast during the Rate Framework term.

Table C3-37: FBC Approved and Forecast Station Upgrade/Replacement Projects Expenditures 2025-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Keremeos Transformer Replacement	543	2,701	940	1,954	176
Castlegar Switchgear Replacement	-	-	2,985	1,293	-
Grand Forks T1 Replacement and Equipment Upgrades	-	-	4,422	6,185	1,272
UBO T2 Replacement	-	-	712	-	-
UBO T4 Replacement	-	-	-	413	1,027
Kaleden Transformer Replacement	-	-	-	319	2,055
Blueberry Station Upgrade	-	-	-	980	2,979
Total Station Sustainment	**543**	**2,701**	**9,060**	**11,143**	**7,509**

All of these projects are forecast to cost over $1 million, with the exception of the UBO T2 Replacement, and are described below:

- **Keremeos Transformer Replacement**: This project is driven by equipment condition issues. The Keremeos Transformer T1 (KER T1) was manufactured in 1974. The KER T1 load tap changer (LTC) is not functioning and is deemed to have failed; as a result, the transformer has lost its ability to regulate voltage. Based on the resulting operational challenges to control customer voltage, the KER T1 transformer needs to be replaced. This project was identified in the Annual Review for 2023 Rates.[108] At that time, the project was expected to be undertaken in 2023 and 2024 at an estimated total cost of $3.2 million; however, the project was delayed due to longer lead times than anticipated for the power transformer. The estimated total cost of this project has decreased slightly due to a minor

[108] Appendix C2, p. 10.

scope change, with a new estimated cost of $3.1 million, and is scheduled to be substantially complete in 2026.

- **Castlegar Switchgear Replacement**: This project is driven by equipment condition issues and is necessary to continue to provide a reliable supply to the town of Castlegar and the surrounding area. A third-party condition assessment completed in 2021 found the metal-clad switchgear to be in very poor condition and recommended the switchgear be replaced. Accordingly, this project will replace the metal-clad switchgear with an air-insulated bus and outdoor vacuum breakers. This project will also require a new control building, and reconfiguration of the transmission and distribution infrastructure to accommodate the switchgear replacement. The estimated total cost of this project is $4.5 million, with expenditures forecast to be incurred from 2024 to 2026.
- **Grand Forks T1 Replacement and Equipment Upgrades:** This project will address aging infrastructure and equipment condition at the Grand Forks Terminal (GFT) station. The project will result in improved reliability and will mitigate environmental and safety risks. The GFT Transformer T1 (GFT T1) was manufactured in 1965. A third-party condition assessment report recommends replacing GFT T1 by 2026. All GFT high voltage and remaining low voltage minimum oil-filled circuit breakers also need to be replaced along with their associated isolation switches which are now obsolete. To improve and simplify protection and operation of the station, a 63 kV ring bus will be installed by modifying the existing 63 kV breaker configuration, which will result in one less breaker required. All other upgrade work aims to mitigate maintenance or protection issues, as well as address equipment condition. The estimated cost of the project is $13.3 million, with expenditures occurring from 2024 to 2027.
- **UBO T4 Replacement**: This project is driven by equipment condition and capacity issues. The Upper Bonnington Transformer T4 (UBO T4) is a Generating Step-up Unit (GSU) that exports generation from the UBO G4 generator. UBO T4, which was manufactured in 1965, is undersized and its condition is deteriorating. An internal FBC condition assessment of UBO T4 was completed in 2023, which found the unit requires replacement in the next two to three years. The estimated total cost of this project is $1.5 million, with expenditures forecast to be incurred from 2026 to 2027.
- **Kaleden Transformer Replacement:** This project is driven by equipment condition issues and aging infrastructure. The project is necessary to continue supplying reliable electricity to Kaleden and will also increase the capacity of the substation. The Kaleden Transformer T1 (KAL T1) was manufactured in 1959. KAL T1 is equipped with a discontinued LTC that is no longer supported by the manufacturer. FBC has experienced previous failures of this LTC model in other areas of the system. It is expected that the KAL T1 LTC will soon begin to experience the same failures. A second transformer is also proposed to improve reliability as only a portion of KAL load can be offloaded to the neighbouring substation during a KAL T1 outage. The existing KAL substation property may be too small to accommodate the rebuild, and land may need to be acquired to either expand or relocate the substation. As explained in the Annual Review for 2023 Rates, this

project was deferred to advance the Keremeos Transformer Replacement project, which presented a larger risk at that time.[109] The estimated cost of this project is $9.7 million, with expenditures forecast to be incurred from 2026 to 2029.

- **Blueberry Station Upgrade:** This project is driven by equipment condition issues and aging infrastructure. The project is necessary to continue supplying reliable electricity to Blueberry, Genelle, and part of Castlegar, and will also increase the capacity of the substation. Blueberry Transformer T1 (BLU T1) was manufactured in 1968. A third-party condition assessment completed in 2021 recommended that the metal-clad switchgear be replaced by 2027. This project will replace BLU T1, install a second transformer, and replace the metal-clad switchgear with an air-insulated bus and outdoor vacuum breakers. The project is estimated to cost $10.0 million, with expenditures forecast to be incurred from 2026 to 2029.

3.4.2.4 Distribution Sustainment Capital

Distribution Sustainment capital expenditures are required to proactively manage the condition and integrity of FBC's distribution line facilities, manage the risk to employees and public safety, and ensure an acceptable level of service is maintained for customers.

Table C3-38 below provides the 2025-2027 Forecast capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison. Each category of expenditure is discussed below.

Table C3-38: FBC Approved and Forecast Distribution Sustainment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Distribution Line Condition Assessment	1,730	1,841	1,684	1,543	1,850
Distribution Line Rehabilitation	3,498	3,268	4,728	4,448	5,154
Distribution Line Rebuilds	2,563	1,781	5,299	5,707	3,423
Secondary Network and Transformer Connectivity	-	-	264	264	265
Distribution Urgent Repairs	2,839	2,859	3,376	3,122	3,388
Small Planned Capital	952	842	929	937	1,120
Forced Upgrades and Line Moves	1,158	1,281	1,426	1,474	1,538
PCB Environmental Compliance	1,702	2,430	758	-	-
Porcelain Cutouts Replacement	2,438	3,507	2,491	-	-
Meter Exchanges	139	140	144	152	162
Other Distribution Sustainment Programs	461	270	1,347	1,367	1,392
Total Distribution Sustainment	**17,480**	**18,219**	**22,446**	**19,014**	**18,291**

Overall, the 2025-2027 Forecast is comparable to the 2023 and 2024 Approved levels, with the largest increases occurring in Distribution Line Rebuilds and Other Distribution Sustainment Programs. Further details on each category are provided below. With regard to the PCB

[109] Appendix C2, p. 10.

Environmental Compliance and Porcelain Cutouts Replacement programs, these have been previously discussed in the 2020-2024 MRP Application[110] and the costs in 2025 are the remaining costs to complete the programs.

3.4.2.4.1 DISTRIBUTION LINE CONDITION ASSESSMENT

The Distribution Line Condition Assessment program is based on an eight-year cycle of inspecting and testing all FBC distribution line facilities. The program consists of a pole test and treat and a condition assessment. The test and treat component of the program is aimed at the section of pole at ground level and below. The above ground visual inspection focuses on the condition of the pole itself and all equipment (anchoring, cross-arms, insulators, guying, apparatus, and grounding) attached to the pole. If an issue is detected during the condition assessment, the deficiency is documented and corrected in the following year. FBC manages the program on an eight-year cycle to levelize both the annual costs and the resources required.

3.4.2.4.2 DISTRIBUTION LINE REHABILITATION

The Distribution Line Rehabilitation program includes specific rehabilitation projects for various distribution facilities and involves expenditures for stubbing poles, replacing poles, cross-arms, insulators, guy wires, and correcting other defects identified through the previous years' assessments. The Distribution Line Rehabilitation program deals with issues that, while not severe enough to require immediate repairs (in which case they would be carried out immediately under the Distribution Urgent Repairs program), are serious enough that they must be addressed in the year following the condition assessment.

3.4.2.4.3 DISTRIBUTION LINE REBUILDS

The Distribution Line Rebuilds program involves the replacement of aged and deteriorated equipment on a larger scale than would typically be performed under the Distribution Line Rehabilitation program. Items include rebuilding failing overhead and underground conductors, replacing rotted poles and platforms, replacing leaking transformers, and installing ground grids at ungrounded services, as well as the replacement of copper conductor in areas considered to be a risk to public or employee safety. FBC identifies these deficiencies through condition assessment data, site assessments and normal daily operations.

The primary reason for the increased expenditures during the Rate Framework term is that, starting in 2025, this program will also include the rebuilding of underground subdivisions where FBC has direct-buried primary and secondary cables that are approaching end-of-life. FBC has identified that these areas are in poor condition and have experienced outages in the past.

3.4.2.4.4 SECONDARY NETWORK AND TRANSFORMER CONNECTIVITY PROJECT

This project will update inaccurate or missing information in FBC's Geographic Information System (GIS). The project will correct inaccurate mapping between a distribution transformer and its AMI meter connections, update inaccurate or missing information for secondary conductor

[110] 2020-2024 MRP Application, pages C-97 and C-98.

type, and update inaccurate or missing phasing information for the primary conductor supplying the distribution transformers. Improving data in GIS related to accurate connectivity of customers supplied by a particular transformer, secondary conductors, and primary phasing will help to improve system planning and design to better respond to electrification mandates. This project will also help identify the need for secondary upgrades in the FBC service territory to continue providing safe and reliable service to FBC customers. The estimated total cost for this project is $1.3 million, with expenditures forecast to be incurred from 2025 to 2029.

3.4.2.4.5 DISTRIBUTION URGENT REPAIRS

The Distribution Urgent Repairs program is required to repair or replace components that are in poor condition and in danger of immediate failure on the distribution system due to weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions, or other unexpected reasons that can cause outages or present risks that must be addressed in an expedient manner. FBC's forecast expenditures are based on historical costs, with actual expenditures varying from year to year due to the severity and number of structure failures.

3.4.2.4.6 SMALL PLANNED CAPITAL

The Small Planned Capital program is similar to the Distribution Condition Assessment and Distribution Rehabilitation programs but captures off-cycle work required to keep the distribution lines safe and reliable. Each year, operational and safety concerns on the distribution system, including storm damage, clearance problems and aging equipment are identified by field staff outside of the normal assessment cycle. Repairs to address these concerns are required to maintain a safe and reliable distribution system. The repairs are generally non-urgent in nature and consequently are not completed under the Distribution Urgent Repair program.

3.4.2.4.7 FORCED UPGRADES AND LINE MOVES

This program is required to complete distribution upgrades driven by third party requests. The following are potential situations where upgrades or line moves are required:

- Requests from governing authorities (e.g., Ministry of Transportation and Infrastructure or municipalities) to relocate distribution lines located on road allowance or highway rights-of-way to accommodate road widening or improvements;
- Requests to relocate distribution lines where FBC does not have sufficient land rights for the distribution line facilities located on customer property; and
- Third party utility requests for upgrade of FBC transmission and distribution line plant to accommodate a shared use arrangement.

3.4.2.4.8 METER EXCHANGES

This category includes the meter replacements and exchanges for metering equipment that fails during the metering compliance or meter re-test program. Metering infrastructure includes meters, current transformers, potential transformers, and ancillary equipment.

Subsequent to the implementation of advanced meters in 2017, FBC restarted the meter exchange compliance sample program in 2022 (pilot) and the full regular program in 2023. Meters are now exchanged and tested a year ahead of meter seal expiry dates. This will continue as an annual program going forward. FBC has expenditures for meters and ancillary equipment to cover compliance sample exchanges, meter damage, and meter failures.

3.4.2.4.9 OTHER DISTRIBUTION SUSTAINMENT PROJECTS

Other Distribution Sustainment expenditures include the following:

- FBC has a number of padmount switchers in critical locations that are near end of life. These switches are 1980's vintage and often serve significant load that cannot be supplied from any other source. When these switchers fail, they result in significant outages with long restoration times. The replacement of end-of-life SF6 gas and oil insulated switchers will continue to be prioritized based on condition and criticality.
- The Underground Cable Replacement program began in 2011 and continues to be an important program for sustainment of the Kelowna network. The replacement of main 350MCM feeder cables manufactured pre-1990 continues to be the focus of this program. FBC has also experienced problems with aged 1/0 aluminium cables of similar vintage in recent years.
- Installation of fault indicators. Fault indicators provide a significant operational benefit by supporting the quick identification and localization of faults and subsequent repair of faulted cables. Without these fault indicators, outage times can be greatly lengthened which negatively impacts reliability for customers. In general, fault indicators should be installed on each primary phase conductor on every switcher node, every junction box node, and on cables leaving feed-through transformers. Fault indicators will allow failures to be located much more easily and therefore improve fault isolation and system restoration in a cost-effective manner.

3.4.2.5 Telecommunications Capital

FBC's telecommunications systems are integral components in the protection relaying system, remedial action schemes, substation operations and control, and field dispatch systems. These systems require ongoing investment for the replacement or upgrade of aging systems for safe and reliable operation of the power system, as well as to address changing standards and regulations such as Mandatory Reliability Standards.

Table C3-39 below provides the 2025-2027 Forecast Telecommunications capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison. Each category of expenditure is discussed below.

Table C3-39: FBC Approved and Forecast Telecommunications Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Communication Upgrades	339	344	313	435	444
Relay Replacement	-	-	700	544	662
Station Smart Device and Recloser Upgrades	326	324	1,217	803	822
SCADA Systems Sustainment	964	1,443	970	1,012	1,078
Systems Upgrades and Replacements	1,384	2,472	2,828	3,946	663
Other Telecommunications	593	616	275	286	301
Total Telecommunications Sustainment	**3,606**	**5,199**	**6,304**	**7,028**	**3,971**

FBC is forecasting increases in Telecommunications capital in 2025 and 2026, with spending forecast to decrease in 2027. The primary categories driving the increases are Station Smart Device and Recloser Upgrades, and Systems Upgrades and Replacements. Additionally, FBC has added a new category of Telecommunications capital titled “Relay Replacement”. Each of the categories is described below, with projects over $1 million identified separately.

3.4.2.5.1 COMMUNICATION UPGRADES

This category includes upgrades to FBC’s telecommunications facilities. These upgrades will enhance the system operators’ ability to monitor the status of the transmission and distribution systems and respond to system events. Furthermore, the upgrades will maintain the integrity of the existing infrastructure used to protect the power system, FBC employees and the general public from damages and outages resulting from major system faults and events.

Some FBC telecommunication equipment is near or beyond its designed operational life. Individual components are increasingly unreliable, and manufacturers no longer supply spare parts or provide product support. In some cases, equipment can no longer be tested and adjusted regularly because it fails when test systems are operated, resulting in long delays putting equipment back in service.

3.4.2.5.2 RELAY REPLACEMENT

FBC has a number of aging and failing electronic relays that also create operational challenges to operate the system safely and reliably. Replacement of these relays is a priority and will facilitate operations, engineering, and planning areas, and enhance system reliability by providing co-ordination of protective devices, accurate information, and real time telemetry on system status, faults and other problems, decreasing the need for complex protection schemes. This new Relay Replacement program will update these devices and integrate them into the telecommunications network. In addition, ongoing upgrades to obsolete or failing intelligent electronic devices at substations will occur as needed.

The program will be managed by prioritizing upgrades based on several factors including device malfunctions, obsolescence and vintage, complexity of troubleshooting, probability of failure and the potential for cost and operational efficiencies benefiting system operation and planning.

3.4.2.5.3 STATION SMART DEVICE AND RECLOSER UPGRADES

This program will address the replacement of other station devices and equipment such as meters, fuses, digital fault recorders, transformer non-electrical protection devices & schemes, and auxiliary protection devices, as well as upgrading distribution field recloser controller and SCADA control addition to aid FBC in operating its electric system safely and reliably.

3.4.2.5.4 SCADA SYSTEMS SUSTAINMENT

The SCADA sustainment program funds annual sustainment projects for SCADA software systems and infrastructure located at the System Control Centre or the Backup Control Centre and communications infrastructure directly connecting the System Control Centre to the Backup Control Centre. Additionally, as MRS continue to evolve, this program will fund MRS-related system upgrade projects that are necessary to maintain compliance with these standards.

3.4.2.5.5 SYSTEM UPGRADES AND REPLACEMENTS

A number of FBC's telecommunications and Protection and Control (P&C) systems have reached end of life and require upgrades or replacement. Included in this category are three projects in excess of $1 million. Each project is discussed further below.

Kootenay RAS Replacement

This project will replace aging relay equipment and add redundant back-up relaying. FBC purchased, designed, and installed the current Remedial Action Scheme (RAS) system in the early 2000s. The overall FBC RAS is broken up into two systems, with the Kootenay RAS completed in 2004 and the Okanagan RAS completed in 2006. The RAS system consists of Schweitzer Engineering Laboratories (SEL) relays (type SEL-421 and SEL-2100), which will be over 20 years old at the time of project completion and are at risk of failing. This system is without redundancy, so if any one of the relays fail, there is no backup, disabling a section of this RAS system until a replacement relay can be put into service.

The estimated total project cost, which is addressing the Kootenay RAS, is $1.3 million, with costs forecast to be incurred in 2027 and 2028.

VHF Radio System Replacement

The existing FBC Very High Frequency (VHF) radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy analog technology is becoming more difficult to support as most new hires are not trained or experienced with these technologies. New 2-way digital radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage, and ability to send data in addition to voice.

The current system consists of 14 VHF repeaters (6 Okanagan, 3 Boundary, 5 Kootenays) and several VHF and Ultra High Frequency (UHF) links connecting the system together. This system will be replaced with spectrally efficient digital radio technology, allowing FBC to leverage the existing FEI radio system and share system components in overlapping coverage areas.

As explained in the Annual Review for 2023 Rates,[111] the first stages of the project are expected to start in 2024. The estimated cost of this project is $4.4 million, and the project is expected to complete in 2026.

eDNA System Replacement

In 2010, FBC purchased and installed eDNA, a data historian product used to collect and archive real time system data from generation sites and from SCADA. The software provider has announced that, as of 2026, eDNA will be at end of life and will no longer be supported, driving the need for FBC to replace this system. The current eDNA product utilizes the corporate IT network both for transport and to store this important data. This project will install a new replacement product for eDNA and migrate existing data into a more secure operations technology network environment where security considerations are more easily managed. The estimated total cost of the project is $3.3 million, with expenditures being incurred in 2025 and 2026.

3.4.2.5.6 OTHER TELECOMMUNICATIONS

This program includes the purchase of new or replacement communications equipment in support of field staff. This equipment includes landline equipment, radio communications for field use, and the installation of fibre cabling and wireless systems intended for multiple applications. These installations provide voice as well as data communications as required. This program supports the communications infrastructure needed for FBC to carry out general business operations, addressing the need for replacing or supplementing communications systems based on identified deficiencies.

3.4.2.6 FBC Contributions in Aid of Construction (CIAC)

FBC's customer contribution policy provides customers a capital credit or allowance based on the amount of investment in distribution poles, conductors, and transformers for the rate classes covered in the applicable retail rate. Any investment in poles, conductors, and transformers necessary to provide service to a customer in excess of this credit or allowance will be paid as a capital CIAC by the new customer. The recoveries in this category are forecast based on the

[111] Appendix C2, p. 12.

anticipated work for forced upgrades and historical levels of receivables for new connects and identified recoverable projects.

The two tables below provide the realized and projected CIAC over the Current MRP term, and the forecasts for 2025 to 2027 with 2023 and 2024 Approved amount provided for comparison.

Table C3-40: FBC Actual and Projected Contributions in Aid of Construction, 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
New Connects	(6,301)	(7,600)	(7,348)	(8,169)	(6,925)
Forced Upgrades	(391)	(689)	(1,150)	(596)	(614)
Total CIAC	**(6,692)**	**(8,289)**	**(8,498)**	**(8,765)**	**(7,539)**

Table C3-41: FBC Approved and Forecast Contributions in Aid of Construction Forecast 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
New Connects	(10,218)	(6,925)	(8,085)	(8,364)	(8,485)
Forced Upgrades	(1,410)	(614)	(765)	(791)	(816)
Total CIAC	**(11,628)**	**(7,539)**	**(8,850)**	**(9,155)**	**(9,301)**

3.4.3 FBC Other Capital

FBC Other Capital includes Equipment, Facilities, and IS expenditures, as well as a new category for Corporate Security expenditures.

Table C3-42 below summarizes the actual and projected Other capital expenditures from 2020 to 2024.

Table C3-42: FBC Actual and Projected Other Capital Actual Expenditures 2020-2024 ($000s)[112]

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Equipment	3,444	2,711	4,155	4,212	4,877
Facilities	3,434	3,685	2,796	4,452	4,096
Information Systems	7,865	7,679	8,588	8,189	8,547
Corporate Security	1,293	1,274	1,381	1,286	1,228
Total Other Capital	**16,036**	**15,349**	**16,921**	**18,139**	**18,748**

Table C3-43 below provides the 2025-2027 Forecast Other capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

[112] During the Current MRP, Corporate Security was included in the IS portfolio under Cybersecurity and in the Sustainment capital portfolio under Physical Security. Actuals for Corporate Security are now shown separately to allow for comparison with the 2025 to 2027 Forecast amounts.

Table C3-43: FBC Approved and Forecast Other Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Equipment	4,099	3,717	6,307	6,194	5,842
Facilities	4,305	4,096	6,945	6,792	4,763
Information Systems	8,246	8,372	9,150	9,400	9,550
Corporate Security	1,008	1,028	2,668	2,536	2,544
Total Other Capital	**17,658**	**17,213**	**25,070**	**24,922**	**22,699**

Each of the categories is discussed further below.

3.4.3.1 Equipment

Equipment capital expenditures include the acquisition of vehicles and equipment and specialized tools and equipment. Expenditures for the equipment category are driven by obsolescence, excessive wear, and regulatory compliance.

Table C3-44 below summarizes the actual and projected Equipment capital expenditures from 2020 to 2024.

Table C3-44: FBC Actual and Projected Equipment Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Vehicles and Equipment	2,550	1,845	3,641	3,520	4,250
Tools and Equipment	894	866	515	692	627
Total Equipment	**3,444**	**2,711**	**4,155**	**4,212**	**4,877**

Table C3-45 below provides the 2025-2027 Forecast Equipment capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-45: FBC Approved and Forecast Equipment Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Vehicles and Equipment	3,490	3,090	5,670	5,545	5,179
Tools and Equipment	609	627	637	649	662
Total Equipment	**4,099**	**3,717**	**6,307**	**6,194**	**5,842**

The forecast capital spending for Tools and Equipment is consistent with both the 2023 and 2024 Approved amounts and with the actual/projected spending during the Current MRP term.

FBC is forecasting an increase in Vehicles and Equipment over the Rate Framework term. The forecast for Vehicles and Equipment is described further below.

- **Vehicles and Equipment:** This category includes the replacement and/or acquisition of specialized heavy fleet vehicles, specialty equipment, mid-duty service vehicles, light duty passenger vehicles, and off-road vehicles necessary to meet the operational requirements of FBC. Over the next few years, FBC has a substantial capital replacement requirement based on replacement triggers identified by age, engine hours and utilization to maintain safe and reliable vehicles and equipment able to respond to customer calls and provide emergency response. FBC plans to replace 63, 24 and 35 vehicles in 2025, 2026 and 2027, respectively. These replacements encompass light duty, medium duty and heavy-duty trucks and vans, trailers, and other equipment.

  FBC considers many factors when determining the need for vehicle replacements. These include suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, and compliance with regulations and sustainability. Each replacement decision is evaluated on a unit-by-unit basis.

3.4.3.2 Facilities

Facilities capital expenditures include the acquisition or leasing of land, non-plant buildings such as offices, field musters and warehouses, and office furniture and equipment. The expenditures focus primarily on capacity planning, upgrading, and replacement of end-of-life assets.

Table C3-46 below provides the actual and projected Facilities capital expenditures from 2020 to 2024.

Table C3-46: FBC Actual and Projected Facilities Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Facilities	3,434	3,685	2,796	4,452	4,096
Total Facilities	**3,434**	**3,685**	**2,796**	**4,452**	**4,096**

Table C3-47 below provides the 2025-2027 Forecast Facilities capital expenditures as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-47: FBC Approved and Forecast Facilities Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Facilities	4,305	4,096	6,945	6,792	4,763
Total Facilities	**4,305**	**4,096**	**6,945**	**6,792**	**4,763**

Compared to the 2023 and 2024 Approved Facilities expenditures, FBC is forecasting an increase in spending in 2025 and 2026, with spending forecast to decrease closer to historical levels in 2027. The key projects included within the 2025-2027 timeframe are discussed below.

Grand Forks Field Office Storage Addition and Yard Reconfiguration

Due to structural concerns, FBC has removed covered storage from this facility and needs to replace it. Concurrently, FBC will make improvements to the flow and flooding concerns for the yard compound. The estimated cost for this project is $2.5 million. FBC will commence the detailed design of the improvements in 2024, with construction to follow in 2025.

Trail Esplanade Interior Office Space

Due to employee growth, FBC will be repurposing the 1st floor office space that it currently leases to another tenant. The tenant is expected to exit the space in 2024. Commencing in 2025, FBC will undertake the following improvements prior to its employees moving into the space: (i) revise the layout; (ii) perform interior finishes; and (iii) add security. FBC's estimated cost of the improvements is $1 million.

Princeton Field Office

The Princeton Field Office is circa 1960 and provides office, warehouse, and yard space for FBC's Princeton crews. This project includes reconfiguring the current office space and mezzanine area to address the lack of sufficient space to support appropriate wash/change rooms, kitchen and crew touch down space. The estimated cost of this project is $1.25 million, with expenditures occurring in 2025 and 2026.

Maintenance of Existing Facilities

FBC needs to maintain its existing facilities. Over the next decade, FBC's buildings and building equipment are entering a large capital replacement cycle due to their age. To sustain aging assets, FBC needs to increase its Facilities capital renewal project expenditures, ultimately impacting the upcoming three-year period.

Building equipment, including HVAC, fire protection, roofing and paving replacements will increase to on average $1.5 million per year. A plan has been developed to systematically replace targeted assets over a three-year period, prioritizing asset condition and criticality. With this proactive approach, FBC can better distribute expenditures over the three-year Rate Framework term without compromising critical downtime.

3.4.3.3 Information Systems

FBC's IS expenditures focus on sustaining, enhancing, replacing, and upgrading existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

Table C3-48 below summarizes the actual and projected IS capital expenditures from 2020 to 2024.

Table C3-48: FBC Actual and Projected IS Capital Expenditures 2020-2024 ($000s)[113]

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
IS Sustainment	5,557	5,019	4,649	5,354	5,622
Application Enhancements	447	887	628	327	337
Business Technology Applications	1,861	1,773	3,311	2,508	2,588
Total Information Systems	**7,865**	**7,679**	**8,588**	**8,189**	**8,547**

Table C3-49 below provides the 2025-2027 Forecast IS capital expenditures by category as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-49: FBC Approved and Forecast IS Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
IS Sustainment	3,679	3,782	6,000	6,200	6,300
Application Enhancements	1,167	1,190	650	700	750
Business Technology Applications	3,400	3,400	2,500	2,500	2,500
Total Information Systems	**8,246**	**8,372**	**9,150**	**9,400**	**9,550**

Overall, on average, FBC's actual/projected IS capital spending has been consistent with the approved amounts during the Current MRP term. While the overall spending has been consistent with approved, spending at the individual category level varies from year to year. This is because FBC manages the IS capital portfolio as a whole, with variations in spending amongst the categories due to a degree of overlap in the business drivers for each of the categories and annual prioritization of requests for IS capital work.

For the term of the Rate Framework, FBC is forecasting a level of IS Sustainment capital that is consistent with the level of capital spending that FBC actually incurred during the Current MRP term and projects to incur in 2024. Although the 2025-2027 Forecast IS Sustainment capital expenditures are higher than the 2023 and 2024 Approved amounts, this is offset by decreases in Application Enhancements and Business Technology Applications compared to the 2023 and 2024 Approved amounts.

The changes in each category are described in the subsections below.

3.4.3.3.1 INFORMATION SYSTEMS SUSTAINMENT

IS Sustainment capital includes infrastructure sustainment, end-user device sustainment, and application sustainment:

113 Cybersecurity was included within IS Capital Expenditures in the Current MRP; however, it is now included in a new portfolio called Corporate Security, as discussed in Section C3.4.3.4 below. As such, capital expenditures related to cybersecurity are not included in Tables C3-48 and C3-49.

- **Infrastructure sustainment:** the capital funding required to replace or upgrade outdated or end-of-life hardware and server software in the data centres. This includes, among other things, servers, operating systems, local area network (LAN) and wide area network (WAN) equipment.
- **End-user device sustainment:** the capital funding required to replace or upgrade end user equipment and software. This includes, among other things, PCs, operating systems, desktop applications, printing equipment and all mobile devices.
- **Application sustainment:** the capital funding required to sustain existing software applications. This includes required upgrades to maintain support, reliability, and performance of existing applications.

As shown in Tables C3-48 and C3-49 above, IS Sustainment capital is the largest area of IS capital spending. Actual IS Sustainment capital spending was higher than the approved amounts during the Current MRP term due to the addition of sustainment costs to support new business tools and devices (e.g., connecting internal systems and data to mobile field users). FBC expects that the IS Sustainment capital spending during the 2025-2027 term of the Rate Framework will be similar to the levels of actual spending experienced during the Current MRP term.

3.4.3.3.2 APPLICATION ENHANCEMENTS

Application Enhancements capital funding is used to modify the functionality or enable capabilities of existing applications to meet annual business requirements. Actual spending on Application Enhancements can fluctuate from year to year based on higher/lower business requests for enhancements to current systems.

FBC has reduced the 2025-2027 Forecast expenditures for Application Enhancements compared to the 2023 and 2024 Approved amounts to be more reflective of actual spending during the Current MRP term.

3.4.3.3.3 BUSINESS TECHNOLOGY APPLICATIONS

Business Technology Applications (Transform) include capital funding for initiatives that impact the way business is conducted and that support business unit priorities. This includes the introduction of new technologies to meet business requirements, system integration that changes business processes and/or the introduction of new business processes, and harmonization of systems that benefit both FEI and FBC. The prioritization and selection of projects for each year are completed by the Fall of the previous year. This process is designed to ensure that projects with higher value will be considered first when allocating finite resources. In addition, the rapid pace of technology changes necessitates more frequent replacement of systems due to obsolescence, loss of technical support and maintenance, risk of cyber threats, or to leverage the benefits of new functionality.

FBC has reduced its 2025-2027 Forecast expenditures compared to the 2023 and 2024 Approved levels to be more reflective of the actual/projected spending levels during the Current MRP term.

3.4.3.4 Corporate Security

Expenditures related to Corporate Security have historically been split between Sustainment capital and Other capital. In the Current MRP, Cybersecurity was included as a category within IS capital, and Physical Security was included within Sustainment capital. Starting in 2025, FBC is now tracking these costs as a new portfolio in Other capital and has included the historical actuals in Table C3-50 for reference.

Table C3-50: FBC Actual and Projected Corporate Security and Business Continuity Capital Expenditures 2020-2024 ($000s)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Corporate Security	1,293	1,274	1,381	1,286	1,228

Table C3-51 below provides the 2025-2027 Forecast capital expenditures for Corporate Security as well as the 2023 and 2024 Approved expenditures for comparison.

Table C3-51: FBC Approved and Forecast Corporate Security and Business Continuity Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Corporate Security	1,008	1,028	2,668	2,536	2,544

As shown in Table C3-51 above, FBC is forecasting an increase in Corporate Security capital expenditures during the Rate Framework term.

As companies respond to the ever changing cyber and physical security threat landscape due to elements such as state sponsored groups, special interest hacktivists and commercially available hacking tools, additional spending is required to enhance FortisBC's Corporate Security risk management programs. These programs are based on a responsive model that adapts to an evolving threat landscape.

Starting in 2025, FBC is forecasting an increase in capital costs for its patch management program of $1.196 million (please refer to Section C2.3.4.4 for a discussion of the O&M component of the patch management program). In recent years, FBC has increased expenditures for patching to respond to evolving security risks and to reduce the threat landscape and vulnerabilities. Increased sophistication in attacker techniques has forced hardware and software companies to release updated code and operating system patches on a more frequent basis to counteract these threats and vulnerabilities. The increased frequency of these vendor released updates requires FBC 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. Additionally, the patching program must increase scope to include all critical and non-critical applications. This prevents attackers from exploiting known flaws in software or devices which could potentially lead to compromised system reliability, including data integrity, confidentiality, or availability.

Additionally, FBC is continuing to strengthen the physical protection of its facilities by enhancing its ability to implement and maintain technologies and strategies that manage the threat landscape. This includes improving the physical security of its operations centres and updating its aging camera infrastructure to address end of life/end of support technology for its video management systems. This work is required to address identified cybersecurity vulnerabilities in legacy systems, as well as camera performance issues pertaining to outdated versions and hardware across many locations, which impacts site monitoring and response at these locations.

3.4.4 FBC Regular Flow-through Capital Expenditures

Flow-through capital expenditures are Regular capital expenditures that are forecast each year in the Annual Reviews, with variances captured in the Flow-through deferral account. FBC is approved to treat certain capital items as flow-through due to a variety of factors, including their uncontrollable nature or uncertainty in scope, costs, and timing. FBC is also approved to treat capital expenditures related to Clean Growth Initiatives as flow-through.

For the Rate Framework, FBC will continue to forecast Regular Flow-through capital related to its EV DCFC Service, as approved by Decision and Order G-215-21. In addition, as explained in Section C2.5.2, FBC is proposing to treat the incremental MRS assessment report costs as forecast (flow-through) during the term of the Rate Framework. These incremental costs may be O&M, capital, or both. Please refer to Section C2.5.2 for the background and rationale for the proposed flow-through treatment.

3.4.5 FBC Regular Capital Summary

Based on FBC's current knowledge of system requirements and industry drivers, FBC is forecasting increased levels of spending over the course of the Rate Framework relative to the Current MRP. With the increased provincial focus on electrification, the entirety of FBC's system, from generation to local distribution infrastructure and the necessary support systems, requires investment to address both the ability to accommodate load growth (through Growth capital expenditures), and the ability of the existing infrastructure to support current and increasing levels of demand.

With regard to Growth and Sustainment capital, the increased capital spending is primarily driven by the following:

- Increased requirements for system improvements to the transmission and distribution systems to accommodate load growth; and
- Upgrades to aging assets, particularly Generation and Stations assets, to meet current codes and standards, to address the condition and age of infrastructure, and to improve reliability.

Other capital is forecast to increase as Equipment and Facilities are entering a large capital replacement cycle due to their age. FBC is also proposing increased investment in corporate security, including increased expenditures in patch management, given the need to address the risk environment.

Finally, FBC proposes to continue its flow-through treatment for Regular capital related to its EV DCFC service and add MRS assessment report costs to this category of expenditures.

3.4.6 FBC Major Capital Projects

Major Projects are capital expenditures that do not form part of Regular capital spending as they are approved through a CPCN or other application. In the MRP Decision, the BCUC determined that FBC's CPCN threshold for the Current MRP term would be $20 million.[114] FBC proposes to maintain the currently approved CPCN threshold of $20 million for the Rate Framework term.

The following are examples of the Major Project applications that may arise during the course of the Rate Framework term:

- FortisBC Enterprise Resource Planning (ERP) Modernization and Electric Customer Information System (CIS+) Replacement
- FBC South Slocan Dam Free Overflow Spillway Concrete Refurbishment
- FBC Creston Station Upgrade
- FBC Stony Creek Station Upgrade

Each of these projects is described in more detail below.

FortisBC ERP Modernization and Electric CIS+ Replacement

Forecast Implementation Timeline: *2025 to 2027*

SAP was initially installed in 1998 and is the ERP system used extensively across FortisBC. FortisBC has been informed that SAP will no longer provide support for the current platform beyond 2027 and, as such, the ERP Modernization project will transition the existing FortisBC system to the new SAP S/4 HANA version. Additionally, FBC will be replacing CIS+, which is a system deployed in 1999 that FBC uses to house the meter to cash process and information for all electric customers. At nearly 25 years old, this system is no longer supported by the software manufacturer and requires ongoing customized support to ensure the continued accuracy and security of customer billing information. FBC intends to align the customer billing system with FEI's system. As such, FBC will be seeking to replace the current CIS+ system with SAP S/4 HANA at the same time as FortisBC transitions to SAP S/4 HANA.

[114] MRP Decision, p. 133.

In summary, the ERP Modernization and Electric CIS+ Replacement scope is to upgrade to a newer, more advanced version of the current ERP system used by both FEI and FBC, and to replace the current FBC CIS+. Costs for the project will be allocated between FEI and FBC. Further discussion on the project and the cost allocation will be provided in the upcoming application.

South Slocan Dam Free Overflow Spillway Concrete Refurbishment

Forecast Construction Timeline: *2026 to 2032*

The South Slocan Dam was built in 1928 as a concrete gravity dam with two separate lengths. One length contains the power intake structure and powerhouse and is constructed on the west channel of the Kootenay River. The other length consists of a free overflow spillway constructed on the east channel of the Kootenay River. The total crest length is 764 metres (2,505 feet) and the maximum height is 23 metres (75 feet).

The scope of this project includes the rehabilitation of deteriorated concrete of the free overflow spillway, installation of dam safety instrumentation, installation of post tensioned anchors, and upgrade of the flashboards.

The upgrade of the free overflow spillway is essential for the proper operation of the South Slocan Dam since there are no spillway gates and no other mechanical or electrical equipment for the flow control system for the passage of floods at South Slocan Dam. The free overflow sections of the spillway comprise the flow control for flood passage.

Creston Station Upgrade

Forecast Construction Timeline: *2025 to 2027*

This project is driven by equipment condition issues and aging infrastructure. The project is necessary to continue supplying reliable electricity to Creston and the surrounding area and will also increase the capacity of the substation.

The Creston Transformer T1 (CRE T1) was manufactured in 1974, and the Creston Transformer T2 (CRE T2) was manufactured in 1976. CRE T1 and CRE T2 are each equipped with a discontinued LTC that is no longer supported by the manufacturer. The condition of the CRE T1 and CRE T2 LTCs is deteriorating. FBC has experienced previous failures of the same LTC model used in CRE T1 in other areas of the system. FBC expects that the CRE T1 LTC will soon begin to experience the same issues. The CRE T2 LTC has also been recommended for immediate service by a third party due to age. Furthermore, the metal-clad switchgear has been in service since 1961 and, based on a a third-party condition assessment completed in 2021, is recommended for replacement by 2025.

This project proposes to rebuild the CRE substation, which includes replacing the metal-clad switchgear with air-insulated bus and outdoor vacuum breakers. The existing CRE substation property is too small to accommodate the rebuild, and land needs to be acquired to either expand or relocate the substation.

Stoney Creek Station Upgrade

Forecast Construction Timeline: *2026 to 2029*

This project is driven by equipment condition issues and aging infrastructure. The project is necessary to continue supplying reliable electricity to portions of Trail, including the Boundary Regional Hospital and Warfield, and will also increase the capacity of the substation.

The Stoney Creek Transformer T1 (STC T1) was manufactured in 1969. An internal FBC condition assessment completed in 2023 found the STC T1 to be nearing end-of-life and the majority of the STC equipment to be in poor operating condition. The assessment also identified that corrosion from nearby industry is beginning to impact the safe and reliable operation of the equipment. The assessment recommends rebuilding the station by 2028 and that FBC consider relocating the substation to prevent premature equipment degradation from corrosion.

3.5 CONCLUSION

FortisBC's proposed capital expenditures during the Rate Framework term reflect the appropriate level of capital expenditures needed to ensure the safety and reliability of the FortisBC gas and electric systems and to provide service to new and existing customers. The proposed forecast approach for FBC Regular capital and FEI Regular Sustainment and Other capital, coupled with the proposed formula approach for FEI Growth capital, are needed to meet system requirements and customer needs in the changing operating environment, while also providing incentive and flexibility to implement capital plans efficiently.

The primary drivers for the increase in capital expenditures are increased requirements for system improvements to accommodate load growth, upgrades to aging generation assets to meet current codes and standards, and equipment replacements necessary to address condition, aging infrastructure and improve reliability.

4. ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

4.1 INTRODUCTION

This section includes a description of the cost and revenue items required to determine the Companies' annual revenue requirements, which will be included in each year's Annual Review materials. The components that make up the FEI and FBC annual revenue requirements will largely remain the same, and FortisBC is proposing to continue the treatment approved during the Current MRP, where variances between forecasts and actuals are captured in a single Flow-through deferral account except where an approved deferral account either already exists or new deferral accounts arise and are approved by the BCUC during the term of the Rate Framework.

4.2 REVENUE FORECASTS

Revenues include the amounts received from customers at the existing approved rates for the sale and delivery of energy, plus various other revenues (e.g., revenues received under tariff supplements, etc.).

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. As in the Current MRP, the Companies will calculate the revenue forecast to be recovered at the existing approved rates in each year's Annual Review, based on a one-year forecast of the energy consumption and customer counts (i.e., demand/load forecasts). The Companies are proposing to continue the treatment of variances approved during the Current MRP, which includes:

- **FEI:** Revenue variances related to the use rates of residential and commercial customers (Rate Schedules 1, 2 and 3/23) will continue to be subject to the Revenue Stabilization Adjustment Mechanism (RSAM) mechanism which has been in existence since 1994. All other variances in revenues will be captured in the Flow-through deferral account.
- **FBC:** All variances in revenues will be captured in the Flow-through deferral account.

The purpose of the demand/load forecasts provided in the Annual Review process is to provide a one-year forecast of energy, as well as customer counts for the residential, commercial, and industrial rate classes, which are then used to set rates for the single test-year of each Annual Review. The demand/load forecasts provided in the Annual Review are not intended for long-term planning of the Utilities. Forecasts used for long-term planning purposes are completed separately in other proceedings and are not comparable to a single-year forecast used to set rates for the immediate year.

In contrast to a short-term single-year forecast which relies on immediate market conditions and recent actual demand data, long-term forecasts for resource planning or the development of Major Projects typically cover 20 years or longer and are more subjective, with a higher degree of uncertainty in the variety of factors impacting the forecasts, including economic indicators (such as carbon pricing), regulatory and policy changes, and codes and standards changes (among others).

As discussed in Section A3, FortisBC proposes to host a targeted workshop on demand/load forecasting to review and discuss the differences between the methods employed for a single-year short-term forecast used to set rates annually and the method employed for long-term forecasting for the purposes of future infrastructure and resource planning. FortisBC also notes that as discussed in Section B3.1.1, the next long-term resource plans for FEI and FBC are expected to be filed in 2026 and 2025, respectively (i.e., during the Rate Framework term). Through the consultation and development of the long-term resource plans, BCUC staff and interveners will have the opportunity to participate in sessions specifically focused on long-term forecasting methods, and these methods will be thoroughly reviewed in the respective long-term resource plan regulatory processes.

The methods for determining the demand/load forecasts used to set rates annually during the term of the Rate Framework for each Company are described below.

4.2.1 Demand Forecasts (FEI)

FEI proposes to continue the use of the existing forecasting methods from the Current MRP for the purposes of setting delivery rates in each Annual Review over the term of the Rate Framework. FEI's forecasting methods are based on the recommendations contained in the Forecasting Method Study which was filed in the 2020-2024 MRP Application. This Forecasting Method Study was based on the culmination of research and testing over a number of years since 2015.[115] Please refer to Appendix C4-1 for a detailed description of FEI's current demand forecast methods.

FEI's forecasting methods have consistently produced a high level of accuracy when forecasting for the upcoming rate-setting year. Table C4-1 provides the aggregate variance in demand (excluding NGT and LNG customers) between actuals and forecast from 2015 to 2023. During this time the forecasting method has remained the same, with the exception that in 2020, the BCUC approved the adoption of the Exponential Smoothing (ETS) method for the use-rate forecasts of residential and commercial rate schedules (i.e., RS 1, 2, 3, and 23).[116] As demonstrated below, variances in aggregate demand have been less than five percent from 2015 to 2023 with the exception of 2016, and the Mean Absolute Percentage Error (MAPE)[117] over the period was approximately 2.7 percent.

[115] In response to the BCUC's Decision and Order G-86-15 regarding FEI's Annual Review for 2015 Delivery Rates, FEI began testing alternative forecasting methods in 2015 and included the results in a Forecasting Method Study that was filed in the 2020-2024 MRP Application.

[116] ETS was adopted for the RS 1, 2, 3, and 23 UPC forecasts as a result of the Forecasting Method Study filed as part of the 2020-2024 MRP Application. All other components of the forecasting method remained the same as the method used during the 2014-2019 PBR Plan term.

[117] MAPE measures the average absolute percentage difference between actual and forecast, i.e., average of the absolute variance in percentage.

Table C4-1: FEI's Demand Forecasting Variance (excluding NGT and LNG) from 2015 to 2023

Aggregate Demand (GJ)	2015	2016	2017	2018	2019	2020	2021	2022	2023
Actual	209,461,021	219,284,171	223,268,141	225,749,105	226,415,934	229,038,780	232,277,344	218,624,370	214,096,826
Forecast	205,083,634	205,658,686	212,768,380	226,154,710	232,598,417	231,967,326	227,138,737	228,364,535	214,583,313
Variance = (ACT-FCST)	4,377,387	13,625,485	10,499,761	(405,605)	(6,182,483)	(2,928,546)	5,138,607	(9,740,165)	(486,487)
% Variance = (Variance/ACT)	2.1%	6.2%	4.7%	-0.2%	-2.7%	-1.3%	2.2%	-4.5%	-0.2%

In addition, Table C4-2 below provides the aggregate variance (excluding NGT and LNG customers) in customer counts between actuals and forecast from 2015 to 2023. For the aggregate customer count, upon which FEI's formula O&M is based, the variances have been consistently small at less than two percent since 2015, and the MAPE for customer counts over the period is minor at approximately 0.5 percent.

Table C4-2: FEI's Customer Count Forecasting Variance (excluding NGT and LNG) from 2015 to 2023

Aggregate Customers (Year-End)	2015	2016	2017	2018	2019	2020	2021	2022	2023
Actual	979,277	991,591	1,006,043	1,027,092	1,038,354	1,051,752	1,062,480	1,073,302	1,085,331
Forecast	975,747	986,172	1,005,520	1,013,027	1,032,420	1,049,143	1,058,838	1,074,510	1,080,167
Variance = (ACT-FCST)	3,530	5,419	523	14,065	5,934	2,609	3,642	(1,208)	5,164
% Variance = (Variance/ACT)	0.4%	0.5%	0.1%	1.4%	0.6%	0.2%	0.3%	-0.1%	0.5%

The small variances since 2015 show that the existing forecasting methods for FEI have been effective in providing reasonably accurate forecasts in each Annual Review. Since the process for forecasting energy demand and customer counts will be repeated in each Annual Review with updated actuals, any ongoing changes in customer behaviour or the trend of customers' energy use profile (due to the energy transition or for other reasons) will be reflected in the actuals each year when the forecasts are developed. Furthermore, as mentioned above, FEI is proposing to continue with the RSAM and Flow-through deferral account treatment which will capture all variances between forecast and actual demand. As such, the impacts of any variances will be accounted for and flowed to customers in the following year.

Given the performance of FEI's existing forecasting methods and the short-term nature of the single test-year forecast with updates completed each year, as well as the use of deferral accounts to capture all forecasting variances, FEI considers the existing forecasting methods continue to be appropriate for the three-year term of the Rate Framework. As explained in Section C1.10, FEI is requesting that the demand methods for setting delivery rates in the Annual Reviews be approved for the term of the Rate Framework and that these methods be out of scope for the Annual Reviews during the Rate Framework term.

4.2.1.1 NGT and Non-NGT Demand Forecasts (FEI)

As part of FEI's Annual Reviews and calculation of the revenue requirement, FEI will continue to provide CNG and LNG demand forecasts related to NGT customers (for CNG and LNG for transportation) and non-NGT customers for LNG sales under RS 46, based on existing contract demand as well as ongoing discussions with existing and potential customers that are expected to secure firm contracts with FEI.

In the Annual Review for 2024 Delivery Rates Decision and Order G-334-23 (2024 Annual Review Decision), the BCUC directed FEI:[118]

> …to discuss alternative methodologies for forecasting non-NGT LNG demand and to provide an update on its forecasts for LNG export volumes related to spot purchase agreements as part of its next revenue requirements application. [Emphasis added]

FEI considers that forecasting non-NGT LNG demand consistent with its current practice continues to be the best approach at this time. FEI forecasts its non-NGT LNG demand by including a forecast of volume for which FEI has firm contract demand plus demand associated with customers that have spot purchase contracts. The spot purchase customer demand is derived from direct conversations with those customers. This approach is similar to FEI's method for forecasting Industrial customer demand, where FEI circulates a survey to its Industrial customers requesting them to forecast their own expected usage. FEI's non-NGT LNG demand is typically not backed by firm take-or-pay commitments as most are spot purchases, with the majority of this demand being for the ISOtainer LNG business. FEI's ISOtainer LNG demand is affected by factors such as LNG market price, foreign exchange, and logistics costs, making the non-NGT LNG forecast more uncertain. Therefore, FEI considers that its own customers are best able to forecast their own demand.

In response to the BCUC's directive in the 2024 Annual Review Decision, FEI considered the following alternative forecasting methods:

1. Exclude any spot demand from the forecast, which is the method FEI used prior to 2016. In the Annual Review for 2015 Delivery Rates Decision and Order G-86-15, the BCUC directed FEI "to address the issue of spot purchases more fully and provide a proposal for including some or all of these purchases in the demand forecast based on an analysis of the probability of various outcomes". In response, starting in 2016, FEI included an annual forecast of spot volumes based on discussions with customers.
2. Utilize the most recent full year of actuals as the subsequent period's forecast, without adjustment. This approach would not account for any changes in demand that FEI would be anticipating for the upcoming year based on conversations with customers (existing or potential) or developments in the market. Further, due to the timing of the Annual Reviews, there would be a two-year lag between the actuals used as the forecast for the test period (e.g., when setting rates for 2025, FEI would be using the most recent full year of actual demand, which would be 2023).

Of the two alternatives identified above, FEI considers the first alternative to be more reasonable, because it would account for expected changes in customer demand since the previous Annual Review forecast but would exclude speculation in spot related demand which is the area of the forecast that can create the largest variances.

[118] Page 9.

FEI continues to consider its current forecasting method to be the most appropriate. FEI acknowledges that there is a large degree of uncertainty in the non-NGT LNG ISOtainer demand, which also means that the likelihood of changes occurring more quickly is higher (i.e., there is a higher likelihood compared to other customer classes that spot purchase agreements could materialize and result in increased demand during the test year). Further, and similar to the Industrial customer forecasting approach, FEI is in contact with its existing and potential customers, and it therefore is reasonable to consider these conversations (including the customers' own demand expectations) when developing the upcoming test year's demand forecast.

Finally, and regardless of the method adopted, the revenue variances that result from demand variances are accounted for in FEI's Flow-through deferral account and these variances are recovered from or returned to customers in subsequent years.

4.2.2 Load Forecasts (FBC)

FBC proposes to continue the use of the existing forecasting methods from the Current MRP for the one-year forecast in each Annual Review over the term of the Rate Framework. Please refer to Appendix C4-2 for a detailed description of FBC's current load forecast methods.

FBC's forecasting methods have consistently produced a high level of accuracy when forecasting for the upcoming rate-setting year. Table C4-3 below provides the aggregate variance in load between actuals and forecast from 2015 to 2023. The forecasting method has remained the same over this period. As demonstrated below, the variances in the aggregate load have been less than three percent with the exception of 2022,[119] and the MAPE for the load forecast over this period is approximately 1.5 percent.

Table C4-3: FBC's Load Forecasting Variance from 2015 to 2023

Aggregate Demand (GWh)	2015	2016	2017	2018	2019	2020	2021	2022	2023
Actual	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,785	3,808
Forecast	3,499	3,540	3,559	3,485	3,602	3,602	3,664	3,591	3,775
Variance = (ACT-FCST)	(53)	(60)	(47)	79	(10)	14	13	194	33
% Variance = (Variance/ACT)	-1.5%	-1.7%	-1.3%	2.2%	-0.3%	0.4%	0.4%	5.1%	0.9%

In addition, Table C4-4 below provides the aggregate variance in customer counts between actuals and forecast from 2015 to 2023. For the aggregate customer count, upon which FBC's formula O&M is based, the variances have been consistently less than two percent since 2015 and the MAPE for customer counts over the period is small at approximately 0.7 percent.

[119] As explained in the Annual Review for 2023 Rates (page 23) and in the response to BCUC IR1 7.3 in the Annual Review for 2024 Rates, the larger variance in 2022 was primarily due to higher than forecast data centre load.

Table C4-4: FBC's Customer Count Forecasting Variance from 2015 to 2023

Aggregate Customers (Year-End)	2015	2016	2017	2018	2019	2020	2021	2022	2023
Actual	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,698
Forecast	132,164	133,578	134,585	136,602	139,459	142,865	143,721	148,462	152,011
Variance = (ACT-FCST)	(281)	(28)	1,208	1,986	1,569	849	2,109	(27)	(1,313)
% Variance = (Variance/ACT)	-0.2%	0.0%	0.9%	1.4%	1.1%	0.6%	1.4%	0.0%	-0.9%

The small variances since 2015 show that the existing forecasting methods for FBC have been effective in providing a one-year forecast in each Annual Review. Since the process for forecasting energy demand and customer counts will be repeated in each Annual Review with updated actuals, any ongoing changes in customer behaviour or the trend of customers' energy use profile (due to the energy transition or for other reasons) will be reflected in the actuals each year when the forecasts are developed. Furthermore, as mentioned above, FBC is proposing to continue with the Flow-through deferral account treatment which will capture all variances between forecast and actuals. As such, the impacts of any variances will be accounted for and flowed to customers in the following year.

Given the performance of FBC's existing forecasting methods and the short-term nature of the single test-year forecast with updates completed each year, as well as the use of deferral accounts to capture all forecasting variances, FBC considers the existing forecasting methods continue to be appropriate for the three-year term of the Rate Framework. As explained in Section C1.10, FBC is requesting that the demand methods for setting rates in the Annual Reviews be approved for the term of the Rate Framework and that these methods be out of scope for the Annual Reviews during the Rate Framework term.

4.3 *COST OF ENERGY*

4.3.1 Cost of Gas (FEI)

FEI's cost of gas includes the cost of the gas commodity, the cost of midstream resources (storage and transportation), and the Core Market Administration Expense (CMAE) costs associated with providing the gas supply function. With the exception of the CMAE costs, as further discussed below, FEI does not request approval of forecast gas costs as part of the Annual Review process. Instead, any rate changes related to gas costs are dealt with separately through the quarterly gas cost reports to the BCUC. Any variations between forecast and actual gas costs will continue to be returned to or recovered from customers through the existing deferral account mechanisms (i.e., the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA)).

While FEI does not request approval of forecast gas costs as part of the Annual Review process, the forecast cost of gas is required for the calculation of FEI's annual revenue requirement over the test year of each Annual Review.

With regard to the CMAE costs, FEI has been filing for approval of the CMAE budget as part of its Annual Review process during the Current MRP term. Prior to that time, FEI submitted its annual CMAE budget for approval in its fourth quarter Gas Cost Reports.

The change in approach to filing the CMAE budget arose from BCUC Decision and Order G-79-14. In that decision, the BCUC directed FEI to include the CMAE budget in its revenue requirement applications, commencing in 2020 (i.e., after the conclusion of the 2014-2019 PBR Plan term). The BCUC stated (on page 10):

> The Panel acknowledges FEI's request to submit the CMAE budgets with the fourth quarter gas cost reports. However, the Panel is concerned that if the CMAE Budget is submitted at the same time, the Commission would have insufficient time to properly review the CMAE Budget. Further, the Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications.

Further, in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20 (page 16), the BCUC stated:

> The Panel directs FEI to include, in its next revenue requirements or MRP application following the MRP term, a comprehensive review of the CMAE costs including consideration of whether these costs are conducive to a formulaic approach or whether they should continue to be forecast with flow-through treatment, and whether the current allocation percentages to the CCRA and MCRA remain appropriate.

The comprehensive review directed by the BCUC in the 2020-2021 Annual Review Decision is included in Appendix C4-3 of the Application.

FEI has at various times in the past included the CMAE budget review separately (2006-2009 and 2014-2019) or as part of (2010-2013 and during the Current MRP) its rate-setting applications.

With the most recent direction from the BCUC in the 2020-2021 Annual Review Decision, FEI has taken the opportunity to complete a comprehensive review of the CMAE costs and, based on this review, FEI has concluded that: (1) forecasting the CMAE costs annually (as opposed to applying a formulaic approach) continues to be the most appropriate approach; and (2) the review of the annual CMAE costs is most appropriately undertaken as a separate application filed at or near the same time that FEI files its third quarter gas cost reports (Q3 Gas Cost Reports).

First, FEI clarifies how variances in CMAE costs are currently treated, because FEI believes that there may be some confusion as to what "flow-through" treatment means in the context of CMAE costs, and this confusion may have bearing on the BCUC's assessment of how to treat the CMAE costs going forward. While the CMAE costs were forecast annually as part of the Annual Reviews during the Current MRP, the variances in CMAE costs are not subject to "flow-through treatment" in the way that this term is used in the Annual Reviews. Since CMAE costs form part of commodity and midstream rates, and not delivery rates, variances are not captured in the Flow-through deferral account. Variances are instead captured in FEI's commodity and midstream rates. This distinction is important because, if the CMAE costs were to be moved to form part of FEI's Base O&M (and thus be subject to the annual indexed-based formula), variances between forecast and actual costs would impact the earnings sharing mechanism, yet these costs are in reality being recovered through commodity and midstream rates. This creates a disconnect between the impact the variances would have on delivery rates (i.e., through the ESM) and the method by which the actual costs are being recovered.

Second, FEI's delivery rates do not include any gas costs (including any midstream costs), and the Annual Review process makes no other requests related to FEI's gas costs or gas cost related charges. Therefore, FEI submits that the Annual Review process is not the appropriate forum to review the CMAE costs and that these costs should be reviewed at the same time that the other gas cost items are reviewed. However, FEI acknowledges the BCUC's previous concern that including the CMAE budget in the fourth quarter gas cost report (Q4 Gas Cost Report) did not provide enough time to review the budget, as the Q4 Gas Cost Report is typically filed with the BCUC in the latter part of November. To address this issue, FEI proposes to file the CMAE budget at or near the same time as the Q3 Gas Cost Report, which is typically filed in early September. This will allow adequate time for the annual CMAE budget to be reviewed and approved prior to the end of the year.

Accordingly, FEI seeks approval to continue to forecast the CMAE budget annually, but to file the budget for review as a separate application at or near the same time as the Q3 Gas Cost Reports. Please refer to Appendix C4-3 for a detailed explanation of FEI's proposals regarding CMAE.

4.3.2 Power Supply (FBC)

FBC's power supply cost includes power purchase expense, wheeling expense, and water fees. In addition to cost variances, load variances due to customer growth, usage, or weather also contribute to variances in power purchase expense.

FBC will continue to forecast power supply costs each year and include this forecast (in the same format) in the Annual Reviews. Further, FBC proposes to continue recording variances between forecast and actual power supply costs in the Flow-through deferral account.

4.4 *Other Revenue*

The Companies will continue to forecast Other Revenue each year in the Annual Reviews during the term of the Rate Framework and will include discussions of each of the items consistent with the approach in the Annual Reviews during the Current MRP term. Components of Other Revenue that currently have deferral account treatment are:

- FEI's NGT Tanker Rental Revenue and CNG & LNG Service Revenue;
- FEI's earned return and income tax expenses for the cost of service of FEI's biomethane assets;

- FEI's Southern Crossing Pipeline Third Party Revenue; and
- FBC's carbon credits for the EV DCFC service.

FortisBC proposes to continue this treatment, with the variances in the remaining components of Other Revenue continuing to result in variances in earnings and being shared through the earnings sharing mechanism.

4.4.1 Late Payment Charges

In the FEI 2024 Annual Review Decision (pages 10-11), the BCUC stated the following:

> …variances between forecast and actual Late Payment Charges are not subject to flow-through treatment, so that any variances between forecast and actuals become subject to earnings sharing between shareholders and ratepayers on a 50/50 basis under the MRP and may, therefore, be perceived as susceptible to under-forecasting of these revenues on that basis, even though there is no evidence to that effect in this proceeding. To address this concern, **the Panel directs FEI to evaluate the impacts of alternative methodologies for forecasting Late Payment Charges, including forward-looking approaches (e.g., as a function of projected revenue or customer bills) and backward-looking approaches (e.g., the current two-year versus prior three-year historical average basis) as part of its next revenue requirements application.**

Starting in FEI's and FBC's Annual Reviews for 2023 Rates, the Companies changed their approach to forecasting late payment charges. This revised approach uses the average of the previous year's actual late payment charges and the current year's projected late payment charges. Previous to the 2023 Annual Reviews, the Companies used the three-year average of historical actuals.

The primary reason for the change in forecasting approach was that in recent years, factors such as the COVID-19 pandemic, the implementation of customer relief measures, and ongoing inflationary impacts, had resulted in the historical results prior to the 2021/2022 timeframe not providing an accurate representation of the expected future late payment charges. Therefore, to account for the changes (i.e., increases) in late payment charges being experienced, both FEI and FBC shortened the historical timeframe used to calculate the forecast so that the forecast was based on the more recent and relevant years.

Tables C4-5 and C4-6 below show the approved and actual late payment charges for both Companies from 2020 to 2023 as well as the 2024 Approved late payment charges.

Table C4-5: FEI Late Payment Charges ($000s)[120]

FEI	2020	2021	2022	2023	2024
Approved	$ 1,683	$ 2,968	$ 2,719	$ 3,385	$ 3,607
Actual	822	2,635	3,638	3,863	
Variance	**(861)**	**(333)**	**919**	**478**	

Table C4-6: FBC Late Payment Charges ($000s)

FBC	2020	2021	2022	2023	2024
Approved	$ 205	$ 829	$ 875	$ 994	$ 962
Actual	203	892	962	895	
Variance	**(2)**	**63**	**87**	**(99)**	

As Table C4-5 above shows, in the three years prior to FEI changing the forecasting approach, FEI over-forecast late payment charges in two of the years; however, in 2022 the under forecast was more significant. The under-forecast was due to FEI using three years of actual results that were prior to the COVID-19 pandemic and other impacts previously discussed (i.e., 2018, 2019 and 2020). For 2023 (i.e., the first year using the revised forecasting approach), the actual late payment charges were still less than the approved, but the under-forecast was much less significant.

With regard to FBC, the actual results have been both higher and lower over the Current MRP term, though the Company notes that the result in 2023 using the revised forecasting approach is an over forecast, not an under forecast (thus the opposite of the concern stated by the BCUC in the FEI 2024 Annual Review Decision).

Further, had FortisBC continued to use the previous method (i.e., 2024 forecast based on 2020, 2021, and 2022 Actuals), then the 2024 forecasts for both FEI and FBC would have been significantly lower (FEI's forecast would be $2.365 million and FBC's forecast would be $0.686 million). FortisBC does not consider these amounts to be a reasonable forecast for 2024, as they are significantly lower than the 2023 Actuals.

Even though the economic impacts of the COVID-19 pandemic have dissipated, FortisBC considers that its current approach for both Companies remains appropriate because it excludes historical years where peak pandemic and inflationary impacts likely influenced late payment charges. At least in the near term, FortisBC anticipates that there may be continued volatility in late payment charges and, as such, the appropriate approach to forecasting is to use the most recent actual and projected results. The current forecasting approach, which uses the most recent information available, will ensure the latest upward or downward trends in the late payment charge revenue is accounted for. This holds true whether the cause of the trend is due to the general

[120] FEI's Late Payment Charges include Fort Nelson for consistency, as Fort Nelson was approved for common rates with FEI commencing in 2023.

economy or factors more specific to gas and electric customer bills such as higher usage or carbon tax changes.

FortisBC also considered a forward-looking approach such as using a percentage of the projected revenue for the forecast year to forecast the late payment charges, as suggested by the FEI 2024 Annual Review Decision. However, FortisBC could not find an observable trend between the actual late payment charges and the projected revenue that would suggest this method is reasonable.

Considering the above, FortisBC considers its current forecasting approach for late payment charges continues to be the most reasonable. At the conclusion of the three-year Rate Framework period, with the benefit of additional years of actual results using this revised forecasting approach, FEI and FBC will assess whether a different forecasting approach should be used.

4.5 O&M

FortisBC's O&M under the Rate Framework will continue to include both formula and forecast components. Please refer to Section C2 for details of FEI's and FBC's O&M over the three-year term of the Rate Framework.

As part of the Annual Review process, FortisBC will continue to calculate formula O&M by adjusting the previous year's Base O&M amount for the inflation factor, productivity factor and customer growth, which are discussed in Sections C1.3 through C1.5. Variances in formula O&M will result in variances in earnings and will be shared through the earnings sharing mechanism.

For those items which are forecast on an annual basis, FEI and FBC will continue to include appropriate discussion of each of the items in the Annual Reviews. FortisBC will also continue to capture the variances between forecast and actual amounts in the Flow-through deferral account, as discussed in Section C4.13.2, or through other approved deferral accounts.

4.6 RATE BASE

FEI's and FBC's rate base is comprised of the mid-year net plant in service of each utility, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income taxes, and other utility plant adjustments.

The mid-year net plant in service component of rate base is increased by capital additions that result from ongoing capital expenditures and is reduced by accumulated depreciation. The treatment of Regular capital expenditures and Major Capital expenditures is discussed in Section C3 of the Application, where forecasts for FEI's Regular Sustainment and Other capital expenditures and FBC's Growth, Sustainment and Other capital expenditures are also provided. FEI's Regular Growth capital formula is also discussed. As discussed in that section, variances in Regular capital expenditures (other than flow-through capital expenditures) will result in earnings variances that are subject to the earnings sharing mechanism.

The other components of rate base listed above will continue to be forecast each year as part of the Annual Review process under the Rate Framework.

FEI and FBC will also continue to propose any new deferral accounts to be included in rate base as part of the Annual Review process, and the Companies have included a summary of their currently approved deferral accounts in Appendices C4-4 (FEI) and C4-5 (FBC).

4.7 *DEPRECIATION AND AMORTIZATION*

Annual depreciation expense will continue to be based on the approved depreciation rates[121] and the opening plant account balances which include plant additions consistent with both the forecast Regular capital expenditures and (for FEI) the formula-based Growth capital expenditures, as well as any Major Capital projects approved for inclusion in rate base.

Amortization of deferrals will also continue to be forecast each year as part of the Annual Review process with the actual amortization expense each year equal to the approved amount. FEI and FBC will also include the amortization of any proposed new deferral accounts.

4.8 *FINANCING AND RETURN ON EQUITY*

In each Annual Review, FEI and FBC will calculate their respective revenue requirements based on the deemed equity component and allowed return on equity (ROE) approved by the BCUC. The current deemed equity component and allowed ROE were determined by the BCUC in Decision and Order G-236-23, dated September 5, 2023, as part of Stage 1 of the Generic Cost of Capital (GCOC) proceeding, as follows:

- **FEI:** a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and
- **FBC:** a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.

During the term of the Rate Framework, if the BCUC approves any changes to the deemed equity component and allowed ROE, FortisBC will incorporate these revised rates such that there is no variance in the revenue requirement associated with the return on equity.

Regarding the financing costs, FortisBC will continue to forecast short-term and long-term interest rates and interest expense for the test year as part of the Annual Review process. Interest expense is largely outside of the Companies' control, and interest rate variances have historically been subject to deferral account treatment (either through a specific Interest Variance deferral account or the Flow-through deferral account). Debt capital markets are dynamic and volatile, changing constantly to reflect current and expected economic conditions and government monetary and fiscal policy. While FortisBC takes appropriate measures to develop a forecast of

[121] FEI and FBC have completed updated depreciation studies and have proposed updated depreciation rates in Section D2 of the Application.

interest rates, it has no control over actual interest rates and, therefore, little control over the forecasting risk that is associated with interest rates. During the term of the Rate Framework, FortisBC proposes to continue its existing treatment of capturing variances in interest rates, volumes, and timing of issuances on long-term debt, as well as variances in interest rates for short-term debt, in the Flow-through deferral account.

4.9 *PROPERTY TAXES*

Property taxes are forecast annually, and any variances are adjusted to actual at the end of the year through the Flow-through deferral account. Property taxes are driven primarily by legislation, market values of properties and/or changes in tax policies and are outside the control of the Companies. FortisBC proposes to continue this treatment over the term of the Rate Framework.

4.10 *INCOME TAXES*

Each year, FortisBC will forecast income taxes, based on currently enacted income tax rates. These rates are outside of the Companies' control, and variances have historically been subject to deferral account treatment (either through a specific Income Tax Rate variance deferral account or through the Flow-through deferral account). FortisBC has no control over whether governments change the income tax rates or laws subsequent to submitting revenue requirement forecasts to the BCUC for approval. Governments have previously made changes to tax laws and income tax rates, which have led to variances from income taxes approved for rate-setting purposes. For the Rate Framework, FortisBC proposes to continue the treatment of capturing variances in income tax rates and any underlying changes to tax laws or legislation that impact the calculation of income tax expense or income tax rates in the Flow-through deferral account.

4.11 *EARNING SHARING AND RATE RIDERS*

Each year, FortisBC will continue to calculate the earnings sharing proposed to be distributed to or recovered from customers based on 50 percent of the variances from the allowed rate of return on equity, as discussed in Section C1.7.

Furthermore, in the case of FEI, the Annual Reviews will continue to include calculations of the delivery and other rate riders approved by the BCUC, which currently include:

- The Storage & Transportation Renewable Natural Gas (S&T RNG) Rate Rider;[122]
- The RSAM Rate Rider; and
- The Fort Nelson Residential Customer Common Rate Phase-in Rate Rider.

[122] The S&T RNG Rate Rider will begin, and the Biomethane Variance Account (BVA) Rate Rider will discontinue, effective July 1, 2024.

FEI is also proposing a new Clean Growth Innovation Fund (CGIF) and to continue with its associated basic charge rate rider, which are discussed in Section C5. Consistent with the Current MRP, FEI will continue to provide progress reports on the operation and progress of its CGIF in each Annual Review.

4.12 *EXOGENOUS FACTORS*

As discussed in Section C1.6, and consistent with the Current MRP, FortisBC will continue to identify exogenous factor events that have occurred or that are forecast to occur during the term of the Rate Framework as part of the Annual Review process. In this way, the cost-of-service impacts caused by exogenous factors that are beyond the control of the Companies will be included in customers' rates. Exogenous factor treatment of such amounts will ensure that customers pay only for the actual costs in circumstances where FEI or FBC does not control the level of expenditures.

4.13 *NON-RATE BASE DEFERRAL ACCOUNTS*

FortisBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base as discussed in Section C4.6 above, earning a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and, subject to BCUC approval, attract a weighted average cost of capital (WACC) return (which is equal to a rate base return).

FortisBC is not proposing any changes to its existing deferral accounts in this proceeding, other than as discussed below. Any other necessary changes will be proposed through the Annual Review process. FortisBC discusses the CGIF deferral account and the Flow-through deferral account below.

4.13.1 Clean Growth Innovation Fund Deferral Account (FEI)

FEI is proposing an enhanced CGIF for the term of the Rate Framework. Please refer to Section C5 for further details.

As part of the administration of the CGIF, FEI proposes to continue using the existing approved CGIF deferral account during the term of the Rate Framework. However, as discussed in Section C5, FEI is proposing to return the unused balance of the funds collected during the Current MRP term in 2025.

Consistent with the Current MRP, the CGIF will be funded by customers in the form of a rider on the basic charge at $0.40 per customer per month so that all of FEI's customers will fund innovation equally. The amounts collected from customers will be recorded as credits in the deferral account. The expenditures (funding provided by FEI) will be recorded in the deferral account as debits. The deferral account balance will not be trued up each year but rather will continue through the term of the Rate Framework with a commitment by FEI to not spend more than collected over the term of the Rate Framework. The deferral account will continue to be non-rate base attracting a WACC rate of return. At the end of the Rate Framework, the unused balance in the deferral account will be returned to customers.

4.13.2 Flow-Through Deferral Accounts (FEI and FBC)

FEI and FBC are proposing to continue using their existing Flow-through deferral accounts during the term of the Rate Framework. The existing Flow-through deferral accounts were approved in the MRP Decision: "The Panel approves the continuation of the general Flow-through deferral account for the MRP term of 2020 through to 2024..."

The Flow-through deferral accounts will continue to capture the annual variances between the approved and actual amounts for costs and revenues that are included in rates on a forecast basis with flow-through treatment approved (with the exception of those that have separate deferral account treatment).

Please refer to Table C4-7 below for the specific items proposed to be included in the Flow-through deferral accounts and those that will be subject to earnings sharing treatment during the term of the Rate Framework.

Table C4-7: Treatment of Variances in Revenue Requirement Items from Forecast

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects[2,3]	Flow-through deferral	Flow-through deferral
Depreciation on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects[2,3]	Flow-through deferral	Flow-through deferral
Revenues from CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate/timing variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects[2,3]	Flow-through deferral	Flow-through deferral
Interest on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax variances due to changes in tax rates/laws	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects[2,3]	Flow-through deferral	Flow-through deferral
Income tax on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, renewable and low carbon gas initiatives (biomethane service and renewable gas development), variable LNG production, integrity digs, AMI project, EV charging stations, MRS triennial audits, and MRS assessment reports.

2: Cost of service for NGT fueling stations and tankers, variable LNG production, Methane Emission Mitigation, and EV DCFC stations will be captured in the Flow-through deferral account.

3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA.

4.14 SUMMARY

Over the term of the Rate Framework, FEI and FBC will continue to prepare their respective annual revenue requirements for the cost and revenue items described in this section. The components that make up FEI's and FBC's annual revenue requirements will largely remain the same as in the Current MRP. FortisBC is also proposing to continue the approved treatment of capturing the majority of the variances between forecast and actuals in a single Flow-through deferral account, and as discussed in Section C5, FEI is proposing to continue with the CGIF deferral account. The items proposed to be treated as flow-through are identified in Table C4-7 above.

FortisBC is proposing to continue with its current forecasting methods for both FEI and FBC. As demonstrated in Section C4.2, the current forecasting methods for both utilities have consistently produced accurate results for the purpose of setting rates annually. As discussed in Section C1.10, FortisBC is requesting that the load/demand forecasting methods for setting rates in the Annual Reviews be approved for the term of the Rate Framework and that these methods be out of scope in the Annual Reviews.

Additionally, FEI performed a comprehensive assessment of the CMAE budget, as described in Section C4.3.1 and in Appendix C4-3. Based on this assessment, FEI seeks approval to continue to forecast the CMAE budget annually, but to file the budget for review as a separate application at or near the same time as the Q3 Gas Cost Reports.

5. FEI CLEAN GROWTH INNOVATION FUND

5.1 *INTRODUCTION*

The importance of the clean energy transition, supported by policy direction from all levels of government, has amplified the urgency for innovation and the adoption of new technologies in the energy sector to advance decarbonization. Recognizing this imperative, FEI is seeking to renew and enhance the Clean Growth Innovation Fund (CGIF) to expedite clean energy innovation. The CGIF supports the CleanBC goal of decarbonization by advancing innovative technologies that will help FEI reduce GHG emissions for its customers and support the transition to a lower carbon economy while optimizing the use of its gaseous energy delivery system for the benefit of its customers.

As detailed in this section, FEI is proposing to continue the CGIF for the Rate Framework term to support the clean energy transition along the gas value chain with specific enhancements, including a broader focus on cost mitigation and an additional criterion for resilience. In particular, the proposed enhancements to the CGIF will support and advance British Columbia's clean energy transition by investing in solutions that will reduce GHG emissions in the Province while mitigating costs for customers. Continuation of the CGIF will also continue the acceleration of clean energy innovation by helping to achieve performance breakthroughs and cost reductions on emerging technologies, while providing cost effective, safe, and reliable solutions for FEI's customers. This section is organized as follows:

- Section C5.2 reviews the current CGIF;
- Section C5.3 sets out FEI's CGIF proposals for the Rate Framework term; and
- Section C5.4 discusses the proposed administration process for the CGIF.

5.2 *THE 2020 CGIF*

The MRP Decision and Orders G-165-20 and G-166-20 approved the CGIF for FEI (the 2020 CGIF) and denied the CGIF for FBC. The BCUC denied FBC's proposed CGIF based on a limited scope of identified innovations (electricity storage and medium and heavy-duty electric vehicle charging) and insufficient funding ($2.5 million over five years) to make a meaningful contribution to the scope that was identified.

Conversely, the BCUC approved FEI's request to establish a CGIF, stating:

> In contrast to FBC, FEI needs to step up its innovation efforts in order to meet the ambitious targets pertaining to renewable gas outlined in the CleanBC Plan. As already noted, the focus on decarbonization and electrification increases FEI's risk profile as a gas utility. Greater innovation efforts are needed within FEI if natural gas is to remain a viable fuel in the long term in light of those climate objectives.

FEI has explained that existing gaps in its innovation funding remain unfilled, which its Innovation Fund is designed to address.

On August 1, 2020, subsequent to the MRP Decision, FEI began collecting a $0.40 per month per customer bill CGIF rider from its customers. FEI expects to collect approximately $5.229 million in 2024 based on the forecast average non-bypass customer count for 2024.

In finding that it was reasonable and in the public interest for FEI's customers to bear the cost of the 2020 CGIF, the BCUC identified the following benefits for customers:

- Improving gas pipeline inspections and reducing inspection costs;
- Providing cleaner and more affordable energy sources;
- Mitigating the risk of future rate increases; and
- Ensuring the long-term viability of the gas utility by reducing the risk of stranded assets through the development of new technologies.

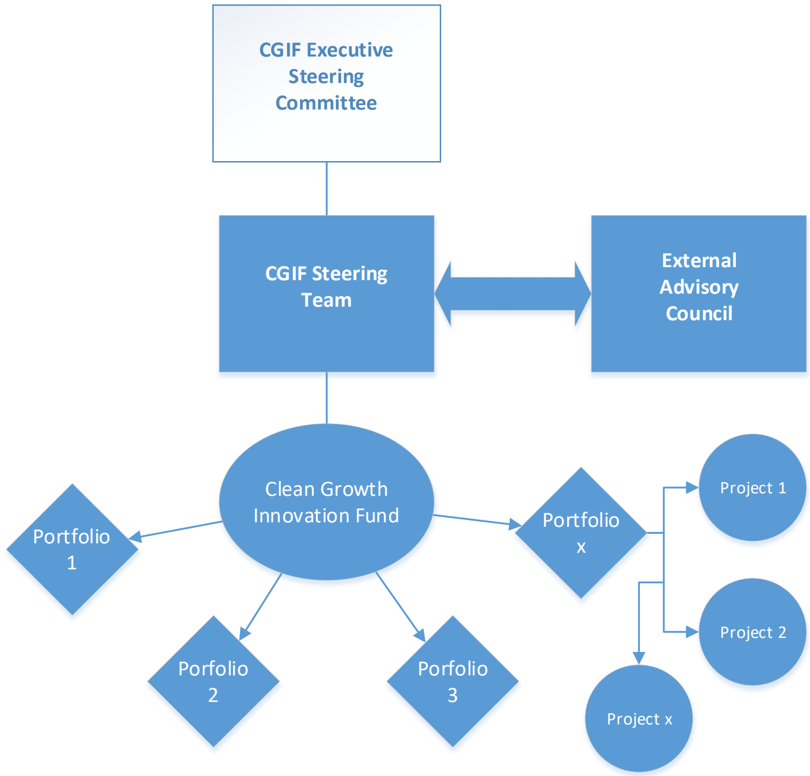
Over the term of the Current MRP, grants from the 2020 CGIF have been primarily directed toward bullets two and four: decarbonizing the gas value chain.

In the sections below, FEI reviews the underlying governance model of the 2020 CGIF, overall and application-specific expenditures during the Current MRP term (including the surplus to be returned to customers), and the fund's performance to date.

5.2.1 The Existing Governance Model Has Worked Effectively During the Current MRP Term

The governance processes established for the 2020 CGIF have been effective and contributed to the overall success of the fund in accelerating the pace of clean energy innovation. FEI established groups to review innovative proposals and provide recommendations for the 2020 CGIF, as shown in the figure below.

Figure C5-1: CGIF Governance Structure



Proposed projects are generally grouped together into portfolios to streamline the review process. To date, CGIF portfolios have contained between 1 and 25 proposals. CGIF portfolios are first reviewed by subject matter experts from throughout the Company. The recommendations of the Company's subject matter experts are reviewed by the CGIF Steering Team (CGIF-ST) and are either approved or rejected. Some proposals are approved by the CGIF-ST with conditions. The CGIF-ST is comprised of FEI senior managers that provide leadership to a variety of departments that are key to assessing the technical and business aspects of the portfolio proposals.

Proposals recommended by the Company's subject matter experts are presented to the External Advisory Council (EAC) for input and comment that will support final portfolio approvals. The input and comments from the EAC are considered throughout the decision process. The EAC currently includes representatives from the following stakeholders:

- MoveUP;
- BCSEA;
- BC Ministry of Energy, Mines and Low-Carbon Innovation;
- Foresight Cleantech Accelerator Centre;
- BC Bioenergy Network; and
- University of Victoria.

The EAC and each of the internal groups discussed above (i.e., the subject matter experts and CGIF-ST) generally meet once per CGIF portfolio cycle to review proposals against the following five 2020 CGIF criteria:

1. Amount of co-funding secured (from applicant and third parties);
2. Estimated carbon dioxide-equivalent (CO2e) reduction in British Columbia;
3. Estimated non-CO2e emission reduction (NOx, Sox) in British Columbia;
4. Estimation of energy cost reductions for customers; and
5. Relevant experience of the applicant project team.

Criteria 1 and 5 require subjective assessments of CGIF applications, which are tested and validated as part of the governance processes. Of the objective criteria, 2, 3 and 4, most of the CGIF grants approved to date have addressed criterion 2 directly (and often criteria 3 and 4 directly or indirectly), with the majority of funding approved related to production, distribution and end-use of gaseous fuels.

The CGIF Executive Steering Committee (ESC) is the final stage of portfolio review and is responsible for: (1) making a final decision regarding which projects, if any, within a given portfolio are approved; and (2) providing overall strategic direction over 2020 CGIF expenditures. The ESC reviews each portfolio with the benefit of recommendations and summaries of the commentary received from FEI subject matter experts, the CGIF-ST and the EAC to determine whether a project should be approved.

5.2.2 Unused CGIF Funds will be Returned to Customers

Table C5-1 below shows the amounts FEI expects to collect from customers, as well as the amounts expended and committed for 2020 CGIF projects, since the fund’s inception in 2020 to the end of 2024. By the end of 2024, FEI expects to collect $22.827 million from customers and will have spent or committed to spend $16.895 million in grant approvals. This will leave a projected surplus in the CGIF deferral account of approximately $5.810 million.

Table C5-1: Clean Growth Innovation Fund 2020-2024[123] ($ millions)

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Projected 2024	Total
Portfolio Approvals	**$ 1.500**	**$ 2.200**	**$ 1.526**	**$ 4.169**	**$ 7.500**	**$ 16.895**
Opening Balance	**$ -**	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (10.510)**	**$ -**
Funding collected	(2.099)	(5.093)	(5.176)	(5.230)	(5.229)	(22.827)
Expenditures	1.022	1.127	0.972	1.431	6.867	11.419
Accrued committed					5.476	5.476
Tax	0.291	1.071	1.135	1.026	(1.920)	1.603
Financing	(0.005)	(0.130)	(0.301)	(0.551)	(0.494)	(1.481)
Closing Balance	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (10.510)**	**$ (5.810)**	**$ (5.810)**

As part of the MRP Decision, the BCUC directed "any unused balance in the deferral account to be returned to customers at the end of the Proposed MRP term through a disposal mechanism subject to approval by the BCUC". Accordingly, as part of this Application, FEI proposes to return the ending balance in the deferral account, currently projected at $5.810 million, through amortization of the deferral account over one year (i.e., in 2025).

5.2.3 Expenditures Supported Multiple Applications

As shown in Table C5-1 above, annual CGIF approvals and spending both increased throughout the term of the Current MRP. This acceleration in approvals and spending is due to a number of factors, including:

1. **Necessary Ramp-Up Period Delayed 2020 CGIF Expenditures:** After the 2020 CGIF was approved by the BCUC in June 2020, time was needed to establish the governance and representation, reporting, and relationships that enabled projects to be brought forward and reviewed. The number of partner relationships and degree of awareness of the CGIF continued to grow throughout the term of the Current MRP.

2. **Increased Funding Requests Supporting GHG Reductions:** The number of funding requests for projects that support the GHG emissions reduction CGIF criteria has steadily increased since the 2020 CGIF was implemented. For example, FEI's latest round of projects evaluated through the Natural Gas Innovation Fund's (NGIF) Global Cleantech Challenge (a collaboration with the International Gas Union to encourage clean technology innovators from around the world to access grant funding, demonstration host partners and technology validation for customers in Canada) received a record 55 proposals.

[123] The amount shown as "Accrued committed" in the table is for multi-year initiatives where CGIF contributions are tied to specific project milestones where the commitment has been made but the amounts will not have been paid by the end of 2024.

3. **Increased Funding Requirements as Projects Progressed Toward Commercialization:** As the Technology Readiness Level (TRL) of projects increase, so too does the funding required to continue development and reach full-scale commercialization. These higher funding requirements accelerated overall spending later in the Current MRP term.

4. **Collaboration with Other Organizations to Identify New Projects and Technologies:** By increasingly collaborating with other funding organizations, FEI has been able to identify additional projects and technologies that may qualify for CGIF funding. For example, FEI has established new relationships with organizations such as the Centre for Innovation and Clean Energy and Foresight and Carbon Management Canada and has launched challenges targeted at identifying proponents and solutions that meet the CGIF funding criteria.

FEI has provided grant funding through the 2020 CGIF for innovations along the gas value chain. The gas value chain comprises the following application areas: (1) production; (2) distribution; and (3) end-use. FEI describes each application area below:

1. **Production:** related to creating renewable, low-carbon hydrogen, RNG and syngas for distribution through the gas network or direct end-use near the production facility. This area is described further in Section C5.2.3.1 below.
2. **Distribution:** focus on accommodating renewable hydrogen in the existing gas system. This area is described further in Section C5.2.3.2 below.
3. **End-use:** focus on more effective uses of energy and the ability to use renewable fuels (with a specific category for transportation), creating hybrid energy systems that efficiently use both gaseous fuels and electricity. This area is described further in Section C5.2.3.3 below.

FEI has also provided grant funding through the 2020 CGIF for carbon capture, utilization and storage (CCUS) and generalized low-carbon investments, which are described in further detail in Sections C5.2.3.4 and C5.2.3.5, respectively, below.

Table C5-2 below shows the total approved grants from the 2020 CGIF up to the end of 2023 for each application and sub-application.

Table C5-2: 2020 CGIF Approved Investment by Application 2020-2023 ($ millions)[124]

Application	Sub-Application	Portfolio Approvals
Production	Renewable Hydrogen	2.483
	Renewable Natural Gas	1.514
	Renewable Syngas	0.344

[124] The total approved amount of $9.395 million equals to the Portfolio Approvals up to the end of 2023 (i.e., the sum of the Portfolio Approvals line for 2020, 2021, 2022 and 2023 in Table C5-1).

Application	Sub-Application	Portfolio Approvals
	Subtotal	**4.341**
Distribution	Renewable Hydrogen	**0.500**
	Subtotal	**0.500**
End-Use	Renewable Hydrogen	0.407
	Hybrid Systems	0.280
	Renewable Natural Gas	0.125
	Subtotal	**0.813**
Carbon Capture	End-Use	0.469
	Storage	0.600
	Subtotal	**1.069**
General Low-Carbon	General Initiatives	**2.672**
	Subtotal	**2.672**
TOTAL		**9.395**

These five application categories are detailed below.

5.2.3.1 Production (Upstream)

The majority of the grant funding approved through December 31, 2023 under the 2020 CGIF ($4.341 million) has been for production applications, including investments related to the production of renewable and low-carbon gases for use in FEI's gas distribution network or for direct consumption by larger customers. These renewable and low-carbon gaseous fuels support FEI's and provincial CleanBC decarbonization objectives by providing customers with renewable and low-carbon fuels, thereby reducing GHG emissions.

The 2020 CGIF has provided grant funds for novel methods of producing renewable, low-carbon hydrogen in two ways: electrolysis and pyrolysis. Electrolysis requires water and low-carbon electricity and produces hydrogen by splitting water into hydrogen and oxygen molecules. Pyrolysis produces low-carbon hydrogen by "cracking" methane and other hydrocarbons (the main component of natural gas) into hydrogen and solid carbon.

To date, the 2020 CGIF has approved grant funds to multiple renewable hydrogen production projects. One example is the Vancouver-based start-up company Ekona which makes a novel non-catalytic pulse methane pyrolysis system for low-cost, clean, hydrogen production using natural gas as a feedstock, and with a solid carbon by-product. Funding from the 2020 CGIF (along with other funding) allowed the company to build a proof-of-concept reactor in 2021 and to complete the commissioning of a brassboard system reflecting the final operational product system in 2023. Developments thus far have resulted in Ekona receiving $79 million in equity investments from a diverse set of investors, further accelerating the commercialization of this low-carbon hydrogen production system.

In addition, the 2020 CGIF has provided grant funds for organizations that are advancing the production of low-carbon RNG (or biomethane). These expenditures have been focused on two primary areas: (1) improving the efficiency of existing RNG production facilities; and (2) expanding the range of feedstocks from which RNG can be created. FEI provides an example of each focus area below.

- **Improved Efficiency of Existing RNG Production Facilities:** The 2020 CGIF has provided funding for Metro Vancouver's effort to develop technology that will boost the methane content of RNG produced by anaerobic digestion at their wastewater treatment plants. If successful, this innovation could be adapted for use in other anaerobic digestors producing RNG.
- **Expansion of RNG Feedstocks:** The 2020 CGIF has partially funded G4 Insight's PyroCatalytic Hydrogenation (PCH) reactor. G4 Insights is a company focused on developing and commercializing proprietary PCH technology to convert forestry and agricultural crop waste into RNG. The 2020 CGIF funding will enable the company to build on this work and increase the plant scale by a factor of 10. Biomass from waste wood is the largest potential feedstock for producing renewable gases that has yet to be tapped.

  The 2020 CGIF has also granted funding to a BC-based company and an Interior pulp mill to scale-up a technology to create low-carbon syngas from wood waste and displace conventional natural gas use in the existing lime kiln. If successful, the syngas produced would eliminate the CO_2e emissions associated with the combustion of conventional natural gas at the mill. Excess syngas production could be converted to RNG to export via the existing natural gas pipelines serving the pulp mill, increasing renewable and low-carbon gas supply for FEI's customers.

5.2.3.2 Distribution

As of December 31, 2023, the 2020 CGIF had approved grant funding for distribution applications of $0.500 million focused on accommodating hydrogen in the existing gas distribution system. As RNG is chemically similar to conventional natural gas, it does not require changes to existing gas distribution assets, unlike low-carbon hydrogen. The accommodation of low-carbon hydrogen in existing assets supports provincial CleanBC decarbonization objectives by providing customers with low-carbon gaseous fuels, thereby reducing greenhouse gas emissions.

The 2020 CGIF approved grant funding for the Hydrogen Lab, which has been established at UBC Okanagan and the University of Victoria. The Hydrogen Lab is providing valuable insights into seven specific areas which will support FEI as it moves toward blending low-carbon hydrogen into existing gas infrastructure (hydrogen-enriched natural gas or HENG).

- **Subproject 1:** Analytical modelling of injection and transmission of HENG.

- **Subproject 2:** Detonation and flammability of HENG.
- **Subproject 3:** Hydrogen embrittlement of metal alloys and welded joints.
- **Subproject 4:** Real-time portable sensing system for monitoring of HENG mixing and leak detection.
- **Subproject 5:** Machine learning-based modelling and design of an integrated HENG process control system based on simulation and operational data.
- **Subproject 6:** Effect of HENG on thermoacoustic oscillations (a combination of pressure change and heat transfer) and burning rate of partially premixed flames.
- **Subproject 7:** Separation of hydrogen gas from HENG.

Other projects to advance low-carbon hydrogen adoption are underway as part a separately funded broad provincial effort to assess and establish the feasibility of blending hydrogen into the provincial gas grid called the British Columbia Gas System Hydrogen Blending Study and Technical Assessment project. This effort, in partnership with the Ministry of Energy, Mines and Low Carbon Innovation and Enbridge Inc., will build upon knowledge gained through the CGIF Hydrogen Lab project to lead toward safe and efficient distribution of low-carbon hydrogen to FEI customers.

5.2.3.3 End-Use

As of December 31, 2023, the 2020 CGIF had approved grant funding for end-use applications of $0.813 million for the three sub-applications discussed in turn below: (1) HENG or hydrogen end-use product development; (2) hybrid system development; and (3) transportation.

First, funding approved for HENG and hydrogen-compatible end-use investments includes the development and testing of a 100 percent hydrogen compatible residential furnace by a Calgary-based company (as shown in Figure C5-2 below), as well as two investments in companies making HENG-compatible Combined Heat and Power (CHP) units for residential and small commercial deployments. CHP units can produce both electric power and heat, so they are both a low-carbon end-use product and a technology capable of mitigating peak demand and providing resilience in the electric system.

Figure C5-2: Prototype 100% Hydrogen Furnace

2020 CGIF grant funding was also provided for testing the installation of a CHP in a commercial building combined with solar panels and a custom control system. The system functioned well but the underlying costs were high. Continued reductions in technology costs are likely to favourably change the overall cost-effectiveness of these types of solutions.

Further, the 2020 CGIF funded a study initiated by the Greenhouse Growers' Association members and United Flower Growers members who rely heavily on the use of natural gas for the provision of heat and plant growth (currently accounting for approximately 12 percent of the cost structure for greenhouses). The grant for the study focused on evaluating decarbonization options and cost implications facing greenhouses, including:

- Low-carbon heating options, including RNG and associated reduced GHGs;
- Emerging technology review (including energy storage, heating, carbon capture, and conservation and efficiency);
- Lighting and heating, including examination of the use of CHPs for meeting heating loads and offsetting electricity costs;
- Heating decarbonization options (technology and fuel supply);
- GHG emissions including carbon capture and offsets;
- Hydrogen generation and CO_2 to produce synthetic methane;
- Carbon capture and use, as well as storage and sequestration; and
- Evaluation of the cost impacts and energy implications of HENG.

Finally, the 2020 CGIF provided grant funding for university research which assessed the GHG emission reductions from the use of natural gas/RNG instead of diesel and heavy marine fuel in marine engines.

All of the above end-use application projects have helped advance the understanding of innovative technologies and how they can help FEI's customers optimize their use of low-carbon fuels, supporting provincial CleanBC decarbonization objectives.

5.2.3.4 Carbon Capture

Carbon capture technologies provide a means of removing carbon dioxide before it is released into the atmosphere or when it is already in the atmosphere. In either case, funding from the 2020 CGIF supports CleanBC's objectives by providing a pathway to lowering GHG emissions in British Columbia. Approved grant funding for this applicable category total $1.069 million to the end of 2023.

Carbon capture grants are divided into two sub-categories: end-use and storage.

- End-use carbon capture expenditures focus on capturing and purifying carbon dioxide post-combustion. In some cases, the carbon dioxide is converted into other marketable products and in others the carbon dioxide is being selectively captured for permanent storage.
- Carbon capture storage grants focus on taking captured carbon dioxide and permanently transforming it into a non-GHG form, such as a mineral, or permanently storing it.

FEI provides an example of each sub-category below.

Funding was approved under the 2020 CGIF for an end-use carbon capture project being undertaken by a Calgary-based company developing modular, containerized carbon capture systems using patented membrane contactors to replace conventional spray towers and absorbers. The expected result of the project is a 30 percent increase in efficiency and a 50 percent reduction in absorber size, significantly decreasing carbon capture capital and operating costs. The company is currently raising capital for a significant expansion and transition to commercialization.

Funding was approved under the 2020 CGIF for two GeoscienceBC-led initiatives related to carbon capture storage. One is for a pilot project that will test the ability of certain rock formations to permanently mineralize (and therefore sequester) gaseous carbon dioxide, and the other is for a comprehensive geological study of the Georgia basin to assess the potential for permanent carbon storage. Work related to the pilot project and the study remains ongoing.

5.2.3.5 Generalized Low-Carbon

Another significant area of funding has been for generalized low-carbon applications, with approved funding to the end of 2023 of $2.672 million. These expenditures are related to low-carbon initiatives that broadly advance decarbonization of the gaseous fuel distribution system and therefore support FEI and provincial CleanBC emissions reduction objectives.

This application category includes FEI's share of the annual operating expenses of the Canadian Gas Association's NGIF, of which FEI is a member with several other Canadian utilities and oil and gas producers. In total, 27 of the 40 proposals approved for funding by the 2020 CGIF are NGIF projects that are co-funded with other Canadian utilities and oil and gas producers. This category also includes four years of FEI membership fees related to its participation in the Low Carbon Resource Initiative (LCRI), approved in Portfolio 3 of the 2020 CGIF. The LCRI is an initiative sponsored by utilities in North America that is focused on addressing the need to accelerate development and demonstration of low- and zero-carbon energy technologies to 2030 and beyond. Through partnerships with LCRI, NGIF and other funding partners, FEI has been able to support projects which are co-funded by multiple other parties, thereby increasing the impact of each dollar invested by the 2020 CGIF.

5.2.4 The 2020 CGIF Has Helped Advance the Clean Energy Transition

The 2020 CGIF performed well, approving significant funding for a variety of innovative methods of producing, distributing and utilizing low-carbon fuels. These funding grants are amplified by contributions from government, other utilities and the private sector,[125] creating a larger impact for each dollar invested. The organizations that are receiving this funding and creating the innovative products and services that will help decarbonize gas infrastructure are key to preserving the significant investment in the existing gas delivery system that has been made on

[125] The NGIF estimates that the leverage of the Industry Grants program (which is one of the main recipients of CGIF funding) is about 10x Industry Grants - NGIF Capital. This leverage ratio is further increased for FEI because it is one of up to 15 NGIF members providing the funding for the grants made by NGIF. Overall leverage for 2020 CGIF projects is estimated to be over 20x.

behalf of FEI customers. In particular, innovations that increase the availability and lower the cost of renewable and low carbon gases support the continued role of gas infrastructure.

The 2020 CGIF has also enabled benefits more broadly.

First, in addition to grant funding to support or progress development of a given project, organizations receiving funding from the 2020 CGIF benefited from the support provided by FEI and other partner utilities. This support includes, for example: (1) providing and facilitating access to utility and customer assets for testing and pilots; and/or (2) receiving utility feedback regarding how well their products and services address the needs of the utility and its customers.

Second, the information gained through the fund has helped FEI staff to understand and prioritize key pre-commercial technologies that will be required to meet the CleanBC decarbonization goals. Without the 2020 CGIF, FEI staff would have less direct exposure to the start-up companies and academic institutions developing the technologies that will decarbonize gaseous fuels, mitigate costs for customers and make the gas distribution system more resilient. The exposure to innovative ideas and technologies provided by the fund provides FEI staff with a better understanding of the different advantages and disadvantages of new technologies, often through pilot demonstrations, as well as insight into the challenges faced by start-ups when trying to move pre-production technologies into production. The development of internal knowledge through CGIF learnings is a significant benefit that will allow FEI to continue its role as a leader in the clean energy transition.

Third, the 2020 CGIF has enabled investments in a number of technologies that could reduce the cost of current and future gaseous fuels. The ongoing energy transition will drive higher costs for customers, all else equal. In the MRP Decision (pages 155-156), the BCUC recognized the need for investments to fund innovation activities that are designed to provide benefits to customers, including innovations that mitigate the risk of future rate increases. The 2020 CGIF has invested in a number of technologies that could reduce the cost of current and future low-carbon gaseous fuels; however, FEI believes that cost reductions remain an opportunity that should continue to be explored.

As discussed in Section C5.2.2 above, the 2020 CGIF, has seen a continued increase in the amount of funding approved and spent across the Current MRP term. This is in part due to increased collaborations with other funding organizations, but also because there is increasing interest and maturity in gas decarbonization technologies. Also, as shown in Section C5.2.3, the 2020 CGIF has funded innovations across the gas value chain.

As noted in Section C5.2.2 above, FEI will be returning approximately $5.8 million to customers, which represents the unspent funds collected during the Current MRP term. FEI does not consider this a failure of the 2020 CGIF, but rather, reflects the time it took to establish governance processes and establish relationships with new innovators and funding agencies. There has also been an overall increase in innovations related to the energy transition that has increased the opportunities available over the Current MRP term. As discussed below, to build on the momentum gained during the Current MRP term, there is an opportunity for the CGIF to expand support for innovative technology pilots, particularly as some of the innovative technologies supported by the CGIF approach commercialization.

Ultimately, the 2020 CGIF has helped achieve the goals identified by the BCUC in the MRP Decision and has provided other significant benefits that will help to support the clean energy transition and CleanBC decarbonization goals. As discussed further below, based on the momentum and success of the 2020 CGIF, FEI proposes that the fund continue (as enhanced) during the Rate Framework term to support innovation activities and address key issues related to the clean energy transition for FEI customers in 2025 and beyond.

5.3 *THE 2025 CGIF*

With the clean energy transition well underway and the need for innovation and technology solutions becoming increasingly important to achieving climate and energy goals, FEI proposes to enhance the CGIF for the years 2025 to 2027 (2025 CGIF), building on the momentum established by the processes implemented and relationships established for the 2020 CGIF.

5.3.1 Proposed Enhancements to the CGIF

FEI is proposing that the 2025 CGIF continue the gas decarbonization funding activities already established under the 2020 CGIF, while expanding the scope of funding to address other impacts of climate adaption and the energy transition. In particular, a key focus area for the 2025 CGIF will be to invest in cost-effective technology solutions that will help support FEI's customers through the energy transition. Another area of focus FEI has identified relates to gas system infrastructure resilience. The impacts of climate change are already being realized in the form of extreme weather events in British Columbia. Wildfires, atmospheric rivers, polar vortexes and heat domes, weather systems that would have been considered highly anomalous in the past, are now occurrences that make energy system resilience increasingly important and a prime innovation opportunity that will benefit FEI customers.

The enhanced scope of the 2025 CGIF will allow FEI to support technologies which are vital to BC's clean energy transition, will help to achieve performance breakthroughs and cost reductions on emerging technologies, and will provide greater access to cost effective, safe, and resilient solutions for FEI customers.

To support the above funding scope, FEI proposes one addition to the 2020 CGIF evaluation criteria – energy system resilience benefits –- which is important for the reasons outlined above. The proposed 2025 CGIF evaluation criteria would then be as follows:

1. Carbon dioxide-equivalent (CO_2e) reduction potential in British Columbia;
2. Non-CO_2e emission reduction (NOx, SOx) potential in British Columbia;
3. Potential energy system resilience benefits for FEI customers;
4. Energy cost mitigation potential for FEI customers;

5. Amount of co-funding secured (from applicant and third parties); and
6. Relevant experience of the applicant project team.

Based on these criteria, and in consideration of the clean energy transition, FEI recommends that the 2025 CGIF focus on funding innovations that will help to address the following seven application categories which are key to the clean energy transition:

1. **Production:** the development of low-carbon gaseous fuel technologies;
2. **Distribution**: adapting the existing gas delivery system to distribute low-carbon gaseous fuels such as hydrogen;
3. **End Use:** the development of end-use technologies, including dual-fuel innovations, to assist FEI's customers through the energy transition;
4. **Cost Mitigation:** investment in technological solutions that reduce costs for customers;
5. **Resilience**: investment in technological solutions that will improving the resiliency of the gas delivery systems in response to adverse climatic events;
6. **Carbon Capture and Storage:** investments in end-use carbon capture and storage; and
7. **Generalized Low-Carbon:** initiatives that broadly advance decarbonization and support CleanBC emission reduction objectives.

Each of these items are addressed further in the sections below.

5.3.1.1 Production: Investments to Support the Development of Low-Carbon Gaseous Fuels

FEI considers that gaseous energy will continue to be a critical component of a decarbonized energy system in British Columbia. Existing gas infrastructure in the Province is a multi-billion dollar asset that provides reliable, safe, affordable and high-quality energy services to British Columbians.

Gas infrastructure has historically delivered conventional natural gas. However, the gas infrastructure is capable of delivering other gaseous fuels, including renewable and low-carbon fuels such as RNG and hydrogen. FEI's 2022 Long-Term Gas Resource Plan envisions having approximately 25 percent of total gas supply from renewable and low-carbon gas by 2030.

It is important for FEI to continue to invest in novel technologies and processes for creating and storing lowest-cost, low-carbon gases, to ensure the long-term viability of the gas utility and support the energy transition in British Columbia.

5.3.1.2 Distribution: Adapting the Existing Gas Delivery System to Low-Carbon Gaseous Fuels

RNG is chemically similar to conventional natural gas such that it requires no modifications to the existing gas distribution system (and to customer equipment). Although hydrogen is highly compatible with existing infrastructure when blended with natural gas (or RNG) in relatively small percentages, there are still a number of safety, regulatory and technical challenges that need to be addressed along the gas value chain.

The CGIF has already invested in research with the University of British Columbia and University of Victoria into the impacts of HENG. FEI has also now initiated the H2Transform initiative, which is a pilot project for the injection of HENG into FEI's distribution system that is currently in its early stages. FEI expects that future CGIF investment in transmission and distribution technologies will align with this work that is already underway.

5.3.1.3 Cost Mitigation: Addressing the Costs Associated with the Energy Transition for Gas Customers

The energy transition is expected to increase energy costs for British Columbians. The CGIF can play a key role in supporting cost-effective energy solutions for customers by focusing more broadly on innovations that have the potential to reduce costs. To date, the CGIF has focused on cost reductions directly related to the energy transition such as those related to reducing the cost of RNG. However, there are innovations that can help FEI reduce costs in other business areas that will also provide benefits to customers.

For example, satellite-enhanced vegetation management may be a useful tool with the potential to make vegetation management more cost effective by moving it from a time-based approach to a condition-based approach. Similarly, remote sensing and control has the potential to reduce costs for both utilities by reducing the need to physically visit or continuously monitor gas assets. Some remote sensing devices are specific to each energy system (for example hydrogen detectors) while others are useful for both gas and electric utilities (camera-based intrusion detection).

FEI proposes to also fund innovations that will help customers directly reduce their costs. Examples include combined heat and power (CHP) technologies that provide heat for industrial and agriculture requirements while providing a useful biproduct (carbon dioxide) that can be used by agricultural customers to support the growth of plants.

5.3.1.4 Resilience

Gas system climate adaption will be required to mitigate impacts from extreme temperatures, atmospheric rivers and other unusual weather conditions. Innovations are required that will increase energy system resilience, particularly for above-ground assets, related to floods, fires and other adverse climatic events. This could mean investment in new technologies that provide remote detection of adverse weather conditions or of weather-related asset failures, for example.

While FEI already has cameras (both visual and thermal) deployed at critical assets such as substations, innovations are being developed that will better utilize this data source. Artificial Intelligence (AI) algorithms can identify anomalies at these substation sites, such as intrusion and wildfires in near real-time and alert substation personnel for actions while avoiding the need for 24/7 human monitoring.

Another way to make energy systems more resilient to disruptions in transmission and distribution systems is to increase energy supply and storage capabilities close to customers. Given the technology landscape, it is likely that biomethane and low-carbon hydrogen will be produced in a distributed manner, with production facilities connected directly to the distribution systems or customers. Distributed energy resources such as these have the potential to improve both gas and electric system resilience, but only if appropriate monitoring, control and storage systems are in place. To support this, FEI will need tools to manage an increasingly complex system.

The distributed nature of hydrogen production, in particular, is likely to require distribution-scale storage systems to allow for production disruptions and large fluctuations in demand. Customers that are reliant on hydrogen will not initially have access to the large-scale production, transmission and distribution networks that can backstop smaller distribution electric and biomethane production facilities. FEI is looking at a variety of solutions in this space including one from Calgary-based Ayrton Energy,[126] which is developing liquid organic hydrogen carrier storage systems.

FEI proposes to also consider innovations that allow customers' gas equipment to continue functioning in the absence of electric supply. While whole-home battery backup systems and vehicle-to-grid would accomplish this goal, they are relatively expensive. Residential gas-fueled hot water and space heating appliances do not require large amounts of electricity and could keep running for significant periods from small, integrated battery systems, providing reliability and safety benefits for British Columbians.

Although FEI may not directly own these customer-oriented solutions if they prove successful, it is important to be aware of innovations that could be beneficial in helping customers manage and secure their energy sources in the future.

5.3.1.5 End-Use

Most FEI investments in innovative end-use technology are made as part of the Conservation and Energy Management Innovative Technology program and funded through Demand Side Management expenditures. However, as part of the 2020 CGIF, a small amount of investment has been applied to developing hydrogen-ready equipment such as residential home heating appliances. Support for hydrogen-ready end-use appliances, including those that are capable of using hydrogen, are key to the future deployment of hydrogen across FEI's service territory.

[126] https://ayrtonenergy.com/.

5.3.1.6 Carbon Capture, Utilization and Storage

The CGIF will continue to support CCUS technologies. CCUS is likely to be key to economic decarbonization of certain emission sources. For example, it may be less expensive to sequester or utilize carbon emissions in industrial applications than it would be for the customer to convert the industrial equipment to use low-carbon electricity or gaseous fuel. Similarly, when FEI is considering how to best manage CO_2 emissions from operations such as RNG and LNG facilities, it is important to understand an array of technical solutions for utilizing or storing those emissions.

FEI will continue to work with governments and other organizations to create a robust framework for carbon sequestration in BC. This means development of sequestration technologies uniquely suited to the geology in British Columbia as well as supporting research into the geology itself.

5.3.1.7 Generalized Low-Carbon

FEI proposes to continue to make expenditures related to low-carbon initiatives that broadly advance decarbonization of the combined electric and gaseous fuel distribution systems. Included in this category is FEI’s share of the annual operating expenses of the NGIF and LCRI.

5.3.2 2025 CGIF Administration and Collection

FEI proposes to maintain the 2020 CGIF governance structure currently in place, which includes the CGIF-ST, the ESC, and the EAC (as outlined in Section C5.2.1 above).

FEI proposes to continue utilizing the innovation rider and to continue to collect $0.40 per month from FEI’s customers’ bills. Although this funding was in excess of requirements in the Current MRP, as shown in Table C5-1 above, approved funding amounts steadily increased from 2020 to 2024. FEI expects this to continue now that the CGIF is an established source of funding. Portfolio approvals totalled $4.169 million in 2023 which came close to the $5.230 million in funding collected from customers through the existing rider in that year. In 2024, FEI is forecasting approved funding of $7.5 million which is expected to significantly exceed CGIF rate rider collections. FEI has also proposed to expand the scope of funding activities (as outlined in Section C5.3.1), which will increase potential funding opportunities. The $0.40 per customer monthly rate rider would collect approximately $5.2 million in 2025, similar to the levels in 2023 and 2024. At the end of the Rate Framework, the unused balance in the deferral account will be returned to customers.

5.4 *CONCLUSION*

The 2020 CGIF has provided significant funding for a variety of innovative methods of producing, distributing and utilizing renewable and low-carbon fuels. These investments support FEI customers by providing cleaner and more affordable energy sources, seeking to lower costs, and maintaining the long-term viability of the gas utility through the development of new technologies.

FEI is proposing an enhanced 2025 CGIF that builds on the initial efforts of the 2020 CGIF and continues to support BC's clean energy transition. The 2025 CGIF will accelerate the pace of clean energy innovation by helping to achieve performance breakthroughs and cost reductions on emerging technologies, and provide cost effective, safe, and resilient solutions for FEI customers.

6. SERVICE QUALITY INDICATORS

6.1 INTRODUCTION

In this section, FortisBC summarizes its proposed Service Quality Indicators (SQIs) for FEI and FBC. Within a multi-year rate-making framework, SQIs form the basis for determining a utility's quality of service and represent a broad range of business processes that are important elements of the customer experience. Under the Current MRP, SQIs with approved benchmark and performance ranges set by a threshold level are used to monitor the Companies' performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers. Other SQIs do not have benchmark or performance ranges and are instead informational indicators that provide visibility into key aspects of FortisBC's business. FortisBC proposes to continue this approach. A full discussion of the proposed SQIs for FEI and FBC is included in Appendices C6-1 and C6-2, respectively.

Maintaining a high level of service quality is important to the long-term success of the Companies. The SQIs will serve to ensure that service quality to customers is maintained at acceptable levels throughout the term of the Rate Framework. The following subsections describe the criteria used to establish SQIs, and explain how benchmarks and thresholds are selected, as well as the difference between measured SQIs and informational indicators.

6.1.1 SQI Selection Criteria

In developing the proposed suite of Service Quality Indicators for the current Application, the criteria used to establish the SQIs for the past multi-year rate plans in 1998, 2004, 2014 and 2020 were considered, as FortisBC believes that the criteria continue to remain appropriate. The criteria are presented in the following table.

Table C6-1: Criteria for the Design and Selection of SQIs

ID	Criterion	Description
1	Value to customers	The indicator must represent a service or service attributes that customers value.
2	Controllable	Only those indicators over which the Company has control should be included. SQIs should not be linked to exogenous events over which the actions of the Company's employees have little or no influence.
3	Cost effective	The information collection activities associated with the indicator must be cost effective.
4	Simple and transparent	The indicator should be simple to administer, and results should be easy to understand and interpret.
5	Traceable and Quantifiable	The indicators should have been previously tracked to ensure they are stable over time. The indicators must be quantifiable.
6	Flexible	The indicators should allow sufficient flexibility to allow modifications, additions and deletions as required over time.

6.1.2 Choice of Benchmarks

Benchmarks are reference points against which levels of service quality can be compared. The objective of SQIs is to ensure that the Companies continue to provide an "acceptable level" of service at an "acceptable level" of cost to customers. Therefore, in setting SQI benchmarks, it is necessary to consider whether customers are willing to pay for additional improvements in the indicators, as incremental costs for achieving further improvements increase as the limit of the indicator is approached. Benchmarks typically reflect either industry standards or the Companies' performance over recent prior periods.

6.1.3 Thresholds and Satisfactory Performance Ranges

Thresholds or satisfactory performance ranges used in the Current MRP were first introduced in the 2014-2019 PBR Plan as an effective way to manage SQIs. As part of the Decision regarding FortisBC's 2014-2019 PBR Plan Application, the BCUC agreed that it was not appropriate to require FortisBC to be held to a specific performance benchmark. The BCUC stated:

> The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases, a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks, it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.**

Through a consultative process, FortisBC and stakeholders reached an agreement titled the "Consensus Recommendation"[127] on appropriate thresholds to consider. The Consensus Recommendation was approved pursuant to Order G-14-15.

6.1.4 Informational Indicators

Some SQIs do not have benchmarks or thresholds and are classified as informational indicators. An SQI works well as an informational indicator when there are factors outside of the Companies' control that may influence the metric's performance. For example, the Customer Satisfaction Index is an informational indicator as it recognizes that uncontrollable factors can have an adverse influence on customer satisfaction, such as the market price (commodity cost) of natural gas in the case of FEI and storm-related unplanned outages in the case of FBC.

[127] Please refer to Appendix C6-3 for a copy of the Consensus Recommendation.

Another consideration when determining whether an SQI should be an informational indicator is the amount of historical performance data available, as without an adequate amount of historical data available to identify trends, it is challenging to establish an appropriate benchmark or threshold.

As a result, informational indicators are generally more directional in nature, providing a high-level view into key business functions.

6.2 SQI OVERVIEW AND STAKEHOLDER FEEDBACK

6.2.1 SQI Overview

The BCUC approved a balanced set of SQIs for the Current MRP covering safety, responsiveness to customer needs and reliability. Of FEI's 13 approved SQIs, nine have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation, and four of the SQIs are for information only, and as such do not have benchmarks or performance ranges. Of FBC's 12 approved SQIs, eight have benchmarks and performance ranges set by a threshold level, and four of the SQIs are for information only.

The current suite of SQIs for FEI and FBC have been appropriate and useful in monitoring the Companies' performance to ensure that any efficiencies and cost reductions do not result in a degradation of service quality. For the Rate Framework, FortisBC reviewed the current SQIs to assess their continued appropriateness in measuring service quality and for the level of the benchmarks and thresholds for each metric. Based on this review, FEI and FBC are proposing updates and modifications to the existing suite of SQIs in order to build on the experience gained during the Current MRP term. Additionally, FEI is proposing to introduce a new category of informational indicators that relate to the Company's response to the energy transition.

As further discussed in the following sections, FortisBC is proposing to make the "Meter Reading Accuracy" metric an informational indicator and rename it "Meter Reading Completion" to better reflect what the metric is measuring. FortisBC is also proposing updates to the benchmarks and/or thresholds for the All Injury Frequency Rate (AIFR) indicator, FEI's Public Contact with Gas Lines indicator, and FBC's System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) indicators. In addition, FEI is proposing a new category of informational indictors specific to the energy transition.

Similar to the Current MRP, FEI and FBC will report each year's results to the BCUC and stakeholders at the Annual Reviews to allow a comparison of the Companies' SQI performance against the benchmark targets and the thresholds for each of the SQIs (as applicable). Also consistent with the Current MRP, failure to meet SQI benchmark thresholds, if determined by the BCUC after further process to be considered a serious degradation of service quality in whole or in part due to the actions (or inactions) of the Companies, may result in a reduction to the share of earnings sharing retained by the Companies, up to a maximum reduction to reflect a 60 percent share to the customer (i.e., penalty of 10 percent of the earnings sharing earned by the Companies), instead of the standard 50 percent.

FortisBC proposes to continue using the review process outlined in the Consensus Recommendation approved by Order G-14-15 to evaluate SQI results, as this process was used successfully during the 2014-2019 PBR Plan term and the Current MRP term. The Consensus Recommendation provides guidance on the objectives of performance ranges and the review process for the SQI results, including a two-phase process (Phase 1 – Identification of Results for Discussion at the Annual Review and Phase 2 – Determination of Any Financial Consequences). As recently as in its decision on FEI's Annual Review for 2024 Delivery Rates, the BCUC confirmed that the existing process for review of SQI performance outlined in the Consensus Recommendation remains appropriate:[128]

> The Panel disagrees with RCIA's characterization of the Consensus Recommendation with respect to SQIs. The current SQI review process leaves room for the BCUC's consideration of the relevant specific circumstances which may have contributed to the results (e.g., pandemics, economic conditions, extreme weather, etc.) as opposed to the automatic imposition of a penalty for any sustained degradation of service. The Panel views this to be consistent with the spirit of the Consensus Recommendation and the BCUC's previous directives in that regard.

6.2.2 Stakeholder Feedback

FortisBC engaged with interveners and BCUC staff on its proposed SQIs during a workshop on November 20, 2023. The key highlights of the feedback received from interveners in this area are outlined below. A more detailed summary of the feedback received, and the material used by FortisBC to facilitate the discussion, is included in Appendix B2-3. Explanations regarding how FortisBC considered the feedback received at the workshop is included throughout Appendices C6-1 and C6-2 as applicable.

FortisBC received the following general comments about its proposed SQIs at the workshop:

- One intervener noted that FortisBC should ensure that customers are not burdened with extra costs due to efforts by the utility to enhance its SQI results.
- One intervener shared their thoughts on how to approach SQIs overall, including their view that SQIs should map the overall progress of the company and that four broad new SQI areas should be developed in the areas of energy transition, affordability, resiliency, and effectiveness/efficiency. This intervener also shared their view that SQIs with stable performance should instead be informational indicators (i.e., these SQIs do not warrant benchmark and performance ranges).

[128] Page 29 of Decision and Order G-334-23.

- There was general support from interveners for exploring possible leading indicators to establish a means of more effectively measuring overall employee safety.

In addition to general comments, interveners provided the following specific suggestions regarding FortisBC's proposed SQIs:

- **Customer SQIs:** First, interveners asked FortisBC to consider the value of reporting meter reading completion effectiveness once AMI is in place. Second, interveners expressed opposition to the idea of lowering the threshold on the Telephone Service Factor (TSF) (non-emergency) SQI for FEI and FBC from 68 percent to 65 percent. Third, there was a suggestion to include a metric, or provide more information, for measuring how FortisBC responds when a customer problem is not resolved on first contact and, generally, to see more and different information regarding SQI performance.
- **Reliability SQIs:** First, interveners proposed moving the Generator Forced Outage Rate (GFOR) and Interconnection Utilization from being informational indicators to having benchmarks and thresholds, as well as determining whether GFOR performance could be reported during certain times. Second, interveners raised Major Events as an area of interest and, in particular, how these events should be considered when reporting on SAIDI and SAIFI. Finally, one intervener also expressed concern that basing the benchmark and/or threshold on an increasing trend in SAIDI performance over time (i.e., higher results) may implicitly contribute to declining SAIDI performance.
- **Safety SQIs:** FortisBC did not receive any specific comments of note as part of the workshop, beyond those regarding possible leading indicators as noted above.

FortisBC appreciates the feedback received at the workshop and has carefully considered the comments and suggestions from interveners when developing its suite of SQIs for the Rate Framework. FortisBC's proposals and rationale for the proposed suite of SQIs are described in the following sections and in Appendices C6-1 and C6-2.

6.3 *FEI'S PROPOSED SERVICE QUALITY INDICATORS*

FEI reviewed the existing SQIs and believes that overall, they remain appropriate to ensure that service quality to customers is maintained throughout the term of the Rate Framework. As further explained below and in Appendix C6-1, FEI is proposing the following changes which build off of and enhance its existing suite of SQIs:

- FEI proposes to change the benchmarks and thresholds of some SQIs, recognizing recent historical performance.
- FEI proposes to change the name of the Meter Reading Accuracy metric to Meter Reading Completion to better reflect what the metric is measuring, and to change it to an informational indicator.

- FEI proposes to introduce a new suite of informational indicators to report on the results of FEI's activities related to the energy transition. While not a traditional category of SQIs, FEI considers it important to report on these metrics within the Annual Review process given the overall focus on the energy transition within the Rate Framework, and to be responsive to the comments received from both the BCUC and interveners.

The following table provides a comparison of FEI's current and proposed SQIs. The areas of the table that are shaded green reflect changes to existing indicators as well as new indicators. The changes and new indicators are discussed in the subsections below the table.

Table C6-2: Comparison of FEI Current and Proposed SQIs

Safety Indicators

		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	Emergency Response Time	>= 97.7%	96.2%	>=97.7%	96.2%
Annual results	Telephone Service Factor (Emergency)	>= 95%	92.8%	>=95%	92.8%
3 Year rolling average	All Injury Frequency Rate	<= 2.08	2.95	<= 1.64	2.21
Annual results	Public Contacts with Gas Lines	<=8	12	<=6	10

Responsiveness to Customer Needs Indicators

		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	First Contact Resolution	>= 78%	74%	>=78%	74%
Annual results	Billing Index	<= 3	5	<=3	5
Annual results	Meter Reading Completion	>= 95%	92%	Informational	Informational
Annual results	Telephone Service Factor (Non Emergency)	>= 70%	68%	>=70%	68%
Annual results	Meter Exchange Appointment Activity	>=95%	93.8%	>=95%	93.8%
Annual results	Customer Satisfaction Index	Informational	Informational	Informational	Informational
Annual results	Average Speed of Answer	Informational	Informational	Informational	Informational

Reliability Indicators

		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	Transmission Reportable Incidents	Informational	Informational	Informational	Informational
Annual results and 5 Year rolling average	Leaks per KM of Distribution System Mains	Informational	Informational	Informational	Informational

Energy Transition Indicators

		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	Scope 1 Emissions	N/A	N/A	Informational	Informational
Annual results	Renewable and Low Carbon Energy Supply Volume	N/A	N/A	Informational	Informational
Annual results	Natural Gas for Transportation Volume	N/A	N/A	Informational	Informational
Annual results	Demand Side Management Energy Savings	N/A	N/A	Informational	Informational

6.3.1 All Injury Frequency Rate

FortisBC is committed to ensuring its employees can perform their work and go home safely at the end of each day.

During the November 2023 consultation session, FortisBC discussed the difference between leading and lagging safety indicators and explained that it was exploring introducing a leading safety indicator to enhance its reporting on safety, as FEI and FBC currently report on the All Injury Frequency Rate (AIFR), which is a lagging indicator. Stakeholders were generally supportive of the concept.

When measuring and monitoring safety, lagging indicators measure what happened after the fact (i.e., outcomes) and can alert the Companies to a failure in the safety system, or to the existence of an uncontrolled hazard, *following* an event. At FortisBC, such events are used to learn and improve, identifying gaps in existing safety defenses and establishing corrective actions to prevent future reoccurrences. In contrast, leading indicators are proactive and preventative measures that can shed light on the effectiveness of safety and health activities and reveal potential gaps *prior* to an event occurring.

FortisBC has been exploring potential leading indicators but does not yet have a formal, defined indicator to propose for inclusion as an SQI. Instead, FortisBC will continue to examine and develop a leading safety indicator during the term of the Rate Framework and will propose a suitable leading indicator either during the Rate Framework (as part of the Annual Review process) or subsequent to the conclusion of the three-year term of the Framework. FEI and FBC expect that any new leading safety indicator would initially be informational only, as there will likely be a lack of adequate historical information to establish a benchmark or threshold. This approach will allow FEI and FBC to evaluate suitable metrics, propose a suitable metric, and engage in discussions with the BCUC and interveners on whether the selected metric is appropriate for inclusion in the Companies' suite of SQIs.

FEI proposes to continue to report on the existing AIFR SQI. The three-year rolling average and annual results during the Current MRP term are provided in the table below.

Table C6-3: FEI AIFR History and Proposed Metrics

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
AIFR – three year rolling average	1.66	1.75	1.59	1.58	2.08	1.64	2.95	2.21
AIFR - annual	1.43	1.99	1.36	1.35	n/a	n/a	n/a	n/a

The results from 2020 to 2023, shown in Table C6-3 above, have been better than the currently approved benchmark of 2.08. For the term of the Rate Framework, FEI proposes to lower the benchmark based on the average of the recent three-year rolling average of the annual results from 2021 to 2023. FEI accordingly proposes to lower the benchmark from 2.08 to 1.64. Additionally, FEI proposes to lower the threshold from 2.95 to 2.21, consistent with past practice.[129]

Please refer to Appendix C6-1 for further details on the AIFR.

6.3.2 Public Contacts with Gas Lines

FEI proposes to continue to report on Public Contacts with Gas Lines. Based on the improved performance in recent years, which FEI believes is sustainable, FEI proposes to lower the benchmark from 8 to 6.

Table C6-4: FEI Public Contact with Gas Lines History and Proposed Metrics

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Public Contact with Gas Lines – annual	7	6	6	5	8	6	12	10

The results from 2020 to 2023, shown in Table C6-4 above, have been better than the currently approved benchmark of 8. The benchmark in place during the Current MRP term was based on the average of the annual results from 2016 to 2018. From 2020 to 2023, the annual results have trended downward. Increased awareness through targeted workshops with municipalities and excavating contractors, together with a higher number of calls generated by the BC 1 Call program, have contributed to the improved performance.

FEI proposes to lower the benchmark to 6, which is based on the average of the most recent three years of results from 2021 to 2023 and reflects the recent downward trend in gas line contacts. FEI proposes to revise the threshold to 10, as this is reflective of the positive historical performance observed.

Please refer to Appendix C6-1 for further details on the Public Contact with Gas Lines SQI.

6.3.3 Meter Reading Completion (formerly Meter Reading Accuracy)

FEI proposes to change the name of the Meter Reading Accuracy metric to Meter Reading Completion as the revised name better reflects what the metric is measuring (i.e., the number of scheduled meters that were read).

Further, while FEI proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill, FEI proposes to change this metric to an informational indicator and remove the existing benchmark and threshold. The reason

[129] The threshold is set at 2 standard deviations from the recent 10-year history of the three-year rolling averages of the annual results.

for this proposed change is that during the term of the Rate Framework, FEI will be in the process of deploying AMI. As the deployment of AMI will be ongoing throughout the Rate Framework term, resulting in a mix of meter types (manual and advanced), using a benchmark and threshold will no longer provide an effective means of assessing FEI's service quality. FEI instead proposes to continue reporting on this SQI as an informational indicator until AMI is fully implemented, at which point it will assess this metric and determine if it should be re-instated as a measured SQI with adjusted benchmarks and thresholds.

Table C6-5: FEI Meter Reading Completion History and Proposed Metrics

Description	2020	2021	2022	2023
Meter Reading Completion	89%	88%	88%	95%

The currently approved benchmark and threshold for Meter Reading Completion are 95 percent and 92 percent, respectively. As shown in Table C6-5, for the first three years of the Current MRP, FEI performed worse than the threshold; however, the 2023 results indicate a return to benchmark-level performance. The results from 2020 to 2022 were discussed in detail in each of the Annual Reviews during the Current MRP term. As explained in these Annual Reviews, the lower than threshold performance of the Meter Reading Completion SQI between 2020 and 2022 was primarily a result of the COVID-19 pandemic and its broader impacts.

Please refer to Appendix C6-1 for further details on the Meter Reading Completion SQI.

6.3.4 Energy Transition Informational Indicators

As outlined in Section B2.4, feedback received on the Rate Framework suggested that FEI should be engaged in, and adapt to, the energy transition and consideration should be given to creating a new energy transition focused reporting area. In response to this feedback, FEI proposes to introduce a number of energy transition informational indicators, listed in Table C6-6 below, which align with the pillars of the Company's Clean Growth Pathway to 2050. FortisBC's pillars for the Clean Growth Pathway to 2050 seek to lower emissions by increasing the supply of renewable and low-carbon gases, investing in energy efficiency, advancing low- and no-carbon transportation, and investing in LNG for marine shipping in place of higher-carbon fuels.

These informational indicators will provide an annual assessment of FEI's GHG emissions, renewable gas supply, energy efficiency savings, and natural gas for transportation volumes. While the proposed energy transition informational indicators are a departure from FEI's more traditional SQIs, as they do not directly measure or relate to service quality, FEI considers these new indicators useful for providing context on how FEI is addressing the energy transition. Further, FEI considers it appropriate to classify the energy transition indicators as informational because of the rapidly evolving and uncertain policy and environment, trajectory of development for low-carbon technologies, and changing market circumstances which are largely outside of FEI's control but will nonetheless impact FEI's progress in the energy transition.

FEI has been tracking these informational indicators and reporting on the results through various external filings, including FortisBC's annual sustainability report and in filings to the BCUC such as the DSM annual report. The proposed new informational indicators will centralize tracking and reporting of the associated results. The table below provides the historical results from these areas over the Current MRP term for context. Please refer to Appendix C6-1 for further information on the proposed energy transition informational indicators.

Table C6-6: FEI Energy Transition Informational Indicators

Performance Measure	Description	2020 Results	2021 Results	2022 Results	2023 Results
Scope 1 Emissions	Total direct GHG emissions from FEI owned or controlled sources ($MtCO_2e$)	0.14	0.15	0.24	0.14[130]
Renewable and Low Carbon Energy Supply Volume	Acquired annual Renewable Gas and Low Carbon Energy supply (TJ)	306	790	2,295	2,778
Natural Gas for Transportation Volume	Total gas consumed by CNG and LNG customers (TJ)	2,413	2,652	3,077	3,117
Demand Side Management Energy Savings	Measure of lifetime gas savings from conservation and energy management programs (TJ)[131]	7,937	12,304	10,811	10,104

6.4 FBC'S PROPOSED SERVICE QUALITY INDICATORS

FBC reviewed the existing SQIs and believes that overall, they remain appropriate to ensure that service quality to customers is maintained throughout the term of the Rate Framework. As further explained below and in Appendix C6-2, FBC is proposing the following changes which build off of and enhance its existing suite of SQIs:

- FBC proposes to change the benchmarks and thresholds of some SQIs, recognizing their recent historical performance.
- FBC proposes to change the name of the Meter Reading Accuracy metric to Meter Reading Completion to better reflect what the metric is measuring and to change it to an informational indicator.

The following table provides a comparison of FBC's current and proposed SQIs. The four metrics with green shaded areas reflect changes from the current SQIs. Each change is discussed in detail below the table.

130 2023 GHG emissions from natural gas operations are currently being reviewed by a third-party verifier. As such, values may change.

131 FEI calculates lifetime gas savings based on the net present value of gas savings over the lifetime of all measures implemented during the year.

Table C6-7: Comparison of FBC Current and Proposed SQIs

		Current		*Proposed*	
Safety Indicators		Benchmark	Threshold	Benchmark	Threshold
Annual results	**Emergency Response Time**	>= 93%	90.6%	>=93%	90.6%
3 Year rolling average	**All Injury Frequency Rate**	<= 1.64	2.39	<=1.31	2.56
Responsiveness to Customer Needs Indicators					
Annual results	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual results	**Billing Index**	<= 3	5	<=3	5
Annual results	**Meter Reading Completion**	>= 98%	96%	Informational	Informational
Annual results	**Telephone Service Factor**	>= 70%	68%	>=70%	68%
Annual results	**Customer Satisfaction Index**	Informational	Informational	Informational	Informational
Annual results	**Average Speed of Answer**	Informational	Informational	Informational	Informational
Reliability Indicators					
Annual results	**System Average Interruption Duration Index - Normalized**	3.22	4.52	3.24	4.71
Annual results	**System Average Interruption Frequency Index - Normalized**	1.57	2.19	1.64	2.25
Annual results	**Generator Forced Outage Rate**	Informational	Informational	Informational	Informational
Annual results	**Interconnection Utilization**	Informational	Informational	Informational	Informational

6.4.1 All Injury Frequency Rate

FBC proposes to continue to report on the existing AIFR SQI which is a lagging indicator. Please refer to Section C6.3.1 above for a description of the leading versus lagging indicators of employee safety. Consistent with FEI, FBC proposes to explore leading indicators of safety that could be considered for future inclusion as an SQI.

The three-year rolling average and annual results of the AIFR SQI during the Current MRP term are provided in the table below.

Table C6-8: FBC AIFR History and Proposed Metrics

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
AIFR – three year rolling average	0.87	0.67	1.42	1.84	1.64	1.31	2.39	2.56
AIFR – annual	0.66	0.89	2.60	1.97	n/a	n/a	n/a	n/a

The results from 2020 to 2022 have been better than the currently approved benchmark of 1.64, with the 2023 results better than the threshold. For the term of the Rate Framework, FBC proposes to lower the benchmark based on the average of the recent three-year rolling average of the annual results from 2021 to 2023. FBC accordingly proposes to lower the benchmark from 1.64 to 1.31. Additionally, FBC proposes to increase the threshold from the currently approved 2.39 to 2.56, consistent with past practice.[132]

6.4.2 Meter Reading Completion (formerly Meter Reading Accuracy)

FBC proposes to change the name of the Meter Reading Accuracy metric to Meter Reading Completion, as the revised name better reflects what the metric is measuring (i.e., the number of scheduled meters that were read).

Further, FBC proposes to change this metric to an informational indicator and remove the existing benchmark and threshold. As shown in Table C6-9 below, the information gathered through the Meter Reading Completion SQI remains valuable as FBC did not achieve 100 percent performance accuracy during the Current MRP term, despite relatively stable performance. Some AMI meters are not automatically read, either because a customer has requested the radio be turned off or due to the location of the meter not allowing for a proper signal to be received. Further, failures related to weather and system issues can still occur. Having visibility on meter reading completion through the proposed informational indicator will ensure FBC remains focused on obtaining meter readings in both manual and automatic reading situations.

Table C6-9: FBC Meter Reading Completion History and Proposed Metrics

Description	2020	2021	2022	2023
Meter Reading Completion	99%	99%	99%	99%

Please refer to Appendix C6-2 for further details on the Meter Reading Completion SQI.

[132] The threshold is set at 2 standard deviations from the recent 10-year history of the three-year rolling averages of the annual results.

6.4.3 System Average Interruption Duration and Frequency Indexes

FBC proposes to continue to report on SAIDI and SAIFI and to adjust the benchmarks and thresholds.

For SAIDI, the proposed benchmark and threshold incorporate the recent 2021 to 2023 results. Consistent with the approach used to determine the benchmark in the Current MRP, the proposed benchmark is based on the average of the most recent three years' results (i.e., 2021 to 2023). As SAIDI is significantly impacted by external factors, resulting in variability in SAIDI performance, FBC considers that a three-year performance average establishes a benchmark that is consistent with the level of costs required to provide this level of service and provides a consistent methodology that allows for changes in service quality to be detected. Similar to the approach used to determine the threshold for the Current MRP, the proposed threshold is based on statistical analysis (i.e., standard deviation) of the SAIDI historical results from 2010 to 2019 and now inclusive of 2020 to 2023.

The table below provides a summary of the SAIDI results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table C6-10: FBC SAIDI History and Proposed Metrics

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
SAIDI (annual normalized results)	3.17	4.27	2.42	3.04	3.22	3.24	4.52	4.71

For SAIFI, the proposed benchmark and threshold incorporate the recent 2021 to 2023 results. Consistent with the approach used to determine the benchmark in the Current MRP, the proposed benchmark is based on the average of the most recent three years' results (i.e., 2021 to 2023). Similar to the approach used to determine the threshold for the Current MRP, the proposed threshold is based on statistical analysis (i.e., standard deviation) of the SAIFI historical results from 2010 to 2019 and now inclusive of 2020 to 2023.

Table C6-11: FBC SAIFI History and Proposed Metrics

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
SAIFI (annual normalized results)	1.64	2.08	1.52	1.31	1.57	1.64	2.19	2.25

Please refer to Appendix C6-2 for further details.

6.5 *CONCLUSION*

FortisBC's proposed updates and modifications to the Companies' suite of SQIs build on the experience gained during the Current MRP and are designed to ensure that any efficiencies and cost reductions do not result in a degradation of service quality during the term of the Rate Framework.

These SQIs cover responsiveness to customer needs, reliability, and safety. FEI is also proposing to introduce a new category of informational indicators, which is responsive to feedback received on the Rate Framework and will provide an annual assessment of FEI's GHG emissions, renewable energy and natural gas for transportation supply efforts, and DSM energy savings. These new indicators will provide added context on how FEI is addressing the energy transition.

Ultimately, the proposed suite of SQIs for FEI and FBC are both comprehensive and balanced.

7. INDICATIVE RATES

In this section, FortisBC provides projections of its 2025 rates under the Rate Framework. The purpose of this is twofold: (1) to illustrate how the various components of the Rate Framework fit together; and (2) to provide some insight into the upcoming rate changes for 2025.

FortisBC is not requesting approval of 2025 rates in this Application. FortisBC will file for interim 2025 rates before the end of 2024. As part of the 2025 interim rates filings, the Companies will include the impacts of various items related to the close out of the Current MRP, including the true-up of rate base, projections of the Flow-through deferral account and Earnings Sharing amounts, and the returning of unused CGIF funds from the Current MRP to FEI's customers. FEI will also propose an amortization period for the 2023 and 2024 Revenue Deficiency deferral account. After the BCUC issues its decision in relation to this Application, FEI and FBC will file for permanent 2025 rates as part of the first Annual Review, and will include any adjustments to 2025 rates resulting from the BCUC's determinations on the Rate Framework. This approach is consistent with how interim and permanent rates were determined for the first year (i.e., 2020) of the Current MRP.

However, to provide an understanding of the rate implications of the various proposals included in this Application, FEI and FBC have calculated indicative rates for 2025, which are provided below. The tables below show the indicative 2025 delivery rate increase for FEI (Table C7-1) and indicative 2025 rate increase for FBC (Table C7-2). The tables group the rate impacts into three categories:

1. **Resetting MRP:** Adjustments to revenue requirements necessary to reset rate base at the termination of the Current MRP and the resetting of Base O&M for 2025. The rate base impact is due to adding to rate base the capital expenditures excluded during the Current MRP term (expenditures over the approved amounts). The adjustments to O&M are described in Sections C2.2.1 and C2.3.1.
2. **Studies:** Adjustments for the impacts of the various accounting and allocation studies which are described in Section D. These include the depreciation, lead/lag, corporate services, and capitalized overhead studies.
3. **Projected Revenue Requirements:** Includes the level of Regular forecast capital (and formula for FEI Growth capital) expenditures set out in Section C3, as well as the Major Projects that are expected to be included in rate base for each Company in 2025. For FEI, the deferral amortization includes an assumption of a five-year amortization period for the 2023-2024 Revenue Deficiency deferral account as well as the proposed one-year amortization of the unused funds in the CGIF deferral account. FortisBC has also included high-level projections of demand/load and other revenue requirement changes for 2025.

The indicative 2025 delivery rate increase for FEI, shown in Table C7-1 below, is 6.2 percent. Of this increase, approximately 2.5 percent is due to the impact of the BCUC Stage 1 GCOC

Decision.[133] The overall rates in 2025 include the delivery rate, as well as commodity and storage and transport rates. All else equal, the annual bill increase that results from the delivery rate increase is 4.2 percent, or $3.74 per month for the average residential customer.

Table C7-1: FEI Indicative 2025 Delivery Rate Change

Particular	Incremental Revenue Requirement ($millions)
Resetting MRP	
Rate Base	14.1
Base O&M	(9.2)
Subtotal	**4.9**
Studies	
Depreciation Study	2.0
Capitalized overheads study	5.9
Corporate Services	-
Cash Working Capital - Lead Lag	-
Subtotal	**7.9**
Projected Revenue Requirements	
Customer Growth and Volume - Margin	(23.9)
Rate Base Growth (2025)	13.4
Major Project - Inland Gas Upgrades	2.4
Major Project - CTS-TIMC	7.3
Net O&M	26.9
Deferral Amortization	0.6
2023/2024 Revenue Deficiency Deferral Amortization (GCOC)	13.0
2024 Deferred Deficiency (GCOC)	15.9
Taxes	7.7
Other	(3.8)
Subtotal	**59.5**
Total	**72.3**
Margin @ Existing Rates (2024 Approved)	1,164.4
Approximate Delivery Rate Change	**6.2%**

[133] The sum of the 2023-2024 Revenue Deficiency Deferral Account amortization and the 2024 deferred deficiency (both are related to the GCOC decision) is approximately $28.9 million, thus the equivalent delivery rate impact would be 2.5 percent ($28.9 million / $1,164.4 million).

For FBC, the indicative 2025 rate increase is 5.3 percent, as shown in Table C7-2 below. This is equal to approximately $9.47 per month for the average residential customer.

Table C7-2: FBC Indicative 2025 Rate Change

Particular	Incremental Revenue Requirement ($millions)
Resetting MRP	
Rate Base	0.6
Base O&M	3.7
Subtotal	**4.3**
Studies	
Depreciation Study	4.3
Capitalized overheads study	(0.4)
Corporate Services	-
Cash Working Capital - Lead Lag	0.2
Subtotal	**4.1**
Projected Revenue Requirements	
Net Margin (Revenue less Power Supply)	(1.7)
Rate Base Growth (2025)	6.1
Major Project - AS Mawdsley Substation	0.3
Net O&M	2.8
Deferral Amortization, excl. GCOC Deferral	1.9
2023 Revenue Deficiency Amortization (GCOC)	1.5
Taxes	3.1
Other	1.8
Subtotal	**16.0**
Total	**24.4**
Revenue @ Existing Rates (2024 Approved)	458.9
Approximate Rate Change	**5.3%**

The indicative rate increases for 2025 fall within the range of recent rate increases for both FEI and FBC. However, these projected rate impacts for 2025 should be considered indicative only and will be updated in FortisBC's future requests for interim rates to be filed later this year. The Companies will then file for permanent 2025 rates as part of the Annual Review process, subsequent to the BCUC issuing a decision on this Application.

FortisBC Energy Inc. and FortisBC Inc.

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

Section D:

POLICIES AND SUPPORTING STUDIES

Table of Contents

Index of Tables and Figures

D: POLICIES AND SUPPORTING STUDIES

1. INTRODUCTION TO SUPPORTING STUDIES

FortisBC will continue to report on any accounting policy changes in its Annual Reviews during the term of the Rate Framework and bring forward any changes for approval as required. In this Application, FortisBC is not proposing any accounting policy changes.

In the sections that follow, FortisBC provides updated studies that will support the calculation of FortisBC's revenue requirements for the term of the Rate Framework. These include:

- Section D2 – Depreciation Studies
- Section D3 – Lead/Lag Studies
- Section D4 – Corporate Services Study
- Section D5 – Capitalized Overhead Studies

In addition to the studies referenced above, FortisBC completed a review of the Cost Driver Approach for shared services between FEI and FBC, which was previously approved for use by the BCUC for the Current MRP. Based on discussions with the departments sharing services and a review of the cost pools for the shared resources, FortisBC confirmed that the cost driver approach, using the four current cost drivers (customers, employees, Massachusetts formula and management time estimate) remain appropriate. The Cost Driver Approach is simple to understand, easy to administer, and stable over time, and therefore superior to the timesheet approach used prior to the Current MRP.

As part of the Cost Driver Approach, during the Rate Framework term, FortisBC will annually review the allocation basis for each cost driver (e.g., for costs allocated using the number of customers, the number of FEI and FBC customers will be updated to determine the allocation percentage used), and update the percentages as required.

2. DEPRECIATION STUDIES

2.1 INTRODUCTION

In this Application, FEI and FBC are proposing updates to their respective depreciation rates and net salvage based on the results of the depreciation studies included in Appendix D2-1 (FEI) and Appendix D2-2 (FBC) (2022 Depreciation Studies). The filing of the 2022 Depreciation Studies in this Application complies with the BCUC directive in the MRP Decision and Orders G-165-20 and G-166-20 that FortisBC "update the depreciation studies for FEI and FBC prior to or along with its next RRA following the Proposed MRPs."

FortisBC retained Concentric to perform a review of the Companies' depreciation rates. The results of this review are included in the 2022 Depreciation Studies and have been prepared based on FEI's and FBC's plant-in-service balances as of December 31, 2022. The last depreciation studies were prepared using the plant-in-service balances for FEI and FBC as of December 31, 2017 (2017 Depreciation Studies).

Consistent with the 2017 Depreciation Studies, Concentric has estimated the depreciation rates using the straight-line method and the Average Life Group (ALG) procedure applied on a remaining life basis for each depreciable group of assets. The life and net salvage rates were developed using various statistical methods such as Iowa type survivor curves and "goodness of fit" criterion, a review of actual retirement activity, operational interviews with FEI and FBC staff, and informed judgement based on their experience in the gas and electric industries. The process followed by Concentric involves the determination of an estimated average service life for each asset class and whether certain assets have depreciation surpluses or deficits, both of which drive the recommended depreciation rates. Straight-line depreciation is developed for the assets in a particular class beginning with the original cost, the estimated average and remaining service life characteristics, and accounting for the accumulated depreciation already booked in that class.

In preparing the depreciation study for FEI, Concentric and FEI considered whether accelerated depreciation methods should be explored. As discussed in Section B3.2.2.4 of the Application, FEI does not consider it appropriate at this time to accelerate depreciation and thereby increase costs for customers. This is supported by Concentric in Section 3.1.2 of the 2022 Depreciation Study. While there is strong evidence that the future of conventional natural gas may be impacted by climate change legislation, the extent that this may change the useful life of FEI's assets remains unknown. An example cited in the 2022 Depreciation Study is the impact of hydrogen blending, which may potentially have a life lengthening impact on the transmission and distribution systems. However, additional research will be required across the entire hydrogen and natural gas supply chain to fill the current knowledge gap and better inform future decisions as to the impacts of hydrogen blending on the useful lives of the existing gas assets.

On pages 3-3 and 3-4 of the 2022 Depreciation Study, Concentric discusses the developments in other jurisdictions regarding the assessment and adoption of accelerated depreciation. Concentric's review did not identify any jurisdictions that have adopted economic planning horizons – a form of accelerated depreciation – for setting depreciation rates for natural gas distribution utilities.

Concentric concludes on page 3-4 of the 2022 Depreciation Study:

> At this time, the future impacts of the relevant climate change legislation have not been sufficiently studied, nor have specific programs been put into place that would provide the indications of the changes in utilization levels. As the energy transition continues to evolve, a change in depreciation methodology may or may not be required in the future, depending on the impact that the energy transition has on the existing gas asset system.

The future impacts and whether they may require the introduction of an economic planning horizon into the depreciation rate calculations are better addressed in a future depreciation study filing and therefore were not included in the calculation and determination of depreciation rates in this Application.

As a result, the 2022 Depreciation Studies were prepared using methodologies consistent with the 2017 Depreciation Studies. The 2022 Depreciation Studies recommend updates for both depreciation rates and net salvage rates for FEI and FBC. The studies are summarized below.

2.2 *2022 DEPRECIATION STUDY FOR FEI*

FEI implemented the depreciation and net salvage rates from the 2017 Depreciation Study effective January 1, 2020 pursuant to the MRP Decision and Order G-165-20. FEI's 2022 Depreciation Study included in Appendix D2-1 was prepared based on its gas plant-in-service as of December 31, 2022.

The overall results of the 2022 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of CIAC rates, are shown in Tables D2-1 and D2-2 below. Implementation of the rates from the 2022 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $2.0 million per year, a 0.02 percent overall increase to the composite depreciation rate compared to the current approved rates.

Table D2-1: Impact of Implementing Depreciation Study Recommendations for FEI ($ millions)

	Existing	Recommended	Change
Depreciation	201.9	198.0	(3.9)
Net Salvage	57.1	63.0	5.9
CIAC	(7.7)	(7.7)	0.0
Total	**251.3**	**253.3**	**2.0**

Table D2-2: Depreciation Study Average Rate Recommendations for FEI (%)

	Existing	Recommended	Change
Depreciation	2.50	2.45	(0.05)
Net Salvage	0.71	0.78	0.07
Total	**3.21**	**3.23**	**0.02**

Further discussion of Concentric's recommended changes to depreciation, net salvage and amortization of CIAC follows.

2.2.1 Depreciation Rates

The 2022 Depreciation Study was developed using the ALG depreciation methodology, consistent with the 2017 Depreciation Study. The 2022 Depreciation Study recommends an average composite depreciation rate of 2.45 percent for FEI, which is a decrease of 0.05 percent from the 2.50 percent derived from the 2017 Depreciation Study.

While there are certain specific asset classes that are expected to have slightly longer service lives based on actual retirement history, the overall decrease in the average composite depreciation rate is not indicative of overall longer expected service lives for FEI's assets. Instead, the adjustment downward in the average composite depreciation rate is primarily attributable to depreciation surpluses for certain asset classes that put downward pressure on the depreciation rates. The existence of depreciation surpluses and deficits occur in the normal course of asset retirements and one of the objectives for undertaking a depreciation study on a cyclical basis is to recommend depreciation rates that will prospectively unwind such variances.

As a result, FEI's total depreciation expense is decreasing by approximately $3.9 million due to the changes in the depreciation rates. This change excludes the effects on depreciation expense resulting from future additions and retirements to property, plant and equipment (PP&E), as well as changes to the net salvage rates. The recommended depreciation rates are set out in Table D2-3 below. Rates noted with an asterisk are not included in the depreciation study since they are calculated separately by reference to other criteria (for example, lease structures and vehicles are depreciated based on specific lease terms).

Table D2-3: Impact of Implementing Recommended Depreciation Rates for FEI

Line #	Class	Description	2017 Depreciation Study Rate	2022 Depreciation Study Rate	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Increase + / Decrease -
1	175-00	Unamortized Conversion Expense - Squamish*	10.00%	10.00%	-	-	-
2	175-10	Unamortized Conversion Expense *	1.00%	1.00%	1,087	1,087	-
3	178-00	Organization expense	1.00%	1.00%	7,281	7,281	-
4	401-01	Franchises and Consents	1.08%	2.50%	2,127	4,923	2,796
5	402-01	Computer S/W-Applic 8 Year	12.50%	12.50%	9,745,779	9,745,779	-

Line #	Class	Description	2017 Depreciation Study Rate	2022 Depreciation Study Rate	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Increase + / Decrease -
6	402-02	Computer S/W-Applic 5 Year	20.00%	20.00%	5,187,441	5,187,441	-
7	402-03	Intangible Plant	2.50%	2.50%	47,665	47,665	-
8	432-00	Mfg. Gas Structures	2.50%	2.50%	32,801	32,801	-
9	433-00	Mfg. Gas Equipment	5.00%	5.00%	60,057	60,057	-
10	434-00	Mfg. Gas Holders	2.50%	2.50%	73,702	73,702	-
11	436-00	Mfg. Gas Compressor Equipment	4.00%	4.00%	14,663	14,663	-
12	437-00	Mfg. Gas Meas/Reg Equipment	5.00%	5.00%	108,524	108,524	-
13	442-00	LNG Gas Structures - Tilbury	2.20%	3.70%	2,238,729	3,765,136	1,526,407
14	443-00	LNG Gas Equipment - Tilbury	1.23%	1.71%	2,259,197	3,140,835	881,638
15	448-11	LNG Gas - Piping - Tilbury	2.45%	2.50%	1,294,644	1,321,065	26,421
16	448-21	LNG Gas - Pre-Treatment - Tilbury	3.84%	4.01%	1,309,402	1,367,371	57,969
17	448-31	LNG Gas - Liquefaction Equipment - Tilbury	2.45%	2.50%	2,176,167	2,220,579	44,412
18	448-41	LNG Gas - Send Out Equipment - Tilbury	2.41%	2.50%	257,279	266,887	9,608
19	448-51	LNG Gas - Sub-Station and Electrical - Tilbury	2.41%	2.50%	921,708	956,129	34,421
20	448-61	LNG Gas - Control Room - Tilbury	6.09%	6.75%	280,632	311,046	30,414
21	449-00	LNG Gas Other Equipment - Tilbury	2.77%	2.10%	802,060	608,060	(194,000)
22	442-01	LNG Gas - Structures Mt Hayes	3.85%	3.06%	735,286	584,409	(150,877)
23	443-05	LNG Gas Equipment Mt Hayes	1.65%	1.65%	1,020,302	1,020,302	-
24	448-10	LNG Gas - Piping Mt Hayes	2.45%	2.43%	311,504	308,962	(2,542)
25	448-20	LNG Gas - Pre-Treatment Mt Hayes	3.84%	3.71%	1,126,953	1,088,801	(38,152)
26	448-30	LNG Gas - Liquefaction Equipment Mt Hayes	2.45%	2.42%	709,019	700,337	(8,682)
27	448-40	LNG Gas - Send Out Equipment Mt Hayes	2.41%	2.43%	572,212	576,961	4,749
28	448-50	LNG Gas - Sub-Station and Electrical Mt Hayes	2.41%	2.43%	525,097	529,455	4,358
29	448-60	LNG Gas - Control Room Mt Hayes	6.09%	5.01%	405,880	333,902	(71,978)
30	448-65	LNG Gas - Mt. Hayes Inspection*	20.00%	20.00%	314,372	314,372	-
31	449-01	LNG Gas - Other Equipment Mt Hayes	3.08%	3.47%	188,911	212,831	23,920
32	465-30	LNG - Mains Mt Hayes	1.54%	1.54%	97,127	97,127	-
33	467-00	LNG - Measuring and Regulating Equipment Mt Hayes	2.34%	2.28%	138,748	135,190	(3,558)
34	462-00	TP Compressor Structures	3.32%	2.97%	1,531,788	1,370,304	(161,484)
35	463-00	TP Meas/Reg Structures	2.13%	2.19%	553,574	569,167	15,593

Line #	Class	Description	2017 Depreciation Study Rate	2022 Depreciation Study Rate	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Increase + / Decrease -
36	464-00	TP Other Structures	3.62%	3.31%	248,731	227,431	(21,300)
37	465-00	TP Transmission Pipeline	1.46%	1.48%	24,524,862	24,860,819	335,957
38	465-20	TP Mains - Inspection *	15.20%	15.20%	5,782,682	5,782,682	-
39	465-10	TP Mains - Byron Creek *	5.03%	5.03%	68,966	68,966	-
40	466-00	TP Compressor Equipment	2.42%	2.31%	4,913,889	4,690,530	(223,359)
41	466-10	TP Compressor Equipment - Overhauls *	10.19%	10.19%	887,899	887,899	-
42	467-10	TP Meas/Reg Equipment	2.12%	2.27%	1,977,089	2,116,978	139,889
43	467-20	TP Telemetry Equipment	8.97%	6.01%	1,967,271	1,318,094	(649,177)
44	467-30	TP Meas/Reg Equipment - Byron Creek *	2.41%	2.41%	7,023	7,023	-
45	468-00	TP Communications Equipment	0.00%	0.00%	-	-	-
46	465-11	IP Transmission Pipeline (Whistler Pipeline)	1.54%	1.53%	909,244	903,340	(5,904)
47	467-31	IP Meas/Reg Equipment (Whistler Pipeline)	2.26%	2.14%	7,082	6,706	(376)
48	472-00	DS Structures	2.15%	2.01%	1,169,978	1,093,794	(76,184)
49	472-10	DS Structures - Byron Creek *	4.67%	4.67%	5,773	5,773	-
50	473-00	DS Services	2.18%	2.11%	33,469,477	32,394,769	(1,074,708)
51	474-00	DS Meters/Regulators Installations	7.45%	4.35%	2,767,849	1,616,126	(1,151,723)
52	474-02	DS Meters/Regulators Installations New	4.55%	4.55%	10,922,774	10,922,774	-
53	475-00	DS Mains	1.35%	1.42%	30,801,754	32,398,882	1,597,128
54	476-00	DS NGV Fuel Equipment	0.00%	0.00%	-	-	-
55	477-30	DS Meas/Reg Equipment - Byron Creek	0.00%	0.00%	-	-	-
56	477-20	DS Telemetering	3.59%	4.97%	1,042,409	1,443,112	400,703
57	477-10	DS Meas/Reg Additions	2.51%	2.66%	5,711,764	6,053,105	341,341
58	478-10	DS Meters	6.06%	3.38%	7,649,628	4,266,624	(3,383,004)
59	478-20	DS Instruments	2.92%	2.86%	458,658	449,234	(9,424)
60	472-20	Biogas - Structures and Improvements	2.69%	2.69%	40,830	40,830	-
61	475-10	Biogas - Mains on Municipal Land	1.56%	1.54%	27,344	26,993	(351)
62	475-20	Biogas - Mains on Private Land	1.56%	1.53%	6,401	6,278	(123)
63	418-10	Biogas - Purication Overhaul	5.00%	5.00%	1,021	1,021	-
64	418-20	Biogas - Purification Upgrader	5.00%	5.00%	502,598	502,598	-
65	477-40	Biogas - Reg and Meter Equipment	3.22%	3.24%	139,103	139,967	864
66	474-10	Biogas - Reg and Meter Installations	5.32%	5.08%	42,676	40,751	(1,925)

Line #	Class	Description	2017 Depreciation Study Rate	2022 Depreciation Study Rate	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Increase + / Decrease -
67	478-30	Biogas - Meters	4.89%	5.19%	4,118	4,371	253
68	476-10	NGV - Transport CNG Dispensing Equipment	5.00%	5.00%	856,043	856,043	-
69	476-20	NGV - Transport LNG Dispensing Equipment	5.00%	5.00%	685,688	685,688	-
70	476-30	NGV - Transport CNG Foundations	5.00%	5.00%	158,062	158,062	-
71	476-40	NGV - Transport LNG Foundations	5.00%	5.00%	52,440	52,440	-
72	476-50	NGV - Transport LNG Pumps	10.00%	10.00%	7,688	7,688	-
73	476-60	NGV - CNG Dehydrator	5.00%	5.00%	40,202	40,202	-
74	482-10	GP (Frame) Structures	3.17%	2.75%	862,349	748,094	(114,255)
75	482-20	GP (Masonry) Structures	1.52%	1.36%	2,006,579	1,795,360	(211,219)
76	482-30	GP (Leased) Structures *	9.49%	9.49%	329,752	329,752	-
77	483-10	GP Computer Hardware	25.00%	25.00%	12,678,703	12,678,703	-
78	483-20	GP Computer Systems Software	12.50%	12.50%	1,068,140	1,068,140	-
79	483-30	GP Office Equipment	6.67%	6.67%	153,629	153,629	-
80	483-40	GP Furniture	5.00%	5.00%	828,787	828,787	-
81	484-00	GP Vehicles	11.07%	7.15%	6,057,656	3,912,578	(2,145,078)
82	484-10	Vehicles-Leased*	9.44%	9.44%	69,134	69,134	-
83	485-10	GP Heavy Work Equipment	5.14%	4.04%	37,154	29,202	(7,952)
84	485-20	GP Heavy Mobile Equipment	6.09%	8.51%	741,722	1,036,463	294,741
85	486-00	GP Small Tools/Equipment	5.00%	5.00%	2,970,799	2,970,799	-
86	488-10	GP Telephone Equipment	6.67%	6.67%	81,590	81,590	-
87	488-20	GP Radio Equipment	6.67%	6.67%	1,138,352	1,138,352	-
88		**Total Annual Depreciation**			**201,935,080**	**198,001,327**	**(3,933,753)**
89							
90		**Annual Composite Rate**			**2.50%**	**2.45%**	**-0.05%**

Note: Numbers above are in dollars with depreciation calculated using the January 1, 2023 gross asset values.

The asset categories with the more significant changes in depreciation expense as compared to the 2017 Depreciation Study are:

- LNG Gas Structures – Tilbury (442-00)
- LNG Gas Equipment – Tilbury (443-00)
- Services (473-00)
- Distribution Mains (475-00)

- Meters and Regulators Installations (474-00, 474-02)
- Meters (478-10)
- GP Vehicles (484-00)

Each of these asset categories is discussed below. Please refer to pages 3-7 to 3-21 of the 2022 Depreciation Study for further details and discussion.

2.2.1.1 LNG Gas Structures – Tilbury (442-00)

For LNG Gas Structures – Tilbury (442-00), Concentric recommends a 28-year life, an increase from the 25-year service life recommended in the 2017 Depreciation Study.

A review of retirements, additions, and other plant transactions for the period 1972 to 2022 along with the recent Tilbury 1A (T1A) additions into rate base suggest that an average service life of 28 years is more indicative for this account and is also consistent with the average service life for the Mt. Hayes plant. Extending the average life by three years is also in alignment with operational and management staff opinion and supported by Concentric's professional judgment. Please refer to page 3-7 of Appendix D2-1 for further details.

The large new additions that this asset class has experienced in the past five years and the true-up for the depreciation rate over the remaining life of the assets result in an increase of approximately 1.5 percent in the depreciation rate for LNG Gas Structures – Tilbury. The inclusion of a true-up in the development of the depreciation rate is necessary to recognize that over the life of a group of assets, differences may arise (i.e., due to change in the expected life of assets) between the booked and the calculated (theoretical) accumulated depreciation reserve.

2.2.1.2 LNG Gas Equipment – Tilbury (443-00)

For 443-00 LNG Gas Equipment – Tilbury, Concentric recommends a 57-year life, an increase from the 40-year service life recommended in the previous study.

Account 443-00 LNG Gas Equipment – Tilbury, includes both the more recent T1A additions and the existing Base Plant assets. With the addition of the costs for T1A to this account since the 2017 Depreciation Study, the estimated life used for depreciation for account 443-00 LNG Gas Equipment – Tilbury has been revised to 57 years based on the Iowa curve 57-S4, and represents an increase from the 40 years previously estimated. The estimated 60-year life for the T1A LNG Gas Equipment is also applied to account 443-05 LNG Gas Equipment Mt. Hayes. Please refer to pages 3-8 and 3-9 of Appendix D2-1 for further details.

The large new additions that this asset class have experienced in the past five years and the true-up for the depreciation rate over the remaining life of the assets results in an increase of 0.48 percent in the depreciation rate for LNG Gas Equipment – Tilbury.

2.2.1.3 Services (473-00)

For Services (473-00), Concentric recommends a 47-year life, consistent with the 2017 Depreciation Study.

A review of retirements, additions, and other plant transactions for the period 1963 to 2022 suggests that an average service life of 47 years continues to be reflective of the historical retirement activity and future expectations for retirements and falls within the typical range of lives used for this account.

The average age of retirement experienced from 2017 through 2022 indicated no material changes since the last study; therefore, the 47-year life still captures the initial retirements up until age 30. Additionally, in determining the recommended 47-year life, Concentric reviewed a selection of peer Canadian natural gas distribution companies and the average service life estimates among these peers ranged from 45 through 70 years.

Please refer to pages 3-14 and 3-15 of Appendix D2-1 for further details.

The true-up for the depreciation rate over the remaining life of the assets result in a decrease of 0.07 percent in the depreciation rate for Services.

2.2.1.4 Distribution Mains (475-00)

For Distribution Mains (475-00), Concentric recommends a 65-year life, consistent with the 2017 Depreciation Study. The Distribution Mains account contains both steel and plastic distribution mains, with plastic mains first being installed in 1981. FEI has an ongoing mains replacement program based on age and risk of future problems. Almost all of the pipe being replaced is older vintages, suggesting the life of mains should be on the longer end of the range experienced by peer utilities, where service life estimates ranged from an average of 55 through 80 years.

A recent review of retirements, additions, and other plant transactions for the period 1924 to 2022 suggest that an average service life of 65 years continues to be reflective of the historical data. Discussions with operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for Distribution Mains which is further supported by the professional judgement of Concentric.

The average age of retirement experienced from 2017 through 2022 indicated no material changes since the last study and the future expectations for retirements are expected to remain consistent.

Please refer to pages 3-16 and 3-17 of Appendix D2-1 for further details.

The true-up for the depreciation rate over the remaining life of the assets results in an increase of 0.07 percent in the depreciation rate for Distribution Mains.

2.2.1.5 Meters and Regulators Installations (474-00, 474-02) and Meters (478-10)

The Meters and Regulators Installations (474-00 and 474-02) and Meters (478-10) accounts will be impacted by the exchange of new AMI meters for existing meters as part of the approved AMI project. Below, FEI provides the accounting for these accounts and a discussion of the recommended depreciation rates, incorporating the expected impacts of the AMI project.

2.2.1.5.1 RECOVERY OF EXISTING METERS AND INSTALLATION COSTS AND PREVIOUSLY RETIRED METERS AND INSTALLATION COSTS

FEI's existing meters and their installation costs will be removed from service as they are exchanged with new AMI meters in phases over the term of the AMI project. In accordance with Decision and Order C-2-23, the remaining rate base value of meters to be exchanged as part of the AMI project (account 478-10), along with the associated meter installation costs (accounts 474-00, 474-02), are to be captured in the "Existing Meter Cost Recovery" deferral account with a rolling amortization period of five years.

The same treatment was approved for the remaining rate base value of previously retired meters and meter installation costs, which currently reside in accumulated depreciation for accounts 478-10, 474-00 and 474-02, except that these amounts are captured in a separate account called the "Previously Retired Meter Cost Recovery" deferral account.

2.2.1.5.2 METERS AND REGULATORS INSTALLATIONS (474-00, 474-02)

In developing the recommended depreciation rate for Meters and Regulators Installations (474-00), Concentric excluded the recovery of historical losses for previously retired assets from the calculation, as the historical losses are being recovered using the Previously Retired Meter Cost Recovery deferral account. The historical losses are currently recorded in the accumulated depreciation account and will be transferred to the Previously Retired Meter Cost Recovery deferral account beginning January 1, 2025.

For Meters and Regulators Installations (474-00), approximately 77 percent of this account relates to the installation costs of older gas meters that follow an amortization accounting method and are expected to be completely retired in 2035 or sooner as part of the AMI project. The remaining 23 percent of this account is for assets relating to installation of station regulators that are almost fully amortized, following traditional regulatory retirement accounting practices, and are expected to be in service until the end-of-life of the asset.

For the recovery of the remaining net book value of the meter assets (meter installation and station regulators) recorded in 474-00, Concentric recommends an Iowa 23-SQ, a change from the previously approved weighted approach of an Iowa 20-S0 and 23-SQ for this account. The Iowa 23-SQ is recommended for the meter installation and station regulator assets based on indications from management and operations, and on the professional judgement of Concentric. As the majority of the investment in this account relates to assets under amortization accounting, there was no retirement rate analysis prepared. The recommended depreciation rate applies to the assets that are being retired in phases through the AMI project and to those assets expected to remain in service until their end-of-life.

For the Meters and Regulators Installations 474-02 account, which was established to capture new plant additions only, similar to the reasons outlined for 474-00, Concentric recommends an Iowa 22-SQ, resulting in similar recommended depreciation rates for both accounts 474-00 and 474-02.

For the meter installations that are being retired in phases due to the AMI project, the remaining net book value will be transferred to the Existing Meter Cost Recovery deferral account.

Please refer to pages 3-15 and 3-16 of Appendix D2-1 for further details.

This change and the true-up of the depreciation rate over the remaining life of the assets result in a decrease of 3.10 percent in the depreciation rate for this asset category.

2.2.1.5.3 METERS (478-10)

In developing the recommended depreciation rate for Meters (478-10), Concentric excluded the recovery of historical losses for previously retired meter assets from the calculation, as the historical losses are being recovered using the Previously Retired Meter Cost Recovery deferral account. The historical losses are currently recorded in the accumulated depreciation account and will be transferred to the Previously Retired Meter Cost Recovery deferral account beginning January 1, 2025.

For Meters (478-10), approximately 60 percent of the assets residing in the account relate to meters subject to retirement under the AMI project, while the remaining 40 percent of assets in this account follow traditional regulatory retirement accounting practices and are expected to be in service until the end-of-life of the asset.

For the recovery of the remaining net book value of the meter assets, Concentric recommends changing the annual depreciation accrual to be weighted in accordance with the retirement practices for each of the two groups of assets in this account. Concentric recommends an Iowa 5-SQ for meters subject to retirement under the AMI project and an Iowa 18-R4 for the remainder of the assets in this account. These recommended survivor curves are based on indications from management and operations, and on the professional judgement of Concentric. This approach results in recognizing both the straight-line amortization accounting treatment as well the typical retirement patterns of the non-amortized metering assets. The recommended depreciation rate applies to both the meters that are being retired in phases through the AMI project and to those meters expected to remain in service until their end-of-life.

For meters that are being retired in phases due to the AMI project, the remaining net book value will be transferred to the Existing Meter Cost Recovery deferral account.

Please refer to pages 3-18 and 3-19 of Appendix D2-1 for further details.

This change and the true-up of the depreciation rate over the remaining life of the assets result in a decrease of 2.68 percent in the depreciation rate for this asset category.

2.2.1.6 GP Vehicles (484-00)

For GP Vehicles (484-00), Concentric recommends a 10-year life, an increase from the 7-year service life recommended in the 2017 Depreciation Study.

A review of retirements, additions, and other plant transactions for the period 1957 to 2022 suggests that an average service life of 10 years is more reflective of the historical retirement activity, and 10 years falls within the typical range of lives used for this account by peer companies which is between 7 and 16 years. Most of the retirements in this account occur up until age 21. Therefore, lengthening the life by three years provides a better fit with the historical data and is aligned with the views of FEI operational and subject matter experts that the recommended 10-year life is consistent with the future retirement activity expected for this account.

Please refer to pages 3-20 and 3-21 of Appendix D2-1 for further details.

This change and the true-up of the depreciation rate over the remaining life of the assets result in a decrease of 3.92 percent in the depreciation rate for this asset category.

2.2.2 Net Salvage

As approved by the BCUC, FEI provides for net salvage (removal costs less salvage proceeds) on its existing assets as a cost of providing service, recovered from customers over the useful life of the asset:[134]

> The Commission Panel directs the FEU to continue forecasting salvage costs in each test period and to include this estimate in future revenue requirements applications.

The 2022 Depreciation Study includes updated estimates of net salvage rates which FEI has included in amortization expense. As directed by the BCUC, FEI records its negative salvage provision in its deferral schedules rather than within the plant continuity schedules:[135]

> Therefore, the Commission Panel directs the FEU to establish a rate base credit account to tabulate the total net negative salvage provisions less actual salvage costs. The Panel does not approve the presentation of the net negative salvage provision as a component of plant-in-service within the Utilities' assets.

The result is that the net salvage expense is included as a component of deferred charge amortization expense.

[134] FortisBC Energy Utilities (FEU) 2012-2013 Revenue Requirements and Rates Decision and Order G-44-12, p. 85.
[135] FEU 2012-2013 Revenue Requirements and Rates Decision and Order G-44-12, p. 84.

The updated net salvage rates based on gas plant-in-service as of December 31, 2022 are included in Appendix D2-1, Section 5.

The asset classes where net salvage is included are shown in Table D2-4 below, comparing the recommended and existing net salvage rates and the impact on net salvage expense. As recommended by the 2022 Depreciation Study, the average composite net salvage rate increases from 0.71 percent using the current approved rates to 0.78 percent using the recommended rates. The recommended net salvage rate increase is supported by the increases in FEI's actual cost of asset removal activities. This change results in an increase to net salvage expense of approximately $5.9 million.

1 **Table D2-4: Impact of Implementing Recommended Net Salvage Rates for FEI**

Line #	Class	Description	Net Salvage 2017	Net Salvage 2022	2017 Depreciation Study Net Salvage Rate	2022 Depreciation Study Net Salvage Rate	Net Salvage Based on 2017 Rate	Net Salvage Based on 2022 Rate	Increase + / Decrease -
1	437-00	Mfg. Gas Meas/Reg Equipment	n/a	n/a	0.00%	0.00%	-	-	-
2	442-00	LNG Gas Structures	-10%	-10%	0.68%	0.30%	691,971	305,281	(386,690)
3	443-00	LNG Gas Equipment - Tilbury	-20%	-20%	1.12%	0.30%	2,057,155	551,024	(1,506,131)
4	449-00	LNG Gas Other Equipment	-10%	-5%	0.82%	-0.17%	237,433	(49,224)	(286,657)
5	442-01	LNG Gas - Structures Mt. Hayes	-10%	-10%	0.49%	0.40%	93,582	76,393	(17,189)
6	443-05	LNG Gas Equipment Mt. Hayes	-20%	-20%	0.36%	0.36%	222,611	222,611	-
7	448-10	LNG Gas - Piping Mt. Hayes	-10%	-10%	0.28%	0.28%	35,601	35,601	-
8	448-11	Piping - Tilbury	-10.00%	-10.00%	0.28%	0.24%	147,959	126,822	(21,137)
9	448-20	LNG Gas - Pre-Treatment Mt Hayes	-10%	-10%	0.50%	0.48%	146,739	140,869	(5,870)
10	448-21	Pre-treatment - Tilbury	-10.00%	-10.00%	0.50%	0.34%	170,495	115,937	(54,558)
11	448-30	LNG Gas - Liquefaction Equipment Mt Hayes	-20%	-20%	0.57%	0.57%	164,955	164,955	-
12	448-31	Liquefaction Equipment - Tilbury	-20.00%	-20.00%	0.57%	0.46%	506,292	408,587	(97,705)
13	448-40	LNG Gas - Send Out Equipment Mt Hayes	-10%	-10%	0.28%	0.28%	66,481	66,481	-
14	448-41	Send Out Equipment - Tilbury	-10.00%	-10.00%	0.28%	0.25%	29,891	26,689	(3,202)
15	448-50	LNG Gas - Sub-Station and Electrical Mt Hayes	-20%	-20%	0.56%	0.57%	122,014	124,193	2,179
16	448-51	Substation and Electrical - Tilbury	-20.00%	-20.00%	0.56%	0.48%	214,173	183,577	(30,596)
17	449-01	LNG Gas - Other Equipment Mt Hayes	-10.00%	-5.00%	0.32%	0.14%	19,627	8,587	(11,040)
18	465-30	LNG - Mains Mt Hayes	-20%	-20%	0.30%	0.31%	18,921	19,552	631

Line #	Class	Description	Net Salvage 2017	Net Salvage 2022	2017 Depreciation Study Net Salvage Rate	2022 Depreciation Study Net Salvage Rate	Net Salvage Based on 2017 Rate	Net Salvage Based on 2022 Rate	Increase + / Decrease -
19	467-00	LNG - Measuring and Reg Equip Mt Hayes	-7.00%	-5.00%	0.21%	0.13%	12,452	7,708	(4,744)
20	462-00	TP Compressor Structures	-3%	-3%	0.11%	0.12%	50,752	55,366	4,614
21	463-00	TP Meas/Reg Structures	-15.00%	-15.00%	0.62%	0.46%	161,134	119,551	(41,583)
22	464-00	TP Other Structures	-5%	-5%	0.29%	0.25%	19,926	17,178	(2,748)
23	465-00	TP Transmission Pipeline	-20.00%	-23.00%	0.42%	0.47%	7,055,097	7,894,990	839,893
24	467-20	TP Telemetry Equipment	n/a	0.00%	0.00%	0.02%	-	4,386	4,386
25	466-00	TP Compressor Equipment	-3.00%	-3.00%	0.07%	0.10%	142,137	203,053	60,916
26	467-10	TP Meas/Reg Equipment	-5%	-5%	0.16%	0.14%	149,214	130,563	(18,651)
27	465-11	IP Transmission Pipeline (Whistler Pipeline)	-20%	-20%	0.34%	0.33%	200,742	194,838	(5,904)
28	467-31	IP Meas/Reg Equipment (Whistler Pipeline)	-7.00%	-7.00%	0.35%	0.19%	1,097	595	(502)
29	472-00	DS Structures	-15%	-20%	0.52%	0.53%	282,971	288,413	5,442
30	473-00	DS Services	-70%	-85%	2.09%	2.47%	32,087,709	37,921,838	5,834,129
31	474-00	DS Meters/Regulators Installations	-20.00%	-20.00%	3.37%	0.87%	1,252,034	323,225	(928,809)
32	474-02	DS Meters/Regulators Installations New	n/a	0%	0.00%	0.00%	-	-	-
33	475-00	DS Mains	-25.00%	-30.00%	0.50%	0.56%	11,408,057	12,777,024	1,368,967
34	477-20	DS Telemetering	-5.00%	-5.00%	0.48%	0.31%	139,375	90,013	(49,362)
35	477-10	DS Meas/Reg Additions	-12.00%	-12.00%	0.45%	0.40%	1,024,021	910,241	(113,780)
36	478-10	DS Meters	n/a	0%	0.00%	-0.17%	-	(214,594)	(214,594)
37	472-20	Biogas - Structures and Improvements	-10%	-10%	0.29%	0.28%	4,402	4,250	(152)
38	475-10	Biogas - Mains on Municipal Land	-25.00%	-25.00%	0.39%	0.38%	6,836	6,661	(175)
39	475-20	Biogas - Mains on Private Land	-25%	-25%	0.39%	0.39%	1,600	1,600	-

Line #	Class	Description	Net Salvage 2017	Net Salvage 2022	2017 Depreciation Study Net Salvage Rate	2022 Depreciation Study Net Salvage Rate	Net Salvage Based on 2017 Rate	Net Salvage Based on 2022 Rate	Increase + / Decrease -
40	477-40	Biogas - Reg and Meter Equipment	n/a	0.00%	0.00%	0.01%	-	432	432
41	418-20	Biogas - Purification Upgrader	-5.00%	-5.00%	0.24%	0.25%	24,125	25,130	1,005
42	474-10	Biogas - Reg and Meter Installations	-25%	-25%	1.44%	1.29%	11,551	10,348	(1,203)
43	478-30	Biogas - Meters	n/a	0.00%	0.00%	-0.02%	-	(17)	(17)
44	482-10	GP (Frame) Structures	-4.00%	-4.00%	0.37%	0.38%	100,653	103,373	2,720
45	482-20	GP (Masonry) Structures	-4%	-10%	0.08%	0.18%	105,609	237,621	132,012
46	484-00	GP Vehicles	15%	15%	-3.70%	-1.55%	(2,024,691)	(848,181)	1,176,510
47	485-10	GP Heavy Work Equipment	5%	5%	-0.67%	-0.18%	(4,843)	(1,301)	3,542
48	485-20	GP Heavy Mobile Equipment	15.00%	0.00%	-0.67%	1.72%	(81,602)	209,485	291,087
49		**Total Annual Net Salvage**					**57,076,258**	**63,001,724**	**5,925,466**
50									
51		**Annual Composite Rate**					**0.71%**	**0.78%**	**0.07%**

1 *Note: Numbers above are in dollars with depreciation calculated using the January 1, 2023 gross asset values.*

The asset categories that account for the majority of the change in net salvage expense are:

- LNG Gas Equipment – Tilbury (443-00)
- Services (473-00)
- Distribution Mains (475-00)
- GP Vehicles (484-00)

Each of these accounts is discussed below. Please refer to pages 3-7 to 3-21 of Appendix D2-1 for further details and discussion.

2.2.2.1 LNG Gas Equipment – Tilbury (443-00)

For LNG Gas Equipment – Tilbury (443-00), Concentric recommends a negative 20 percent rate to represent the net salvage expectations, consistent with the 2017 Depreciation Study. There have been no recorded retirements since 2008 for this account, and no net salvage has been recorded in the years since the 2017 Depreciation Study. Even though the net salvage percent remains at negative 20 percent, Concentric recommends a decrease in the net salvage provision rate of approximately 0.82 percent for this asset category to true up the accumulated net salvage surplus as a result of increasing the expected average service life of the asset category from 40 to 57 years.

2.2.2.2 Services (473-00)

For Services (473-00), Concentric recommends a negative 85 percent rate to represent the net salvage expectations, an increase from the negative 70 percent recommended in the 2017 Depreciation Study. This account continues to experience a significant amount of net salvage activity consistent with prior years. A recent review of the retirements and discussions with FEI's management indicates that the historical results are a reasonable basis for future expectations for the equipment in this account. The recommended increase by negative 15 percent leads to an increase of approximately 0.38 percent in the overall net salvage rate for this asset category.

2.2.2.3 Distribution Mains (475-00)

For Distribution Mains (475-00), Concentric recommends a negative 30 percent rate to represent the net salvage expectations, an increase from the negative 25 percent recommended in the 2017 Depreciation Study. This account continues to experience a significant amount of net salvage activity consistent with prior years. A recent review of the retirements and discussions with FEI's management indicates that the historical results are a reasonable basis for future expectations for the equipment in this account. The recommended increase by negative 5 percent leads to an increase of approximately 0.06 percent in the overall net salvage rate for this asset category.

2.2.2.4 GP Vehicles (484-00)

For GP Vehicles (484-00), Concentric recommends a positive 15 percent rate to represent the net salvage expectations, consistent with the 2017 Depreciation Study. Even though the net salvage percent remains at positive 15 percent, Concentric recommends an increase in the net salvage provision rate of approximately 2.15 percent for this asset category primarily to true up the accumulated net salvage surplus. The inclusion of a true-up in the development of the net salvage depreciation rate is necessary to recognize that over the life of a group of assets, differences may arise (i.e., due to change in expected life of assets) between the booked and the calculated (theoretical) net salvage provision.

2.2.3 Amortization of Contributions in Aid of Construction

Consistent with past practice, the amortization rate for CIAC is calculated as a function of the depreciation rates for Transmission and Distribution plant, the asset types that CIAC is received for.

The recommended amortization rates of 1.72 percent[136] for Distribution CIAC and 1.48 percent[137] for Transmission CIAC are based on the average of the recommended depreciation rates for the Distribution Services, Mains and Meters/Regulators Installation costs and Transmission Pipeline and IP Transmission Pipeline. The decrease of 0.02 percent in the Distribution CIAC amortization rate is offset by a 0.02 percent increase in the Transmission CIAC amortization rate, resulting in no impact on the overall CIAC amortization expense.

2.3 *2022 DEPRECIATION STUDY FOR FBC*

FBC implemented the depreciation and net salvage rates from the 2017 Depreciation Study effective January 1, 2020 pursuant to the MRP Decision and Order G-166-20. FBC's 2022 Depreciation Study, which is included in Appendix D2-2, has been prepared based on the electric plant-in-service as of December 31, 2022. The overall results of the 2022 Depreciation Study, consisting of the aggregate of rates for depreciation, net salvage and amortization of CIAC rates, are compared to the overall results of the 2017 Depreciation Study and are shown in Tables D2-5 and D2-6 below. Implementation of the rates from the 2022 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $4.3 million per year, an approximate 0.20 percent overall increase in the composite depreciation rate compared to the current approved rates.

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[136] For FEI Distribution CIAC, the rate is calculated by dividing the sum of the depreciation for DS Services, Mains and Meter installation costs by the sum of their original cost at December 31, 2022.

[137] For FEI Transmission CIAC, the rate is calculated by dividing the sum of the depreciation for Transmission Pipeline and IP Pipeline by the sum of their original cost at December 31, 2022.

Table D2-5: Impact of Implementing Depreciation Study Recommendations for FBC ($ millions)

	Existing	Recommended	Change
Depreciation	53.8	57.0	3.2
Net Salvage	16.0	17.2	1.2
CIAC	(4.7)	(4.8)	(0.1)
Total	**65.3**	**69.6**	**4.3**

Table D2-6: Depreciation Study Average Rate Recommendations for FBC (%)

	Existing	Recommended	Change
Depreciation	2.26	2.40	0.14
Net Salvage	0.71	0.77	0.06
Total	**2.97**	**3.17**	**0.20**

Further discussion of the recommended changes by Concentric to the depreciation, net salvage, and amortization of CIAC follows.

2.3.1 Depreciation Rates

The 2022 Depreciation Study was developed using the ALG depreciation methodology consistent with the previous 2017 Depreciation Study. The implementation of the recommended 2022 Depreciation Study rates results in an increase to the average composite depreciation rate for FBC from 2.26 percent to 2.40 percent. This results in FBC's total depreciation expense increasing by approximately $3.2 million. This change excludes the effects on depreciation expense resulting from future additions and retirements to PP&E as well as changes to the net salvage rates. The recommended depreciation rates, excluding the net salvage rates, are set out in Table D2-7 below.

Table D2-7: Impact of Implementing Recommended Depreciation Rates for FBC

Line #	Class	Description	2017 Depreciation Study Rate	2022 Depreciation Study Rate	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Increase + / Decrease -
1	330.10	Land Rights	1.07%	1.02%	10,287	9,806	(481)
2	331.00	Structures and Improvements	1.38%	1.42%	289,925	298,329	8,404
3	332.00	Reservoirs, dams, and waterways	1.41%	1.32%	1,639,574	1,534,920	(104,654)
4	333.00	Water wheels, turbines, and generators	1.36%	1.36%	1,662,886	1,662,886	-
5	334.00	Accessory electrical equipment	2.25%	2.15%	1,163,775	1,112,051	(51,724)
6	335.00	Other power plant equipment	1.75%	2.15%	804,901	988,878	183,977
7	336.00	Roads, railroads, and bridges	1.44%	1.42%	18,539	18,282	(257)
8	350.20	Surface and mineral	1.27%	1.27%	107,306	107,306	-
9	353.00	Substation equipment	1.68%	1.65%	4,606,344	4,524,088	(82,256)

Line #	Class	Description	2017 Depreciation Study Rate	2022 Depreciation Study Rate	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Increase + / Decrease -
10	355.00	Poles, towers, and fixtures	1.64%	1.71%	2,129,782	2,220,687	90,905
11	356.00	Conductors and devices	1.77%	1.81%	2,259,314	2,310,372	51,058
12	359.00	Roads and trails	1.96%	1.86%	21,990	20,868	(1,122)
13	360.20	Surface and mineral	1.25%	1.26%	156,963	158,218	1,255
14	362.00	Substation equipment	1.84%	1.89%	5,353,692	5,499,172	145,480
15	364.00	Poles, towers, and fixtures	1.75%	1.81%	4,590,797	4,748,196	157,399
16	365.00	Conductors and devices	1.54%	1.61%	6,495,084	6,790,315	295,231
17	368.00	Line transformers	2.31%	2.55%	4,772,811	5,268,688	495,877
18	369.00	Services	0.51%	1.80%	17,500	61,766	44,266
19	370.10	AMI Meters	6.25%	5.56%	2,620,938	2,331,587	(289,351)
20	372.00	EV Stations	10.00%	10.00%	525,956	525,956	-
21	373.00	Street lighting and signal systems	4.06%	3.73%	569,223	522,956	(46,267)
22	390.10	Structures-Masonry	2.37%	2.47%	1,223,884	1,275,525	51,641
23	390.20	Operations Building	1.50%	1.61%	270,775	290,632	19,857
24	391.00	Office furniture and equipment	4.42%	5.54%	228,976	286,998	58,022
25	391.10	Computer Hardware	21.60%	25.00%	2,827,942	3,273,082	445,140
26	391.20	Computer Software	8.96%	10.73%	4,534,962	5,430,820	895,858
27	391.60	AMI Computer Software	10.00%	10.00%	958,169	958,169	-
28	392.10	Light Duty Vehicles	4.79%	11.17%	228,872	533,715	304,843
29	392.20	Heavy Duty Vehicles	6.50%	7.13%	1,965,995	2,156,545	190,550
30	394.00	Tools and work equipment	4.11%	5.39%	346,630	454,583	107,953
31	397.00	Communications structures and equipment	2.84%	4.75%	380,248	635,978	255,730
32	397.10	Fiber	6.97%	6.67%	719,001	688,054	(30,947)
33	397.20	AMI Communications structures and equipment	6.67%	6.67%	331,481	331,481	-
34		**Total Annual Depreciation**			**53,834,522**	**57,030,909**	**3,196,387**
35							
36		**Annual Composite Rate**			**2.26%**	**2.40%**	**0.14%**

Note: Numbers above are in dollars with depreciation calculated using the January 1, 2023 gross asset values.

The asset categories that account for the majority of the forecast change in depreciation expense are:

- Line Transformers (368.00)
- Light Duty Vehicles (392.10)
- Computer Hardware (391.10)
- Computer Software (391.20)

Each of these is discussed below. Please refer to pages 3-3 to 3-18 of the 2022 Depreciation Study included as Appendix D2-2 for further discussion.

2.3.1.1 Line Transformers (368.00)

For Line Transformers (368.00), Concentric recommends a 40-year service life, which is a decrease from the 42-year service life recommended in the 2017 Depreciation Study. A review of retirements, additions, and other plant transactions for the period 1940 to 2022 suggests that an average service life of 40 years is more reflective of the historical retirement activity, and 40 years falls within the typical range of lives used for this account by peer utilities which is between 30 and 50 years. This account has experienced an increase in retirements from age interval 25 onwards. Therefore, shortening the service life by two years supports the early- to mid-term retirements.

Please refer to page 3-15 of Appendix D2-2 for further details.

The recommended shorter life of the Line Transformers and the true-up of the depreciation rate over the remaining life of the assets result in an increase of 0.24 percent in the depreciation rate for this asset category.

2.3.1.2 Light Duty Vehicles (392.10)

For Light Duty Vehicles (392.10), Concentric recommends a 12-year life, consistent with the 2017 Depreciation Study. A review of retirement transactions suggests that an average life of 12 years continues to be consistent with the historical retirement activity and 12 years falls within the typical range of lives used for this account by peer utilities, which is between 6 and 14 years. In discussions with operational staff and management, expectations are that an average service life of 12 years is a good representation of historical life and future expectations for this account.

Even though there is no change in the service life, the true-up of the depreciation rate over the remaining life of the assets results in an increase of 6.38 percent in the depreciation rate for this asset category.

2.3.1.3 General Plant Accounts

While the 2017 Depreciation Study adopted the amortization accounting method for certain General Plant accounts, there are still a number of General Plant accounts for which the depreciation rate is not yet indicative of the amortized amount. This is due to the true-up inherent in the depreciation rate calculation as a result of historical differences between the book reserve and the calculated accrued amortization for these accounts.

The asset classes that account for the biggest change in the depreciation rates as a result of the amortization accounting method are Computer Hardware (391.10) and Computer Software (391.20).

2.3.1.3.1 COMPUTER HARDWARE (391.10)

For Computer Hardware (391.10), Concentric recommends a 4-year life which is consistent with the 2017 Depreciation Study. As a result of the true-up of the depreciation reserve, the depreciation rate has increased from 21.60 percent to 25 percent, which is indicative of the recommended 4-year average service life for this asset category. This change results in an increase of approximately 3.40 percent in the depreciation rate.

2.3.1.3.2 COMPUTER SOFTWARE (391.20)

For Computer Software (391.20), Concentric recommends an 8-year life which is consistent with the 2017 Depreciation Study. The recommended amortization accounting for this asset category and the true-up of the depreciation rate over the remaining life of the assets result in an increase of approximately 1.77 percent in the depreciation rate for this asset category.

2.3.2 Net Salvage

As approved by the BCUC in the FBC Annual Review for 2016 Rates Decision and Order G-202-15, FBC provides for net salvage (removal costs less salvage proceeds) on its existing assets as a cost of providing service, recovered from customers over the useful life of the asset.

The 2022 Depreciation Study includes updated estimates of net salvage rates which FBC has included in depreciation expense. The updated net salvage rates are based on the electric plant-in-service as of December 31, 2022, and are included in Appendix D2-2, Section 5.

Table D2-8 below compares the recommended and existing net salvage rates and the impact on net salvage expense (i.e., depreciation expense). As recommended by the 2022 Depreciation Study, the average composite net salvage rate increases from 0.71 percent to 0.77 percent using the recommended rates. The recommended net salvage rate increase by 0.06 percent is primarily driven by the increases in FBC's actual cost of removal activities as well the upward and downward changes in the net salvage percentage for various asset classes outlined in Table D2-8 below. This change results in an increase to net salvage expense of approximately $1.2 million.

1 **Table D2-8: Net Salvage Rates by Asset Class for FBC**

Line #	Class	Description	Net Salvage 2017	Net Salvage 2022	2017 Depreciation Study Net Salvage Rate	2022 Depreciation Study Net Salvage Rate	Net Salvage Based on 2017 Rate	Net Salvage Based on 2022 Rate	Increase + / Decrease -
1	331.00	Structures and Improvements	-10%	-10%	0.30%	0.29%	63,027	60,926	(2,101)
2	332.00	Reservoirs, dams and waterways	-25%	-30%	0.49%	0.67%	569,781	779,088	209,307
3	333.00	Water wheels, turbines and generators	-25%	-30%	0.43%	0.50%	525,765	611,355	85,590
4	334.00	Accessory electrical equipment	-20%	-25%	0.88%	0.85%	455,165	439,648	(15,517)
5	335.00	Other power plant equipment	-15%	-5%	0.37%	0.11%	170,179	50,594	(119,585)
6	353.00	Substation equipment	-25%	-30%	0.65%	0.74%	1,782,217	2,028,985	246,768
7	355.00	Poles, towers and fixtures	-35%	-40%	0.88%	1.09%	1,142,810	1,415,526	272,716
8	356.00	Conductors and devices	-30%	-35%	0.75%	0.95%	957,336	1,212,626	255,290
9	362.00	Substation equipment	-30%	-30%	0.77%	0.73%	2,240,404	2,124,019	(116,385)
10	364.00	Poles, towers and fixtures	-35%	-40%	0.98%	1.11%	2,570,846	2,911,877	341,031
11	365.00	Conductors and devices	-35%	-35%	0.84%	0.85%	3,542,773	3,584,949	42,176
12	368.00	Line transformers	-25%	-30%	0.82%	1.02%	1,694,245	2,107,475	413,230
13	370.10	AMI Meters	0%	0%	0.00%	0.01%	-	4,194	4,194
14	373.00	Street lighting and signal systems	-15%	-15%	0.89%	0.76%	124,780	106,554	(18,226)
15	390.10	Structures - Masonry	-5%	-5%	0.16%	0.29%	82,625	149,758	67,133
16	390.20	Operations Buildings	-5%	-5%	0.13%	0.13%	23,467	23,467	-
17	392.10	Light Duty Vehicles	15%	10%	-0.98%	-4.34%	(46,826)	(207,370)	(160,544)
18	392.20	Heavy Duty Vehicles	15%	10%	0.00%	-1.14%	-	(344,805)	(344,805)
19	397.00	Communications structures and equipment	0%	0%	0.60%	0.86%	80,334	115,146	34,812
20		**Total Annual Net Salvage**					**15,978,928**	**17,174,012**	**1,195,083**
21									
22		**Annual Composite Rate**					**0.71%**	**0.77%**	**0.06%**

2 *Note: Numbers above are in dollars with depreciation calculated using the January 1, 2023 gross asset values.*

Overall, the 2022 Depreciation Study results in a recommended combined depreciation and net salvage rate of 3.17 percent (depreciation of 2.40 percent plus net salvage of 0.77 percent), which is slightly higher than the existing composite depreciation rate of 2.97 percent.

2.3.3 Amortization of Contributions in Aid of Construction

The amortization rate for Distribution CIAC is calculated as a function of the depreciation rates for Distribution plant, which is the main asset type for which CIAC is received.

Consistent with past practice, the recommended amortization rate of 2.05 percent for Distribution CIAC is based on the average of the recommended depreciation rates for the Distribution Poles, Towers and Fixtures, Distribution Conductors and Devices, Distribution Line Transformers, and Distribution Meters Plant. With the higher recommended depreciation rates for the majority of these asset classes, the amortization rates for CIAC will also be higher, resulting in an increase to CIAC amortization of approximately $0.1 million per year.

For EV Stations CIAC, the amortization rate is based on the average of the recommended depreciation rates for EV assets residing in the Distribution Poles, Towers and Fixtures, Distribution Conductors and Devices, Distribution Line Transformers, and EV Stations asset categories. As a result, the amortization rate for EV stations CIAC is recommended to increase by 0.75 percent, from 8.37 percent to 9.12 percent.

2.4 *CONCLUSION*

The adoption of the depreciation rates as outlined in the 2022 Depreciation Studies for FEI and FBC is necessary in order to properly reflect the assets' useful lives and a fair allocation and recovery of depreciation expense between current and future ratepayers.

For FEI, implementation of the rates from the 2022 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $2.0 million per year, a 0.02 percent overall increase to the composite depreciation rate compared to the current approved rates.

For FBC, implementation of the rates from the 2022 Depreciation Study results in a net increase of aggregate depreciation and net salvage expense of approximately $4.3 million per year, an approximate 0.20 percent overall increase to the composite depreciation rate compared to the current approved rates.

3. LEAD-LAG STUDIES FOR CASH WORKING CAPITAL

3.1 *INTRODUCTION AND SUMMARY*

In this Application, FortisBC is requesting approval to adopt updated lead-lag days as determined in the 2023 Lead-Lag Studies included in Appendix D3-1 for FEI and Appendix D3-2 for FBC. The updated lead lag days will be used for the calculation of cash working capital requirements in the Companies' 2025 and future rate applications until another lead-lag study is performed. The filing of the 2023 Lead-Lag Studies in this Application is consistent with the BCUC's statement on page 137 of the MRP Decision that "the Panel agrees with FortisBC that an update in 2025 is appropriate."

Cash working capital is defined as the average amount of capital provided by investors in a company, over and above investments in plant and intangibles, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days and are supported by a lead-lag study. The study recognizes that there are timing differences between when FEI and FBC provide a service and when they receive payment (revenue lag) as well as the time between when they receive a service and subsequently make payment (expense lead). The difference between the total revenue lag and total expense lead is the net lag. A net lag number greater than zero indicates a cash working capital shortfall position which is added to rate base; this occurs when the payment of an expense precedes the collection of its related revenue stream. In some cases, however, revenue may be received prior to payment for the related expense (a net lead or negative net lag), which indicates a cash working capital surplus position, and a reduction to rate base.

The methodology and approach used to determine each of the individual components of the 2023 Lead-Lag Studies are included in Appendix D3-1 for FEI and Appendix D3-2 for FBC, with the methodology results of the studies summarized below. Consistent with the traditional approach in Canada and the 2018 Lead-Lag Studies, the 2023 studies include only cash operating expenditures, whereas depreciation, interest and equity return are excluded from the studies and the calculation of cash working capital.

3.2 *2023 LEAD-LAG STUDY FOR FEI*

FEI's 2023 Lead-Lag Study is included in Appendix D3-1. The following is a summary of the methodology and results of the study.

Summary of Methodology

- FEI used 2022 actual data, which was the most recent full year of available actual data, to perform the analysis and derive the "Proposed Lead Lag Days" in the table below.

- The study is similar in scope and methodology to FEI's previous study performed in 2018 using 2017 actual data.
- The results of the study using the new lead and lag days have been compared to the results using the lead and lag days derived in the 2018 study.

Summary of Results

- When applied to 2024 approved data,[138] the 2023 Lead-Lag Study results in a net lag of 5.1 days, which is consistent with the net lag of 5.1 days that results when using the 2018 Lead-Lag Study.
- This difference of 0.0 days is the result of a 1.2 day decrease in expenditure lead days, offset by a 1.2 day decrease in revenue lag days. The decrease in expenditure lead days is primarily attributable to a shorter payment lead for carbon tax and PST remittances as well as a shorter service lead for O&M expenditures. The decrease in revenue lag days is primarily attributable to a decrease in collection lag for residential customers.

A summary of the results of the 2023 Lead-Lag Study for FEI is presented in the table below, comparing the impact to 2024 Forecast revenue requirements of the proposed 2023 Lead-Lag Study results versus the currently approved 2018 Lead-Lag Study results. The table shows that the updated study has no impact to total cash working capital requirements.

[138] Compliance Filing to the FEI Annual Review for 2024 Delivery Rates Decision and Order G-334-23, Appendix A, Schedule 14, Line 27, Column 5.

Table D3-1: Summary of FEI Lead-Lag Study Results

Line	Particulars	2024 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days	2024 Forecast (000's $)	Approved Lead Lag Days	Dollar Days
1	**Sales Revenue**						
2	Residential Tariff Revenue	1,092,727	38.5	42,068,285	1,092,727	40.3	44,036,898
3	Commercial Tariff Revenue	586,461	37.6	22,061,744	586,461	37.8	22,168,226
4	Industrial Tariff Revenue	193,678	45.3	8,774,971	193,678	47.7	9,238,441
5	Bypass and Special Rates	41,569	40.0	1,663,382	41,569	37.6	1,562,994
6							
7	**Total Sales Revenue**	1,914,435	39.0	74,568,383	1,914,435	40.2	77,006,559
8							
9	**Other Revenues**						
10	Late Payment Charges	3,607	52.9	190,660	3,607	53.8	194,057
11	Application Charges	1,797	38.1	68,391	1,797	39.0	70,083
12	Other Utility Income	37,075	38.1	1,411,017	37,075	39.0	1,445,925
13							
14	**Total Other Revenues**	42,479	39.3	1,670,068	42,479	40.3	1,710,065
15							
16	**TOTAL REVENUES**	1,956,914	**39.0**	76,238,451	1,956,914	**40.2**	78,716,624
17							
18	Energy Purchases	744,149	40.1	29,875,690	744,149	40.0	29,765,960
19	Operating & Maintenance	305,157	29.9	9,129,398	305,157	31.8	9,703,993
20	Property Taxes	83,359	0.6	47,922	83,359	1.3	108,367
21	Operating Fees	12,248	343.9	4,211,485	12,248	352.9	4,322,319
22	Carbon Tax	615,283	28.9	17,755,764	615,283	30.7	18,889,188
23	GST	47,796	33.3	1,593,709	47,796	39.7	1,897,501
24	PST	48,479	40.9	1,983,666	48,479	45.8	2,220,338
25	Income Tax	87,400	15.2	1,328,480	87,400	15.2	1,328,480
26							
27	**TOTAL EXPENDITURES**	1,943,870	**33.9**	65,926,113	1,943,870	**35.1**	68,236,146
28							
29	**NET LEAD-LAG DAYS (Line 16 - Line 27)**		**5.1**			**5.1**	
30							
31	**CASH WORKING CAPITAL (Line 27/365 x Line 29)**		**$ 27,161**			**$ 27,161**	
32							

3.3 *2023 LEAD-LAG STUDY FOR FBC*

FBC's 2023 Lead-Lag Study is included as Appendix D3-2. The following is a summary of the methodology and results of the study.

Summary of Methodology

- FBC used 2022 actual data, which was the most recent full year of actual available data, to perform the analysis and derive the "Proposed Lead Lag Days" in the table below.
- The study is similar in scope and methodology to FBC's previous study performed in 2018 using 2017 actual data.
- The results of the study using the new lead and lag days have been compared to the results using the lead and lag days derived in the 2018 study.

Summary of Results

- When applied to 2024 approved data,[139] the 2023 Lead-Lag Study results in a net lag of 12.7 days as compared to a net lag of 9.6 days that results when using the 2018 Lead-Lag Study.
- The difference of 3.1 days is the result of a 4.7 day decrease in expenditure lead days offset by a 1.6 day decrease in revenue lag days. The decrease in expenditure lead days is primarily due to automation of the power purchase payment process, resulting in a shorter payment lead. This was offset by a decrease in revenue lag days primarily due to a decrease in service lag days for residential customers due to an increase in customers billed monthly vs bi-monthly.
- When applied to the forecast revenues and operating expenses for 2024, this change in net days would have resulted in an increase of approximately $2.4 million in cash working capital ($3.7 million increase from expenses offset by a $1.3 million decrease from revenues).

A summary of the results of the 2023 Lead-Lag Study for FBC is presented in the table below, comparing the impact to the 2024 Forecast revenue requirements of the proposed 2023 Lead-Lag Study results versus the currently approved 2018 Lead-Lag Study results. The table shows the increase in total cash working capital requirements of $2.450 million ($10.037 million less $7.587 million).

[139] Evidentiary Update to FBC Annual Review for 2024 Rates, Appendix A, Schedule 14, Line 29, Column 5.

Table D3-2: Summary of FBC Lead-Lag Study Results

Line	Particulars	2024 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days	2024 Forecast (000's $)	Approved Lead Lag Days	Dollar Days
1	**Sales Revenue**						
2	Residential Tariff Revenue	219,891	54.2	11,909,656	219,891	56.0	12,313,896
3	Commercial Tariff Revenue	118,276	44.0	5,198,789	118,276	45.1	5,334,248
4	Wholesale Tariff Revenue	59,319	36.7	2,178,116	59,319	37.5	2,224,463
5	Industrial Tariff Revenue	53,156	35.7	1,899,426	53,156	38.0	2,019,928
6	Lighting Tariff Revenue	2,371	44.0	104,258	2,371	34.6	82,037
7	Irrigation Tarrif Revenue	4,234	39.8	168,368	4,234	47.0	198,998
8							
9	**Total Sales Revenue**	457,247	46.9	21,458,612	457,247	48.5	22,173,569
10							
11	**Other Revenues**						
12	Apparatus and Facilities Rental	6,199	90.3	559,851	6,199	90.0	557,910
13	Contract Revenue	2,260	60.0	135,478	2,260	62.2	140,563
14	Transmission Access Revenue	1,723	60.2	103,725	1,723	65.2	112,340
15	Late Payment Charges	962	53.7	51,602	962	54.0	51,922
16	Connection Charge	561	38.4	21,543	561	30.5	17,104
17	Other Utility Income	388	55.3	21,451	388	63.4	24,606
18							
19	**Total Other Revenues**	12,092	73.9	893,650	12,092	74.8	904,444
20							
21	**TOTAL REVENUES**	469,339	**47.6**	22,352,262	469,339	**49.2**	23,078,013
22							
23	Power Purchases	173,694	45.8	7,957,100	173,694	51.5	8,945,261
24	Wheeling	7,324	39.7	290,820	7,324	46.9	343,514
25	Water Fees	12,513	1.9	24,094	12,513	1.4	17,518
26	Operating and Maintenance	63,174	23.9	1,509,851	63,174	28.6	1,806,768
27	Property Tax	18,573	4.1	76,543	18,573	4.9	91,008
28	GST	703	39.4	27,718	703	45.4	31,916
29	Income Tax	12,484	15.2	189,757	12,484	15.2	189,757
31							
32	**TOTAL EXPENDITURES**	288,466	**34.9**	10,075,883	288,466	**39.6**	11,425,742
33							
34	**NET LEAD-LAG DAYS (Line 21 - Line 32)**		**12.7**			**9.6**	
35							
36	**CASH WORKING CAPITAL (Line 32/365 x Line 34)**		**$ 10,037**			**$ 7,587**	
37							

4. CORPORATE SERVICES STUDY

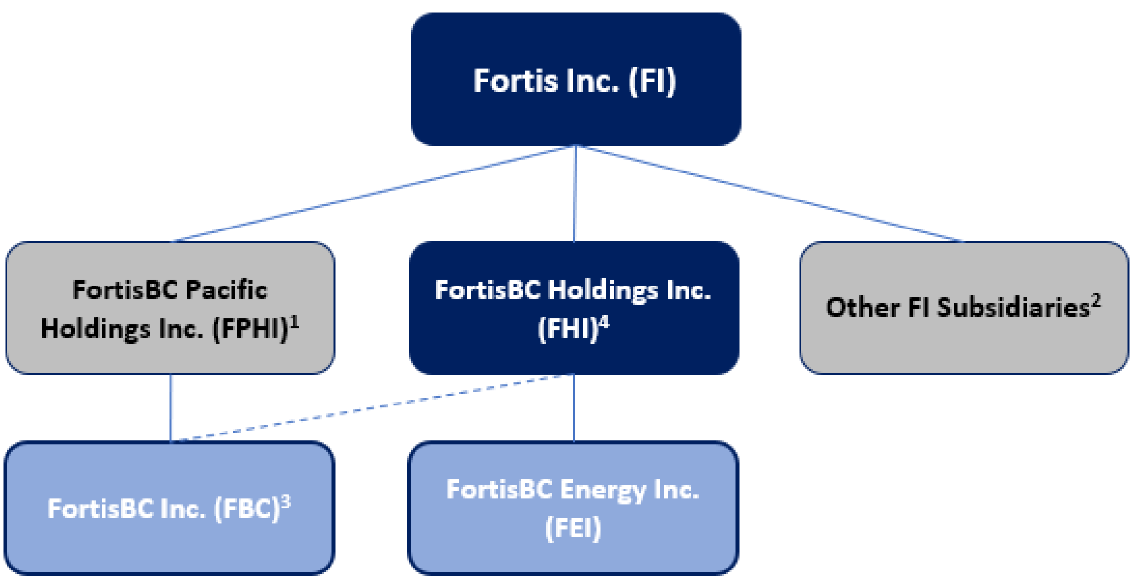
4.1 *INTRODUCTION*

In this Application, FortisBC is requesting approval of the methodologies of allocating common corporate service costs from Fortis Inc. (FI) and FortisBC Holdings Inc. (FHI) to FEI and FBC. The allocation methodologies include a formula that is based on total assets, excluding goodwill, and controllable operating expenses for FI corporate services, and the use of a Massachusetts Formula for FHI corporate service allocations. Both methodologies and the nature of the FI and FHI corporate service costs have been reviewed and endorsed by KPMG in the 2023 Corporate Service Cost Study (2023 CSC Study) included as Appendix D4-1. FortisBC is seeking approval of the allocation methodology, rather than the forecast of corporate service costs. The actual costs and allocation percentages will vary each year of the Rate Framework term depending on the size of the eligible corporate cost pool at FI and FHI, as well as the relative size of the FI and FHI allocators.

The corporate services function consists of certain specialized functions that reside in FI and FHI. FI provides corporate service functions for FHI and then FHI passes along a majority of these activities to FEI and FBC, along with FHI corporate services. As a result, both FI and FHI provide expertise and corporate services to FEI and FBC, resulting in economies of scale to those companies.

In Figure D4-1 below, the entities that provide the corporate services (FI and FHI) are in the dark blue boxes and the BCUC-regulated entities that share in the corporate services (FBC and FEI) are in the light blue boxes.

Figure D4-1: 2023 Corporate Services Study Organizational Chart



Notes:

[1] FPHI is not regulated by the BCUC and does not receive corporate services from either FI or FHI. While FPHI is the legal parent of FBC, it has no employees and provides no services to FBC. FPHI does have contracts in place to provide operation and management services to non-regulated third-party generation owners. These non-regulated services utilize resources provided by FBC, which are charged through to FPHI in accordance with the Code of Conduct and Transfer Pricing Policy, meaning that regulated FBC customers receive the benefit of a margin on such services.

[2] Other FI subsidiaries that benefit from FI corporate services and therefore are included in the allocation include CH Energy Group, UNS Energy Corp., ITC Holdings Corp, FortisAlberta, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities, and Fortis Turks and Caicos.

[3] While FBC is a direct subsidiary of FPHI, it receives corporate service support from FHI and therefore is considered as part of the sharing allocation pursuant to the 2023 CSC Study.

[4] Up until November 1, 2023, FHI owned FortisBC Midstream Inc. (FMI), the parent company and owner of the Aitken Creek Gas Storage Facility (ACGS). Consistent with the 2018 Corporate Service Cost Study (2018 CSC Study) that was approved as part of the MRP Decision, ACGS received a portion of the FI and FHI corporate service cost allocation. On November 1, 2023, FMI was sold to a subsidiary of Enbridge Inc. and consequently no longer received a portion of the FI and FHI corporate service costs.

4.2 Review of Changes Since 2018 Corporate Services Study

The following changes have occurred with respect to FI and FHI corporate service costs that are incurred for the benefit of FEI and FBC and the approach in allocation to FEI and FBC since the 2018 CSC Study:

- FI removed the position of EVP – Western Utility Operations at the end of 2019, the costs of which were previously allocated only to FHI and FortisAlberta Inc. As noted in the 2018 CSC Study, the 2018 Forecast amount for this charge was $0.4 million allocated to FHI.
- ACGS has been removed from the sharing methodology of FI and FHI corporate service costs. This is a result of the entity no longer being part of the Fortis group effective November 1, 2023, when FMI, the parent company and owner of ACGS, was sold to a subsidiary of Enbridge Inc. The removal of ACGS from the sharing methodology has resulted in a proportional decrease to the amount of corporate service costs allocated to FHI by FI of approximately $0.3 million if ACGS was removed for all of 2023 because the size of the FHI group became smaller in comparison to the overall FI entity. The removal of ACGS also resulted in a proportional increase to the total allocation of corporate service costs to FEI and FBC by FHI of approximately $0.8 million if ACGS was removed for all of 2023 because there are fewer entities in the FHI group to allocate its eligible costs to. This is discussed in Section 6 of the 2023 CSC Study.

While there have been changes from the 2018 CSC Study, the general process, nature of eligible corporate service costs, and allocation methodology of corporate services costs from FI and FHI is generally consistent. FortisBC will continue to rely on these corporate services during the term of the Rate Framework, using the same cost allocation methodology as supported by the 2023 CSC Study.

4.3 DESCRIPTION OF FI CORPORATE SERVICES

4.3.1 FI's Stand-Alone Business Operating Model

FI is a holding company which, directly or indirectly, owns utility operations in 10 US states, five Canadian provinces and three Caribbean countries. FI has a stand-alone business operating model, whereby its subsidiaries operate substantially autonomously from FI and each other, other than FEI and FBC who have a common Board of Directors, Executive Leadership Team, and have integrated many corporate functions. Each operating subsidiary is responsible for its own operations and regulatory activities. Since FI is a public holding company, its business operations are different than those of its operating subsidiaries. FI activities are in support of its ability to provide and maintain an equity investment in the operating subsidiaries, and to provide a market return to its widely held shareholder base. In addition, FI provides strategic oversight, strategic planning, and corporate governance, as well as managing and administering the group-wide insurance program and the coordination of cross-functional sharing of best practices across the operating subsidiaries.

While FI provides these services, each operating subsidiary has its own board of directors and executive management team based in the area served by the subsidiary. The subsidiary executive management is accountable to its own board of directors and responsible for key aspects of utility operations such as safety, customer satisfaction, service continuity, environment and sustainability impacts, cost management, financial performance, and community involvement. The subsidiary executive and management teams also determine human resource requirements and hiring practices, negotiate collective bargaining agreements, establish operating and capital budgets, and serve as the direct contact and decision-making authorities in regulatory matters. With this structure and operating philosophy, FI has a relatively low number of employees and level of operating costs.

4.3.2 FI Functional Areas and Corporate Services

The functional areas of FI that provide corporate services include the board of directors, executive, financial reporting, treasury and taxation, legal, planning and forecasting, internal audit, insurance/risk management, investor relations, human resources, communications and corporate affairs, sustainability, information systems, and cybersecurity. These functional areas support the following overarching business activities of FI, which are:

- Maintaining and providing additional equity to operating subsidiaries by raising equity through the Canadian and US public capital markets;
- Complying with public company securities requirements, resulting from being registered with the Ontario Securities Commission and the US Securities and Exchange

Commission, and corresponding listings on the TSX and NYSE, for which compliance is required to support its equity investment in the operating subsidiaries;

- Providing strategic oversight and coordinating and sharing best practices among the FI group of companies; and
- Administering the corporate-wide group insurance program.

The majority of the operating costs for each of the FI functional areas providing these corporate services are recovered from the operating subsidiaries. The nature of these functional area operating costs is generally consistent with those corporate services provided by FI to FHI, and to FEI and FBC by way of the FHI management fee.

4.3.2.1 Benefits of Provision of Equity Capital by FI

FI is listed on the TSX and NYSE. The liquidity of FI's stock in both Canada and the US, together with its dividend reinvestment plan (DRIP) and other share plans, provides a large and robust equity platform for its utility operations to draw upon. The group of FI's operating subsidiaries is diversified across multiple jurisdictions, and are primarily regulated utilities. This diversified portfolio of regulated electric and natural gas utilities allows FI to access capital markets on a cost efficient and effective basis. The operating subsidiaries benefit from FI's financial strength and access to capital markets as it allows them to obtain and maintain capital to meet their individual operational needs.

The operating subsidiaries benefit from the services provided, as the equity maintained and supplied by FI is required to ensure that the operating subsidiaries' capital structures are consistent with those approved by their respective regulators. Specifically, FEI and FBC obtain debt to finance their approved capital structures, while FI provides the remaining required equity financing under FEI's and FBC's approved capital structures. If FI did not supply the necessary equity capital, the operating subsidiaries would have to obtain the equity capital from other sources individually and incur the associated costs. FI utilizes the public markets to access the equity needed in support of its operating subsidiaries, provides shareholder relations services, and ensures overall corporate governance requirements of equity market regulators are effectively met for the operating subsidiaries. FEI and FBC, as regulated utility entities, will require incremental equity financing provided by FI in order to fund their regular capital expenditures and major projects over the coming years. These services provided by FI are outlined in Sections 4.2 and 4.3 of the 2023 CSC Study, but specifically excluded from the FI costs are the direct, incremental costs of issuing debt or equity by FI.

4.3.2.2 Benefits of Strategic Oversight and Sharing of Best Practices from FI

The operating subsidiaries benefit from the strategic oversight and sharing of best practices across the group of FI companies. The strategic oversight provided by FI enhances the corporate governance at the local operating subsidiary level while still allowing each operating subsidiary the ability to manage its local operations and make key business decisions in a substantially autonomous manner. The sharing of best practices allows each operating subsidiary to leverage the cumulative knowledge and experience of its affiliated subsidiaries across many functional areas, including operations and safety, human resources, customer service, communications, sustainability, financial reporting, planning and forecasting, information technology, risk management, cybersecurity, legal, regulatory, and internal audit. Sharing of best practices allows for more effective and efficient operations at the local operating subsidiary level than if the subsidiary was operating on a stand-alone basis separate from the Fortis group. The collaboration also provides for certain cost efficiencies, such as through joint procurement activities. FI's operating subsidiaries, including FEI and FBC, would not have the benefit of this strategic oversight and sharing of best practices if they were not under the umbrella of FI.

4.3.2.3 Benefits from FI Administered Company-wide Group Insurance Program

FortisBC's customers benefit from lower insurance premiums due to economies of scale obtained with the consolidated Fortis group of companies as compared to if FEI and FBC were required to seek out their insurance premiums on a stand-alone basis. The actual insurance premiums are charged directly to FHI, FEI, FBC, and other FHI subsidiaries (including ACGS while it was still owned by FHI) based on replacement value for property insurance and revenue for liability policies. In addition to insurance premiums, FI corporate services include FI's cost to manage and administer the insurance program. The FI risk management department is responsible for group property and casualty insurance policies renewal processes, determining and developing risk transfer strategies, determining policy limits and optimal retention levels, handling and administration of FI group first party property damage claims and third-party claims, and overseeing risk and loss control inspections including the management of recommendations and subsequent response.

4.4 *FI CORPORATE SERVICES ALLOCATION METHODOLOGY*

The costs of the FI corporate services, as described in Section D4.3 above, are allocated to FHI, FEI and FBC (together defined as the FortisBC Subsidiaries), as well as to ACGS while it was still owned by FHI, on a percentage basis. The allocation is calculated using the following factors:

1. Controllable operating costs for the FortisBC Subsidiaries as a percent of all Fortis group operating costs; and
2. Total assets (excluding goodwill) for the FortisBC Subsidiaries as a percent of all Fortis group total assets.

The use of more than one factor for the cost allocation reflects a balanced methodology, consistent with the approach used by other utility holding companies and their subsidiaries. Using more than one factor recognizes that there is not one perfect allocator, and mitigates the inherent risk associated with using one measure for calculating general cost allocations.

The two cost allocation factors are weighted as follows: (i) 75 percent to total assets (excluding goodwill); and (ii) 25 percent to total controllable operating expenses. The 75 percent weighting recognizes that assets provide the basis upon which regulated utilities earn a return, with total assets (excluding goodwill) closely correlating with the equity investment required by the operating subsidiaries. The lower 25 percent weighting for controllable operating expenses recognizes that FI's subsidiaries operate in a substantially autonomous manner, and directly manage most costs.

The FI allocator formula is as follows:

(FortisBC Subsidiaries' portion of Total FI Assets (Excluding Goodwill) x 75%)

+

(FortisBC Subsidiaries' portion of Total FI Controllable Cost Allocation x 25%)

=

Total Allocation to FortisBC Subsidiaries (FHI, FEI, FBC, and ACGS while it was still owned by FHI)

After applying the above allocator formula, the percentage allocation of FI corporate services to FortisBC Subsidiaries is as shown in Table D4-1 below.

Table D4-1: FI Corporate Services 2023 Allocation to FortisBC Subsidiaries

Allocation Factor	Weighting	FortisBC Subsidiaries 2023 Allocation
Asset Allocation (excluding Goodwill)	75%	21.3%
Controllable Cost Allocation	25%	23.3%
Total Allocation from 2023 CSC Study		21.8%[1]
Total Allocation from 2018 CSC Study		21.4%

Note:

[1] *Includes ACGS. As outlined in Section 6 of the 2023 CSC Study, the removal of ACGS from the Fortis group would result in an approximate 0.9 percent decrease to the total allocation.*

The application of the above total allocation of 21.8 percent results in allocations of business activities performed by FI to support the FortisBC Subsidiaries as shown in Table 7 of the 2023 CSC Study.

The total allocation of FI corporate services is generally consistent with the 2018 CSC Study. The amount increased slightly as the proportion of FortisBC Subsidiaries' total assets and controllable costs within the group of FI entities has increased, though the increase has been partially offset by the removal of an EVP, Western Utility Operations that existed in FI in the 2018 CSC Study that was allocated to the FortisBC Subsidiaries and FortisAlberta specifically.

In addition, as outlined in Section 6 of the 2023 CSC Study, the total allocation of FI corporate services has been recalculated to remove ACGS, resulting in a decrease in the total allocation from 21.8 percent to 20.9 percent. This amount is also lower than the 21.4 percent determined in the 2018 CSC Study. The recalculated, lower percentage is representative of the expected FI corporate services allocation rate over the term of the Rate Framework.

FortisBC notes that the actual charges each year will be updated based on FI eligible corporate service costs and a recalculation of the allocation factors using the same methods described above.

4.5 *DESCRIPTION OF FHI CORPORATE SERVICES*

In addition to the FI corporate services described above, FHI, the parent company of FEI, provides key corporate functions directly to FEI, FBC and certain of FHI's other subsidiaries. FHI corporate services provided to FEI and FBC are incremental to the corporate services provided by FI, and are described by department as follows:

- **Governance and Board of Directors:** FHI ensures all continuous disclosure and governance activities required by external regulators, stakeholders, and third parties are appropriately carried out, manages the relationship and corporate activities of the FEI and FBC common Board of Directors, and develops and maintains governance procedures and policies.
- **External Financial Reporting:** FHI is responsible for the preparation of monthly, quarterly and annual financial statements for FHI, FEI, FBC and other FHI subsidiaries, coordination with external auditors, analysis of financial information for advisory purposes within FEI and FBC, technical accounting analysis and position papers, preparing continuous disclosure document filings (e.g., quarterly and annual Management Discussion and Analysis and the Annual Information Form), managing consistent accounting policy treatment across the FortisBC group of companies, oversight of compliance with securities regulations such as sustainability requirements and SEC registration, and maintaining internal controls over financial reporting.
- **Internal Audit:** FHI is responsible for planning and conducting audits and operational reviews of all areas of the gas and electric utilities, as well as facilitating the annual enterprise risk management assessment process. This department monitors and evaluates the effectiveness and efficiency of internal controls and risk management strategies for FEI and FBC, as well as providing both assurance and advisory services to support operational areas, enhancing information system controls and data analysis, and ensuring ongoing compliance with regulatory requirements.
- **Legal:** FHI provides legal services and counsel on issues including regulatory, environmental, business development, employment, securities, financing, and intellectual property, and manages legal matters that have been outsourced to outside legal counsel.
- **Insurance and Risk Management:** FHI is responsible for managing the insurance program on a day-to-day basis. The insurance and risk management department is responsible for managing the claims process, renewal of all third party insurance, and for overseeing the allocation of cost of the premiums paid for those policies.

- **Taxation:** FHI provides a full range of services in income and commodity taxes, including financial reporting for taxes (year-end and quarterly tax provisions for current and future income taxes), tax compliance (filing of tax returns, coordination of tax audits), regulatory tax accounting (tax calculations for rate filings and annual reports), tax planning, including guidance and support for significant transactions, and tax dispute management and resolution.
- **Treasury and Financial Planning:** FHI is responsible for the execution of short-term and long-term financing, cash management and forecasting, the arrangement of operating credit facilities, and the negotiation of bank-service fees for all FortisBC companies. FHI is also responsible for treasury related controls and compliance, compliance reporting, hedging of interest rate and foreign exchange risks, providing information in support of credit ratings, maintaining bank and debt investor relationships, and assisting in the preparation of certain regulatory submissions, including in support of ROE, capital structure, and financing related matters.
- **Facilities and Support:** FHI provides building space strategy, certain computer software support, and administration and computer outsourcing.

In addition to the corporate services specifically provided by FHI, the FI corporate service costs, as described in Section D4.3 above and as outlined in Table 7 of the 2023 CSC Study, are also included in the pool of eligible FHI corporate service costs. The pool of eligible FHI corporate service costs allocated to FEI and FBC excludes certain costs that are specific to FHI or are non-recoverable from ratepayers, including:

- Services directly charged to other related entities, including those services provided to and remaining in FHI;
- Business development costs;
- Legal fees incurred for non-regulated entities;
- Pension bonus amounts for defined benefit supplemental pension plans; and
- Ineligible components of the FI management fee related to stock compensation costs.

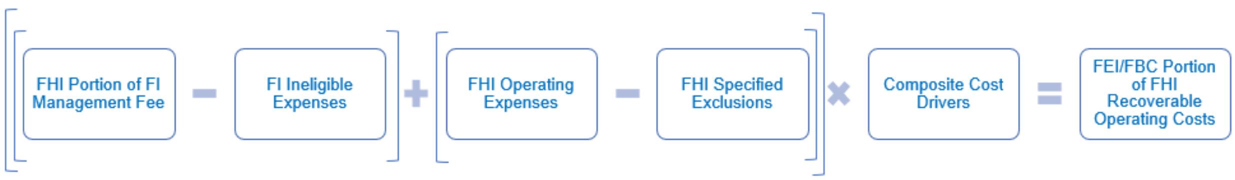
The nature of FHI corporate service costs, after the previously mentioned exclusions, are generally consistent with those that existed in FHI during the Current MRP term. The methodology of how these costs are allocated to FEI and FBC is discussed in the next section.

4.6 *FHI CORPORATE SERVICES ALLOCATION METHODOLOGY*

The eligible pool of the FHI corporate service costs is allocated to FEI and FBC using what is commonly known as the Massachusetts Formula, which consists of a hybrid of an activity-based costing method and a financial composite cost allocator. The Massachusetts Formula is a widely used and accepted method for allocating costs in the utility industry in North America. The Massachusetts Formula is generally used when there is substantial sharing of costs amongst entities. It is calculated as an average of: (i) gross margin (revenue less cost of gas or energy); (ii) payroll; and (iii) average net book value (NBV) of tangible capital assets plus inventories. The forecast amounts for each of the three components are estimated for all applicable entities and given equal weight. An average is then computed for each operating entity which, when compared to the total, calculates a ratio used to allocate its share of the cost pool.

FEI and FBC have applied the Massachusetts Formula to allocate common costs in previously approved rate setting filings, including during the Current MRP term and the previous 2014-2019 PBR Plan term. Continuing to apply this same cost allocation methodology to corporate service costs charged to FEI and FBC allows for a consistent and familiar methodology which has previously been reviewed and tested in regulatory proceedings. The following figure depicts the Massachusetts Formula allocator methodology, taking into account both the FI corporate service costs and the FHI corporate service costs.

Figure D4-2: Application of Massachusetts Formula to Allocate FHI Corporate Service Costs



After applying the Massachusetts Formula, the allocation percentages of FHI corporate services to be applied to FEI and FBC are approximately 77 percent and 23 percent, respectively, excluding ACGS, as outlined in Table 13 of the 2023 CSC Study. If this method was in place for 2023, allocations of business activities performed by FI and FHI to support FEI and FBC would be as shown in Table D4-2, which is a combination of the summary of 2023 budgeted FHI corporate service costs from Table 10 of the 2023 CSC Study, and the updated Massachusetts Formula allocation from Table 13 of the 2023 CSC Study.

Table D4-2: 2023 FHI Corporate Services Costs Allocation

FHI Corporate Services Cost Pools Eligible for Allocation	FHI Operating Costs	Specified Exclusions	Eligible Costs (Cost Pools)	FEI (77.2%) [2]	FBC (22.8%) [2]
Governance & Board of Directors	$ 2,052,945	$ (67,361)	$ 1,985,584	$ 1,532,596	$ 452,988
External Financial Reporting	917,818	(258,686)	659,132	508,759	150,373
Internal Audit	1,707,758	(153,698)	1,554,060	1,199,519	354,541
Legal	3,281,011	(1,165,247)	2,115,764	1,633,077	482,687
Insurance & Risk Management	381,816	(9,545)	372,271	287,342	84,929
Taxation	1,340,076	(279,486)	1,060,590	818,629	241,961
Treasury & Financial Planning	1,717,916	(571,652)	1,146,264	884,757	261,507
Facilities & Support	1,429,529	(187,343)	1,242,186	958,796	283,390
Fortis Inc. Management Fee [1]	10,550,000	(2,992,000)	7,558,000	5,833,730	1,724,270
Estimated Impact of ACGS Disposal [1]	(435,550)	123,523	(312,027)	(240,842)	(71,185)
Other Excluded Costs	7,440,020	(7,440,020)	-	-	-
Total	**$ 30,383,339**	**$ (13,001,515)**	**$ 17,381,824**	**$ 13,416,363**	**$ 3,965,461**

Notes:

[1] The FI Management Fee has been adjusted in a separate line in Table D4-2 above to reflect the disposal of ACGS. As outlined in Section 6 of the 2023 CSC Study, the removal of ACGS from the Fortis group results in an approximate 0.9 percent decrease to the total FI Management Fee cost allocation.

[2] For presentation purposes, the Massachusetts Formula has been calculated to reflect the disposal of ACGS. Prior to the sale, ACGS absorbed approximately 4.4 percent of total FI and FHI corporate service costs, as represented in Table 11 and Table 12 of the 2023 CSC Study.

The above table calculates an FHI management fee of approximately $13.4 million and $4.0 million for FEI and FBC, respectively, if this model had been in place for 2023. Please note that the above table provides an illustration of how the methodology to allocate corporate service costs is applied, and is not intended to represent the actual allocations that occurred during 2023. The actual costs and the formula indicators will be known in the years when the services are provided. However, for context, the FHI management fee represented in the 2018 CSC Study, using the same approach, was $11.0 million and $3.4 million for FEI and FBC, respectively.

As outlined in Section 6 of the 2023 CSC Study, the removal of ACGS from the Fortis group influences both the proportion of corporate service costs allocated by FI to FHI, and the proportion of FHI corporate service costs allocated to FEI and FBC. In particular, the FI corporate service costs allocated to FHI would decrease from approximately 21.8 percent to 20.9 percent of the total, while the Massachusetts Formula used to allocate costs from FHI to FEI and FBC would increase by approximately 3.4 percent and 1.0 percent for FEI and FBC, respectively, as a result of this change.

4.7 CONCLUSION

The allocation of FI and FHI corporate service costs has been reviewed by KPMG in the 2023 CSC Study. In Section 7 of the 2023 CSC Study, KPMG states:

> KPMG evaluated FI's and FHI's corporate service cost allocation methodologies in alignment with evaluation criteria introduced in Section 2.3 of the 2023 CSC Study. Overall, both allocation methodologies appear to be a reasonable mechanism to allocate corporate service costs.

Based on the recommendations from the 2023 CSC Study, FortisBC will continue to apply the methodology of aggregating its common corporate service costs from FI and FHI and allocating them to FEI and FBC using the methodologies described above and in more detail in the 2023 CSC Study.

5. CAPITALIZED OVERHEAD STUDIES

5.1 INTRODUCTION

For the term of the Rate Framework, FEI is proposing to apply a capitalized overhead rate of 14.5 percent of gross O&M, net of biomethane O&M transferred to the BVA, and FBC is proposing to apply a capitalized overhead rate of 15.5 percent of gross O&M, to regular capital expenditures. This compares to the 16 percent for FEI and 15 percent for FBC used during the term of the Current MRP. The capitalized overhead rates reflect a reasonable basis for capitalization of costs related to capital activities for both FEI and FBC, that have not been directly charged to capital projects. The allocation of capitalized overhead costs is consistent with the methodology from prior years' studies and filings, and corroborated with established rate-regulated utility practice, the BCUC's Uniform System of Accounts (USofA), and US GAAP.

While certain jurisdictions do not require regular filing and approval of the allocations for capitalized overhead costs, FortisBC has a practice of periodically filing updated capitalized overhead studies and requesting regulatory approval of the methodology used and associated rate to ensure that its capital expenditures include the appropriate level of capitalized overhead costs.

Consistent with past practice, FortisBC engaged KPMG to perform a review of its capitalized overhead methodology for the term of the Rate Framework and prepare a capitalized overhead study for each of FBC and FEI (referred to as the 2023 Capitalized Overhead Studies). The 2023 Capitalized Overhead Study for FEI is included as Appendix D5-1 and the 2023 Capitalized Overhead Study for FBC is included as Appendix D5-2.

In the sections below, FortisBC discusses the basis for allocating overhead costs to capital projects, FortisBC's methodology for capitalized overhead studies, and the results of the most recent capitalized overhead studies for FEI and FBC.

5.2 OVERHEAD COSTS ALLOCATED TO CAPITAL PROJECTS

Utilities operate in a capital-intensive industry where an ongoing capital program is required to sustain the current system, address public and employee safety, and ensure reliability of energy supply to customers. Utilities' capital expenditures include the physical construction or purchase of property, plant and equipment. Multiple business activities of the utility are involved to construct and bring an item of property, plant and equipment into service.

Certain activities incurred during the construction or acquisition of a capital asset are considered direct costs, as they meet the definition of costs to be capitalized under US GAAP by being associated with the acquisition, development, and construction activities to bring an asset to the condition necessary for it to be capable of operating for its intended use. Examples of direct costs include labour and employee benefits, travel costs, vehicle costs, engineering services, procurement activities, consulting costs, and certain overhead costs. Directly attributable activities can be charged directly to the capital project or may be charged to capital projects from O&M indirectly through a capitalization methodology. For several directly attributable activities that support the construction of multiple capital projects, the use of a capitalized overhead allocation is a more efficient process to allocate direct costs as compared to direct charging each individual activity to each specific project.

Other activities that are not directly attributable to a specific project, such as certain activities performed by human resources, finance, legal, facilities, and information systems, may also be capitalized. These activities are integral in supporting a utility's capital program, and therefore allocating these indirect overhead costs to capital projects for regulated utilities is an accepted practice embedded in US GAAP. Accounting Standards Codification 980, Regulated Operations (ASC 980) explicitly acknowledges the capitalization of indirect costs as approved by a regulator.

In addition to generally accepted accounting principles, the capitalization of overhead costs is embedded in the BCUC's USofA. Both the BCUC Gas USofA, initially established in the 1960s, and the BCUC Electric USofA, initially established in the 1980s, include "Cost of overhead charged to construction" as a cost item to be included in section 6, "plant acquired or constructed", as defined below:

> Cost of overhead charged to construction includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of actual and reasonable costs.

While the Federal Energy Regulatory Commission (FERC) does not have jurisdiction within Canada, its accounting guidelines can be referenced for establishing regulated utility industry practice of costs incurred to support capital expenditures. FERC's USofA "Electric Plant Instruction, Number 4, Overhead Construction Costs" is clear that capital expenditures should contain all costs, direct charged and indirectly allocated, related to construction activity. While no single guideline, statement or source exists that is universally accepted by utilities and regulators as the definitive standard, all of the above support that both direct and indirect overhead costs are appropriately allocated to capital projects for rate-regulated utilities.

5.3 *METHODOLOGY FOR FORTISBC CAPITALIZED OVERHEAD STUDIES AND APPLICATION OF CAPITALIZED OVERHEAD RATES*

FortisBC assesses the activities of its various business areas in support of its capital program. Depending on the level of capital work, these activities may be increasing, decreasing, or remaining constant.

FortisBC's O&M includes the costs for activities that are primarily for operating the business, independent of the levels of capital. However, a portion of O&M is required to initiate and enable capital activity, which is then allocated to capital expenditures as overheads capitalized. For FortisBC, capitalized overhead is calculated by applying the overhead capitalization rate to gross O&M costs, after O&M has been reduced by direct charges to capital and other non-O&M

accounts. While the capitalized overhead rate is calculated on an aggregate basis at the entity level, the resulting capitalized overhead amount is allocated to capital on a more detailed pro-rata basis (based on capital additions in the period) to the appropriate asset accounts for each individual capital project.

The capitalized overhead rates determined in the 2023 Capitalized Overhead Studies are assigned to regular capital, which excludes CPCNs and certain other major capital projects. The rationale is that the majority of costs and activities for these types of projects, including incremental external contractor costs, have been charged directly to CPCNs and major projects and therefore do not require a mechanism such as a capitalized overhead rate to allocate additional costs from O&M. Consistent with historical and current practice, the actual amount of overheads capitalized will be recorded at the forecast amount so that there will be no variances in either the capital additions or O&M related to the total amount of capitalized overhead in any given year.

As in 2018, FortisBC engaged KPMG to perform a review of its capitalized overhead methodology. KPMG's 2023 Capitalized Overhead Studies use a similar approach as was undertaken in the capitalized overhead studies prepared in 2018 and approved as part of the MRP Decision.

As indicated in the 2023 Capitalized Overhead Studies, KPMG reviewed FortisBC's capitalized overhead methodology in detail and evaluated it against nine criteria, the first of which is cost causality. As stated by KPMG, its review of the available guidance highlighted a common general principle: "That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity." KPMG found that FortisBC's methodology satisfied this criterion, concluding that the mechanisms used to estimate the proportions of capital related costs demonstrate a reasonable causal link to capital projects.

Overall, for FEI, KPMG concludes, at page 3: "KPMG's evaluation finds that FEI's capital overhead cost allocation methodology is a reasonable mechanism to establish the overhead capitalization rate." Similarly, for FBC, KPMG similarly concludes, at page 3: "FBC's capital overhead cost allocation methodology is a reasonable mechanism to establish the overhead capitalization rate."

5.4 *RESULTS OF CAPITALIZED OVERHEAD STUDY FOR FEI*

For the term of the Rate Framework, FEI proposes a capitalized overhead rate of 14.5 percent of gross O&M, net of biomethane O&M transferred to the BVA, as compared to the current 16 percent rate approved by the MRP Decision. According to KPMG, the decrease in the rate can be attributed to: (1) certain process improvements, where direct charging mechanisms to individual projects by the engineering and operations functional areas end up requiring less need to account for their costs through an indirect overhead rate; and (2) stability in the rate of capital spending over time, as compared to the assessment performed in the 2018 Capitalized Overhead Study for FEI. The decrease in the rate is also explained by a general increase in operating costs of functional areas which are not generally involved in capital activity. These areas include renewable gas development, LNG operations, Indigenous and external relations, customer service, and certain areas of engineering and operations. As these areas grow in proportion to the overall O&M budget, the relative proportion of functional areas which are involved in initiating and enabling capital activity decreases, leading to a decrease in the blended overhead rate.

The results of the 2023 Capitalized Overhead Study for FEI indicate that certain areas of engineering and operations who do not direct charge to capital continue to be a major driver of the capitalized overhead allocation for FEI, but that the overall increase in O&M for these groups has increased to manage operations as opposed to facilitate capital. As a result, the relative proportion of engineering and operations involved in capital activity has decreased compared to the prior study. Consistent with the prior study, there also continues to be requirements from various other business areas to enable the capital program, such as procurement, information systems, legal, human resources, and finance.

The table below provides a comparison of the results of the 2023 Capitalized Overhead Study for FEI against prior levels of gross O&M, approved capitalized overhead rates, the net O&M, and the resulting capitalization rate as a percentage of capital expenditures over the past six years. This comparison includes the period covered by the last capitalized overhead study prepared in 2018 and approved by the MRP Decision, effective for the term of the Current MRP, as well as the year immediately prior.

Table D5-1: FEI Capital, O&M and Capitalized Overhead 2019-2024 ($000s)

	2019 Approved	2020 Approved	2021 Approved	2022 Approved	2023 Approved	2024 Approved	2024 Revised [1]
Gross O&M	281,148	314,410	329,307	333,303	354,647	370,207	370,207
Capitalized OH Rate on Gross O&M	12%	16%	16%	16%	16%	16%	14.5%
Capitalized OH	(33,738)	(50,306)	(52,689)	(53,328)	(56,744)	(59,233)	(53,680)
Net O&M	247,410	264,104	276,618	279,975	297,903	310,974	316,527
CapEx (excl OH)	189,281	242,349	254,715	301,782	336,373	285,505	285,505
Capitalization Rate on CapEx	18%	21%	21%	18%	17%	21%	19%

[1] 2024 Revised is representative of changes to 2024 Approved had the capitalized overhead rate from the 2023 Capitalized Overhead Study for FEI included in Appendix D5-1 been used.

As shown in Table D5-1 above, a 14.5 percent capitalized overhead rate for 2024 (applied to gross O&M net of biomethane O&M transferred to the BVA) results in a level of net O&M (gross O&M less capitalized overhead) that is higher compared to prior years, which is expected given the higher operating costs required in various departments as discussed in Section C2.2 of this Application. The proportion of capitalized overhead to the annual capital expenditures is presented as the capitalization rate. FEI's proposed capitalized overhead rate of 14.5 percent and the resulting capitalization rate of 19 percent are within a reasonable range compared to the prior years shown.

FEI estimates that the impact on customer delivery rates of a change to the capitalized overhead rate is approximately 0.35 percent for every 1 percent change in the capitalized overhead rate. Therefore, all else equal, decreasing the capitalized overhead rate from 16 percent to 14.5 percent would increase customer delivery rates by approximately 0.52 percent in the year of implementation (2025 in this case).

5.5 *RESULTS OF CAPITALIZED OVERHEAD STUDY FOR FBC*

For the term of the Rate Framework, FBC proposes a capitalized overhead rate of 15.5 percent of gross O&M, as compared to the current 15 percent rate approved by Order G-166-20. The increase in the rate is marginal and is generally a result of a recalculated general allocator for several support groups, partially offset by processes implemented to increase direct charging to capital in the operations and engineering functional areas, which resulted in a corresponding lower amount allocated to capital indirectly through the capitalized overhead rate.

The results of the 2023 Capitalized Overhead Study for FBC resulted in lower amounts of indirect capital in the areas of engineering and operations. There continue to be requirements from various other business areas to enable the capital program, such as procurement, information systems, legal, human resources, and finance.

KPMG also assessed FBC's Direct Overhead, which is a loading pool of supervisory and other administrative costs that are directly involved in capital projects. These costs are collected in standing orders and allocated to transmission & distribution capital projects at the end of the year. The primary reason for this approach is the administrative burden associated with charging certain costs to individual projects. Costs included in FBC's Direct Overhead are excluded from the O&M used for determining the indirect capitalized overhead rate, and are instead included directly as part of forecast Regular capital expenditures. The methodology to determine FBC's Direct Overhead remains consistent with prior years and is considered reasonable by KPMG. Based on the results of the Direct Overhead loading model for 2023, the estimated Direct Overhead loading pool is approximately $5.5 million, as compared to approximately $5.0 million in the capitalized overhead study prepared in 2018 for FBC.

The table below provides a comparison of the results of the 2023 Capitalized Overhead Study for FBC against prior levels of gross O&M, approved capitalized overhead rates, the net O&M, and the resulting capitalization rate as a percentage of capital expenditures over the past six years. This comparison includes the period covered by the last capitalized overhead study prepared in 2018 and approved by the MRP Decision, effective for the term of the Current MRP, as well as the year immediately prior.

Table D5-2: FBC Capital, O&M and Capitalized Overhead 2019-2024 ($000s)

	2019 Approved	2020 Approved	2021 Approved	2022 Approved	2023 Approved	2024 Approved	2024 Revised [1]
Gross O&M	59,201	62,200	65,302	68,032	72,667	74,322	74,322
Capitalized OH Rate on Gross O&M	15%	15%	15%	15%	15%	15%	15.5%
Capitalized OH	(8,880)	(9,330)	(9,795)	(10,177)	(10,900)	(11,148)	(11,520)
Net O&M	50,321	52,870	55,507	57,855	61,767	63,174	62,802
CapEx (excl OH)	57,633	93,244	87,573	83,140	93,776	93,933	93,933
Capitalization Rate on CapEx	15%	10%	11%	12%	12%	12%	12%

Note:

[1] *2024 Revised is representative of changes to 2024 Approved had the capitalized overhead rate from the 2023 Capitalized Overhead Study for FBC included in Appendix D5-2 been used.*

As shown in Table D5-2 above, a 15.5 percent capitalized overhead rate for 2024 results in a level of net O&M (gross O&M less capitalized overhead) that is higher compared to prior years, given the increases in gross O&M and the slight increase in the rate. The proportion of capitalized overhead to the annual capital expenditures is presented as the capitalization rate. FBC's proposed capitalized overhead rate of 15.5 percent and the resulting capitalization rate of 12 percent are within a reasonable range compared to the prior years shown.

FBC estimates that the impact on customer rates of a change to the capitalized overhead rate is approximately 0.17 percent for every 1 percent change in the capitalized overhead rate. Therefore, all else equal, increasing the capitalized overhead rate from 15 percent to 15.5 percent would decrease customer rates by approximately 0.09 percent in the year of implementation (2025 in this case).

5.6 *CONCLUSION*

Based on the conclusions of the 2023 Capitalized Overhead Studies conducted by KPMG, FEI is proposing to apply a capitalized overhead rate of 14.5 percent of gross O&M, net of biomethane O&M transferred to the BVA, and FBC is proposing to apply a capitalized overhead rate of 15.5 percent of gross O&M, to regular capital expenditures for the term of the Rate Framework.

Appendix A

COMPANY INFORMATION

Appendix A1-1

LIST OF ABBREVIATIONS

LIST OF ABBREVIATIONS

Acronym	Definition
ACGS	Aitken Creek Gas Storage Facility
ACP	Annual Contracting Plan
AFUDC	Allowance for Funds Used During Construction
AHE	Average Hourly Earnings
AI	Artificial Intelligence
AIFR	All Injury Frequency Rate
AIP	Asset Investment Planning
ALG	Average Life Group
AMI	Advanced Metering Infrastructure
AR	Assessment Reports
AUC	Alberta Utilities Commission
AWE	Average Weekly Earnings
AWE:BC	Average Weekly Earnings for British Columbia
BC or B.C.	British Columbia
BC OPBS	Output-based Pricing System
BCER	BC Energy Regulator
BC Hydro	British Columbia Hydro and Power Authority
BCUC	British Columbia Utilities Commission
BVA	Biomethane Variance Account
CCA	Capital Cost Allowance
CCOA	Climate Change Operational Adaptation
CCRA	Commodity Cost Reconciliation Account
CCUS	Carbon Capture, Utilization, and Storage
CEA	*Clean Energy Act*
CGIF	Clean Growth Innovation Fund
CGIF-ST	Clean Growth Innovation Fund Steering Committee
CHP	Combined Heat and Power
CHS	Corporate Health Study
CI	Carbon intensity
CIAC	Contributions in Aid of Construction
CIS	Customer Information System
CMAE	Core Market Administration Expense
CMMS	Computerized Maintenance Management System
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide

Acronym	Definition
CO_2e	Carbon Dioxide Equivalent
COF	Coffee Creek
Concentric	Concentric Advisors, ULC
Corra Linn	Corra Linn Dam Spillway Gates Replacement Project
COV	City of Vancouver
CPCN	Certificate of Public Convenience and Necessity
CPI:BC	Consumer Price Index for British Columbia
CRA	Crawford Bay
CSA	Canadian Securities Administration
CSC Study (2023)	2023 Corporate Service Cost Study
CSR	Contaminated Sites Regulation
CTS	Coastal Transmission System
Custom IR	Custom Incentive Rate-setting
DCFC	Direct Current Fast Chargers
DEI	Diversity, Equity, and Inclusion
DEP	Diversified Energy Planning
DG	Distributed Generation
DP	Distribution Pressure
DRIP	Dividend Reinvestment Plan
DRIPA	*Declaration on the Rights of Indigenous Peoples Act*
DSM	Demand Side Management
E&I	Electrical and Instrumentation
EAC	Executive Advisory Council
ECM	Efficiency Carry-Over Mechanism
EGD	Enbridge Gas Distribution
EMAT	Electromagnetic Acoustic Transducer
EMB	Eligible Mitigation Benefits
ERP	Enterprise Resource Planning
ESC	Executive Steering Committee
ESG	Guidance for Environmental, Social, and Governance
ESM	Earning Sharing Mechanism
ESM	Earning Services Model
ETS	Exponential Smoothing
EV	Electric Vehicles
FAES	FortisBC Alternative Energy Inc.
FBC	FortisBC Inc.
FEED	Front End Engineering Design

Acronym	Definition
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
FHI	FortisBC Holdings Inc.
FI	Fortis Inc.
FortisBC	Collectively FEI and FBC, the Companies, or the Utilities
FMI	FortisBC Midstream Inc.
FPHI	FortisBC Pacific Holdings Inc.
FPIC	Free, Prior and Informed Consent
FTE	Full Time Equivalent
FWI	Fixed Weighted Index
GAAP	Generally Accepted Accounting Principles
GC	Growth Capital
GCA	Gross Customer Additions
GCOC	Generic Cost of Capital
GGRR	Greenhouse Gas Reduction Regulation
GHG	Greenhouse Gas
GHGRS	Greenhouse Gas Reduction Standards
GIS	Geographic Information System
GFOR	Generator Forced Outage Rate
GFT	Grand Forks Terminal Station Reliability Project
GJ	Gigajoule
GSU	Generating Step-up Units
HCA	*Heritage Conservation Act*
HENG	Hydrogen-enriched Natural Gas
ICM	Incremental Capital Module
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
I-Factor	Inflation Index
ICG	Industrial Customers Group
IGU	Inland Gas Upgrades
ILI	In-line Inspection
IMP	Integrity Management Program
IP	Intermediate Pressure
IRs	Information Requests
IS	Information Systems
ITS	Interior Transmission System
KBTA	Kelowna Bulk Transformer Addition

Acronym	Definition
LAN	Local Area Network
LBO	Lower Bonnington Dam
LCFS	Low Carbon Fuel Standards
LCRI	Low Carbon Resource Initiative
LDAR	Leak Detection and Repair
LMIPSU Project	Lower Mainland Intermediate Pressure System Upgrade Projects
LNG	Liquefied Natural Gas
LTC	Load Tap Changer
LTERP	Long Term Electric Resource Plan
LTGRP	Long Term Gas Resource Plan
MAPE	Mean Absolute Percentage Error
MBR	Migratory Birds Regulation
MCRA	Midstream Cost Reconciliation Account
MOCBs	Minimum Oil Circuit Breakers
MOTI	Ministry of Transportation and Infrastructure
MRP	Multi-year Rate Plan or Plans
MRS	Mandatory Reliability Standards
MSP	Medical Services Plan
Mt	Million Tonnes
MTO	Material Take-off
MOTI	The Ministry of Transportation and Infrastructure
NBV	Net Book Value
NGIF	Canadian Gas Association’s Natural Gas Innovation Fund
NGT	Natural Gas for Transportation
NGV	Natural Gas Vehicles
NOx	Nitrogen Oxide
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OHS	Occupational Health and Safety
OIC	Order in Council
OPEB	Other Post-Employment Benefits
PAR	Progressive Aboriginal Relations
PBR	Performance Based Ratemaking
PCBs	Polychlorinated Biphenyls
PFP	Partial Factor Productivity
PCH	Pyro Catalytic Hydrogenation
PGR	Pattullo Gas Line Replacement

Acronym	Definition
PJ	Petajoule
PP&E	Property, Plant and Equipment
PPA	Power Purchase Agreement
PP&E	Property, Plant and Equipment
PPE	Power Purchase Expense
PSI	Power Supply Incentive
PSIs	Preliminary Site Investigations
PST	Provincial Services Tax
PSV	Pressure Relief Valves
R&D	Research and Development
RG	Renewable Gas
RGSD	Regional Gas Supply Diversification
RNG	Renewable Natural Gas
ROE	Return on Equity
ROW	Right of Way
RSAM	Revenue Stabilization Adjustment Mechanism
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCP	Southern Crossing Pipeline
SEC	Securities Exchange Commission
SIF	Strategic Innovation Fund
SLC	South Slocan Dam
SLCA	Service Line Cost Allowance
SQI or SQIs	Service Quality Indicator or Indicators
tCO_2e	Tonnes of Carbon Dioxide Equivalent
TDGA	*Transportation of Dangerous Goods Act*
TFP	Total Factor Productivity
Tilbury	Tilbury LNG Storage Facility
TIMC	Transmission Integrity Management Capabilities
TP	Transmission Pressure
TRL	Technology Readiness Levels
TSF	Telephone Service Factor
UBO	Upper Bonnington Dam
UCA	*Utilities Commission Act*
UCC	Undepreciated Capital Cost
UCGC	Unit Cost Growth Capital

Acronym	Definition
UCOM	Unit Cost O&M
UNDRIP	United Nations Declaration on the Rights of Indigenous Peoples
UPC	Usage Per Customer
US GAAP	US Generally Accepted Accounting Principles
USofA	Uniform System of Accounts
VFI	Vacuum Fault Interrupter
VIEU	Vertically Integrated Electric Utility
VITS	Vancouver Island Transmission System
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network
X-Factor	Productivity Factor
ZEV	Zero Emission Vehicle

Appendix A1-2

FEI 2019-2023 KEY OPERATING FACTS

FEI
Annual Report Statistics
2019-2023

	2019	2020	2021	2022	2023 [1]
Customers:					
12 Month Average Residential Customers	936,569	948,873	960,814	970,531	980,540
12 Month Average Commercial Customers	96,637	97,026	97,496	97,833	98,681
12 Month Average Industrial Customers	381	618	667	715	776
12 Month Average Transportation Customers	645	453	425	401	368
12 Month Average NGV Customers	8	7	10	12	14
Total Average Customers	**1,034,240**	**1,046,977**	**1,059,412**	**1,069,492**	**1,080,379**
Total Year End Customers	1,040,721	1,054,097	1,064,800	1,075,595	1,086,497
Gas Deliveries (Normalized Actual):					
Residential Gas Delivery (TJ)	77,277	81,837	82,481	80,650	80,281
Commercial Gas Delivery (TJ)	58,175	58,169	59,566	60,964	61,912
Industrial Gas Delivery (TJ)	8,391	15,362	16,637	17,695	18,645
Transportation Gas Delivery (TJ)	88,626	79,905	80,443	66,335	58,791
NGV Gas Delivery (TJ)	23	20	19	20	18
Total Gas Deliveries	**232,492**	**235,293**	**239,146**	**225,664**	**219,647**
O&M ($000s):					
Gross O&M Decision	$ 282,161	$ 315,425	$ 330,242	$ 334,279	$ 354,647
Gross O&M Actual	284,701	314,761	329,319	329,103	355,454
O&M Transferred to Biomethane BVA	-1,149	-2,354	-2,810	-4,156	-6,196
Capitalization Allowed	-33,859	-50,428	-52,801	-53,484	-56,744
Total Net O&M	**$ 249,693**	**$ 261,979**	**$ 273,708**	**$ 271,463**	**$ 292,514**
Headcount					
Average Full Time Equivalent (FTE)	1,765	1,765	1,917	1,961	1,988
Distribution Fast Facts:					
Outages caused by Third Party	1,381	1,607	1,479	1,328	1,155
Gas Odour Calls	15,045	16,879	20,879	20,254	19,395
CO Calls	2,374	2,001	1,253	1,305	1,282
Fire Calls	983	795	603	604	653
Meter Recalls	39,971	26,549	43,334	29,563	25,856
Locates	4,272	4,136	4,009	3,612	3,060
Calls to BC 1 Call	144,413	141,262	163,584	157,174	158,478
Lock Offs	9,847	1,517	4,621	10,918	12,458
Unlocks	9,610	2,482	4,215	9,501	10,724
Service Lines (Risers)	922,269	931,158	941,263	949,241	955,937
Total Valves	30,674	31,146	31,618	32,067	32,515
Regulator Stations	483	503	504	529	530
Line Heaters	245	253	258	259	264
Pipeline Stats:					
Total TP Pipe (KM's)	2,960	2,971	2,970	2,987	2,969
Total IP (KM's)	701	725	732	699	717
Total DP Service Pipe (KM's)	22,845	22,927	23,057	23,575	23,853
Total DP Main Pipe (KM's)	23,460	23,559	23,734	23,913	24,045
Total Pipeline	**49,966**	**50,182**	**50,493**	**51,174**	**51,584**
System Outages:					
Outages	1,076	983	1,072	948	886
Customers Affected	2,303	1,173	1,150	1,581	1,813
System Leaks:					
Distribution Pipeline Leaks	**951**	**847**	**810**	**970**	**767**
BGC1	723	646	542	529	371
BGC2	173	150	212	317	275
BGC3	55	51	56	124	121
Emergency Response Time (minutes)	20.33	18.85	18.21	18.73	19.23
Miscellaneous:					
Rate Base, Mid-Year	$ 4,529,822	$ 5,024,590	$ 5,211,278	$ 5,409,035	$ 5,911,852
Allowed Return	8.75%	8.75%	8.75%	8.75%	9.65%

[1] 2023 amounts are preliminary actuals, subject to completion of the 2023 FEI BCUC Annual Report to be filed April 30, 2024

Appendix A1-3

FBC 2019-2023 KEY OPERATING FACTS

FBC
Annual Report Statistics
2019-2023

	2019	2020	2021	2022	2023 [1]
Customers:					
12 Month Average Residential Customers	121,378	123,647	125,911	127,899	130,263
12 Month Average Commercial Customers	15,817	16,077	16,390	16,674	16,825
12 Month Average Industrial Customers	52	48	43	42	42
12 Month Average Wholesale Customers	6	6	6	6	6
12 Month Average Lighting Customers	1,475	1,453	1,421	1,391	1,359
12 Month Average Irrigation Customers	1,080	1,090	1,106	1,100	1,107
Total Average Customers	**139,808**	**142,321**	**144,877**	**147,112**	**149,602**
Total Year End Direct Customers	141,027	143,714	145,830	148,435	150,698
Total Year End Indirect Customers	37,753	38,298	39,046	39,485	39,882
Energy Sales (Normalized Actual):					
Residential (GWh)	1,265	1,359	1,350	1,348	1,340
Commercial (GWh)	928	922	960	957	970
Industrial (GWh)	472	431	454	542	556
Wholesale (GWh)	578	570	566	572	593
Lighting (GWh)	11	11	10	9	9
Irrigation (GWh)	36	37	43	37	38
Total Energy Sales	**3,290**	**3,330**	**3,383**	**3,465**	**3,507**
O&M:					
Gross O&M Decision ($000s)	$59,201	$62,200	$65,302	$68,032	$72,667
Gross O&M Actual ($000s)	$58,519	$60,682	$62,135	$64,163	$68,461
Capitalization Allowed ($000s)	$(8,880)	$(9,330)	$(9,795)	$(10,177)	$(10,900)
Total Net O&M ($000s)	**$ 49,638**	**$ 51,352**	**$ 52,340**	**$ 53,986**	**$ 57,561**
Headcount					
Full Time Equivalent (FTE)	534	549	541	549	567
Transmission & Distribution Stats:					
Distribution Lines (km)	6,022	6,045	6,060	6,092	6,118
Transmission Lines (km)	1,290	1,290	1,244	1,224	1,224
Total Transmission and Distribution Lines (km)	7,312	7,335	7,304	7,316	7,342
Total Substations	65	65	65	65	65
System Losses (%) - Gross Load	8.1	8.0	8.1	8.3	8.0
Peak Demand (MW) - Summer	623	648	764	720	689
Peak Demand (MW) - Winter	696	740	777	835	685
Power Supply Stats:					
Generation (GWh)	1,604	1,561	1,673	1,585	1,561
Generating Capacity (MW)	225	225	225	225	225
Total Power Purchases (GWh)	2,041	1,985	2,157	2,267	2,208
Total DSM Energy Saved (GWh)	25.8	26.2	29.7	35.9	31.4
Miscellaneous:					
Rate Base, Mid-Year ($000s)	$ 1,355,193	$ 1,418,909	$ 1,505,738	$ 1,578,977	$ 1,666,960
Allowed Return	9.15%	9.15%	9.15%	9.15%	9.65%

[1] 2023 amounts are preliminary actuals, subject to completion of the 2023 FBC BCUC Annual Report to be filed April 30, 2024

Appendix A1-4

FEI TABLE OF BCUC DIRECTIVES

No.	Decision Page No.	Directive No.	Description / Details	Status	Section in this Application
G-165-20 – FEI MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024					
1.	156	61	***Clean Growth Innovation Fund:*** The Panel directs any unused balance in the deferral account to be returned to customers at the end of the Proposed MRP term through a disposal mechanism subject to approval by the BCUC.	Completed	Section C5.2.2
G-319-20 – FEI ANNUAL REVIEW FOR 2020 AND 2021 DELIVERY RATES					
2.	16	9	***CMAE Budget:*** The Panel directs FEI to include, in it next revenue requirements or MRP application following the MRP term, a comprehensive review of the CMAE costs including consideration of whether these costs are conducive to a formulaic approach or whether they should continue to be forecast with flow-through treatment, and whether the current allocation percentages to the CCRA and MCRA remain appropriate.	Completed	Section C4.3.1; Appendix C4-3
C-3-22 – FEI APPLICATION FOR A CPCN FOR THE COASTAL TRANSMISSION SYSTEM (CTS) TRANSMISSION INTEGRITY MANAGEMENT CAPABILITIES (TIMC) PROJECT					
3.	36		***Sustainment Capital:*** FEI estimates $84.983 million in Sustainment Capital will be required over the life of the Project. This amount is not included in the estimated total Project cost of $137.8 million. FEI will request BCUC approval for this cost either in the Multi-Year Rate Plan (MRP) Capital Forecast Update filed as part of its 2023 Annual Review, or in the next MRP or revenue requirement application filing, depending on the timing of the work.	Completed	Section C3.3.2.2
G-253-22 – FEI APPLICATION FOR APPROVAL OF REGIONAL GAS SUPPLY DIVERSITY (RGSD) DEVELOPMENT ACCOUNT					
4.		4	***RGSD Project:*** The recoverability and disposition of any costs recorded in the RGSD Development Account will be subject to BCUC review and determination in a future application, such as a subsequent FEI annual review or in a CPCN application for the RGSD Project.	Will be proposed in a future application	n/a
G-352-22 – FEI ANNUAL REVIEW FOR 2023 DELIVERY RATES					
5.	35		***Public Contact with Gas Lines:*** Although this SQI is performing better than the benchmark, the Panel agrees with RCIA's comment on the need for FEI to provide a better explanation as to why it nonetheless experiences higher numbers of gas line hits than its counterparts in other provinces. The Panel also agrees with both RCIA and FEI that further discussion regarding this SQI and any possible changes is best addressed during the next MRP application.	Completed	Appendix C6-1

No.	Decision Page No.	Directive No.	Description / Details	Status	Section in this Application
G-334-23 – FEI ANNUAL REVIEW FOR 2024 DELIVERY RATES					
6.	9		***Demand Forecast:*** The Panel directs FEI to discuss alternative methodologies for forecasting non-NGT LNG demand and to provide an update on its forecasts for LNG export volumes related to spot purchase agreements as part of its next revenue requirements application.	Completed	Section C4.2.1.1
7.	11		***Other Revenue – Late Payment Charges:*** The Panel directs FEI to evaluate the impacts of alternative methodologies for forecasting Late Payment Charges, including forward-looking approaches (e.g. as a function of projected revenue or customer bills) and backward-looking approaches (e.g. the current two-year versus prior three-year historical average basis) as part of its next revenue requirements application.	Completed	Section C4.4.1
8.	23		***Amortization Alternatives for the 2023 and 2024 Revenue Deficiency Deferral Account:*** The Panel agrees with RCIA that the issue of the appropriate length of the amortization period for the 2023 and 2024 Revenue Deficiency deferral account is better addressed in the next FEI rates application… …Accordingly, we find it appropriate to defer to that panel's determination of the amortization period of that deferral account in that proceeding.	FEI will request approval of the amortization period in its 2025 Rates Application.	Section C7. For the purposes of calculating the indicative rates shown in Section C7, FEI has utilized a five-year amortization period.

Appendix A1-5

FBC TABLE OF BCUC DIRECTIVES

No.	Decision Page No.	Directive No.	Description / Details	Status	Section in this Application
G-340-23 – FBC Annual Review for 2024 Rates					
1.	19		***2024 Mandatory Reliability Standards Audit Deferral Account:*** The Panel notes that the 2024 MRS audit will be the fifth audit since the introduction of the MRS audit process in 2021, and since these costs are now recurring in nature, it is timely for FBC to now review its forecasting methodology for MRS costs. Accordingly, we encourage FBC to consider whether flow-through treatment of these costs continues to be appropriate as part of its next rates application.	Completed	Section C2.5.2
2.	24		***Climate Change Operational Adaptation (CCOA) Plan Deferral Account:*** The Panel notes that any costs beyond 2024 (i.e. 2025 and beyond) associated with the execution or implementation of the CCOA Plan should not be included in this deferral account, but rather are subject to review and approval as part of the next rates application. The Panel would strongly encourage FBC to integrate its CCOA Plan into its next rates application or multi-year plan to address the expectations of stakeholders and rate payers in the ongoing energy transition and climate change mitigation initiatives in BC.	Ongoing	For a discussion of how the CCOA Plan is considered in the Rate Framework, refer to Section B1.6.1.2. FBC will report on the deferral account balance in the Annual Reviews.

Appendix B

RATE SETTING FRAMEWORK CONSIDERATIONS

Appendix B2-1

PRE-2020 PBR EXPERIENCE

Appendix B2-1

Pre-2020 PBR Experience

Table of Contents

Index of Tables

1. FORTISBC PRE-2020 MULTI-YEAR RATE PLAN EXPERIENCE

Both FEI and FBC have a long history with multi-year rate plans (MRPs), and specifically performance-based rate-setting (PBR), going back to the 1990s. In this section, FortisBC discusses the previous generations of PBR plans it has employed. Understanding FEI's and FBC's experiences with previous PBR plans provides additional insight into FortisBC's perspective in developing this Application, as the Rate Framework builds on the successes and lessons learned from these plans, incorporating some similar elements with adjustments where appropriate. FortisBC's experience with the 2020-2024 MRP (Current MRP) is discussed in Section B2 of the Application. This appendix provides further details regarding FEI's and FBC's pre-2020 MRPs.

1.1 *FEI EXPERIENCE*

1.1.1 FEI 1998 PBR Plan

The 1998 PBR plan was approved on July 23, 1997 by Order G-85-97. The plan was originally set for three years but was later extended by a year, ending in 2001. This was FEI's (then BC Gas) first generation of PBR plan that covered both capital and O&M expenditures.[1] The following table provides a brief summary of the main features of the 1998 PBR plan.

Table 1: Main Features of FEI's 1998 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		Initially three years (1998-2000), subsequently extended to 2001
Formula	O&M	$O\&M_t = [O\&M_{t-1} * (1+G-X) * (1+I)]$ + Costs of defined required activities G = Forecast percentage growth in the average number of customers
	Capital	<u>Type I: Unit cost approach</u> Allowed Unit Cost $_t$ = Unit Cost $_{t-1}$ * (1+I-X) Allowed Cost $_t$ = Allowed Unit Cost $_t$ * Units Forecast $_t$ <u>Type II: Aggregate cost approach</u> Allowed Cost $_t$ = Cost $_{t-1}$ * (1+I-X)
I-Factor		CPI-BC
X-Factor		Various values set as part of the negotiated settlement process (NSP)
Y-Factor		Included deferral accounts for items such as interest, DSM expenses, tax variances and RSAM
Z-Factor		Available for costs caused by exogenous factors, no materiality threshold

[1] A formula-based approach to setting O&M was first adopted in FEI's 1994-1995 negotiated settlement and refined in the 1996-1997 negotiated settlement.

Item	Description
ESM	50:50 sharing of variances between authorized and actual earnings net of specific incentive programs which were considered as non-utility earnings
ECM	Available through the capital efficiency mechanism
Incremental Capital	Available through CPCN process, no materiality threshold was defined
SQI	Included five metrics

As shown above, the 1998 PBR plan included two types of capital formulas. The first and more widely used unit cost approach was employed to calculate the allowed costs for capital cost categories such as mains, services, meters and system improvements and reinforcements. The unit costs for some of these categories (such as mains and services) were calculated based on regional unit costs (i.e., Interior unit cost and Lower Mainland unit cost) to account for the differences in unit cost in different regions of FEI's service territory. The remaining capital costs not suitable for the unit cost approach were calculated using the aggregate formula presented in Table 1 above. Further to the formula driven costs, the utility was able to apply for incremental capital funding using the CPCN process. The negotiated settlement specified that any efficiency gained as a result of these projects could also be used to achieve the targeted O&M productivity level.

The 1998 PBR plan also included a "capital efficiency mechanism". Under this mechanism, the variance between actual unit costs and allowed unit cost was multiplied by the actual number of units. This amount would then be added or subtracted from the utility's rate base. The capital efficiency incentive adjustment to rate base was phased out over three years.

1.1.2 FEI 2004 PBR Plan

The 2004 PBR plan was originally approved by Order G-51-03 for a four-year period (2004-2007), and subsequently extended for two years, ending in 2009. This plan maintained a few features of the 1998 PBR plan (similar ESM, deferral accounts, use of CPCN process for incremental capital funding, inflation factor, etc.) while introducing changes to other elements (such as capital formulas). The table below provides a brief summary of the main features of FEI's 2004 PBR plan.

Table 2: Main Features of FEI's 2004 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		Initially four years (2004-2007), subsequently extended to 2009
Formula	O&M	$O\&M_t = [O\&M_{t-1} * (1+G) * (1+I - X)]$ G = Forecast percentage growth in the average number of customers
	Capital	$\text{Allowed Unit Cost}_t = \text{Unit Cost}_{t-1} * (1+I-X)$ $\text{Allowed Cost}_t = \text{Allowed Unit Cost}_t * \text{Units Forecast}_t$ Two formulas: (i) growth capital; (ii) Other capital
I-Factor		CPI-BC
Item		**Description**
X-Factor		Various percentage of inflation factor determined as part of the NSP
Y-Factor		Included deferral accounts for items such as debt interest, DSM expenses, tax variances, pension and RSAM
Z-Factor		Available for costs caused by exogenous factors, no materiality threshold
ESM		50:50 sharing of variances between the allowed and actual ROE (net of GSMIP, DSM Incentive, load building and incentives for partially controllable items) using the common equity component of the actual rate base
Safeguard Mechanism		Any party could request a review process if the achieved ROE after ESM varies from the approved ROE by 150 bps in any year of the plan
ECM		Available through the phase-out of capital benefits
Incremental Capital		Available through CPCN process; materiality threshold of $5 million
SQI		Included six SQIs and two directional indicators
Other incentives		Included separate incentive mechanism (not subject to ESM) such as incentives for partially controllable costs (municipal taxes) and load building incentives

As indicated in the table above, the 2004 PBR plan included both capital expenditures and O&M expenditures. For O&M expenses, the approved 2003 O&M was used as the base, and then escalated by inflation, a productivity factor and a customer growth factor. Customer growth was expressed as the change in the average number of customers from one year to the next. Similar to O&M, the capital expenditures approved in the 2003 Revenue Requirements Application (RRA) were used as the base, and then escalated for inflation and a productivity factor. The capital expenditures were separated into two categories: (1) growth capital (customer addition-driven capital expenditures such as capital needed to install service lines); and (2) other capital (where the average number of customers was used as the cost driver). The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer growth. Further, similar to the 1998 PBR plan, CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes.

The 2004 PBR plan also included an efficiency carry-over mechanism for capital-related costs. It involved determining the difference between the formulaic and actual capital expenditures over the term of the PBR, and then, rather than full rebasing right away, the Company received 2/3 of its 50 percent share in the first year following the expiry of the plan, and 1/3 of its 50 percent share in the next year.

1.2 *FBC EXPERIENCE*

1.2.1 FBC 1996 PBR Plan

In 1996, FBC (then West Kootenay Power), as part of its 1996 RRA, received BCUC approval by Order G-73-96 to enter into a PBR plan to replace cost of service regulation. The plan consisted of “targeted” cost categories with cost drivers, base costs, escalators, productivity improvement factors and a sharing mechanism. In addition to cost categories, performance standards including customer satisfaction and system reliability were included as part of the PBR plan, and were subject to annual review to confirm that service quality was being maintained throughout the term.

The PBR plan was originally approved for 1996-1998, but the Negotiated Settlement Agreement (NSA) contemplated a potential continuation of the PBR Plan. A one-year extension was approved for 1999 by Order G-123-98. The NSA approved by Order G-123-98 also required FBC to file a multi-year rate-making proposal to commence in 2000. FBC’s 2000-2002 RRA, extending the plan and amending the incentive mechanism, was approved by Order G-134-99. Subsequent one-year extensions to the plan were approved for 2003 by Order G-10-03 and for 2004 by Order G-38-04. Certain of the mechanisms included as part of the original PBR plan were modified in subsequent extensions. These modifications included the introduction of a power purchase variance mechanism and market incentive mechanism, as well as the exclusion of capitalized overhead from the sharing mechanism.

Table 3: Main Features of FBC's 1996-2004 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		9 years (1996-2004); approved for three years (1996-1998) and extended for 1999, 2000-2002, 2003 and 2004
Formula	O&M	$O\&M_{t} = [(O\&M/customer)_{t-1} * [1 + (I-X)]] *(customer_{t})$ Forecast percentage growth in the average number of customers
	Capital	Four categories of capital expenditures escalated by applicable drivers including customer growth and system peak load
I-Factor		CPI-BC (O&M, General Plant capital) or CPI-Canada (all other capital)
X-Factor		Various percentages for each year determined as part of the initial NSP
Y-Factor		Items such as pension expense and certain lease costs were excluded from the formulas and treated as flow-through. Other items such as DSM expenses were also treated outside the formula. Non-routine capital approved by project
Z-Factor		For extraordinary costs outside of the "steady state" operations as determined by O&M formula; no materiality threshold
ESM		Symmetric 50:50 sharing for variance between allowed and actual O&M expense, other income, income taxes and interest volume. Incentives for power purchase expense included from 2000 - 2004
Item		**Description**
Safeguard Mechanisms		Other than the ESM, no financial safeguard provided. The 1999-2000 application included a review of the plan and the extensions to the plan were contingent on the mutual agreement of parties
SQI		A number of performance standards were established to provide an overall assessment of the FBC's performance

1.2.2 FBC 2007 PBR Plan

FBC's subsequent PBR plan commenced in 2007 pursuant to an NSA approved by Order G-58-06 and remained in effect (after an approved three-year extension) until 2011.

The 2007 Plan was based on the previous PBR plan in key aspects and included the continued use of cost and growth escalators and a productivity factor. A key difference in the 2007 PBR plan was the exclusion of capital expenditures. Instead, capital expenditures were approved as part of a separate annual filing or by way of filing CPCN applications for major projects. As well, a symmetric ESM calculated based on the variance between allowed and actual ROE replaced the previous line-by-line review used to determine the level of any incentive sharing between the Company and its customers. A brief summary of the main features of FBC's 2007 PBR plan is provided in the table below.

Table 4: Main Features of FBC's 2007 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		5 years (2007-2011); approved for two years and extended to the end of 2011
Formula	O&M	$O\&M_{t} = [(O\&M/customer)_{t-1} * [1 + (I-X)]] * (customer_{t})$ Forecast percentage growth in the average number of customers
	Capital	Not subject to formula; set based on separate capital expenditure schedule filings or CPCN applications
I-Factor		CPI-BC
X-Factor		Various percentages for each year determined as part of the initial NSP
Y-Factor		Items such as pension and other post-employment benefits (OPEB) and office lease costs were excluded from the formulas; other items such as DSM expenses were also treated outside the formula
Z-Factor		For extraordinary costs outside of the "steady state" operations as determined by O&M formula; no materiality threshold
ESM		Symmetric 50:50 sharing for variance between the allowed and actual earnings up to 200 bps. Differences greater than 200 bps to be placed in a deferral account for review and disposition in annual review
Item		**Description**
Safeguard Mechanisms		Other than ESM, no financial safeguard provided; however, the 2008 annual review included a review of the PBR plan and the extension to the plan were contingent on the mutual agreement of parties
SQI		A number of performance standards with associated targets were established to provide an overall assessment of the FBC's performance

As shown above, the O&M formula was based on a unit cost approach where the base O&M unit cost is escalated by an I-X index and the result is multiplied by the average number of customers to calculate the allowed O&M expense in each year. The inflation index and growth factor in the formula were forecast with no true-up for actual amounts. Capitalized overhead was also determined by formula, at 20 percent of gross O&M expense.

The 2007 PBR plan further expanded the number of service quality indicators to improve the measurement of customers' satisfaction with both the quality and reliability of service, as well as the convenience of customers' routine interactions with FBC. Under this negotiated incentive framework, failure to meet one (or more) targets did not necessarily constitute unacceptable performance. Rather, the BCUC would take into account the reasons given by the Company on why certain performance targets were not met and why the Company should be entitled to an incentive payment.

1.3 *FEI'S AND FBC'S JOINT PBR EXPERIENCE*

1.3.1 FEI and FBC 2014-2019 PBR Plan

Following periods of traditional cost of service rate-setting[2], FEI and FBC returned to performance-based rate setting for the 2014-2019 period. The 2014-2019 PBR plan was approved in September 2014 by Orders G-138-14 and G-139-14 for FEI and FBC. This was the first PBR proceeding in which FEI's and FBC's PBR plan applications were reviewed in the same oral hearing process. The table below provides a brief summary of the main features of FEI's and FBC's 2014-2019 PBR plans.

Table 5: Main Features of FEI's and FBC's 2014-2019 PBR Plans

Item		FEI PBR Plan	FBC PBR Plan
Process		Written and oral hearing	
Formula	O&M	$OM_t = OM_{t-1} * [1 + (I-X)] * (1+G/2)$ G = Percentage growth in average number of customers	
	Capital	$\text{Allowed Cost}_t = \text{Cost}_{t-1} * (1+I-X) * (1+G/2)$ Three categories: (i) growth capital, (ii) sustainment capital (iii) other capital	$\text{Allowed Cost}_t = \text{Cost}_{t-1} * (1+I-X) * (1+G/2)$ Three categories: (i) growth capital, (ii) sustainment capital (iii) other capital
		G = Service line additions for growth capital, average number of customers for Sustainment and Other capital	G = Average number of customers
I-Factor		Composite index: 55% AWE:BC + 45% CPI:BC	
X-Factor		Fixed at 1.10% for the entire PBR term	Fixed at 1.03% for the entire PBR term
Y-Factor		Flow-through deferral account as well as a number of other deferral accounts such as DSM expenses, cost of gas/power supply, and pension/OPEB expense	
Z-Factor		Available for prudently incurred costs caused by exogenous factors	
		Materiality threshold: 0.5% of 2013 base O&M which equalled $1.15 million	Materiality threshold: 0.5% of 2013 base O&M which equalled $0.301 million
ESM		50/50 symmetric sharing for variances in formula O&M and for earnings on formula capex variances within a dead band	

[2] For FEI, the 2010-2011 and 2012-2013 RRAs. For FBC, the 2012-2013 RRA.

<table>
<tr><th>Item</th><th>FEI PBR Plan</th><th>FBC PBR Plan</th></tr>
<tr><td>Safeguard Mechanisms</td><td colspan="2"><u>Dead band for capital formula</u>
- If the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount
- One-year 10% dead band or two-year cumulative 15% dead band

<u>PBR Off-ramp</u>
Off ramp triggered if earnings in any one year varies from approved ROE by more than +/- 200 bps (post sharing) and/or earnings vary from approved ROE by more than +/- 150 bps (post sharing) in two consecutive years</td></tr>
<tr><td>ECM</td><td colspan="2">Only on a case-by-case basis</td></tr>
<tr><td rowspan="2">Incremental Capital</td><td>Available through CPCN process</td><td>Available through CPCN process plus specific major non-recurring projects</td></tr>
<tr><td>Materiality threshold of $15 million</td><td>Materiality threshold of $20 million</td></tr>
<tr><td>SQIs</td><td>Included nine SQIs and four informational indicators</td><td>Included eight SQIs and three informational indicators</td></tr>
</table>

As indicated in the table above, the 2014-2019 PBR plans included both capital expenditures and O&M expenditures.

The BCUC approved a Base O&M Expense based on 2013 Approved O&M, subject to certain adjustments that resulted in minor overall changes to the proposed base values. An O&M formula escalated the base O&M amount for inflation and the annual growth in average number of customers, less productivity. Other than the quantum of the productivity factor, there were two differences from what was applied for:

i. A 0.5 discount factor was applied to the growth factor which reduced the allowed O&M amount; and

ii. The inflation and growth factors were set using the actual historical numbers on a lagged basis, rather than using forecasts.

FEI and FBC classified capital expenditures as growth, sustainment, and other. The 2014-2019 PBR Plan Decisions approved the proposed capital formulas subject to the same two adjustments made to O&M. The capital expenditure formulas used were the same as the O&M formula, with the exception of the formula for FEI's growth capital, which substituted service line additions for customer growth.

The 2014-2019 PBR Plan Decision approved FEI's base capital as determined by its 2013 approved capital expenditures, subject to some adjustments. Pursuant to the amalgamation reconsideration decision,[3] the BCUC directed FEI to file a proposal for the addition of the O&M and capital requirements of FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) to FEI's base O&M and capital to reflect the amalgamated FEI entity. Order G-106-15 set FEVI's sustainment capital based on a five-year average of FEVI's actual sustainment capital expenditures without any adjustment for inflation or other factors and reduced FEVI's previously approved 2014 sustainment capital by $6.3 million, which resulted in a similar reduction to base capital expenditures for 2015 and each of the remaining years in the PBR plan term. The BCUC also determined that FBC's base capital would be determined from its 2013 approved capital expenditures, subject to certain adjustments such as the exclusion of major non-recurring projects.

This was the first proceeding in which the X-Factor was set based on the detailed productivity studies conducted by external experts. Similarly, consistent with the transition in other jurisdictions, this was the first PBR plan that included a composite inflation factor consisting of both labour and non-labour input price indices.

In the 2014 PBR Applications, FEI and FBC proposed to include a "capital dead-band" of 10 percent of approved formulaic expenditures, to safeguard customers and the Companies from significant variances between actual and formula driven capital expenditures. Under this approach, variances from approved expenditure amounts and within the dead band were excluded from rate base during the PBR term. As approved by Orders G-196-17 and G-38-18, if the capital dead band was exceeded, the opening plant in service for ratemaking purposes in the following year would be adjusted by the amount that actual capital fell outside of the dead band, and the capital expenditures utilized in calculating the earnings sharing would be adjusted by the same amount. In addition to the proposal for a one-year 10 percent dead band and in response to interveners' requests, the BCUC approved a two-year cumulative 15 percent dead band for formulaic capital spending.

The 2014-2019 PBR plans also included several other components to protect customers and the Companies from windfall earnings or losses. These included an ESM, Z-Factor, Y-Factor, offramp provisions and service quality indicators.

[3] Order G-21-14.

Appendix B2-2

JURISDICTIONAL COMPARISON

Appendix B2-2

Jurisdictional Comparison

Table of Contents

Index of Tables

1. INTRODUCTION

In addition to FBC's and FEI's (collectively, FortisBC) 2020-2024 Multi-Year Rate Plan (Current MRP), various models of MRPs, also known as incentive rate-setting mechanisms (IRM or IR) or performance-based rate-setting (PBR), are currently adopted by several natural gas and electric utilities in Alberta, Ontario and Quebec.

This appendix provides a comparison of MRPs' features and related regulators' decisions in these jurisdictions. Specifically, Alberta's third generation PBR plans for natural gas and electric distributors, the Ontario Energy Board's (OEB) regulatory framework for Ontario's electric distributors and the Enbridge Gas Distribution (EGD) incentive rate-setting plan in Ontario, as well as Energir's MRP are discussed in the following sections. Unless specifically stated, the various historical plans applied to these utilities in the past are not discussed in this study.

This study relies on publicly available information, which includes regulatory filings and reports available in the utility regulators' websites. The report outlines the essential features of each reviewed plan.

The review of most recent rate cases in these jurisdictions indicate that there has been no significant change in rate-setting mechanisms in any of the studied jurisdictions. All incentive frameworks presented in this report are designed to promote a continuous efficiency focus and/or to achieve targeted outcomes, while ensuring that service quality requirements and government policy objectives are met. They are also designed to create an efficient regulatory process for the period of the MRPs, allowing the utilities to effectively manage business priorities and increase innovative solutions to the utilities' challenges. Nevertheless, within these common principles, each jurisdiction has tailored the plans to fit its specific circumstances. This supports the popular belief that there is no one "right" incentive model and that the framework adopted for each utility should be in keeping with their specific circumstances and their history with incentive regulation. In other words, while MRPs in various jurisdictions may share many common features, the overall package is tailored to fit the circumstances of each utility.

2. ALBERTA – 3RD GENERATION PBR PLANS FOR DISTRIBUTION UTILITIES

2.1 BACKGROUND AND DEVELOPMENT

Alberta's second generation five-year PBR plan expired on December 31, 2022. In March 2021, the Alberta Utilities Commission (AUC) issued Bulletin 2021-04 indicating its intention to review the distribution utilities' costs and revenues and initiated two related streamlined proceedings: (i) a process to review the legacy PBR performance to date; and (ii) a process to establish 2023 rates. These two proceedings are further described in the following sections.

2.1.1 AUC's Evaluation of PBR Experience in Alberta

In its review and assessment of PBR performance in Decision 26356-D01-2021, the AUC found that, on balance, PBR has been able to achieve many of the objectives that were reflected in the founding PBR principles:

- **Principle 1. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality:** The AUC concluded that PBR has incented the utilities to find efficiencies in service delivery to maximize their profits, similar to what may be experienced in a competitive market, but not to the greatest extent possible. On the basis of the Rule 002 reports, the AUC further found that the utilities have maintained service quality during the PBR terms. The AUC further indicated that the utilities' ability to earn above their approved ROE during the PBR term is, at least directionally, indicative that the utilities were able to achieve efficiencies under the PBR.
- **Principle 2. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return:** As shown in the table below, utilities in Alberta were generally able to achieve returns that were higher than their allowed ROE and for some utilities, by a significant amount.

Table 1: Approved and Actual ROEs for Albertan Utilities during the PBR Terms

Year	Approved ROE	Fortis	ATCO Electric	ENMAX[1]	EPCOR	ATCO Gas North	ATCO Gas South	Apex
	(%)							
2013	8.30	9.49	10.99	8.05	9.97	10.97	12.98	11.96
2014	8.30	9.77	9.74	7.82	10.39	11.86	9.81	11.27
2015	8.30	11.12	9.90	6.15	10.37	12.15	9.78	6.16
2016	8.30	9.70	13.03	9.93	8.98	13.89	11.75	5.83
2017	8.50	9.20	13.21	9.64	8.02	16.61	15.33	9.80
2018	8.50	8.90	8.34	6.53	10.81	10.49	11.66	9.37
2019	8.50	10.14	11.15	9.31	11.63	10.57	11.96	10.26
2020	8.50	10.13	9.82	9.19	11.36	11.60	9.88	9.25

The AUC clarified that a “a return in excess of the approved ROE, in itself, does not necessarily indicate that there is a problem with the PBR plans.”[1]

- **Principle 3. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time:** The AUC assessed that while certain challenges were experienced during the two terms, there were notable achievements recognized by the majority of parties. The annual PBR rate adjustment filings that are routine, regular and mechanical in nature, allowed for an expedited review by the AUC and customer groups, while allowing the utilities to plan for the development of their applications and any subsequent related proceedings.
- **Principle 4. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design:** The AUC commented that Principle 4 was achieved during the PBR terms through the PBR plan features such as introducing a revenue-per-customer cap for natural gas utilities and a price cap for electric utilities, Z and Y Factors, and rebasing based on actuals specific to each utility.
- **Principle 5. Customers and the regulated companies should share the benefits of a PBR plan:** Overall, the AUC determined that this principle was not adequately met during the two PBR terms. The AUC noted that customers share the benefits by having any achieved efficiencies reflected in the 2023 rates through rebasing application. Nevertheless, the AUC agreed with the interveners that an earning sharing mechanism to allow customers to share in the benefits during the PBR term can improve achieving Principle 5.

Overall, the AUC found that it would be in the public interest to proceed with the next generation PBR regulatory regime for the distribution utilities.

[1] AUC Decision 26356-d01-2021, page 13.

2.1.2 Process to Establish 2023 Rates

Although the AUC's Bulletin 2021-04 initially indicated that the 2023 rates should be set based on a cost-of-service methodology, the AUC's Decision 26354-D01-2021 determined that the AUC shall not prescribe a specific methodology for developing their 2023 revenue requirement forecasts. Instead, it adopted a hybrid methodology for assessing the 2023 forecasts where the extent to which expenditures are examined is guided by the nature, size or complexity of the associated cost to facilitate a streamlined review of the 2023 rate applications.

The AUC indicated that adopting a hybrid methodology permits utilities to both streamline their submissions pertaining to costs that are routine or less controversial, and to focus their 2023 rate applications on complex issues. The AUC further stated that a hybrid methodology achieves an appropriate balance between regulatory efficiency and providing an adequate opportunity for interveners and the AUC to test a utility's case.

In practice, utilities choose a range of methodologies for their O&M and capital addition forecasts. These includes a bottom-up forecast approach, typically used in cost-of-service applications, as well as a mechanistic approach, typically used in streamlined rebasing applications, where the actual costs may be averaged, escalated by inflation and growth factor and/or adjusted for other incremental cost items. The table below provides a brief description of O&M and capital additions rebasing methodologies used by FortisAlberta and ATCO.

Table 2: Hybrid Rebasing Methodologies used by FortisAlberta and ATCO Electric

Category	FortisAlberta	ATCO Electric
2023 O&M forecast	Bottom-up approach. Detailed estimate of FTEs, contractors, and other general operating costs. Forecasts were compared with historical actual spending escalated for inflation and growth factor.	Hybrid. The majority of costs forecast mechanistically (2018-2020 O&M adjusted for inflation and growth factors), with a bottom-up approach used for other costs, such as for vegetation management, IT costs, and incremental A&G costs (among others).
2023 Capital additions forecast	Hybrid. Majority based on a bottom-up approach, although in many cases FortisAlberta embedded some form of mechanistic forecast: Unit cost (avg of 2018-2020 adjusted for inflation) * number of units.	Hybrid. Some cost items forecast mechanistically, such as externally driven system modifications, environment, safety and reliability, metering, and pole replacement. Other cost items forecast based on a bottom-up approach, such as for customer growth, forestry protection, overhead line rebuilds, and grid modernization.

2.2 MAIN FEATURES OF AUC'S 2ND GENERATION PBR PLANS EXTENDED TO 3RD GENERATION PBR

Following its decision to proceed with the third generation PBR (PBR3) regulatory regime for the distribution utilities, the AUC issued Bulletin 2022-06 and invited parties to comment on the proceeding's scope. Following submissions from various parties, the AUC issued a final issues list identifying the scope of the proceeding. Based on the finalized issues list, the scope of the third generation PBR proceeding was mainly limited to the following items: (i) annual PBR rate adjustments; (ii) price cap and revenue-per-customer cap; (iii) I-factor; (iv) X-factor; (v) capital funding provisions; (vi) consideration of introducing an ESM and the need for an ECM; and (vii) quantification and tracking of efficiencies.

The AUC further determined that the rest of the second generation PBR plan (PBR2) parameters would be out of scope for the 2024-2028 PBR proceeding (unless a change in the above-mentioned items requires a change in out-of-scope items such as was the case for the re-opener mechanism). The table below provides a summary of the second generation PBR plans' parameters that were excluded from re-examination in the third generation PBR proceeding as well as items that were reviewed as part of the scope for the third generation PBR but remained unchanged.

Table 3: The Elements of the 2018-2022 PBR Plans Extended to 3rd Generation PBR Plans

Item	Alberta Electric Utilities	Alberta Natural Gas Utilities
Term	5 years	
Type	Price cap	Revenue per customer cap
Formula	Rates $_t$ = Rates $_{t-1}$ * (1 + I – X)	Revenue per customer $_t$ = Revenue per customer $_{t-1}$ * (1 + I – X)
Annual rate adjustments	Distribution rate changes to be reflected on customer bills on January 1 of each year	
Y-factor	Foreseeable and outside management control	
Z-factor	Unforeseen, outside management control, materiality threshold: dollar value of a 40 bps change in ROE on an after tax basis	
SQI	Reporting requirements under Rule No.2. No automatic penalties	

As indicated, the plan term, formula types, the Z and Y factor treatments, as well as the service quality indicators (SQIs), were items from the second generation PBR that were carried forward to be applied in the third generation PBR plans. In the following section each of these elements is briefly discussed.

Term

The five-year term is maintained. The third generation PBR plans will be in place for the 2024 to 2028 period.

PBR Formula

As stated above, in the PBR3 proceeding, the AUC explored whether the circumstances that led to the adoption of two different types of PBR plans for gas and electric distribution utilities continue to apply or whether all distribution utilities can be regulated under the same type of PBR plan. However, none of the parties advocated for a change from the existing plans and therefore the

AUC ultimately determined to continue to employ a price cap for electric distribution utilities (ATCO Electric, ENMAX, EPCOR and FortisAlberta) and a revenue-per-customer cap for natural gas distribution utilities (AltaGas and ATCO Gas).

Under a revenue-per-customer plan, the approved revenue-per-customer from the previous year is escalated by the PBR formula on a class-by-class basis to arrive at the upcoming year's revenue-per-customer cap. Rates for each rate class are then derived by dividing the upcoming year's revenue-per-customer by the forecast consumption per customer. In contrast, under a price cap plan, approved rates from the previous year are escalated by the PBR formula to arrive at the upcoming year's rates.

Annual Rate Adjustment

As indicated above, the AUC determined that the timing of the annual rate adjustment is within the scope for the PBR3 proceeding. The AUC explored the possibility of implementing the annual PBR rate adjustments on July 1 of each year (rather than January 1 of each year) as a way to address concerns with rate changes taking place at a time of year when customers may already face increased utility costs and other expenses. None of the parties supported this proposed change and therefore the AUC determined that dates for associated PBR rate filings will remain the same as in the previous PBR2 plan.

Z-Factor Treatment

The Z-factor is associated with unforeseen events outside the control of the company, for which the company has no other reasonable opportunity to recover the costs within the PBR formula. The following five criteria approved in Decision 2012-237, all of which must be satisfied, will continue to be adopted by the AUC in determining eligibility for Z-Factor treatment:

1. The impact must be attributable to some event outside management's control;
2. The impact of the event must be material. The materiality threshold is set as the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established;
3. The impact of the event should not have a significant influence on the inflation factor in the PBR formulas;
4. All costs claimed as an exogenous adjustment must be prudently incurred; and
5. The impact of the event must be unforeseen.

Y-Factor Treatment

In contrast to the Z-factor, a Y-factor is applied to the costs that arise in the normal course of business, but that the company has no control over. A materiality threshold similar to the one approved for the Z-factor mechanism is applied to Y-factor treatment.

In addition to the Y-factor criteria, the AUC will allow the distribution utilities to recover as Y-factor rate adjustments, specific costs incurred at the direction of the AUC and flow-through costs that have been approved for continued flow-through treatment under the distribution utilities' PBR plans. The following types of costs were determined to satisfy the Y-factor criteria: AESO[2] flow-through items, farm transmission costs, accounts that are a result of AUC directions, income tax impacts other than tax rate changes, municipal fees, load balancing deferral accounts, production abandonment costs, and the weather deferral account.

Service Quality Indicators (SQIs)

With respect to service quality indicators for PBR, the AUC decided to continue to use AUC Rule 002, which sets out quarterly and annual service quality reporting requirements for electric and gas distributors. The AUC will continue to rely on the legislative provisions to address enforcement issues should service quality degrade.

2.3 INFLATION FACTOR

The inflation factor in PBR2 was in the form of a composite inflation factor comprised of labour and non-labour components and was calculated based on historic actual changes rather than forecasts. The Alberta Average Weekly Earnings (Alberta AWE) was used as the labour inflation index and Alberta's Consumer Price Index as the non-labour inflation index (Alberta CPI). The weighting of the factors approved in Decision 2012-237 continued to be applied in the PBR2 plans (55 percent Alberta AWE and 45 percent Alberta CPI).

Utilities in the PBR3 proceeding raised concerns that the inflation factor may not have accurately captured the inflationary pressures they experienced during the PBR term. Therefore, in the resulting Decision 26356-D01-2021, the AUC indicated it would consider evidence on whether modifications were necessary to the inflation factor. After reviewing the utilities' and interveners' submissions, the AUC decided to make the following changes to the inflation factor.

2.3.1 Changes to the Composite Inflation Factor

In the PBR3 proceeding, parties generally agreed that a composite inflation factor, consisting of labour and non-labour inflation factors, continued to be appropriate. However, parties proposed, among other things, modifications to the weightings between labour and non-labour inflation factors and a different labour inflation index. The AUC determined that the new composite inflation factor should be calculated as follows:

$$\boldsymbol{I_t = 60\%\ x\ FWI_t + 40\%\ x\ CPI_t}$$

where:

[2] Alberta Electric System Operator.

I_t Inflation factor for the year.

FWI_t Alberta fixed weighted AHE index for the January to December period.

CPI_t Alberta consumer price index for the January to December period.

The continued use of the Alberta CPI for tracking the price changes of non-labour inputs was generally not contested. As a result, there has been no change to the Alberta CPI that is used to track the changes in non-labour input prices. The main modifications relate to using a new labour inflation index (from Alberta AWE to Alberta FWI) and a change in labour and non-labour weightings. These are further discussed below.

2.3.1.1 Labour Input Price Index

In the PBR3 proceeding, ATCO Gas, ATCO Electric, FortisAlberta, and Apex proposed to replace the existing labour inflation index (Alberta AWE) with Alberta FWI.

The fixed weighted AHE is defined as the fixed weighted index of average hourly earnings for all employees. ATCO and Apex argued that FWI performs better in tracking utilities' actual labour-related inflation and is not influenced by changes in the mix of occupations or changes in hours worked per week. Further, FortisAlberta commented that FWI excludes overtime which can reduce volatility and avoid skewing the assessment of underlying wage trends. Interveners also agreed that replacing AWE with FWI is appropriate. Considering this general consensus, the AUC approved the utilities' proposal to use the Alberta FWI to track the changes in labour-related prices.

2.3.1.2 Weighting of the Inflation Factor Components.

The weighting for labour and non-labour components of the composite inflation factor was another issue that was explored in the PBR3. The following table provides the Alberta utilities' labour and non-labour weightings, assuming that the contractor costs are classified as labour[3] and calculated over the preceding four- or five-year period and prior to adjustment for labour in CPI.

Table 4: Weightings of Labour to Non-Labour I-Factor Indexes Using Consistent Assumptions

	ENMAX	ATCO Electric	ATCO Gas	Fortis	EPCOR	Apex
Time period	2018-2022	2018-2021	2018-2021	2018-2022	2018-2021	2018-2021
Index weights (labour/non-labour)	57:43	63:37	68:32	67:33	55:45	72:28

[3] The AUC accepted that utilities' contractor costs relate mostly to labour and move in line with the labour costs escalation.

Based on the above table, and applying its informed judgement, the AUC determined that a 60:40 ratio for labour to non-labour components, fixed for the PBR term was appropriate:[4]

> Using consistent assumptions on the time period of four to five years and classification of contractor costs as labour, as summarized in Table 3 above, the historical cost ratios are approximately 64 per cent labour and 36 per cent non-labour across all six distribution utilities. As observed in Decision 2012-237,95 the CPI includes some embedded labour costs. In addition, there are some non-labour expenses in contractor costs. Therefore, to address the potential for over-weighting labour costs, the Commission adjusts this historical ratio to 60:40 for labour to non-labour components …
>
> Finally, the Commission agrees with the distribution utilities that the approved I factor weightings will remain the same throughout the PBR3 plan. As explained in Decision 2012-237, this will ensure that the distribution utilities' incentives will not be influenced by the relative rates of inflation between the components in the I factor.

2.3.2 Historical Data vs Forecast with True-Up

In the PBR1 and PBR2 plans, the inflation factor was calculated using a "lagged approach", where the actual inflation for the most recent 12-month period was used to calculate the inflation factor for the upcoming year, with no subsequent true-up.

In their evidence, some utilities noted that because inflation was consistently rising throughout the PBR2 term, the effect of the lags did not average out. Therefore, using the lagged approach in determining the inflation factor was one of the main contributors of it not accurately tracking against actual inflation experienced by the utilities. The AUC agreed with the utilities that because the inflation environment has become more uncertain in recent years, it may no longer be reasonable to presume that inflation would average out over the PBR3 term. Thus, the AUC agreed that the forecast and true-up approach should be used in PBR3 to more closely reflect ongoing economic conditions and corresponding changes in input prices.

2.4 X-FACTOR DETERMINATION

In the 2012 PBR decision, the AUC used the services of NERA (Dr. Makholm) for TFP analysis. For the third generation PBR, the AUC asked Dr. Makholm of NERA to update its previous study. In addition, both utilities (Dr. Meitzen and Mr. Crowley) and interveners (Dr. Lowry of PEG) conducted separate TFP studies. A summary of the TFP growth numbers from these experts are provided in the table below.

[4] AUC Decision 27388-D01-2023, page 23.

Table 5: TFP Study Findings in AUC's 3rd Generation PBR Proceedings

Study	Output measure	Data period	Number of firms	TFP growth calculation (final)
NERA 2023	Volume	1972-2021	65	0%
Lowry 2023	Number of customers Number of customers + Volume	2006-2021	88	+0.08% -0.51%
Meitzen/Crowly 2023	Volume Number of customers + Volume	2007-2021	65	-1.08% -0.28%

As shown in the table above, the productivity growth numbers computed by the experts in the AUC's PBR3 proceeding that were considered in the AUC decision[5], range from -1.08 percent to +0.08 percent.

The TFP results were sensitive, among other things, to the choice of the output measure. Dr. Makholm and Dr. Meitzen initially relied on volume (MWh) as the output measure while Dr. Lowry relied on the number of customers. Nevertheless, consistent with its 2016 decision, the AUC considered that a composite output measure was a more reasonable assumption and requested that the experts also compute their studies based on a 50:50 weighting of customers and volumes composite output measure:[6]

> In Decision 20414-D01-2016 (Errata), the Commission accepted that because distribution utilities collect revenue based on both fixed and variable charges, both volume and number of customers are valid output measures. The Commission indicated that a useful way to proceed in future TFP growth studies might be to use some combination of the output measures and, as a starting point, to examine the sensitivity of the TFP growth results to different combinations of output measures … This sensitivity analysis clearly demonstrated that assigning more weight to a volumetric output measure of KWh sold results in a smaller TFP growth number and assigning more weight to the number of customers output measure results in a larger TFP growth number.
>
> Given that is it very unlikely that the majority of the utilities in PEG's and Dr. Meitzen's studies obtain their revenue entirely from either volumetric or fixed charges, the Commission considers that a composite output measure reflecting a 50:50 weighting of customers and volumes to be a more reasonable assumption

5 Dr. Lowry's study included sub-sample studies that were not considered in the AUC's decision.
6 AUC Decision 27388-D01-2023, pp.37-38, paras 138-140.

> for the purposes of this decision as compared to relying entirely on either of those measures. In future PBR proceedings, the Commission will consider evidence on more precise output weightings that are feasible, practical, reasonable and do not result in significant regulatory burden.

Referring to the wide range of TFP numbers produced by experts in the proceeding, the AUC re-iterated its findings in the PBR2 decision that, there is not one correct TFP growth number and that its decision should be informed by a range of TFP numbers:[7]

> Again, as stated in Decision 20414-D01-2016 (Errata), the TFP growth value is likely not a correct single number. Rather, it is a reasonable value that falls within a range of values, depending on the assumptions made and the data sets used in producing the studies. It is not an exact science because many assumptions used in the studies "reflect the practitioner's decisions and beliefs based on the available choices that can be applied to the data, and there is generally no test presented in evidence that can be applied to determine which assumptions are more applicable to particular data or the purposes for which it is used.

Ultimately, based on the evidence and considering all the variability caused by different assumptions applied to the TFP studies, the AUC used its judgement to set an X-Factor of +0.1 percent, inclusive of any stretch factor, for both electric and natural gas utilities. However, the AUC also used its judgement to approve an "X-Factor premium" of 0.3 percent to increase the X-Factor to 0.4 percent. As acknowledged by the AUC, for all practical purposes, the X-Factor premium functions as an additional stretch factor. The only distinction is that the X-Factor premium of 0.3 percent is not applied to the K-bar calculation used to calculate the need for incremental capital:[8]

> The Commission has carefully considered and weighed the evidence on the record with respect to industry TFP growth considerations and the expert testimony related thereto, the decisions of other regulators, and parties' proposals. The Commission has applied its specialized expertise, regulatory experience, and judgement to this evidence, and finds that an X factor of 0.1 per cent, inclusive of industry TFP growth and a stretch factor, is reasonable for the PBR3 term, prior to the inclusion of any benefit-sharing provisions. As further discussed in Section 9, the Commission approves an X factor premium of 0.3 per cent as one of two additional benefit-sharing provisions introduced in the PBR3 plan. With the exception of the calculation of K-bar, the total X factor to be used in PBR3 is 0.4 per cent, inclusive of the benefit-sharing premium. For K-bar calculation purposes, an X factor of 0.1 per cent must be used.

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[7] AUC Decision 27388-D01-2023, p.33, para 124.
[8] AUC Decision 27388-D01-2023, p.43, para 163.

2.5 INCREMENTAL CAPITAL FUNDING MECHANISM

The AUC's PBR2 decision recognized that there were certain circumstances where a utility may require capital funding in addition to the funding generated under the I-X formula, and established two capital funding mechanisms: Type I and Type II. In the PBR3 decision, the AUC re-confirmed the need for these two incremental capital funding programs and approved the continued use of the Type I (capital tracker) and Type II (K-bar) capital mechanisms, with some modifications to each.

2.5.1 Type I Capital (Capital Tracker Mechanism)

Type I capital deals with capital additions of an extraordinary nature. The AUC determined that the following extended eligibility criteria were appropriate for Type I capital:

- The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base;
- The project must be required by a third party, or otherwise directly caused by an applicable law related to net-zero objectives; and
- The project cost must have a material effect on the distribution utility.

The Type I capital tracker mechanism in the PBR3 plans must apply an expanded accounting test that compares the revenues provided under the I-X and K-bar to the revenue requirement after incorporation of proposed costs (first on a forecast and then on an actual basis) for projects requesting Type I funding. Any portion of the revenue requirement above the revenue under the I-X and K-bar would be funded through the Type I capital tracker, subject to meeting the Type I criteria and the materiality threshold. The AUC further found that a materiality of 10 basis points of the applicable distribution utility's ROE is reasonable for the Type I funding mechanism to be used in PBR3.

2.5.2 Type II Capital (K-bar)

At its core, the development of Type II capital involves the idea of providing each utility with a predetermined amount of incremental capital funding. The utilities then would be expected to manage their capital programs within the capital funding constraints of the Type II capital amounts provided. In the AUC's opinion, this approach would increase utilities' flexibility in managing their capital needs and reduce regulatory burden. As shown in the table below, the K-bar funding in PBR2 was imperative to the utilities' ability to earn their approved ROEs.

Table 6: Earned ROE Without K-bar Funding in PBR2

Utility	2018	2019	2020	2021	2022F	PBR2 average
	(%)					
Fortis	4.41	4.89	4.87	1.50	0.44	3.22
ENMAX	4.51	6.18	6.21	3.67	2.14	4.54
ATCO Gas	8.04	7.59	7.09	6.46	8.83	7.60
ATCO Electric	7.74	9.53	7.63	8.36	6.78	8.01
EPCOR	7.86	7.45	6.64	4.50	2.09	5.71
Apex	3.66	4.89	2.30	2.30	0.88	2.81
Approved ROE	8.50	8.50	8.50	8.50	8.50	8.50

The accounting test that will determine the K-bar capital funding in PBR3 will be nearly identical to the accounting test that was used to determine the K-bar funding in PBR2, with the exception that the capital inputs will consist of a five-year average of actual capital additions from 2018-2022 and customer growth, discounted by 15 percent. These inputs will be used instead of the Q-Factor. Further, an X-Factor of 0.1 percent, not including the addition of the X-Factor premium, must be used in the K-bar accounting test. The 2024 base K-bar amount will be calculated as follows:

1. Using the 2023 going-in capital-related revenue requirement, calculate the amount of revenue requirement by program or project that is recovered in base rates under the I-X escalation mechanism for 2024.
2. Calculate the average K-bar capital additions, by program or project, in 2023 dollars for the 2018-2022 period. Inflate the average K-bar capital additions by project to 2024 dollars using the I-X index and the customer growth escalator approved for 2024.
3. Calculate the amount of K-bar capital for 2024, based on the capital additions from Step two above and the 2023 mid-year rate base using the method for calculating incurred capital costs from the capital tracker accounting test approved in Decision 2013-435. The distribution utilities should use a five-year average of inflation-adjusted retirements from 2018-2022 as an assumption in the accounting test.
4. Calculate the K-bar by subtracting the recovered capital revenue requirement (Step 1) from the notional revenue requirement.

2.5.3 Alternative Remuneration Schemes

In addition to the two incremental capital funding mechanisms, the AUC also determined that utilities may file applications to earn a return on operating solutions that can act as a viable alternative to capital expenditures, on a pilot basis. These include non-wire solutions that can reduce or delay the need for capital intensive projects. A utility must apply on a per-project basis and a proposal must relate to a scope of work that is not contemplated by an existing agreement and replaces a corresponding capital solution.

In considering the need to incentivize non-capital additions, or operating solutions, the starting point is that the utility's decision-making must be reasonable. Customers are required to pay only for efficient utility service and nothing more. In this regard, the AUC specified that IT service providers are moving towards cloud-based solutions, the cost of which may not be capitalized, and that these services are replacing traditional IT products that were previously eligible for capitalization. In such a case, the AUC considers that the utility does not require an incentive, as it would be unreasonable for it to procure more expensive, non-cloud-based IT products simply because the costs of these products could be capitalized.

2.6 EARNINGS SHARING MECHANISM (ESM) AND RE-OPENER MECHANISM

Alberta's first and second generation PBR plans did not have an ESM. As explained in Section 2.1.1, as part of the proceeding which evaluated the previous PBR's experience, the AUC agreed with the interveners that an ESM to allow customers to share in the benefits during the PBR term can improve achieving Principle 5. As part of the PBR3 decision, the AUC commented that it was prepared to accept a marginal loss of incentive power in favour of more equitable and timely sharing of benefits with customers and approved an asymmetric, two-tiered ESM.

Under the ESM, there is no sharing within a deadband of 200 basis points above the approved ROE. Above the deadband, there are two tiers of sharing. First, between 200 and 400 basis points above the approved ROE, the sharing ratio is 60 percent for distribution utilities and 40 percent for customers. Second, at earnings 400 basis points above the approved ROE or greater, the sharing ratio is 20 percent for distribution utilities and 80 percent for customers.

Additionally, given the structure of the ESM, the AUC found that it is no longer necessary to trigger the reopener review when an achieved ROE exceeds the approved ROE by 300 basis points in two consecutive years during the PBR3 term.

2.7 DISCONTINUATION OF THE EFFICIENCY CARRY-OVER MECHANISM (ECM)

The AUC's PBR1 and PBR2 plans included an ECM to address the weakening of incentives towards the end of the PBR term. In the PBR3 decision, the AUC explored whether the ECM achieved its intended purpose and whether it should be included in the PBR3 plan. The AUC concluded that the ECM is not a determining factor in a distribution utility's decision-making with respect to any cost-saving or efficiency initiatives that are being considered and therefore is not needed and should be discontinued in its current form. The AUC however emphasized that in the future, it may consider alternative remedies to enhance efficiencies at the end of the term, including alternative forms of ECM.

2.8 QUANTIFICATION AND TRACKING OF EFFICIENCIES

In order to track and quantify the achieved efficiencies during the PBR3 term, the AUC directed the utilities to track and report the following metrics:

(i) Controllable O&M per customer.

(ii) Controllable O&M per km of line (pipe).

(iii) Total cost per customer, broken out by Total O&M per customer and Total capital additions per customer separately.

(iv) Total cost per km of line (pipe), broken out by Total O&M per km of line (pipe) and Total capital additions per km of line (pipe) separately reported.

3. ONTARIO – INCENTIVE RATE-SETTING MECHANISM FOR ELECTRIC DISTRIBUTORS

3.1 BACKGROUND AND DEVELOPMENT

In 2012, the OEB established a framework for electricity distribution rate regulation titled "Renewed Regulatory Framework for Electricity (RRF) Distributors: A Performance-Based Approach" which articulates the OEB's goals for an outcomes-based approach to regulation which aligns the interests of customers and utilities. The RRF is intended to elevate utility performance by creating incentives for superior performance.

The OEB has developed a set of rate-setting options to ensure that utilities have sufficient flexibility to adopt a method that best meets their needs. The RRF established three incentive rate-setting methodologies for electricity distributors: Price Cap Incentive Rate-Setting (IR), Custom IR, and the Annual IR Index. Electricity distributors may choose from any of these three options. There are no eligibility criteria for any of these methods, but the rate application must meet the requirements of the rate-setting option. The OEB further commented on the appropriateness of these IR plans for electric distributors based on their specific circumstances.

Table 7 below provides a summary of major differences between each IR plan and their appropriateness for individual utilities depending on their specific circumstances.

Table 7: Incentive Rate-setting Under the OEB's Regulatory Framework for Electric Distributors

Item	Price Cap IR	Custom IR	Annual IR Index
Most appropriate for	Utilities that anticipate some incremental investment needs during the plan term	Utilities with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures	Utilities with relatively steady investment needs (primarily sustainment)
Going-in rates	Single forward test year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by (I-X) index
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years	No fixed term
Incremental capital	Available under ICM and ACM	Not available (although a number of exceptions exist)	Not available

Under the Custom IR methodology, rates are set for a minimum of five years. The Custom IR methodology is intended to fit the specific utility's circumstances. Under the Annual IR Index methodology, rates are subject to the same annual adjustment formula as those under Price Cap

IR. Utilities under the Annual IR Index methodology are not required to set base rates periodically using a cost of service process, but they are required to apply the highest stretch factor. Finally, under the Price Cap IR methodology, base rates are set through a cost of service process for the first year and the rates for the following four years are adjusted using a formula. Unlike the other two rate options, utilities under the Price Cap IR methodology can apply for incremental capital funding during the IR period, subject to meeting the eligibility criteria.

All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates under the Price Cap or a Custom IR application. Distributors using the Annual IR Index methodology must make a DSP filing within five years of the date of the most recent cost of service proceeding, and are required to do so at five-year intervals thereafter. A DSP consolidates documentation of a distributor's asset management process and capital expenditure plan. The capital expenditure plan provides a snapshot of a distributor's capital expenditures over a 10-year period (5 year historical and 5 year forecast).

In the following sections the distinctive features of Custom IR and Price Cap IR plans are discussed in more detail.

3.2 MAIN FEATURES OF PRICE CAP IR UNDER OEB'S RRF

3.2.1 Price Cap Formula

Under the OEB's Price Cap IR methodology, the allowed rate of change in the price of regulated services is adjusted by the growth in an inflation factor minus an X-Factor.

The X-Factor value may change from year to year depending on the OEB's annual total cost benchmarking results. The benchmarking evaluation in each year will place each electric distributor into an efficiency cohort based on its relative efficiency compared to other electric distributors in Ontario where each cohort is given a specific stretch factor.[9] The following section provides more information regarding the I-Factor in the OEB's price cap formula.

3.2.1.1 Inflation Factor

Under the RRF, the OEB concluded that it is appropriate to adopt a more industry specific inflation factor. The percent of change in composite inflation index is calculated as the weighted sum of 70 percent of the annual percentage change in the GDP-IPI FDD and 30 percent of the annual percentage change in the AWE for the prior year relative to the data for two years prior.

As a result of the inflationary pressures faced by utilities after the COVID-19 pandemic, in August 2021, the OEB initiated a generic proceeding to evaluate if the above-mentioned composite

[9] Currently five efficiency cohorts are used with 0.00%, 0.15%, 0.3%, 0.45% and 0.6% stretch factor values (sorted from the most efficient to the least efficient).

inflation factor is still appropriate. Specifically, OEB observed that the labour inflation component of the inflation factor increased by about 7 percent from 2019 to 2020 and, therefore, caused a significant increase in the total inflation factor used to set rates for utilities. As part of the scope of this proceeding, the OEB identified the following labour inflation factors that could be used for computing the composite inflation factor:

a. Average Weekly Earnings (Ontario, all businesses, Salaried employees, including overtime);
b. Average Hourly Earnings (Ontario, all businesses, Salaried employees, including overtime);
c. Average Hourly Earnings (Ontario, all businesses, Hourly wage employees, including overtime); and
d. Average Hourly Earnings (Ontario, all businesses, fixed weight, excluding overtime).

After reviewing the evidence and considering the limited scope of the proceeding, the OEB concluded that the existing formula and inflation indices should continue to apply to the annual rate adjustments:[10]

> Alternatives to Option 1 were raised in this proceeding to address the unforeseen impact COVID-19 had on AWE which is one component of the 2-factor IPI formula. While Statistics Canada data and analysis indicated that COVID-19 and mandatory government ordered lockdowns caused structural changes to the composition of the employed labour market, it was but one of the factors that lead to an increase in AWE.
>
> Given the ongoing uncertainty regarding forecast inflation in 2022, the OEB has decided to use the indices identified in the Report. Although a panel is not bound by policy, the OEB finds no compelling reason to depart from the policy in the Report in the absence of a comprehensive review of the complete framework, which was beyond the scope of this proceeding.

3.2.1.2 X-Factor

The OEB's X-Factor for electric distributors working under the price cap and annual IR indexing is set annually based on an industry TFP of zero percent plus a variable stretch factor between zero to 0.6 percent. The most efficient distributors, based on the cost evaluation ranking, would be assigned the lowest stretch factor of 0.0 percent. Distributors filing an Annual IR Index application will be assigned the highest stretch factor of 0.6 percent.

[10] OEB Decision EB-2021-0212 (November 2021), page 14.

3.2.2 Z-Factor Treatment

Z-Factor treatment of unforeseen events is available to distributors in all three rate-setting options. Under this framework, a materiality threshold based on the distributor's revenue requirement is set to provide the distributors with guidance as to whether or not they should be applying to the OEB for relief from a Z-Factor event. The materiality threshold is differentiated based on the relative magnitude of the revenue requirement. Specifically, the materiality threshold is presented in Table 8 below:

Table 8: Z-Factor Materiality Threshold Relative to the Size of Distributor's Required Revenue

Size of Revenue Requirement	Materiality Threshold
Less than or equal to $10 million	$50 thousand
Greater than $10 million and less than or equal to $200 million	0.5% of distribution revenue requirement
More than $200 million	$1 million

3.2.3 Y-Factor Treatment

All three options include some deferral and variance accounts that are treated outside the incentive formula with some minor differences. These include both commodity and non-commodity related deferral accounts.

3.2.4 Safeguard Mechanisms (Off-ramps/ Reopeners)

The OEB's RRF does not include an earnings sharing mechanism. The OEB however recognized that some form of protection against potential unintended consequences of IR plans is required and concluded to incorporate an off-ramp mechanism in all three rate-setting options.

Under the regulatory framework, each rate-setting option will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated. In addition to the mentioned trigger mechanism a utility may request an early termination and seek to have its rates rebased if it can convince the OEB that early rebasing is necessary.

3.2.5 Incremental Capital Mechanisms for Price Cap IR

Utilities operating under the Price Cap IR methodology may apply for and receive additional capital funding outside the formula using the Advanced Capital Module (ACM) and/or Incremental Capital Module (ICM) mechanisms. This is a major distinguishing feature of Price Cap IRs compared to the other two IR options, neither of which includes a mechanism for incremental capital spending allowances.

The main difference between the ACM and ICM relates to the issue of timing. Under the ACM approach, the need for incremental capital funding is identified at the time of cost of service filings (as part of the DSP filings). At that time, the need for and prudence of any such requests will be determined. Consequently, largely mathematical calculations of ACM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years. The ACM approach was developed to increase regulatory efficiency during the Price Cap IR term and to provide a distributor with the opportunity to smooth out its capital program over the five-year period between cost of service applications. On the other hand, the ICM requests are limited to those projects that were not foreseen or sufficiently planned as part of the DSP.

A summary of the OEB's capital module policy for both ACM and ICM mechanisms is provided in the table below.

Table 9: OEB's Capital Module Policy Under Price Cap IR Plans[11]

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the OEB may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Both ICM and ACM projects must satisfy the eligibility criteria of materiality, need and prudence as set out in the table below.

[11] EB-2014-0219 (Sep 2014); "Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module", Appendix A.

Table 10: Eligibility Criteria for ICM/ACM Mechanisms

Criteria	Description
Materiality	A capital budget must be deemed to be material, and reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the distributor; otherwise, they should be dealt with at rebasing.
Need	The distributor must pass the Means Test. Amounts must be based on discrete projects and should be related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	The distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

On January 22, 2016, the OEB issued the Report of the OEB on New Policy Options for the Funding of Capital Investments: Supplemental Report (Supplemental Report).[12] This report made changes to the materiality threshold on which the ACM and ICM proposals are assessed, but otherwise does not alter the requirements for ACM and ICM proposals.

3.2.6 Service Quality Indicators

The RRF includes a comprehensive set of performance outcomes and uses a scorecard approach to effectively organize performance information in a manner that facilitates evaluations and meaningful comparisons. The scorecard design includes four performance areas as presented in Table 11 below.

Table 11: Performance Areas in Electricity Distributor Scorecard[13]

Performance Area	Description	Measures
Customer focus	Services are provided according to identified customer preferences	Includes indicators such as First contact resolution (FCR), Calls answered on time, Appointments met on time, Billing accuracy, Customer satisfaction surveys
Operational effectiveness	Continuous improvement in productivity and cost performance is achieved; utilities deliver on system reliability and quality objectives	Includes safety (serious incident index, level of compliance with safety regulation, Level of public awareness), system reliability (SAIFI, SAIDI), asset management (DSP implementation progress) and cost control (cost per km of line and per customer) metrics
Public policy responsiveness	Utilities deliver on obligations mandated by government	Conservation and demand management as well as connection of renewable generation metrics

[12] EB-2014-0219 (January 2016), New Policy Options for the Funding of Capital Investments: Supplemental Report.
[13] OEB Report (March 2014), EB-2010-0379.

Performance Area	Description	Measures
Financial performance	Financial viability is maintained; savings from operational effectiveness are sustainable	Financial ratios related to utilities' liquidity (current ratio), leverage (total debt to equity ratio) and profitability

3.3 MAIN FEATURES OF CUSTOM IR UNDER OEB'S RRF

The Handbook for Utility Rate Applications provides specific considerations that are required for a Custom IR plan. A Custom IR plan is customized for the specific circumstances of individual utilities and not subject to a common model.

The OEB's utility rate handbook explains that a Custom IR plan is not analogous to a multi-year cost of service plan and that any Custom IR plan requires explicit incentives for efficiency improvements and cost reduction:[14]

> Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast). The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.

The OEB will use external and internal benchmarking to assess the reasonableness of the applicant's forecasts. The external benchmarking will analyse year-over-year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group.

Although the Custom IR option was part of the RRF for electric distributors, the Enbridge Gas Distribution (EGD) 2014-2018 Custom IR was the first Custom IR approved by the OEB. After EGD's proceeding, a number of major electric distributors including Hydro Ottawa, Toronto Hydro and Hydro One applied for approval of a Custom IR. A common theme amongst all of the Custom IR plans is that capital expenditures are forecast, although in some cases the forecast was then used to derive a custom index as stated in the excerpt above. In the following sections, Hydro One's Custom IR is briefly discussed.

[14] OEB's Handbook for Utility Rate Applications, pp. 25-26.

3.3.1 Hydro One Custom IR

The OEB's decision EB-2021-0110 released in November of 2022 approved a Custom IR plan for Hydro One's 2023-2027 revenue requirement. In its decision, the OEB explained that "with a combined proposed revenue requirement of approximately $20 billion and a proposed investment plan of about $13 billion over the 2023-2027 rate period, this is the largest and most complicated rate case to come before the OEB".[15] Nevertheless, parties to the proceeding were able to achieve a complete settlement for this Custom IR plan.

Hydro One's approved framework consists of rebasing its revenue requirement for 2023 on a cost of service basis, followed by annual adjustments of the revenue requirement for 2024 and 2027 using a custom revenue cap model, which includes a capital adjustment factor (Capital factor or C-Factor). Hydro One's plan also includes an earning sharing mechanism, which will share any earnings above the 100 basis points on a 50:50 basis. The plan's Z-Factor and off ramp provisions are similar to the OEB approved framework for its conventional price cap formula. The plan also included several deferral accounts. In the following section, the custom revenue cap formula is defined in more detail.

3.3.1.1 Custom Revenue Cap formula

The approved custom revenue cap formula consists of the following components:

$$RR_t = RR_{t-1} * (1 + I_t - X + C_t),$$

where:

- I is a composite inflation factor consisting of Canada GDP-IPI and Ontario AWE.
- X is the expected productivity factor fixed for the duration of the plan fixed at 0.45 percent.
- C is the capital factor adjustment, designed to recover incremental revenue in each test year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X adjustment, but reduced by a supplemental stretch factor on capital of 0.2 percent.

The purpose of the C-Factor is to ensure that the total revenue resulting from the Custom IR approach is appropriate for Hydro One's specific circumstances and will support the necessary capital investments, while also ensuring that appropriate incentives are in place with up front benefits to ratepayers.

The capital factor is calculated as the percentage change in the total revenue requirement attributable to new capital investment that is not otherwise recovered from customers through the

[15] EB-2021-0110 (November 2022), page 1.

I – X adjustment. It includes depreciation, return on equity, interest and taxes attributable to new capital investments placed in-service each year of the Custom IR term.

4. ONTARIO – ENBRIDGE GAS DISTRIBUTION INCENTIVE RATE-SETTING PLAN

4.1 BACKGROUND AND DEVELOPMENT

Enbridge Gas Distribution's (EGD) last multi-year rate plan expired on December 31, 2023. As a result, EGD applied for approval of its cost-of-service rebasing application for 2024 rates (the first rebasing application since the amalgamation of EGD and Union Gas) as well as approval of an incentive rate-making mechanism (IRM) for the 2025 to 2028 period.

The OEB divided the review of the application into two phases:

- **Phase 1:** was directed at setting interim 2024 rates and rebasing using a cost-of-service forward test year approach. This phase was concluded through a partial negotiated settlement and subsequent decision by the OEB on the items that were not part of the settlement agreement.
- **Phase 2:** will review EGD's proposed IRM for the 2025 to 2028 period. Phase 2 is still ongoing. Therefore, this section compares EGD's OEB-approved 2019-2023 IRM with EGD's proposals in this most recent application. As shown in the table below, EGD's IRM proposal is largely consistent with the IRM previously approved by the OEB and in place over the 2019 to 2023 period.

Table 12: EGD's Proposed IRM vs 2020-2023 Approved IRM

	2020-2023 Approved IRM	Proposed IRM
Rebasing	Cost of service forecast	No change
Term	5 years (first year is the cost of service rebasing)	No change
Type	Price Cap (Implied Revenue Cap)	No change
Formula	$Rates_t = Rates_{t-1} * (1 + I – X) + AU$ AU: Average Use adjustment	No change
Inflation	GDP IPI FDD[16]	0.75 GDP IPI FDD + 0.25 AHE
X-Factor	0.3%	-1.35%
ESM	If normalized actual ROE is 150 bps above allowed ROE; excess earnings are shared on a 50/50 basis	No change. No sharing in the first year (2024)
Off-ramps	+/- 300 bps normalized ROE for one year	No change
Incremental Capital Funding	Incremental capital module (ICM) similar to the one applied to Ontario's electric utilities	No change

[16] Gross Domestic Product Implicit Price Index Final Domestic Demand.

	2020-2023 Approved IRM	Proposed IRM
Z-Factor	Unforeseen events, outside management control, materiality threshold: $5.5 revenue requirement impact	No change
Y-Factor	Includes items such as cost of gas, DSM expenses, Tax variances, and LRAM	No change
SQIs	Scorecard system	No change

The only two major differences relate to the inflation factor, where EGD is proposing to move to a composite inflation factor consisting of labour and non-labour input price indices similar to the approach applied by regulators in other jurisdictions, as well as the proposed negative X-Factor calculated based on the productivity study prepared by EGD's expert, Dr. Kaufmann. The productivity study was conducted using a sample of US natural gas distribution utilities.

5. ENERGIR INCENTIVE RATE-SETTING PLAN

5.1 BACKGROUND AND DEVELOPMENT

Energir's last cost of service revenue requirement application was filed in the 2018-2019 fiscal year. The subsequent rate application (2020-2022 rate application) was explicitly designed to reduce Energir's regulatory burden so that it can focus its resources on other strategic initiatives such as its Renewable Natural Gas program. Per the Regie's decision in Energir's 2020-2022 rate application, the main pillars of this rate setting plan are as follows:

- An O&M formula to facilitate the approval of O&M expenses.
- A five-year capital investment forecast with approval of recurring individual investments below a certain dollar threshold without the need for detailed application.
- Revenue decoupling to mitigate the volume risk.
- An asymmetric earnings sharing mechanism.
- Service quality indicators.

In its 2023-2025 rate application, Energir confirmed that the regulatory relief provided in its 2020-2022 MRP allowed the company to focus on its strategic initiatives and asked for an extension of the MRP with certain modifications. The following sections provide more details regarding this extended plan.

5.2 MAIN FEATURES OF ENERGIR'S MRP

5.2.1 Plan's Term

Energir's custom MRP was extended for a three-year period (2022-2023 to 2024-2025 fiscal years).

5.2.2 MRP Type and Formula

Similar to FEI's and FBC's Current MRP, Energir's MRP can be defined as a hybrid revenue cap. The indexing formula is applied directly to the O&M expenses and capital investments are forecast.

The following formula was approved for Energir's O&M formula:

$$OPEX_{t+1} = OPEX_t * (1 + I_t + 0.75*G_t)$$

Where

OPEX = O&M expenditures
I = Composite Inflation Factor

G = Growth Factor

5.2.2.1 Inflation Factor (I-Factor)

The composite inflation factor is comprised of both labour and non-labour inflation indices with Quebec's Average Weekly Earnings (AWE) selected as the labour related inflation factor and Quebec CPI as the non-labour related price index.

The Regie further determined that the labour inflation factor (Quebec's AWE) should be based on a three-year average of historical data. In the Regie's opinion, this approach will mitigate the related volatilities and is more in line with the actual labour inflation pressures faced by the utility as the labour cost pressures caused by collective bargaining processes with unions and contract renewals with outsourcing contractors are fixed for a number of years. As for the non-labour component, the preceding year actual Quebec-CPI is used.

In its 2023-2025 rate application, and in response to the AWE index volatility experienced during the COVID-19 pandemic, Energir proposed, and the Regie approved, a cap on labour inflation used in the formula (AWE) at 4 percent, without modifying the data source. Since labour inflation makes 75 percent of the composite inflation factor, the labour inflation is effectively capped at 3 percent. The weighting for labour and non-labour inflation factors will remain fixed over the term of the PBR plan.

5.2.2.2 X-Factor Determination

Energir's proposed O&M indexing formula did not include any X-Factor. However, Energir noted that the 0.75 discount factor to the Growth factor implicitly acts as a X-Factor. In this regard, Energir further pointed to Dr. Lowry's evidence that the discount factor to the growth factor in the formula should lead to a smaller X-Factor.

In its final decision, the Regie rejected interveners' call for application of a productivity factor and agreed with Energir that the proposed O&M formula without the X-Factor provides the same efficiency incentives as the one with an X-Factor:[17]

> Regie is also of the opinion that the use of such a formula contributes to regulatory relief, which is appropriate in the current and medium-term context, when several important files are being examined.

[17] D-2019-028, R-4076-2018 Phase 1, Pages 11-12. The exact text in French as follows:
"Elle est également d'avis que l'utilisation d'une telle formule contribue à l'allégement réglementaire, ce qui est approprié dans le contexte actuel et à moyen terme, alors que plusieurs dossiers d'importance sont en cours d'examen par la Régie. De plus, considérant que la formule paramétrique proposée est alignée sur les efforts de productivité exigés des autres utilités gazières canadiennes, la Régie ne retient pas la recommandation de la FCEI d'ajouter un facteur de productivité à la formule de fixation des dépenses d'exploitation autorisée par la présente décision."

> Furthermore, considering that the proposed parametric formula is aligned with the productivity efforts required of other Canadian gas utilities, the Régie does not accept the CFIB's recommendation to add a productivity factor to the formula for setting operating expenses.

5.2.2.3 Growth Factor

As mentioned earlier, the O&M indexing formula approved by the Regie for Energir's MRP includes a growth factor to account for the growth in costs caused by increased demand or growth in the utility's operating scale. Based on submissions from the distributors and interveners, it was determined that the growth in number of customers is a principal cost driver for Energir's costs and therefore was selected as the appropriate measure for a growth factor in the O&M formula.

Further, it was determined that a 0.75 discount factor should be applied to the growth factor to account for the fixed costs that may not change in the short or medium term with the growth in number of customers. This means that a 1 percent increase in the number of customers will lead to a 0.75 percent increase in the utility's O&M expenditure under the formula.

5.2.3 Earnings Sharing Mechanism (ESM)

In the Regie's opinion, an ESM can mitigate some of the risks attributed to an MRP (such as the risk of excessive earnings caused by significant variances between the revenue generated by the formula and the actual costs). Additionally, the inclusion of an ESM in the plan is aligned with the objectives of the legislative requirement that the reduction in costs should be profitable for both customers and the utilities. Therefore, the Regie decided to include an ESM in Energir's MRP. The main features of this mechanism are as follows:

- An asymmetric ESM with all negative variances to the account of the utility.
- Any variance between the realized and approved ROE that is less than 50 bps will be shared at a 75:25 ratio in favour of the utility.
- Any variance between the realized and approved ROE exceeding 50 bps will be shared equally between ratepayers and utility.

5.2.4 Service Quality Indicators

Similar to the MRP/PBR plans in other jurisdictions, Energir's MRP includes a series of SQIs to ensure that any achieved cost reduction and productivity gain is not as a result of service quality degradation. However, unlike other jurisdictions, Energir's SQI performance and ability to achieve the set targets is directly linked to the ESM and Energir's ability to benefit from any over-earnings through a formula. All SQIs are given a weight and measured against their target and a threshold to measure the realized total SQI performance. If the total realized performance is below a certain percentage, Energir would not benefit from any over earnings.

Appendix B2-3

STAKEHOLDER COMMUNICATIONS

FortisBC 2025+ Rate Setting Framework – BCUC & Intervener Workshop

Monday November 20th, 2023 (9:00 am – 2:15 pm)
FortisBC Downtown Office, 1111 West Georgia, Vancouver BC

Workshop Purpose:

- Review FortisBC's operating context
- Recap the feedback heard to date
- Provide an overview of the key concepts and themes and how they reflect the feedback
- Record current feedback and ideas that have not yet been considered
- Provide an overview of the proposed Service Quality Indicators (SQIs)
- Seek input on the proposed SQIs

Meeting Attendees:

FortisBC Representatives
Doug Slater, Vice President, Indigenous Relations & Regulatory Affairs
Dawn Mehrer, Vice President, Corporate Services & Technology
Sarah Walsh, Director, Regulator Affairs
Brent Graham, Director, Government Relations & Public Policy
Vanessa Connolly, Director, Community & Indigenous Relations
Sarah Nelson, Director, Customer Service
James Wong, Director, Budgeting & Strategic Initiatives
Tyler Bryant, Director, Decarbonization and Sustainability
Colin Norman, Senior Project Manager, Regulatory Affairs
Andrew Doyle, Manager, Project Development
Brooklyne Maligaspe, Manager, Customer Experience & Business Performance
Carrie Grant, Regional Manager, Network Services
Derek Rinn, Regional Manager, Interior South
Janice Joly, Regulatory Governance Coordinator
Chi Le, Regulatory Governance Coordinator

<u>Intervener Representatives</u>
Jim Quail – MoveUP
David Craig – Commercial Energy Consumers (CEC) of BC
Michael Vaney - Residential Consumer Intervener Association (RCIA)
Robert Hobbs - Industrial Customers Group (ICG)
Elroy Switlishoff - Industrial Customers Group (ICG)
Scott Spencer - City of Nelson and BC Municipal Energy Utilities (BCMEU)
Draydan Power - City Penticton and BC Municipal Energy Utilities (BCMEU)

Note that **Bill Andrews** with the BC Sustainable Energy Association (BCSEA) attended for part of the day.

Note that **Leigha Worth** with the BC Public Interest Advocacy Centre (BCPIAC) was invited but sent her regrets just before the meeting started.

<u>BC Utilities Commission Representatives</u>
Bonnie Guzman, Senior Regulatory Analyst, Rates
Stefanie Chapman, Regulatory Analyst, Rates

<u>Note</u>: Feedback captured in this document are summary statements and not verbatim quotes. Unless otherwise stated, feedback listed represents comments from one or two participants at a time.

Workshop Discussion Summary

Discussion Topic	Discussion Summary
Welcome and Introductions	**Welcome and Introduction Summary** • Roundtable introductions of all workshop participants. • Colin Norman provided an overview of the workshop objectives, agenda, and rate plan application project timeline.
Operating Context	**Operating Context Introduction Summary (please see slides for more details)** • Colin Norman provided an overview of key influences that are becoming increasingly predominant in FortisBC's operating environment. **Feedback Summary** • Invest in heat batteries - it needs not be behind the meter. Simply an extension of the gas system.

	Energy Transition Summary (please see slides for more details) • Brent Graham provided an overview of how FortisBC's operating environment has continued to change with regards to policy action and mandates from all levels of government requiring FortisBC to evolve. **Feedback Summary** • RNG (renewable natural gas) should be viewed as a competitive new build option for any municipality. • Need future solutions instead of near-term solutions that worry about rate impact. • Ensure that FortisBC can support a complete low carbon system. • Try to land in a place where gas and electricity are integrated and facilitate low carbon solutions. Huge role that innovation plays with this. **Indigenous Relations & Reconciliation Summary (please see slides for more details)** • Vanessa Connolly provided an overview of how Indigenous relations and reconciliation continues to require enhanced engagement and relationships, capacity support, economic inclusion, and community investment. **Feedback Summary** • Acknowledgement that this has emerged as a much larger component for FortisBC than in the past. **Safe, Reliable and Resilient Service Summary (please see slides for more details)** • Andrew Doyle and Dawn Mehrer provided an overview of how aging infrastructure and new requirements around cybersecurity, regulations and climate adaptation are increasing the need to invest in the reliability, integrity, and security of FortisBC's systems to maintain safe, reliable, and resilient delivery of energy to customers. **Feedback Summary** • Consider earthquake risk in addition to the other operational and cyber risks highlighted.
Review of Key Concepts, Feedback to Date & Adapting the Framework to the Operating Context	**Review of Key Concepts, Feedback to Date & Adapting the Framework to the Operating Context Summary (please see slides for more details)** • Sarah Walsh provided an overview of the rate plan framework options considered, key framework items that will be in the application, a summary of the initial feedback received and how those themes are proposed to be addressed in this application, and the proposed draft outline of the overall rate framework.

	Feedback Summary • Assume cost savings that flow from losing attachments isn't symmetrical from gaining attachments. Amount that you save by losing customers is not the same as the cost you incur by attaching customers. If the utilities are starting to move in somewhat different directions, it might make it difficult to apply the same theme. • Current (formula) approach could cause problems in terms of property funding and O&M costs. • Do not see issue with having a joint application. • Get rid of processes that don't add value and focus on those that do add value. Spend more time in collaborative process before filing. That leaves us focusing on collaborative items we agree on, and then use the regulatory process as the adversarial process for what we want settled. • Consider adopting a Powerex type model to generate money for customers. • Climate change is highly inflationary. • Get the energy transition into all components of the plan and reconcile on differences between the last plan and now. • Consider linkage between SQIs and targets for CleanBC. • Have the depreciation study consider the potential reduction and efficiency of existing capital assuming a contraction of the (gas) customer base.
Service Quality Indicators (SQIs)	

SQIs Overview	**SQIs Overview Summary (please see slides for more details)**
	• Colin Norman provided some background on the FortisBC SQIs – how they originated, what evaluation criteria have been established for them, how they have evolved over time and an overview of what they look like now and what FortisBC is proposing for this next rate plan application.
	
	Feedback Summary
	• The SQIs should map the overall progress of the company.
	• Suggestion for four broad new SQI areas:
	  ○ energy transition;
	  ○ affordability;
	  ○ resiliency, and;
	  ○ effectiveness/efficiency.
	• Make sure the costs of the efficiencies are not borne by the customers.

Safety SQIs	**Safety SQIs Summary (please see slides for more details)** • Dawn Mehrer provided an overview of the proposed Safety SQIs.

	Feedback Summary • Good idea to explore possible leading indicators to establish a means of more effectively measuring overall Employee Safety. If this is established as an informational indicator then would want to see it explained in the application as to why.
Customer SQIs	**Customer SQIs Summary (please see slides for more details)** • Brooklyne Maligaspe provided an overview of the proposed Customer SQIs. **Feedback Summary** • Seeming consensus to consider what value there is in reporting meter reading completion effectiveness where AMI is in place. With implementation of Gas AMI eventually, the gas meter reading completion metric results will become very high, like what is observed for the electric utility meter reading completion results. The meter reading completion metric would be more of interest on the exceptions that may occur. • Opposition to lowering the threshold on TSF (non-emergency) from current 68% to 65%. ○ Suggestion put forward to solve this with an asterisk. Keep the same standards and put an asterisk that monthly it may vary. Reporting monthly results may be required. • Include a metric (or provide more information) for measuring how FortisBC does when the problem isn't resolved on first contact. • Performance has been very stable overall such that the SQI reporting and performance does not provide much insight as to where there may be performance exceptions (i.e., TSF example). Therefore, would like to see more / different information regarding SQI performance.
Reliability SQIs	**Reliability SQIs Summary (please see slides for more details)** • Carrie Grant provided an overview of the proposed Reliability SQIs. **Feedback Summary** • SQIs that work best as informational indicators are those that have stable performance. • Would be nice if the Generator Forced Outage Rate (GFOR) and Interconnection Utilization were part of the SQIs with benchmarks and thresholds and not just informational indicators. Make the Interconnection Utilization metric a SQI with a benchmark and threshold. • Suggestion to report on GFOR performance during certain times like when the generators are supposed to run (i.e., during freshet conditions, etc.). • With major events, what are you doing in advance of them, and what are you doing when they occur, lots of variability but easy to measure.

	○ Measure planned resource capability and how quickly it responds, and how that quickness and response impacts the customer duration measure. Include those emergency practice events in SQIs reporting. • Could be useful information to show actual SAIDI and SAIFI adjusted for events other than just excluding major events, with different thresholds for different events. Might give a better sense of what you are dealing with. • Concern expressed that basing the benchmark and/or threshold on an increasing trend in SAIDI performance over time (i.e., higher results) may implicitly contribute to declining SAIDI performance. • Consider adding in an average service quality index and an interconnection metric in addition to SAIFI. If there is no variability at the two decimal level then move to the third decimal level.
Wrap Up	
Wrap Up	**Wrap Up Summary** • Colin Norman asked each participant individually if they had any other feedback they would like to share on what was presented over the full workshop session or if they had a key piece of feedback that they wanted to ensure FortisBC took away from the session. Participants were then thanked for their attendance and open dialog and the session was closed. **Feedback Summary** • No new feedback was brought forward. Participants expressed their thanks for the workshop and for the open discussion.

FortisBC 2025+ Rate Setting Framework

BCUC and Intervener Workshop

November 20, 2023

Workshop Objectives

- Review FortisBC's operating context
- Recap the feedback that we've heard so far
- Provide an overview of the key concepts and themes and how they reflect the feedback
- Record current feedback and ideas that haven't yet been considered
- Provide an overview of the proposed SQIs
- Seek input on the proposed SQIs

Agenda

TIME	DESCRIPTION	SPEAKERS
9:00 AM - 9:15 AM	Introductions, Workshop Objectives, Agenda Review, Timeline of Filing	Colin Norman
9:15 AM - 10:15 AM	Operating Context	Brent Graham, Vanessa Connolly, Andrew Doyle, Dawn Mehrer
10:15 AM - 11:00 AM	Review of Key Concepts, Feedback to Date & Adapting the Framework to the Operating Context	Sarah Walsh
11:00 AM - 11:10 AM	Break	
11:10 AM - 11:30 AM	SQIs Overview	Colin Norman
11:30 AM - 12:15 PM	Safety SQIs	Dawn Mehrer
12:15 PM - 12:45 PM	Lunch	
12:45 PM - 1:30 PM	Customer SQIs	Brooklyne Maligaspe
1:30 PM - 2:15 PM	Reliability SQIs	Carrie Grant
2:15 PM - 2:45 PM	Wrap Up	Colin Norman

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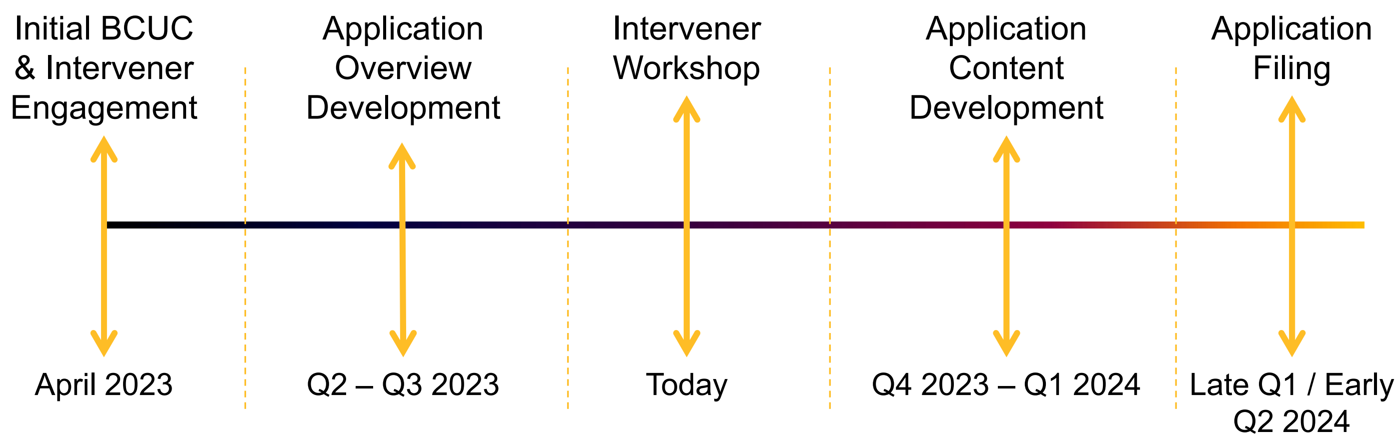
Timeline


Initial BCUC & Intervener Engagement
April 2023
Application Overview Development
Q2 – Q3 2023
Intervener Workshop
Today
Application Content Development
Q4 2023 – Q1 2024
Application Filing
Late Q1 / Early Q2 2024

Operating Context

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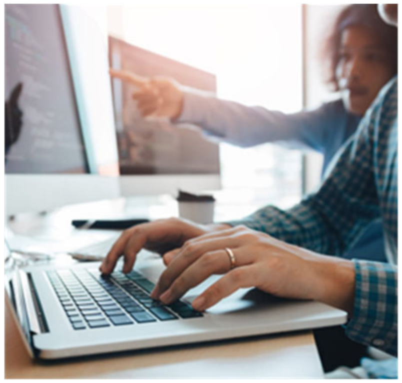
Evolving Operating Context – Key Influences on Revenue Requirements

Energy Transition	Indigenous Relations & Reconciliation	Safe, Reliable and Resilient Service



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Energy Transition

Brent Graham
Director, Government Relations & Public Policy

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FortisBC's Clean Growth Pathway to 2050

FortisBC's **Clean Growth Pathway to 2050** is a diversified approach that supports British Columbia's climate and economic needs.

Demand Side Mangement

Renewable Gas

Zero & low carbon transportation

LNG for marine fueling

The Importance of the Gas and Electric Systems in BC's Energy Transition

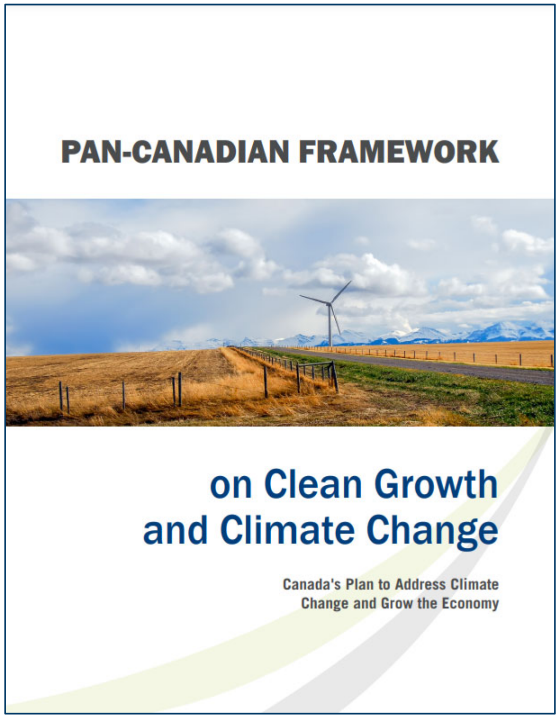
- BC's Gas and electric systems must complement each other to ensure safe, resilient, reliable and affordable service in pursuit of GHG reduction targets
- BC's winter peak is mainly met with gas system vs summer peak is with electric system
- Advanced DSM needed across buildings and industrial sectors
- Combination of electric and gas solutions in all sectors
- FortisBC has made significant progress towards reducing GHGs in BC

Key Policies in 2020-2024 MRP

December 2018

ENERGY STEPCODE
BUILDING BEYOND THE STANDARD

April 2017



December 2016

Provincial: CleanBC Roadmap to 2030

- BC's 2021 plan to reduce GHG emissions 40% below 2007 levels by 2030. Built on 2018 CleanBC plan.
- Key role for energy efficiency and leveraging BC's gas system to deliver RNG and hydrogen.
- One of the main policies is the GHG Reduction Standard: a GHG emission cap on natural gas utilities in BC buildings and industrial sectors.

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Municipal: Zero Carbon Step Code for Buildings

- Legislation in May 2023: progressive carbon performance targets
- Layered on top of BC Energy Step Code's energy efficiency requirements
- Municipalities can choose whether to adopt level above base
- By 2030, all new construction must be zero-carbon performance

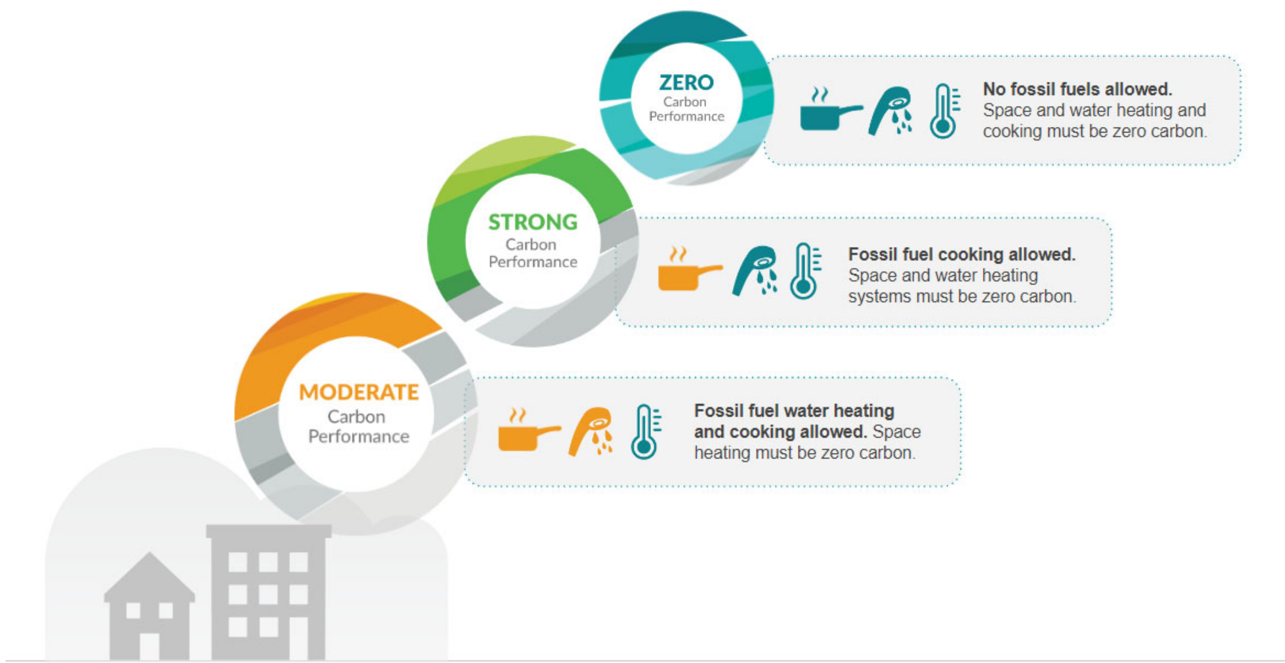

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Illustration of Linkages Between Recent BCUC Proceedings and Related Provincial Plans, Strategies and Policies

BCUC Application	Related Provincial Plans, Strategies and Policies*
Comprehensive Review and Application for a Revised Renewable Gas Program	• BC Energy & Zero Carbon Step Code • Greenhouse Gas Reduction Regulation • BC Hydrogen Strategy • GHG Reduction Standard • BC Clean Transportation Action Plan • BC Low Carbon Fuel Standard • Carbon tax
2024-2027 Demand Side Expenditures Plan	
2022 Long Term Gas Resource Plan	

*Additional plans, strategies and policies may be applicable to FortisBC BCUC applications

Discussion

- Questions for clarification?
- Any additional observations or considerations?

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Indigenous Relations & Reconciliation

Vanessa Connolly
Director, Community & Indigenous Relations

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Current Landscape

- UN Declaration – adopted by provincial and federal governments
- Declaration on the Rights of Indigenous Peoples Act (DRIPA)
- Truth & Reconciliation Commission's Calls to Action (TRC)
- Canadian legal decisions

A member of the Wild Moccasin Dancers performing a Traditional dance at Surrey Ops for employees during National Indigenous History Month

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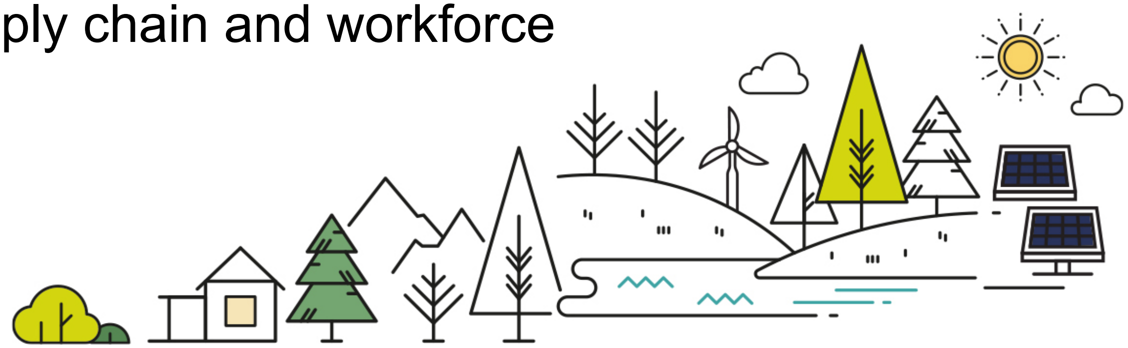
Community perspectives

- Indigenous led documents are shaping the landscape
- Increased expectations for engagement
- Support for energy planning and collaboration on projects
- Increased participation in supply chain and workforce



Where we have been?

Progressive Aboriginal RELATIONS SILVER LEVEL

Canadian Council for Aboriginal Business

- **Trop Right:** Skeetchestn Relationship Agreement signing ceremony**.**
- **Bottom:** Filming of New Energy webseries with Chief Ian Campbell of Squamish Nation. and Actor Simon Baker.

- Progressive Aboriginal Relations Certification
- Impact Benefit Agreements for Eagle Mountain-Woodfibre Pipeline and Tilbury LNG Projects
- First modern Relationship Protocol Agreement signed with Skeetchestn Indian Band
- Youth tour with Williams Lake Indian Band
- Socio Economic Impact Program
- Community Investment
- Indigenous Employee Circle

Moving Forward

LEADERSHIP ACTIONS, EMPLOYMENT, BUSINESS DEVELOPMENT & ENGAGEMENT

UNDERSTANDING THE CHANGING ENVIRONMENT

ALIGNMENT WITH INDIGENOUS LED DOCUMENTS

INDIGENOUS RECONCILIATION REPORT

Discussion

- Questions for clarification?
- Any additional observations or considerations?

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Safe, Reliable and Resilient Service

Andrew Doyle
Manager, Project Development

Dawn Mehrer
Vice President, Corporate Services & Technology

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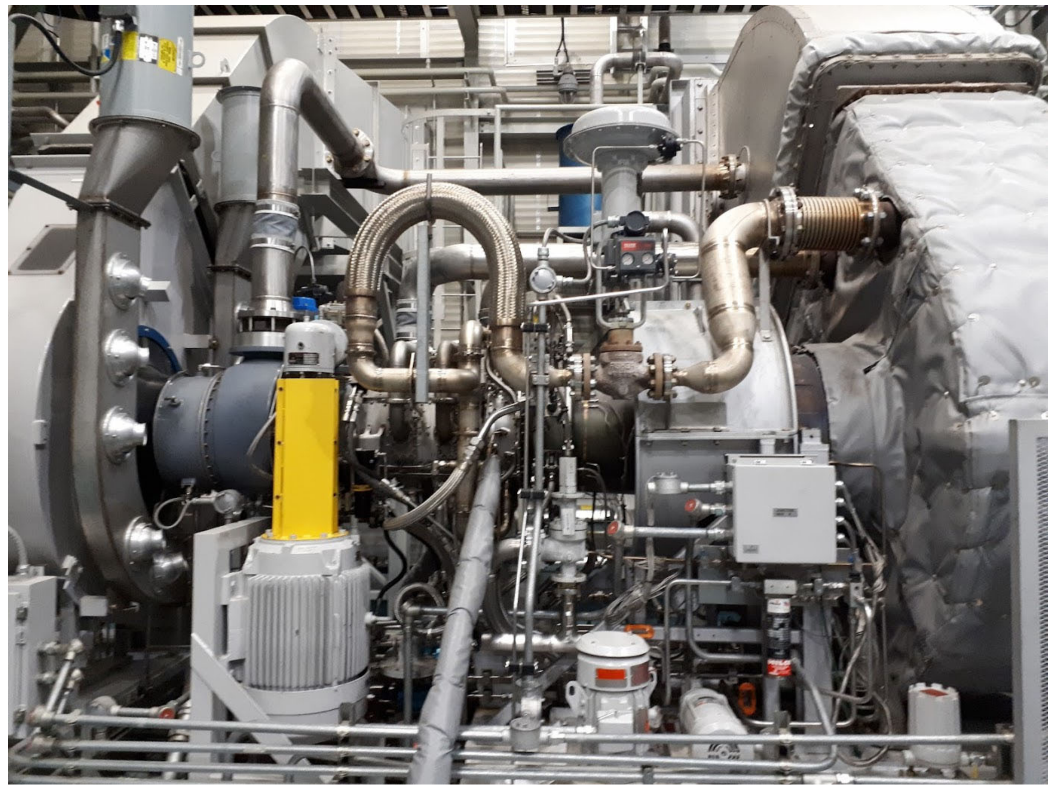
Aging Infrastructure

Drives an increased need for maintenance, investment, and planning lead time.

New Requirements and Regulations

Increasingly prescriptive regulations result in a redirection of funds and potential delay of other work to meet requirements and timelines



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Climate Adaptation

Increasingly severe weather events drive a need to better understand potential impacts and the flexibility to respond appropriately

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Cybersecurity: Current Landscape

External Landscape:

- Political unrest.
- Direct threats on utility infrastructure.
- Software being easier to buy and install.
- Vendors focusing on immediate response to security gaps.

Internal Landscape:

- Recruitment for and development of new skills is constant.
- More devices connected to the network than ever before.
- Threat warning feeds increasing – approximately 100 / day.
- More attention on cybersecurity from a variety of sources.

Cybersecurity: Coming Soon

Generative AI phishing fears realized as model develops "highly convincing" emails in 5 minutes

ID R&D

The Economist

Menu | Weekly edition | The world in brief | Search

Culture | Johnson

AI is making it possible to clone voices

The Hacker News

New Malware-as-a-Service Threat Emerges in the Cybercrime Underground

Discussion

- Questions for clarification?
- Any additional observations or considerations?

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Review of Key Concepts, Feedback to Date & Adapting the Framework to the Operating Context

Rate Framework Options

- **Cost of service regulation:**
  - Typically involves a forecast revenue requirement that reflects the total amount that must be collected in rates for the utility to recover its cost and earn its allowed return.
- **Performance-based regulation (PBR):**
  - Typically involves setting the rates (price cap)/revenues (revenue cap) for a base year and applying an indexing formula to adjust the base year rates/revenues in the subsequent years.
- **Hybrid (i.e., FortisBC's framework):**
  - Majority of items are forecast; some items are escalated based on a formulaic index.
  - Actual vs forecast variances are either shared between the customer and company or are flowed through to customers through amortization of deferral accounts.

High Level Concepts for Rate Framework

- **The rate framework application will:**
  - Include a description of how various items are treated over the term of the plan (e.g., formula vs forecast costs/revenues, earnings sharing vs flow-through treatment of variances)
  - Establish other elements of the plan, including the “X”, “I” and “Z” Factors
  - Review load/demand forecasting methodologies
  - Provide updated depreciation and accounting studies
  - Propose a suite of Service Quality Indicators (SQIs)
- **The rate framework application will not:**
  - Include detailed rate forecasts or an application for permanent rates

Initial Feedback

BCUC	Interveners	FortisBC
• Process efficiencies • Hear from all • Key theme • Energy transition and affordability • Relook at SQIs • Simplify capital description • Joint FEI/FBC application	• Regulatory efficiencies with transparency • Skepticism on cost efficiencies • Adapt to current times • Energy transition and affordability • RG confidence • Gas utility viability	• Incentive to perform and time to focus on key issues • Funding for emerging requirements/challenges • Flexibility to adapt • Gas AMI • Affordability • Fair return

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Addressing Key Themes from Feedback

Regulatory Efficiency	Reduce Complexity	Energy Transition and Uncertainty in Environment	Affordability
Five-year term - multi year framework with a well-defined annual rate setting process will allow for regulatory efficiencies and time to focus on key issues	Changes to presentation and structure of application to facilitate understanding. Application provides an opportunity to revisit components of the framework and clarify the terms and mechanisms	Annual cost of service forecast for costs supporting the energy transition or with high degree of uncertainty	Expanded focus on new or growing markets and sources of revenue
Streamlined annual review process – predetermine what is in and out of scope	Predictable and repeatable forecasting methods agreed to in advance	Annual forecast of clean energy items	Detailed review of Capital and Base O&M and X and I Factors for O&M
	Streamlined annual review process – predetermine what is in and out of scope	Review of applicability of current SQIs	

Draft Outline of Overall Rate Framework

Annually Forecast Cost of Service with Deferrals to Flow Through Variances	• Demand • Power supply/Cost of Gas • Property Tax • Income Tax and Interest Rates • Flow-through O&M and Capital • Amortization
Annually Forecast Cost of Service with Sharing on Variances	• Other Revenue • Depreciation • Capital Additions/Rate Base
Formula with Sharing on Variances	• Base O&M • Components of FEI Growth Capital
Other	• Exogenous or “Z” Factors • Service Quality Indicators (SQIs)

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Discussion

- Questions for clarification?
- Any additional observations or considerations?

BREAK

FortisBC 2025+ Rate Setting Framework

Service Quality Indicators Workshop

November 20, 2023

Welcome!

- Introductions
- Online participants – to provide feedback or ask questions please "raise your hand" or use the chat box
- Workshop Objectives:
  - Provide an overview of the proposed SQIs
  - Seek input on the proposed SQIs

Agenda

Topic	Presenter(s)
SQI Overview	Colin Norman *Senior Project Manager, Regulatory Affairs*
SQI Review & Discussion ➢ Safety ➢ Customer ➢ Reliability	Dawn Mehrer *Vice President, Corporate Services and Technology* Brooklyne Maligaspe *Manager, Customer Experience and Business Performance* Carrie Grant *Regional Manager, Network Services*
Next Steps & Wrap Up	Colin Norman *Senior Project Manager, Regulatory Affairs*

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Service Quality Indicators Overview

Colin Norman
Senior Project Manager, Regulatory Affairs

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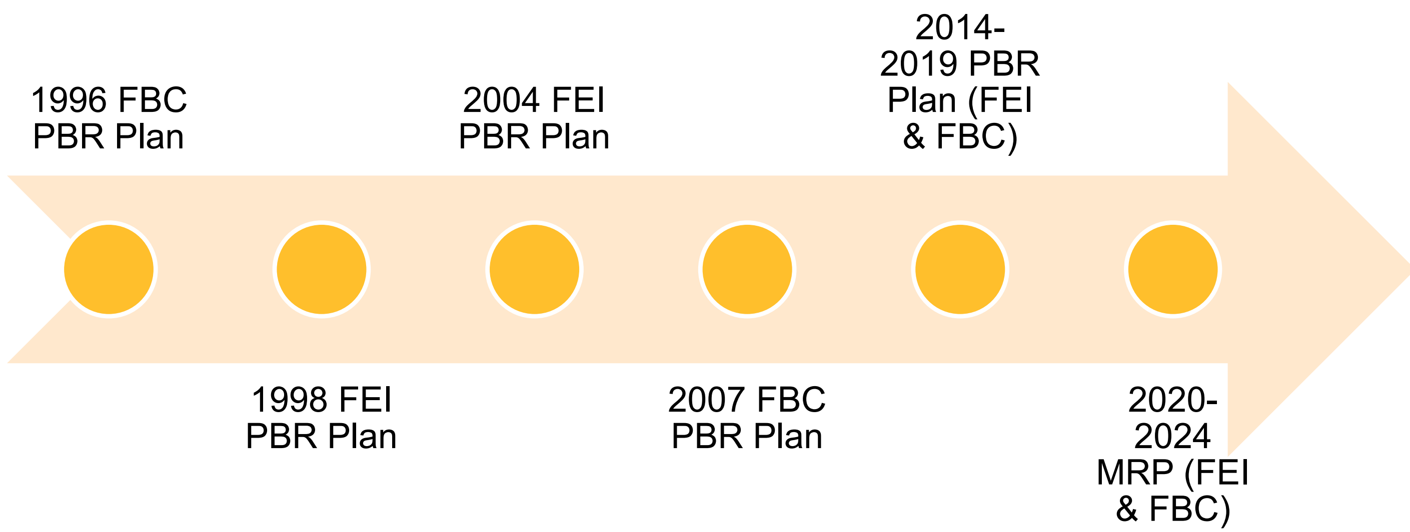
Service Quality Indicators History



From 2020-2024 MRP Application:

“SQIs form the basis of determining a utility’s quality of service and represent a broad range of business processes that are important elements to the customer experience. … SQIs are used to monitor the Utilities’ performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.”

Evaluation Criteria

- Value to customers
- Controllable
- Cost effective
- Simple and transparent
- Traceable and quantifiable
- Flexible

FEI's Proposed Service Quality Indicators

= change being considered

Indicators with Benchmarks and Thresholds

			Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	**Safety**	**Emergency Response Time** - Calls responded to within one hour	>= 97.7%	96.2%	>=97.7%	96.2%
Annual results	**Safety**	**Telephone Service Factor (Emergency)** - Calls answered in 30 seconds or less	>= 95%	92.8%	>=95%	92.8%
3 Year rolling average	**Safety**	**All Injury Frequency Rate**	<= 2.08	2.95	<= 2.08	2.95
Annual results	**Safety**	**Public Contacts with Gas Lines**	<=8	12	<=6	12
Annual results	**Responsiveness to Customer Needs**	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual results	**Responsiveness to Customer Needs**	**Billing Index**	<= 3	5	<=3	5
Annual results	**Responsiveness to Customer Needs**	**Meter Reading Completion** - Number of scheduled meter reads that were read	>= 95%	92%	TBD	TBD
Annual results	**Responsiveness to Customer Needs**	**Telephone Service Factor (Non Emergency)** - Calls answered in 30 seconds or less	>= 70%	68%	>=70%	65%
Annual results	**Responsiveness to Customer Needs**	**Meter Exchange Appointment Activity**	>=95%	93.8%	>=95%	93.8%

Informational Indicators

Annual results	**Responsiveness to Customer Needs**	**Customer Satisfaction Index**	n/a	n/a	n/a	n/a
Annual results	**Responsiveness to Customer Needs**	**Average Speed of Answer (replaces Telephone Abandonment Rate)**	n/a	n/a	n/a	n/a
Annual results	**Reliability**	**Transmission Reportable Incidents**	n/a	n/a	n/a	n/a
Annual results and 5 Year rolling average	**Reliability**	**Leaks per KM of Distribution System Mains**	n/a	n/a	n/a	n/a

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FBC's Proposed Service Quality Indicators

= change being considered

Indicators with Benchmarks and Thresholds

			Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual	**Safety**	**Emergency Response Time -** Calls responded to within two hours	>= 93%	90.6%	>=93%	90.6%
3 Year	**Safety**	**All Injury Frequency Rate**	<= 1.64	2.39	<=1.64	2.39
Annual	**Responsiveness to Customer Needs**	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual	**Responsiveness to Customer Needs**	**Billing Index**	<= 3	5	<=3	5
Annual	**Responsiveness to Customer Needs**	**Meter Reading Completion** - Number of scheduled meter reads that were read	>= 98%	96%	>=98%	96%
Annual	**Responsiveness to Customer Needs**	**Telephone Service Factor -** Calls answered in 30 seconds or less	>= 70%	68%	>=70%	65%
Annual	**Reliability**	**System Average Interruption Duration Index - Normalized**	3.22	4.52	3.29	4.80
Annual	**Reliability**	**System Average Interruption Frequency Index - Normalized**	1.57	2.19	1.75	2.36

Informational Indicators

Annual results	**Responsiveness to Customer Needs**	**Customer Satisfaction Index**	n/a	n/a	n/a	n/a
Annual results	**Responsiveness to Customer Needs**	**Average Speed of Answer (replaces Telephone Abandonment Rate)**	n/a	n/a	n/a	n/a
Annual results	**Reliability**	**Generator Forced Outage Rate**	n/a	n/a	n/a	n/a
Annual results	**Reliability**	**Interconnection Utilization**	n/a	n/a	n/a	n/a

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Safety SQIs

Dawn Mehrer

Vice President, Corporate Services & Technology

Summary of FEI SQIs - Safety

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
Employee Safety Lagging Indicator: All Injury Frequency Rate (AIFR)	<=2.08	No Change	2.95	No Change
Employee Safety Leading Indicator (informational): TBD	N/A			
Public Contact with Gas Lines	<=8	**Change to Benchmark <=6**	12	No Change
Emergency Response Time	>=97.7%	No Change	96.2%	No Change
Telephone Service Factor (Emergency)	>=95%	No Change	92.8%	No Change

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Summary of FBC SQIs - Safety

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
Employee Safety Lagging Indicator: All Injury Frequency Rate – FBC (AIFR)	<=1.64	No Change	2.39	No Change
Employee Safety Leading Indicator (informational): TBD	N/A			
Emergency Response Time	>=93%	No Change	90.6%	No Change

Employee Safety: Lagging vs Leading Indicators

- Lagging indicators:
  - Easier to objectively measure/quantify.
  - Measure the existence of incidents and impacts to employees.
  - Generally, not a good measure for how “safe” an organization is.
  - Can drive unintended behaviours.
- Leading indicators:
  - Proactive identification of gaps or weak signals
  - Provides further insight into the safety culture within an organization
  - More difficult to objectively measure or assign reliable targets.

A balanced view of the effectiveness of safety systems and programs uses both leading and lagging indicators.

Lagging Indicator – All Injury Frequency Rate (AIFR)

Category: **Safety**

Definition: **All Injury Frequency Rate (AIFR)**

Employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed).

How metric is calculated:

$$\frac{\text{Number of Employee Injuries X 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

Lagging Indicator – *AIFR*

History on SQI(s):

Safety Service Quality Indicators						
Description	**2020**	**2021**	**2022**	**Aug YTD 2023**	**Benchmark**	**Threshold**
FEI All Injury Frequency Rate (AIFR)	1.66	1.75	1.59	1.69*	<= 2.08	2.95
FBC All Injury Frequency Rate (AIFR)	0.87	0.67	1.42	1.98*	<=1.64	2.39
*3 year rolling average						

Recommendation on SQI(s):

Maintain existing SQI benchmarks and thresholds.

FEI: <u>Benchmark</u> ~ <= 2.08 ; <u>Threshold</u> ~ 2.95

FBC: <u>Benchmark</u> ~ <= 1.64 ; <u>Threshold</u> ~ 2.39

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Employee Safety – Leading Indicator Themes

- How quickly or how completely we action safety improvements after they are identified.
- A measurement of the % of employees participating in a safety meeting on a regular basis.
- The level of engagement in safety survey participation.
- The number of new controls linked to high hazard activities.
- Number of field visits and inspections completed.

Public Contacts with Gas Lines

Category: **Safety**

Definition: **Public Contacts with Gas Line Hits**

Measures the overall effectiveness of the Company's efforts to minimize damage to the gas system through public awareness, which is designed to reduce interruptions and the associated public safety and service issues to customers.

How metric is calculated:

$$\frac{\text{Number of Line Damages}}{\text{1,000 BC 1 Call Requests Received}}$$

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SQI Description– *Public Contacts with Gas Lines*

History on SQI(s):

FEI Safety Service Quality Indicators						
Description	2020	2021	2022	Aug YTD 2023	Benchmark	Threshold
Public Contact with Gas Lines	7	6	6	6	8	12

Recommendation on SQI(s):

Benchmark ~ 6

Benchmark is based on the average of 2020 – 2022 results ((7+6+6)/3)

Threshold ~ 12

Maintaining threshold at 12 based on historical trends related to volatility that influence public contacts and the use of BC1C services.

Discussion

- Questions for clarification?
- Any additional observations or considerations?

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Customer SQIs

Brooklyne Maligaspe

Manager, Customer Experience & Business Performance

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Summary of FEI Customer SQIs

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
First Contact Resolution	78%	No Change	74%	No Change
Billing Index	3.0	No Change	5.0	No Change
Meter Reading Accuracy	95%	TBD	92%	TBD
Telephone Service Factor (non-emergency)	70%	No Change	68%	Lower Threshold to 65%
Meter Exchange Appointment Activity	95.0%	No Change	93.8%	No Change
Customer Satisfaction Index	Informational Metric			
Average Speed of Answer	Informational Metric			

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Summary of FBC Customer SQIs

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
First Contact Resolution	78%	No Change	74%	No Change
Billing Index	3.0	No Change	5.0	No Change
Meter Reading Accuracy	98%	No Change	96%	No Change
Telephone Service Factor	70%	No Change	68%	Lower Threshold 65%
Customer Satisfaction Index	Informational metric			
Average Speed of Answer	Informational metric			

SQI Description– Meter Reading Completion

Definition of metric and the category (safety, responsiveness to customer needs, reliability):

Category: **Responsiveness to customer needs**

Definition: **Meter Reading Accuracy**

Number of scheduled meters that were read

SQI Description – Meter Reading Completion

How metric is calculated:

$$\frac{\text{Number of actual readings obtained}}{\text{Total number of meter readings requested}}$$

SQI History – Meter Reading Completion

Description	2020	2021	2022	August 2023 YTD
FEI Meter Reading Accuracy	89.2%	88.0%	87.8%	95%
FBC Meter Reading Accuracy	99%	99%	99%	99%

- Higher FBC results are due to AMI deployment.
- FEI expects to have AMI deployment be completed during the term of this upcoming rate plan.

SQI Recommendation – Meter Reading Completion

Why this SQI is appropriate:

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers

Recommendation on SQI:

FEI/FBC proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill.

FEI/FBC proposes changing the name of this metric from **Meter Reading Accuracy** to **Meter Reading Completion**, as that better reflects what the metric is measuring.

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SQI Recommendation – FEI Meter Reading Completion

Recommendation on SQI:

FEI proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill.

FEI is considering changes to this metrics benchmark and threshold.

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
Meter Reading Completion	95%	TBD	92%	TBD

Challenges

- Variability in deployment of AMI
- Early stages of AMI
- Differences between Electric AMI deployment vs Gas AMI deployment
  - Over longer duration
  - In house vs contracted meter readers

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SQI Recommendation – FBC Meter Reading Completion

Why this SQI is appropriate:

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers

Recommendation on SQI:

FBC proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill.

FBC proposes to leave as is.

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
Meter Reading Completion	98%	No Change	96%	No change

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SQI Description – TSF (Non-emergency)

Definition of metric and the category (safety, responsiveness to customer needs, reliability):

Category: **Responsiveness to customer needs**

Definition: **Telephone Service Factor - Non-Emergency (TSF – Non-emergency)**

Percent of non-emergency calls answered within 30 seconds or less

SQI Description – TSF (Non-emergency)

How metric is calculated:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Total number of non-emergency calls}}$$

SQI History – TSF (Non-emergency)

Gas Description	2020	2021	2022	August 2023 YTD
FEI TSF (non-emergency)	70%	70%	62%	70%
FBC TSF (Trouble/Non-Trouble)	70%	70%	65%	70%

SQI Recommendation – TSF (Non-emergency)

Why this SQI is appropriate:

Telephone service factor (TSF) is a measurement of the percentage of calls answered within a defined window of time. This is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers.

Recommendation on SQI:

FEI/FBC propose to continue to report on TSF (Non-Emergency) and lower the existing threshold to 65 percent for non-emergency calls.

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
TSF (non-emergency)	70%	70%	68%	65%

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Discussion

- Questions for clarification?
- Any additional observations or considerations?

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Reliability SQIs

Carrie Grant

Regional Manager, Network Services

Reliability SQIs – FEI (Gas)

Summary of FEI Reliability SQIs

Category	SQI Name	SQI Type	Change
Reliability	Transmission Reportable Incidents	Informational	No
Reliability	Leaks per KM of Distribution System Mains	Informational	No

Discussion

- Questions for clarification?
- Any additional observations or considerations?

Reliability SQIs – FBC (Electric)

Summary of FBC Reliability SQIs

Category	SQI Name	Benchmark		Threshold		Change
		Current	**Proposed**	**Current**	**Proposed**	
Reliability	System Average Interruption Duration Index – Normalized (SAIDI)	3.22	3.29	4.52	4.80	Change Benchmark & Threshold
Reliability	System Average Interruption Frequency Index – Normalized (SAIFI)	1.57	1.75	2.19	2.36	Change Benchmark & Threshold
Reliability	Generator Forced Outage Rate	Informational				No Change
Reliability	Interconnection Utilization	Informational				No Change

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SQI Description– System Average Interruption Duration Index (SAIDI)

Category: **Reliability**

Definition: **System Average Interruption Duration Index (SAIDI)**

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events.

SQI Description – SAIDI

SAIDI = $\frac{\text{Total Number of Customers Served}}{\text{Total Customer Hours of Interruption}}$

How metric is calculated:

- Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage. The measurement of performance is based on annual results.
- FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events".
- Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Electricity Canada standard for reporting.

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SQI Description – System Average Interruption Frequency Index (SAIFI)

Category: **Reliability**

Definition: System Average Interruption Frequency Index (SAIFI)

- SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during a year), after adjusting for the impact of major events.

SQI Description – System Average Interruption Frequency Index (*SAIFI)*

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

How metric is calculated:

- The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage. The measurement of performance is based on annual results.
- FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding “major events”.
- Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Electricity Canada standard for reporting.

SQI History – SAIDI & SAIFI

SAIDI				
Description	**2020**	**2021**	**2022**	**YEF**
Annual Normalized Results	3.17	4.27	2.42	3.25
Benchmark	3.22			
Threshold	4.52			

SAIFI				
Description	**2020**	**2021**	**2022**	**YEF**
Annual Normalized Results	1.64	2.08	1.52	1.48
Benchmark	1.57			
Threshold	2.19			

SQI Considerations – SAIDI & SAIFI

Why this SQI is appropriate:

This is a recognized industry standard on measuring electric system reliability.

Other similar/related SQIs considered:

Considerations

- Customer Average Interruption Duration index (CAIDI)
- Customer Average Interruption Frequency Index (CAIFI)
- Momentary Average Interruption Frequency Index (MAIFI)

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SQI Recommendation – SAIDI & SAIFI

Description	Benchmark		Threshold	
	Current	**Proposed**	**Current**	**Proposed**
SAIDI	3.22	3.29	4.52	4.80
SAIFI	1.57	1.75	2.19	2.36

Discussion

- Questions for clarification?
- Any additional observations or considerations?

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Wrap up!

Next Steps

Further Iterate SQIs
FortisBC
December - January

File Rate Plan Application
FortisBC
end-Q1 / early Q2 2024

SQIs Workshop
FortisBC &
Workshop Participants
Today

Closing Remarks

Colin Norman

Appendix

FEI's Current Service Quality Indicators

Results Type	Area	Measure
Annual results	Safety	Emergency Response Time - Calls responded to within one hour
Annual results	Safety	Telephone Service Factor (Emergency) - Calls answered in 30 seconds or less
3 Year rolling average	Safety	All Injury Frequency Rate
Annual results	Safety	Public Contacts with Gas Lines
Annual results	Responsiveness to Customer Needs	First Contact Resolution
Annual results	Responsiveness to Customer Needs	Billing Index
Annual results	Responsiveness to Customer Needs	Meter Reading Accuracy - Number of scheduled meter reads that were read
Annual results	Responsiveness to Customer Needs	Telephone Service Factor (Non Emergency) - Calls answered in 30 seconds or less
Annual results	Responsiveness to Customer Needs	Meter Exchange Appointment Activity
Informational Indicators		
Annual results	Responsiveness to Customer Needs	Customer Satisfaction Index
Annual results	Responsiveness to Customer Needs	Average Speed of Answer (replaced Telephone Abandonment Rate)
Annual results	Reliability	Transmission Reportable Incidents
Annual results and 5 Year rolling average	Reliability	Leaks per KM of Distribution System Mains

= revised in 2020-2024 MRP

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FBC's Current Service Quality Indicators

Results Type	Area	Measure
Annual	Safety	Emergency Response Time - Calls responded to within two hours
3 Year	Safety	All Injury Frequency Rate
Annual	Responsiveness to Customer Needs	First Contact Resolution
Annual	Responsiveness to Customer Needs	Billing Index
Annual	Responsiveness to Customer Needs	Meter Reading Accuracy - Number of scheduled meter reads that were read
Annual	Responsiveness to Customer Needs	Telephone Service Factor - Calls answered in 30 seconds or less
Annual	Reliability	System Average Interruption Duration Index - Normalized
Annual	Reliability	System Average Interruption Frequency Index - Normalized
Informational Indicators		
Annual results	Responsiveness to Customer Needs	Customer Satisfaction Index
Annual results	Responsiveness to Customer Needs	Average Speed of Answer (replaced Telephone Abandonment Rate)
Annual results	Reliability	Generator Forced Outage Rate
Annual results	Reliability	Interconnection Utilization

= revised in 2020-2024 MRP

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Additional SQI Information

1. Emergency Response Time (FEI)
2. Emergency Response Time (FBC)
3. Telephone Service Factor (Emergency)
4. Billing Index (FEI and FBC)

Emergency Response Time (FEI)

Category: **Safety**

Definition: **Emergency Response Time**

Emergency response time measures responsiveness to emergency events including gas odour calls, carbon monoxide calls, house fires and hit lines.

How metric is calculated:

$$\frac{\text{Number of Emergency Calls responded to in one hour}}{\text{Total number of emergency calls}}$$

Emergency Response Time (FEI)

<u>History on SQI:</u>

FEI Safety Service Quality Indicators						
Description	2020	2021	2022	Aug YTD 2023	Benchmark	Threshold
Emergency Response Time	97.7%	97.7%	97.7%	97.6%	>= 97.7%	96.2%

<u>Recommendations on SQI:</u>

Maintain existing SQI benchmarks and thresholds.

<u>Benchmark</u> ~ 97.7% ; <u>Threshold</u> ~ 96.2%

Emergency Response Time (FBC)

Category: **Safety**

Definition: **Emergency Response Time**

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. How metric is calculated:

$$\frac{\text{Number of Emergency Calls responded to in two hours}}{\text{Total number of emergency calls}}$$

Emergency Response Time (FBC)

History on SQI:

FBC Safety Service Quality Indicators						
Description	2020	2021	2022	Aug YTD 2023	Benchmark	Threshold
Emergency Response Time	92%	93%	94%	91%	>= 93%	90.6%

Recommendations on SQI:

Maintain existing SQI benchmarks and thresholds.

Benchmark ~ >=93%; Threshold ~ 90.6%

Telephone Service Factor (Emergency) (FEI)

Category: **Safety**

Definition: **Responsiveness to customer needs**

Percent of emergency calls answered within 30 seconds or less

How metric is calculated:

$$\frac{\text{Number of emergency calls answered within 30 seconds}}{\text{Total number of emergency calls}}$$

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SQI Recommendation – TSF (Emergency)

History on SQI:

FEI Safety Service Quality Indicators						
Description	2020	2021	2022	Aug YTD 2023	Benchmark	Threshold
Telephone Service Factor - Emergency	96.9%	96.9%	97.1%	97.7%	>= 95%	92.8%

Recommendation on SQI:

Maintain existing SQI benchmarks and thresholds.

Benchmark ~ >=95%; Threshold ~ 92.8%

SQI Description – Billing Index

Definition of metric and the category (safety, responsiveness to customer needs, reliability):

Category: **Responsiveness to customer needs**

Definition: **Billing Index**

Measure of customer bills produced meeting performance criteria

SQI Description – Billing Index

How metric is calculated:

Billing sub-measure	Percent achieved (PA)	Formula	Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data)	99.9%	If [PA ≥ 99.9%, 5000 * (1 – PA), 100 * (1.05 – PA)]	5.0
Billing Timeliness (Percentage of invoices delivered to Canada Post within two days of the file creation)	95%	(100% - PA)*100	5.0
Billing Completion (Percentage of customers billed within two business days of the scheduled billing date	95%	(100%-PA)*100	5.0
Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			5.0

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SQI History – Billing Index

Description	2020	2021	2022	August 2023
FEI Billing Index	0.62	0.94	1.02	0.77
FBC Billing Index	0.13	0.12	0.14	2.08

Factors that impact this metric:

- Performance of Company's billing system
  - Technical issue in January 2023 led to FBC YTD 2023 Billing Index of 2.08
- Weather variability

SQI Recommendation – Billing Index

Why this SQI is appropriate:

The Billing Index indicator tracks the effectiveness of the Company's billing processes by measuring the percentage of customer bills produced meeting performance criteria.

Recommendation on SQI:

FEI/FBC propose to continue to report on the Billing Index as the Company believes that customers value complete, timely and accurate bills.

Reflective of the recent historical performance and efficiencies achieved by the Company in producing bills, FEI/FBC propose to maintain the current benchmark and threshold.

Description	Benchmark		Threshold	
	Current	Proposed	Current	Proposed
Billing Index	3.0	3.0	5.0	5.0

Additional Information

Incident Classification Matrix

OGC Incident Classification Matrix

BC Oil & Gas Commission

Consequence		Probability: 4 – Uncontrolled, with control unlikely in near term	Probability: 3 – Escalation possible; under or imminent control	Probability: 2 – Escalation unlikely; controlled or likely imminent control	Probability: 1 – Escalation highly unlikely; controlled or imminent control	Probability: 0 – Will not escalate; no hazard; no monitoring required
4	Major on site equipment or infrastructure loss Major act of violence, sabotage, or terrorism which impacts permit holder assets Reportable liquid spill beyond site, uncontained and affecting environment Gas release beyond site affecting public safety	Level 3	Level 3	Level 2	Level 2	Level 1
3	Threats of violence, sabotage, or terrorism Reportable liquid spill or gas release beyond site, potentially affecting public safety, environment, or property HAZMAT worker exposure exceeding allowable Major on site equipment failure	Level 3	Level 2	Level 2	Level 1	Level 1
2	Major on site equipment damage A security breach that has potential to impact people, property or the environment Reportable liquid spill or gas release potentially or beyond site, not affecting public safety, environment, or property	Level 2	Level 2	Level 1	Level 1	Minor Notification Form
1	Moderate on site equipment damage A security breach that impacts oil and gas assets Reportable liquid spill or gas release on location ** Occurrence of magnitude 4.0 or greater induced earthquake within 3 km of oil and gas operations or any earthquake which is felt on surface within a 3 km radius of oil and gas operations	Level 2	Level 1	Level 1	Minor Notification Form	Minor Notification Form
0	No consequential impacts	Level 1	Level 1	Minor Notification Form	Minor Notification Form	No notification Required

Appendix C

PROPOSED RATE SETTING FRAMEWORK

Appendix C1-1

REPORT ON INDEXING FORMULA COMPONENTS FOR FORTISBC

Report on Indexing Formula Components for FortisBC

LKaufmann Consulting Inc.

Lawrence R. Kaufmann, Ph.D.

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March 2024

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Table of Contents

1. Introduction and Executive Summary

1.1 Introduction

Since the mid-1990s, the British Columbia Utilities Commission ("BCUC") has approved formula-based methods to recover allowed operations and maintenance ("O&M") costs and, to a lesser extent, capital costs, for FortisBC Energy Inc. ("FEI") and FortisBC Inc. ("FBC") (together, "FortisBC" or the "Companies"). The first formula-based plans used inflation minus X formulas to update allowed O&M cost per customer, as well as other targeted costs. Inflation was measured by the British Columbia consumer price index ("BC-CPI"), while the X factors were designated percentages of measured inflation. As a result, initial X factors for FEI and FBC did not have explicit, pre-determined values but instead varied with the inflation rate.[1] This approach extended into the following decade, and beyond, in separate, approved plans for FEI (2004-2009) and FBC (2007-2011).

The BCUC adopted a different approach in the Companies' 2014-2019 multi-year rate plans ("MRPs"). One important innovation was changing the inflation factor from the BC-CPI to a weighted average of inflation in the BC-CPI and BC average weekly earnings ("BC-AWE"). The weights approved for the BC-CPI and BC-AWE were 45% and 55%, respectively.[2]

In addition, the 2014-2019 MRPs included specific X factor values for FEI and FBC. In each case, the X factor was the sum of a productivity factor and a stretch factor. FEI's X factor was set at 1.10%, with a 0.9% productivity factor and a 0.2% stretch factor. FBC's approved X factor was 1.03%, comprised of a 0.93% productivity factor and a 0.10% stretch factor. Like many other North American incentive regulation plans, the BCUC's determination of these productivity and stretch factor values relied heavily on total factor productivity ("TFP") evidence provided by different parties.

However, in FEI's and FBC's most recently approved MRPs, where the majority of capital spending was excluded from the formula approach, the BCUC questioned whether TFP studies from other jurisdictions were appropriate for setting X factors for the Companies. In its Decision, the BCUC wrote:

> "…if the X-Factor is to apply to a utility's entire operation, it would be reasonable for the TFP studies to be applicable to FortisBC. However, this is not the case with the Proposed MRPs where the X-Factor applies only to O&M expenses and a small part of the capital expenditures…the Panel finds that TFP studies are not sufficiently relevant to be applied to FEI and FBC's MRPs…(and) the Panel is not persuaded that productivity studies from other jurisdictions can be applied or are relevant in this instance."[3]

In addition, the BCUC stated that:

1 The X factor percentages deducted from inflation were determined through negotiation.
2 The same indices and weights were also approved in Alberta's 2012 PBR plans.
3 BCUC Decision and Orders, G-165-20 and G-166-20, p. 59.

> "…we acknowledge that FortisBC has just ended the Current PBR Plans and it would not be reasonable to expect the same level of productivity improvement that was achieved over the last six years. We therefore accept there will be increased challenges associated with achieving savings as the Utilities undertake a further performance-based framework. Accordingly, the Panel accepts that a reduction of current X-Factors from the Current PBR Plans for both Utilities is appropriate to allow them a reasonable opportunity to earn a fair return. Therefore, in consideration of regulatory decisions in other jurisdictions and using our experience and judgement, the Panel determines that an X-Factor of 0.5 percent inclusive of the stretch factor is applicable for both FEI and FBC for the Proposed MRP term."[4]

In our view, the BCUC correctly found that TFP evidence from other jurisdictions is not entirely appropriate for determining the Companies' allowed O&M expenses. Metrics that are focused more directly on O&M productivity are a better fit for this purpose when "the X factor applies only to O&M expenses and a small part of the capital expenditures." It is also straightforward to develop O&M productivity measures that provide more relevant and informative evidence to the BCUC.

In this context, LKaufmann Consulting Inc. ("LKC") was retained by Fasken Martineau DuMoulin LLP ("Fasken"), on behalf of FortisBC, to provide independent expert advice regarding the productivity and stretch factors, as well as the appropriateness of an adjustment to the growth factors, in the indexing formulas of FortisBC's upcoming rate frameworks.

LKC is well-qualified to advise on these matters. Dr. Lawrence Kaufmann, the principal of LKC, has participated in over 200 consulting projects addressing incentive regulation and other energy policy issues in 15 countries. Over the last 20 years, his clients have been almost evenly divided between utility companies and regulatory agencies, including past, multi-year consulting relationships with the Ontario Energy Board and the Essential Services Commission of Victoria, Australia. He has also provided expert witness testimony in 12 North American jurisdictions, Australia and New Zealand. He was assisted in this project by Mr. Ralph Zarumba of Nexus Economics LLC, who has provided expert witness testimony or reports 80 times over a distinguished utility and consulting career exceeding 30 years. The Curriculum Vitae of Dr. Kaufmann and Mr. Zarumba are provided in Appendix 4.

LKC confirms that it has a duty to provide objective evidence to the regulator and not to be an advocate for any party. LKC has prepared this report, and all of its written and oral testimony in this proceeding will be submitted, in conformance with this duty.

1.2 Executive Summary

In this report, LKC makes recommendations on the following elements of the Companies' indexing formulas for their upcoming rate plans:

1. O&M productivity factors for both FEI and FBC.[5]

4 BCUC, op cit, pp. 61-62.

5 FEI's formula-based plan applies to the recovery of O&M and growth capital costs, but O&M expenses account for more than 70% of combined O&M and capital costs, The majority of costs are therefore associated with O&M expenses.

2. Stretch factors for both FEI and FBC.
3. Whether it is appropriate to apply a discount to FEI and FBC's customer growth factors used in the Companies' O&M formulas.

For FEI's productivity factor recommendation, LKC used indexing methods and the best available data to compute the growth in O&M partial factor productivity ("O&M PFP") for the gas distribution industry. The estimated, industry-wide O&M PFP trend is the most appropriate O&M productivity "target" for FEI's indexing formula. FEI's recommended stretch factor was informed by the BCUC's previously approved stretch factors for FEI, as well as O&M unit cost and O&M PFP benchmarking evidence against the gas distribution industry.

FBC's recommended productivity factor was also calculated using indexing methods and the best available data. However, in recognition of FBC's unique characteristics, LKC computed two different measures of O&M PFP growth for the electric utility industry. One PFP measure was developed using a sample of 20 U.S. utilities which, like FBC, serve a relatively small number of customers. The second O&M PFP estimate was developed using a broad sample of 82 U.S. electric utilities. In LKC's opinion, a careful consideration of these two studies indicates that the broad-based utility sample provides the most relevant and appropriate O&M productivity target for FBC's rate framework. FBC's recommended stretch factor was informed by the BCUC's previously approved stretch factors for FBC, as well as O&M unit cost and O&M PFP benchmarking evidence for FBC against the electric utility industry.

In addition to the productivity and stretch factors, LKC was asked to advise on the appropriateness of the 0.75 discount factor currently applied to FEI's and FBC's customer growth factors used in the Companies' O&M indexing formulas. In previous proceedings, the customer growth issue was debated using statistical tools such as correlation coefficients. However, appropriate values for FEI and FBC's customer growth factors are not a matter of statistics. Instead, the appropriate value of the customer growth factor should be determined by a proper application of cost theory and indexing logic. This analysis shows that any discounts on the Companies' customer growth factors are not logically or mathematically consistent with the Companies' approved inflation factor and the O&M PFP indices appropriate for calibrating the Companies' formulas. Any discount on the Companies' customer growth factor would not be consistent with the structure and basic design of FortisBC's incentive regulation-based rate frameworks.

Given this conceptual framework and empirical research, LKC recommends:

- An X factor of 0.38% for FEI's O&M and growth capital indexing formula, comprised of:
    - An O&M productivity factor of 0.28%
    - A stretch factor of 0.10%.
- An X factor of 0.20% for FBC, comprised of:
    - A productivity factor of 0.20%
    - A stretch factor of zero.

- No discounts on the customer growth factors for either FEI or FBC.

In addition to its estimation of O&M PFP trends for the gas distribution and electricity transmission and distribution industries, LKC has estimated O&M PFP growth under FEI's and FBC's MRPs, as well as longer periods. These trends are provided to inform the BCUC of the Companies' own O&M PFP growth under incentive regulation. The Companies' own PFP performance may also have implications for appropriate stretch factor values for FEI and FBC. It should be recognized, however, that productivity factors for FortisBC should not be linked to the Companies' own past O&M PFP experience. Doing so would undermine performance incentives and therefore be contrary to the theory and practice of incentive regulation. This issue is explained in the following Section.

2. Incentive Regulation Fundamentals

2.1 The Competitive Market Paradigm and Productivity Factors

FortisBC and the BCUC both have considerable experience with incentive-based ratemaking. Nevertheless, a brief review of incentive regulation fundamentals may be instructive. Understanding the basics of incentive regulation should provide a more solid foundation for evaluating the details of the Companies' rate frameworks, as well as the appropriate choice and measurement of the empirical elements necessary to operationalize its rate plans.

In general terms, incentive regulation is an approach to utility regulation that relies on well-defined rules that create strong performance incentives. Stronger incentives encourage utilities to improve their cost performance and/or enhance the quality of service provided to customers. Better-incentivized utilities can, in turn, achieve cost efficiencies that enable "win-win" outcomes of increased earnings for shareholders and lower prices for customers.

One important feature of index-based incentive regulation is that rate changes are determined at specified intervals (typically annually). Rate adjustments usually rely on "automatic," index-based formulas. Multi-year, index-based rate changes therefore do not require laborious cost of service rate reviews.

It is critical for rate and revenue adjustment formulas to link rate changes to "external" data rather than the utility's own costs. While incentive regulation is in effect, using external data to update rates severs the link between the utility's allowed costs (determined by the rate or revenue adjustment formula) and its actual costs. This separation will strengthen utilities' cost-control incentives, since actual cost reductions are not reflected in rate changes (as they would be in a cost of service rate case) but instead go to the bottom line.

Incentive regulation uses economic reason to identify appropriate external metrics for rate adjustment formulas. This is achieved through an application of "the competitive market paradigm." The aim of incentive regulation is to replicate the behavior and outcome of competitive markets, so the formulas used to adjust utility rates in index-based regulation are designed to be consistent with how prices change in competitive markets.

Competitive market prices depend on industry-wide conditions, not the costs or circumstances of any particular firm. Incentive rate-setting replicates this outcome by using industry-wide measures to calibrate rate adjustment formulas. Relying on industry-wide data, rather than the utility's own performance, is important for ensuring that formula-based rate adjustments depend on external metrics rather than the utility's own costs.

Indexing techniques also show that the trend in competitive industry prices is equal to inflation in the price of inputs used in production minus the growth in industry productivity. Indexing logic therefore establishes that a rate or revenue adjustment formula has two key components: (1) the inflation factor (which measures industry input price inflation); and (2) the productivity factor (measuring changes in a relevant industry productivity index). Again, it should be emphasized that the inflation factor and the productivity factor depend on industry input price inflation and industry productivity, respectively. The inflation and productivity factors do not depend on the inflation or productivity of any given firm. The application of the competitive market paradigm therefore requires that industry input price and productivity measures be used for the inflation factor and productivity factor components of rate adjustment mechanisms, including FortisBC's proposed rate frameworks.

It is worth noting that a number of prominent economists have supported the merits of the competitive market paradigm. Perhaps the best example comes from Professor Alfred Kahn, who wrote in his seminal textbook on utility regulation that "the single most widely-accepted rule for the governance of the regulated industries is to regulate them in such a way as to produce the same results as would be produced by effective competition, if it were possible."[6]

2.2 Stretch Factors and Cost Benchmarking

Another important component of index-based incentive regulation is the stretch factor. Incentive ratemaking is designed to create stronger performance incentives than traditional regulation. As a result, it is often reasonable to expect utilities to achieve incremental cost savings over the term of a new incentive regulation plan.

The stretch factor is a commitment by the utility to share a certain amount of incremental cost performance gains with customers during an incentive regulation plan. Stretch factors are prospective in nature: companies commit to pass cost savings onto customers at the outset of an incentive regulation plan before any incremental productivity gains have been generated. Utilities are also "at risk" in the sense that customers receive the full benefit of the stretch factor even if the company does not achieve a corresponding amount of incremental cost improvements. The value of the stretch factor often depends on the following two matters.

First, the value of the stretch factor depends on the company's cost performance at the outset of the plan. Companies that are cost efficient at the beginning of an incentive regulation term have relatively little potential to achieve additional cost improvements. It is therefore reasonable for those companies to have relatively low stretch factors. The converse is also true. Companies that are not efficient at the outset of a ratemaking plan will have more opportunities to cut costs and achieve efficiencies. A higher stretch factor is therefore warranted for these utilities.

Second, the value of the stretch factor often depends on how many times a utility has been subject to an incentive rate-setting framework. During a company's first-generation incentive rate-making plan,

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[6] Kahn, A, *The Economics of Regulation*: Principles and institutions, Volume 1, p. 17

company operations are likely to exhibit inefficiencies that are relatively easy to identify and correct. At the next "second generation" plan, however, it will likely become more difficult to recognize and implement new reforms that lead to cost savings. This process continues for each subsequent plan; all else equal, it is increasingly difficult for a utility to achieve incremental cost performance gains for each subsequent iteration or "generation" of incentive regulation.[7]

Because stretch factors often depend on a company's relative cost efficiency at the outset of a plan, benchmarking studies can be valuable for informing regulators' judgements on appropriate stretch factor levels. For example, if companies display relatively low unit costs relative to industry norms, it is often indicative of good cost performance which, in turn, warrants relatively low stretch factors. Similarly, if a company's unit costs systematically exceed the industry's average, it may be indicative of inferior cost performance that warrants relatively higher stretch factors.

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[7] This process is sometimes described as moving closer to the technological "frontier," or the lowest possible cost that is achievable within an industry given technological constraints. Companies by definition cannot exceed the frontier, and all else equal, incremental gains in cost performance decline as companies approach the frontier.

3. O&M PFP and the Companies' Indexing Formulas

As discussed above, FortisBC's current indexing plans apply primarily to O&M costs rather than capital costs. FBC's indexing formula applies only to the recovery of O&M expenses for its electricity operations. FEI's indexing formulas apply to the recovery of O&M and growth capital costs for its gas distribution operations. Over 70% of FEI's formula driven costs are associated with O&M, with the remainder stemming from growth capital.

Because it recovers O&M and growth capital costs, a productivity factor for FEI's rate framework would theoretically be constructed using data on changes in O&M PFP and changes in growth capital PFP. In principle, both sources of PFP growth could be estimated and aggregated into a single PFP index.

In practice, however, it is not possible to construct an ideal PFP measure that includes both O&M and growth capital PFP. This is primarily because gas distribution companies do not report growth capital expenditures on the FERC Form Two or other publicly available forms. Accordingly, the data necessary to calculate a combined O&M-growth capital PFP measure are typically not available.

However, it is possible to calculate a PFP measure for *all* capital expenditures. This overall capital PFP measure could, in turn, be used as a proxy for growth capital PFP. This growth capital proxy could then be aggregated with O&M PFP into a single index.

The resulting index would include capital costs associated with capital replacement, enhanced capacity, safety and all other, non-growth factors driving capital cost. This capital measure would therefore go well beyond growth capital PFP. In fact, the process of aggregating O&M PFP with capital PFP would literally re-create *total* factor productivity. This is precisely the outcome that the BCUC found was not "relevant to be applied to FEI and FBC's MRPs", since "the X Factor applies only to O&M expenses and a small part of the capital expenditures."

Given the data constraints, and the fact that TFP measures do not align with the costs recovered by the Companies' plans, LKC believes O&M PFP is the best, practical measure for FEI's rate plan. Over 70% of FEI's formula-driven costs are associated with O&M, so the majority of costs recovered by the plan will be reflected in FEI's productivity factor. Any alternative metric raises concerns regarding data, methodology, and consistency between the scope of the productivity measure and the revenues recovered under FEI's formula plan.

In sum, it is appropriate to calibrate the Companies' indexing formulas using measures of O&M PFP rather than total factor productivity. Doing so aligns the metrics used in the formulas with the costs covered by those formulas. Developing appropriate O&M metrics for the indexing formulas is also a straightforward application of indexing theory, as discussed below.

4. Indexing Basics and Application to FortisBC

4.1 Indexing Basics

The growth in O&M PFP is defined as the growth in total output minus the growth in O&M input quantities. Because the Companies' indexing formulas are applied on a per customer basis, the appropriate output measure for both Companies is the number of customers.[8] Customer numbers are measured and reported directly by utilities.

In contrast, O&M input quantities are not observed and measured directly. Instead, they are measured by recognizing that an index of O&M costs is equal to the product of an O&M input price index and an O&M input quantity index. This is expressed mathematically below:

$$OM^{Inputprice} * OM^{Quantity} = OM^{Cost} \qquad [1]$$

If we take the natural logarithm of both sides of equation [1] and differentiate with respect to time, it leads to the following expression (where %Δ is the percent change in the associated variable).

$$\%\Delta OM^{Inputprice} + \%\Delta OM^{Quantity} = \%\Delta OM^{Cost} \qquad [2]$$

Equation [2] can be re-expressed as

$$\%\Delta OM^{Quantity} = \%\Delta OM^{Cost} - \%\Delta OM^{Inputprice} \qquad [3]$$

Equation [3] shows that growth in the quantity of O&M inputs is equal to growth in O&M cost minus the growth in O&M input prices. Subtracting the measured growth in O&M input quantities from the growth in outputs is equal to the growth in O&M PFP.

4.2 The Application to FortisBC

These calculations can be illustrated through applications to FEI's and FBC's own experience. In this section, LKC will develop O&M PFP measures for the Companies for two distinct and relevant sample periods. The first period is 2014-2022. The second period is 2007-2022.

The 2014-2022 period coincides with the Companies' formula rate plans. This period therefore reflects the Companies' most recent experience. In addition, the 2014-2022 period coincides with the BCUC's explicit use of productivity and stretch factors within the Companies' rate frameworks. The

[8] This result is derived and proven in Appendix One, for both FEI and FBC.

Companies' O&M PFP trends over this period may therefore shed light on how the Companies have performed under this recently adopted regulatory approach.

The second sample period is 2007 through 2022. The 2022 endpoint of this period represents the most recent year for which relevant data are available to calculate O&M PFP. The 2007 starting point was chosen to calculate a 15-year trend in industry O&M PFP.

Using a 15-year period to estimate productivity trends has become widespread in incentive regulation. This period is long enough to average out the annual "ebbs and flows" in utility expenditures and thereby minimize the impact of year-to-year volatility and the experience of a small number of years on estimated productivity growth. At the same time, this period is recent enough to reflect the industry's current, long-run conditions rather than dated, obsolete experience. By balancing these objectives, a 15-year sample period is likely to provide a reliable measure of long-run productivity trends (partial or total-factor).

LKC will therefore use a 2007-2022 period to estimate long-run O&M PFP trends for FEI and FBC. To facilitate comparisons of the Companies' 2014-2022 and 2007-2022 O&M PFP results, the O&M measure used in both sample periods will be gross O&M. For both FEI and FBC, gross O&M is somewhat greater than formula O&M between 2014 and 2022. Gross O&M costs are reported directly by FortisBC and easily expressed on a growth rate basis.

Each company's O&M input prices must also be computed. In its 2014-2019 MRPs, input price inflation was a weighted average of inflation in BC average weekly earnings and the BC-CPI, with weights of 55% and 45% applied to the BC-AWE and BC-CPI, respectively. In the 2020-2024 MRPs, weights on the AWE and BC-CPI were based on FEI's and FBC's actual cost shares from the year before. LKC used data on the BC-AWE and BC-CPI and annual cost share weights to compute a Tornqvist indices of monthly O&M input prices in BC. Inflation in these O&M input prices can then be subtracted from the growth in gross O&M costs to calculate the growth in O&M input quantities.[9]

Subtracting the growth in O&M input quantities from output growth will by definition be equal to growth in O&M PFP. It can be shown mathematically that the appropriate output measure to apply in the Companies' rate plans is the number of customers. It therefore follows that FEI's and FBC's O&M PFP growth is equal to the growth in its number of customers minus the growth in O&M input quantities, as computed in equations [1] through [3].

LKC used this framework to estimate the growth in O&M PFP for FEI and FBC for the 2014-2022 and 2007-2022 periods. These illustrative examples therefore calculate the Companies' "internal" O&M PFP growth for two periods: 1) the 2014-2022 formula years; and 2) the longer-term, 2007-2022 period.[10]

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[9] The basic form of the Tornqvist input price index is $\ln(IP_t/IP_{t-1})=\sum(1/2)*(S_{i,t}+S_{i,t-1})*\ln(xp_{1,t}/xp_{t-1})$, where IP_t is the input price index in year t, $S_{,i,t}$ is the applicable cost share for input price subindex i in year t, and $xp_{i,t}$ is the value of the input price subindex xp_i in year t.

[10] For FEI, the 2014 value of O&M costs is equal to formula O&M plus O&M costs for FEVI, and FEW, since all of those O&M costs were subsequently included in FEI's MRP.

Beginning with FEI, Table 1 below shows FEI's average customer growth, average growth in gross O&M for gas distribution, and average O&M input price inflation, for both sample periods. O&M PFP is then computed as average customer growth minus [average growth in gross O&M minus average growth in O&M input prices]. All growth rates are in logarithmic terms.

Table 1

FEI's "Internal" O&M PFP Growth over the 2014-2022 and 2007-2022 Periods

Sample Period	2014-2022	2007-2022
Customer numbers	1.31%	1.08%
O&M	3.02%	3.16%
Input Price inflation	2.97%	2.42%
OM Quantity growth	0.05%	0.74%
O&M PFP Trend	1.26%	0.34%

Beginning with the 2014-2022 period, FEI's customers have grown by 1.31% per annum during these years. Gross O&M expenses grew at an average annual rate of 3.02%, while O&M input price inflation averaged 2.97% per annum. As a result, O&M input quantities increased by 0.05% per annum (i.e. 3.02% O&M growth minus 2.97% input price inflation = 0.05% change in O&M quantity). When the 0.05% annual change in input quantities is subtracted from the 1.31% customer growth rate, it can be seen that FEI's O&M PFP trend over the 2014-2022 formula years is 1.26%.

In contrast, FEI's customer numbers grew more slowly over the long-term, 2007-2022 period (1.08% per annum, compared with 1.31% annual growth between 2014 and 2022). Even more saliently, FEI's O&M quantities grew at an average annual rate of 0.74% over the 2007-2022 period, which is clearly well above the 0.05% average *increase* in O&M input quantity over the shorter sample period. There is accordingly a sharp contrast between FEI's 1.26% annual PFP growth for the 2014-2022 interval compared with FEI's annual PFP growth of 0.34% per annum over the longer-term, 2007-2022 period.

Turning next to FBC, Table 2 below presents the same, relevant data for FBC's electricity operations for the 2014-2022 and 2007-2022 periods. Beginning with the shorter 2014-2022 period, FBC customers grew at an average rate of 1.59% per annum, while the company's gross O&M grew by 0.90% per annum. O&M input prices grew at a 2.99% rate, so O&M output quantity *declined* by 2.09% per annum (*i.e*. 0.90%-2.99%=-2.09%). When this 2.09% annual decline in O&M quantity is subtracted from FBC's 1.59% customer growth, it shows that FBC's O&M PFP increased by 3.68% per annum between 2014 and 2022.

Table 2

FBC's "Internal" O&M PFP Growth over the 2014-2022 and 2007-2022 Periods

Sample Period	2014-2022	2007-2022
Customer numbers	1.59%	1.32%
O&M	0.90%	2.67%
Input Price inflation	2.99%	2.43%
OM Quantity growth	-2.09%	0.24%
O&M PFP Trend	3.68%	1.08%

Over the 2007-2022 period, FBC's customer numbers grew by 1.32% per annum, or 27 basis points below its 2014-2022 trend. O&M input quantities also grew by 0.24% per annum, which is well above the average annual 2.09% *decline* in O&M quantity over the shorter 2014-2022 period. Overall, FBC's O&M PFP grew by 1.08% per annum over long-term, 2007-2022 period, which is less than one-third of its measured O&M PFP growth over the shorter, 2014-2022 interval.

These illustrations have some important implications for the Companies' proposed indexing formulas. First, they show that it is feasible, and relatively simple, to derive productivity measures that focus entirely on O&M costs and O&M PFP, rather than total costs and TFP. This is essential, since the BCUC has found that "TFP studies are not sufficiently relevant to be applied to FEI and FBC's MRPs in this instance."

Second, and relatedly, the illustrations show that O&M PFP studies are a better fit for the indexing plans than TFP evidence. Using O&M evidence to calibrate the Companies' productivity factors aligns the metrics used in the MRPs with the majority of costs recovered by the indexing formulas. This alignment would be weaker if productivity factors were based on TFP evidence.

The data also show that O&M PFP measures can be volatile. This is evident in the divergent estimates of O&M PFP growth for the 2014-2022 and 2007-2022 periods, for both companies. This is an important finding, because it supports the view that changes in O&M PFP can be affected by a wide range of factors, including the timing of relatively large O&M expenditures, changes in inflationary pressures, and other exogenous factors that impact output growth, O&M growth, or both.

As discussed above, these ebbs, flows, and transitory developments in business operations tend to balance out over longer sample periods. Longer-term measures of O&M PFP growth therefore provide more reliable estimates of underlying O&M PFP trends for utility industries. This, in turn, implies that longer-term measures of O&M PFP are generally a more appropriate basis for productivity factors in index-based incentive regulation plans than O&M PFP measured over relatively short intervals.

Finally, the data show that the Companies' O&M PFP growth improved markedly over the 2014-2022 period. These O&M PFP improvements coincided with more rapid customer growth for the

Companies, so it is reasonable to conclude that some of the O&M PFP improvement has been driven by exogenous, and perhaps transitory, output growth. It is also possible that the regulatory frameworks put in place in 2014 have strengthened incentives and contributed to improved O&M PFP cost performance.

However, it would not be appropriate to link the Companies' productivity factors to their own O&M PFP results. As explained in Section Two above, productivity factors must rely on data that are "external" to the utility's own experience. Severing the link between a utility's allowed costs and its actual costs is necessary to create strong performance incentives. Linking X factors to a utility's own cost performance therefore undermines incentives and is antithetical to the theory and practice of incentive regulation.

The competitive market paradigm provides a more solid foundation for calibrating the Companies' productivity factors. Well-designed incentive regulation plans create strong performance incentives for FEI and FBC by relying on productivity factors based on industry-wide, long-term trends in their respective industries. The Companies' customers benefit from the plan's stretch factors and, importantly, from cost savings attained by the Companies under incentive regulation that are rebased into rates established at the outset of new regulatory plans. The following section estimates appropriate industry-wide O&M PFP growth measures for the Companies' rate frameworks.

5. Productivity Factors for FEI and FBC

As discussed above, using a 15-year period to estimate productivity trends has become widespread in incentive regulation. This period is long enough to average out the annual ebbs and flows in utility expenditures and thereby minimize the impact of year-to-year volatility in O&M PFP. LKC has therefore used a 15-year, 2007-2022 period to estimate O&M PFP trends for both the gas distribution and the electric utility transmission and distribution industry. Below LKC develops an estimated productivity factor for FEI's O&M cost recovery mechanism. This is followed by estimating a productivity factor for FBC's O&M cost recovery mechanism.

5.1 FEI

LKC developed a productivity factor for FEI using data on the U.S. gas distribution industry. This work relied on a sample of 54 U.S. gas distributors. The sampled companies are listed in Table 3 below.

Table 3

U.S. Gas Distributors used to estimate industry O&M PFP
2007-2022

Sample Company	
Atlanta Gas Light Company	North Shore Gas Company
Avista Corporation	Northern Illinois Gas Company
Baltimore Gas and Electric Company	Northern Indiana Public Service Company
The Berkshire Gas Company	Northern States Power Company
Black Hills Energy Arkansas, Inc.	Ohio Gas Company
Bluefield Gas Company	Orange And Rockland Utilities, Inc.
Boston Gas Company	Pacific Gas and Electric Company
Brooklyn Union Gas Company	The Peoples Gas Light and Coke Company
Cascade Natural Gas Corporation	Peoples Gas System
Central Hudson Gas & Electric Corporation	Public Service Company Of North Carolina, Inc.
Colonial Gas Company	Public Service Electric and Gas Company
Columbia Gas of Kentucky, Inc.	Puget Sound Energy, Inc.
Columbia Gas of Maryland, Inc.	Questar Gas Company
Connecticut Natural Gas Corporation	Rochester Gas and Electric Company
Consolidated Edison Company Of New York, Inc.	South Jersey Gas Company
Consumers Energy Company	Southern California Gas Company
Corning Natural Gas Corporation	The Southern Connecticut Gas Company
Delta Natural Gas Company, Inc.	Southern Indiana Gas and Electric Company
DTE Gas Company	St. Joe Natural Gas Co, Inc.
Duke Energy Ohio, Inc.	St. Lawrence Gas Company, Inc.

Sample Company	
Louisville Gas and Electric Company	Superior Water, Light and Power Company
Madison Gas and Electric Company	The East Ohio Gas Company
Mountaineer Gas Company	Virginia Natural Gas, Inc.
National Fuel Gas Distribution Corporation	Washington Gas Light Company
New Jersey Natural Gas Company	Wisconsin Gas LLC
New York State Electric & Gas Corporation	Wisconsin Power and Light Company
Niagara Mohawk Power Corporation	Yankee Gas Services Company

Our methodology for estimating O&M PFP trends for FEI's rate framework is similar to the approach previously applied in Section 4. LKC used the S&P utility database to compute growth in gas distributors' customer numbers. We also used S&P data for gas distributors' O&M expenses, excluding gas purchase costs.

LKC also developed an input price index for the U.S. gas distribution industry that was comparable to the input price index described above for FEI. However, the U.S. input price index naturally utilized American counterparts to BC's labor and non-labor input price measures. For the labor input price index, LKC substituted the BC-AWE with the U.S. Employment Cost Index for Utilities. For the non-labor measure, we substituted the BC-CPI with the U.S. Gross Domestic Product Price Index ("GDP-PI"). We applied the same, annual weights used in FEI's plans to these U.S.-based labor and non-labor price indices.[11]

The results of the O&M PFP research for the U.S. gas distribution industry are presented in Table 4 below.

Table 4

Computation of O&M PFP Trend for U.S. Gas distribution
Average 2007-2022

Customer Growth	O&M Growth	Industry Input Price Inflation	O&M Quantity Growth	O&M PFP Growth
0.67%	2.98%	2.59%	0.39%	0.28%

It can be seen that customer growth for gas distributors averaged 0.67% per annum. Input prices grew by 2.59% per annum over the 2007-2022 period. O&M costs grew by 2.98% per annum, and O&M quantity accordingly grew at an average rate of 0.39%. Subtracting O&M input quantity growth from the average growth in customers shows that O&M PFP for the gas distribution industry has grown by 0.28% per annum over the sample period.

[11] For the 2014-2019 MRPs, these weights were 55% and 45%, respectively. After 2019, LKC used the same, annually updated weights that were in effect for the 2020-2022 MRPs. We then used the relevant weights for each year and the U.S labor and non-labor subindices to construct a Tornqvist index of O&M input prices, which was in turn used to measure input price inflation in the US gas distribution industry.

5.2 FBC

FBC's circumstances are unique, and they pose challenges when developing an appropriate O&M PFP measure for its rate framework. FBC is a vertically integrated electric utility (VIEU), which were once the norm in the industry but have become less common as utilities have divested generation assets. It also uses hydropower to generate electricity which, of course, is the dominant source of power generation in BC and the northwestern U.S. but is less prominent in much of North America. FBC's hydropower operations are also diverse. It owns and operates four small "run of the river" facilities on the Kootenay river, which differ from the large water storage dams that generate most of the power in the region. It also operates and maintains five hydro facilities owned by others.

In addition, FBC delivers power to a primarily rural, low customer-density territory that is experiencing significant residential and commercial growth in the Okanagan region and cities like Kelowna. FBC's small customer numbers and relatively dispersed operations may be expected to increase its O&M unit costs relative to the electric utility industry norm.

While FBC is a VIEU, its electricity transmission and distribution ("T&D") and related customer care operations account for the bulk of its O&M costs. Over the 2007-2022 period, generation accounted for just 5.2% of FBC's O&M costs. This share has been declining over time, and it is well below generation's share of O&M costs for most VIEUs.

Because generation accounts for a small portion of FBC's O&M, it is reasonable to exclude generation expenses from the PFP analysis used to establish an appropriate, industry-based productivity factor for FBC's rate framework. An O&M PFP measure that excludes generation expenses will still reflect approximately 95% of the O&M expenses recovered by FBC's rate plan. When FBC's generation costs are excluded, its O&M costs can be allocated into four broad categories:

1) Transmission O&M (including system control expenses);
2) Distribution O&M;
3) Customer Care O&M (*i.e.* customer accounts and customer service); and
4) Administrative and General expenses.

LKC focused entirely on those four cost categories when estimating industry O&M PFP trends for electric utilities. However, because of FBC's unusual conditions, small size and dispersed operations, LKC estimated O&M PFP trends for two different samples of electric utilities. The first sample was comprised of 20 relatively small, U.S. electric utilities whose business conditions make them plausible "peers" for FBC. These small company, peer utilities are listed in Table 5.

Table 5

FBC's Small Company, Electric Utility Peers

Alaska Electric Light and Power Company
Black Hills Power Company
Black Hills, Colorado Electric, Inc.
Cleco LLC
Consolidated Water Power Company
Empire District Electric Company
Evergy, Kansas South Inc.
Evergy, Missouri West Inc.
Green Mountain Power Corp.
Hawaiin Electric Company
Hawaii Electric Ligtht Company
Kentucky Power Company
Kingsport Power Company
Maui Electric Company, Ltd.
Minnesota Power Enterprises Inc.
Mississippi Power Company
Monogahela Power Company
Otter Tail Power Company
Upper Peninsula Power Company
Wheeling Power Company

The 20 selected peers have relatively high-quality data over the 2007-2022 period used to estimate O&M PFP trends.[12] They are also representative of the diversity in size and geographic location of the U.S. electric utility industry. In addition, the 20 sampled VIEUs served an average of 163,252 customers in 2022, which is comparable to FBC's 147,112 customer numbers in the same year. Given this similarity in size, the potential to achieve scale economies across the small company sample is likely to be similar to FBC's own potential to realize scale economies.[13]

12 Small utilities often report more missing data, particularly for relatively distant periods, than larger utilities.

13 This conclusion is bolstered by the relatively equal distribution of sampled VIEUs by customer numbers: four companies had 50,000 or fewer customers; four companies had customer numbers between 50,001 and 100,00 customers; six companies had customer numbers between 100,001 and 200,000 customers; two companies had customer numbers between 200,001 and 300,000 customers; and four companies had customer numbers between 300,000 and 400,000.

The second sample was a broad-based, 82 company sample that comprises nearly the entire U.S. electric utility industry. This broader sample is therefore consistent with the competitive market paradigm, wherein industry-wide productivity trends are used to set productivity factors. A complete list of the 82 sampled companies is presented in Table 3.2 in Appendix 3.

LKC calculated O&M PFP trends for the US small company and entire industry samples over the 2007-2022 period. Data on electric utility customer numbers and O&M expenditures excluding generation expenses were obtained from the S&P utility database. O&M input price indices were also developed for the U.S. electric utility industry, using the same methodology and labor and non-labor price measures described above.[14] The results of the O&M PFP research for the small company sample is presented in Table 6 below.

Table 6

Computation of O&M PFP Trend for Small Electric Utility Peers 2007-2022

Customer Growth	O&M Growth	Industry Input Price Inflation	O&M Quantity Growth	O&M PFP Growth
0.42%	3.39%	2.55%	0.84%	-0.42%

It can be seen that customer growth for the small company sample has been a modest 0.42% per annum. O&M expenses grew much more rapidly, at an average rate of 3.39.%. Annual input price inflation was 2.55%, which implies that O&M input quantity grew by 0.84% per annum (*i.e.* 3.39%-2.55%=0.84%). When the average growth in O&M inputs is subtracted from the 0.42% output growth, it yields a -0.42% O&M PFP trend.

This result is consistent with the challenging conditions facing many small U.S. electric utilities. In particular, it should be noted that the small company sample averaged just 0.42% customer growth per annum over a sustained, 15-year period. While small companies often have the potential to achieve scale economies that reduce unit costs, these scale economies clearly cannot be achieved for utilities experiencing anemic, or even non-existent, output growth.

These long-term trends for U.S. small electric utilities contrast with FBC's own O&M PFP experience, as previously presented in Table 2. Table 2 shows that FBC averaged customer growth of 1.32% per year between 2007 and 2022. This is more than triple the customer growth for the US small company sample over the same period. Since FBC's annual output growth exceeds the small companies'

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[14] While the same methodology was used to develop input price indices for the U.S. gas distribution and electric utility industries, the FortisBC weights used to construct industry input price indices differed somewhat between the gas distribution and electric utility industries. Before 2020, FortisBC's labor and non-labor weights were 55% and 45%, respectively, for both FEI (gas distribution) and FBC (electric utility). Beginning in 2020, FortisBC used different weights for its gas and electricity operations, depending on actual cost shares from the preceding year. For FEI, labor's weight was 52% in 2020 and 2021, and 51% in 2022. For FBC, labor's weight was 62% in 2020 and 2021, and 63% in 2022. LKC's analysis and construction of input price indices did not extend beyond 2022.

average growth by 214%, it is not surprising that FBC's O&M PFP trend differs markedly from those of its small electric utility peers.

Table 7 computes O&M PFP trends for the sample of 82 electric utilities. This sample includes nearly the entire U.S. electric industry, including the 20 small electric utilities examined above. However, the larger sample also includes electric utilities operating under a wide range of geographic and business conditions. Because this broad, diverse sample encompasses the entire electric utility industry, it is consistent with the competitive market paradigm that underpins both the theory and practice of incentive regulation.

Table 7

Computation of O&M PFP Trend for U.S. Electric Utility Industry 2007-2022

Customer Growth	O&M Growth	Industry Input Price Inflation	O&M Quantity Growth	O&M PFP Growth
0.91%	3.26%	2.55%	0.71%	0.20%

In 2022, the average U.S. electric utility served 915,534 customers. This is more than five times greater than the U.S. small company sample. Customer growth for the entire, 82 company sample averaged 0.91% per annum over the 2007-2022 period. This is more than double the customer growth of the 20 small company cohort within the broader industry. It is also more similar to (but still somewhat below) FBC's long-term, 2007-2022 customer growth rate of 1.32%.

Non-generation O&M expenses grew at an average rate of 3.26.% for the larger company sample. Annual input price inflation was 2.55%, and O&M input quantity grew accordingly by 0.71% per annum. When the growth in O&M quantity is subtracted from customer growth, the measured O&M PFP trend for the 82 electric utility sample is 0.20%

LKC believes the PFP trend that uses the entire 82 company sample is a more appropriate basis for FBC's productivity factor than the small company alternative. While FBC's cost structure may in theory be more similar to its small company peers, the differences in output growth between FBC and the small company sample are stark. Given this disparity, and the theoretical and precedential support for using the largest possible sample to calibrate productivity factors, LKC recommends that FBC's productivity factor be equal to the industry-wide, long-run estimate of 0.20% O&M PFP growth.

6. Stretch Factors for FEI and FBC

6.1 General Framework

In addition to productivity factors, the Companies' rate frameworks include stretch factors. As discussed above, the value of stretch factors often depends on two matters. The first is the company's cost performance at the outset of the plan. Benchmarking studies are often used to assess a utility's relative cost performance.

The second relevant issue is how many times a utility has been subject to incentive rate-setting. All else equal, it is increasingly difficult for utilities to achieve incremental cost performance gains for each subsequent iteration or "generation" of an incentive regulation plan. The BCUC has supported this position. In particular, when the 2014-2019 MRPs expired, the BCUC stated that:

> "we acknowledge that FortisBC has just ended the Current PBR Plans and it would not be reasonable to expect the same level of productivity improvement that was achieved over the last six years. We therefore accept there will be increased challenges associated with achieving savings as the Utilities undertake a further performance-based framework. Accordingly, the Panel accepts that a reduction of current X-Factors from the Current PBR Plans for both Utilities is appropriate."[15]

The principle articulated by the BCUC in 2020 still applies and should be reflected in the Companies' proposals. There are increased challenges associated with achieving savings under each additional rate plan and, in light of these challenges, a reduction of the Companies' current X-Factors (and more particularly, a reduction in its stretch factors) is often appropriate in the proposed plans.

Notwithstanding this general principle, determining an appropriate stretch factor is rarely as formulaic as estimating productivity trends.[16] A degree of judgement is inherent, and inevitable, in any determination of a reasonable stretch factor value. However, judgement can and should be informed by a rigorous conceptual framework and relevant empirical evidence. To promote transparency and rigor, LKC has outlined the approach it followed for developing stretch factor recommendations for FEI and FBC:

1. First, we carefully reviewed the BCUC's stretch factor findings for the 2014-2019 and 2020-2024 MRPs. We drew conclusions on how much stretch factors changed between those plans. These estimated changes were then taken to be an appropriate basis for adjusting stretch factors in the Companies' subsequent rate frameworks in light of the "increased challenges associated with achieving savings as the Utilities undertake a further performance-based framework."

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[15] BCUC, *op cit*, pp. 61-62.

[16] It should be noted, however, that regulators in Ontario and Massachusetts have used formulas to update stretch factors.

2. Next, we reviewed benchmarking evidence that compares FEI's and FBC's O&M unit costs to equivalent costs within the Companies' respective industries, as well as the Companies' O&M 2007-2022 O&M PFP trends relative to analogous trends for the respective industries.
3. Drawing on the BCUC regulatory precedents and the empirical results, LKC recommended stretch factors that we believe are consistent with the regulatory and empirical evidence.

6.2 Regulatory Findings and Stretch Factor Precedents

As discussed, stretch factors often depend on the number of times a utility has been subject to incentive regulation. In general, the potential for incremental cost performance gains, and hence the appropriate value for the stretch factor, will decline for later iterations, or "generations," of utility incentive regulation plans. This understanding is evident in FortisBC's recent regulatory history.

In the 2014-2019 MRPs, the approved stretch factors for FBC and FEI were 0.2% and 0.1% respectively. FEI's productivity factor was equal to 0.90%, while FBC's was slightly higher, at 0.93%. The Companies' overall X factors were therefore 1.1% for FEI and 1.03% for FBC.

The BCUC did not identify specific stretch factors for the following 2020-2024 MRPs. Instead, it established an X-factor of 0.5%, inclusive of the stretch factor, for both FBC and FEI. This represented a more than 50% decline in the overall X factor for both companies.

In light of this X factor reduction, when the BCUC found "it would not be reasonable to expect the same level of productivity improvement that was achieved over the last six years," it clearly indicated that it was reasonable to expect a lower level of productivity improvement for FortisBC under the 2020-2024 MRPs. Obviously, the BCUC would not reduce X factors if it expected productivity growth to accelerate, or even remain unchanged.

However, the BCUC did not provide any indication on how slowing productivity growth might be allocated between the Companies' approved productivity factors and approved stretch factors. Evidence on this issue is important because, in principle, it is the stretch factor that is most directly impacted by the "increased challenges associated with achieving savings as the Utilities undertake a further performance-based framework." The productivity factor, in contrast, depends on industry-wide trends, not company-specific conditions or a utility's increasing difficulty of identifying opportunities to make incremental cost performance gains.

In the absence of evidence on this issue, one straightforward inference on the values of approved 2020-2024 stretch factors can be obtained by allocating each company's X factor reduction proportionally across the productivity factor and the stretch factor components. For example, in the 2020-2024 plan, FEI's X factor declined from 1.1% to 0.5%, which is a 54.45% reduction. If this 54.45% reduction is applied equally to the productivity and stretch factor components of FEI's X factor, the stretch factor would decline from 0.2% to 0.091% and the productivity factor would decline from 0.9% to 0.409%.

Similarly, FBC's X factor declined from 1.03% to 0.5%, which is a 51.15% reduction. If this 51.15% reduction is applied equally to FBC's productivity and stretch factors, its stretch factor would decline from 0.1% to 0.049% and its productivity factor would decline from 0.93% to 0.0451%.

More simply, FortisBC's X factors in its 2020-2024 MRP are somewhat more than 50% below the X factors approved for the 2014-2019 MRPs. All else equal, it is reasonable to assume these X factor reductions are consistent with an approximately 50% reduction of the stretch factor components of FortisBC's 2020-2024 X factors. This is also reasonable conceptually, because it is typically more difficult to achieve incremental cost performance gains in each new iteration of incentive regulation. Regulators elsewhere have also approved similar reductions in stretch factors as utilities move from first generation to second generation incentive regulation plans. For example, when Boston Gas's first incentive regulation plan expired and a new plan was implemented, the approved stretch factor (which in Massachusetts is called a "consumer dividend") fell from 0.5% to 0.3%, which is a 40% reduction.

While the BCUC did not make any findings on stretch factor values for the 2020-2024 MRPs, we believe it is reasonable to infer that the stretch factor components of the X factors declined by about 50% in the 2020-2024 MRPs, generally in line with the declines in the X factors themselves. For FEI, this would mean that its "implicit" stretch factor in the current MRP is about 0.1%. For FBC, this implies that its "implicit" stretch factor is currently about 0.05%.

Looking ahead to the proposed rate plans, the "increased challenges associated with achieving savings as the Utilities undertake a further performance-based framework" continues to apply. Accordingly, it may be reasonable to apply the same 50% reduction in stretch factors in the proposed rate plans. Since the current, "implicit" stretch factors for FEI and FBC are approximately 0.1% and 0.05%, respectively, a further 50% reduction in stretch factors in the next rate plan would reduce those stretch factors to 0.05% for FEI and 0.025% for FBC. Given the increased challenges of finding cost savings, LKC believes these stretch factor values are consistent with BCUC precedents and merit consideration for the Companies' rate frameworks.

It should be noted, however, that these recommendations rest entirely on BC's regulatory record and precedents, as well as the principle that it is increasingly difficult to achieve incremental cost savings for additional iterations of incentive regulation. In the analysis below, LKC considers other important elements for determining appropriate stretch factors, including each Company's relative cost performance at the outset of the plan, as revealed through industry cost benchmarking studies, and related evidence on the Companies' cost performance.

6.3 FEI

LKC undertook benchmarking analyses for the Companies. In these studies, cost performance was evaluated over the three-year, 2020-2022 period. This interval is much shorter than the 2007-2022 period used to estimate industry O&M PFP trends. This is appropriate, because benchmarking evidence is designed to assess the Companies' *current* cost performance at a point in time (*i.e.* just prior to the outset of the Companies' new rate plans). In contrast, our previous evidence was designed to measure productivity over a series of years and identify long-run industry O&M PFP trends. This objective necessarily requires a longer sample period.

FEI's O&M unit costs were benchmarked against the 54 U.S. gas distributors previously used to estimate O&M PFP trends. Table 8 provides data on O&M cost per customer for FEI and for the U.S. gas distribution, 54 company average. Please note that, to permit benchmarking comparisons, all costs in Table 10 are expressed in U.S. dollars.[17]

It can be seen that FEI's O&M costs per customer are almost identical to the U.S. average. FEI's O&M unit costs are 0.2% below average O&M costs per customer across the U.S. distribution industry. In isolation, this evidence would support the view that FEI is an average cost performer.

Table 8

U.S. Gas Distribution Benchmarking
2020-2022 US$ Average

FEI Avg. Cost/Customer	U.S. Gas Distribution Cost/Customer	Percent Difference FEI/US Gas Distribution Avg.
$257.20	$262.18	-0.2%

In addition, it should be recalled that FEI's own internal, O&M PFP growth averaged 1.26% over the 2014-2022 period. This performance greatly exceeds the industry's O&M PFP trends, and by out-performing industry norms, FEI has likely generated significant cost savings for customers that have since been rebased into customer rates. This experience should also be considered when considering an appropriate stretch factor for FEI.

6.4 FBC

In Table 9, LKC benchmarked FBC's O&M cost performance against both the sample of small U.S. peer utilities and the full, electric utility industry sample.[18] Please note that, to enable cost comparisons, all FBC benchmarking analyses in Table 9 are expressed in U.S. dollars.

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[17] An exchange rate of 0.84C$/US$ was used to express FEI costs in US dollars. This value is approximately equal to the long-run, Canadian/US purchasing power exchange rate.

[18] Consolidated Water Company was appropriately included in the 20 company small cusomer group and 82 company sample used to compute O&M PFP trends.. However, it was excluded from the benchmarking analyses because it served a small number of industrial customers. Its data may therefore skew O&M cost per customer sample averages.

Table 9

Small Company and Overall Electric Utility Benchmarking, Total O&M per Customer 2020-2022 US$ Average

FBC Average Cost/Customer	U.S. Small Company Average O&M Cost/Customer	U.S. Overall Company Average O&M Cost/Customer	Percent Difference FBC/US Average Small Company Cost per Customer.	Percent Difference FBC/US Average Cost per Customer
$340.15	$947.88	$523.23	-64.1%	-35.0%

Table 9 shows that FBC's total O&M cost per customer is $340.15. This is 64.1% below the average O&M cost per customer of $947.88 for the U.S. small company sample. Table 9 also provides data on total O&M cost per customer for the full electric utility sample. It can be seen that O&M costs per customer for the electric utility industry averaged $523. This value is 44.8% below average O&M expenses per customer for the US small utility sample. [19] This finding aligns with expectations, because the relatively small and dispersed operations of the small company sample typically increase utilities' O&M unit costs relative to the industry norm.

However, many of those basic conditions also apply to FBC, and its unit O&M costs are 64.1% below their peers. It is therefore more surprising that FBC's O&M costs per customer are 35.0% below the U.S. electric utility average. This result is not expected, since the average US utility is larger and would be expected to have realized, and internalized, scale economies that have not been achieved by the average smaller utility.

Recall that O&M costs for FBC and the U.S. samples are equal to the sum of O&M costs in four different cost categories: 1) electricity distribution expenses; 2) electricity transmission expenses; 3) customer care expenses, which are in turn equal to the sum of customer accounts and customer service and information expenses; and 4) administrative and general expenses.

To provide greater insight into FBC's cost performance, LKC examined each of the four cost categories that were used to compute total O&M electric utility expenses for FBC and the two US electric utility samples. In particular, LKC benchmarked: 1) electricity distribution expenses per customer; 2) transmission expenses per customer; 3) customer care expenses per customer; and 4) administrative and general expenses per customer. These analyses examined how FBC's unit costs for each cost category compared with analogous measures for the small company and full electric utility samples. The results of this work are presented in Table 10 and are expressed in U.S. dollars.

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[19] (*i.e.* $523/$947.88 – 1 = -44.8%).

Table 10

Benchmark Comparisons of O&M per Customer by Cost Category (2020-2022)
US $ Average

Cost Category	FBC	Small Company Sample	Full Industry Sample	% Difference FBC/Small Companies	% Difference FBC/Full Industry Sample
Distribution O&M per Customer	$95.85	$321.57	$131.75	-70.2%	-27.2%
Transmission O&M per Customer	$78.74	$267.15	$126.31	-70.5%	-37.7%
Customer Care O&M per Customer	$34.74	$89.49	$92.87	-61.4%	-62.6%
A&G expenses per Customer	130.81	$269.66	$172.30	-51.5%	-24.1%
Total O&M per Customer	340.15	$947.88	$523.23	-64.1%	-35.0%

Table 10 shows that FBC's O&M unit costs were below the O&M unit costs of both the small company sample and the industry-wide sample in every cost category. FBC's O&M unit costs were at least 51% below those of its small company peers in each category. Indeed, FBC's distribution O&M per customer and transmission O&M per customer were both more than 70% lower than its peers, and FBC's customer care and A&G unit costs were each more than 51% below the small company average.

FBC's cost gaps were not as large for the industry-wide sample. However, FBC's O&M unit costs are at least 24% below the U.S. industry average in all four cost categories. FBC's total O&M per customer was 35% below the U.S. average.

Overall, FBC's benchmarking studies provide strong evidence that it is registering superior cost performance in all the non-generation activities covered by its ratemaking frameworks. It should also be remembered that FBC's own "internal" O&M PFP growth averaged 3.68% over the 2014-2022 period. This rate of O&M PFP growth greatly exceeds the O&M PFP trend typical of small utilities (-0.42% per annum), as well as the O&M PFP trend of the electric utility industry. FBC has therefore outperformed the industry's O&M PFP performance since the implementation of its incentive plans in 2014. This exceptional performance has almost certainly generated cost savings that have since been rebased into rates and thereby benefited customers.

7. X-Factor Recommendations

7.1 FEI

LKC's recommended productivity factor for FEI is 0.28%. This value is equal to the O&M PFP growth rate for the U.S. gas distribution industry for the 2007-2022 period.[20] LKC believes this recommendation is consistent with the competitive market paradigm and therefore consistent with the theory and practice of incentive regulation. LKC also believes this recommendation is consistent with the standards of rigorous empirical research and provides the most appropriate productivity "target" for FEI's upcoming rate framework.

LKC's recommended stretch factor for FEI is 0.1%. As discussed above, we believe it is reasonable to conclude that the "implicit" stretch factor in FEI's current rate plan is about 0.1%. In LKC's opinion, the evidence does not provide any compelling reason to adjust the (implicit) consumer dividend of 0.1%.

FEI's empirical evidence suggests the company is an average cost performer. However, it should also be recognized that FEI's O&M PFP trend on its recent rate frameworks has outperformed industry norms. This experience has generated cost savings that have almost certainly been rebased into rates and thereby created benefits for FEI customers.

It is also relevant that FEI's explicit consumer dividend was 0.2% in the MRP approved in 2014. FEI's upcoming rate plan will represent the third "generation" of the MRPs that were first approved in 2014. In light of the "increased challenges associated with achieving savings as the Utilities undertake a further performance-based framework," a 0.1% reduction in the consumer dividend over the course of two incentive regulation plans would be reasonable and consistent with the BCUC's past findings regarding the increased challenges of achieving savings in "further" incentive-base plans.

Based on the empirical evidence, BCUC's regulatory precedents, economic reason and the difficulty of finding cost savings in new iterations of incentive regulation, LKC believes an explicit stretch factor of 0.1% is reasonable and warranted for FEI.

Given a recommended productivity factor of 0.28%, and a stretch factor of 0.1%, LKC recommends that an overall X factor of 0.38% be applied to FEI's rate framework.

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[20] It should be noted that, when expressed to three digits, the measured O&M PFP trend for the U.S. gas distribution industry was equal to 0.274%, which rounds down to 0.27%. However, the components used to measure industry O&M PFP add up to 0.28% (*i.e.* 0.67%-(2.98%-2.59%) =0.28%. It is not unusual for productivity results to differ by a basis point depending how they are calculated, and in LKC's opinion either 0.27% or 0.28% would be a reasonable productivity factor for FEI. To promote transparency and understaning of how the components of O&M PFP growth interact, LKC recommends a productivity factor of 0.28%.

7.2 FBC

LKC recommends a productivity factor of 0.20% for FBC's rate framework. This value is equal to the O&M PFP growth rate for the U.S. electric utility industry for the 2007-2022 period. LKC believes this recommendation is consistent with the competitive market paradigm and therefore consistent with the theory and practice of incentive regulation. We also believe this recommendation is consistent with the standards of rigorous empirical research and provides the most appropriate productivity "target" for FBC's upcoming rate framework.

LKC also recommends a stretch factor of zero for FBC's rate plan. This recommendation is supported by the empirical benchmarking evidence showing that FBC exhibits exceptional cost performance within the electric utility industry. FBC's O&M unit costs are 64% below the O&M unit costs of its small company peers and 35% below the average O&M unit costs of the US electric utility industry. FBC's exceptional cost performance also extends to all four cost categories that comprise approximately 95% of the costs recovered by FBC's rate framework. In addition, FBC's cost performance on its recent rate plan greatly exceeds industry norms, and this performance has almost certainly generated cost savings that have been rebased into FBC's rates and benefited customers. In light of all this evidence, LKC believes that no stretch factor is warranted for FBC. Given a recommended productivity factor of 0.20%, and the recommended stretch factor of zero, LKC recommends that an overall X factor of 0.20% be applied to FBC's rate framework.

8. Customer Growth Factors for FEI and FBC

In addition to the productivity and stretch factors, LKC was asked to comment on the appropriateness of the discount applied to the growth factor in FEI's and FBC's O&M indexing formulas. This issue has been somewhat controversial in previous proceedings, where parties argued for or against discounting the growth factor using statistical tools such as correlation coefficients. While this analytical approach may have intuitive appeal, the customer growth issue ultimately does not hinge on statistical data or tests. Instead, the appropriate value of the customer growth factor should be determined by a proper application of indexing logic and cost theory.

One illustration of this point is provided in a May 2021 Electricity Journal article titled *Escalating Power Distributor O&M Revenue*.[21] The paper was written by Dr. Mark Lowry and David Hovde. The name of the article is itself an indicator of its relevance to the Companies' MRPs, which are focused on adjusting (aka "escalating") O&M revenue.

The paper focuses on developing an appropriate index-based framework for adjusting allowed O&M revenue in incentive regulation plans. In doing so, it identifies the main components of O&M revenue indexing formulas, as well as what those components measure. For example, Lowry and Hovde write:

> "The growth in the cost of a company is the difference between the growth in its input price and productivity indexes plus the growth in a cost-based output index. This result provides the basis for a revenue cap index of general form:
>
> > Growth Allowed Revenue Utility = growth Input Prices − (X + S) + growth ScaleCUtility
> >
> > where:
> >
> > X = ProductivityC
> >
> > S = Stretch factor (aka consumer dividend).
>
> Here X, the X factor, reflects a base productivity growth target which is typically the average trend in the productivity of a regional or national sample of utilities ("ProductivityC").
>
> The scale escalator ("ScaleC Utility") has one or more output variables that drive cost. A consistent cost-based treatment of output growth should be used in the productivity research."[22]

While the terminology in the article is a bit different, Lowry and Hovde's O&M indexing framework is similar to the indexing framework used for FortisBC since 2014. The growth in what they call "a revenue cap index of general form" depends on four factors:

1) an inflation factor (*i.e.* "growth InputPrices"); minus a
2) productivity factor (*i.e.* "the X factor, which "reflects a base productivity target"); minus a

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[21] Lowry, M.L. and D. Hovde, *Escalating Power Distributor O&M Revenue*, Electricity Journal, 34 (2021), 106975. Dr. Lowry has previously advised the Commercial Energy Consumers Association of British Columbia.

[22] Lowry, M., *op cit.*

3) stretch factor (*i.e.* “S=Stretch factor aka consumer dividend”); plus a
4) customer growth factor (*i.e.* “the scale escalator (which) has one or more output variables that drive cost”).

Moreover, Lowry and Hovde emphasize that the revenue cap index of general form applies to “subsets of cost as well as to total cost. Thus, an index designed to escalate only O&M revenue can reasonably take the form”: Growth Allowed O&M revenue = growth O&M Input Prices – [(X factor + Stretch factor)] + growth scale escalator. [23]

The general framework described by Lowry and Hovde has been applied in FortisBC’s MRPs. The FEI and FBC applications of this framework use customer numbers as the sole “scale escalator,” or output measure, for each plan. The Companies’ MRPs also use an established and approved measure of industry input price inflation. Going forward, the X-factor proposals use measures of O&M partial factor productivity trends as the basis for their productivity factors, consistent with the Lowry/Hovde model. The basic design of the Companies’ proposed indexing formulas is therefore identical with the framework developed by Lowry and Hovde.

However, the article does more than identify the components of an appropriate index-based mechanism for adjusting allowed O&M costs; it also explains what those components do, and do not, measure. For example, after emphasizing that “a consistent cost-based treatment of output growth should be used in the productivity research,” Lowry and Hovde write (in footnote 5), that the “growth of OutputsC Utility *is not the effect of output growth on cost because economies of scale are part of this effect and these are captured in the productivity trend* (emphasis added).”[24]

In other words, an important element of a “consistent cost-based treatment of output growth” is recognizing that changes in output (*i.e.* customer numbers) do not measure or reflect “the effect of output growth on cost.” Instead, “these are captured in the productivity trend.” While Lowry and Hovde do not explain why economies of scale are reflected in the productivity trend rather than the scale variable itself, the reason comes from basic microeconomic cost theory.

Cost theory shows that economies of scale is one of several sources of productivity growth. A rigorous mathematical derivation of this fact is presented (along with similar findings) in Appendix Two of this report. Since economies of scale is a component of productivity change, a properly constructed productivity index will by definition capture the impact of scale economies.

There is also a more commonplace explanation: claiming that scale economies are reflected in the growth factor puts the cart before the horse. The logical sequence of events is that customer growth occurs, and scale economies follow. The phenomenon instigating the change will not measure the consequences.

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[23] Lowry, M. *Op cit*. For clarity, the formula following the quote condenses and re-states Lowry and Hovde’s equation, but it does not change or distort its meaning or implications.

[24] Lowry, M.N., *op cit*.

Another way to look at this is that, in a well-designed cost recovery mechanism, the productivity factor and customer growth factor have two distinct purposes. The productivity factor is designed to capture all the factors contributing to achieved cost efficiencies. The customer growth factor has a different purpose: to scale revenues upward or downward in response to changes in the scale of output, as measured by customer growth. There should accordingly be a one-to-one relationship between the number of customers served and the value of revenues received.

The Companies' proposed indexing formula uses properly constructed O&M productivity indices. This change is responsive to BCUC concerns regarding the use of TFP metrics. It will also better align the MRP formulas with the costs recovered by the formulas.

In light of this more rigorous and carefully focused framework, it is also more important for other elements of the indexing formula to be properly aligned. Indexing logic, basic cost theory, and common sense all support the conclusion that economies of scale are captured in the O&M PFP trend and not the customer growth factor. For all components of the Companies' indexing formulas to be internally consistent, no discounts of the customer growth factor should be applied to the Companies' allowed O&M adjustment formulas. Any discount of the customer growth factor would be unwarranted and tantamount to a "double counting" of scale economies, which are in fact fully recovered in the productivity factors. Accordingly, LKC recommends that no discounts should be applied to the customer growth factors for FEI and FBC's proposed indexing formulas.

Appendix One: Indexing and Choice of Output

Indexing and Choice of Output:

Consider a regulatory mechanism where allowed revenue recovers cost:

(1) Revenue = Cost

Equation (2) expresses equation (1) on a rate of change basis

(2) %Δ Revenue = Δ%Cost

The lefthand side of equation (1) can be expressed as:

(3) Revenue = revenue per customer * customer numbers

Equation (3) can be re-expressed on a rate of change basis

(4) %ΔRevenue = %Δ(revenue per customer) + %Δcustomers

Total cost is equal to an index of Input prices multiplied by an index of Input quantities

(5) Cost = Input Prices * Input Quantities

Equation (5) can be re-expressed on a rate of change basis

(6) %Δ Cost = %Δ Input prices + %Δ Input Quantities

Substitute equations (4) and (6) into equation (2)

(7) %Δ Revenues per customer + %Δcustomers =%Δ Input prices +%Δ Input Quantities

Re-express equation (7)

(8) %Δ Revenues per customer =%Δ Input prices +%Δ Input Quantities - %Δcustomers

Re-express equation (8)

(9) %Δ Revenues per customer = %Δ Input prices – (%Δcustomers -%Δ Input Quantities)

Equation (9) is an example of an incentive regulation mechanism, where allowed revenues are recovered on a revenue per customer basis (*i.e.* the left hand-side of (9) is revenues per customer). The allowed change in revenues per customer is equal to the growth in input prices minus the growth in productivity (*i.e.* the last parentheses in table nine measures the change in output quantities minus the growth input quantities). It can be seen that customer numbers is the measure of output. The derivation of this mechanism therefore shows customer numbers is the appropriate output quantity measure in productivity indices when the regulatory mechanism (like FortisBC's MRPs) recovers revenues on a revenue per customer basis.

Appendix Two: Sources of Productivity Change

Sources of Productivity Change:

Productivity measures the transformation of inputs into outputs. In the present context, "inputs" refer to the resources an energy network procures in order to provide network outputs. Total factor productivity ("TFP") measures the relationship between all the outputs provided by a utility and all the inputs that the utility procured to provide those outputs. Partial factor productivity ("PFP") measures the relationship between the utility's comprehensive output and a more narrow measure of inputs. For example, labor productivity would measure the productivity of a utility with respect to its use of labor inputs only.

In most utility applications, TFP and PFP are measured with indexes that aggregate several types of output and inputs into comprehensive output quantity and input quantity metrics. Each dimension of output quantity and input quantity is measured by what is sometimes referred to as a subindex. The analysis that follows below is equally applicable for TFP and PFP applications, although TFP will be referenced more frequently. A TFP *level* index is defined as the ratio of an output quantity index to a comprehensive input quantity index.

$$TFP = \frac{Output\,Quantities}{Input\,Quantities}. \qquad [1]$$

TFP therefore represents a comprehensive measure of the extent to which firms convert inputs into outputs. Comparisons can be made between firms at a point in time or for the same firm (or group of firms) at different points in time. The latter metric is a measure of TFP growth, and the trend in a TFP index is the difference between the trends in the component output quantity and input quantity indexes.

$$trend\,TFP = trend\,Output\,Quantities - trend\,Input\,Quantities. \qquad [2]$$

The measures for PFP are analogous. A PFP level index is defined as the ratio of an index of comprehensive output quantity to an input quantity subindex, such as an index of O&M input. In this example, the growth in O&M PFP would be equal to the growth in comprehensive output quantity minus the growth in O&M input quantity. Mathematically, it can be shown that the growth in TFP can be decomposed into a weighted average of the growth in PFP for the different inputs used in production.

In casual discussions, productivity and efficiency are treated as if they are identical. This may not be surprising, but it is not correct and can be misleading. For example, a decline in measured TFP could be interpreted as an industry (or entire economy) becoming less efficient. This is usually not the case, because several factors contribute to TFP change, and efficiency is a much narrower concept.

This Appendix below presents a mathematical derivation which shows that TFP can be decomposed into several different components. Although this analysis is somewhat technical, it is useful for understanding the relationship between productivity and efficiency, as well as other concepts that are often discussed when discussing the cost structure of energy networks.

Our analysis begins by assuming a firm's cost level is the product of the minimum attainable cost level C^* and a term η that may be called the inefficiency factor.

$$C = C^* \cdot \eta . \qquad \text{[A1.1]}$$

The inefficiency factor takes a value greater than or equal to 1 and indicates how high the firm's actual costs are above the minimum attainable level.[25]

Minimum attainable cost is a function of the firm's output levels, the prices paid for production inputs, and business conditions beyond the control of management. Let the vectors of input prices facing a utility, output quantities and business conditions be given by $\boldsymbol{W}$ (= $W_1,W_2...W_J$), $\boldsymbol{Y}$ (= $Y_1,Y_2...Y_I$), and $\boldsymbol{Z}$ (= $Z_1,Z_2...Z_N$), respectively. We also include a trend variable (T) that allows the cost function to shift over time due to technological change. The cost function can then be represented mathematically as:

$$C^* = g(\boldsymbol{W}, \boldsymbol{Y}, \boldsymbol{Z}, T). \qquad \text{[A1.2]}$$

Taking logarithms and totally differentiating Equation [A1.2] with respect to time yields

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g}. \qquad \text{[A1.3]}$$

Equations [A1.1] and [A1.3] imply that the growth rate of *actual* (not minimum) cost is given by

$$\dot{C} = \left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j \varepsilon_{W_j} \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} \right) + \dot{g} + \dot{\eta}. \qquad \text{[A1.4]}$$

The term ε_{Y_i} in equation [A1.4] is the elasticity of cost with respect to output i. It measures the percentage change in cost due to a small percentage change in the output. The other ε terms have analogous definitions. The growth rate of each output quantity i is denoted by $\dot{Y}$. The growth rates of input prices and the other business condition variables are denoted analogously.

Shephard's lemma holds that the derivative of minimum cost with respect to the price of an input is the optimal input quantity. The elasticity of minimum cost with respect to the price of each input

[25] A firm that has attained the minimum possible cost has no inefficiency and an inefficiency factor equal to 1. The natural logarithm of 1 is zero, so if a firm is operating at minimum cost, the inefficiency factor drops out of the analysis that follows.

j can then be shown to equal the optimal share of that input in minimum cost (SC_j^*). Equation [A1.4] may therefore be rewritten as:

$$\begin{aligned}\dot{C} &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \sum_j SC_j^* \cdot \dot{W} + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}. \\ &= \sum_i \varepsilon_{Y_i} \cdot \dot{Y} + \dot{W}^* + \sum_n \varepsilon_{Z_n} \cdot \dot{Z} + \dot{g} + \dot{\eta}.\end{aligned} \qquad \text{[A1.5]}$$

The W^* term above is the growth rate of an input price index, computed as a weighted average of the growth rates in the price subindexes for each input category. The *optimal* (cost-minimizing) cost shares serve as weights. We will call W^* the optimal input price index.

Recall from the indexing logic presented earlier in this document that:

$$T\dot{F}P = \dot{Y} - \dot{X} \qquad \text{[A1.6]}$$

And

$$\dot{X} = \dot{C} - \dot{W} \qquad \text{[A1.7]}$$

The input price index above is weighted using actual rather than optimal cost shares. Substituting equations [A1.6] and [A1.7] into [A1.5], it follows that:

$$\begin{aligned}T\dot{F}P &= \dot{Y} - \left(\dot{C} - \dot{W}\right) \\ &= \dot{Y} - \left[\left(\sum_i \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_n \varepsilon_{Z_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right) - \dot{W}\right] \\ &= \dot{Y} - \left[\left\{\left[\left(1 - \frac{1}{\sum \varepsilon_{Y_i}}\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \sum_i \frac{\varepsilon_{Y_i}}{\sum_i \varepsilon_{Y_i}} \cdot \dot{Y}_i\right] + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right\} - \dot{W}\right] \\ &= \dot{Y} - \left\{\left[\left(\frac{1}{\sum \varepsilon_{Y_i}} - 1\right) \cdot \sum \varepsilon_{Y_i} \cdot \dot{Y}_i + \dot{Y}^{\varepsilon} + \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n + W^* + \dot{g} + \dot{\eta}\right] - \dot{W}\right\} \\ &= \cdot\left(1 - \sum \varepsilon_{Y_i}\right) \cdot \dot{Y}_i + \left(\dot{Y} - \dot{Y}^{\varepsilon}\right) - \left(W^* - \dot{W}\right) - \sum_n \varepsilon_{\dot{Z}_n} \cdot \dot{Z}_n - \dot{g} - \dot{\eta}\end{aligned}$$

[16]

The first is the **scale economy effect**. Economies of scale are realized if, when all other variables are held constant, changes in output quantities lead to reductions in the unit cost of production.[26]

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26 Technically, this will be the case if the sum of the cost elasticities with respect to the output variables in the cost function is less than one.

The second term is the **nonmarginal cost pricing effect**. This is equal to the difference between the growth rates of two output quantity indexes. The first is the index used to compute TFP growth, which in ratemaking applications should be constructed by weighting each output by its share of regulated revenue. Hence, the first term is the growth in an output quantity index constructed using revenue weights. The other output quantity index, denoted by $\dot{Y}^{\varepsilon}$, is constructed using cost elasticity weights. It can be shown that revenue weights will differ from cost elasticity weights if prices are not proportional to marginal costs. Accordingly, this term is interpreted as the effect on TFP growth resulting from departures from marginal cost pricing.[27]

The third term Is the **cost share effect**. This measures the impact on TFP growth of differences in the growth of input price indexes based on optimal and actual cost shares. This term will have a non-zero value if the firm does not utilize the optimal input mix.

The fourth term is the **Z variable effect.** It reflects the impact on TFP growth of changes in the values of variables in the Company's service territory or broader institutional environment (*e.g.* regulatory or government policy) that are beyond management control.

The fifth term is **technological change**. It measures the effect on TFP growth of a proportional shift in the cost function. A downward shift in the cost function is equivalent to an "increase" or improvement in technology.

The sixth term is the **productive inefficiency effect**. This measures the effect on TFP growth of a change in the firm's productive inefficiency factor. Firms decrease their productive inefficiency as they approach the cost frontier, which represents the lowest cost attainable for given values of output quantities, input prices, and other business conditions.

Three of these six components of TFP growth reflect changes in efficiency, and three do not. The three components that measure changes in efficiency are: 1) the non-marginal cost pricing effect, which reflects changes in demand-side allocative efficiency; 2) the cost share effect, which reflects changes in supply-side allocative efficiency; and 2) the productive inefficiency effect, which reflects changes in productive efficiency.

The technological change effect reflects changes in the technology available to the firm but not how efficiently the firm is producing given that technology. This is consistent with the view that technological change is typically exogenous to the energy network itself.[28] Accordingly, this

[27] See Denny, Fuss and Waverman, p. 197.

[28] This view is not appropriate for all companies, particularly firms like Apple or Boeing that engage in extensive research and development (R&D) and are accordingly responsible for significant technological innovations within their respective industries. Nevertheless, the assumption that technological change is exogenous appears valid for energy networks. Even though energy utilities sometimes provide funding for institutes that promote technological change within their industries, utilties themselve rarely undertake R&D designed to enhance their own energy delivery capability.

component of TFP growth cannot reflect changes in the firm's efficiency *per se*, since efficiency must reflect endogenous behavior on the part of the firm.

The Z factor component by definition reflects impacts on the firm's TFP that result from factors outside its control. This includes factors within its defined service territory or the broader regulatory/institutional environment. An example of a broad institutional change impacting measured TFP could be the additional investment costs networks must incur to comply with a specific government policy directive. An example of a factor within the service territory that can impact measured TFP growth is a movement towards less dense development patterns. If development with the territory becomes more spatially dispersed, networks would need to construct more infrastructure assets to connect new customers compared with the assets that were previously installed to connect existing customers. New connections therefore require more inputs relative to outputs than in the past, but utilities have no control over the resulting negative impact on their TFP since they have an obligation to provide service within their territory.

Similarly, if an increase in the number of customers served leads utilities to realize scale economies, the increase in measured TFP reflects factors beyond company control. Such scale economy effects simply reflect the underlying characteristics of the technology, and the fact that the incremental cost of serving an additional customer can be less than the utility's average cost of serving the existing customer base. When this occurs, the average cost of production falls whenever output (which utilities have an obligation to serve) within a given territory expands. This is an exogenous effect rather than an increase in efficiency resulting from endogenous, deliberate choices on the part of the network to reduce unit costs.

This discussion shows that productivity is a broader concept than efficiency. Certainly, improved productive and allocative efficiency can contribute to TFP growth. However, TFP growth can also result from factors beyond the network's control, including broader technological change, the realization of scale economies, and Z-factor effects.

Interestingly, TFP and efficiency can also move in opposite directions. Consider a utility experiencing rapid growth and thereby realizing considerable scale economies, which simultaneously devotes less effort to managing costs and thereby becomes less productively efficient. Even though this firm's efficiency has declined, its measured productivity would increase if the magnitude of the scale economy effect was greater than the magnitude of productive inefficiency effect. Alternatively, consider a firm that successfully improves its productive efficiency at the same time that it must comply with a new government mandate. If the improvement in the firm's productive and allocative efficiency is less than the magnitude of the Z-factor effect, its measured TFP will decline in spite of its improved efficiency performance.

Appendix Three: Detailed Empirical Results

Table 3.1								
		Calculation of Gas Distribution O&M PFP Growth						
Year	Total Gas Distribution Customers	Annual % Change Gas Distribution Customers	Gas Distribtuion O&M Cost	Annual % Change Gas Distribution O&M Cost	Gas Distribution Input Price Inflation Index	Annual % Change Gas Distribution Input Price Index	Annual % Change Gas Distribution O&M Input Quantities [4]-[6] =[7]	Annual % Change Gas Distribution O&M PFP [2]-[7]=[8]
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2007	34,944,549		5,418,328		100.00			
2008	35,132,387	0.54%	5,498,322	1.47%	102.63	2.60%	-1.13%	1.67%
2009	35,177,230	0.13%	5,933,454	7.62%	104.57	1.87%	5.75%	-5.62%
2010	35,370,758	0.55%	6,094,232	2.67%	108.20	3.41%	-0.73%	1.28%
2011	35,542,249	0.48%	6,232,844	2.25%	111.21	2.74%	-0.50%	0.98%
2012	35,713,399	0.48%	6,270,453	0.60%	114.18	2.64%	-2.04%	2.52%
2013	35,942,472	0.64%	6,621,580	5.45%	116.08	1.65%	3.79%	-3.15%
2014	36,135,570	0.54%	6,672,546	0.77%	118.36	1.94%	-1.17%	1.71%
2015	36,431,808	0.82%	6,713,821	0.62%	120.92	2.14%	-1.53%	2.34%
2016	36,749,374	0.87%	6,989,975	4.03%	123.21	1.87%	2.16%	-1.29%
2017	37,027,568	0.75%	7,194,486	2.88%	125.98	2.23%	0.66%	0.10%
2018	37,354,716	0.88%	7,793,920	8.00%	129.31	2.61%	5.40%	-4.52%
2019	37,665,349	0.83%	7,912,174	1.51%	132.92	2.75%	-1.25%	2.07%
2020	37,933,217	0.71%	7,863,653	-0.62%	135.26	1.75%	-2.36%	3.07%
2021	38,606,276	1.76%	8,349,418	5.99%	139.94	3.40%	2.60%	-0.84%
2022	38,654,766	0.13%	8,477,399	1.52%	147.38	5.19%	-3.66%	3.79%
Average		0.67%		2.98%		2.59%	0.40%	0.27%

Table 3.2

U.S. Electric Utility Sample

Line Number	Company	Line Number	Company
1	AES Indiana	42	Minnesota Power Enterprises, Inc.
2	Alabama Power Company	43	Mississippi Power Company
3	Alaska Electric Light and Power Company	44	Monongahela Power Company
4	Appalachian Power Company	45	Nevada Power Company
5	Arizona Public Service Company	46	NextEra Energy, Inc.
6	Atlantic City Electric Company	47	Northwestern Wisconsin Electric Co Inc
7	Black Hills Power, Inc.	48	NSTAR Electric Company
8	Black Hills Colorado Electric, Inc.	49	OGE Energy Corp.
9	Central Maine Power Company	50	Ohio Edison Company
10	Cleco Power LLC	51	Ohio Power Company
11	Commonwealth Edison Company	52	Oklahoma Gas and Electric Company
12	Consolidated Water Power Company	53	Otter Tail Corporation
13	DTE Electric Company	54	PacifiCorp
14	Duke Energy Carolinas, LLC	55	Pennsylvania Electric Company
15	Duke Energy Florida, LLC	56	Pennsylvania Power Company
16	Duke Energy Indiana, LLC	57	Portland General Electric Company
17	Duke Energy Progress, LLC	58	Potomac Electric Power Company
18	Duquesne Light Company	59	PPL Electric Utilities Corporation
19	El Paso Electric Company	60	Public Service Company of New Hampshire
20	Entergy Arkansas, LLC	61	Public Service Company of New Mexico
21	Entergy Mississippi, LLC	62	Public Service Company of Oklahoma
22	Evergy Kansas Central, Inc.	63	Rockland Electric Company
23	Evergy Kansas South, Inc.	64	Southern California Edison Company
24	Evergy Metro, Inc.	65	Southwestern Electric Power Company
25	Evergy Missouri West, Inc.	66	Southwestern Public Service Company
26	Florida Power & Light Company	67	Tampa Electric Company
27	Georgia Power Company	68	The Cleveland Electric Illuminating Company
28	Green Mountain Power Corporation	69	The Connecticut Light and Power Company
29	Hawaii Electric Light Company, Inc.	70	The Dayton Power and Light Company
30	Hawaiian Electric Company, Inc.	71	The Empire District Electric Company
31	Idaho Power Company	72	The Potomac Edison Company
32	Indiana Michigan Power Company	73	The Toledo Edison Company
33	Jersey Central Power & Light Company	74	The United Illuminating Company
34	Kentucky Power Company	75	Tucson Electric Power Company
35	Kentucky Utilities Company	76	UIL Holdings Corporation
36	Kingsport Power Company	77	Unitil Energy Systems, Inc.
37	Liberty Utilities (Granite State Electric) Corp.	78	Upper Peninsula Power Company
38	Lockhart Power Company	79	Versant Power
39	Massachusetts Electric Company	80	Virginia Electric and Power Company
40	Maui Electric Company, Ltd.	81	West Penn Power Company
41	Metropolitan Edison Company	82	Wheeling Power Company

Table 3.3								
Calculation of Small Customer Group Peers O&M PFP Growth								
Year	Small Sample Customers	Annual % Change Small Sample Customers	Small Sample Total O&M Cost	Annual % Change Small Sample Total O&M Cost	Input Price Inflation Index	Annual % Change Input Price Index	Annual % Change Small Sample O&M Input Quantities [4]-[6]=[7]	Annual % Change Small Sample O&M PFP [2]-[7]=[8]
	[1]	[2]	[3]		[5]	[6]	[7]	[8]
2007	3,072,320		$ 1,879,721		100.00			
2008	3,019,044	-1.75%	$ 1,941,322	3.22%	102.63	2.60%	0.63%	-2.37%
2009	2,937,748	-2.73%	$ 2,044,770	5.19%	104.57	1.87%	3.32%	-6.05%
2010	2,948,509	0.37%	$ 2,118,374	3.54%	108.20	3.41%	0.13%	0.24%
2011	2,953,605	0.17%	$ 2,223,558	4.85%	111.21	2.74%	2.10%	-1.93%
2012	3,000,823	1.59%	$ 2,342,013	5.19%	114.18	2.64%	2.55%	-0.97%
2013	3,133,560	4.33%	$ 2,397,869	2.36%	116.08	1.65%	0.70%	3.63%
2014	3,146,160	0.40%	$ 2,643,383	9.75%	118.36	1.94%	7.81%	-7.41%
2015	3,151,742	0.18%	$ 2,826,304	6.69%	120.92	2.14%	4.55%	-4.37%
2016	3,177,451	0.81%	$ 2,808,112	-0.65%	123.21	1.87%	-2.52%	3.33%
2017	3,195,892	0.58%	$ 2,854,277	1.63%	125.98	2.23%	-0.60%	1.18%
2018	3,203,145	0.23%	$ 2,960,787	3.66%	129.31	2.61%	1.06%	-0.83%
2019	3,212,329	0.29%	$ 2,955,539	-0.18%	132.92	2.75%	-2.93%	3.22%
2020	3,232,668	0.63%	$ 3,033,519	2.60%	135.42	1.86%	0.74%	-0.11%
2021	3,254,576	0.68%	$ 2,861,643	-5.83%	139.88	3.24%	-9.08%	9.75%
2022	3,270,106	0.48%	$ 3,127,568	8.89%	146.65	4.73%	4.16%	-3.68%
Average		0.42%		3.39%		2.55%	0.84%	-0.43%

Table 3.4

Calculation of All Utilities O&M PFP Growth

Year	Large Sample Customers	Annual % Change Large Sample Customers	Large Sample Total O&M Cost	Annual % Change Large Sample Total O&M Cost	Input Price Inflation Index	Annual % Change Input Price Index	Annual % Change Large Sample O&M Input Quantities [4]-[6]=[7]	Annual % Change O&M PFP [2]-[7]=[8]
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
2007	65,513,024		24,717,454		100.00			
2008	65,774,804	0.40%	25,237,876	2.08%	102.63	2.60%	-0.52%	0.91%
2009	65,786,818	0.02%	25,823,444	2.29%	104.57	1.87%	0.42%	-0.41%
2010	66,036,271	0.38%	27,928,445	7.84%	108.20	3.41%	4.43%	-4.05%
2011	66,924,222	1.34%	29,006,577	3.79%	111.21	2.74%	1.04%	0.29%
2012	67,237,303	0.47%	30,162,095	3.91%	114.18	2.64%	1.27%	-0.80%
2013	67,769,035	0.79%	29,852,617	-1.03%	116.08	1.65%	-2.69%	3.47%
2014	68,314,776	0.80%	31,291,168	4.71%	118.36	1.94%	2.77%	-1.97%
2015	68,780,295	0.68%	31,711,060	1.33%	120.92	2.14%	-0.81%	1.49%
2016	69,572,890	1.15%	32,657,024	2.94%	123.21	1.87%	1.07%	0.08%
2017	70,321,099	1.07%	34,785,871	6.32%	125.98	2.23%	4.09%	-3.02%
2018	71,097,485	1.10%	36,632,691	5.17%	129.31	2.61%	2.57%	-1.47%
2019	72,273,503	1.64%	35,740,263	-2.47%	132.92	2.75%	-5.22%	6.86%
2020	73,053,498	1.07%	38,241,796	6.77%	135.42	1.86%	4.90%	-3.83%
2021	73,396,577	0.47%	37,400,002	-2.23%	139.88	3.24%	-5.47%	5.94%
2022	75,073,760	2.26%	40,288,832	7.44%	146.65	4.73%	2.71%	-0.45%
Average		0.91%		3.26%		2.55%	0.70%	0.20%

Appendix Four: Curriculum Vitae

Lawrence Kaufmann

Resume

March 2024

Address: 12520 Central Park Drive
Austin, Texas 78732
(608) 443-9813 (cell)

Education:

	Ph.D.:	Economics, University of Wisconsin-Madison, 1993
	BA & MA:	Economics, University of Missouri-Columbia, 1984
	High School:	St. Louis University High, St. Louis, MO, 1980

Relevant Work Experience, Primary Positions:

February 2021 – present: President, LKaufmann Consulting

December 2008 – February 2021: President, LKaufmann Consulting
Senior Advisor, Pacific Economics Group and Navigant Consulting
Fellow, Canadian Energy Research Institute

Advise companies and public agencies, particularly energy utilities and regulators, on various regulatory and industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

January 2001– December 2008: Partner, Pacific Economics Group, Madison, WI
November 1998 – December 2000: Vice President, Pacific Economics Group, Madison, WI

Advise energy utilities and regulators on various industry restructuring issues. Duties include consultation on performance-based regulation (PBR), developing service quality incentive plans, analyzing appropriate code of conduct policies for competitive markets, and providing supporting empirical research. Duties involve preparing public testimony and written reports, overseeing empirical research, client contact and briefings, and public presentations.

August 1993 – October 1998: Senior Economist, Christensen Associates, Madison, WI

Assisted in the development and evaluation of PBR plans for energy utilities and other regulated enterprises. Duties included theoretical and empirical research (including the estimation of total factor productivity trends), written reports, client contact and briefings, public presentations, and monitoring regulatory trends in the United States and overseas.

January 1993 - July 1993: Research Assistant to Dr. Robert Baldwin, Department of Economics, University of Wisconsin-Madison

Project investigated whether dumping penalties imposed by the United States have led to a diversion of imports from the nations on which the duties were assessed to other exporters.

January 1991 - May 1993: Dissertation research on the impact of foreign investment on Mexican firms.

Dissertation examined whether there has been any spillover of advanced multinational technologies to competing Mexican firms. Research included development of a theoretical model of spillovers through Mexican recruitment of multinational personnel, interviews and data collection in Mexico, and empirical tests of theoretical conclusions. Dissertation research was funded through a fellowship from the Mellon Foundation.

June 1989 - December 1990: Research Associate, Credit Union National Association, Madison, WI

Initiated and assisted on several long-term research projects, including the assessment of capital positions at Corporate credit unions, comparing the asset portfolios of credit unions and banks, and analysis concerning the development of credit union industries in Poland and Costa Rica.

January 1988 - August 1988: Investment Banking Officer and Associate Economist, Centerre Bank, St. Louis, MO
April 1985 - December 1987: Assistant Economist, Centerre Bank, St. Louis, MO

As Assistant Economist, the primary duty was to prepare country risk reports on nations to which the bank was lending. As Associate Economist and Investment Banking Officer, duties expanded to include writing a twice-weekly column on interest rate trends and preparing special reports on regional, national and international economic trends for senior management.

August 1983 - December 1984 and four semesters during the period September 1988 - May 1993:

Teaching assistant for classes in introductory microeconomics, introductory macroeconomics, international economics and the history of economic thought.

Professional Memberships: American Economic Association
National Association of Business Economists

Foreign Language Proficiency: Spanish

Major Consulting Projects:

1. Plan design, productivity factors, customer growth discounts, and cost benchmarking in support of an incentive regulation plan, Fortis BC, 2023-2024
2. Plan design, policy testimony, and cost benchmarking in support of a performance-based regulation plan, National Grid, 2023-2024
3. Plan design, policy testimony, total factor productivity and cost benchmarking in support of a performance-based regulation plan, EGI, 2021-2023.

4. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Berkshire Gas, 2021-2022.

5. Plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan. Eversource Energy, 2021-2022.

6. Advise on appropriate labor and consumer price indices in labor compensation dispute. Crescent River Port Pilots' Association.

7. Plan design, policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Boston Gas, 2020-2021.

8. Advice on PBR strategy and application. Fortis BC, 2018-2020.

9. Policy testimony and cost benchmarking study in support of performance-based regulation plan. National Grid/Massachusetts Electric, 2018-2019.

10. Confidential advice on regulatory strategy. Client wishes to remain anonymous at this time, 2018.

11. Advice on regulatory environment and investment strategy. Client wishes to remain confidential at this time, 2017-2018.

12. Escalators for operating and construction expenses. Epcor Water West, 2017-18.

13. Rebuttal testimony on cost and wage benchmarking. Puerto Rice Electric Power Authority, 2016-2017.

14. Review and respond to comments on Epcor Water testimony. Epcor Water, 2016.

15. Review of regulatory framework to encourage efficient investment and accommodate uncertainty. Client wishes to remain confidential at this time, 2016.

16. Assessment of Ontario Power Generation ratemaking proposal. Ontario Energy Board, 2016.

17. Testimony on cost and wage benchmarking. Puerto Rico Electric Power Authority, 2016.

18. Testimony recommending updated inflation escalators in performance-based regulation plan. Epcor Water, 2015-2016.

19. Testimony recommending productivity factor for updated performance-based regulation plan. Epcor Water, 2015-2016.

20. Finalize reliability standards for electricity distributors in Ontario. Ontario Energy Board, 2015-2016.

21. Testimony on benefits of expanding bidding process for expansion of Alliant Riverside Energy Center facility. Associated Builders and Contractors of Wisconsin, 2015.

22. Cost benchmarking study. Puerto Rico Electric Power Authority, 2015.

23. Multi-client "Utility of the Future" and PBR study. Clients wish to remain confidential at this time, 2015.

24. Advise on benchmarking methods for electricity distribution. ANEEL, Brazilian Electricity Regulatory Agency, 2014.

25. The impact of gas extension tariffs on the development of the CNG market in Wisconsin. Reinhart Boerner Van Deuren on behalf of Kwik Trip, 2014.

26. TFP study and review of price controls in New Zealand. New Zealand Electricity Network Association, 2014.
27. Advise on benchmarking and regulatory issues in Toronto Hydro Custom IR application. Ontario Energy Board, 2014-15.
28. Advise on interrogatory responses. Consumer Energy Coalition of British Columbia, 2014.
29. Survey and analysis of implementation issues associated with customer-specific reliability metrics. Ontario Energy Board, 2013-15.
30. Empirical analysis and recommendation of appropriate reliability benchmarks. Ontario Energy Board, 2013-15.
31. Cost of service review (transmission and distribution operations) and cost benchmarking for Israel Electric Corporation. Public Utility Authority of Israel, 2013-15.
32. Value of reliability improvements from undergrounding power lines. Wisconsin Public Service, 2013.
33. Advise on and assess gas distribution incentive regulation plans. Ontario Energy Board, 2013-14.
34. Advise on price control application. UK Power Networks, 2013.
35. Advise on electricity distribution incentive regulation plans and other aspects of renewed regulatory framework for electricity. Ontario Energy Board, 2012-13.
36. Response to Productivity Commission Report on Energy Network Regulatory Frameworks. Energy Safe Victoria, 2012.
37. Statement on appropriate opt-out policies for smart meters to Wisconsin Public Service Commission. SMART Water, 2012.
38. Submission to Australia's Productivity Commission on the role of benchmarking in utility regulation. Energy Safe Victoria, 2012.
39. Assist Staff on review of cost of service applications for Enbridge Gas Distribution and Union Gas. Ontario Energy Board, 2012.
40. Assist with responses on data requests in testimony on alternative regulation plan. Potomac Electric Power, 2011-12.
41. Assess incentive regulation plans for Union Gas and Enbridge Gas Distribution in Ontario. Ontario Energy Board, 2011.
42. Advise on demand-side management and decoupling plans, and utility involvement in conservation and renewable energy businesses. ATCO Gas, 2011.
43. Advise on defining and measuring utility performance and the use of performance measures and standards in electric utility regulation. Ontario Energy Board, 2011-12.
44. Advise on rate mitigation strategies. Ontario Energy Board, 2011.
45. Advise on PBR strategy in Alberta. EDTI, 2011-12.
46. Estimate total factor productivity trend for gas distributors in New Zealand. Powerco, on behalf of industry, 2011.

47. Evaluation of reliability standards and alternative regulatory approaches for maintaining the reliability of electricity supplies. Ontario Energy Board, 2010-12

48. Prepare submission on rule change application and respond to consultant reports on TFP spreadsheet simulations and the impact of the regulatory framework on energy safety. Energy Safe Victoria, 2010.

49. Research on operating productivity and input price changes and testimony in support of an incentive-based formula to recover changes in gas distribution operating expenses. National Grid, 2010.

50. Prepare submission on rule change application and respond to consultant reports on TFP methodology. Essential Services Commission, 2010.

51. Advise on submission on rule change application. Victoria Department of Primary Industries, 2010.

52. Productivity research Victoria gas distribution industry, Essential Services Commission, 2010.

53. Productivity research Victorian power distribution industry, Essential Services Commission, 2010.

54. Advise on revenue decoupling and alternative regulatory strategies in context of upcoming gas distribution rate case. Northwest Natural Gas, 2009-2010.

55. Advise on revenue decoupling. Ontario Energy Board, 2009-2010.

56. Develop a "top down," econometrically-based measure of reductions in gas consumption resulting from utility DSM programs, and evaluate the merits of this approach compared to the existing "bottom up" methodology. Ontario Energy Board, 2009-2010.

57. Respond to proposals to amend National Energy Regulatory Framework to allow alternative approaches to incentive regulation. Essential Services Commission, 2009-2010.

58. Evaluate consultant reports and prepare submission on the update of price control formulas. New Zealand Energy Network Association, 2009.

59. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.

60. Estimate TFP trend for New Zealand electricity distributors. New Zealand Energy Network Association 2009.

61. Evaluate consultant reports in review on alternate regulatory arrangements. Essential Services Commission 2009.

62. Submission on the application of total factor productivity in utility network regulation. Essential Services Commission, 2008-09.

63. Estimate total factor productivity trends, benchmark gas distribution cost performance, and testify in support of research. Bay State Gas, 2008-09.

64. Advise on appropriate regulatory treatment of early termination fees in retail energy markets. Essential Services Commission, 2008.

65. Advise on appropriate regulation of gas connection charges. Essential Services Commission, 2008.

66. Advise on appropriate cost of capital. Jamaica Public Service, 2008.

67. Estimate total factor productivity trends and benchmark bundled power cost performance for use in a productivity based regulation plan. Jamaica Public Service, 2008.

68. Estimate gas distribution total factor productivity trends. Essential Services Commission, 2008.

69. Update estimate total factor productivity trends electricity distributors. Essential Services Commission, 2008.

70. Respond to productivity and benchmarking studies. New Zealand Electricity Networks Association, 2008.

71. Response to comments on appropriate productivity and input price measures to be used to update gas distributors' operating expenses. Essential Services Commission, 2007-08.

72. Advise on update of performance based regulatory plan for power distributors, including recommendations for total-factor productivity based X factors. Ontario Energy Board, 2007-08.

73. Estimate lost wage and health damages. Wolfgram and Associates, 2007.

74. Response to critique of X factor recommendations. Ontario Energy Board, 2007.

75. Review of benchmarking methods and proposed benchmarking for the pricing of unbundled copper local loop. Telecom NZ, 2007.

76. Report on the relationship between revenue decoupling and performance-based regulatory mechanisms. Massachusetts energy distribution companies, 2007.

77. Research on revenue decoupling experience in California. National Grid, 2007.

78. Report on regulatory reforms needed to facilitate demand response, advanced metering infrastructure and energy efficiency objectives. Essential Services Commission, 2007.

79. Estimate lost wage and health damages. Wolfrgram and Associates, 2007.

80. Evaluation of gas distribution construction cost trends. Essential Services Commission, 2007.

81. Appropriate productivity trends and labor inflation rates to be used to adjust operating expenses in incentive-based ratemaking. Essential Services Commission, 2007.

82. Testify in support of rate adjustment under a performance based regulation plan. Bay State Gas, 2007.

83. Report on service quality regulation and benchmarking, submitted as expert witness testimony. Detroit Edison, 2007.

84. Develop and testify in support of alternative regulation plan for gas distribution services. Client confidential at this time, 2007.

85. Evolution of energy asset management companies and outsourcing relationships. Davidson Kempner Advisers, 2007.

86. O&M partial factor productivity trends for gas distribution services. Essential Services Commission, 2006-07.

87. Principles for designing gas supply PBR plans and assessing the impact of retail gas costs. DLA Piper Rudnick, 2006-07.

88. Framework for analyzing appropriate early termination fees in competitive retail electricity markets. Essential Services Commission, 2006-07.

89. Testify in support of exogenous factor recovery of revenues lost due to declining natural gas usage. Bay State Gas, 2006.

90. Service quality benchmarking. Canadian Electricity Association, 2006.

91. Analyze natural resource and recreational damage calculations for environmental damage to trout stream. Michael, Best and Friedrich, 2006.

92. Evaluate outsourcing contract and report benchmarking Envestra's gas distribution operations and maintenance expenses. ESCOSA, 2006.

93. Report on the use of partial factor productivity trends in the updated gas access arrangement. Essential Services Commission, 2006.

94. Advise on approved X factors and total factor productivity trends in approved alternative regulation plans for electric utilities. Central Maine Power, 2006.

95. Estimate total factor productivity and input price trends power distribution industries in all Australian States and territories, Essential Services Commission, 2006.

96. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

97. Develop and testify in support of an alternative regulation plan for gas distribution services. Client wishes to remain confidential at this time, 2006.

98. Testimony on treatment of outsourcing contract costs and labor-nonlabor cost allocations. Essential Services Commission, 2005-06.

99. Incorporate lessons from incentive regulation and benchmarking overseas into newly-established regulatory framework for nation's electric utilities. Bundesnetzagentur (BNA), Bonn Germany, 2005-2006.

100. Submission to Ministerial Council on Energy related to Regulatory Rulemaking. Essential Services Commission, 2005.

101. Evaluation of early termination fee policies for energy retailers. Essential Services Commission, 2005.

102. Advise on alternative regulation strategies for gas distribution services. Client wishes to remain confidential at this time, 2005-2006.

103. Report on comprehensive framework for using performance indicators to evaluate market power abuses, efficiency gains, and the distribution of benefits to stakeholders. Essential Services Commission, 2005.

104. Evaluation of regulatory options and estimation of total factor productivity for Port of Melbourne Corporation. Essential Services Commission, 2005.

105. Evaluation of regulatory options for taxi services in Melbourne, Australia. Essential Services Commission, 2005.

106. White Paper advising government agency on regulatory reform of State's electric power industry. Department of Natural Resources Newfoundland and Labrador, 2005.

107. Review report on CAPM and differences in beta between rural and urban power distributors. Essential Services Commission, 2005.

108. Develop "incentive power" model and apply towards evaluation of regulatory options in Victoria, Australia. Essential Services Commission, 2004-2005.

109. Review report on labor price forecasts for Victoria, Australia. Essential Services Commission, 2004-2005.

110. Develop and testify in support of performance-based regulation plan. Bay State Gas, 2004-2005.

111. Review of gas regulatory framework in Ontario, Canada. Ontario Energy Board, 2004-2005.

112. Benchmarking gas distribution operations. Powerco, Vector, NGC (New Zealand), 2004.

113. Report on methodologies for updating CPI-X price controls and assemble US gas transmission pipeline data, to be used in update of price controls for gas transmission services. Comision Reguladora de Energia (Mexico), 2004-2005.

114. Benchmark comprehensive power and water utility operations. Aqualectra (Curacao, Netherlands Antilles), 2004-2005.

115. Benchmarking power distribution operations. Energex and Ergon Energy, 2004.

116. Regulatory treatment of hub and storage facilities. NICOR Gas, 2004.

117. Review and comment on proposed service quality regulation. Essential Services Commission, 2004.

118. Review and contribute to report on ring fencing policies. Essential Services Commission, Victoria Australia, 2004.

119. Estimate lost earnings in litigation case. Wolfgram and Gherardini, 2004.

120. Respond to Productivity Commission report on Gas Access Arrangements. Essential Services Commission, Victoria Australia, 2004.

121. Analysis of PBR plans for rates and service quality worldwide. Jamaica Public Service, 2004.

122. Undertake benchmarking and total factor productivity studies in support of an X factor in a performance-based regulatory plan. Jamaica Public Service, 2003-2004.

123. Evaluate incentive regulation options. Questar Gas, 2003-2004.

124. Project evaluating implementation of total factor productivity in energy utility regulation. Essential Services Commission, Victoria Australia, 2003-2005.

125. Evaluate incentive regulation reports commissioned by Australian Competition and Consumer Commission. Essential Services Commission, Victoria Australia, 2003.

126. Evaluate proposed regulatory thresholds regime. Powerco New Zealand, 2003.

127. Evaluate benchmarking methods and regulatory reform proposals. Jamaica Public Service, 2003.

128. Evaluate proposals for service quality regulation in province of Ontario. Hydro One, 2003.

129. Evaluate benchmarking methods and regulatory reform proposals. Overseas New Zealand client wishes to remain confidential at this time, 2003.

130. US-Japan power transmission benchmarking. Central Research Institute of Electric Power Industry (Japan), 2003.

131. Benchmarking power distribution operations and maintenance (O&M) costs benchmarking and O&M productivity growth. Superintendente de Electricidad (Bolivia), 2003.

132. Benchmarking gas distribution operations and maintenance expenses. ACTEW (Australia), 2003.

133. Estimate lost earnings in wrongful death case. Wolfgram and Gherardini, 2003.

134. Advise on updating incentive plan for demand-side management. Hawaiian Electric, 2003.

135. Estimate and testify in support of damages in patent infringement case, Trombetta, LLC vs. Dana Corporation and AEC. Ryan, Kromholz and Mannion, 2003.

136. Analyze service quality proposals for a natural gas distributor, recommend modifications and testify in support of recommendations. New England Gas, 2002-2003.

137. Develop a service quality incentive plan for power distributors in Queensland, Australia; the plan is to be developed through a consultative process between the companies, major customer groups, and the regulator. Queensland Competition Authority, 2002-2003.

138. Consultation on developments regarding Wisconsin Electric's "Power the Future" initiative. Fidelity Investments, 2002.

139. Confidential report on US experience with benchmarking and alternative regulation. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

140. Confidential report on capital cost measurement. Central Research Institute of Electric Power Industry (Japan), 2002-2003.

141. Report on merits and feasibility of benchmarking New Zealand power distributors. United Networks, 2002.

142. Impact of gas marketing expenditures on residential gas consumption. Envestra, 2002.

143. Advise on index-based performance-based regulation plan for a power distribution utility. Client wishes to remain confidential at this time, 2002.

144. Estimate productivity trend gas distribution industry and testify in support of trend. Boston Gas, 2002-2003.

145. Gas distribution benchmarking study. TXU Australia, Envestra and Multinet, 2002.

146. Benchmarking power transmission cost. Transend, 2002.

147. Advise on the development of an incentive regulation proposal for a North American power transmission utility. Hydro One Networks, 2001-2002.

148. Application of productivity and econometric benchmarking in an update of an incentive regulation plan. Ameren UE, 2001-2002.

149. Litigation regarding violations of Unfair Trade Practices Act for Tamoxifen, Taxol, and Buspar prescription drugs. Miner, Barnhill, and Galland, P.C., 2001-2002.

150. Recommend reforms of Western Australia power market, including reforms of wholesale markets, retail markets, structure of the incumbent utility, and regulatory arrangements; work was summarized in a report to the Electricity Reform Task Force. Western Power, 2001.

151. Faculty member of Regulatory Training Seminar in Bolivia. Seminar organized by the Public Utility Research Center and sponsored by SIRESE, 2001.

152. White Paper on implementing total factor productivity measures in regulation for the Utility Distributor's Forum. CitiPower, 2001.

153. Electronic forum on service quality incentives and research topics. Edison Electric Institute, 2001.

154. Economies of scale and scope in power services. Western Power, 2001.

155. Report evaluating the merits of alternative benchmarking methods and their application to energy distributors. Electricity Supply Association of Australia, 2001.

156. Response to report on benchmarking and incentive regulation. Client confidential at this time, 2000-2001.

157. Report on consistency of Price Determination with legislative mandates. TXU Australia, 2000-2001.

158. Develop methodology for service quality benchmarking and construction of appropriate deadbands. Massachusetts Gas and Electric Distribution Companies, 2000.

159. Advise on Performance-Based Regulation strategy, including development of a service quality incentive. BCGas, 2000.

160. Power distribution benchmarking. Queensland Competition Authority, 2000.

161. Develop and testify in support of service quality incentive. Western Resources, 2000.

162. Response to regulatory proposals for "ring fencing" operations. CitiPower, 2000.

163. Benchmarking evaluation of power distribution costs. Client name withheld, 2000.

164. Updated White Paper on Metering and Billing Competition in California. Edison Electric Institute, 2000.

165. Economies of scale and scope in power delivery and metering services. Massachusetts Utility Distribution Companies, 2000.

166. Evaluation of merger benefits. Client wishes to remain anonymous at this time, 2000.

167. Response to study on benchmarking capital spending. CitiPower, 2000.

168. Response to incentive regulation proposals of Pareto Economics in Victorian distribution price review. CitiPower, 2000.

169. Estimate scale economies in power generation, scope economies between power transmission and power generation, and implications for public policy in Western Australia. Western Power, 2000.

170. White Paper on "best practice" regulation and evaluation of price and non-price regulation of energy and water utilities in Australia, the US, and the UK. Electricity Association of New South Wales, 2000.

171. Power transmission benchmarking. Client confidential at this time, 2000.

172. Development of performance-based regulation plan for power distribution services. Texas Utilities, 2000.

173. Response to UMS benchmarking study on O&M costs. Victorian power distributors, 2000.

174. Response to Consultation Paper on Detailed Proposal for Form of the Price Control. CitiPower, 1999-2000.

175. White Paper on cost structure of power distribution. Australian power distributors (coalition contact: the Electricity Supply Association of Australia), 1999-2000.

176. White Paper on benchmarking principles and applications. Victorian power distributors, 1999-2000.

177. Service quality testimony. Hawaiian Electric, Maui Electric, and Hawaii Electric Light, 1999.

178. Faculty member of Regulatory Training Seminar in Argentina. Seminar organized by the Public Utility Research Center and sponsored by Enargas, 1999.

179. Service quality benchmarking study. Southern California Edison, 1999.

180. US-Australia performance benchmarking study. Victorian Distribution Businesses, Victoria, Australia, 1999.

181. Cost benchmarking for power delivery and customer services. Southern California Edison, 1999.

182. Development of Service Quality Incentive and Testimony in Support of Plan. Oklahoma Gas and Electric, 1999.

183. Evaluation of Intervenor Assessments of Customer Benefits in Proposed Merger. Western Resources, 1999.

184. Response to Regulator Proposals for Regulatory Methodology, Efficiency Measurement and Benefit-Sharing, and Form of Distribution Price Controls. CitiPower, Australia, 1999.

185. Response to Incentive Regulation Proposal of Australian Competition and Consumer Commission. CitiPower, Australia, 1998.

186. Report on Metering and Billing Competition in California. Edison Electric Institute, 1998-99.

187. Evaluation of Economies of Vertical Integration for Electric Utilities in Illinois. Edison Electric Institute, 1998.

188. Assessment of Cost Performance of Power Distributors in the United States and Australian state of Victoria. Victorian Power Distributors, 1998.

189. Formal Response to Regulatory Proposals for Price Cap Regulation/Development of Regulatory Options. Victorian Power Distributors, 1998.

190. Development of Service Quality Incentive and Testimony in Support of Plan. Louisville Gas and Electric/Kentucky Utilities, 1998.

191. Regulatory Support for Overall PBR Strategy. Louisville Gas and Electric/Kentucky Utilities, 1998.

192. Testimony on Impact of Brand Name Restrictions in Maine's Retail Energy Markets. Edison Electric Institute, 1998.

193. Development of Service Quality Incentive. Hawaiian Electric, 1998.

194. Regulatory Support for Comprehensive PBR Strategy and Feasibility of Retail Competition in Power Supply Services. Hawaiian Electric, 1997-98.

195. White Paper on Controlling Cross-Subsidization in Electric Utility Regulation. Edison Electric Institute, 1997-98.

196. White Paper on Cost Structure of Integrated Electric Utilities and Implications for Retail Competition. Edison Electric Institute, 1997-98.

197. Regulatory Support for a Price Cap Plan for Combination Utility. San Diego Gas and Electric, 1997-98.

198. White Paper on Price Cap Methodologies for Power Distributors in Victoria, Australia. Victorian Power Distributors, 1997.

199. Development of a Price Cap Plan for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.

200. White Paper on Price Cap Regulation for Power Distribution. Edison Electric Institute, 1997.

201. Comprehensive Report on Performance-Based Regulatory Options for a Local Gas Distribution Utility. Atlanta Gas Light, 1997.

202. White Paper on Use of Electric Utility Brand Names in Competitive Markets. Edison Electric Institute, 1997.

203. Options for Price Cap Regulation for Power Distribution in Colombia. Comision Reguladora de Energía y Gas en Colombia, 1997.

204. Options for Performance-Based Regulation for Power Transmission and Stranded Cost Recovery for an Electric Utility. Client wishes to remain confidential at this time, 1997.

205. Regulatory Support for an Index-Based Incentive Plan of a Local Gas Distribution Utility. BCGas, 1997.

206. Recommendations for a service quality incentive plan. Hawaiian Electric, 1997.

207. Survey of Service Quality Incentive Plans and Assessment of Options. BCGas, 1996.

208. Regulatory Support for a Price Cap Plan. Southern California Gas, 1996.

209. Determination of service territories for newly-privatized gas distributors in Mexico. Comisión Reguladora de Energía, 1996.

210. Assessment of Regulatory Options for a Public Enterprise. United States Postal Service, 1996-97.

211. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Brooklyn Union Gas, 1996.

212. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Client wishes to remain confidential at this time, 1996.

213. Assessment of Options for Service Quality Incentives. Client wishes to remain confidential at this time, 1996.

214. Development of a Price Cap Plan for an Electric Utility. Client wishes to remain confidential at this time, 1996.

215. Assessment of Lessons from Natural Gas Restructuring for Electric Utilities. Client wishes to remain confidential at this time, 1996.

216. Advised on the Establishment of a Regulatory Framework for the Mexican Natural Gas Industry. Comision Reguladora de Energia, 1996.

217. White Paper on Unbundling Electric Utility Services. Edison Electric Institute, 1996.

218. Regulatory support for a Price Cap Plan of a Local Gas Distribution Utility. Boston Gas, 1995.

219. Development of a Price Cap Plan for a Local Gas Distribution Utility. Client wishes to remain confidential at this time, 1995.

220. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Client outside of the United States wishes to remain confidential at this time, 1995.

221. Organization of a Conference on Price Cap Regulation. Edison Electric Institute, 1995.

222. Development of Regulatory Strategies Regarding the Transition to Retail Competition in the Electric Power Industry. Niagara Mohawk Power, 1995.

223. Assessment of Incentive Regulation Options in the Context of a Proposed Restructuring of the Electric Utility Industry. Alberta Power Limited, 1995.

224. Development of a Price Cap Plan for the Gas Operations of a Combination Utility. Public Service Electric and Gas, 1995.

225. Development of a Price Cap Plan for the Electric Operations of a Combination Utility. Public Service Electric and Gas, 1995.

226. White Paper on Incentive Regulation Theory and Its Application to Electric Utilities. Electric Power Research Institute, 1994-95.

227. Productivity Trends of U.S. Gas Distributors. Southern California Gas, 1994-95.

228. White Paper on Price Cap Regulation. Edison Electric Institute, 1994.

229. Regulatory Support for a Price Cap Plan. Central Maine Power, 1994.

230. Advanced Benchmarking Methods for U.S. Electric Utilities. Southern Electrical System, 1994.

231. Development of and Regulatory Support for a Price Cap Plan. Niagara Mohawk Power, 1994.

232. Competitive Price Scenarios for Power Markets in the Northeastern U.S. Niagara Mohawk Power, 1993-94.

233. Survey of Price Cap Plans in the U.S. and Abroad. Niagara Mohawk Power, 1993.

Expert Witness Testimony:

1. Before the British Columbia Utilities Commission; evidence on behalf of Fortis BC, 2024. Subject: Empirical Support for Incentive Regulation formulas.
2. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2023-24. Subject: performance-based regulation and performance benchmarking
3. Before the Ontario Energy Board, evidence on behalf of Enbridge Gas Inc., 2021-2024. Subject: plan design, policy testimony, total factor productivity and cost benchmarking in support of a multi-year, incentive ratemaking plan.
4. Before the Massachusetts Department of Public Utilities, rebuttal evidence on behalf of Eversource Electric, 2021-22. Subject: performance-based regulation and performance benchmarking.
5. Before the Massachusetts Department of Public Utilities, evidence on behalf of Berkshire Gas, 2021-2022. Subject: plan design, policy testimony, cost benchmarking in support of a performance-based regulation plan (settled in 2022).
6. Before the Massachusetts Department of Public Utilities, evidence on behalf of Eversource Electric, 2021-22. Subject: performance-based regulation and performance benchmarking.
7. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: rebuttal testimony on performance-based regulation and performance benchmarking
8. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2020. Subject: performance-based regulation and performance benchmarking.
9. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2019. Subject: rebuttal testimony on performance-based regulation and performance benchmarking.
10. Before the Massachusetts Department of Public Utilities, evidence on behalf of National Grid, 2018. Subject: performance-based regulation and performance benchmarking.
11. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: rebuttal testimony on cost and wage benchmarking.
12. Before the Puerto Rico Energy Commission, evidence on behalf of the Puerto Rico Electric Power Authority, 2016. Subject: cost and wage benchmarking.
13. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.
14. Before the Edmonton City Council, evidence on behalf of Epcor Water and Sewer Inc., 2016. Subject: updated inflation factors in a performance-based regulation plan.
15. Before the Wisconsin Public Service Commission, evidence on behalf of Associated Builders and Contractors of Wisconsin, 2015. Subject: assessing the merits of an expanded bidding process for the expansion of the Alliant Riverside Energy Center facility.
16. Before the Ontario Energy Board, evidence on behalf of OEB Staff, 2015. Subject: review of Custom Incentive Regulation proposal and benchmarking evidence of Toronto Hydro.

17. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: surrebuttal testimony on the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

18. Before the Wisconsin Public Service Commission; evidence on behalf of Kwik Trip, 2014. Subject: the impact of gas extension tariffs on the development of the CNG marketplace in Wisconsin.

19. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2014: Subject: review of Customized Incentive Regulation proposal for Enbridge Gas Distribution.

20. Before the Ontario Energy Board; evidence on behalf of OEB Staff, 2013. Subject: total factor productivity estimation, cost benchmarking, and establishing incentive regulation plans for Ontario electricity distributors.

21. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: sur-surrebuttal testimony on the value of reliability improvements from undergrounding power lines.

22. Before the Wisconsin Public Service Commission; evidence on behalf of Wisconsin Public Service, 2013. Subject: rebuttal testimony on the value of reliability improvements from undergrounding power lines.

23. Before the Wisconsin Public Service Commission; evidence on behalf of SMART Water, 2012. Statement on appropriate opt-out policies for smart meters.

24. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: rebuttal testimony in support of a net inflation adjustment mechanism applied to operating and maintenance expenditures.

25. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of National Grid, 2010. Subject: empirical support for a net inflation adjustment mechanism applied to operating and maintenance expenditures.

26. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2009. Subject: direct testimony on performance based regulation.

27. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2008. Subject: estimating partial factor productivity growth for O&M expenditures for natural gas distributors.

28. Before the Ontario Energy Board, 2008. Subject: appropriate values for total factor productivity-based productivity factor; benchmarking-based productivity "stretch factors;" and appropriate thresholds for capital investment modules; in an incentive regulation plan for electricity distributors in the Province.

29. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: direct testimony on performance based regulation.

30. Before the Circuit Court of the City of St. Louis, Missouri, Division 9, in Michele Thrash v. Freightliner *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and medical treatment.

31. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2007. Subject: panel testimony on revenue decoupling and performance based regulation.

32. Before the New Zealand Commerce Commission, evidence on behalf of Telecom New Zealand, 2007. Subject: principles for price benchmarking and the merits of alternative methods of benchmarking unbundled copper local loop prices.

33. Before the Circuit Court of the City of St. Louis, Missouri, Division 13, in Anastacia McNutt v. Globe Transport, Inc *et al*, 2007. Subject: deposition testimony on estimated damages for lost income and past and future medical treatment.

34. Before the Michigan Public Service Commission; evidence on behalf of Detroit Edison, 2007. Subject: service quality regulation and benchmarking.

35. Before the Appeal Panel, South Australia, Australia; evidence on behalf of the Essential Services Commission of South Australia, 2006. Subject: the operating expenditures and outsourcing management fee of Envestra Ltd.

36. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: rebuttal testimony on exogenous recovery of revenues lost due to declining natural gas usage.

37. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2006. Subject: direct testimony on exogenous recovery of revenues lost due to declining natural gas usage.

38. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2006. Subject: regulatory treatment of an outsourcing contract to a related corporate party in a power distribution price determination.

39. Before the Appeal Panel Constituted Pursuant to Section 55 of the *Essential Services Commission Act* 2001, Victoria Australia; evidence on behalf of the Essential Services Commission, 2005. Subject: labor and non-labor shares in operating expenditures.

40. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: rebuttal testimony on performance based regulation and benchmarking.

41. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Bay State Gas, 2005. Subject: performance based regulation and benchmarking.

42. Before the New Zealand Commerce Commission, evidence on behalf of Vector and NGC, 2004. Benchmarking evidence for New Zealand gas distributors.

43. Before the New Zealand Commerce Commission, evidence on behalf of Powerco, 2003. Evaluation of total factor productivity and benchmarking evidence in studies undertaken for the Commission.

44. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: rebuttal testimony on performance based regulation, total factor productivity measurement and benchmarking

45. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Boston Gas, 2003. Subject: performance based regulation, total factor productivity measurement and benchmarking

46. Before the US District Court for the Western District of Wisconsin, Trombetta, LLC vs. Dana Corporation and AEC, 2003. Subject: estimate damages in solenoid patent infringement case.

47. Before the Rhode Island Public Utilities Commission: evidence on behalf of New England Gas, 2003. Subject: direct testimony on alternative service quality regulation proposals.

48. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2001. Subject: reply to surrebuttal testimony in support of service quality incentive plan.

49. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: rebuttal testimony in support of service quality incentive plan.

50. Before the Supreme Court of Victoria, Australia; evidence on behalf of TXU Australia, 2000. Subject: Whether the regulator's price determination complied with legal mandates to use price-based incentive regulation.

51. Before the Kansas Corporation Commission; evidence on behalf of Western Resources, 2000. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

52. Before the Massachusetts Department of Telecommunications and Energy; evidence on behalf of Massachusetts gas and electric distribution companies, 2000. Subject: Service quality benchmarking.

53. Before the Hawaii Public Service Commission; evidence on behalf of Hawaiian Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

54. Before the Oklahoma Corporation Commission; evidence on behalf of Oklahoma Gas and Electric, 1999. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

55. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Rebuttal testimony in support of service quality incentive plan and benefits of companies' regulatory proposal to low-income customers.

56. Before the Kentucky Public Service Commission; evidence on behalf of Louisville Gas and Electric and Kentucky Utilities, 1998. Subject: Support of a service quality incentive plan, including valuation of quality and other intangible aspects of customer welfare.

57. Before the Maine Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1998. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

58. Before the California Public Utilities Commission, evidence on behalf of the Edison Electric Institute, 1997. Subject: Merits of allowing utility companies to use their brand names in competitive retail energy markets.

Publications:

1. *The Price Cap Designers Handbook* (with M. N. Lowry), Edison Electric Institute, 1995.

2. "The Treatment of Z Factors in Price Cap Plans" (with Mark Newton Lowry), *Applied Economics Letters*, 2: 1995.

3. "Forecasting Productivity Trends of Natural Gas Distributors" (with Mark Newton Lowry), *AGA Forecasting Review*, March 1996.

4. *Performance-Based Regulation for Electric Utilities: The State of the Art and Directions for Further Research* (with Mark Newton Lowry), Palo Alto: Electric Power Research Institute, 1996.

5. *Developing Unbundled Electric Power Service Offerings: Case Studies of Methods and Issues* (with Laurence Kirsch), Washington: Edison Electric Institute, 1996.

6. *"*A Theoretical Model of Spillovers Through Labor Recruitment", *International Economic Journal*, Autumn 1997.

7. *Branding Electric Utility Products: Analysis and Experience in Related Industries* (with Mark Newton Lowry and David Hovde), Washington: Edison Electric Institute, 1997.

8. "The Branding Benefit", *Electric Perspectives*, November 1997.

9. *Price Cap Regulation for Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1998.

10. *Controlling for Cross-Subsidization in Electric Utility Regulation* (with Mark Meitzen and Mark Netwon Lowry), Washington: Edison Electric Institute, 1998.

11. "Price Caps for Distribution Service: Do They Make Sense?", *Edison Times*, December 1998 (with Eric Ackerman and Mark Newton Lowry).

12. *Economies of Scale and Scope in Power Distribution* (with Mark Newton Lowry), Washington: Edison Electric Institute, 1999.

13. *Competition for Metering, Billing and Information Services: The Experience in California So Far*, Edison Electric Institute, 1999.

14. *Third Party Metering, Billing and Information Services: Further Evidence from California*, Edison Electric Institute, 2000.

15. "Performance Based Regulation of Energy Utilities" (with Mark Newton Lowry), *Energy Law Journal*, 2002

16. "Performance Based Regulation and Business Strategy" (with Mark Newton Lowry), *Natural Gas*, 2003.

17. "Performance Based Regulation and Energy Utility Business Strategy" (with Mark Newton Lowry), *Natural Gas and Electric Power Industries Analysis 2003*, Financial Communications, Houston, 2003

18. "Price Control Regulation in North America: Role of Indexing and Benchmarking," (with M.N. Lowry and L. Getachew), *Proceedings of Market Design Conference*, Stockholm, Sweden, 2003.

19. "Performance Based Regulation Developments for Natural Gas Utilities" (with Mark Newton Lowry), *Natural Gas and Electricity*, 2004.

20. "Incentive Power and the Design of Regulatory Regimes," *Network*, December 2005.

21. "Alternative Regulation for Electric Utilities" (with Mark Newton Lowry), *Electricity Journal*, June 2006.

22. "Performance Indicators and Price Monitoring: Assessing Market Power," *Network*, March 2007.

23. “Incentive Regulation in North American Energy Markets” *Energy Law and Policy*, Carswell Publishing, Toronto, Canada, 2009.

24. “Regulatory Reform in Ontario: Successes, Shortcomings and Unfinished Business” *Public Utilities Fortnightly*, November 2009

25. “An Update to Keystone XL Development,” *CERI Crude Oil Report*, September 2015

26. “Mexico Natural Gas Reform,” *Geopolitics of Energy*, January-February 2016

27. “Clean Energy Policy in the U.S.” *Geopolitics of Energy*, July 20616.

28. “The Energy Policy Outlook Under President Trump,” *Geopolitics of Energy*, November-December 2016.

29. “Electricity Security, Renewables, and the South Australia Power Outages,” *Geopolitics of Energy*, April-May 2017.

30. “Prospects for Nuclear Power in the U.S.,” *Geopolitics of Energy*, August 2017.

31. “The Past and Future of the X Factor in Performance-Based Regulation,” *Geopolitics of Energy*, February 2019

32. “The Past and Future of the X Factor in Performance-Based Regulation,” *The Electricity Journal*, April 2019

Presentations at Seminars and Professional Meetings:

1. Department of Energy/NARUC, Orlando, FL, 1995.
2. Illinois Commerce Commission and the Center for Regulatory Studies, St. Charles, IL, 1995.
3. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 1995.
4. Marketing Conference, Edison Electric Institute, Chicago, IL, 1997.
5. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 1997.
6. Code of Conduct Conference, Denver, CO, 1997.
7. Code of Conduct Conference, Denver, CO, 1998.
8. Forum on Price Cap Regulation for Power Distribution. Melbourne, Australia, 1998.
9. Conference on Competition and Regulatory Reform in Hawaii. Honolulu, HI, 1998
10. Alternative Approaches Towards Price Cap Regulation. Melbourne, Australia, 1998.
11. Economics Meetings, Edison Electric Institute. Charlotte, NC, 1998.
12. Metering, Billing and Information Services Policy Convention, EEI, Chicago, IL, 1999.
13. Electricity Deregulation Conference. Vail, CO, 1999.
14. PURC Regulatory Training Seminar for Natural Gas Policy, Buenos Aires, Argentina, 1999.
15. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2000.
16. Seminar on Theory and Practice of Economic Regulation, Sydney, Australia, 2000.
17. Power Delivery Reliability Conference. Denver, CO, 2000.
18. Performance-Based Regulation Conference. Chicago, IL, 2000.
19. Regulatory Studies Program, NARUC/Michigan State University, East Lansing, MI, 2000.
20. Performance-Based Ratemaking Conference, Denver, CO 2000.
21. Energy Forum, Institute of Public Affairs, Melbourne, Australia, 2000.
22. Chamber of Commerce and Industry, Perth, Australia, 2001.
23. Energy Regulation Conference, Melbourne, Australia, 2001.
24. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2001.

25. PURC Regulatory Training Seminar, La Paz, Bolivia, 2001.
26. Performance-Based Regulation Conference, Denver, CO, 2001.
27. Cost Structure of Energy Networks, Sydney, Australia, 2002.
28. Advanced Rate School, Edison Electric Institute, Indianapolis, IN, 2002.
29. Performance-Based Ratemaking Conference, Denver, CO 2002.
30. How to Regulate Electricity Lines Companies?, New Zealand Institute for the Study of Competition and Regulation, Wellington, New Zealand, 2003
31. Public Utility Regulation Seminar: Tariff Design and Incentives, Acapulco, Mexico, 2003
32. Rates and Regulation Meeting: Southeastern Electric Exchange, Williamsburg, VA, 2003.
33. Workshop on Service Quality Regulation in Ontario, Toronto, ON 2003.
34. Joint Canadian Electricity Association Distribution Council and Customer Council Meeting, Halifax, Nova Scotia, 2004.
35. Asia-Pacific Productivity Conference, Brisbane, Australia, 2004. [invitation, paper submitted]
36. Workshop on Productivity Measurement, Melbourne Australia, 2005.
37. Utility Regulators Forum, Canberra Australia, 2005.
38. CAMPUT Energy Regulation Course, Kingston Canada, 2006.
39. Performance Based Regulation Seminar, Toronto Canada, 2006.
40. Performance Benchmarking for Energy Utilities, Arlington, Virginia, 2006.
41. Performance Benchmarking for Energy Utilities, Seattle, Washington, 2007.
42. Alternative Regulation Seminar, Boston, Massachusetts, 2007.
43. CAMPUT Energy Regulation Course, Kingston Canada, 2007.
44. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
45. Performance Benchmarking for Energy Utilities, Denver, Colorado, 2008.
46. Alternative Regulation Seminar, Toronto, Canada, 2008.
47. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2008.
48. CAMPUT Energy Regulation Course, Kingston Canada, 2008.
49. Performance Benchmarking for Energy Utilities, Chicago, IL, 2008.
50. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2009.
51. Alternative Regulation Seminar, Boston, MA, 2009.
52. CAMPUT Energy Regulation Course, Kingston Canada, 2009.
53. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
54. Alternative Regulation Seminar, Boston, MA, 2010.
55. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2010.
56. CAMPUT Energy Regulation Course, Kingston Canada, 2010.
57. Alternative Regulation Seminar, Toronto Canada 2010.
58. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2011.
59. Alternative Regulation Seminar, Philadelphia PA, 2011.
60. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2012.
61. Alternative Regulation Seminar, Chicago, IL, 2012.
62. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
63. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2013.
64. World Bank International Training Program on Utility Regulation, Gainesville, FL, 2014.
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Appendix C2-1

FEI HISTORY OF O&M 2019-2023

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
2019-2023 ACTUAL
($000)

Line No.	Particulars	Reference	2019	2020	2021	2022	2023
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Supervision	110-11	$ 15,427	$ 15,977	$ 15,377	$ 17,048	$ 17,497
2	Distribution Supervision Total	110-10	15,427	15,977	15,377	17,048	17,497
3							
4	Support - Distribution	110-21	8,911	9,565	9,237	8,740	8,548
5	Preventative Maintenance - Distribution	110-22	2,767	3,111	2,951	3,297	2,900
6	Operations - Distribution	110-23	8,509	9,923	10,324	9,048	8,855
7	Emergency Management - Distribution	110-24	6,516	7,237	7,590	6,595	6,557
8	Field Training - Distribution	110-25	2,865	3,727	3,618	4,087	3,551
9	Meter Exchange - Distribution	110-26	3,191	2,791	3,563	3,428	2,310
10	Distribution Operations Total	110-20	32,760	36,354	37,283	35,195	32,721
11							
12	Corrective - Distribution	110-31	8,585	8,317	8,898	9,651	8,871
13	Distribution Maintenance Total	110-30	8,585	8,317	8,898	9,651	8,871
14							
15	Account Services - Distribution	110-41	1,513	1,499	1,407	1,322	1,370
16	Bad Debt Management - Distribution	110-42	1,041	317	658	1,294	1,374
17	Distribution Meter to Cash	110-40	2,555	1,816	2,065	2,617	2,744
18							
19	**Distribution Total**	**110**	**59,327**	**62,463**	**63,623**	**64,510**	**61,833**
20							
21	Transmission Supervision	120-11	1,910	2,233	2,535	3,014	2,261
22	Transmission Supervision Total	120-10	1,910	2,233	2,535	3,014	2,261
23							
24	Pipeline / Right of Way Operations	120-21	16,131	19,377	21,741	21,481	28,935
25	Compression Operations	120-22	5,940	6,348	6,655	6,942	7,638
26	Measurement Control Operations	120-23	1,404	1,377	1,358	1,490	1,374
27	Transmission Operations Total	120-20	23,475	27,101	29,755	29,913	37,947
28							
29	Pipeline / Right of Way - Maintenance	120-31	251	390	739	854	568
30	Compression - Maintenance	120-32	1,188	1,233	1,171	1,186	1,055
31	Measurement Control Operations	120-33	110	175	175	121	160
32	Transmission Maintenance Total	120-30	1,549	1,799	2,085	2,161	1,783
33							
34	**Transmission Total**	**120**	**26,934**	**31,133**	**34,374**	**35,088**	**41,991**
35							
36	LNG Plant Operations	130-11	15,919	16,838	17,260	17,407	18,984
37	LNG Plant Operations Total	130-10	15,919	16,838	17,260	17,407	18,984
38							
39	LNG Plant Maintenance	130-21	288	164	193	204	159
40	LNG Plant Maintenance Total	130-20	288	164	193	204	159
41							
42	**LNG Plant Total**	**130**	**16,207**	**17,003**	**17,454**	**17,611**	**19,142**
43							
44	**Operations Total**	**100**	**102,468**	**110,599**	**115,450**	**117,209**	**122,966**
45							
46	Customer Service Supervision	200-11	-	1,769	1,699	1,456	1,727
47	Customer Assistance	200-12	10,126	9,707	10,360	11,295	12,273
48	Customer Billing	200-13	11,826	10,739	10,742	11,091	11,157
49	Meter Reading	200-14	12,244	12,170	14,547	13,855	15,619
50	Credit & Collections	200-15	2,337	2,397	3,013	3,370	3,291
51	Customer Operations	200-16	4,573	4,799	4,688	4,713	4,924
52	Customer Service Total	200-10	41,106	41,582	45,048	45,781	48,992
53							
54	**Customer Service Total**	**200**	**41,106**	**41,582**	**45,048**	**45,781**	**48,992**

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
2019-2023 ACTUAL
($000)

Line No.	Particulars	Reference	2019	2020	2021	2022	2023
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Energy Solutions & External Relations Supervision	300-11	$ 1,493	$ 1,096	$ 1,248	$ 1,130	$ 1,229
2	Energy Solutions	300-12	8,146	9,451	10,435	11,999	15,317
3	Energy Efficiency	300-13	1,723	1,969	1,971	865	998
4	Corporate Communications & External Relations	300-14	8,928	11,270	9,754	11,020	12,092
5	Forecasting, Market & Business Development	300-15	7,731	9,091	10,214	12,253	13,105
6	Energy Solutions & External Relations Total	300-10	28,020	32,876	33,622	37,267	42,741
7							
8	**Energy Solutions & External Relations Total**	**300**	**28,020**	**32,876**	**33,622**	**37,267**	**42,741**
9							
10	Energy Supply & Resource Development	410-11	2,643	2,171	3,400	3,107	3,331
11	Gas Control	410-12	2,400	2,536	2,480	2,939	3,377
12	Energy Supply & Resource Development Total	410-10	5,043	4,707	5,880	6,046	6,708
13							
14	**Energy Supply & Resource Development Total**	**410**	**5,043**	**4,707**	**5,880**	**6,046**	**6,708**
15							
16	Information Systems Supervision	420-11	3,681	3,790	2,636	2,539	2,247
17	Application Management	420-12	14,192	14,232	16,335	18,520	20,694
18	Infrastructure Management	420-13	7,905	9,462	9,063	8,821	9,365
19	Information Systems Total	420-10	25,778	27,484	28,035	29,880	32,307
20							
21	**Information Systems Total**	**420**	**25,778**	**27,484**	**28,035**	**29,880**	**32,307**
22							
23	System Planning	430-11	6,780	5,899	6,308	6,376	6,641
24	Engineering	430-12	9,663	10,713	11,601	11,866	12,291
25	Project Management	430-13	2,281	2,081	1,815	2,372	2,734
26	Engineering Services & Project Management Total	430-10	18,724	18,694	19,724	20,614	21,666
27							
28	**Engineering Services & Project Management Total**	**430**	**18,724**	**18,694**	**19,724**	**20,614**	**21,666**
29							
30	Supply Chain	440-11	5,296	6,445	6,377	6,090	5,842
31	Measurement	440-12	6,496	6,640	6,557	6,585	6,601
32	Property Services	440-13	1,632	1,518	1,970	1,630	1,955
33	Operations Support Total	440-10	13,424	14,603	14,904	14,305	14,398
34							
35	**Operations Support Total**	**440**	**13,424**	**14,603**	**14,904**	**14,305**	**14,398**
36							
37	Facilities Management	450-11	10,338	11,061	11,055	10,818	10,880
38	Facilities Total	450-10	10,338	11,061	11,055	10,818	10,880
39							
40	**Facilities Total**	**450**	**10,338**	**11,061**	**11,055**	**10,818**	**10,880**
41							
42	Environment Health & Safety	460-11	5,209	5,549	6,067	6,957	7,666
43	Environment Health & Safety Total	460-10	5,209	5,549	6,067	6,957	7,666
44							
45	**Environment Health & Safety Total**	**460**	**5,209**	**5,549**	**6,067**	**6,957**	**7,666**
46							
47							
48	**Business Services Total**	**400**	**78,515**	**82,098**	**85,665**	**88,620**	**93,625**

($000)

Line No.	Particulars	Reference	2019	2020	2021	2022	2023
	(1)	(2)	(3)	(4)	(5)	(4)	(3)
1	Financial & Regulatory Services	510-11	$ 14,108	$ 18,029	$ 19,075	$ 19,226	$ 20,319
2	Financial & Regulatory Services Total	510-10	14,108	18,029	19,075	19,226	20,319
3							
4	**Financial & Regulatory Services Total**	**510**	**14,108**	**18,029**	**19,075**	**19,226**	**20,319**
5							
6	Human Resources	520-11	9,919	9,975	10,002	9,626	9,794
7	Human Resources Total	520-10	9,919	9,975	10,002	9,626	9,794
8							
9	**Human Resources Total**	**520**	**9,919**	**9,975**	**10,002**	**9,626**	**9,794**
10							
11	Legal	530-11	1,810	1,849	1,765	1,956	2,025
12	Internal Audit	530-12	959	1,082	1,235	1,246	1,266
13	Risk Management/Insurance	530-13	6,611	8,757	10,588	11,771	12,651
14	Governance	530-10	9,381	11,689	13,587	14,974	15,942
15							
16	**Governance Total**	**530**	**9,381**	**11,689**	**13,587**	**14,974**	**15,942**
17							
18	Administration & General	540-11	(3,543)	2,392	1,808	(10,560)	(4,745)
19	Shared Services Agreement	540-12	4,727	5,521	5,061	6,960	5,821
20	Retiree Benefits	540-16	-	-	-	-	-
21	Corporate Total	540-10	1,184	7,913	6,869	(3,600)	1,076
22							
23	**Corporate Total**	**540**	**1,184**	**7,913**	**6,869**	**(3,600)**	**1,076**
24							
25	**Corporate Services Total**	**500**	**34,592**	**47,606**	**49,533**	**40,226**	**47,130**
26							
27	**Total Gross O&M Expenses**		**284,701**	**314,761**	**329,319**	**329,103**	**355,454**
28							
29	Less: Biomethane Transferred to BVA		(1,149)	(2,354)	(2,810)	(4,156)	(6,196)
30	Less: Capitalized Overhead		(33,859)	(50,428)	(52,801)	(53,484)	(56,744)
31							
32	**Total O&M Expenses**		**$ 249,693**	**$ 261,979**	**$ 273,708**	**$ 271,464**	**$ 292,515**

Appendix C2-2

FBC HISTORY OF O&M 2019-2023

FORTISBC INC.

OPERATING AND MAINTENANCE EXPENSES - ACTIVITY VIEW
2019-2023 ACTUAL
($000s)

Line No.	Account	Particulars	2019	2020	2021	2022	2023
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1		GENERATION					
2	535R	Supervision & Administration	$ 614	$ 910	$ 775	$ 777	$ 934
3	536	Water Fees	10,396	10,968	10,741	11,838	12,008
4	542	Structures	1,075	1,172	1,236	1,091	1,073
5	543	Dams & Waterways	310	270	221	246	480
6	544	Electric Plant	1,017	1,038	1,146	952	1,412
7	545	Other Plant	355	328	410	511	500
8			$ 13,767	$ 14,687	$ 14,528	$ 15,416	$ 16,406
9							
10		OTHER POWER SUPPLY					
11	555	Purchased Power	$ 139,002	$ 139,354	$ 152,473	$ 153,457	$ 164,812
12	556	System Control	2,383	2,583	2,479	2,609	2,683
13			$ 141,385	$ 141,937	$ 154,951	$ 156,066	$ 167,496
14							
15		TRANSMISSION & DISTRIBUTION					
16	560R-1	Supervision & Administration	$ 2,942	$ 3,352	$ 3,514	$ 4,163	$ 4,458
17	560R-2	System Planning	3,863	4,189	4,471	4,849	4,784
18	561	Load Dispatching	1,428	1,631	1,493	1,485	1,526
19	562	Transmission Station Expense	892	929	1,027	1,208	1,330
20	563R-1	Transmission Line Maintenance	569	505	537	571	638
21	563R-2	Transmission Right of Way Maintenance	1,004	955	1,065	1,389	1,273
22	565	Wheeling	5,896	5,846	6,000	6,898	7,087
23	567	Rents	3,159	3,275	3,444	3,578	3,684
24	583R-1	Distribution Line Maintenance	3,867	4,307	4,162	4,558	5,095
25	583R-2	Distribution Right of Way Maintenance	4,575	4,437	4,269	4,525	4,431
26	586	Meter Expenses	492	584	557	637	737
27	592	Distribution Station Expense	1,650	1,711	1,612	1,532	1,712
28	596	Street Lighting	91	84	72	60	43
29	598	Other Plant	644	633	720	533	501
30			$ 31,073	$ 32,436	$ 32,944	$ 35,988	$ 37,300
31		CUSTOMER SERVICE					
32	901	Supervision & Administration	$ 1,715	$ 1,354	$ 1,585	$ 1,767	$ 1,724
33	902	Meter Reading	74	71	74	59	81
34	903	Customer Billing	1,508	1,325	1,421	1,380	1,305
35	904	Credit & Collections	830	995	1,019	917	896
36	910	Customer Assistance	1,799	1,889	1,966	2,148	2,005
37			$ 5,925	$ 5,634	$ 6,065	$ 6,270	$ 6,011

FORTISBC INC.
OPERATING AND MAINTENANCE EXPENSES - ACTIVITY VIEW
2019-2023 ACTUAL
($000s)

Line No.	Account	Particulars	2019	2020	2021	2022	2023
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1		ADMINISTRATIVE AND GENERAL					
2	920	Salaries					
3	920.1	Executive and Senior Management	$ 397	$ 442	$ 437	$ 436	$ 456
4	920.2	Legal	459	534	484	445	591
5	920.3	Human Resources	1,098	1,252	1,145	1,125	1,245
6	920.4	Regulatory and Finance	1,299	1,175	1,169	1,081	1,138
7	920.6	Information Services	1,756	1,813	1,971	1,941	1,880
8	920.7	Materials Management	(50)	-	-	-	-
9		Other	(505)	(1,528)	(1,310)	(2,855)	(1,254)
10			$ 4,453	$ 3,688	$ 3,896	$ 2,173	$ 4,056
11							
12		ADMINISTRATIVE AND GENERAL cont'd					
13	921	Expenses					
14	921.1	Executive and Senior Management	$ 24	$ 7	$ 6	$ 22	$ 64
15	921.2	Legal	224	480	483	550	577
16	921.3	Human Resources	143	78	95	68	85
17	921.4	Regulatory and Finance	431	827	482	533	467
18	921.6	Information Services	1,613	1,860	1,738	1,932	2,144
19	921.7	Materials Management	424	305	336	348	314
20		Other	283	336	234	262	364
21			$ 3,144	$ 3,893	$ 3,374	$ 3,715	$ 4,015
22							
23	567	Special Services	$ 2,465	$ 2,397	$ 2,686	$ 3,000	$ 2,786
24	283R-1	Insurance	849	1,080	1,224	1,356	1,531
25	283R-2	Maintenance to General Plant	1,621	1,555	1,635	1,599	1,630
26	586	Transportation Equipment Expenses	252	212	251	597	238
27			$ 5,186	$ 5,244	$ 5,796	$ 6,552	$ 6,185
28							
29		**TOTAL**	**204,932**	**207,519**	**221,554**	**226,179**	**241,468**
30							
31	Less:	Water Fees	(10,396)	(10,968)	(10,741)	(11,838)	(12,008)
32		Power Purchases	(139,002)	(139,354)	(152,473)	(153,457)	(164,812)
33		Wheeling	(5,896)	(5,846)	(6,000)	(6,898)	(7,087)
34		**Net O&M Expense**	**49,638**	**51,351**	**52,340**	**53,986**	**57,561**
35							
36	Add:	Capitalized Overhead	8,880	9,330	9,795	10,177	10,900
37							
38		**GROSS O&M Expense**	**58,518**	**60,681**	**62,135**	**64,163**	**68,461**

Appendix C2-3

HISTORY OF FORMULA O&M 2019-2023

Appendix C2-3

History of Formula O&M

2019-2023

Table of Contents

Index of Tables

1. HISTORY OF FORMULA O&M 2019 TO 2023

FEI's and FBC's formula O&M expenditures by department (function) are provided in Tables 1 and 2 below, respectively, for the past five years, from 2019 to 2023, along with explanations for the more significant changes from year to year.[1]

FortisBC views and manages the approved formula O&M funding as an overall O&M funding envelope and not at the individual department level. A key benefit of this approach, particularly during the energy transition, has been the ability to shift funds amongst departments depending on business priorities and how the priorities change. While costs for departments may vary from year to year for a number of reasons, the important focus when considering the O&M spending under the Current MRP is at the overall formula O&M envelope level and how the Companies are managing their overall spending relative to the approved formula O&M envelope.

In this regard, during the Current MRP, the Companies have been successfully managing their spending levels, with savings shared with customers. Additionally, the Companies continue to deliver safe, reliable and resilient service.

1.1 *FEI FORMULA O&M 2019 TO 2023*

The table below shows FEI's O&M spending by department for those costs that were subject to an indexing approach during the Current MRP term (Formula O&M).

[1] Differences between the Formula O&M view by department and the BCUC Activity view include adjustments to the Formula O&M view by department for exclusion of flow-through O&M costs (including pension/OPEB at a high level) and normalization of COVID-19 pandemic net cost reductions and the refund to customers from 2020 to 2022. Additionally, for FBC only, FBC's Activity view includes capitalized overhead at the Activity level. For FEI, the departments are defined similarly as that reported in the BCUC Activity view (i.e., Information Systems). For FBC, the departments reported are different than the BCUC Activity view which is based on the Uniform System of Accounts.

Table 1: FEI Formula O&M Expenditures by Department from 2019 to 2023 ($000s)

Department Name	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
Operations and LNG	91,316	98,815	102,536	103,901	104,806
Customer Service	41,106	41,483	44,932	45,781	48,992
Energy Solutions & External Relations	24,755	27,802	27,835	28,335	30,868
Energy Supply & Resource Dev	5,043	4,863	6,010	6,046	6,708
Information Systems	25,778	27,371	28,198	29,880	32,307
Engineering Services & PM	18,724	18,989	19,968	20,614	21,666
Operations Support	13,424	14,804	15,109	14,305	14,398
Facilities	10,338	10,681	10,695	10,818	10,880
Environment Health & Safety	5,209	5,287	5,737	6,957	7,666
Finance & Regulatory Services	14,108	11,257	11,819	11,818	11,826
Human Resources	9,919	10,420	10,236	9,626	9,794
Governance	3,087	3,220	3,265	3,489	3,571
Corporate	6,300	8,508	6,491	8,691	8,430
Pension/OPEB (O&M Portion) [1]	(19,426)	(22,299)	(22,372)	(22,390)	(16,931)
Employer Health Tax & MSP Reduction [1]	(2,093)	-	-	-	-
Total Formula O&M [2]	**247,587**	**261,201**	**270,459**	**277,871**	**294,980**
% year over year change	**n/a**	**5.5%**	**3.5%**	**2.7%**	**6.2%**

1 These flow-through costs are embedded in each of the department total

2 Net cost reductions related COVID-19 Pandemic normalized from O&M actuals for 2020 (+$1.7 m); 2021 (+$2.2 m); 2022 (-$3.9 m)

In general, O&M costs[2,3] increased over the five-year timeframe due in part to overall inflationary pressures (record high inflation was experienced in 2022 and 2023) and a growing customer base.

For 2020, the key drivers of the increased O&M are as follows:

- Net incremental funding approved as part of the Current MRP of approximately $7.5 million in the following departments: Operations and LNG ($3.1 million), Energy Solutions and External Relations ($3.3 million), and Information Systems ($1.1 million);
- In Operations and LNG, an increase of approximately $5.1 million due to an approved reclassification of flow-through LNG O&M to formula O&M, offset partially by a decrease

[2] Although pension/OPEB costs are flow-through and not part of formula O&M, these costs are included in each department's costs and have only been removed at an aggregate level. This is due to the complexity in determining the exact departmental allocation. Similarly, for 2019, the impact of the Employer Health Tax and MSP Reduction approved as an exogenous factor is shown separately. Fort Nelson O&M costs have been included for all years in the table.

[3] The BCUC approved that COVID-19 incremental costs and savings from 2020 and 2021 that totaled to $3.860 million be returned to customers in 2022 through the Flow-through deferral account. Net cost impacts related to the COVID-19 pandemic normalized from O&M actuals in the table above were as follows: 2020 (+$1.680 million); 2021 (+$2.180 million); and 2022 (-$3.860 million).

of approximately $2.6 million due to an approved reclassification of integrity dig costs from formula O&M to flow-through O&M; and

- In Operations Support, higher inventory management costs and project costs to review and update the standards for gas materials standards, which continued into 2021.

These increases were partially offset by the following:

- Lower spending in Energy Supply and Resource Development due to lower project development costs which vary from year to year; and
- An approved reclassification of BCUC fees from formula to forecast O&M of approximately $2.8 million in the Finance & Regulatory Services department.

For 2021, the key drivers of the increased O&M are as follows:

- In Operations and LNG, higher costs due to flood repair costs of approximately $1.5 million which were recovered through the Company's insurance claim in 2023 (please refer to Section C1.6.1 of the Application for further details of the flooding damage and remediation);
- Higher meter reading costs due to a new meter reading contract of approximately $2 million in Customer Service; and
- Additional environmental and sustainability resources in the Environment, Health and Safety department to support increased requirements for reporting, compliance and disclosure of FEI's progress towards decarbonization and other sustainability goals. Increases in these areas continued in 2022 and 2023.

For 2022, in addition to the increases in Environment, Health and Safety described above, a key driver of the increase was the incurrence of higher software licensing fees in the Information Systems department.

For 2023, the key drivers of the increased O&M are as follows:

- In the Information Systems department, software licensing fees continued to increase in 2023;
- Higher meter reading costs of approximately $2 million in Customer Service due to increased read volumes and a contractual increase for read rates; and
- In Energy Solutions and External Relations, an increase due to higher media costs for communications related to energy transition solutions as well as consulting costs to provide energy solutions to customers.

Contributing to fluctuations in expenditures between years in some departments is the timing of expenditures (i.e., due to one time and temporary events), reflecting the circumstances and priorities for the departments in the year.

1.2 *FBC FORMULA O&M 2019 TO 2023*

The table below shows FBC's O&M spending by department for those costs that were subject to an indexing approach during the Current MRP term (Formula O&M).

Table 2: FBC Formula O&M Expenditures by Department from 2019 to 2023 ($000s)

Department Name	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual
Generation	3,421	3,410	3,720	3,577	4,398
Operations	21,564	22,333	22,330	23,473	24,474
Customer Service	7,733	5,538	6,054	5,953	5,854
Communications & External Relations	1,597	1,724	1,554	1,697	1,645
Energy Supply	1,305	1,366	1,362	1,488	1,532
Information Systems	4,450	6,130	6,458	7,082	7,045
Engineering	3,923	5,851	6,220	6,270	6,305
Operations Support	1,162	879	989	1,220	884
Facilities	3,146	2,989	3,239	3,343	3,298
Environment Health & Safety	1,419	1,488	1,430	1,914	1,952
Finance & Regulatory Services	3,763	3,821	3,548	3,709	3,771
Human Resources	1,570	1,776	2,191	1,664	1,600
Governance	1,470	1,608	1,727	1,748	1,906
Corporate	2,703	2,946	2,492	2,916	3,161
Pension/OPEB (O&M Portion) [5]	(3,334)	(3,515)	(3,515)	(3,515)	(1,742)
Employer Health Tax & MSP Reduction [5]	(376)				
Total Formula O&M [6]	**55,516**	**58,344**	**59,800**	**62,539**	**66,083**
% year over year change	**n/a**	**5.1%**	**2.5%**	**4.6%**	**5.7%**

1 These flow-through costs are embedded in each of the department total

2 Net cost reductions related to COVID-19 Pandemic normalized from O&M actuals for 2020 (+$0.10 m); 2021 (+$0.93 m); 2022 (-$1.03 m)

In general, O&M costs[4,5] increased over the five-year timeframe due in part to overall inflationary pressures (record high inflation was experienced in 2022 and 2023) and a growing customer base.

For 2020, the key drivers of the increased O&M are as follows:

[4] Although pension/OPEB costs are flow-through and not part of formula O&M, these costs are included in each department's costs and have only been removed at an aggregate level. This is due to the complexity in determining the exact departmental allocation. Similarly, for 2019, the impact of the Employer Health Tax and MSP Reduction approved as an exogenous factor is shown separately.

[5] The BCUC approved that COVID-19 incremental costs and savings from 2020 and 2021 that totaled to $1.030 million be returned to customers in 2022 through the Flow-through deferral account. Net cost impacts related to the COVID-19 pandemic normalized from O&M actuals in the table above were as follows: 2020 (+$0.100 million); 2021 (+$0.930 million); and 2022 (-$1.030 million).

- Net incremental funding approved as part of the Current MRP of approximately $0.9 million in the following departments: Operations ($0.4 million), Generation ($0.2 million), and Information Systems ($0.3 million); and
- The inclusion of approved costs of approximately $1.5 million for the Mandatory Reliability Standards (MRS) Assessment Report (AR) 10 in Engineering as part of formula O&M which were previously accounted for as an exogenous factor during the 2014-2019 PBR Plan term.

These increases were partially offset by the following:

- An approved reclassification of BCUC fees from formula to forecast O&M of approximately $0.2 million in Finance & Regulatory Services; and
- The approved incorporation of FBC's ongoing AMI costs which resulted in $1 million of net cost reductions in formula O&M, impacting Customer Service (decrease) and Information Systems (increase).

For 2021, the key drivers of the increased O&M are as follows:

- Higher spending in the Generation department for dam safety resulting from the continuation of dam safety review activities from 2020; and
- Higher legal costs for management of labour relations issues in Human Resources.

For 2022, the key drivers of the increased O&M are as follows:

- Higher software licensing fees and consulting costs in Information Systems; and
- Additional resources in the Environment, Health and Safety department to support increased requirements for reporting, compliance and disclosure of FBC's progress towards sustainability goals.

For 2023, the key drivers of the increased O&M are as follows:

- In Generation, increased costs due to unplanned repairs on the Upper Bonnington, Corra Linn and South Slocan dams, and on the generators at the Lower Bonnington and Corra Linn plants; and
- In Governance, higher costs due to the timing difference of legal and claims settlement fees in the Insurance department and increased labour costs in 2023 compared to 2022 for the Internal Audit department due to vacancy related savings in 2022.

Contributing to fluctuations in expenditures between years in some departments is the timing of expenditures (i.e., due to one time and temporary events), reflecting the circumstances and priorities for the department in the year.

Appendix C4-1

FEI FORECAST METHODS

Appendix C4-1

Demand Forecast Methods

Table of Contents

Index of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides a detailed description of its demand forecast methods. While FEI is not forecasting demand for the purposes of this Application, FEI has illustrated its demand forecast method in this appendix assuming a 2025 forecast year.

The following table shows the high-level methods used for each component of FEI's demand forecast.

Table 1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Exponential Smoothing (ETS) method, using normalized historical UPC	Product of customers and use rates
Commercial	3 year average historical additions	Prior year customers + customer adds	ETS method, using normalized historical UPC	Product of customers and use rates
Industrial				Annual survey of industrial customers

FEI's demand forecast methods are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in the FEI Annual Review for 2015 Delivery Rates and Order G-86-15. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

In the following sections, FEI provides background information, including a description of FEI's regions and rate classes, the time periods used in the forecast, and the weather normalization process, followed by a description of each of FEI's forecast methods used to derive the 2025 demand forecast, in the following order:

- Residential Customer Additions;
- Commercial Customer Additions;
- Residential and Commercial Use Rates;
- Residential and Commercial Demand Forecast; and
- Industrial Demand Forecast.

2. BACKGROUND INFORMATION

2.1 *FEI REGIONS*

FEI is divided into four regions as shown in Figure A3-1.

Figure 1: FEI Regions

The Mainland region is further divided into the following sub-regions:

- Lower Mainland
- Inland
- Columbia
- Revelstoke

Forecasting is performed at the sub-regional level for each rate schedule in the Mainland region and summed up to derive the Mainland region forecast, which is then added to the forecast for the Vancouver Island, Whistler and Fort Nelson regions to derive the total forecast for each rate schedule within FEI.

2.2 *ACTUAL, SEED AND FORECAST YEARS*

FEI's demand forecasts contain data from three timeframes:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.
- **Forecast Year(s)**: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or two or more years depending on the filing.
- **Seed Year:** The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2024 and the Seed Year forecast is based on the latest actual years, including 2023. As such, the 2024 Seed Year forecast in this Application will differ from the 2024 Forecast presented in the Annual Review for 2024 Delivery Rates, for which 2023 year-end actual data was not available.

2.3 *RATE CLASSES*

The following residential, commercial and industrial rate classes are included in the annual demand forecast:

Table 2: Rate Classes

Residential	
Rate Schedule 1 - Residential	This rate schedule is applicable to firm gas supplied at one premise for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, row houses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
Commercial	
Rate Schedule 2 - Small Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of less than 2,000 gigajoules (GJ) of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 3 - Large Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of greater than 2,000 GJ of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 23 - Commercial Transportation	This rate schedule is applicable to shippers with a normalized annual consumption at one premise of greater than 2,000 GJ of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

Industrial	
Rate Schedule 4 – Seasonal	This rate schedule applies to the sale of gas to one customer who, pursuant to this Rate Schedule, consumes gas during the off-peak period.
Rate Schedule 5 - General Firm	This rate schedule applies to the sale of firm gas through one meter station to a customer. Firm gas service under this Rate Schedule means the gas FEI is obligated to sell to a customer on a firm basis subject to interruption or curtailment.
Rate Schedule 7 - General Interruptible Sales	This rate schedule applies to the provision of a bundled interruptible transportation service and the sale of firm gas through one meter station to a customer.
Rate Schedule 22/22A/22B - Large Volume Transportation	This rate schedule applies to the provision of firm and/or interruptible transportation service (subject to a minimum of 12,000 GJ per month) through the FEI system and through one meter station to one shipper except as previously agreed upon.
Rate Schedule 25 - General Firm Transportation	This rate schedule applies to the provision of firm transportation service through the FEI system and through one meter station to one shipper.
Rate Schedule 27 - General Interruptible Transportation	This rate schedule applies to the provision of interruptible transportation service through the FEI system and through one meter station to one shipper.

2.4 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (Rate Schedules (RS) 1, 2, 3 and 23) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules as described in this section. Separate normalization factors are developed for each region, rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each region and rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load. As the relationship between weather and the usage is not linear, FEI considers three non-linear models that are often used when modeling weather impact. One is based on the Gompertz distribution (the "Gompertz" model). The other two methods are variants based on the logit formulation with one (Logit-4) allowing for an additional parameter for optimal fitting. The models are:

- Gompertz

$$Estimated\ Monthly\ UPC = A \times e^{\left(-e^{-B \times (Avg.Monthly\ Temp. - C)}\right)}$$

- Logit-3

$$Estimated\ Monthly\ UPC = \frac{A}{1 + B \times e^{(-C \times Temp)}}$$

- Logit-4

$$Estimated\ Monthly\ UPC = \frac{(D + (A - D))}{1 + B \times e^{(-C \times Temp)}}$$

The A/B/C/D parameters are estimated through a least squares method to minimize the sum of squared errors (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

3. RESIDENTIAL CUSTOMER ADDITIONS

The residential net customer additions forecast was developed based on housing starts data from the Conference Board of Canada (CBOC) for single-family dwellings (SFD) and multi-family dwellings (MFD).[1] The housing starts data was as follows:

Table 3: BC Housing Starts Data

BRITISH COLUMBIA	2023	2024	2025	2026	2027
Housing Starts, Singles, British Columbia	8,202	10,086	9,547	9,027	8,524
Forecast Percent Change		**22.97%**	**-5.35%**	**-5.44%**	**-5.58%**
Housing Starts, Multiples, British Columbia	41,608	38,622	37,684	36,727	35,754
Forecast Percent Change		**-7.18%**	**-2.43%**	**-2.54%**	**-2.65%**
Total	49,810	48,708	47,231	45,754	44,278

From the above housing starts forecast, the 2025F SFD growth rate is calculated as follows:

$$2025F\ SFD\ Growth\ Rate = \left(\frac{9{,}547}{10{,}086}\right) - 1 = -5.35\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

[1] CBOC Housing Starts 20-Year Outlook completed on December 18, 2023. Data released as e-data on December 20, 2023.

Table 4: Growth Rates

Housing Type	2024S	2025F	2026F	2027F
SFD Forecast Percentage Change	22.97%	-5.35%	-5.44%	-5.58%
MFD Forecast Percentage Change	-7.18%	-2.43%	-2.54%	-2.65%

The following table incorporates the FEI proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2023 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally, the CBOC growth rates for 2024 and 2025 are applied to the SFD and MFD proportions for 2024 in columns F and G and for 2025 in columns I and J.

Table 5: FEI Proportions of Actual Account Additions by SFD and MFD

				Internal Split		Actual Adds 2023			2024S			2025F			2026F			2027F		
Region	2021A	2022A	2023A	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total	SFD	MFD	Total	SFD	MFD	Total
Mainland				A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Lower Mainland	569,546	573,352	578,284	34.2%	65.8%	4,932	1,687	3,245	2,074	3,013	5,086	1,963	2,939	4,902	1,856	2,865	4,721	1,753	2,789	4,542
Inland	237,600	240,693	243,014	72.7%	27.3%	2,321	1,687	634	2,074	589	2,663	1,963	575	2,538	1,856	560	2,416	1,753	545	2,298
Columbia	22,316	22,595	22,774	59.7%	40.3%	179	107	72	131	67	198	124	65	190	118	64	181	111	62	173
Revelstoke	1,716	1,763	1,823	85.2%	14.8%	60	51	9	63	8	71	60	8	68	56	8	64	53	8	61
Whistler	3,045	3,070	3,119	86.8%	13.2%	49	43	6	52	6	58	50	6	55	47	6	53	44	6	50
Vancouver Island	129,764	132,861	135,000	68.3%	31.7%	2,139	1,460	679	1,795	630	2,426	1,699	615	2,314	1,607	599	2,206	1,517	583	2,101
Fort Nelson	1,860	1,836	1,830	66.7%	33.3%	(6)	(4)	(2)	(5)	(2)	(7)	(5)	(2)	(6)	(4)	(2)	(6)	(4)	(2)	(6)
Total FEU	**965,847**	**976,170**	**985,844**			**9,674**	**5,030**	**4,644**	**6,185**	**4,311**	**10,496**	**5,854**	**4,206**	**10,061**	**5,536**	**4,099**	**9,635**	**5,227**	**3,991**	**9,218**

For example, the Lower Mainland 2025F SFD value of 1,963 (column I) is derived as follows:

- Lower Mainland 2023 Internal Split – SFD percentage = 34.2% (column A);
- Lower Mainland 2023 Actual additions = 4,932 (column C)

$$LML\ 2023Actual\ SFD = 34.2\%\ \times 4{,}932 = 1{,}687\ (column\ D)$$

$$LML\ 2024\ Seed\ SFD = (1 + 22.9\%) \times 1{,}687 = 2{,}074\ (column\ F)$$

$$LML\ 2025\ Forecast\ SFD = (1 + (-5.3\%)) \times 2{,}074 = 1{,}963\ (column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated as an average of the net customer additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland RS 2.

Table 6: Customer Additions for Lower Mainland RS 2

	Year	Customers	Customer Additions	Rate Switch	Net Customer Additions	Average 2021-2023 of Customer Additions
		A	B	C	D	E
1	2020	54,619				
2	2021	54,671	52		52	
3	2022	54,702	31		31	
4	2023	54,257	(445)	1,021	576	220
5	2024S	54,477				220
6	2025F	54,696				220
7	2026S	54,916				220
8	2027F	55,136				220

Customer additions are calculated in column D. The three-year average of additions is shown in E4 and is 220. 220 additions are forecast in each of 2024 to 2027.

$$2024S\ Customers = 2023\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2024S = 54{,}477 = 54{,}257 + 220$$

Identical calculations are completed for all regions and all small commercial rate schedules.

However, due to rate switching between the large commercial rate schedules (specifically RS 3 and RS 23), forecasting for these two classes was done as a group and then proportioned per 2023 customers distribution.

The following table shows how the Lower Mainland large commercial customer additions forecast was developed. Other regions are similar.

Table 7: Lower Mainland Large Commercial Customer Additions Forecast Development

		Customers							Proportion	
	Customers	RS 3	RS 23	Total	Total Additions	Rate Switch RS3	Net Customer Additions	Average 2021-2023 of Customer Additions	RS 3*	RS 23*
		A	B	C	D	E	F	G	H	I
1	2020	5,075	430	**5,505**						
2	2021	5,240	391	**5,631**	126		126			
3	2022	5,415	320	**5,735**	104		104			
4	2023	6,568	217	**6,785**	1,050	(1,021)	29	86	84	3
5	2024S	6,652	220						84	3
6	2025F	6,735	223						84	3
7	2026F	6,819	225						84	3
8	2027F	6,902	228						84	3

* Final Customer totals are rounded

For each actual year (rows 1-4) the rate class customers from columns A and B are summed in column C.

Aggregate customer additions are shown in column D.

The three-year average customer additions is 86 and shown in column G, row 4.

The 2023 proportion is calculated from columns A/C on row 4.

For example, the RS 3 proportion is:

$$RS\ 3\ Proportion = \frac{6{,}568}{9{,}785} = 0.97$$

The proportion of the aggregate customer additions (86) is assigned to RS 3 is then:

$$RS\ 3\ Customer\ Additions = 0.97\ \times 86 = 84$$

A similar calculation is performed for RS 23 to arrive at 3 customer additions.

On row 5 the 2024S customer additions for RS 3 are shown in column A and calculated as:

$$2024S = \ 6{,}652 = 6{,}568 + 84$$

The remaining calculations are similar.

5. RESIDENTIAL AND COMMERCIAL USE RATES

5.1 THE EXPONENTIAL SMOOTHING METHOD

FEI develops its use rate forecasts based on 10 years of annual use rates by region and rate class. The UPC values are weather-normalized using the process set out in Section 2 above.

The 10 years of data is used to calculate the UPC forecast using ETS, as implemented in Microsoft Excel.

ETS is a time series forecasting method that dynamically calculates and applies exponential weights to the trend and level of a series of historical observations. Older values are generally given lower weighting than more recent values, but this varies depending on the source data. ETS is a popular technique implemented in many statistical and analytics software packages including Microsoft Excel (version 2016 and later).

ETS is implemented as both a formula and "wizard" in Excel 2016. Intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in its software.

The UPC method for Lower Mainland RS 1 (residential) is demonstrated below. All residential and commercial use rate forecasts in all regions are developed using the same method.

5.1.1 Lower Mainland RS 1 UPC Example

The forecast UPCs for Lower Mainland RS 1 were calculated as follows:

Start with 10 years of weather normalized annual UPCs:

LML	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	93.6	92.9

In Excel, the "forecast.ets()" function is used to calculate the 2024 and 2025 forecasts.

LML	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	93.6	92.9	=FORECAST.ETS(M8,C9:L9,C8:L8,0,0,1)

FORECAST.ETS(target_date, values, timeline, [seasonality], [data_completion], [aggregation])

The resulting forecasts for 2024 to 2027 are shown:

LML	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024S	2025F	2026F	2027F
Rate 1	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	93.6	92.9	93.8	93.7	93.5	93.3

5.2 AMALGAMATION OF UPCS IN FIS

Once the use rates are seasonalized and developed for each region and each rate schedule (RS 1, RS 2, RS 3 and RS 23), they are entered into FIS. The amalgamated use rates are calculated using the following relationship:

$$Use\ Rate = \frac{\sum Volume}{\sum Accounts}$$

FIS calculates both the monthly volume and accounts by region and rate class. In an external spreadsheet the volumes and accounts are summed by month and by rate class for all regions.

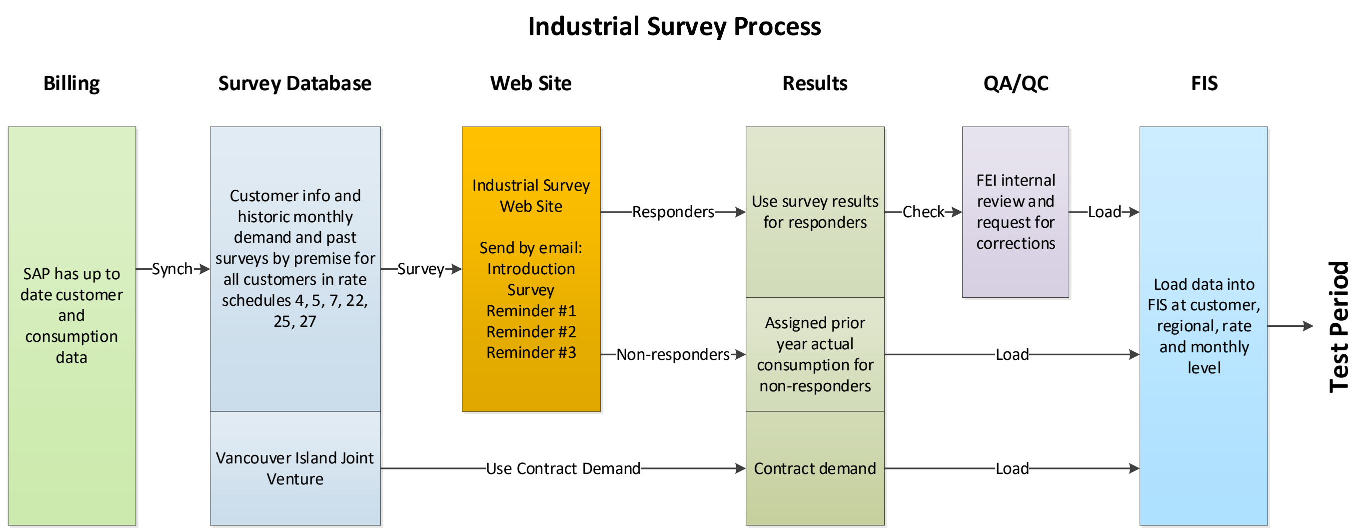
6. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast at the sub-regional level. The sub-regions, regions and months are then summed to arrive at the amalgamated demand forecast.

7. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure 2: Industrial Forecast Process



Each customer in each industrial class receives a customized email message with a secure link to their individual survey. The customer then uses the web based survey to complete their forecast of demand for the next five years and submits it to FEI. Once the survey is closed (typically after a six-week duration), the survey responses are checked and then the data is loaded into the FIS system. The following sections describe the process in detail.

7.1 CREATE THE SURVEY

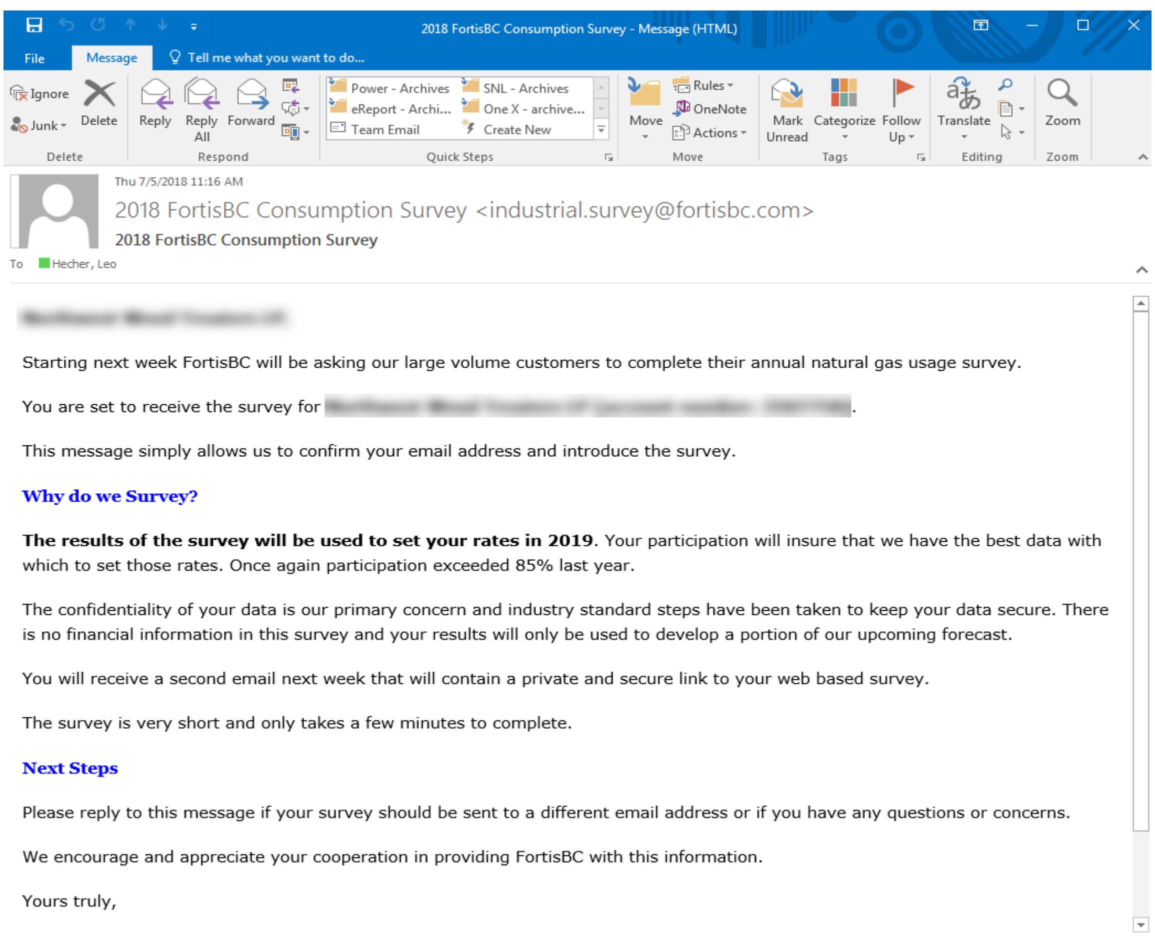
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey, all industrial classes are selected. Commercial and residential customers are not surveyed.

7.2 SEND OUT THE INTRODUCTION EMAIL

The customer is introduced to the survey several days before the actual surveys are sent out. This allows the customer time to update their contact information and possibly to assign the survey to a different employee if there have been staffing changes. FEI has found this to be an important step and contributes to the high success rate because a minimal number of surveys are sent to the wrong person.

The survey web site creates the form letters and manages the send out. The following is an example of the introductory email.

Figure 3: Survey Introductory Email Example

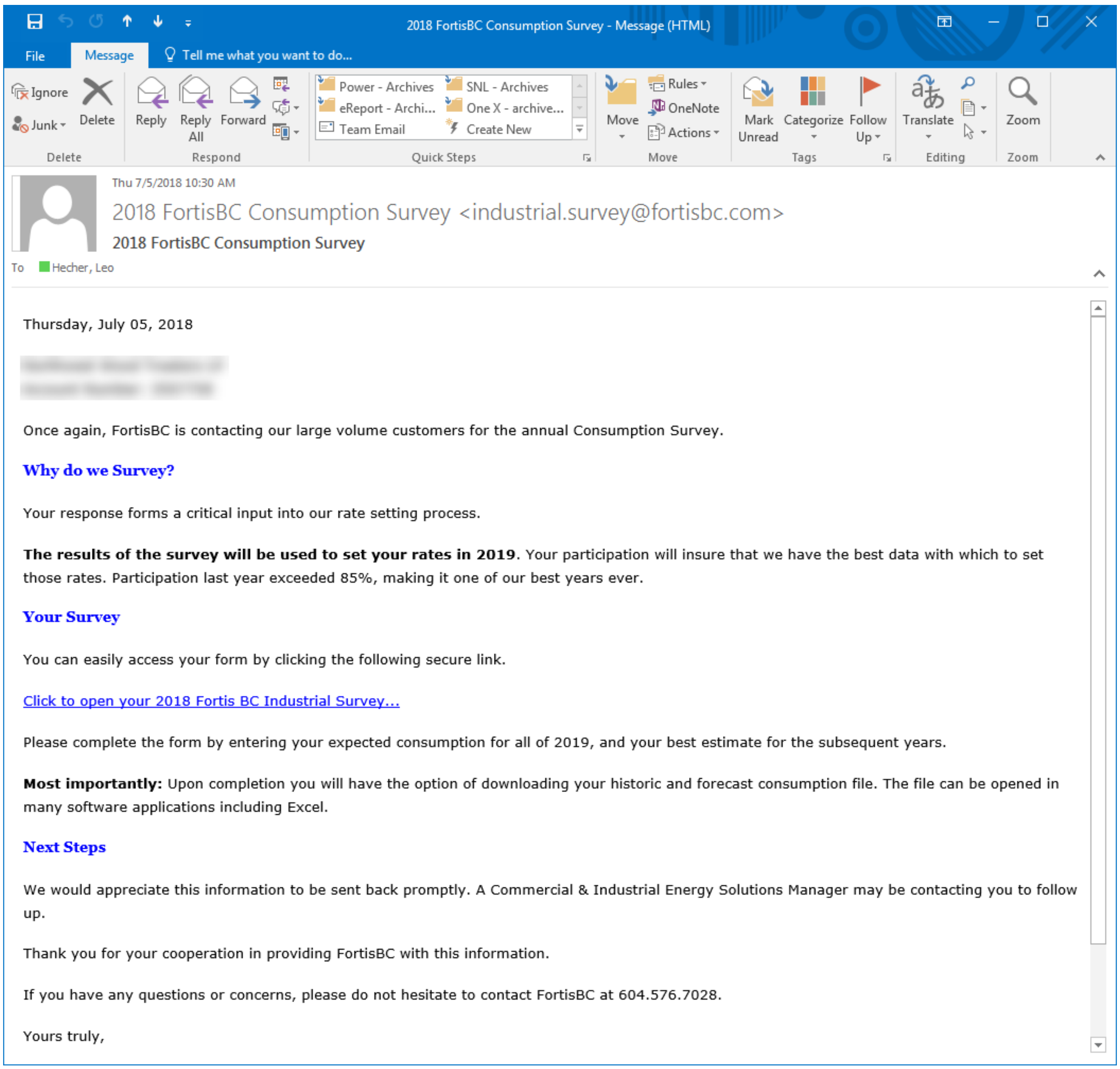


Replies to these emails are used to update the contact and other information in the survey web site.

7.3 *SEND OUT THE SURVEY EMAIL*

An email with a customized link to the survey is sent out several days after the reminder. The survey is not sent until all the changes that resulted from the introductory email have been processed. As in the following sample email, each customer is sent an HTML link to the survey. An encrypted globally unique identifier in the link ensures that customers cannot access surveys from other customers.

Figure 4: Survey Email Example



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 10:30 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

To Hecher, Leo

Thursday, July 05, 2018

Once again, FortisBC is contacting our large volume customers for the annual Consumption Survey.

Why do we Survey?

Your response forms a critical input into our rate setting process.

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Participation last year exceeded 85%, making it one of our best years ever.

Your Survey

You can easily access your form by clicking the following secure link.

Click to open your 2018 Fortis BC Industrial Survey...

Please complete the form by entering your expected consumption for all of 2019, and your best estimate for the subsequent years.

Most importantly: Upon completion you will have the option of downloading your historic and forecast consumption file. The file can be opened in many software applications including Excel.

Next Steps

We would appreciate this information to be sent back promptly. A Commercial & Industrial Energy Solutions Manager may be contacting you to follow up.

Thank you for your cooperation in providing FortisBC with this information.

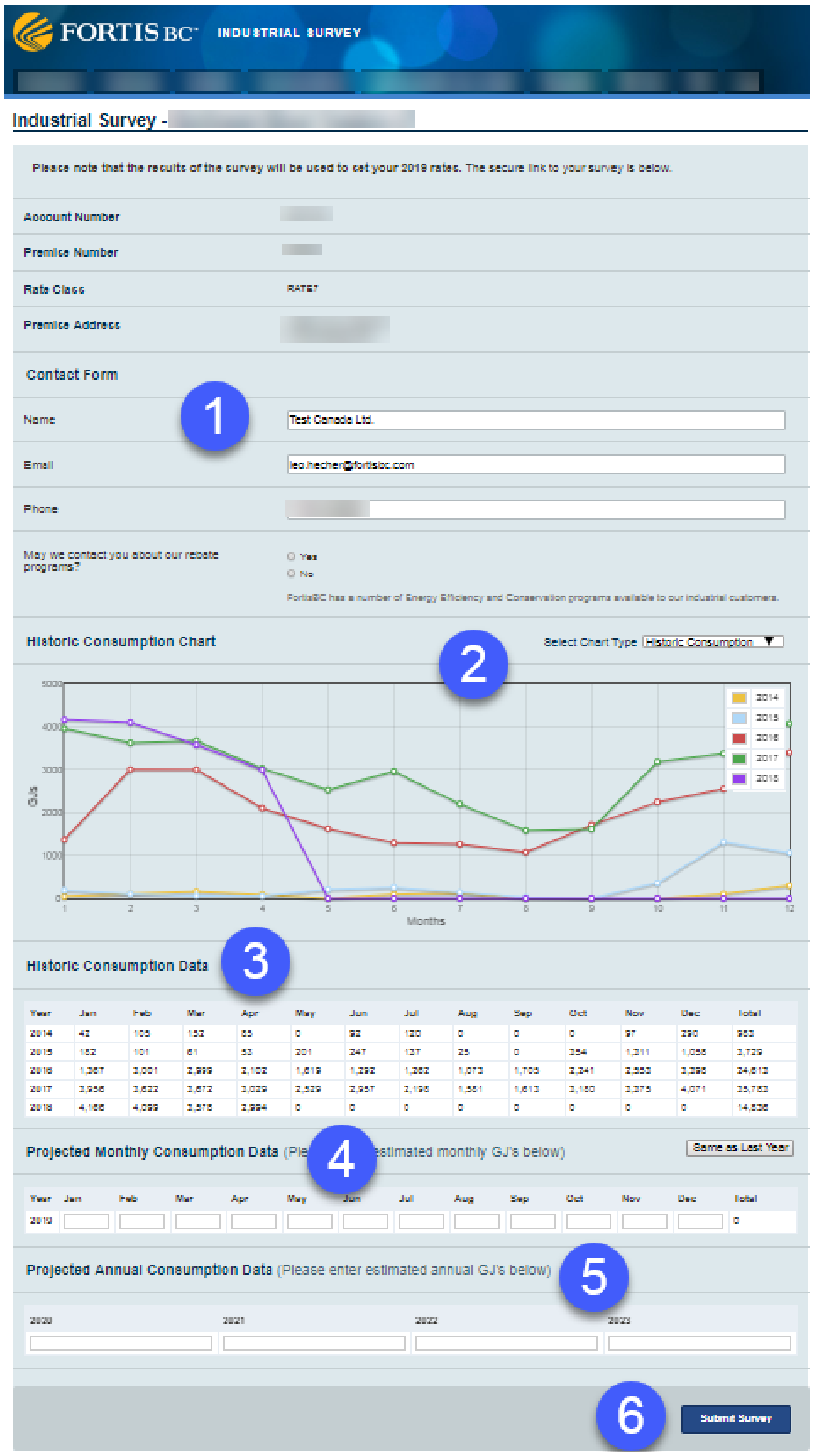
If you have any questions or concerns, please do not hesitate to contact FortisBC at 604.576.7028.

Yours truly,

7.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

Figure 5: Survey (Web) Form Example



Notes:

1) The user can change the contact name (normally a person's name), email and phone number. It is saved and will be used in subsequent years. This allows the recipient to redirect next year's survey.

2) A line chart showing the customer's actual historic consumption is shown for the prior five years. The customer can use the pick list to show a chart that shows last year's actual consumption and last year's survey. This allows the customer to see any variance in their survey from last year.

3) A table of historical consumption is shown for the prior five years. Zeroes are shown in this example because the survey database is not updated until the start of a real survey.

4) The customer is asked for monthly consumption for the coming year. The total at the right side is automatically updated to reduce typing errors. If the customer believes that its consumption is not changing, they can use the "Same as last year" button as a fast alternative to typing in the same values.

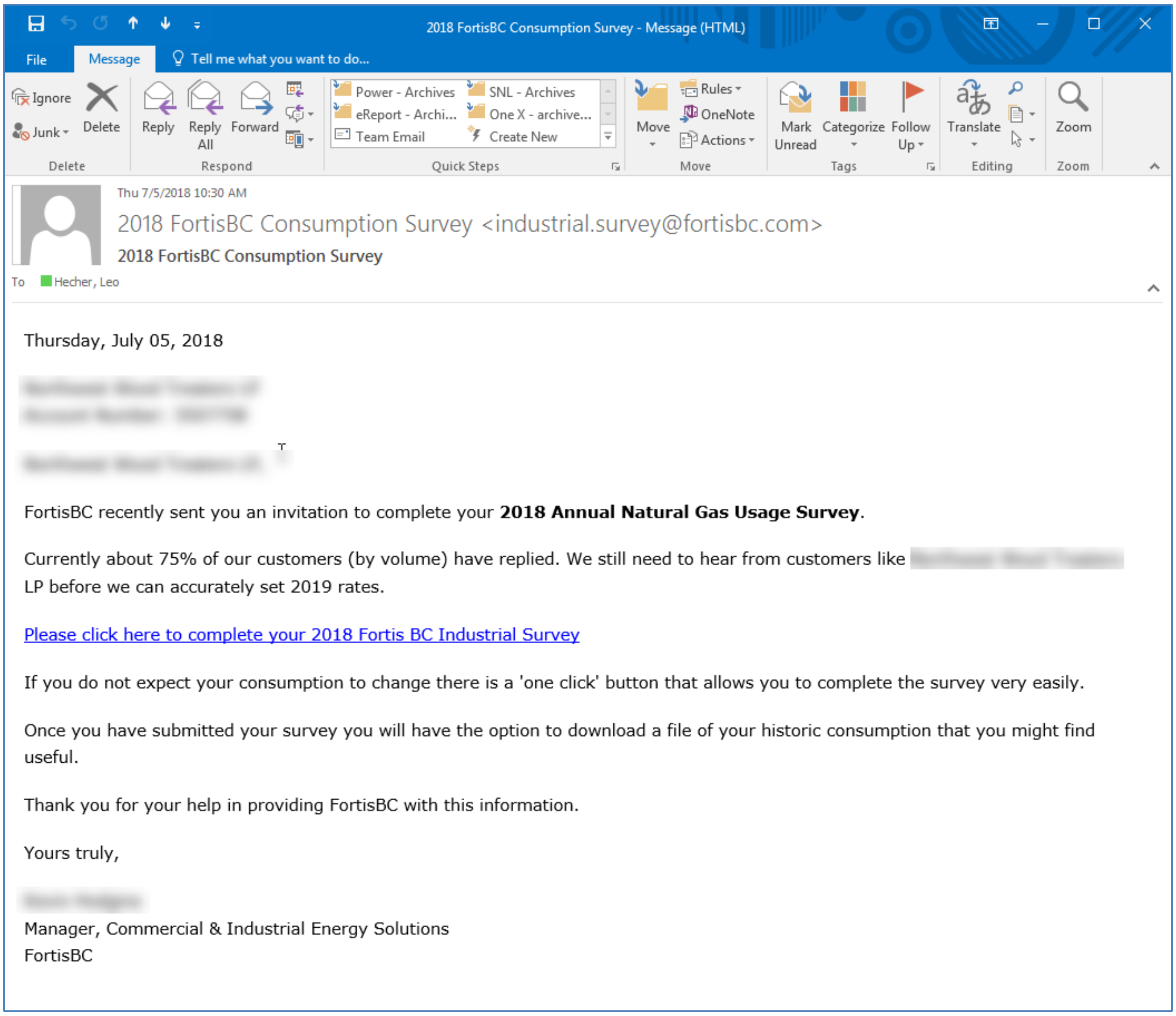
5) Annual forecasts are requested for the remaining four years of the survey.

6) Once the data has been entered the user clicks the Submit button to save the survey. Upon submitting the survey the user will be able to download a Microsoft Excel file containing the data from Step 3 above.

7.5 NON RESPONDERS AND THE REMINDER EMAIL

Once the survey is started, responses start coming in within the hour. A steady response rate normally continues for several days, but eventually slows. The survey system tracks the status of each survey and at all times FEI knows the response rate. Until the target response rate is reached, FEI sends out a weekly reminder email to those customers that have not yet responded. The reminder email contains the same link to the survey. The reminder step enhances the response rate of the survey. A sample is shown below:

Figure 6: Example of Survey Reminder Email



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 10:30 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

To Hecher, Leo

Thursday, July 05, 2018

FortisBC recently sent you an invitation to complete your **2018 Annual Natural Gas Usage Survey**.

Currently about 75% of our customers (by volume) have replied. We still need to hear from customers like LP before we can accurately set 2019 rates.

Please click here to complete your 2018 Fortis BC Industrial Survey

If you do not expect your consumption to change there is a 'one click' button that allows you to complete the survey very easily.

Once you have submitted your survey you will have the option to download a file of your historic consumption that you might find useful.

Thank you for your help in providing FortisBC with this information.

Yours truly,

Manager, Commercial & Industrial Energy Solutions
FortisBC

7.6 *MONITORING THE RESPONSE RATE*

The response rate for the survey is measured in terms of number of respondents and the volume from those respondents. FEI is not only concerned with the number of customers that reply but also the volume those customers represent. The response rate from a volumetric perspective is always higher than the customer count response rate because large customers (for example those in RS 22) are more likely to reply to the survey.

The response rate is measured by counting the number of responses compared to the number of customers in the survey. Some customers will not respond because the survey has been sent to an invalid email address. In these cases, FEI attempts to correct the address so that a survey can be completed. FEI notes that if an address cannot be corrected during the time of the survey, then the customer remains in the denominator of the response calculation ratio.

The following screen shot is for demonstration purposes only.

Figure 7: Example of Survey Results Dashboard

7.7 *REVIEWING THE SURVEYS*

Surveys from large volume customers are reviewed by the Forecast Manager and one or more Commercial and Industrial Energy Solutions Managers. The Commercial and Industrial Energy Solutions Managers are well informed about the issues with each individual customer and are able to rationalize the survey received from the customer. Where surveys are contrary to the information the Commercial and Industrial Energy Solutions Managers have, a follow up call is made and the survey is adjusted if required.

7.8 *CLOSING OFF THE SURVEY AND LOADING FIS*

Once the target response rate has been achieved in early July, the survey is closed. The data in the survey web site is then transferred automatically to the current forecast in FIS. Industrial rate classes are forecast by individual customer so the data for each customer is copied. Checks are completed to make sure that that data was copied properly and that the survey web site and that the current FIS forecast are in sync.

Customers that do not respond to the survey are assigned their prior year's consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

8. SUMMARY OF DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month, region and rate class to prepare the overall forecast of demand.

Appendix C4-2

FBC FORECAST METHODS

Appendix C4-2

FBC Load Forecast Methods

Table of Contents

Index of Tables

1. INTRODUCTION

In this appendix, FBC provides a detailed description of its load forecast methods. While FBC is not forecasting load for the purpose of this Application, FBC has illustrated its load forecast method in this appendix assuming a 2025 forecast year.

In the following sections, FBC summarizes its load forecast methods, describes the time periods used in the forecast, and explains the weather normalization process, followed by a description of FBC's forecast methods, in the following order:

- Before-savings load forecast for Residential, Commercial, Wholesale, Industrial, Irrigation and Lighting load classes;
- Demand-side management (DSM) savings forecast; and
- Peak demand forecast.

2. BACKGROUND INFORMATION

2.1 *SUMMARY OF LOAD FORECAST METHODS*

The following table shows the high-level methods used for each component of FBC's load forecast.

Table 1: Summary of FBC Load Forecast Methods

Rate Group	Customers	Use Rate	Load
Residential	Regression against service territory population	Time series trend analysis of historical UPC	Product of customers and use rates
Commercial			Regression against CBOC GDP
Wholesale			Annual survey of wholesale customers
Industrial			Annual survey of industrial customers
Irrigation			Five-year average
Lighting			Last observation carried forward ("same as last year")

2.2 *ACTUAL, SEED AND FORECAST YEARS*

FBC's demand forecasts contain data from three timeframes:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.[1]
- **Seed Year:** The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2024 (2024S) and the Seed Year forecast is based on the latest actual years, including 2023. As such, the 2024 Seed Year forecast in this Application will differ from the 2024 Forecast presented in the Annual Review for 2024 Rates, for which 2023 actual data was not available.
- **Forecast Year(s):** This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2025 is the Forecast Year (2025F).

2.3 *WEATHER NORMALIZATION OF RESIDENTIAL AND WHOLESALE LOAD*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential and wholesale load classes; therefore, these classes are normalized. The commercial class shows a low R^2 value for all seasons and therefore was not normalized.

The 2024 spring, summer and fall irrigation class data will be normalized because a correlation is now present in the 2023 actual data.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

[2] Industrial and lighting loads are typically insensitive to the weather.

Table 2: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	44,524	73,811	76,665	71,818
Slope HDD	174	100	-	87
Slope CDD	-	-	242	-
Adjusted R^2	0.80	0.73	0.86	0.76

Table 3: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	30,295	30,691	33,140	34,776
Slope HDD	55	47	-	33
Slope CDD	-	-	103	-
Adjusted R^2	0.81	0.88	0.86	0.82

Table 4: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	50,957	49,648	69,253	71,660
Slope HDD	25	18	-	(2)
Slope CDD	-	-	78	-
Adjusted R^2	0.29	0.16	0.43	(0.05)

Table 5: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,212	(12)	5,201	5,573
Slope HDD	(1)	-	-	(11)
Slope CDD	-	-	24	-
Adjusted R^2	0.06	0.84	0.65	0.75

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[3] and Cooling Degree Days (CDD)[4] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential and wholesale classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: Winter (November to February); Spring (March to May); Summer (June to August); and Fall (September to October). Thus, all

[3] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[4] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

monthly load and degree day data for each season is used and four separate regressions are calculated for each class.

4. To normalize a month, e.g., February 2023:
   a. obtain the month's HDD (or CDD) information from Environment Canada;
   b. calculate the deviation from the 10-year average (2014-2023) HDD (CDD) as found in Step 2;
   c. apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and
   d. add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

3. BEFORE-SAVINGS LOAD FORECAST

FBC forecasts energy requirements by customer class based on weather normalized historical loads. These are referred to as the "before-savings"[5] loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2023) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

3.1 *RESIDENTIAL*

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

[5] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2023".

The before-savings UPC is based on an historic trend of annual UPC values. Each year, FBC chooses the regression period based on statistical criteria and other information available, such as the year-to-date actual customer count. As the trend in correlation between population and customers can change from year to year as the latest actual data is added, the regression period may change from forecast to forecast.

For 2025, the before-savings UPC is based on a 10-year historic trend of annual UPC values from 2014 to 2023, the results of which are shown in the table below.

Table 6: Results of UPC Trend Analysis

Regression	UPC
Start Year	2014
End Year	2023
R^2	0.883
Adjusted R^2	0.869
df	9
Intercept	315
Slope UPC	-0.15

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t + Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table 7: Results of Residential Customer Count Regression

Regression	Residential
Start Year	2020
End Year	2023
R^2	0.994
Adjusted R^2	0.991
df	3
Intercept	50,603
Slope Population	0.27

The residential class represented 38.0 percent of the net load in 2023.

3.2 COMMERCIAL

The before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship between forecast commercial load and provincial GDP is reflected in the following equation.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + CoK\ Event_t)$$

Coefficients b0 and b1 are obtained from an ordinary least squares (OLS) regression analysis on the 2009 to 2023 commercial load data. GDP_t is the CBOC GDP forecast in the future year "t". For example, for 2025 GDP_{2025} is the CBOC forecast for GDP in 2025. The CoK_t is the regression output used to model the City of Kelowna integration event in 2013.

The commercial class represented 27.4 percent of the net load in 2023.

Table 8: Results of Commercial Regression

Regression	Commercial
Start Year	2009
End Year	2023
R^2	0.931
Adjusted R^2	0.920
df	14
Intercept	245,869
Slope GDP	2
Slope CoK Event	120,626

3.3 WHOLESALE

The Company forecasts the wholesale load based on load surveys from the wholesale customers[6]. FBC usually receives survey responses from all the wholesale customers. FBC sums the forecasts from wholesale customers to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc.

The wholesale class represented 16.8 percent of the net load in 2023.

3.4 INDUSTRIAL

The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey[7] and, for customers who did not respond,

[6] The wholesale survey is completed in April-May of each year.
[7] The industrial survey is completed in April-May of each year.

escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in.

The industrial survey is sent via email to each industrial customer in the form of an Excel spreadsheet. Due to the relatively low number of industrial customers, this method is the most efficient and cost-effective way to gather the required information.

It is reasonable to expect that the number of customers responding to the survey will change from year to year. FBC is not concerned with a small change in the number of customers responding to the survey because the focus is on the response rate by load which remains high (90 percent or better in 2021, 2022 and 2023) and consistent.

The goal of the industrial survey is to receive a high return rate of survey responses by load, as load is the main input into the revenue forecast for the industrial class. Further, a reasonable level of staff effort[8] is applied each year to encourage every customer to respond, but the final decision to participate is up to the customer. A balanced approach needs to be used when soliciting a response to avoid customers reacting negatively and refusing to answer further surveys.

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.

The industrial class represented 16.6 percent of the net load in 2023.

3.5 *IRRIGATION*

The before-savings irrigation load forecast uses a five-year average so that extreme weather events, such as those that occurred in 2023, are included in the forecast but do not overly influence it.

The irrigation class represented 1.1 percent of the net load in 2023.

3.6 *LIGHTING*

The before-savings lighting load uses the 2023 actuals due to the variability in the load, primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2023.

The lighting class represented 0.2 percent of the net load in 2023.

[8] FBC contacts each individual customer multiple times by email and phone.

4. DEMAND SIDE MANAGEMENT (DSM) SAVINGS

FBC forecasts load reductions resulting from its DSM programs consistent with the Company's approved DSM Plans.

FBC groups DSM measures into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. The annual sector targets beginning with the Seed Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions. Savings from past DSM programs are reflected in the historical actual data used to prepare the forecast. Therefore, to avoid double counting, FBC deducts only the incremental savings from new DSM programs to the before-savings forecast. The before-savings forecast minus incremental DSM savings results in the after-savings load forecast.

The following example shows the before savings residential forecast for 2024S and 2025F along with the cumulative DSM savings. The after savings residential load forecast is then shown in the final row of the table and is the result of subtracting the cumulative DSM from the before savings forecast.

Table 9: Cumulative DSM Example

	2024	2025
Residential Before Savings Load, GWh	1,333.1	1,333.6
Cumulative DSM, GWh	4.5	9.1
Residential After Savings Load, GWh	1,328.6	1,324.5

5. PEAK DEMAND FORECAST

The peak demand forecast is produced by taking the 10-year average (2014-2023) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks are used for both the winter and the summer. The 12 monthly peaks, as well as the seasonal peaks, are then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after-DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before-DSM peak forecast for each month in each year.

Appendix C4-3

FEI REVIEW OF CMAE FORECAST AND REGULATORY PROCESS

Appendix C4-3

FEI Review of CMAE Forecast and Regulatory Process

Table of Contents

Index of Tables and Figures

1. INTRODUCTION

This Appendix provides FEI's response to BCUC directives with respect to the review of FEI's Core Market Administration Expense (CMAE).

The BCUC Decision on the CMAE 2014 Budget and Order G-79-14, dated June 18, 2014, directed FEI to submit its CMAE budget within its next revenue requirements application (i.e., after the 2014-2019 PBR Plan period), stating:

> The Panel acknowledges FEI's request to submit the CMAE budgets with the fourth quarter gas cost reports. However, the Panel is concerned that if the CMAE Budget is submitted at the same time, the Commission would have insufficient time to properly review the CMAE Budget. **Further, the Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications. Therefore, until such time as FEI files its next revenue requirements application, the Panel directs FEI to submit future CMAE budgets separately to the Commission at least two weeks prior to the fourth quarter gas cost report to allow the Commission sufficient time to review the CMAE Budget, and to determine if there are sufficient variances from the previous CMAE Budget to warrant a more fulsome review.**
>
> **The Panel directs that the CMAE Budget review and approval process be included within the FEI revenue requirements application starting with the next such application filed by FEI.**
>
> While the Panel acknowledges FEI's position that CMAE is an essential component of the cost of gas, the Panel believes there is benefit to reviewing the CMAE Budget with other similar costs within the larger FEI budget.

Further to the BCUC's determinations above, during the remaining term of the 2014-2019 PBR Plan, FEI submitted its 2015 to 2019 CMAE budgets for BCUC approval at least two weeks prior to filing its 2014 to 2018 fourth quarter gas cost reports (Q4 Report). For example, FEI filed its 2019 CMAE Budget Application for BCUC review and approval on November 7, 2018, which was two weeks before the 2018 Q4 Report for the Mainland and Vancouver Island Service Area, which was filed on November 23, 2018.

For the term of the Current MRP, FEI filed its request for approval of its CMAE budget for the upcoming year as part of its Annual Reviews.[1]

In FEI's Annual Review for 2020 and 2021 Delivery Rates, the BCUC directed FEI to consider the suitability of using a formulaic approach for CMAE costs and the appropriate allocation of

[1] Due to the timing related to the regulatory review of the 2020-2024 MRP Application, the 2020 CMAE Budget Application was filed separately on November 6, 2019, two weeks prior to the filing of the FEI 2019 Q4 Report for the Mainland and Vancouver Island Service Area.

CMAE costs between the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA):[2]

> Therefore, the Panel directs FEI to include, in its next revenue requirements or MRP application following the MRP term, a comprehensive review of the CMAE costs including consideration of whether these costs are conducive to a formulaic approach or whether they should continue to be forecast with flow-through treatment, and whether the current allocation percentages to the CCRA and MCRA remain appropriate.

Further, in FEI's Annual Review for 2023 Delivery Rates, the BCUC reminded FEI of its requirement to file a comprehensive review of CMAE costs pursuant to the BCUC's direction in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision.

Based on FEI's analysis and consideration of approaches, FEI is proposing to:

- Continue to forecast its CMAE budget by cost component using a new, simplified template;
- Submit the CMAE forecast for approval as a separate application at or near the same time as its Third Quarter Gas Cost Report (Q3 Report);
- Review the prior year's forecast to actual CMAE variances within the CMAE forecast application, noted above, using a new, simplified template;
- Continue to treat the CMAE as part of the cost of gas, allocating 25 percent of costs to the CCRA and 75 percent to the MCRA; and
- Record variances between forecast and actual CMAE using the same allocation as is used to allocate the CMAE forecast to CCRA and MCRA.

The remainder of this Appendix is organized as follows:

- Section 2 provides an overview of FEI's Gas Supply functions funded by the CMAE.
- Section 3 presents FEI's consideration of the approaches for the forecasting and regulatory treatment of CMAE costs, and identifies FEI's proposed approach.
- Section 4 provides FEI's review of the allocation of CMAE costs between the CCRA and MCRA, and sets out FEI's updated allocation percentages.
- Section 5 presents FEI's proposed changes to the prescribed template for use in its request for approval of the CMAE forecast and the prior year's CMAE variance discussion, filed at or near the same time as the Q3 Report.
- Section 6 summarizes FEI's proposals regarding CMAE.

[2] Decision and Order G-319-20, p. 16. See also Decision and Order G-352-22, p. 27.

2. OVERVIEW OF THE GAS SUPPLY FUNCTIONS FUNDED BY THE CMAE

FEI's CMAE budget funds the Gas Supply staff and resources, as well as the support received from other FEI departments (via a shared services fee), to perform the gas supply activities required to serve core market customers. Necessary CMAE activities include:

- Planning, managing, and optimizing the commodity and midstream gas supply portfolios (consistent with the development of the Annual Contracting Plans, and implementation of the BCUC accepted Annual Contracting Plans);
- Planning, managing, and optimizing the use of financial derivatives (consistent with the development of the price risk mitigation applications, and implementation of the BCUC approved plans);
- Managing all the gas supply resources (including the Customer Choice Program marketer supply and the Renewable Natural Gas supply) on a daily basis to meet load requirements, and to mitigate costs of any unneeded resources (alignment with the BCUC approved Gas Supply Mitigation Incentive Program);
- Establishing appropriate contracts with counterparties and managing any associated credit exposure;
- Managing upstream regulatory developments so that unfavourable developments are minimized, and beneficial opportunities are identified;
- Completing accounting, audit, and compliance activities related to invoice settlements, and submission of reports to various regulatory and government agencies;
- Managing and supporting Gas Supply technology systems (including software licensing and maintenance fees, and data subscription services); and
- Supporting various internal departments (such as Forecasting, Legal, Tax, and Treasury), as allocated via the shared services fee.

Since the mid-1990s, FEI's CMAE budget has been separated from FEI's O&M expense and recovered via gas cost recovery rates as part of the total cost of gas.

The following table summarizes, for each of the years 2018 to 2022, the actual CMAE, the gross cost of the commodity and midstream gas supply portfolios (excluding the Customer Choice Program marketer supply and the Renewable Natural Gas supply), the mitigation revenue generated which reduces the cost of gas to be recovered from customers, CMAE as a percent of both the cost of gas before and after mitigation revenue is considered, and the year-over-year change in CMAE and BC-CPI.

Table 1: 2018-2022 Actual Annual CMAE, Gross Cost of Gas, and Mitigation Revenue and Various Percentages

Line No.	Particulars	Reference	2018	2019	2020	2021	2022
1	Gross Cost of Gas (includes midstream costs) ($million)		591.8	647.5	631.7	889.8	1,242.4
2	Mitigation Revenue ($million)		181.7	246.2	118.2	196.6	369.9
3	Cost of Gas less Mitigation Revenue ($million)	Line 1 - Line 2	410.1	401.3	513.5	693.2	872.5
4	Mitigation Revenue as a Percent of Gas Costs	Line 2 / Line 1	30.7%	38.0%	18.7%	22.1%	29.8%
5	Actual CMAE ($million)		5.8	4.8	5.1	5.1	5.3
6	CMAE as a percent of Gas Costs	Line 5 / Line 1	1.0%	0.7%	0.8%	0.6%	0.4%
7	CMAE as a percent of Gas Costs after Mitigation Revenue	Line 5 / Line 3	1.4%	1.2%	1.0%	0.7%	0.6%
8	Year-over-Year change in CMAE	(Line 5 / Prior Year Line 5) - 1	36.7%	-16.5%	5.3%	-0.4%	5.4%
9	BC-CPI Inflation % (All items)		2.7%	2.3%	0.8%	2.8%	6.9%

As shown in the table above, the CMAE is a small component of the total cost of gas but can vary from year to year. The cost of gas supply portfolio, in contrast, is the largest single component of FEI's revenue requirement. The revenues associated with mitigation activities materially offset the cost of gas, which can change dramatically with changes in commodity costs or in storage and transportation costs.

FEI discusses the rationale for its proposed treatment of CMAE as it relates to the overall gas supply portfolio costs and BC-CPI below.

3. APPROACHES FOR FORECASTING AND REGULATORY TREATMENT OF CMAE

By Decision and Order G-319-20, the BCUC directed FEI to consider whether CMAE costs were conducive to a formulaic approach or whether they should continue to be forecast with flow-through treatment. As discussed below, FEI determined that CMAE costs were not conducive to being derived by a formulaic approach. FEI is instead proposing a simplified forecasting approach with streamlined variance reporting.

3.1 *FEI CONSIDERED AND REJECTED A FORMULAIC APPROACH*

In assessing whether CMAE costs were conducive to a formulaic approach, FEI considered the implications of recovering CMAE costs through delivery charges, as compared to cost of gas charges. FEI considers that continuing to recover the forecast CMAE costs, and variances between forecast and actual CMAE, from Sales Service customers via gas cost recovery charges (Cost of Gas and Storage & Transport charges) remains appropriate for the following reasons.

First, as discussed in Section 2 above, CMAE costs are incurred to support various gas supply related activities for FEI's Sales Service customers.[3] FEI has historically used separate, BCUC-approved charges for gas supply activities on its Sales Service customers' bills (Cost of Gas and Storage & Transport charges). Delivery charges include the costs that FEI incurs to convey gas through its own pipeline system after it has received that gas at its various interconnection points with upstream pipelines and, unlike cost of gas charges, apply to both Sales Service and Transportation Service[4] customers. If CMAE were to be included in delivery charges, then Transportation Service customers would bear some of those costs without having caused them. This approach would not follow cost causation principles. Further, while CMAE costs are currently flowed-through to customers through cost of gas charges, adopting a formulaic approach would instead result in these costs being passed onto customers through delivery charges, which are subject to earnings sharing (i.e., variances between formula and actual costs would be shared 50/50 with customers as opposed to the actual costs flowing to customers).

Second, as noted above, CMAE costs also vary considerably from year to year. For example, as shown in Table 1 (Line 8)) above, CMAE cost variances have ranged from -16.5 percent to

[3] Sales Service customers purchase their gas commodity from FEI and FEI secures their upstream resources to move that gas from trading hubs, such as Station 2 in Northern BC, to its various interconnection points with upstream pipelines. While Customer Choice customers do not acquire their commodity from FEI, FEI does use the aforementioned upstream resources to transport the gas Customer Choice customers acquire from gas marketers to its various interconnection points, so are considered Sales Service customers and do pay Storage & Transport charges.

[4] Transportation Service customers purchase their own gas commodity and secure their own upstream resources to move that gas from various trading hubs to FEI's interconnection points with upstream pipelines.

+36.7 percent in the last five years, which is an order of magnitude greater than BC-CPI. While FEI expects that it could manage these variances, as actual year-over-year CMAE dollar variances are small compared to the size of FEI's O&M, this would not resolve the cost causation issue identified above.

Based on the above assessment, and given the size of CMAE costs relative to the gas supply portfolio, FEI considers that the drawbacks of adopting a formulaic approach outweigh the potential regulatory efficiency to be gained, particularly given that the CMAE budget can be reviewed efficiently through the approach proposed in this Appendix. In the section below, FEI discusses two approaches to forecasting CMAE costs.

3.2 *SIMPLIFIED FORECAST AND VARIANCE REPORTING WILL ENHANCE REGULATORY EFFICIENCY AND EFFECTIVENESS*

Having confirmed that recovering CMAE from Sales Service customers via cost of gas charges remains appropriate, FEI considered the following approaches for forecasting CMAE costs:

1. **Status Quo:** As has been done during the Current MRP term, FEI would continue to file a detailed CMAE budget for BCUC review and approval as part of the Annual Reviews. FEI would also continue to submit year-end actual costs and variances, including explanations of variances, to the BCUC as part of FEI's CCRA and MCRA Status Report (Status Report) filed by April 30 of the following year. The BCUC-approved CMAE forecast costs, including variances between the approved budget and actual costs, would be flowed through to customers via gas cost recovery charges.
2. **Simplified Forecasting and Variance Reporting:** FEI would provide a CMAE forecast each year at or near the same time as FEI files its Q3 Report using a simplified forecasting and variance reporting template. FEI would also provide explanations of variances between the approved forecast and actual CMAE from the last complete year as part of this filing.

FEI outlines these two approaches for forecasting CMAE in further detail below, before discussing the allocation of CMAE costs between CCRA and MCRA in Section 4.

3.2.1 Approach 1: Status Quo

This approach would maintain the method and process for forecasting the CMAE budget, on a line-by-line basis, using the BCUC Template for CMAE Budget Application, as directed pursuant to Orders G-79-14 and G-23-15. Since the filing of the 2021 CMAE Budget Application, the CMAE budget review and approval has been part of the Annual Review process. Year-end results of the approved costs, actual costs, and variances, including explanations of variances, are also submitted to the BCUC as part of the Status Report filed by April 30 of the following year. The year-end results are filed using the BCUC Template for Reporting CMAE Actuals, as directed pursuant to Order G-79-14. Variances between the BCUC Approved budget and actual costs are flowed through gas costs, which results in Sales Service customers paying actual CMAE costs.

While the current review process provides ample opportunity for regulatory review by the BCUC, it is also inefficient. In particular, FEI considers that it is duplicative to undertake a detailed review of CMAE forecast costs as part of the Annual Review process, followed by a detailed review of the year-end actual costs as part of the Status Report submission.

3.2.2 Approach 2: Simplified Forecasting and Variance Reporting

To address the inefficiencies of the existing process for forecasting the CMAE budget and filing CMAE variance reporting, FEI developed an approach which simplifies the CMAE forecasting and variance reporting into one process. These changes were designed to maintain an appropriate balance of regulatory efficiency and effectiveness, reflecting that while CMAE can vary materially, the overall amount of the CMAE is quite small compared to FEI's total gas supply cost. As shown in Table 1 above, even if mitigation revenues are included, CMAE costs have only accounted for 0.6 to 1.4 percent of FEI's gas supply costs over the last five years.

FEI's simplified approach would maintain a number of the characteristics of the existing approach (Approach 1). First, CMAE costs would continue to be treated as a component of gas costs (consistent with the approach used by FEI and its predecessor utilities for approximately 30 years) and would be recovered through gas cost recovery rates from Sales Service customers. Second, variances between the actual CMAE costs and the approved CMAE forecast would continue to be treated as a flow-through in setting the following year's gas cost recovery rates.

Adopting this approach would: (1) simplify forecasting and discussion of the prior year's variances; and (2) create regulatory efficiency by setting the forecast and discussing variances at the same time, using a scaled process, with a simplified template. Given the size of the CMAE in absolute terms and in relation to total gas supply costs, FEI considers that this proposal strikes the appropriate balance between regulatory efficiency and effectiveness.

3.2.3 Summary of Approaches

The following table provides a summary of the pros and cons for the two approaches.

Table 2: Pros and Cons of Approaches

Approach	Pros	Cons
1. Status Quo	• Known and understood process • Flow-through treatment ensures only actual costs are recovered from customers	• Inefficient regulatory review process with duplicative examination of the cost items in both the Annual Review process and in the annual Status Report

Approach	Pros	Cons
2. Simplified Forecasting and Variance Reporting	• A simplified review and variance reporting process can be done at or near the same time as the Q3 Report, enhancing regulatory efficiency • Retains flow-through treatment of CMAE costs, ensuring only actual costs are recovered from customers	• Regulatory review is not as efficient as a formulaic approach to setting the CMAE costs

In summary, FEI proposes that the BCUC approve Approach 2, which would simplify forecasting and variance reporting. In particular, Approach 2 would enhance the efficiency for forecasting CMAE costs while still providing the BCUC with a reasonable opportunity for regulatory oversight through a single process that includes the prior year's variance review. Further, maintaining the flow-through treatment of costs through the cost of gas charges ensures only actual costs are recovered from Sales Service customers.

4. CMAE ALLOCATION OF COSTS – CURRENT AND PROPOSED

In Decision and Order G-319-20, the BCUC also directed FEI to assess "whether the current allocation percentages to the CCRA and MCRA remain appropriate".[5] This section describes the allocation of CMAE costs between the CCRA and MCRA for the years up to 2024 and FEI's review of the CMAE activities with respect to cost allocations. While two alternatives are presented, FEI's recommended option is that CMAE costs be allocated to both the CCRA and MCRA.

4.1 *CURRENT (2024) AND PRIOR YEARS ALLOCATION*

The CMAE budget funds the staff and resources to perform the gas supply activities required to provide secure gas supply that is safe, reliable, and cost effective to its customers. These CMAE activities are provided on the basis of a single administrative function and the costs are allocated between the gas supply commodity and midstream portfolios. The costs are currently allocated 30 percent to the CCRA and 70 percent to the MCRA based on the activities performed by employees in the gas supply area.

4.2 *FEI'S REVIEW FOR COST ALLOCATION AND ALTERNATIVE ALLOCATIONS*

For the Rate Framework term (2025 to 2027), FEI is proposing that the forecast CMAE costs, and the variances between actual and forecast CMAE costs, continue to be allocated to the CCRA and MCRA. However, FEI is proposing to revise the allocation so that 25 percent of the costs (and variances) are allocated to the CCRA and 75 percent are allocated to the MCRA.

As part of FEI's assessment of the appropriate allocation, FEI considered allocating the entire CMAE budget, including prior year's variances between CMAE actual and forecast costs, to only the MCRA. For context, recovery of the total 2024 Approved CMAE budget amount of $6.05 million via 100 percent allocation to the MCRA would equate to $0.040 per GJ of the Storage and Transport Charge for Rate Schedule 1 residential customers in the Mainland and Vancouver Island service area. The benefit of this approach is that it simplifies the recovery of CMAE costs into a single account that continues to be applicable to all Sales Service customers, with all recovery of actual CMAE costs occurring through FEI's Storage & Transport charges. However, accounting for all CMAE costs in only the MCRA fails to follow cost causation principles. This is because the gas supply functions described in Section 2 are undertaken to: (1) acquire baseload gas (which is recovered via FEI's Cost of Gas charge); and (2) manage supply to meet daily load requirements and transport gas to various interconnects (which are recovered via FEI's Storage & Transport charges).

[5] Decision and Order G-319-20, p. 16. See also Decision and Order G-352-22, p. 27.

Accordingly, FEI determined that allocating the entire CMAE budget to the MCRA would not be consistent with cost causation. Recognizing that some percentage of costs should be allocated to the CCRA, and in consideration of FEI's allocation during the Current MRP term of 30 percent to the CCRA and 70 percent to the MCRA, FEI conducted an internal survey of its staff that are involved with the gas supply activities to determine whether the allocation of CMAE costs for 2025 should be changed. Based on the survey results, FEI determined that the allocation between the CCRA and MCRA should shift to 25 percent and 75 percent, respectively. The change is primarily driven by additional gas supply resources, related to growth in the RNG supply and in resiliency resources, being managed through the midstream portfolio. FEI anticipates the shift in the allocation from CCRA to MCRA will continue if conventional natural gas supply within the commodity portfolio decreases and the supply of off system renewable gas increases. FEI will re-evaluate the allocation at the end of the Rate Framework term.

5. PROPOSED CHANGES TO THE PRESCRIBED TEMPLATES

As described above, FEI has been preparing its CMAE annual budget for BCUC review and approval using the BCUC Template for CMAE Budget Application, as directed pursuant to Orders G-79-14 and G-23-15 (Order G-25-15 directing the use of a revised template format). FEI then reports CMAE year-end results of the approved costs, actual costs, and variances including explanations of variances to the BCUC as part of the Status Report, using the BCUC Template for Reporting CMAE Actuals, as directed pursuant to Order G-79-14.

FEI describes the proposed new template (the Template for CMAE Forecast Cost and Variance Reporting) below that would replace the current prescribed templates. The proposed new template will support FEI's proposed simplified forecasting and variance reporting approach to determining the annual CMAE forecast.

5.1 PROPOSED SIMPLIFIED TEMPLATE FOR CMAE FORECAST COST AND VARIANCE REPORTING

The cost components FEI is proposing on the new template will combine some of the cost component rows that are shown on the currently prescribed templates. A summary of the cost component changes is as follows:

- **Information Systems (IS):** No change.
- **Consulting and Legal:** No change.
- **Subscriptions & Administration:** Combines the previous 3 categories of Subscriptions & Memberships, Sundries, and Training & Travel into the single category named Subscriptions & Administration.
- **Labour:** Combines the MoveUP and M&E labour costs into the single category named Labour.
- **Energy Management Service Revenue:** Removed as the last revenue received for this type of activity was in 2013.
- **Shared Services:** No change.

The cost component categories shown on the proposed template for the CMAE Forecast Cost Application and Variance Reporting are designed to support the simplified forecasting and variance reporting approach to determining the annual CMAE forecast. FEI provides the new template below. Column (1) contains the proposed combined cost categories discussed above; column (2) will contain the forecast for which FEI will be seeking approval of in its application filed at or near the same time as the Q3 Report (e.g., 2025); column (3) will contain the current year's approved CMAE (e.g., 2024); column (4) will contain the current year's projected CMAE cost (e.g., 2024); and columns (5) through (9) will contain the last completed year's approved, actual, variance, variance percent and variance explanation for each of the cost categories (e.g., 2023).

Figure 1: Template for CMAE Forecast Cost and Variance Reporting

Line No.		2025	2024		2023				
2	**CMAE Cost Component** *($000, unless specified* (1)	**Forecast** (2)	**Approved** (3)	**Projected** (4)	**Approved** (5)	**Actual** (6)	**Variance** (7)	**Variance %** (8)	**Variance Explanation** (9)
3	Information Systems (IS)								
4	Consulting & Legal								
5	Subscriptions & Administration								
6	Labour								
7	Shared Services								
8	**Total**								

FEI considers that combining the CMAE variance reporting from the last completed year (e.g., 2023) with a current year CMAE projection (e.g., 2024) and test year CMAE forecast (e.g., 2025) into a single review process will provide for a more fulsome and efficient review and approval of the CMAE budget.

The changes FEI is proposing to the template are designed to support the simplified approach for approval of the CMAE budget, while also providing a cost component breakdown of the total CMAE budget to enable a reasonable variance analysis.

6. SUMMARY OF FEI PROPOSALS REGARDING CMAE

FEI is seeking BCUC approval of the following proposals regarding CMAE during the 2025-2027 Rate Framework term:

- To continue to forecast the CMAE budget by cost component using a new, simplified template;
- To submit the CMAE forecast for approval as a separate application at or near the same time as FEI's Third Quarter Gas Cost Report;
- To review the prior year's forecast to actual CMAE variances within the CMAE forecast application, noted above, using a new, simplified template;
- To continue to treat CMAE as part of FEI's Cost of Gas, allocating 25 percent of costs to the CCRA and 75 percent to the MCRA; and
- To record variances between forecast and actual CMAE using the same allocation as is used to allocate the forecast CMAE to CCRA and MCRA (i.e., 25 percent to the CCRA and 75 percent to the MCRA).

Appendix C4-4

FEI EXISTING DEFERRAL ACCOUNTS

1 FEI EXISTING DEFERRAL ACCOUNTS

2 **Table 1: FEI Rate Base Deferral Accounts**

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Forecasting Variance Account	Midstream Cost Reconciliation Account (MCRA)	G-25-04; L-5-01; L-40-11; G-138-14	Captures the costs FEI incurs in performing the midstream function and the revenues collected through midstream rates. Gas Supply, in its midstream role, uses the pipeline and storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plans to manage load variability. The MCRA accumulates any resulting cost variances, including any volume-related variances due to differences between the forecast and actual consumption. The resulting variances are taken into account when determining future midstream rates. In addition, price and volume variances between the forecast and actual amount of company use gas are booked against and managed through the MCRA.	Reviewed quarterly and adjusted on an annual basis. Recovered from customers over 2 years.
Forecasting Variance Account	Commodity Cost Reconciliation Account (CCRA)	G-25-04; L-5-01; L-40-11	Captures the costs incurred by FEI to purchase its portion of the baseload commodity supply under the Essential Services Model and the commodity recovery revenues received from sales customers choosing to remain on the utility standard rate offering. Commodity price-related variances collected in the CCRA are taken into account when determining future commodity rate changes. The commodity rate is reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold, and the $/GJ value of the calculated rate change exceeds the minimum rate change threshold of $0.50/GJ.	Adjusted quarterly; recovered over a 12 month period from Quarter-end.

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Forecasting Variance Account	Revenue Stabilization Adjustment Mechanism (RSAM)	G-59-94; G-138-14	Stabilizes the Company's delivery margin revenue from the Residential and Commercial customer classes. The RSAM enables FEI to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to what customers would have paid based on forecast use.	2 years
Forecasting Variance Account	Interest on MCRA, CCRA, RSAM and Gas in Storage	G-7-03; G-141-09; G-138-14	Variances from the forecast CCRA, MCRA, RSAM and Gas In Storage balances attract interest at the Company's short-term borrowing rate. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers.	Same as respective margin account; Gas in Storage collected over 3 years.
Forecasting Variance Account	SCP Mitigation Revenues Variance Account	G-124-00; G-70-10; G-138-14	Captures any variation from the Southern Crossing Pipeline (SCP) revenues forecast and actual revenues received.	2 years
Forecasting Variance Account	Pension & OPEB Variance	G-51-03	Captures the variance between actual pension and Other Post Employment Benefit (OPEB) expense and the amount forecast in rates.	3 years
Forecasting Variance Account	BCUC Levies Variance	G-112-04	Captures the variance between actual annual BCUC levies and the amount forecast in rates.	1 year
Benefits Matching Account	Demand-Side Management (DSM)	G-36-09; G-44-12; G-10-19; G-45-23	Captures up to $60 million annually in new expenditures on DSM activities. Also includes the amounts transferred from the non-rate base DSM account in the following year.	10 years
Benefits Matching Account	NGV Conversion Grants	G-98-99	Captures amounts awarded by FEI for Natural Gas Vehicle (NGV) conversions for Rate Schedule 6 light duty customers.	5 years

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	Emissions Regulations	G-44-12; G-352-22	Captures potential compliance costs less revenues collected from credits related to Emissions Regulations, particularly the Emissions Trading Regulation and the Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) which are aimed to reduce Greenhouse Gas (GHG) emissions in BC.	1 year
Benefits Matching Account	Greenhouse Gas Reduction Regulation Incentives	G-161-12; G-67-13; G-56-17; G-73-18	Captures all grants and costs, including a portion of application costs, related to Prescribed Undertakings 1 and 3.6 of the GGRR.	10 years
Benefits Matching Account	CNG and LNG Recoveries	G-128-11	Captures the incremental Compressed Natural Gas (CNG) and Liquified Natural Gas (LNG) fueling station recoveries received from fueling station volumes in excess of the minimum contract demand.	1 year
Benefits Matching Account	2025 MRP Application	G-334-23	Captures costs related to the 2025-2027 Rate Framework application and proceeding.	Will be requested in a future application.
Benefits Matching Account	BCUC Initiated Inquiry Costs	G-319-20	Captures costs associated with participation in BCUC-initiated inquiries and proceedings. Previous examples include the BCUC Indigenous Utility Inquiry proceeding, BCUC Municipal Energy Utility Inquiry, BCUC Regulation of Safety Inquiry and BCUC Thermal Energy Guidelines Review.	1 year
Benefits Matching Account	PGR Application and Preliminary Stage Development Costs	C-2-21	Captured preliminary stage development and application costs related to the Pattullo Bridge Crossing Replacement.	3 years
Benefits Matching Account	Transportation Service Report	G-366-21; G-334-23	Captured costs related to the preparation of the Transportation Service Report and associated regulatory review proceeding.	1 year
Benefits Matching Account	2021 Generic Cost of Capital Proceeding	G-366-21	Captures costs related to the 2021 Generic Cost of Capital proceeding.	Will be requested in a future application.

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	2023 DSM Expenditures Schedule Application	G-45-23	Captured external costs for development and regulatory review of the 2023 DSM Expenditure Schedule Application.	1 year
Benefits Matching Account	City of Coquitlam Application Proceeding	G-319-20	Captured costs related to the dispute with the City of Coquitlam regarding the use of land that arose from the Lower Mainland Intermediate Pressure (IP) System Upgrade (LMIPSU) Projects – Coquitlam Gate IP Project.	1 year
Benefits Matching Account	2024-2027 DSM Expenditures Schedule Application	G-334-23	Captured external costs for development and regulatory review of the 2024-2027 DSM Expenditure Schedule Application.	4 years
Benefits Matching Account	2023 Cost of Service Allocation Study	G-334-23	Captures costs related to the 2023 Cost of Service Allocation Study Application and related regulatory proceeding costs.	Will be requested in a future application.
Benefits Matching Account	AMI Application and Feasibility Costs	C-2-23	Captured preliminary stage development and application costs related to the Advanced Metering Infrastructure (AMI) Project.	3 years
Benefits Matching Account	Whistler Pipeline Conversion	G-53-06; G-35-09; G-138-10	Captured costs of converting Whistler customers from propane to natural gas.	20 years
Benefits Matching Account	Gas Assets Records Project	G-44-12	Captured the Gas Asset Records Project costs.	5 years
Benefits Matching Account	Gains and Losses on Asset Dispositions	G-141-09; G-44-12	Captured gains and losses on asset dispositions for 2010 and 2011.	10 years
Benefits Matching Account	Net Salvage Provision/Costs	G-44-12	Captures the annual negative salvage provision calculated using the approved negative salvage rates, offset by the actual net removal costs incurred.	N/A

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	PCEC Start Up Costs	G-44-12	Captured the unrecovered balance of the original amount of pre-start up costs of $1,754,000 incurred by Pacific Coast Energy Corporation (PCEC) to operate a portion of the pipeline facilities for several months prior to the “in-service” date of October 1, 1991.	40 years
Benefits Matching Account	2022 Long Term Gas Resource Plan Application	G-319-20	Captures costs related to the development of the 2022 Long Term Gas Resource Plan Application and related regulatory proceeding costs.	Will be requested in a future application.
Benefits Matching Account	2020–2024 MRP Application	G-196-17; G-319-20	Captured external costs related to the 2020-2024 MRP application and proceeding.	5 years
Benefits Matching Account	2021 Renewable Gas Program Comprehensive Review	G-366-21	Captures the costs related to the development of the Renewable Gas Program Comprehensive Review Application and regulatory proceeding costs.	Will be requested in a future application.
Benefits Matching Account	Gibsons Capacity Upgrade (GCU) Preliminary Stage Development Costs	G-352-22	Captured preliminary stage development costs related to the Gibsons Capacity Upgrade.	3 years
Benefits Matching Account	Transmission Integrity Management Capabilities (TIMC)	G-237-18; C-3-22; C-1-24	Captured preliminary stage development and application costs related to the Coastal Transmission System (CTS) TIMC Project CPCN and Inland Transmission System (ITS) TIMC Project CPCN.	5 years – CTS 1 year - ITS
Benefits Matching Account	Annual Review of 2020-2024 Rates	G-319-20	Captured costs related to the 2020 to 2024 Annual Review applications.	1 year
Benefits Matching Account	FEFN – Common Rates and 2022 Revenue Requirement Application Costs	G-114-22; G-278-22; G-352-22	Captured costs related to the Application for Common Rates and 2022 Revenue Requirements for the Fort Nelson Service Area (FEFN).	1 year

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	Okanagan Capacity Upgrade CPCN Application & Preliminary Stage Development Costs	G-361-23	Captured application costs related to the Okanagan Capacity Upgrade Project CPCN.	3 years (for the application cost portion)
Other Account	Pension & OPEB Funding	G-135-99; G-141-09	Captures the difference between amounts funded by ratepayers for pension and OPEB and amounts actually paid out by the Company.	Life of the Employee Future Benefits
Other Account	US GAAP Pension & OPEB Funded Status	G-44-12	Captures the accumulated other comprehensive income balance related to pensions and OPEBs, with an offsetting entry to the Pension and OPEB Funding deferral account. This deferral account will capture the changes in the accumulated other comprehensive income balance each year as determined by the external actuary. The Pension and OPEB funding account captures the funded status of pensions and OPEB.	N/A
Other Account	BVA Balance Transfer	G-133-16	Captures all Biomethane Variance Account (BVA) related costs except for the supply ending inventory volume valued at the forecast Jan. 1st Biomethane Energy Recovery Charge (BERC) rate in the following year.	1 year
Other Account	COVID-19 Customer Recovery Fund	G-80-20; G-352-22	Captured unrecoverable amounts, bill credits and deferred payments from certain customer groups who are impacted by COVID-19.	3 years
Other Account	Stargas Assets Acquisition Deferral Account	C-1-22	Captured the final purchase price, application costs and legal expenses related to the FEI and Stargas Asset Transfer and CPCN Application.	1 year
Other Account	PST Rebate on Select Machinery and Equipment	G-334-23	Captures the PST rebate received on select machinery and equipment from the Ministry of Finance.	1 year
Other Account	Residual Delivery Rate Riders	G-196-17	Used to dispose of various rate rider deferral accounts which have small residual ending balances.	1 year

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Other Account	FEFN – Transitional Balance	G-278-22	Captured the December 31, 2022 balances transferred from the specific FEFN deferral accounts as a result of common rates for FEI and FEFN.	1 year
Other Account	Existing Meter Cost Recovery	C-2-23	Captures the remaining rate base value of existing meters to be removed from service as part of the AMI Project.	5 years
Other Account	Previously Retired Meter Cost Recovery	C-2-23	Captures the remaining rate base value of previously retired meters as part of the AMI Project.	5 years

Table 2: FEI Non Rate Base Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Forecasting Variance Account	Biomethane Variance Account (BVA)	G-194-10; G-133-16	Captures the costs incurred to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates. Beginning in 2016, this account will be re-based each year end to only include the remaining unsold biomethane inventory volume valued at the following year's Jan. 1 BERC rate. All remaining costs will be transferred to the BVA Balance Transfer deferral at year-end.	Reviewed quarterly and adjusted on an annual basis. Recovered from customers over 1 year.	None
Forecasting Variance Account	Flow-Through Account (2020-2024)	G-162-14; G-165-20	Captures the annual variances between forecast and actual amounts for certain costs and revenues where variances are considered uncontrollable.	1 year	WACC
Forecasting Variance Account	Marketer Cost Variance	A-9-16	Captures and records any under or over recovery of gas marketer fees, compared to marketers O&M costs, to be recovered from or returned to gas marketers in the subsequent year through the annual fee adjustment starting on April 1, 2017.	Recovered directly from gas marketers over 1 year.	WACC

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Rate Smoothing Account	City of Vancouver Biomethane Purchase Agreement	G-235-19	Captures the average production cost for the City of Vancouver landfill gas upgrading plant greater than $30 per GJ. The account will unwind as the production cost reduces down to and below $30/GJ.	N/A	WACC
Rate Smoothing Account	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	G-78-21; G-278-22	Captures the FEFN Residential Customer Common Rate Phase-In rider to FEFN customers only for a period of five years.	1 year	WACC
Rate Smoothing Account	2023 and 2024 Revenue Deficiency Deferral Account	G-275-23; G-334-23	Captures the 2023 Revenue Deficiency of $63.994 million and 2024 Revenue Deficiency of $19.708 million.	Will be requested in a future application.	WACC
Benefits Matching Account	DSM Account	G-44-12; G-163-12; G-138-14; G-10-19	Captures the remaining portion of the actual DSM costs incurred up to the funding cap each year that are above the amount forecast in the rate base deferral account. These amounts are then transferred to the rate base DSM deferral account in the following year.	N/A	WACC
Benefits Matching Account	PEC Pipeline Development Costs and Commitment Fees	G-66-13A	Captured the development costs and commitment fees paid by Pacific Energy Corporation (PEC) to FEI that enabled FEI to commence development work to provide natural gas transportation service to PEC under a long-term Transportation Services Agreement between FEI and PEC.	N/A	None
Benefits Matching Account	Regional Gas Supply Diversity Project Development Costs	G-253-22	Captures development costs related to the Regional Gas Supply Diversity (RGSD) Project.	Will be requested in a future application.	WACC
Benefits Matching Account	Okanagan Capacity Upgrade CPCN Application &	G-361-23	Captures pre-construction development costs related to the Okanagan Capacity Upgrade CPCN.	Will be requested in a future application.	WACC

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
	Preliminary Stage Development Costs				
Benefits Matching Account	Clean Growth Innovation Fund	G-165-20	Captures both the innovation fund costs and the offsetting rider recoveries from customers through the term of the 2020-2024 MRP.	Requested in this Application.	WACC
Other Account	Mark to Market - Hedging Transactions	E-22-95	Approved to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing.	N/A	None
Other Account	Earnings Sharing Account	G-165-20	Captures 50 percent of the ROE variance between achieved and approved ROE for regulatory purposes.	1 year	WACC
Other Account	US GAAP Uncertain Tax Positions	G-44-12	Captures any ongoing differences that arise from the implementation of US GAAP Financial Accounting Standards Board Interpretation No. 48.	N/A	None
Other Account	FEFN – Right-Of-Way Agreement	G-97-15	Captures the costs related to finalizing FEFN's Right-Of-Way Agreement with the Fort Nelson First Nation.	N/A	WACC
Other Account	AMI Foreign Exchange (FX) Mark to Market Valuation	C-2-23	Captures the impact of any foreign exchange hedging used to reduce foreign exchange risk of the AMI Project.	N/A	None

Appendix C4-5

FBC EXISTING DEFERRAL ACCOUNTS

FBC EXISTING DEFERRAL ACCOUNTS

Table 1: FBC Rate Base Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Forecasting Variance Account	BCUC Levies Variance	G-166-20	Captures the variance between actual annual BCUC levies and the amount forecast in rates.	1 year
Benefits Matching Account	Preliminary and Investigative Charges	Uniform System of Accounts Section 183	Costs incurred in determining the feasibility of projects for utility services, other than CPCN projects.	Transferred to Construction Work in Progress (CWIP) upon project commencement.
Benefits Matching Account	Demand Side Management	G-123-98; G-58-06	Captures the costs of FBC's Demand Side Management (DSM) programs and initiatives to promote energy efficiency for customers.	10 years
Benefits Matching Account	Deferred Debt Issue Costs	Various; G-139-14	Captures fees for auditors, legal, dealers, filings, rating agencies and trustees as required for the issuance of debt.	Term of Individual Debenture
Benefits Matching Account	2025 MRP Application	G-340-23	Captures costs related to the 2025-2027 Rate Framework application and proceeding.	Will be requested in a future application.
Benefits Matching Account	2023-2027 DSM Expenditure Schedule	G-371-22	Captured external costs for development and regulatory review of the 2023-2027 DSM Expenditure Schedule.	5 years
Benefits Matching Account	Mandatory Reliability Standards 2024 Audit	G-340-23	Captures costs related to FBC's triennial Mandatory Reliability Standards (MRS) 2024 compliance audit.	3 years
Benefits Matching Account	Joint Pole Use Audit 2023	G-382-22	Captures FBC's portion of costs to carry out the 2023 joint use pole audit.	5 years

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	2021 Generic Cost of Capital Proceeding	G-374-21	Captures costs related to the 2021 Generic Cost of Capital proceeding.	Will be requested in a future application.
Benefits Matching Account	Annual Review for 2020-2024 Rates	G-42-21	Captures costs related to the 2020 to 2024 Annual Review applications.	1 year
Benefits Matching Account	2021 Long Term Electric Resource Plan	G-42-21; G-374-21	Captured costs related to the development of the 2021 Long Term Electric Resource Plan Application and related regulatory proceeding costs.	3 years
Benefits Matching Account	BCUC Initiated Inquiry Costs	G-42-21	Captures costs associated with participation in BCUC-initiated inquiries and proceedings. Previous examples include the BCUC Indigenous Utility Inquiry proceeding, BCUC Municipal Energy Utility Inquiry, BCUC Regulation of Safety Inquiry and Regulation of Electric Vehicle (EV) Charging Service.	1 year
Benefits Matching Account	EV Fleet & Workplace Charging Funding Account	G-11-23	Captures costs incurred to implement the EV Fleet Charging Program as a prescribed undertaking under the Greenhouse Gas Reduction Regulation (GGRR), including funding (incentives paid for EV chargers), program administration costs and regulatory proceeding costs.	10 years
Benefits Matching Account	Mandatory Reliability Standards 2021 Audit	G-42-21; G-374-21	Captured costs related to FBC's triennial MRS 2021 compliance audit.	3 years
Other Account	Pension & OPEB Liability	G-184-10; G-110-12; G-107-15	Captures the difference between the actuarially determined pension and Other Post Employment Benefit (OPEB) expense and the contributions paid by the Company.	Life of the Employee Future Benefits
Other Account	COVID-19 Customer Recovery Fund	G-80-20; G-382-22	Captured unrecoverable amounts, bill credits and deferred payments from certain customer groups who were impacted by the COVID-19 pandemic.	3 years
Other Account	Climate Change Operational Adaptation (CCOA)	G-340-23	Captures costs related tothe development of a CCOA Plan to create a roadmap for adaptation and address risks associated	4 years

Type	Account Name	BCUC Order(s)	Description	Recovery Period
			with five hazards: wildfires, flooding, extreme temperatures, snowstorms and windstorms.	
Other Account	BC Cost of Living Credit	G-340-23	Captures the residual balance of the BC Hydro Cost of Living Credit.	1 year
Other Account	Princeton Office Disposition	G-14-23	Captured the actual revenues and costs associated with the sale of the Princeton Office Properties.	1 year
Other Account	PST Rebate on Select Machinery and Equipment	G-340-23	Captures the PST rebate received on select machinery and equipment from the Ministry of Finance.	1 year
Other Account	Indigenous Relations Agreement (Huth Substation)	G-42-21	Captures costs to address the Penticton Indian Band's (PIB) concerns regarding the Huth Substation in Penticton.	Will be requested in a future application.

Table 2: FBC Non Rate Base Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Forecasting Variance Account	Pension & OPEB Variance	G-110-12; G-139-14	Captures the variance between actual pension and OPEB expense and the amount forecast in rates.	3 years	STI
Benefits Matching Account	Tariff Applications	G-38-18	Captures external costs for regulatory review of applications for new tariffs or for tariff revisions (excluding rate design applications).	1 year	STI
Benefits Matching Account	CPCN Projects Preliminary Engineering	G-139-14	Captures preliminary costs including regulatory review and investigative engineering costs in the development of capital projects subject to CPCN applications.	Transferred to CWIP upon project approval.	WACD

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Benefits Matching Account	2017 Rate Design Application	G-202-15; G-246-18	Captures external costs for development and regulatory review of the 2017 Cost of Service Allocation (COSA) and Rate Design Application.	5 years	WACD
Benefits Matching Account	2020 - 2024 Multi-Year Rate Plan Application	G-38-18; G-42-21	Captured external costs related to the 2020 Multi-year Rate Plan (MRP) application and proceeding.	5 years	WACD
Benefits Matching Account	Rate Design and Rates for EV DCFC Service Application	G-246-18; G-374-21	Captured external costs related to the rate design and rates application for Electric Vehicle Direct Current Fast Charging (EV DCFC) Service application.	3 years	WACD
Forecasting Variance Account	Flow-through Account (2020-2024)	G-166-20	Captures the annual variances between forecast and actual amounts for certain costs and revenues where variances are considered uncontrollable.	1 year	WACC
Rate Smoothing Account	2023 Revenue Deficiency	G-276-23 G-340-23	Captures the 2023 Revenue Deficiency of $6.213 million.	3 years	WACC
Other Account	Earnings Sharing Account	G-166-20	Captures 50 percent of the ROE variance between achieved and approved ROE for regulatory purposes.	1 year	WACC
Other Account	Kettle Valley Future Site Expansion	G-47-13	Cost of land used to provide sufficient extra space for future site expansion, to be recovered from ratepayers when and if this portion of the site becomes used and useful.	None	None

Appendix C6-1

FEI SERVICE QUALITY INDICATOR REPORT

Appendix C6-1

Service Quality Indicators
FortisBC Energy Inc. (FEI)

Table of Contents

Index of Tables and Figures

1. INTRODUCTION

Maintaining a high level of service quality is important to the long-term success of the Company. In support of this, as in the 2014 to 2019 PBR Plan and the 2020 to 2024 MRP, FortisBC Energy Inc. (FEI or the Company) proposes a suite of Service Quality Indicators (SQIs) be established as part of the Rate Framework. The SQIs will serve to ensure that service quality to customers is maintained at acceptable levels throughout the term of the Rate Framework.

FEI proposes a suite of SQIs which builds on its experience. In the following sections, FEI describes the SQI history and development, proposed updates and modifications, and a new suite of Energy Transition informational indicators. These SQI metrics reflect a broad range of business processes that are important elements of the customer experience.

2. HISTORY AND DEVELOPMENT OF SERVICE QUALITY INDICATORS AT FEI

The inclusion of SQIs has continued to evolve throughout the Company's previous multi-year rate plans as follows:

- In the 1998 PBR Settlement, FEI agreed to five service quality indicators.
- The 2004 PBR Settlement continued with the use of three SQIs from the 1998 PBR Settlement, changed the status of two SQIs to directional indicators, and added eight new SQIs to assess the Company's performance.
- The 2014-2019 PBR Plan refined the definition of two existing SQIs, renamed one, continued with five existing SQIs, and added five new SQIs.
- The 2020-2024 MRP continued with the suite of SQIs from the prior plan, with changes limited to the renaming of one SQI and replacement of an informational indicator.

The following table outlines the history and evolution of FEI's SQIs over the four multi-year rate plan eras as well as summarizing the SQIs proposed for the Rate Framework.

Table 1: History and Evolution of SQIs at FEI (1998 - 2025)

ID	Service Quality Indicator	1998 PBR	2004 PBR until 2013	2014 PBR	2020 MRP	2025 Rate Framework
1	Emergency Response Time	Included (only coastal region)	Included (Interior region was added)	Revised definition of emergency response time	Included	Included
2	Telephone Service Factor - Emergency	Included (only coastal region)	Included (Interior region was added)	Included	Included	Included

ID	Service Quality Indicator	1998 PBR	2004 PBR until 2013	2014 PBR	2020 MRP	2025 Rate Framework
3	Telephone Service Factor – Non-emergency	Not available[1]	Included (for interior and coastal regions)	Included	Included	Included
4	Transmission Reportable Incidents	Included	Included	Included	Included	Included
5	Index of Customer Bills not Meeting Criteria	-	Included	Included (Renamed to Billing Index)	Included	Included
6	Percent of Industrial Customer Bills Accurate	-	Included	-	-	-
7	Meter Exchange Appointment Activity	-	Included	Included	Included	Included
8	Accuracy of Transportation Meter Measurement First Report	-	Included	-	-	-
9	Independent Customer Satisfaction Survey	-	Included	Replaced with Customer Satisfaction Index	-	-
9a	Customer Satisfaction Index	-	-	Included	Included	Included
10	Number of Customer Complaints to BCUC	-	Included	-	-	-
11	Number of Prior Period Adjustments	-	Included	-	-	-
12	Leaks per Km of Distribution System Mains	Included	Included	Included	Included	Included
13	Number of 3rd Party Distribution System Incidents	Included	Included	-	-	-
14	First Contact Resolution	-	-	Included	Included	Included
15	Meter Reading Accuracy	-	-	Included	Included	Included (Renamed to Meter Reading Completion)
16	All Injury Frequency Rate	-	-	Included	Included	Included
17	Public Contacts with Pipelines	-	-	Included	Included (Renamed to Public Contacts with Gas Lines)	Included

[1] BC Hydro answered the majority of non-emergency inquiries prior to repatriation in 2002.

ID	Service Quality Indicator	1998 PBR	2004 PBR until 2013	2014 PBR	2020 MRP	2025 Rate Framework
18	Telephone Abandonment Rate	-	-	Included	Replaced with Average Speed of Answer	-
18a	Average Speed of Answer	-	-	-	Included	Included
19	Scope 1 Emissions	-	-	-	-	Included
20	Renewable and Low Carbon Energy Supply Volume	-	-	-	-	Included
21	Natural Gas for Transportation Volume	-	-	-	-	Included
22	Demand Side Management Energy Savings	-	-	-	-	Included

For the Rate Framework, FEI reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to customers is maintained at acceptable levels. For some SQIs, FEI proposes to change their benchmarks and thresholds, recognizing their recent historical performance. FEI has also proposed a suite of new Energy Transition informational indicators. In the following sections, FEI describes the proposed SQIs, and their benchmarks and thresholds.

3. PROPOSED SERVICE QUALITY INDICATORS, BENCHMARKS AND THRESHOLDS

3.1 *SAFETY SQIs*

3.1.1 Emergency Response Time

Emergency response time is included in the current set of SQIs and measures the utility's responsiveness to on average 24,000 annual emergency events that include gas odour calls, carbon monoxide calls, house fires and hit lines. It is calculated as:

$$\frac{\text{Number of emergency calls responded to within one hour}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events, available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The approved benchmark for the Current MRP was 97.7 percent and is the same as that approved for the 2014-2019 PBR Plan. Additionally, the three-year average of the most recent 2021 to 2023 annual results is 97.7 percent, indicating that 97.7 percent remains an appropriate benchmark for the Rate Framework.

The table below summarizes the percentage of emergency events responded to within one hour since the beginning of the Current MRP compared to the approved benchmark and threshold. The table also includes FEI's proposed benchmark and threshold for the Rate Framework.

Table 2: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Emergency Response Time

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Emergency Response Time	97.7%	97.7%	97.7%	97.5%	97.7%	97.7%	96.2%	96.2%

Table 3 below provides details of the emergency activity levels (number of calls), average emergency response times, the number of calls greater than one hour, and the overall percentage of emergency response times one hour or less during the Current MRP term.

Table 3: Summary of FEI Emergency Activity Levels and % of Calls Responded to Within an Hour

	CGA type Emergency[2]	Number of calls over one hour	Percent of responses one hour or less
2020 to 2023	91,221	2,137	97.7%
2023	22,134	560	97.5%
2022	22,679	512	97.7%
2021	23,659	551	97.7%
2020	22,749	514	97.7%

The response time has remained relatively consistent in all operation zones since shift change schedules were implemented in 2015. As noted above, the average of FEI's annual results from 2020 to 2023 is 97.7 percent, which is the same as the existing approved benchmark of 97.7 percent.

FEI proposes to continue to report on Emergency Response Time and considers that the current benchmark represents the level of service expected by its customers and is appropriate.

[2] The following items are included in CGA emergency: Gas odour upstream and downstream, gas odour – industrial, gas odour – other, fires and explosion, CO investigation, mains hit lines, services hit lines, meter/station.

Therefore, FEI proposes to retain its existing benchmark and threshold for the term of the Rate Framework.

3.1.2 Telephone Service Factor (Emergency)

Telephone service factor (TSF) measures the percentage of calls answered within a defined window of time. This SQI assesses how well the Company can balance costs and service levels, with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers.

The principal factors influencing the TSF (Emergency) results include the volume of inbound calls received, reports on the average speed of answer for both emergency and non-emergency[3] calls, and the resources available to answer those calls. Staffing is matched to the calls forecast based on historical data in order to reach the service level benchmark desired.

The TSF (Emergency) SQI measures the percentage of emergency calls answered within 30 seconds and is calculated as:

$$\frac{\text{Number of emergency calls answered within 30 seconds}}{\text{Number of emergency calls received}}$$

The table below provides a summary of the results for TSF (Emergency) since the start of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 4: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Telephone Service Factor (Emergency)

Type of Call	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Emergency	96.9%	96.9%	97.1%	97.8%	95%	95%	92.8%	92.8%

The results from 2020 to 2023 were better than the approved benchmark of 95 percent.

FEI proposes to continue to report on the TSF (Emergency) SQI and retain the existing benchmark and threshold for emergency calls. FEI believes that the proposed benchmark reflects an appropriate balance between cost and service levels, and that customers are satisfied with the level of service being provided.

[3] Non-emergency calls include those related to bill inquiries, service applications and calls general in nature and are discussed in the TSF (Non-Emergency) section of this appendix.

3.1.3 All Injury Frequency Rate

FEI is committed to ensuring its employees can perform their work and go home safely at the end of each day.

During the November 2023 consultation session, FEI discussed the difference between leading and lagging safety indicators and explained that it was exploring introducing a leading safety indicator to enhance its reporting on safety, as FEI currently reports on the All Injury Frequency Rate (AIFR), which is a lagging indicator. Stakeholders were generally supportive of the concept.

When measuring and monitoring safety, lagging indicators measure what happened after the fact (i.e., outcomes) and can alert the Companies to a failure in the safety system, or to the existence of an uncontrolled hazard, *following* an event. At FEI, such events are used to learn and improve, identifying gaps in existing safety defenses and establishing corrective actions to prevent future reoccurrences. In contrast, leading indicators are proactive and preventative measures that can shed light on the effectiveness of safety and health activities and reveal potential gaps *prior* to an event occurring.

FEI has been exploring potential leading indicators but does not yet have a formal, defined indicator to propose for inclusion as an SQI. Instead, the Company will continue to examine and develop a leading safety indicator during the term of the Rate Framework and will propose a suitable leading indicator either during the Rate Framework (as part of the Annual Review process) or subsequent to the conclusion of the three-year term of the Rate Framework. FEI expects that any new leading safety indicator would initially be informational only, as there will likely be a lack of adequate historical information to establish a benchmark or threshold. This approach will allow FEI to evaluate suitable metrics, propose a suitable metric, and engage in discussions with the BCUC and interveners on whether the selected metric is appropriate for inclusion in the Company's suite of SQIs.

FEI proposes to continue to report on the existing AIFR SQI which, as described above, is a lagging indicator. AIFR remains an important measure for FEI as it tracks the impact of safety incidents on its employees. While increases or decreases in incidents do not necessarily reflect an improvement or degradation of safety performance, having more incidents reported means more opportunities for learning and developing better safety protections over time. An increase in incidents can sometimes be attributed to an improved safety culture where employees feel more comfortable in reporting incidents.

The AIFR is based on total number of employee injuries per 200,000 hours worked. Lost time injuries are those that result in one or more days missed from work as a direct result of an occupational injury/illness incident. Medical treatments are considered injuries where treatment was given or prescribed beyond First Aid and observation, and no lost time was involved.

The following formula is used:

$$\text{All Injury Frequency Rate} = \frac{(\text{Number of Employee Injuries}) \times 200{,}000 \text{ hours}}{\text{Total Exposure Hours Worked}^{4}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The table below provides a summary of FEI's AIFR annual and three-year rolling average results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 5: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for AIFR

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
AIFR – three year rolling average	1.66	1.75	1.59	1.58	2.08	1.64	2.95	2.21
AIFR – annual	1.43	1.99	1.36	1.35	n/a	n/a	n/a	n/a

The results from 2020 to 2023 have been better than the currently approved benchmark.

FEI remains committed to its focus on safety. Based on the performance over the Current MRP term, FEI considers it appropriate to adjust the current benchmark and threshold for the term of the Rate Framework. The proposed adjustments will reinforce the Company's enhanced safety culture and shift towards risk mitigation, including preventing events and injuries before they can occur.

The proposed benchmark of 1.64 is based on the three-year rolling average of the 2021 to 2023 annual results[5]. The proposed threshold of 2.21 is calculated consistent with past practice[6].

3.1.4 Public Contacts with Gas Lines

FEI recognizes the importance of public safety. A key area of public safety is contact with buried pipelines. To measure performance in this area, FEI has been using the metric Public Contacts with Gas Lines, which reflects the number of line damages per 1,000 BC 1 Calls received. The Company places significant attention on educating the public of the risk associated with gas line contact. This SQI measures the overall effectiveness of the public's awareness to minimize

[4] Exposure hours reflect actual hours worked excluding time off for vacation, statutory holidays, sickness, etc.
[5] (1.75 + 1.59 + 1.58) / 3 = 1.64.
[6] The threshold is set at 2 standard deviations from the recent 10-year history of three-year rolling averages of the annual results.

damage to the gas system, which reduces risk to public safety and service interruptions for customers.

This indicator is calculated as:

Number of Line Damages per 1,000 BC 1 Calls received

Principal factors influencing results for this metric include economic growth (i.e., construction activity), damage prevention awareness programs and heightened public awareness created by the BC 1 Call program. The recent three-year rolling average results reflect an ongoing positive trend for this metric. Increased awareness through targeted workshops with municipalities and excavating contractors, together with a higher number of calls generated by the BC 1 Call program, have contributed to the improved performance.

The table below provides a summary of FEI's Public Contacts with Gas Lines results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 6: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Public Contact with Gas Lines

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Public Contact with Gas Lines – annual	7	6	6	5	8	6	12	10
BC 1 Call Ticket Volume	141,262	163,584	157,174	158,478	n/a	n/a	n/a	n/a
Line Damages	973	1,034	896	844	n/a	n/a	n/a	n/a

For 2020 through 2023, FEI has performed better than the currently approved benchmark of 8, and the annual results have been trending downward (i.e., performance has been trending positively). FEI proposes to revise the benchmark to 6, which is based on the average of the most recent three years from 2021 to 2023 and which is consistent with the trend in recent years. FEI proposes to revise the threshold to 10, as this is reflective of positive historical performance observed.[7] While performance has improved in recent years, FEI highlights that historical results going back to 2010 have been higher and provide an objective basis to set a satisfactory performance range. As further discussed below, there are a number of factors that may be outside of the Company's control that can influence and contribute to volatility in annual performance for

[7] Annual results reported starting in 2010: 2010 – 18; 2011 – 16; 2012 – 13; 2013 – 10; 2014 – 9; 2015 – 8; 2016 – 8; 2017 – 9; 2018 – 8; 2019 – 7; 2020 – 7; 2021 – 6; 2022 – 6; 2023 – 5.

this metric, including the overall level of construction activities in the Province and the public's awareness of the need for line locates to be performed. Despite the potential for volatility in annual performance, FEI is proposing to lower the benchmark and threshold to reflect the continued improved performance in recent years.

In Decision and Order G-352-22 regarding FEI's Annual Review for 2023 Delivery Rates, the BCUC stated the following (page 35):

> Although this SQI is performing better than the benchmark, the Panel agrees with RCIA's comment on the need for FEI to provide a better explanation as to why it nonetheless experiences higher numbers of gas line hits than its counterparts in other provinces. The Panel also agrees with both RCIA and FEI that further discussion regarding this SQI and any possible changes is best addressed during the next MRP application.

FEI provides the following additional information and discussion as to why FEI's results for this particular metric are higher than other provinces.

The calculation of gas line damages per 1,000 BC 1 Calls received requires both the observed number of gas line damages (the numerator) and the number of locate requests made (the denominator).

Awareness of the need for a line locate influences the denominator in the calculation. In 2021, approximately 240,000 locate requests were made in British Columbia. In contrast, approximately half a million locate requests were made in Alberta and over a million locate requests were made in Ontario during the same period.[8] While the number of line locates in each province is influenced by the overall level of construction activities, it may also be influenced by the regulations in each province, affecting the awareness for line locates to be performed. For example, Ontario One Call is a public safety administrative authority that mandates membership and requires a locate request to be completed prior to excavation, otherwise an Administrative Penalty of up to $10,000 is imposed to the excavator. In contrast, BC 1 Call is a non-profit organization and mandatory membership is only applicable to the industry partners regulated by the British Columbia Energy Regulator (BCER).

Other potential factors that may influence the observed number of gas line damages (numerator) and the willingness of people to request a line locate (denominator) include the population density and where people and underground utilities tend to be more concentrated; and whether the service territories of the reporting companies are in rural or urban areas.

[8] Data as reported in Table 5 of the Damage Information Reporting Tool "DIRT" Report, published by the Canadian Common Ground Alliance, available at: https://canadiancga.com/resources/Documents/DIRT-Reports/DIRT%202021-04B%20ENGLISH.pdf.

As a result of the number of potential factors that could affect results, FEI, in discussion with industry partners, finds it difficult to draw any specific conclusions on the different results from one jurisdiction to another.

FEI also recognizes that damage metrics and statistics can be assessed and presented in any number of formats. As an example, FEI notes that the BC damage numbers (numerator) reported[9] are not significantly disproportionate to BC's proportion of the Canadian population.

3.2 *Responsiveness to Customer Needs SQIs*

3.2.1 First Contact Resolution

First Contact Resolution (FCR) is an area of focus for FEI. Research conducted by Service Quality Measurement[10] (SQM) suggests that it is the single most important driver of customer satisfaction.[11] By maintaining a high level of FCR, the Company can effectively satisfy customers who are looking to have their issues resolved efficiently.

FCR measures the percentage of customers who receive resolution to their inquiry in one contact with FEI's contact centre. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their inquiry was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The table below provides a summary of the FCR results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 7: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for First Contact Resolution

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
First Contact Resolution	81%	79%	78%	77%	78%	78%	74%	74%

The 2023 FCR result of 77 percent was better than the threshold but slightly below the benchmark. For 2020 to 2022, the FCR results met or performed better than the benchmark. While the 2023

[9] Data as reported in Table 2 of the Damage Information Reporting Tool "DIRT" Report, published by the Canadian Common Ground Alliance, available at: https://canadiancga.com/resources/Documents/DIRT-Reports/DIRT%202021-04B%20ENGLISH.pdf.
[10] SQM is a North American call centre industry research firm expert for improving organizations' FCR, employee and customer satisfaction.
[11] SQM Reference https://www.sqmgroup.com/resources/library/blog/fcr-metric-operating-philosophy.

result was slightly below the benchmark, customers continued to indicate high levels of satisfaction. The lower 2023 FCR is primarily due to high bill inquiries in the first quarter of 2023.

During the November consultation session, stakeholders suggested that FortisBC consider developing a metric that measures FortisBC's performance when a customer's inquiry is not resolved during the first contact, or a metric that provides different information on performance other than FortisBC's ability to resolve a customer inquiry in one contact. FEI is not proposing any new metrics at this time as FEI believes the current metric provides insight into customer effort to resolve inquiries and remains appropriate. Contacts that take more than one interaction are typically more complex, requiring analysis that cannot be resolved in one contact as they often require a follow up. FEI does not expect that an additional metric into customer effort would provide more insight as it is expected (and reasonable) that some customer contacts will not be resolved in one contact, such as a high bill inquiry that needs to be investigated or a customer being unsatisfied with the initial resolution and wanting further dialog. Additionally, FEI does not believe other metrics that are commonly measured in contact centres would provide additional insights into effort, as FCR is directly measuring the customer's perception of their resolution.

The currently approved benchmark of 78 percent is consistent with the 2014-2019 PBR Plan benchmark and is based on setting a target that is above the industry average for call centre performance.

Based on the above considerations, FEI proposes to continue to report on FCR and considers that the current benchmark and threshold remain appropriate for the term of the Rate Framework.

3.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing processes by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective of the metric is to achieve a score of three or less.

The relevant formulas and benchmarks for the three sub-measures are presented in the table below.

Table 8: The Benchmarks and Formulas for Calculation of Billing Index SQI[12]

Billing sub-measure	Percent achieved (PA)	Adjustment	Result
Percentage of bills accurate based upon input data	99.9%	* See formula below	3.0
Percentage of bills delivered to Canada Post within two business days of date that the statement file is created	97%	(100% - PA)*100	3.0
Percentage of customers billed within two business days of the scheduled billing date	97%	(100% - PA)*100	3.0
Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			3.0

* IF [PA ≥ 99.9%, 5000 * (1 - PA), 100 * (1.03 - PA)]

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks, and estimation issues.

The table below provides a summary of the Billing Index results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 9: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Billing Index

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Billing Index	0.62	0.94	1.02	1.38	3.0	3.0	5.0	5.0

The results from 2020 to 2023 have been better than the approved benchmark. The 2023 year-end result of 1.38 is largely attributable to two technical issues experienced in the fourth quarter of 2023 which resulted in a timing delay between the creation of the bills and those bills being sent to customers. These technical issues have been corrected.

FEI proposes to continue to report on the Billing Index as the Company believes the metric is appropriate and provides customer value for complete, timely and accurate bills. FEI proposes to maintain the current benchmark and threshold during the term of the Rate Framework.

[12] Calculation formula consistent with the approved benchmark of 3.0.

3.2.3 Meter Reading Completion (formerly Meter Reading Accuracy)

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

Factors influencing this SQI's performance include the resources available, system issues impacting the Company's billing or reading collections systems, weather conditions including road and highway conditions, and traffic related issues.

As explained in Section C6.3.3 of the Application, FEI proposes to change the name of this metric from Meter Reading Accuracy to Meter Reading Completion, as the revised name better reflects what the metric is measuring. Further, and as explained below, while FEI proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill, FEI proposes to change this metric to an informational indicator and remove the existing benchmark and threshold.

The table below provides a summary of the Meter Reading Completion results since the beginning of the Current MRP, and the currently approved benchmark and threshold.

Table 10: Results during the Current MRP for Meter Reading Completion

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Meter Reading Completion	89.2%	88.0%	87.8%	95.0%	95%	Informational	92%	Informational

The currently approved benchmark and threshold for Meter Reading Completion are 95 percent and 92 percent, respectively. For the first three years of the Current MRP, FEI performed worse than the threshold; however, the 2023 result marks a return to benchmark-level performance.

The results from 2020 to 2022 were discussed in detail in each of the Annual Reviews during the Current MRP term. As was explained in previous Annual Reviews, the lower than threshold performance of the Meter Reading Completion SQI between 2020 and 2022 was primarily a result of the COVID-19 pandemic and its broader impacts, as Olameter continued to experience labour market and staffing challenges throughout 2021 and 2022, including periods where subsequent variants of the virus affected their employees. In addition, meter reading efforts in 2021 were significantly impacted by the multiple extreme weather events that occurred, including the active wildfire season, the extreme heat event, and the flooding that led to evacuations of several communities. All of these weather events contributed to larger percentages of estimated reads due to the inability to safely access meters.

The improved performance in 2023 is largely attributable to Olameter's ability to hire and retain staff, along with the lessened impact of the COVID-19 pandemic. FEI continues to work closely with Olameter on their improved performance and, barring the impact of any extreme weather or other unforeseen events, FEI expects Olameter to continue to meet performance levels.

FEI proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill. However, during the term of the Rate Framework, FEI proposes to change this metric to an informational indicator and accordingly remove the existing benchmark and threshold. The reason for this change is that FEI is in the very early stages of implementing its Advanced Metering Infrastructure (AMI) project, and expects that deployment of the new AMI meters will occur throughout most of the Rate Framework term. As the deployment of AMI will be ongoing throughout the Framework term, resulting in a mix of meter types (manual and advanced), using a benchmark and threshold will no longer provide an effective means of assessing FEI's service quality. FEI instead proposes to continue reporting on this SQI as an informational indicator until AMI is fully implemented, at which point it will assess this metric and determine if it should be re-instated as a measured SQI with adjusted benchmarks and thresholds.

The timing of the AMI project deployment has necessitated changes to the treatment of a number of areas of the Rate Framework. In particular, and as explained in Section C2.2.2.2 of the Application, FEI is proposing to remove AMI-related costs from Formula O&M and to instead treat these costs as Flow-through for the duration of the Rate Framework term. Recognizing that the AMI project can impact the related costs and the performance level of the Meter Reading Completion metric in different ways, separating the impacted areas for costs and service quality provide for greater clarity in understanding their impacts. During the deployment phase of the AMI project, FEI will be providing updates and information, where appropriate, on how the AMI project has impacted the performance of the Meter Reading Completion indicator.

3.2.4 Telephone Service Factor (Non-Emergency)

Similar to the TSF (Emergency), this SQI measures how well the Company can balance costs and service levels, with the overall objective of maintaining a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers.

The principal factors influencing the TSF (Non-Emergency) results include volume, the type of inbound calls received, and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF (Non-Emergency) results are billing system related issues and weather patterns that may generate high numbers of billing related queries, and the complexity of the calls.

The TSF (Non-Emergency) SQI measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The table below provides the results for TSF (Non-Emergency) since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 11: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Telephone Service Factor (Non-Emergency)

Type of Call	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Non-Emergency	70%	70%	62%	71%	70%	70%	68%	68%

The 2020 and 2021 results met the benchmark, and in 2023 the result was better than the benchmark. As explained in the Annual Review for 2024 Delivery Rates, the 2022 result fell below the threshold as FEI experienced several challenging circumstances, including higher than expected attrition in the contact centre, compounded by an increased amount of high bill inquiries over the year. In consideration of the results during the Current MRP and FEI's understanding that some utilities have shifted their benchmark in this area down to 65 percent, FEI had planned to propose in this Application to lower the threshold to 65 percent. However, this proposal was not well supported by stakeholders when FEI presented this change at the November 2023 consultation session. Consultation participants suggested instead to keep the benchmark and threshold as is, but ensure that the potential variability of this metric is communicated.

When assessing whether to propose a change to the threshold, FEI explored widening the range between the threshold and benchmark in response to variability in customer behaviour changes like call patterns, shifts in customer expectations and reliance on digital tools, along with weather changes. These factors could lead to future challenges and variability in SQI results which could impact the Company's ability to perform within the current threshold and benchmark.

In addition to the factors discussed above, FEI also considered that estimates of prospective shifts in customer behaviour are subject to several and potentially unknown variables; as such, FEI ultimately believes that historical performance remains a reasonable basis for threshold expectations. To the extent that FEI experiences challenges or materially different costs in meeting the threshold, FEI will bring forward these challenges and pressures through the Annual Review process.

Accordingly, FEI proposes to continue to report on the TSF (Non-Emergency) metric and to maintain the currently approved benchmark and threshold during the term of the Rate Framework. FEI considers that overall, the current metric strikes an appropriate balance between cost and service levels.

3.2.5 Meter Exchange Appointment Activity

This informational indicator tracks the percentage of appointments met for meter exchanges (excluding industrial meter exchanges). The meter exchanges are required to be done in accordance with regulations from Measurement Canada. Exchanging a customer's existing gas meter involves a technician shutting off the customer's gas, exchanging the in-service meter for a new meter, turning the gas back on and then locating and relighting the customer's appliances. An appointment is necessary as the technician requires access to the inside of the premise to perform the relights to the customer's gas appliances.

The calculation for percentage meter exchange appointments met is calculated as:

$$\frac{\text{Number of meter exchange appointments met}}{\text{Number of meter exchange appointments made}}$$

Factors influencing the results include processes, number of emergencies, weather, and traffic conditions. The processes require the contact centre and operations departments to work closely together in order to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The table below provides the results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 12: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Meter Exchange Appointment Activity

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Meter Exchange Appointment Activity	98.1%	98.3%	98.5%	99.1%	95.0%	95.0%	93.8%	93.8%

For 2020 through 2023, FEI has performed better than the currently approved benchmark. FEI values customers' time and strives to meet customers' expectations with regard to the commitments it makes to perform scheduled work at their premises.

FEI proposes to continue to report on the Meter Exchange Appointment metric and retain the existing benchmark and threshold. FEI notes that the volume of meter exchanges that will occur during the AMI project deployment may impact the results. However, FEI expects that the results will improve post-deployment as appointments should no longer be necessary for the majority of meters given that they will have bypass valves installed to allow for exchanges without requiring a relight or customer interaction. Additionally, the overall number of meter exchanges post-AMI deployment will decrease for the first few years.

3.2.6 Customer Satisfaction Index

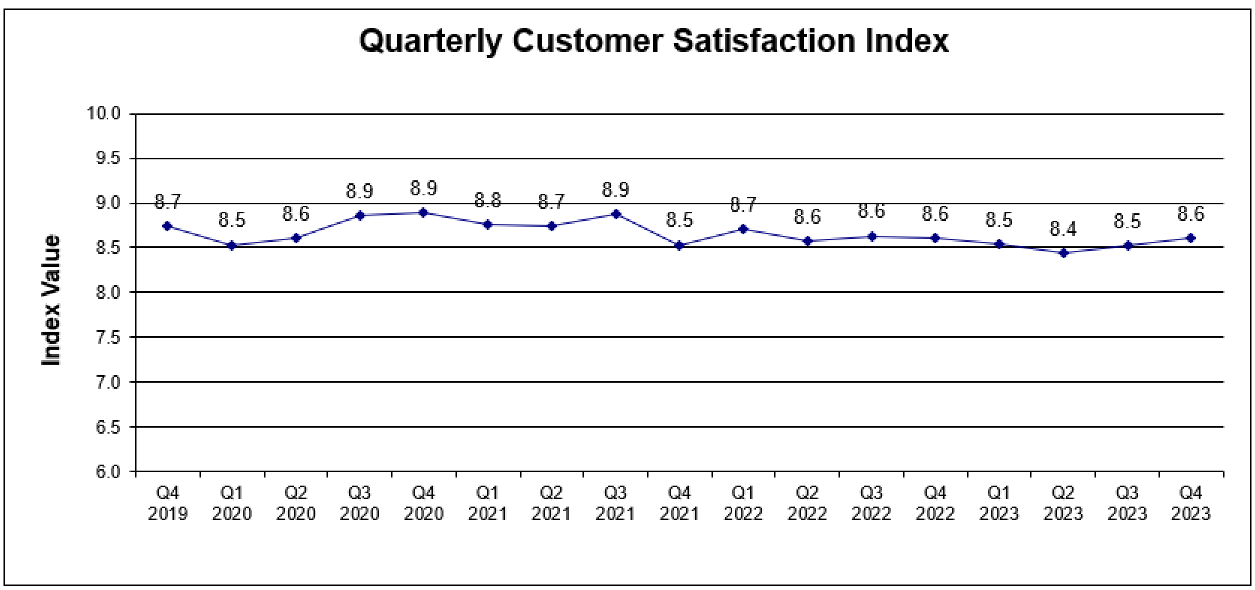
Since 2013, FEI has used the Customer Satisfaction Index (CSI) informational indicator to assess overall customer satisfaction with the Company's natural gas service. The CSI score gathers quarterly feedback from customers, using the same strategy to survey both residential and mass market commercial customers. In addition to covering service touch points such as contact centres and field services, it also evaluates how customers view the Company across a range of other service attributes.

The CSI survey is conducted quarterly involving 600 telephone interviews with customers. Lists of active customers are provided to an external research vendor. The research vendor uses quota sampling to ensure 500 interviews are residential customers, and 100 are mass market commercial customers (Rate Schedule 2).

The index is based on responses to several questions employing a 10 point scale (i.e., top four box answers 7-10). Index contributors include: (1) overall satisfaction with natural gas service from FortisBC; (2) satisfaction with the accuracy of meter reading; (3) satisfaction with energy conservation information; (4) overall satisfaction with the contact centre; and (5) overall satisfaction with field services.

The graph below shows CSI results since 2020.

Figure 1: CSI Results



FEI proposes to continue using this metric as an informational indicator. Results are considered informational in nature and consideration should be given to external factors that can influence customer satisfaction scores. For example, rate changes associated with the overall market price of natural gas can impact customer perceptions and overall satisfaction.

3.2.7 Average Speed of Answer

The Average Speed of Answer (ASA) metric is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (in seconds). The ASA was proposed (and approved) as an informational indicator in the 2020-2024 MRP Application and remains complimentary to the TSF as it provides additional insight on the customer experience for calls that are answered in over 30 seconds, with shorter wait times for customers preferable to longer wait times. FEI is also able to analyze trends in this metric, as wait times at certain times on certain days can be isolated and explained in terms of staffing levels, unexpected absences, technology issues, etc.

The table below provides a summary of the Average Speed of Answer since the beginning of the Current MRP.

Table 13: Results during the Current MRP for Average Speed of Answer

Description	2020	2021	2022	2023
Average Speed of Answer (seconds)	72	65	106	65

The results for 2020, 2021 and 2023 have been relatively consistent with an approximately one-minute wait for a customer service representative to answer a customer's call. As explained in the Annual Review for 2024 Delivery Rates, the 2022 result was impacted by several challenging circumstances that contributed to the year-end performance. These challenges included higher than expected attrition in the contact centre, compounded by an increased amount of high bill inquiries over the year.

FEI proposes to continue using this metric as an informational service quality indicator.

3.3 *RELIABILITY SQIs*

3.3.1 Transmission Reportable Incidents

The Transmission Reportable Incidents metric is an informational indicator that measures the number of reportable incidents to outside agencies for transmission assets as defined by the BC Energy Regulator (BCER). The metric is intended to be an indicator of the integrity of the transmission system.

As of October 1, 2014, the Company reports Transmission Reportable Incidents based on the new BCER reporting criteria, including Level 1, 2, and 3 reportable incidents for both transmission and intermediate pressure assets that operate at a pressure exceeding 100 psi. This includes pipelines, mains, services, stations, LNG plants and compressor stations, but excludes distribution assets that operate below 100 psi.

The following table summarizes the transmission reportable incidents from 2020 to 2023 by severity level.

Table 14: Transmission Incidents by Severity Level during the Current MRP

BCER Severity Level	Number of Reportable Incidents			
	2020	2021	2022	2023
Level 1 (moderate)	1	0	0	0
Level 2 (major)	0	0	3	0
Level 3 (serious)	0	0	0	0

FEI proposes to continue to report transmission incidents as an informational indicator.

3.3.2 Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator that measures the number of leaks on the distribution system per KM of distribution system mains. The metric is intended to be an indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system is surveyed for leaks, with the number of leaks varying from year to year, depending on the condition of the pipe surveyed.

Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system as some sections of the pipeline system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline. As the distribution system ages, the expected number of leaks may increase depending on the Company's pipeline renewal/replacement activities. Increases in leak survey activity levels will generally also result in a higher number of leaks detected.

In the Annual Review for 2015 Delivery Rates Decision, the BCUC directed FEI to provide a five-year rolling average as follows:

> The Panel agrees with BCSEA that a five-year rolling average of Leaks per KM of Distribution System Mains would be helpful information and directs FEI to provide this information in future annual reviews.

The Company's 2020 to 2023 annual and five-year average results are provided in the table below.

Table 15: Historical Leaks per KM of Distribution System Mains during the Current MRP

Leaks per KM of Distribution System Mains	2020	2021	2022	2023
Leaks	152	131	138	131
Total km	23,460	23,707	23,734	23,913
Leaks per km	0.0065	0.0055	0.0058	0.0055
5 year average	0.0056	0.0058	0.0060	0.0059

FEI proposes to continue to report Leaks per KM of Distribution System Mains as an informational indicator.

3.4 *ENERGY TRANSITION INFORMATIONAL INDICATORS*

FEI proposes to introduce a suite of informational indicators that will report on FEI's progress through the energy transition. These new informational indicators recognize the importance of incorporating FEI's response to the energy transition within the Rate Framework, as has been emphasized by the BCUC and by stakeholders.

As discussed in Section C6.1.4 of the Application, in determining which SQIs should be classified as informational indicators, an SQI works well as an informational indicator when there may be factors outside of the Company's control that can influence the metric's performance. For the energy transition area, proposing informational indicators recognizes the evolving and uncertain policy environment which can have an impact on FEI's ability to invest in emissions abatement and the energy transition results. In addition, this classification acknowledges that the proposed energy transition indicators do not necessarily measure actual service quality, as compared to more traditional SQIs, but are responsive to BCUC and intervener feedback and provide context related to how FEI is adapting to the energy transition.

The following tables summarizes the proposed new energy transition informational indicators and the most recent historical results. Each indicator is described in more detail in the following subsections.

Table 16: Energy Transition Informational Indicators

Performance Measure	Description	2020 Results	2021 Results	2022 Results	2023 Results
Scope 1 Emissions	Total direct GHG emissions from FEI owned or controlled sources ($MtCO_2e$)	0.14	0.15	0.24	0.14[13]
Renewable and Low Carbon Energy Supply Volume	Acquired annual Renewable and Low Carbon Energy supply (TJ)	306	790	2,295	2,778
Natural Gas for Transportation Volume	Total gas consumed by CNG and LNG customers (TJ)	2,413	2,652	3,077	3,117
Demand Side Management Energy Savings	Measure lifetime gas savings from conservation and energy management programs (TJ)[14]	7,937	12,304	10,811	10,104

[13] 2023 GHG emissions from natural gas operations are currently being reviewed by a third-party verifier. As such, values may be subject to change.

[14] FEI calculates lifetime gas savings based on the net present value of gas savings over the lifetime of all measures implemented during the year.

3.4.1 Scope 1 Emissions

FEI is committed to finding ways to reduce emissions in areas of operations. Scope 1 emissions, as defined under the Greenhouse Gas Protocol Corporate Accounting and Reporting Standards, are direct emissions from owned or controlled sources. This includes externally verified Scope 1 GHG emissions as reported to the BC Ministry of Environment for FEI and its LNG operations.

The following table summarizes FEI's most recent historical Scope 1 emissions, which are a function of natural gas throughput on FEI's system as well as third-party line hits and incidents that lead to releases of methane. For example, in 2022, an incident with fugitive releases off a transmission pipeline led to approximately 0.06 $MtCO_2e$.

Table 17: Scope 1 Emissions Performance

Description	2020	2021	2022	2023
Total direct GHG emissions from owned or controlled sources ($MtCO_2e$)	0.14	0.15	0.24	0.14[15]

In addition to major incidents, FEI's Scope 1 emissions are primarily the result of:

- Natural gas consumption for compression on FEI's transmission and distribution systems;
- Natural gas consumption in distribution line heaters;
- GHG emissions from third-party distribution gas line damage incidents; and
- Estimated fugitive emissions from the millions of small assets throughout FEI's transmission and distribution system including customer meters and shut off valves.

FEI will continue to look for ways to reduce emissions across the operations of its system. This work includes identifying capital upgrades to reduce natural gas consumption. In addition, FEI places a high emphasis on maintaining and improving the integrity of the gas system, as evidenced by its annual sustainment capital expenditures and its major projects, such as the Inland Gas Upgrade CPCN project and the Transmission Integrity Management Capabilities projects.

3.4.2 Renewable Energy Supply Volume

FEI is displacing conventional natural gas with renewable and low-carbon gases to lower customers' GHG emissions. FEI continues to increase its supply of renewable natural gas and explore the potential of low-carbon gases (such as hydrogen).

[15] 2023 GHG emissions from natural gas operations are currently being reviewed by a third-party verifier. As such, values may be subject to change.

The table below provides a summary of FEI's most recent historical renewable and low carbon gas supply volumes.

Table 18: Renewable and Low Carbon Energy Supply

Description	2020	2021	2022	2023
Acquired annual Renewable and Low Carbon Energy supply (TJ)	306	790	2,295	2,778

3.4.3 Natural Gas for Transportation Volume

FEI is advancing low- and zero-carbon transportation, including CNG and LNG as replacement fuel for heavy-carbon transport fuels. For instance, LNG from FEI's Tilbury facility can reduce GHG emissions from ships by 22 percent in a high methane slip scenario and 27 percent in a low methane slip scenario, compared with marine gas oil/marine diesel oil burned by vessels in the Port of Vancouver Airshed today.[16] For this informational indicator, FEI has combined the CNG and LNG volume delivered to the transportation and marine sector into one overall supply metric. This includes the CNG delivered to CNG stations, LNG stations and the LNG used in marine bunkering. FEI considers the total low- and zero-carbon transportation volumes delivered to be appropriate as an energy transition informational indicator because displacing petroleum-based fuels with natural gas or renewable natural gas leads to GHG emissions reductions.

The table below provides a summary of FEI's most recent historical natural gas for transportation and marine volumes.

Table 19: Natural Gas for Transportation Volumes

Description	2020	2021	2022	2023
Total gas consumed by CNG and LNG customers (TJ)	2,413	2,652	3,077	3,117

3.4.4 Demand Side Management Energy Savings

FEI supports customers in reducing their energy usage. FEI has continued to increase investment to improve energy efficiency in the buildings where people live and work and develop innovative energy projects in BC's communities.

The table below provides FEI's most recent historical DSM energy savings. Savings are listed as lifetime net gas savings. Lifetime in this context refers to the entire stream of savings from measures supported in each of the years listed and annualizing that to present time to show the total value of the stream of savings. This view of the energy savings most accurately reflects the

[16] Affinity Study on the Air Quality Benefits to the Port of Vancouver by Adopting LNG As a Marine Fuel.

overall eventual impact of the savings incurred as a result of the measures incented by FEI's DSM programming. One TJ of gas savings is equivalent to approximately 68 tons of carbon dioxide emissions saved.[17]

Table 20: Demand Side Management Energy Savings

Description	2020	2021	2022	2023
Measures lifetime gas savings from conservation and energy management programs (TJ)[18]	7,937	12,304	10,811	10,104

FEI notes that the slight drop in measure lifetime gas reductions from 2021 to 2023 was primarily due to measure types and the discount rate. In particular, there were more measures with longer lifetimes and more uptake in measures with longer lifetimes in 2021 compared to 2022 and 2023. In addition, the discount rate has increased since 2021 which factors into a lower total net present value of gas savings. Annual gas savings have increased year-over-year since 2020.

Due to the DSM regulation amendment discussed in Section B1.3.3 of the Application, FEI forecasts that there will be a drop off in energy savings in 2024. This regulation amendment has caused a significant shift in DSM programming. Gas fired equipment under 100 percent efficiency can no longer be incented (with a few exceptions) causing overall energy savings potential in the DSM area to shrink. FEI is working on developing advanced measures permitted under the new regulation amendment and will be advancing work to have those adopted by the marketplace. Energy savings are expected to increase year-over-year compared to 2024 starting in 2025.

4. DISCONTINUED SERVICE QUALITY INDICATORS

None.

5. ANNUAL REVIEW PROCESS

FEI proposes to continue with the existing process for reviewing SQI performance at the Annual Reviews whereby FEI will review service quality for a year in the following year's Annual Review. This is consistent with previous BCUC direction and FEI believes this approach to reviewing SQIs has worked well over the past two multi-year rate framework periods (i.e., the 2014-2019 PBR Plan term and the Current MRP term).

In 2016, the BCUC issued its Reasons for Decision accompanying Order G-44-16 in FortisBC Inc.'s (FBC's) All Injury Frequency Rate Compliance Filing. The BCUC determined that it was

[17] As per Environment and Climate Change Canada OpenLCA Clean Fuel Regulation Model.
[18] FEI calculates lifetime gas savings based on the net present value of gas savings over the lifetime of all measures implemented during the year.

appropriate to review FBC's service quality for a year in the following year's annual review. The BCUC stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

At the Annual Review workshop, year-to-date SQI actuals along with prior year-end results will be presented along with commentary on the results. Discussion of the SQI performance will serve to provide a better understanding of any issues affecting the Company's ability to meet the established benchmarks.

6. SUMMARY OF PROPOSED SERVICE QUALITY INDICATORS

The following table summarizes FEI's existing and proposed service quality indicators along with the benchmarks and thresholds. Proposed changes to the SQIs are highlighted in Green.

1 **Table 21: Summary of Proposed Service Quality Indicators**

		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Safety Indicators					
Annual results	**Emergency Response Time**	>= 97.7%	96.2%	>=97.7%	96.2%
Annual results	**Telephone Service Factor (Emergency)**	>= 95%	92.8%	>=95%	92.8%
3 Year rolling average	**All Injury Frequency Rate**	<= 2.08	2.95	<= 1.64	2.21
Annual results	**Public Contacts with Gas Lines**	<=8	12	<=6	10
Responsiveness to Customer Needs Indicators					
Annual results	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual results	**Billing Index**	<= 3	5	<=3	5
Annual results	**Meter Reading Completion**	>= 95%	92%	Informational	Informational
Annual results	**Telephone Service Factor (Non Emergency)**	>= 70%	68%	>=70%	68%
Annual results	**Meter Exchange Appointment Activity**	>=95%	93.8%	>=95%	93.8%
Annual results	**Customer Satisfaction Index**	Informational	Informational	Informational	Informational
Annual results	**Average Speed of Answer**	Informational	Informational	Informational	Informational
Reliability Indicators					
Annual results	**Transmission Reportable Incidents**	Informational	Informational	Informational	Informational
Annual results and 5 Year rolling average	**Leaks per KM of Distribution System Mains**	Informational	Informational	Informational	Informational
Energy Transition Indicators					
Annual results	**Scope 1 Emissions**	N/A	N/A	Informational	Informational
Annual results	**Renewable and Low Carbon Energy Supply Volume**	N/A	N/A	Informational	Informational
Annual results	**Natural Gas for Transportation Volume**	N/A	N/A	Informational	Informational
Annual results	**Demand Side Management Energy Savings**	N/A	N/A	Informational	Informational

2

Appendix C6-2

FBC SERVICE QUALITY INDICATOR REPORT

FORTIS BC™

Appendix C6-2

Service Quality Indicators

FortisBC Inc. (FBC)

Table of Contents

Index of Tables and Figures

1. INTRODUCTION

Maintaining a high level of service quality is important to the long-term success of the Company. In support of this, as in the recent 2014 to 2019 PBR Plan and the 2020 to 2024 MRP, FortisBC Inc. (FBC or the Company) proposes a suite of Service Quality Indicators (SQIs) be established as part of the Rate Framework. The SQIs will serve to ensure that service quality to customers is maintained at acceptable levels throughout the term of the Rate Framework.

FBC proposes a suite of SQIs which builds on its experience. In the following sections, FBC describes the SQI history and development, as well as proposed updates and modifications. These SQI metrics reflect a broad range of business processes that are important elements of the customer experience.

2. HISTORY AND DEVELOPMENT OF SERVICE QUALITY INDICATORS AT FBC

The inclusion of SQIs has continued to evolve throughout the Company's previous multi-year rate plans as follows:

- In the 1996 PBR Settlement, FBC agreed to nine service quality indicators (then referred to as Performance Standards). In 1999, three new indicators were added and one discontinued. In 2000, a second measure was discontinued.
- The 2007 PBR Plan retained the majority of the indicators (six) from the previous PBR Plan, changed the status of one SQI to an informational indicator, discontinued three, and added seven new SQIs to assess the Company's performance.
- The 2014-2019 PBR Plan discontinued eight SQIs, replaced one, continued with eight existing SQIs, and added two new SQIs.
- The 2020-2024 MRP continued with the suite of SQIs from the prior plan, with changes limited to the addition of an informational indicator and the replacement of an informational indicator.

The following table outlines the history and evolution of FBC's SQIs over the four multi-year rate plan eras as well as summarizing the SQIs proposed for the Rate Framework.

Table 1: History and Evolution of SQIs at FBC (1996 - 2025)

	Service Quality Indicator	1996 PBR	2007 PBR	2014 PBR	2020 MRP	2025 Rate Framework
1	System Average Interruption Frequency Index	Included	Definition changed to Normalized	Included	Included	Included
2	System Average Interruption Duration Index	Included	Definition changed to Normalized	Included	Included	Included
3	Customer Average Interruption Duration Index	Included	-	-	-	-
4	Index of Reliability	Included	-	-	-	-
5	Generator Forced Outages	Included (Introduced in 1999)	Included	Included	Included	Included
6	Generation Incapability Factor	Included (Introduced in 1999)	-	-	-	-
7	Generator Operating Factor	Included (1999 only)	-	-	-	-
8	System Losses	Included (1996-1998 only)	-	-	-	-
9	Customer Satisfaction Index	Included	Included (Redesigned)[1]	Included	Included	Included
10	Billing Accuracy	-	Included	Replaced with Billing Index	-	-
10a	Billing Index	-		Included	Included	Included
11	First Contact Resolution	-	-	Included	Included	Included
12	Meters Read as Scheduled	-	Included	Included	Included	Included
13	Telephone Service Factor	-	Included	Included	Included	Included
14	Emergency Response Time	-	Included	Included	Included	Included
15	Residential Connections Completion Time	-	Included	-	-	-
16	Residential Extensions Quoting Time	-	Included	-	-	-
17	Residential Extensions Completion Time	-	Included	-	-	-
18	Injury Frequency Rate	Included (Disabling Injury Frequency Rate)	Definition changed to All Injury Frequency Rate	Included	Included	Included

[1] Redesigned the customer survey to measure overall satisfaction, satisfaction with the contact center, field services and meter reading as well as the level of information provided on energy conservation.

	Service Quality Indicator	1996 PBR	2007 PBR	2014 PBR	2020 MRP	2025 Rate Framework
19	Injury Severity Rate	Included	Included	-	-	-
20	Vehicle Incident Rate	Included	Included	-	-	-
21	Telephone Abandonment Rate	-	-	Included	Replaced with Average Speed of Answer	-
21a	Average Speed of Answer	-	-	-	Included	Included
22	Interconnection Utilization	-	-	-	Included	Included

For the Rate Framework, FBC reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to customers is maintained at acceptable levels. For some SQIs, FBC proposes to change their benchmarks and thresholds, recognizing their recent historical performance. FBC is also proposing to move one SQI from a measured metric to informational. In the following sections, FBC describes the proposed SQIs, and their benchmarks and thresholds.

3. PROPOSED SERVICE QUALITY INDICATORS, BENCHMARKS AND THRESHOLDS

3.1 *SAFETY SQIS*

3.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This will provide ongoing information to assess FBC crew sizes and crew locations in response to system trouble.

The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (during business hours or after business hours), number and type of events (i.e., widespread outages), available resources and location (travel times and traffic congestion) and weather conditions.

The approved benchmark for the Current MRP was 93 percent and is the same as that approved for the 2014-2019 PBR Plan. The recent years' results have been consistent with the approved benchmark.

The following table summarizes the percentage of emergency events responded to within two hours since the beginning of the Current MRP compared to the approved benchmark and threshold. The table also includes FBC's proposed benchmark and threshold for the Rate Framework.

Table 2: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Emergency Response Time

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Emergency Response Time	92%	93%	93%	92%	93%	93%	90.6%	90.6%

Table 3 below provides details of the emergency activity levels (number of calls), average emergency response times, the number of calls greater than two hours, and the overall percentage of emergency response times two hours or less during the Current MRP term.

Table 3: Summary of FBC Emergency Activity Levels and Average Response Time

			Number of calls over two hours	Percent of responses in two hours or less
2020 to 2023	Number of calls	10,113	775	92%
	Average response time (h:mm)	1:06		
2023	Number of calls	2,309	174	92%
	Average response time (h:mm)	1:07		
2022	Number of calls	2,632	196	93%
	Average response time (h:mm)	1:02		
2021	Number of calls	2,482	181	93%
	Average response time (h:mm)	1:03		
2020	Number of calls	2,690	224	92%
	Average response time (h:mm)	1:10		

During the Current MRP term, the percentage of responses within two hours or less averaged approximately 92 percent which is consistent with the existing benchmark of 93 percent. While the results have been relatively stable, variables such as the type of outage and the number of trouble calls contribute to the observed variation in the annual performance for this metric.

FBC proposes to continue to report on Emergency Response Time and considers that the current benchmark represents the level of service expected by its customers and is appropriate. Therefore, FBC proposes to retain its existing benchmark and threshold for the term of the Rate Framework.

3.1.2 All Injury Frequency Rate

FBC is committed to ensuring its employees can perform their work and go home safely at the end of each day.

During the November 2023 consultation session, FBC discussed the difference between leading and lagging safety indicators and explained that it was exploring introducing a leading safety indicator to enhance its reporting on safety, as FBC currently reports on the All Injury Frequency Rate (AIFR), which is a lagging indicator. Stakeholders were generally supportive of the concept.

When measuring and monitoring safety, lagging indicators measure what happened after the fact (i.e., outcomes) and can alert the Companies to a failure in the safety system, or to the existence of an uncontrolled hazard, *following* an event. At FBC, such events are used to learn and improve, identifying gaps in existing safety defenses and establishing corrective actions to prevent future reoccurrences. In contrast, leading indicators are proactive and preventative measures that can shed light on the effectiveness of safety and health activities and reveal potential gaps *prior* to an event occurring.

FBC has been exploring potential leading indicators but does not yet have a formal, defined indicator to propose for inclusion as an SQI. Instead, the Company will continue to examine and develop a leading safety indicator during the term of the Framework and will propose a suitable leading indicator either during the Framework (as part of the Annual Review process) or subsequent to the conclusion of the three-year term of the Framework. FBC expects that any new leading safety indicator would initially be informational only, as there will likely be a lack of adequate historical information to establish a benchmark or threshold. This approach will allow FBC to evaluate suitable metrics, propose a suitable metric, and engage in discussions with the BCUC and interveners on whether the selected metric is appropriate for inclusion in the Company's suite of SQIs.

FBC proposes to continue to report on the existing AIFR SQI which, as described above, is a lagging indicator. AIFR remains an important measure for FBC as it tracks the impact of safety incidents on its employees. While increases or decreases in incidents do not necessarily reflect an improvement or degradation of safety performance, having more incidents reported means more opportunities for learning and developing better safety protections over time. An increase in incidents can sometimes be attributed to an improved safety culture where employees feel more comfortable in reporting incidents.

The AIFR is based on total number of employee injuries per 200,000 hours worked. Lost time injuries are those that result in one or more days missed from work as a direct result of an occupational injury/illness incident. Medical treatments are considered injuries where treatment was given or prescribed beyond First Aid and observation, and no lost time was involved.

The following formula is used:

All Injury Frequency Rate =

$$\frac{\text{(Number of Employee Injuries) x 200,000 hours}}{\text{Exposure Hours}^{2}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The table below provides a summary of FBC's AIFR annual and three-year rolling average results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 4: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for AIFR

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
AIFR – three year rolling average	0.87	0.67	1.42	1.84	1.64	1.31	2.39	2.56
AIFR – annual	0.66	0.89	2.60	1.97	n/a	n/a	n/a	n/a

The results from 2020 to 2022 have been better than the currently approved benchmark of 1.64, with the 2023 results better than the threshold.

FBC remains committed to its focus on safety. Based on the performance over the Current MRP term, FBC considers it appropriate to adjust the current benchmark and threshold for the term of the Rate Framework. The proposed adjustments will reinforce the Company's enhanced safety culture and shift towards risk mitigation, including preventing events and injuries before they can occur.

The proposed benchmark of 1.31 is based on the three-year rolling average of the 2021 to 2023 annual results[3]. The proposed threshold of 2.56 is calculated consistent with past practice[4].

3.2 Responsiveness to Customer Needs SQIs

3.2.1 First Contact Resolution (FCR)

First Contact Resolution (FCR) is an area of focus for FBC. Research conducted by Service Quality Measurement[5] (SQM) suggests that it is the single most important driver of customer

[2] Exposure hours reflect actual hours worked excluding time off for vacation, statutory holidays, sickness, etc.
[3] (0.67 + 1.42 + 1.84) / 3 = 1.31.
[4] The threshold is set at 2 standard deviations from the recent 10-year history of three-year rolling averages of the annual results.
[5] SQM is a North American call centre industry research firm expert for improving organizations' FCR, employee and customer satisfaction.

satisfaction.[6] By maintaining a high level of FCR, the Company can effectively satisfy customers who are looking to have their issues resolved efficiently.

FCR measures the percentage of customers who receive resolution to their inquiry in one contact with FBC's contact centre. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their inquiry was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The table below provides a summary of the FCR results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 5: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for First Contact Resolution

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
First Contact Resolution	82%	82%	77%	79%	78%	78%	74%	74%

The 2020, 2021 and 2023 FCR results were better than the benchmark. As explained in the Annual Review for 2024 Rates, the 2022 result was largely attributable to the increased volume of high bill inquiries. Depending on the nature of the high bill, there may be a need for customers to follow up on their bill, resulting in more than one contact to resolve their concerns. As well, high bill calls can require longer-term payment arrangements which may require changes – leading to customers connecting with FBC multiple times for the same reason.

During the November consultation session, stakeholders suggested that FortisBC consider developing a metric that seeks to measure FortisBC's performance when a customer's inquiry is not resolved during the first contact, or a metric that provides different information on performance other than FortisBC's ability to resolve a customer inquiry in one contact. FBC is not proposing any new metrics at this time as FBC believes the current metric provides insight into customer effort to resolve inquiries and remains appropriate. Contacts that take more than one interaction are typically more complex, requiring analysis that cannot be resolved through a single contact as they often require a follow up. FBC does not expect that an additional metric into customer effort would provide more insight as it is expected (and reasonable) that some customer contacts will not be resolved in one contact, such as a high bill inquiry that needs to be investigated or a customer being unsatisfied with the initial resolution and wanting further dialog. Additionally, FBC does not believe other metrics that are commonly measured in contact

[6] SQM Reference https://www.sqmgroup.com/resources/library/blog/fcr-metric-operating-philosophy.

centres would provide additional insights into effort, as FCR is directly measuring the customer's perception of their resolution.

The currently approved benchmark of 78 percent is consistent with the 2014-2019 PBR Plan benchmark and is based on setting a target that is above the industry average for call centre performance.

Based on the above considerations, FBC proposes to continue to report on FCR and considers that the current benchmark and threshold remain appropriate for the term of the Rate Framework.

3.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing processes by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective of the metric is to achieve a score of three or less.

The relevant formulas and benchmarks for the three sub-measures are presented in the table below.

Table 6: The Benchmarks and Formulas for Calculation of Billing Index SQI[7]

Billing sub-measure	Percent achieved (PA)	Adjustment	Result
Percentage of bills accurate based upon input data	99.9%	* See formula below	3.0
Percentage of bills delivered to Canada Post within two business days of date that the statement file is created	97%	(100% - PA)*100	3.0
Percentage of customers billed within two business days of the scheduled billing date	97%	(100% - PA)*100	3.0
Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			3.0

* IF [PA ≥ 99.9%, 5000 * (1 - PA), 100 * (1.03 - PA)]

[7] Calculation formula consistent with the approved benchmark of 3.0.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks, and estimation issues.

The table below provides a summary of the Billing Index results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 7: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Billing Index

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Billing Index	0.13	0.12	0.14	1.97	3.0	3.0	5.0	5.0

The results from 2020 to 2023 have been better than the approved benchmark. The 2023 year-end result of 1.97 is attributable to a technical issue experienced in February 2023 which resulted in a timing delay between the creation of the bills and those bills being sent to the print vendor. This technical issue has been corrected.

FBC proposes to continue to report on the Billing Index as the Company believes the metric is appropriate and provides customer value for complete, timely and accurate bills. FBC proposes to maintain the current benchmark and threshold during the term of the Rate Framework.

3.2.3 Meter Reading Completion (formerly Meter Reading Accuracy)

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

Factors influencing this SQI's performance typically include the resources available and system issues impacting the Company's billing or reading collections systems.

As explained in Section C6.4.2 of the Application, FBC proposes to change the name of this metric from Meter Reading Accuracy to Meter Reading Completion, as the revised name better reflects what the metric is measuring. Further, and as explained below, while FBC proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill, FBC proposes to change this metric to an informational indicator and remove the existing benchmark and threshold.

The table below provides a summary of the Meter Reading Completion results since the beginning of the Current MRP, and the currently approved benchmark and threshold.

Table 8: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Meter Reading Completion

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Meter Reading Completion	99%	99%	99%	99%	98%	Informational	96%	Informational

The results from 2020 to 2023 have been better than the approved benchmark.

During the November 2023 consultation session, some stakeholders questioned whether there is reduced value in the Meter Reading Completion metric due to the consistency that AMI brings to meter reading completion.

FBC proposes to continue to report on the Meter Reading Completion metric given the value customers place on receiving a timely and accurate bill; however, FBC proposes to change this metric to an informational indicator and remove the existing benchmark and threshold. The information gathered through the proposed Meter Reading Completion informational indicator remains valuable as FBC did not achieve 100 percent performance accuracy during the Current MRP term, despite relatively stable performance. Some AMI meters are not automatically read, either because a customer has requested the radio be turned off or due to the location of the meter not allowing for a proper signal to be received. Further, failures related to weather and system issues can still occur. Having visibility on meter reading completion through the proposed informational indicator will ensure FBC remains focused on obtaining meter readings in both manual and automatic reading situations.

3.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (TSF) (Non-Emergency) SQI measures how well the Company can balance costs and service levels, with the overall objective of maintaining a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers.

The principal factors influencing the TSF (Non-Emergency) results include volume, the type of inbound calls received, and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF (Non-Emergency) results are billing system related issues and weather patterns that may generate high numbers of billing related queries, and the complexity of the calls.

The TSF (Non-Emergency) SQI measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The table below provides a summary of the TSF (Non-Emergency) results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 9: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for Telephone Service Factor (Non-Emergency)

Type of Call	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
Non-Emergency	70%	70%	65%	71%	70%	70%	68%	68%

The 2020 and 2021 results met the benchmark, and in 2023 the result was better than the benchmark. As explained in the Annual Review for 2024 Rates, the 2022 result fell below the threshold as FBC experienced several challenging circumstances, including higher than expected attrition in the contact centre, compounded by an increased amount of high bill inquiries in the first and fourth quarters. In consideration of the results during the Current MRP and FBC's understanding that some utilities have shifted their benchmark in this area down to 65 percent, FBC had planned to propose in this Application to lower the threshold to 65 percent. However, this proposal was not well supported when FBC presented this change at the November 2023 consultation session. Consultation participants suggested instead to keep the benchmark and threshold as is but ensure that the potential variability of this metric is communicated.

When assessing whether to propose a change to the threshold, FBC explored widening the range between the threshold and benchmark in response to variability in customer behaviour changes like call patterns, shifts in customers expectations and reliance on digital tools, along with weather changes. These factors could lead to future challenges and variability in SQI results which could impact the Company's ability to perform within the current threshold and benchmark.

In addition to the factors discussed above, FBC also considered that estimates of prospective shifts in customer behaviour are subject to several and potentially unknown variables; as such, FBC ultimately believes that historical performance remains a reasonable basis for threshold expectations. To the extent that FBC experiences challenges or materially different costs in meeting the threshold, FBC will bring forward these challenges and pressures through the Annual Review process.

Accordingly, FBC proposes to continue to report on the TSF (Non-Emergency) metric and to maintain the currently approved benchmark and threshold during the term of the Rate Framework. FBC considers that overall, the current metric strikes an appropriate balance between cost and service levels.

3.2.5 Customer Satisfaction Index

FBC uses the Customer Satisfaction Index (CSI) methodology to evaluate and monitor overall customer satisfaction with the Company's electricity service. The CSI is conducted quarterly. Each wave includes 350 telephone interviews with the primary decision makers responsible for paying the electricity bills within their household or business. Lists of active customers are provided to an external research vendor. This vendor uses quota sampling to ensure 300 interviews are residential customers, and 50 are mass market small commercial customers.

The index is based on responses to several questions employing a 10 point scale (i.e., top four box answers 7-10). Index contributors include: (1) overall satisfaction with electric service from FBC; (2) satisfaction with the accuracy of meter reading; (3) satisfaction with energy conservation information; (4) overall satisfaction with the contact centre; and (5) overall satisfaction with field services.

The graph below shows CSI results since 2020.

Figure 1: CSI Results

FBC proposes to continue using this metric as an informational indicator. Customer attitudes are often influenced by factors outside the Company's control. Examples include storm related unplanned outages, media coverage, and customer concerns about collection policies. As a result, trend information is more valuable and useful than the actual quarterly number.

3.2.6 Average Speed of Answer

The Average Speed of Answer (ASA) metric is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (in seconds). The ASA was proposed (an approved) as an informational indicator in the 2020-2024

MRP Application and remains complimentary to the TSF as it provides additional insight on the customer experience for calls answered in over 30 seconds, with shorter wait times for customers preferable to longer wait times. FBC is also able to analyze trends in this metric, as wait times at certain times on certain days can be isolated and explained in terms of staffing levels, unexpected absences, technology issues, etc.

The table below provides a summary of the ASA results since the beginning of the Current MRP.

Table 10: Results during the Current MRP for Average Speed of Answer

Description	2020	2021	2022	2023
Average Speed of Answer (seconds)	71	65	98	64

The results for 2020, 2021 and 2023 have been relatively consistent with an approximately one-minute wait for a customer service representative to answer a customer's call. As explained in the Annual Review for 2024 Rates, FBC's 2022 result was impacted by several challenging circumstances that contributed to the year-end performance. These challenges included higher than expected attrition in the contact centre, compounded by an increased amount of high bill inquiries over the year. Recovery of the ASA commenced in March 2023, resulting in the 2023 year-end ASA performance returning to typical levels of approximately one-minute.

FBC proposes to continue using this metric as an informational indicator.

3.3 *RELIABILITY SQIs*

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

During the November 2023 consultation session, some stakeholders suggested that emergency practices in response to major events be included in the SQI reporting. FBC considered this suggestion but determined that such an approach would not be practical to implement, as it would be challenging to measure and benchmark, thereby making it very difficult to assess the Company's performance. FBC works to prepare for storms through activities such as strategic vacation scheduling, training in incident command, regular emergency exercises, and participating in mutual aid, but these activities are not easily measured.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

3.3.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

The table below provides a summary of the SAIDI results since the beginning of the Current MRP, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 11: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for SAIDI

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
SAIDI (Annual normalized results)	3.17	4.27	2.42	3.04	3.22	3.24	4.52	4.71

As shown in the above table, the 2020, 2022 and 2023 results were better than the benchmark. The 2021 results, which were better than the threshold but below the benchmark, were heavily influenced by several factors that did not meet the threshold for normalization. These factors were described in detail in the Annual Review for 2023 Rates and included the collapse of a construction crane in downtown Kelowna and an unprecedented run of extreme heat at the end of June and early July 2021 which dried forest fuels earlier than usual and led to one of the worst fire seasons on record.

Interveners provided feedback in two areas as part of the November 2023 consultation session. First, some interveners expressed concern that basing the benchmark and/or threshold on the average of the last three years of performance data could contribute to declining SAIDI performance over time. As SAIDI is significantly impacted by external factors, resulting in variability in SAIDI performance, FBC considers that a three-year performance average establishes a benchmark that is consistent with the level of costs required to provide this level of service and provides a consistent methodology that allows for changes in service quality to be detected, consistent with the BCUC decision from the 2014-2019 PBR Plan. For example, severe weather events driven by climate change are a type of external factor that has the potential to increasingly impact FBC's SAIDI performance. FBC is completing a Climate Change Risk Assessment to inform future planning to mitigate associated reliability risks.

Second, an intervener suggested adding an average service availability index (ASAI). FBC does not consider it necessary to add this SQI, as an ASAI would not provide more information and would simply display the same information as SAIDI but in a different way. SAIDI is the more common industry metric and provides more readable information compared to ASAI, which requires multiple decimal places to see any change in results.

Accordingly, FBC proposes to continue to report on SAIDI during the term of the Rate Framework and to revise the benchmark and threshold as shown in the above table. The proposed benchmark and threshold incorporate the recent 2020 to 2023 results. Similar to the approach used to determine the threshold for the Current MRP, the proposed threshold is based on statistical analysis (i.e., standard deviation) of the SAIDI historical results from 2010 to 2019 and now inclusive of 2020 to 2023.

3.3.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

The table below provides a summary of the SAIFI results since the beginning of the Current MRP term, the currently approved benchmark and threshold, and the proposed benchmark and threshold for the Rate Framework.

Table 12: Current MRP Results, Benchmark and Threshold, and Proposed Benchmark and Threshold for SAIFI

Description	2020	2021	2022	2023	Benchmark		Threshold	
					Current	Proposed	Current	Proposed
SAIFI (Annual normalized results)	1.64	2.08	1.52	1.31	1.57	1.64	2.19	2.25

The 2020 and 2021 results were better than the threshold but below the benchmark, while the 2022 and 2023 results were better than the benchmark. The 2021 results for SAIFI were similarly impacted by the crane collapse, wildfires, and storms, as was discussed above in the SAIDI section and in detail in the Annual Review for 2023 Rates.

The impact of external factors on SAIDI is equally applicable to SAIFI and can create variability in SAIFI performance. Accordingly, FBC considers that a three-year performance average establishes a benchmark that is consistent with the level of costs required to provide this level of service and provides a consistent methodology that allows for changes in service quality to be detected, consistent with the BCUC decision from the 2014-2019 PBR Plan. As explained in Section 3.3.1 above, FBC is completing a Climate Change Risk Assessment to inform future planning to mitigate associated reliability risks.

Accordingly, FBC proposes to continue to report on SAIFI during the Rate Framework and to revise the benchmark and threshold as shown in the above table. The proposed benchmark and threshold incorporate the recent 2020 to 2023 results. Similar to the approach used to determine the threshold for the Current MRP, the proposed threshold is based on statistical analysis (i.e., standard deviation) of the SAIFI historical results from 2010 to 2019 and now inclusive of 2020 to 2023.

3.3.3 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the Canadian Electricity Association (CEA) as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X 100}$$

The table below provides a summary of the historical results for GFOR since the beginning of the Current MRP term.

Table 13: Results during the Current MRP for GFOR[8]

Description	2020	2021	2022	2023
GFOR	1.3%	0.2%	0.5%	0.4%
CEA Industry Average	4.6%	5.0%		

From 2020 to 2023, the results have been relatively stable from year to year and much lower than the CEA industry average of approximately 5.0 percent.

During the November 2023 consultation session, one of the interveners suggested that GFOR should be adjusted to report on times when the generators are most needed to run (i.e., during freshet) as opposed to total operating time. FBC considered this feedback but concluded the

8 2022 and 2023 CEA Industry Average results are not yet available at the time of filing the Application.

existing GFOR indicator is more appropriate because it allows for FBC's results to be compared to the industry standard. Further, the GFOR provides valuable information to FBC as it allows for internal comparison between years and provides indication of reliability issues or improvements.

Accordingly, FBC proposes to continue to report on the GFOR as an informational indicator.

3.3.4 Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Nelson, City of Penticton, City of Summerland and City of Grand Forks). There are 12 points of interconnection combined between the four customers as shown in the table below:

Table 14: Interconnection Points

Customer	Point of Interconnection
City of Nelson	Rosemont Substation
	Coffee Creek Substation
City of Penticton	Huth Avenue Substation (13kV)
	Huth Avenue Substation (8kV)
	Waterford Substation
	Westminister Substation
	R.G. Anderson Substation
City of Summerland	Summerland Substation
	Trout Creek Substation
City of Grand Forks	Ruckles Substation (DB1)
	Ruckles Substation (DB2)
	Donaldson Drive

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours} + \text{Total Outage Time}}$$

The table below provides a summary of the historical results for Interconnection Utilization since the beginning of the Current MRP term.

Table 15: Results during the Current MRP for Interconnection Utilization

Description	2020	2021	2022	2023
Interconnection Utilization	99.89%	99.90%	99.94%	99.99%

During the November 2023 consultation session, interveners suggested that the Interconnection Utilization metric should be changed from an informational indicator to a measured SQI with benchmarks and thresholds. FBC considered this proposal but concluded that Interconnection Utilization is more appropriate as an informational indicator. FBC added the Interconnection Utilization informational indicator as part of the suite of SQIs in the Current MRP to respond to concerns raised by the BC Municipal Electrical Utilities that the existing SQIs did not address wholesale/municipal customers' concerns. This informational indicator provides municipal customers with more detailed information regarding the reliability of service from FBC, and allows municipalities to benchmark their service against that of other FBC customers. However, the indicator does not address the overall reliability of the system and therefore is less relevant to the rest of FBC's customers. Changing the Interconnection Utilization informational indicator to an SQI with a benchmark and threshold could result in unintended prioritization of reliability for the specific municipalities who are FBC's wholesale customers over the other communities that FBC serves. The overall reliability of the FBC system is reflected in the SAIDI and SAIFI SQIs, and these indicators appropriately are measured against benchmarks and thresholds. The BCUC agreed with FBC's rationale in the MRP Decision,[9] stating that the reliability of the FBC system as a whole is already reflected in the SAIDI and SAIFI indicators and that Interconnection Utilization should therefore be an informational indicator.

Accordingly, FBC proposes to continue providing this metric as an informational indicator. The results during the Current MRP demonstrate that performance has been strong since inclusion of this indicator in the SQIs. In addition to reporting on the results of Interconnection Utilization in the Annual Reviews, FBC meets with municipal customers to review reliability and address concerns.

4. DISCONTINUED SERVICE QUALITY INDICATORS

None.

5. ANNUAL REVIEW PROCESS

FBC proposes to continue with the existing process for reviewing SQI performance at the Annual Reviews whereby FBC will review service quality for a year in the following year's Annual Review. This is consistent with previous BCUC direction and FBC believes this

[9] Page 99.

approach to reviewing SQIs has worked well over the past two multi-year rate framework periods (i.e., the 2014-2019 PBR Plan term and the Current MRP term).

In 2016, the BCUC issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The BCUC determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The BCUC stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

FBC will present year-to-date SQI actuals, the prior year end results and commentary of these results at the Annual Review workshop. Discussion of the SQI performance will serve to provide a better understanding of any issues affecting FBC's ability to meet the established benchmarks.

6. SUMMARY OF PROPOSED SERVICE QUALITY INDICATORS

The following table summarizes FBC's proposed service quality indicators along with the proposed benchmarks and thresholds. Proposed changes to the SQIs are highlighted in Green.

Table 16: Summary of Proposed Service Quality Indicators

Safety Indicators		Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	**Emergency Response Time**	>= 93%	90.6%	>=93%	90.6%
3 Year rolling average	**All Injury Frequency Rate**	<= 1.64	2.39	<=1.31	2.56
Responsiveness to Customer Needs Indicators					
Annual results	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual results	**Billing Index**	<= 3	5	<=3	5
Annual results	**Meter Reading Completion**	>= 98%	96%	Informational	Informational
Annual results	**Telephone Service Factor**	>= 70%	68%	>=70%	68%
Annual results	**Customer Satisfaction Index**	Informational	Informational	Informational	Informational
Annual results	**Average Speed of Answer**	Informational	Informational	Informational	Informational
Reliability Indicators					
Annual results	**System Average Interruption Duration Index - Normalized**	3.22	4.52	3.24	4.71
Annual results	**System Average Interruption Frequency Index - Normalized**	1.57	2.19	1.64	2.25
Annual results	**Generator Forced Outage Rate**	Informational	Informational	Informational	Informational
Annual results	**Interconnection Utilization**	Informational	Informational	Informational	Informational

Appendix C6-3

CONSENSUS RECOMMENDATION

ERICA HAMILTON
COMMISSION SECRETARY
Commission.Secretary@bcuc.com
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

Log No. 48608, 48575

VIA EMAIL
gas.regulatory.affairs@fortisbc.com
electricity.regulatory.affairs@fortisbc.com

February 4, 2015

Ms. Diane Roy
Director, Regulatory Services
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc. and FortisBC Inc. (FortisBC)
Multi-Year Performance Based Ratemaking Plans for 2014 through 2019
approved by Decisions and Orders G-138-14 and G-139-14
Service Quality Indicator Consultation Process Compliance Filing
Consensus Recommendation

The Commission is in receipt of your letter dated January 14, 2014, regarding the Consensus Recommendations of FortisBC and the stakeholders (collectively the Parties) concerning the Service Quality Indicator consultation process which was a compliance filing related to Orders G-138-14 and G-139-14.

The Consensus Recommendation put forward by the Parties represents a variance to determinations reached in the decisions related to the previously cited Orders. Specifically, acceptance of the Consensus Recommendations would, in effect, rescind or modify the intent of the following determination:

> **Taking these points into consideration, the Commission Panel determines the most effective way to manage SQIs is to set a satisfactory performance range**. The achievement of performance metrics that fall within this range is acceptable. Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences.[1]

While establishing thresholds and performance ranges, the Parties do not consider performance at a level inferior to a threshold to necessarily represent a "serious degradation of service," or warrant adverse financial consequences for FortisBC.[2]

The Parties consider that performance inferior to a threshold should warrant examination during the Annual Review process where it will be determined whether further action is warranted. However, the Parties do

[1] FBC 2014-2018 PBR Decision, p. 149, FEI p. 154.
[2] FEI-FBC-SQI Consensus Agreement, p. 5.

.../2

acknowledge that such a circumstance is a factor in determining whether there has been a "serious degradation of service and whether adverse financial consequences for FortisBC are warranted."[3]

There has been no formal request to reconsider or rescind this determination. However, the Parties have all signed on to the Consensus Recommendation and have developed a process allowing for an effective review process for SQI performance. Given the recommendations of the Parties and the need for regulatory efficiency, in these unique circumstances the Panel has reconsidered its original decision on its own motion and is therefore approving the Consensus Recommendation as filed.

Enclosed please find Commission Order G-14-15.

Yours truly,

Erica Hamilton

dg
Enclosure
cc: BCOAPO et al.
(tbraithwaite@bcpiac.com; support@bcpiac.com)

CEC
(cweafer@owenbird.com)

COPE
(jquail@qwlaw.ca)

BCSEA
(wjandrews@shaw.ca)

[3] Ibid, p. 5

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-14-15

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc. and FortisBC Inc.
for Approval of the Service Quality Indicator Performance Ranges

BEFORE: D. M. Morton, Panel Chair/Commissioner
D. A. Cote, Commissioner
N. E. MacMurchy, Commissioner

February 4, 2015

O R D E R

WHEREAS:

A. On January 14, 2015, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC), (collectively, FortisBC) filed the Consensus Recommendation package agreement (Recommendation) to comply with directives in the Commission's Decisions on FortisBC's Multi-Year Performance Based Ratemaking Plans for 2014 through 2019 (PBR Plans) accompanying Orders G-138-14 and G-139-14;

B. In accordance with the Decisions' directives, FortisBC conducted a consultative process with stakeholders and Commission staff, for the purpose of establishing satisfactory performance ranges (thresholds) for each Service Quality Indicator (SQI) benchmark (target);

C. On October 6, 2014, FortisBC invited all registered interveners in the PBR proceedings to participate in workshops to address the Commission's directives;

D. FortisBC held workshops on November 21, December 12 and December 19, 2014, to establish a performance band for each SQI benchmark in the Decisions;

E. The workshops attended by the following parties (Parties): FortisBC, Commercial Energy Consumers of British Columbia Association; British Columbia Old Age Pensioners Organization, et al.; Canadian Office and Professional Employees Union, Local 378; and British Columbia Sustainable Energy Association and Sierra Club British Columbia;

F. During the workshops, the Parties reached an agreement, the Consensus Recommendation, on the SQI thresholds that could apply to each SQI target;

G. The Consensus Recommendation put forward by the Parties represents a variance to determinations reached in the Decisions related to the previously cited orders. Specifically, acceptance of the Consensus Recommendations would, in effect, rescind or modify the intent of the following determination made in the Decisions accompanying Orders G-138-14 and G-139-14, which states:

> **Taking these points into consideration, the Commission Panel determines the most effective way to manage SQIs is to set a satisfactory performance range.** The achievement of performance metrics that fall within this range is acceptable. Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences.

H. No formal request to reconsider or rescind this determination was received. However, given the recommendations of the Parties and the need for regulatory efficiency in these unique circumstances, the Commission Panel considers that approval of the Consensus Recommendation is warranted and has therefore, on its own motion, reconsidered its original decision.

NOW THEREFORE, pursuant to sections 99 and 59-60 of the *Utilities Commission Act*, the Commission orders as follows:

1. The Consensus Recommendation attached as appendix A to this order is approved.
2. The Determination, made in the Decisions accompanying Orders G-138-14 and G-139-14, which states "Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences" is hereby rescinded.

DATED at the City of Vancouver, in the Province of British Columbia, this 4 TH day of February 2015.

BY ORDER

D. M. Morton
Panel Chair/Commissioner

Attachment

CONSENSUS RECOMMENDATION

OF

FORTISBC ENERGY INC., FORTISBC INC., COMMERCIAL ENERGY CONSUMERS OF BRITISH COLUMBIA, BRITISH COLUMBIA OLD AGE PENSIONERS ORGANIZATION, *ET AL*, CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, LOCAL 378; BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB BRITISH COLUMBIA

(COLLECTIVELY, THE "PARTIES")

ON THRESHOLDS FOR SERVICE QUALITY INDICATORS UNDER THE

FORTISBC ENERGY INC. AND FORTISBC INC. 2014-2019 PBR PLANS

RECITALS

A. On September 15, 2014, the Commission issued its Decisions (the "Decisions") on FortisBC Energy Inc.'s ("FEI") and FortisBC Inc.'s ("FBC", and together with FEI, "FortisBC") Applications for Approval of a Multi-Year Performance Based Rate Making Plan for 2014 through 2018.

B. As part of the Decisions, the Commission established Service Quality Indicators ("SQIs") for each of FEI and FBC for use under the FortisBC 2014-2019 PBR Plans. The Commission also established benchmarks to serve as a "target" for each SQI.

C. To establish the satisfactory SQI performance ranges around the benchmark "targets", the Commission directed FEI and FBC "in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory". This process was to take place prior to the first Annual Review. The Commission further stated:

> *"Consultation among the parties should form a part of the process with recommendations flowing from it. In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.*
>
> *In establishing the performance range for SQIs, the Panel expects the Companies and the stakeholders to take into consideration the following factors:*
>
> - *The variance that has been experienced in the benchmark historically;*
> - *The historic trend in the benchmark;*
> - *The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;*
> - *The sensitivity of the benchmark to external factors such as weather or economic conditions; and*

- *The impact of lower SQI levels on the provision of reliable, safe or adequate service.*

D. On October 6, 2014, FortisBC invited all registered interveners in the PBR proceeding to participate in workshops to address the Commission's directives. The following interveners elected to participate, while others declined:

- Commercial Energy Consumers of British Columbia ("CEC") Association;
- British Columbia Old Age Pensioners Organization, et al. ("BCOAPO");
- Canadian Office and Professional Employees Union, Local 378 ("COPE"); and
- British Columbia Sustainable Energy Association and Sierra Club British Columbia ("BCSEA").

E. FortisBC held workshops at the Commission Hearing Room on the following dates:

- November 21, 2014;
- December 12, 2014; and
- December 19, 2014.

F. Representatives of all Parties were present at each workshop. A representative of Commission Staff (Mr. Don Flintoff) attended each of the workshops as an observer.

G. Minutes of the workshops are appended as to the Consensus Recommendation as Attachments A through C. The minutes were reviewed and approved by all Parties, and Mr. Don Flintoff also provided feedback that was incorporated.

- Attachment A: Minutes from November 21, 2014 workshop
- Attachment B: Minutes from December 12, 2014 workshop
- Attachment C: Minutes from December 19, 2014 workshop

H. The Parties exchanged information and data at the workshops. Copies of documents provided by all parties at the workshops are appended to this Consensus Recommendation as Attachments D through R. Brief descriptions of the documents and their authorship are as follows:

- Attachment D: Material provided by FortisBC at the November 21, 2014 workshop outlining its preliminary recommendations on performance ranges.

- Attachment E: Excerpt (page 152) from the Commission's Decision on FortisBC's Multi-Year Performance Based Ratemaking Plan for the years 2014 through 2018 showing the approved service quality indicators and the benchmarks. This was provided by FortisBC for reference at the November 21, 2014 workshop.

- Attachment F: Historical performance data for all SQIs with benchmarks was requested by stakeholders at the November 21, 2014 workshop. In addition, stakeholders requested the standard deviation and range (maximum minus minimum) calculations using 2010 to 2012 period, 2011 to 2013 period, 2012 to 2014 September YTD. This was provided to stakeholders by FortisBC in an email on November 27, 2014.

- Attachment G: Historical data on the number of Gas IBEW employees on the day shifts for the period 2010 to 2014 was requested by stakeholders at the November 21, 2014 workshop. This was provided to stakeholders by FortisBC in an email on November 27, 2014.

- Attachment H: Clarification and documentation related to the normalization methodology used by FortisBC for its SAIDI and SAIFI results was requested by stakeholders at the November 21, 2014 workshop. This was provided to stakeholders by FortisBC in an email on December 4, 2014.

- Attachment I: COPE's alternative proposal to FortisBC's proposed recommendations for SQI acceptable performance ranges. This was provided to stakeholders by COPE in an email on December 4, 2014.

- Attachment J: Comments provided by CEC regarding SQI ranges proposed by FortisBC in an email on December 5, 2014.

- Attachment K: Comments provided by BCSEA regarding FortisBC's SQI consultation process in an email on December 5, 2014.

- Attachment L: Comments provided by Mr. Norm Gabana in a separate discussion with FortisBC representatives on December 1, 2014. The discussion was documented by FortisBC and confirmed by Mr. Norm Gabana in an email on December 3, 2014 as accurate.

- Attachment M: Updated SQI graphs from the first workshop to include different thresholds using recent years' data (i.e. 2010 to 2012). This was provided to stakeholders by FortisBC at the December 12, 2014 workshop.

- Attachment N: Updated table of the approved SQIs along with the benchmarks, FortisBC's initial proposed thresholds, CEC suggested thresholds and FortisBC's amended thresholds. This was provided to stakeholders by FortisBC at the December 12, 2014 workshop as a separate handout.

- Attachment O: Speaking notes regarding COPE's alternative proposal provided by COPE at the December 12, 2014 workshop.

- Attachment P: Historical annual SQI performance data redefined to 3 year, 4 year, 5 year and 6 year rolling averages along with the thresholds recalculated to match. This analysis was requested by stakeholders in support of the alternative SQI threshold methodology presented by CEC. This analysis was provided by FortisBC for illustrative purposes with respect to the CEC proposal in an email on December 17, 2014.

- Attachment Q: Updated table (i.e. same as Attachment N) of the approved SQIs along with the benchmarks, FortisBC's initial proposed thresholds, CEC suggested thresholds and FortisBC's amended thresholds. This was provided again to stakeholders by FortisBC at the December 19, 2014 workshop to help facilitate the discussion.

- Attachment R: The same data as provided in Attachment P except in graphical form for the 3 year and 6 year rolling averages. This was provided by CEC at the December 19, 2014 workshop to help facilitate the discussion.

I. The Parties considered the factors identified for consideration in the PBR Decisions.

J. Parties brought different perspectives to the discussions and different beliefs as to the appropriate approach for determining the thresholds. For instance, CEC expressed their view that (i) service quality should be provided at the benchmark levels established by the Commission and (ii) this service quality should be provided annually and in aggregate over time. FortisBC, in response to this point, expressed its view that (i) service quality metrics are subject to inherent and/or uncontrollable volatility over time, and (ii) the Commission Decisions recognized that there is a range of "satisfactory" performance around benchmarks. These and other issues discussed by the Parties are set out in further detail in the attached documents.

K. Parties have acted in good faith, and have made appropriate compromises on individual SQI thresholds in the interest of reaching agreement on an overall package that will achieve the objectives established by the Commission.

L. The following terms represent the agreement of the Parties as to an appropriate package recommendation to the Commission. The Parties request that the Commission incorporate the recommendation into an Order for the two subject utilities.

AGREED TERMS OF THE CONSENSUS RECOMMENDATION

The Parties agree as follows:

Definition of Performance Ranges

The Parties have defined performance ranges for each SQI as being the range between the benchmark set by the Commission in the Decisions and a "threshold" agreed to in this Consensus Recommendation.

Operation of the SQI Performance Ranges

1. Objectives

The objectives of the performance ranges and the review process of results are to:

a. identify instances of potential deterioration of service quality during the PBR period for which the utility may be accountable

b. give due recognition to normal volatility which may produce SQI scores inferior to the benchmarks that do not represent serious degradation of service

c. provide a transparent and efficient Annual Review process in which all stakeholders have confidence

Based on how the Parties have established the thresholds and performance ranges, the Parties do not consider performance inferior to a threshold to necessarily

- represent a "serious degradation of service", or
- warrant adverse financial consequences for FortisBC

but rather they consider that this circumstance warrants examination at an Annual Review to determine whether further action is warranted. However, performance inferior to a threshold is a factor the Commission may consider in determining whether there has been a "serious degradation of service" and whether adverse financial consequences for FortisBC are warranted.

For clarity, the Parties did not come to any agreement on the implications of circumstances where there is performance inferior to the benchmark in non-consecutive years, or where the average performance over the PBR term is below the benchmark. The Parties have differing views on these matters. However, the Parties agree that nothing in this Consensus Recommendation is intended to limit (a) any right that a Party would otherwise have to raise these matters before the Commission or (b) any right that a Party would otherwise have to object to the matter being raised, or to oppose the substance of the arguments raised.

2. Process

The Parties recommend a two-phase process for the examination of SQI results at each Annual Review:

Phase 1 – Identification of SQI results for discussion at Annual Review

The utility that is subject to the Annual Review in question will provide the results and a brief discussion for all SQIs required by the PBR Decision. It will provide additional explanation on an SQI at an Annual Review if either of the two following circumstances apply to the SQI:

a. the SQI score in the prior calendar year during the term of the PBR Plan is inferior to the agreed threshold; or

b. the SQI score in two successive calendar years during the term of the PBR Plan has been between the benchmark and the threshold.

The specification of the two circumstances which will trigger the utility's obligation to provide further explanation at the Annual Review does not eliminate the ability of the utility or any stakeholder to raise any issue or concern in relation to any SQI, or to ask information requests on any SQI as part of the Annual Review, or to propose a change to a threshold based on new information.

Phase 2 – Determination of any financial consequences

After consideration of the information provided by the utility at an Annual Review explaining any SQI performance outside of the performance range, a stakeholder may initiate a complaint with the Commission. The Commission will determine whether any financial consequences for the utility should be imposed and if so, the nature and degree of those consequences.

Determinations of any financial consequences will be made based on whether there has been a serious degradation of service and having regard to the other factors identified by the Commission in the following passage from the Decision:

> *"When assessing the magnitude of any reduction in each Company's share of the incentive earnings, the Commission will take into account the following factors:*
>
> - *Any economic gain made by each Company in allowing service levels to deteriorate;*
> - *The impact on the delivery of safe, reliable and adequate service;*
> - *Whether the impact is seen to be transitory or of a sustained nature; and*
> - *Whether each Company has taken measures to ameliorate the deterioration in service.*

Agreed Thresholds

1. Considered collectively, and in the context of the overall PBR Plan, the thresholds set out below establish an appropriate performance range around the benchmark specified for each SQI.

Approved Service Quality Indicators (SQIs)

Performance Measure	FEI Indicator	FEI Benchmark	FEI Threshold (Fixed value as indicated for full PBR term) [1]	FBC Indicator	FBC Benchmark	FBC Threshold (Fixed value as indicated for full PBR term) [1]
Safety SQIs						
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	Percent of calls responded to within two hours	93%	90.6%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	N/A	N/A	N/A
All Injury Frequency Rate	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	2.95	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64	2.39
Public contacts with pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	N/A	N/A	N/A
Responsiveness of Customer Needs SQIs						
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	Percent of customers who achieved call resolution in one call	78%	72%
Billing Index	Measure of customer bills produced meeting performance criteria	5	<=5	Measure of customer bills produced meeting performance criteria	5	<=5
Meter Reading Accuracy	Number of scheduled meters that were read	95%	92%	Number of scheduled meters that were read	97%	94%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	Percent of calls answered within 30 seconds or less	70%	68%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	93.8%	N/A	N/A	N/A
Reliability SQIs						
System Average Interruption Duration Index - Normalized	N/A	N/A	N/A	3 year average of SAIDI (average of cumulative customer outage time)	2.22	2.62
System Average Interruption Frequency Index - Normalized	N/A	N/A	N/A	3 year average of SAIFI (average customer outage)	1.64	2.50

1) Determined by adjusting the benchmark for the range for each year of the PBR term and equals the indicated fixed value applicable for the full term of the PBR.

2. Any Party is at liberty to apply to the Commission, in conjunction with an Annual Review, to change a threshold based on new information.

"Serious Degradation of Service"

The Parties have established the thresholds in recognition of the Commission's determination that "*the achievement of performance metrics that fall within this range is acceptable*". The Parties consider performance between the benchmark and the threshold to represent normal volatility. The Parties' views regarding performance inferior to a threshold are set out in section 1.

"Package" Agreement

3. The Parties acknowledge that the Consensus Recommendation was a product of compromise with the intention of achieving the overall objectives outlined in the Commission's Decisions.

4. The Parties intend for this Consensus Recommendation to be presented to the Commission for acceptance and incorporation into an Order, in its entirety. As such, the Parties agree to

   (a) request that the Commission convene a procedural conference to consider next steps in the event that the Commission is unwilling to approve the Consensus Recommendation as a whole; and

   (b) support a reconsideration application seeking acceptance of the Consensus Recommendation in the event that the Commission approves provisions that depart from the Consensus Recommendation.

Counterparts

Authorized signatories of the Parties have executed this agreement in counterparts with the same effect as if all Parties had signed the same document. All counterparts will be construed together and will constitute one and the same instrument.

FortisBC, per authorized signatory	January 13, 2015 Date
British Columbia Old Age Pensioners Organization, *et al*, per authorized signatory	January 14, 2015 Date
British Columbia Sustainable Energy Association and Sierra Club British Columbia, per authorized signatory	Date

to represent normal volatility. The Parties' views regarding performance inferior to a threshold are set out in section 1.

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Counterparts

Authorized signatories of the Parties have executed this agreement in counterparts with the same effect as if all Parties had signed the same document. All counterparts will be construed together and will constitute one and the same instrument.

FortisBC, per authorized signatory	Date
British Columbia Old Age Pensioners Organization, *et al*, per authorized signatory	Date
British Columbia Sustainable Energy Association and Sierra Club British Columbia, per authorized signatory	2015-01-13 Date

WILLIAM J. ANDREWS
Barrister & Solicitor
1958 Parkside Lane
North Vancouver, BC, V7G 1X5

Canadian Office and Professional Employees Union,
Local 378, per authorized signatory

January 13, 2015
Date

Commercial Energy Consumers of British Columbia,
per authorized signatory

January 13, 2015
Date

Commercial Energy Consumers of British Columbia,
per authorized signatory

January 13, 2015
Date

Appendix D

SUPPORTING STUDIES

Appendix D2-1

FEI DEPRECIATION STUDY

2022 Depreciation Study

Calculated Annual Depreciation Accrual Rates
As of December 31, 2022

Headquarters
293 Boston Post Rd West, Ste 500
Marlborough, MA, USA 01752
508.263.6200

Washington, D.C. Office
1300 19th St NW, Ste 620
Washington, DC, USA 20036
202.587.4470

Concentric Advisors, ULC
200 Rivercrest Drive SE, Ste 277
Calgary, AB, Canada T2C 2X5
403.257.5946

April 1, 2024

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Attention: Lilyana Tabakova
Asset Accounting Manager

Dear Lilyana;

As requested, Concentric Advisors, ULC has developed annual depreciation accrual rates for FortisBC Energy Inc. for gas distribution plant in service as of December 31, 2022. The subsequent report presents a detailed description of the methods and parameters used in the formulation of depreciation life and net salvage estimates, as well as the calculations and tabulations of the service life, net salvage, and annual and accrued depreciation.

Concentric gratefully acknowledges the assistance of FortisBC Energy personnel in the completion of the report.

Respectfully submitted,

Larry E Kennedy
Senior Vice President

Donna Bourne
Project Manager

LEK\ta
Project No.100197

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to FortisBC Energy Inc.'s ("FortisBC Energy" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to all gas manufacturing, transmission, distribution and general plant accounts, as of December 31, 2022. The purpose of the study is to determine the annual depreciation accrual rates and amounts applicable to the original cost of gas plant, as of December 31, 2022. Concentric acknowledges that it has a duty to provide opinion evidence to the British Columbia Utilities Commission (BCUC) that is fair, objective and non-partisan. This study determines annual depreciation accrual rates for assets in service as of December 31, 2022.

This study utilizes the Straight-Line method and the Average Life Group ("ALG") procedure applied on a remaining life basis for each depreciable group of assets. The calculations were based on attained ages and estimated average service life and forecasting net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2022, are amortized over the remaining life of assets.

FortisBC Energy's accounting policy has not changed since the last depreciation study was prepared. It continues to recognize the recovery of future costs of removal over the average service of the assets, and therefore includes estimated costs of removal percentages into the depreciation rate calculations.

These estimates of salvage values present the continuation of a moderated process to full cost recovery to avoid sharp increases in costs of removal recovery.

Concentric recommends the calculated annual depreciation accrual rates set forth in this study apply specifically to plant in service, as of December 31, 2022, as summarized by Tables 1, 1A, and 1B (pages 5-2 to 5-13). Supporting data and calculations are provided within this study.

This study results in an annual depreciation expense accrual of $266 million, when applied to depreciable plant balances, as of December 31, 2022 of $8.3 billion. The study results are summarized at an aggregate functional group level as follows:

Functional Group	Original Cost	Annual Accrual	
Intangible Plant	$106,006,959	14.14%	$14,985,808
Manufacturing Plant	$7,998,323	3.62%	$289,747
LNG Plant	$753,949,990	2.89%	$21,814,977
Transmission Plant	$2,151,946,097	2.09%	$44,878,206
Distribution Plant	$4,866,389,799	3.19%	$155,242,720
Bio Gas	$18,959,747	4.28%	$811,023
NG for Transportation	$35,925,601	5.01%	$1,800,124
General Plant	$382,683,701	6.83%	$26,139,886
TOTAL	**$8,323,860,216**	**3.20%**	**$265,962,492**

SECTION 2

2 INTRODUCTION

2.1 Scope

This report sets forth the results of the depreciation study for assets of FortisBC Energy to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of FortisBC Energy's gas distribution, transmission and general plant assets as of December 31, 2022. The rates and amounts are based on the Straight-Line method of depreciation, incorporating the ALG procedure applied on a remaining life basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the system in service as of December 31, 2022.

The service life estimates resulting from this study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2022;
- a review of FortisBC Energy's practices and outlooks as they relate to plant operation and retirement;
- review of the Company's upcoming capital and retirement projects; and
- consideration of current practice in the gas distribution industry, including knowledge of service life estimates used for other gas distribution companies.

The depreciation accrual rates presented in this study are based on generally accepted methods and procedures for calculating depreciation. The estimated survivor curves used in this study are based on studies incorporating actual data through 2022 for most accounts.

2.2 Plan of Study

This study is presented in the following order:

Section 1	Study Highlights, presents a brief summary of the depreciation study and results
Section 2	Introduction, contains statements with respect to the plan and the basis of the study
Section 3	Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.
Section 4	Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation
Section 5	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 1A, and 1B
Section 6	Show the results of the Retirement Rate Analysis
Section 7	Presents the Net Salvage Calculations
Section 8	Presents Detailed Depreciation Calculations
Section 9	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10	Estimation of Net Salvage is an overview of the Net Salvage Analysis

2.3 Depreciation

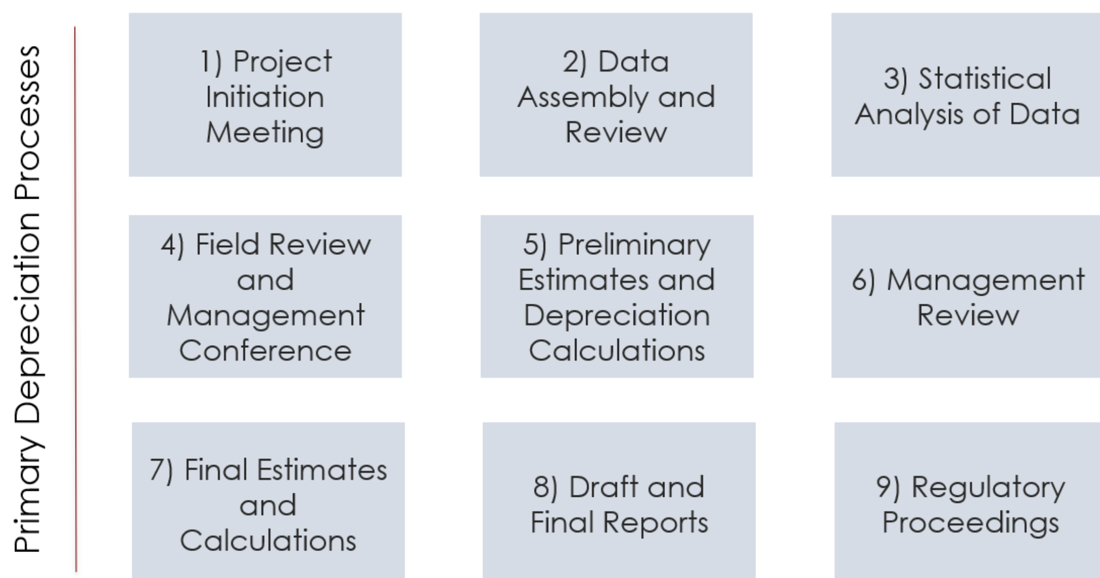
A full and comprehensive depreciation study includes the following components:

1. supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account;
3. selection of an appropriate grouping procedure;
4. detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
5. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

Consistent with the current FortisBC Energy practice, amortization accounting continues to be recommended for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.



2.4 Service Life and Net Salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed judgment, which incorporated a review of the Company's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other natural gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for natural gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in Tables 1, 1A, and 1B (Section 5, pages 5-2 to 5-13) of this study. The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

2.5 Information Provided by FortisBC Energy

FortisBC Energy has provided Concentric with the required information, as of December 31, 2022, for all accounts being studied. This information has been compiled from the plant accounting records and includes the following:

- current balances by vintage year for each account (aged balances). The balances provide the amount of investment sorted by installation year currently in operation. This file is only inclusive of current plant in service and does not include any retirement information;
- detailed retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired as well as the original cost of the asset being retired; and
- detailed cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.6 Data Reconciliation

The above data was reviewed and reconciled to FortisBC Energy's control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;

- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that the cost of removal, retirement and gross salvage data over time corresponds to plant and accounting records and their analyses reflects an accurate representation of net salvage.

SECTION 3

3 DEVELOPMENT OF DEPRECIATION PARAMETERS

3.1 Depreciation

The development of the depreciation calculations requires the input of an average service life, a retirement dispersion curve (i.e., Iowa curve) and net salvage recommendations. Together, the average service life, retirement dispersion curve, and net salvage recommendation are referred to as the depreciation parameters. Additionally, to complete the depreciation calculations, the calculation methods must be established. Specifically, the selection of the depreciation method must establish three types of additional input:

1. the choice of a depreciation method;
2. a basis upon which to apply the method, and
3. in the case of group assets, a procedure to use in grouping the assets.

In this study, the depreciation rates for FortisBC Energy have been calculated in accordance with the Straight-Line method, the ALG procedure and applied using the Remaining Life technique where any accumulated depreciation variances are trued-up within the depreciation rate calculations over the composite remaining life of each account.

Depreciation, as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art and changes in demand and requirements of public authorities.[1]

When considering the action of the elements, the average service life and net salvage calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utility plant has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other natural forces of nature

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[1] Part 201 - Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act - Definitions 12(B)

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing gas utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.1.1 Depreciation Methods & Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group ("ALG") and Equal Life Group ("ELG") procedures.

In the ALG Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

While the Equal Life Group Procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Straight-Line Method, Average Life Group Procedure is a commonly used depreciation calculation that has been widely accepted in jurisdictions throughout North America. Concentric recommends its continued use.

In conducting a thorough depreciation study, consideration must be given to the appropriate calculation procedure. Given the recently released Climate Change Accountability Act, Concentric reviewed the impacts of the legislation on the appropriate depreciation procedures. After such consideration, and discussion with FortisBC Energy, the continued use of the ALG Procedure is recommended at this time in the specific circumstances for FortisBC Energy. These considerations included discussion of the potential use of hydrogen blending within the company, within the long-term use with the transmission and distribution systems.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and ALG Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to correct the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.1.2 Energy Transition and Hydrogen Blending

Long life assets such as those comprising FortisBC Energy's system can be restricted not only by physical forces of retirement such as wear and tear and physical deterioration, but also, and to a much greater extent, by economic forces of retirement. Specifically, the changing North American marketplace for natural gas demand and the rapidly emerging trend of decarbonization legislation may have a significant impact on the estimated service lives of the FortisBC Energy system.

There are several factors affecting the economic viability of the FortisBC Energy system. Long life assets, such as natural gas transmission and distribution systems, are subject to a number of different forces of economic retirement, including changes in legislation constricting the use of carbon-based fuels.

While there is strong evidence that the future of natural gas may be impacted by climate change legislation, it is still unknown to what extent this change will impact FortisBC Energy's system. The introduction of hydrogen blending, for example, may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel, and the level to which hydrogen can be blended into the transmission and distribution stream is further researched. Ultimately, if hydrogen blending proves to be a viable option to meet the legislative requirements, the overall impact to FortisBC may be lessened. However, it may also be required that the move from carbon-based fuels necessitates a greater electrification of the grid, in which case there may be a life shortening impact on the FortisBC Energy system.

The concept of hydrogen blending into natural gas pipelines has been the topic of significant debate over the past few years. In October 2022 a technical report was released by the National Renewable Energy Laboratory ("NREL") titled 'Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology."[2] This report provides a detailed overview of the many studies and pipeline experience of hydrogen blending in pipelines. This NREL report provides detailed analysis of the many topics related to hydrogen blending and the potential for hydrogen blending natural gas pipelines as an approach to achieving near-term emission reductions and early market access for hydrogen technologies such as electrolysers.

The report summarizes findings from literature and recognizes that additional research across the entire hydrogen and natural gas supply chain will be needed to fill current knowledge gaps and better inform decision makers on future blending projects.

The future growth and retirement programs of the FortisBC Energy system may be significantly different than the retirement patterns experienced in the past. While future retirements that are caused by physical forces of retirement such as wear and tear and changes in technology of the assets will continue, it is reasonable to anticipate that the utilization of large groups of assets may change due to the implementation of climate change legislation. Consistent with the potential change in the utilization of the assets, it could be assumed that large scale retirement of assets may be required in the periods between now and 2050.[3] However, as noted above, the overall impact, if any, is unknown at this time. As such, Concentric has intentionally limited life extension estimates on long-lived asset groups instead of implementing an economic planning horizon. Concentric notes that future studies may require additional consideration of alternative depreciation procedures and energy transition mitigation strategies as more information becomes known.

The impact of energy transition on natural gas distribution and transmission pipelines has begun to become a topic of debate in the rate proceedings of gas utilities throughout North America. Common depreciation practice is to deal with anticipated large-scale retirements through the introduction of an economic planning horizon within the depreciation rate calculations or shortened average service life estimates. Additionally, the use of the ELG procedure has also been considered a "first step" in the recovery of the utilities' investment in distribution and transmission systems. Concentric notes that the recent proceeding before the Ontario Energy Board (docket number EB-2022-200) involving Enbridge Gas Inc. considered the possibility of an economic planning horizon and the use of the ELG procedure. All parties involved in this proceeding agreed that energy transition was an overarching concern in selecting depreciation parameters and procedures and, as such, the use of the ELG procedure and the concept of an economic planning horizon was widely debated throughout the

[2] Topolski, Kevin, Evan P. Reznicek, Burcin Cakir Erdener, Chris W. San Marchi, Joseph A. Ronevich, Lisa Fring, Kevin Simmons, Omar Jose Guerra Fernandez, Bri-Mathias Hodge, and Mark Chung. 2022. Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5400-81704.Kevin Simmons, Omar Jose Guerra Fernandez, Bri-Mathias Hodge, and Mark Chung. 2022. Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5400-81704.Kevin Simmons, Omar Jose Guerra Fernandez, Bri-Mathias Hodge, and Mark Chung. 2022. Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5400-81704.

[3] As discussed in the Climate Change Accountability Act, which targets an 80% reduction in GHG emissions by 2050.

proceeding. The Ontario Energy Board ultimately directed the use of the ALG procedure and did not order the use of an economic planning horizon at this time.

Concentric is also aware of the recent British Columbia Utilities Commission decision in Order G-19-24 regarding the Pacific Northern Gas ("PNG") revenue requirement. This order required PNG to investigate the use of an economic planning horizon and report on the findings in PNG's next rate application, to be filed in 2026. However, Concentric notes that the PNG system is largely transmission, where the concept of an economic planning horizon has had more regulatory support, as compared to the FortisBC System. There has also been a recent decision from the California Public Utilities Commission rejecting the use of the Unit of Production method of depreciation and mandating the continued use of the ALG procedure. Also, Concentric is aware of the Colorado Public Utilities Commission, which ordered the use of the ELG procedure, notwithstanding the fact that the applicant had proposed the ALG procedure in their depreciation study.

While other North American jurisdictions have considered similar concerns in setting depreciation parameters and procedures, Concentric's review did not identify any jurisdictions, including the examples provided, that have adopted economic planning horizons when setting depreciation rates for natural gas distribution utilities for the purposes of mitigating energy transition concerns. At this time, the future impacts of the relevant climate change legislation have not been sufficiently studied, nor have specific programs been put into place that would provide the indications of the changes in utilization levels. As the energy transition continues to evolve, a change in depreciation methodology may or may not be required in the future, depending on the impact that the energy transition has on the existing gas asset system. However, Concentric notes that future depreciation studies of the FortisBC Energy system may require the introduction of an economic planning horizon into the depreciation rate calculations.

3.2 Estimation of Survivor Curves

3.2.1 Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as Iowa type curves. The Iowa curves *"…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."* [4] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e., origin-moded curves) where the greatest frequency of

[4] Robley Winfrey, *Statistical Analyses of Industrial Property Retirements*, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion ("residual measure"). The residual measure is based on a least square solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the residual measure, the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely-used practice of fitting Iowa curves up to 1 percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. Concentric will however recognize the observed data points beyond the 1 percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 9.

3.2.2 Survivor Curve and Net Salvage Judgements

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from Concentric's studies of other gas utilities. A detailed peer review is compiled to establish a range of reasonableness for the Iowa curve and net salvage estimate for each account. While the peer review is considered an appropriate test of the estimates, it should never be viewed as definitive. Differences in characteristics such as the account structure, climate conditions, regulatory environment, and area of service must always be considered when reviewing a peer study.

Concentric has maintained an extensive database of natural gas utilities depreciation studies completed throughout North America. In preparing the FortisBC Energy Depreciation Study, Concentric views the following utilities with similar characteristics to FortisBC Energy to be the most relevant peer utilities. As such, the following utilities were considered in the peer review:

- Pacific Northern Gas (PNG) - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, PNG has an extensive transmission and distribution network throughout the province of BC and is therefore subject to similar forces of retirement, cost of removal, and legislative requirements.

- APEX (Formerly AltaGas) - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, APEX has a transmission and distribution network located in small and medium sized cities in Western Canada and is therefore subject to similar forces of retirement and cost of removal.

- ATCO Gas - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, Atco Gas has an extensive distribution network located in large municipalities in Western Canada and is therefore subject to similar forces of retirement and cost of removal. Atco Gas has a similar size customer base to FortisBC Energy.
- Gazifère - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, Gazifère has a distribution network located in small sized municipalities in Quebec and is therefore subject to similar forces of retirement and cost of removal.
- Centra Gas Manitoba - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, Centra Gas Manitoba has a transmission and distribution network located in Manitoba and is therefore subject to similar forces of retirement and cost of removal.
- EGI - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, EGI has an extensive transmission and distribution network located in large municipalities in Ontario and is therefore subject to similar forces of retirement and cost of removal. EGI is Canada's largest and one of North America's largest natural gas distribution and storage utilities.
- Energir - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, Energir has a transmission and distribution network located in Quebec and is therefore subject to similar forces of retirement and cost of removal.

The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. The forecasting of a probable future included management and operational staff interviews. The combination of the historical experience and the probable future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable tables of this study (Section 5). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

The estimates of net salvage for the mass property accounts were based mostly in part on historical data related to actual retirement activity for the years 2000 through 2022, for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, and on a cumulative moving average basis.

The following discussion, dealing with a number of accounts that comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 442.00 – LNG PLANT - STRUCTURES AND IMPROVEMENTS - TILBURY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
101,760,421	1.22%	25-L2	28-L2	-10%	-10%

The investment in the LNG Plant – Structures and Improvements - Tilbury is approximately $101.8 million, representing 1.22 percent of the total depreciable plant studied. This account contains structures and improvements used in connection with Tilbury LNG Plant.

The currently approved life parameter is an Iowa 25-L2. The retirements, additions, and other plant transactions, for the period 1972 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1985 through 2022, of $838,700 were recorded. The currently approved Iowa 25-L2 produced a fit with a related residual measure of 1.9362. An Iowa 28-L2 produced a better fit with a related residual measure of 1.5839, as depicted on page 6-2. Since the previous study, the surviving plant balance has increased by more than 1000 percent. Large additions of new plant relating to structures and improvements have led to the increase in average service life of this account. Conversations with operational staff and subject matter experts indicated that the recommended life of 28 years is in line with their opinion to make the life more consistent with the Mt. Hayes plant. There is not a large peer database to draw from in order to develop a peer comparison for these assets. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion that there is no change in practice and the future retirement activity should not be materially different from what has been experienced in the past. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 28-L2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 28-L2 to represent the future expectations for the investment in this account.

FortisBC Energy has incurred $2,000 in cost of removal in this account between 2008-2022. The historical net salvage activity shows a range from 0 percent to negative 8 percent. A three-year band analysis shows a range from 0 percent to negative 33 percent. A five-year band analysis produces a range from 0 percent to negative 33 percent. The full-depth band for this account shows an amount of negative 8 percent. Canadian natural gas transmission and distribution utilities have net salvage ranging from negative 3 percent to negative 40 percent. As such, with limited cost of removal data and minimal change to the retirement history, Concentric is not recommending a change from the approved negative 10 percent salvage rate at this time.

ACCOUNT 442.01 – LNG PLANT - STRUCTURES AND IMPROVEMENTS – MT. HAYES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
19,098,348	0.23%	25-L2	28-L2	-10%	-10%

The investment in the LNG Plant – Structures and Improvements - Mt. Hayes is approximately $19.1 million, representing 0.23 percent of the total depreciable plant studied. This account contains structures and improvements used in connection with Mt. Hayes LNG Plant.

The currently approved life parameter is an Iowa 25-L2. The retirements, additions, and other plant transactions, for the period 2011 through 2022, were analyzed by the retirement rate method. No retirements for this period were recorded. The currently approved Iowa 25-L2 produced a fit with a related residual measure of 0.0948. An Iowacon 28-L2 produced a better fit with a related residual measure of 0.0702, as depicted on page 6-5. There is not a large peer database to draw from in order to develop a peer comparison for these assets. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion that consistent maintenance and continuous process monitoring will lead to a longer life. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 28-L2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 28-L2 to represent the future expectations for the investment in this account.

As there have been no recorded retirements, there has not been any recorded cost of removal or gross salvage expenditures. As such, Concentric is not recommending a change from the approved negative 10 percent salvage rate at this time.

ACCOUNT 443.00 – LNG PLANT - EQUIPMENT - TILBURY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
183,674,557	2.21%	40-S4	57-S4	-20%	-20%

The investment in the LNG Plant – Equipment - Tilbury is approximately $183.7 million, representing 2.21 percent of the total depreciable plant studied This account contains costs of dikes, tanks and associated equipment used for the storage of liquid natural gas and liquefied petroleum gas for the Tilbury Plant.

The retirements, additions, and other plant transactions, for the period 1972 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1998 through 2022, of $167,115 were recorded. The currently approved Iowa 40-S4 produced a fit with a related residual measure of 0.3385. An Iowa 57-S4 produced a better fit with a related residual measure of 0.0326, as depicted on page 6-7. Since the previous study, the surviving plant balance has increased by almost 1000 percent. Large additions of new plant relating to LNG Plant equipment have led to the increase in average service life of this account. However, there is not a large peer database to draw from in order to develop a peer comparison for these assets.

Interviews with FortisBC Energy operations and management staff have indicated that the currently approved average service life of 40 years is not consistent with their expectations. Conversations with FortisBC Energy operational staff and subject matter experts indicated that an increase in life more in line with the Mt. Hayes Plant is recommended. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 57-S4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 57-S4 to represent the future expectations for the investment in this account.

The net salvage study indicates that the currently approved negative 20 percent net salvage is still appropriate. There have been no recorded retirements since 2008 for this account, and there has not been any net salvage recorded in the years since the last depreciation study. As such, Concentric recommends maintaining the currently approved negative 20 percent net salvage estimate.

ACCOUNT 449.00 – LNG PLANT – OTHER EQUIPMENT - TILBURY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
28,955,236	0.35%	27-R3	27-R3	-10%	-5%

The investment in the LNG Plant – Other Equipment - Tilbury is approximately $28.9 million, representing 0.35 percent of the total depreciable plant studied.

The currently approved life parameter is an Iowa 27-R3. The retirements, additions and other plant transactions, for the period 1970 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1985 through 2022, of $3,933,480 were recorded. The currently approved and proposed Iowa 27-R3 produced a related residual measure of 1.4980, as depicted on page 6-36. Discussions with FortisBC Energy operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for retirements in this account. The additional data since the last study has not indicated an immediate need to change the recommended life for this account. The most consequential retirement experience occurs at age 20, with this retirement comprising 18 percent of total retirement activity. As there is not a large peer database to draw from in order to develop a peer comparison for these assets, no peer comparison was completed. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 27-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 27-R3 to continue to represent the future expectations for the investment in this account.

FortisBC Energy has incurred $294,771 in cost of removal in this account between 2008-2022. The historical net salvage activity shows a range from negative 8 percent to negative 11 percent. A three-year band analysis produces a range from negative 11 percent to negative 36 percent. A five-year band analysis produces a range from negative 11 percent to over negative 200 percent. The full-depth band for this account shows an amount of negative 8 percent. With a data trend of limited cost of removal activity, Concentric is recommending a net salvage percentage of negative 5 percent due to FortisBC Energy‘s recent experience and near-term requirements.

ACCOUNT 462.00 – TRANSMISSION PLANT – COMPRESSOR STRUCTURES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
46,138,194	0.55%	30-S4	30-S4	-3%	-3%

The investment in Transmission Plant – Compressor Structures is approximately $46.1 million, representing 0.55 percent of the total depreciable plant studied. This account consists of the material and installation costs associated with structures for compressor sites.

The currently approved life parameter is an Iowa 30-S4. The retirements, additions and other plant transactions, for the period 1965 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1974 through 2022, of $1,097,479 were recorded. The currently approved and proposed Iowa 30-S4 produced a related residual measure of 3.6084, as depicted on page 6-41. Discussions with FortisBC Energy operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for retirements in this account. The additional data since the last study has not indicated an immediate need to change the recommended life for this account. The most consequential retirement experience occurs at age 18, with this retirement comprising 42 percent of total retirement activity. A review of peer Canadian natural gas transmission utilities indicates a life of between 30 and 55 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 30-S4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 30-S4 to continue to represent the future expectations for the investment in this account.

FortisBC Energy has incurred $11,175 in cost of removal in this account between 2011-2022. The historical net salvage activity shows a range from negative 2 percent to negative 3 percent. A three-year band analysis produces a range from negative 2 percent to negative 12 percent. A five-year band analysis produces a range from negative 2 percent to negative 3 percent. The full-depth band for this account shows an amount of negative 2 percent. Canadian natural gas transmission peers have net salvage ranging from negative 3 percent to negative 5 percent. Concentric recommends maintaining the currently approved negative 3 percent net salvage estimate due to FortisBC Energy's recent experience and near-term requirements.

ACCOUNT 465.00 – TRANSMISSION PLANT – TRANSMISSION PIPELINES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
1,679,785,040	20.18%	65-R4	65-R4	-20%	-23%

The investment in Transmission Plant – Transmission Pipelines is approximately $1.7 billion, representing 20.18 percent of the total depreciable plant studied. FortisBC Energy gas transmission pipelines account consists of completely cathodic protected steel pipeline mains. The mains range in size from ¾ inch up to 42 inch in diameter. System monitoring includes the transmission system being pigged, along with conditional assessments, ongoing maintenance, and inspections and repairs occurring when needed.

The currently approved life parameter is an Iowa 65-R4. The retirements, additions and other plant transactions, for the period 1957 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1962 through 2022, of $27,064,547 were recorded. The currently approved and proposed Iowa 65-R4 produced a related residual measure of 0.2113, as depicted on page 6-50. Discussions with FortisBC Energy operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for retirements in this account. The additional data since the last study has not indicated an immediate need to change the recommended life for this account. There has been an increase of approximately 35 percent in the retirement experience in this account, up from about $20.9 million in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same range of ages as it did previously. A review of peer Canadian natural gas transmission utilities indicates a life of between 65 and 70 years. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 65-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 65-R4 to continue to represent the future expectations for this account.

FortisBC Energy has incurred $6,974,175 in cost of removal in this account between 2002-2022. The historical net salvage activity shows a range from negative 2 percent to negative 30 percent. A three-year band analysis produces a range from negative 3 percent to negative 94 percent. A five-year band analysis produces a range from negative 2 percent to negative 87 percent. The full-depth band for this account shows an amount of negative 30 percent. Canadian natural gas transmission peers have net salvage ranging from negative 20 percent to negative 30 percent. FortisBC has also seen increases in cost of removal since 2018 of over $2 million. Given the concept of gradualism, Concentric is recommending a net salvage rate of negative 23 percent. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

ACCOUNT 465.11 TRANSMISSION PLANT – INTERMEDIATE PIPE - WHISTLER

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
59,041,836	0.71%	65-R3	65-R3	-20%	-20%

The investment in Transmission Plant – Intermediate Pipe is approximately $59.0 million, representing 0.71 percent of the total depreciable plant studied.

This account contains additions installed since 2008. There have been no recorded retirements at the time of this study. Due to the lack of retirements, the retirement rate analysis is not useful for this account.

Given the lack of retirement history, Concentric does not recommend any change to the life or mode of this account. Concentric viewed that the comments from the operational and management personnel was a reasonable expectation for this account and that an Iowa 65-R3 is consistent with the operations and management comments.

Given the lack of retirement history, Concentric does not recommend any change to the net salvage estimate at this time. Comments from operational and management personnel indicate that negative 20 percent is still an appropriate estimate.

ACCOUNT 466.00 TRANSMISSION PLANT – COMPRESSOR EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
203,053,266	2.44%	37-R4	37-R4	-3%	-3%

The investment in Transmission Plant – Compressor Equipment is approximately $203.0 million, representing 2.44 percent of the total depreciable plant studied. This account contains electric and gas turbine compressor equipment.

The currently approved life parameter is an Iowa 37-R4. The retirements, additions and other plant transactions, for the period 1965 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1973 through 2022, of $7,303,847 were recorded. The currently approved and proposed Iowa 37-R4 produced a related residual measure of 2.5464, as depicted on page 6-56. Discussions with FortisBC Energy operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for retirements in this account. The additional data since the last study has not indicated an immediate need to change the recommended life for this account. There has been an increase of approximately 26 percent in the retirement experience in this account, up from about $5.8 million in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same age range of plant as it did previously. A review of peer Canadian natural gas transmission utilities indicates a life of between 30 and 40 years. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 37-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 37-R4 to continue to represent the future expectations for this account.

FortisBC Energy has incurred $158,521 in cost of removal in this account between 2003-2022. The historical net salvage activity shows a range from negative 2 percent to negative 22 percent. A three-year band analysis produces a range from negative 1 percent to negative 36 percent. A five-year band analysis produces a range from negative 1 percent to negative 18 percent. The full-depth band for this account shows an amount of negative 3 percent. Canadian natural gas transmission peers have net salvage ranging from negative 2 percent to negative 7 percent. At this time, Concentric recommends that a negative 3 percent net salvage estimate continue to be used in the depreciation calculations within this study.

ACCOUNT 467.10 TRANSMISSION PLANT – MEASURING AND REGULATING EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
93,258,936	1.12%	37-R1.5	37-R1.5	-5%	-5%

The investment in Transmission Plant – Measuring and Regulating Equipment is approximately $93.3 million, representing 1.12 percent of the total depreciable plant studied. This account includes the equipment that monitors the operation of meters, gauges and other measuring and regulating facilities.

The currently approved life parameter is an Iowa 37-R1.5. The retirements, additions and other plant transactions, for the period 1959 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1968 through 2022, of $8,975,146 were recorded. The currently approved Iowa 37-R1.5 produced a related residual measure of 0.9768, as depicted on page 6-61. Retirements in this account in the previous study equaled $7,461,889, for an increase of 20 percent in the current study, with much of the retirement experience occurring earlier in the life of the account. Discussions with FortisBC Energy operational and management staff indicated that the currently approved 37 year life is still a good representation of the historical life and future expectations for retirements in this account. The additional data since the last study has not indicated an immediate need to change the recommended life for this account. A review of peer Canadian natural gas transmission utilities indicates a life of between 40 and 45 years. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 37-R1.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 37-R1.5 to continue to represent the future expectations for the investment in this account.

FortisBC Energy has incurred $338,863 in cost of removal in this account between 2004-2022. The historical net salvage activity shows a range from negative 3 percent to negative 7 percent. A three-year band analysis shows a range from negative 1 percent to negative 45 percent. A five-year band analysis produces a range from negative 1 percent to negative 25 percent. The full-depth band for this account shows an amount of negative 5 percent. Canadian natural gas transmission peers have net salvage ranging from negative 7 to negative 35 percent. At this time, Concentric recommends that a negative 5 percent net salvage estimate continue to be used in the depreciation calculations within this study.

ACCOUNT 467.20 TRANSMISSION PLANT – TELEMETRY EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
21,931,673	0.26%	10-L1.5	10-L1.5	0%	0%

The investment in Transmission Plant – Telemetry is approximately $21.9 million, representing 0.26 percent of the total depreciable plant studied.

The currently approved life parameter is an Iowa 10-L1.5. The retirements, additions and other plant transactions, for the period 1968 through 2022, were analyzed by the retirement rate method.

Retirements, for the period 1973 through 2022, of $11,991,496 were recorded. The currently approved 10-L1.5 produces a residual measure of 1.5843 as depicted on page 6-64. Discussions with FortisBC Energy operational and management staff indicated that the 10-year life is still a good representation of the historical life and future expectations. The additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same range of ages of plant as it did previously. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 10-L1.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 10-L1.5 to represent the future expectations for the investment in this account.

FortisBC Energy has incurred $29,170 in cost of removal in this account between 2011-2022. The historical net salvage activity shows a range from 0 percent to negative 1 percent. A three-year band analysis shows a range from negative 1 percent to negative 40 percent. A five-year band analysis produces a range from negative 1 percent to negative 24 percent. The full-depth band for this account shows an amount of 0 percent. There is not a large peer database to draw from in order to develop a peer comparison for these assets. With cost of removal amounts incurred of less than $3000 since the previous study, Concentric recommends no change to net salvage estimates at this time. As such, Concentric recommends that a 0 percent net salvage estimate continue to be used in the depreciation calculations within this study.

ACCOUNT 473.00 – DISTRIBUTION PLANT - SERVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
1,535,297,088	18.44%	47-R2	47-R2	-70%	-85%

The investment in Distribution Plant – Services is approximately $1.5 billion, representing 18.44 percent of the total depreciable plant studied. This account contains all services in the distribution plant, consisting of predominantly ¾ inch steel and plastic service lines, with newer services predominantly consisting of plastic.

The currently approved life parameter is an Iowa 47-R2. The retirements, additions and other plant transactions, for the period 1900 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1963 through 2022, of $124,318,225 were recorded. The currently approved Iowa 47-R2 produced a related residual measure of 1.7744. Retirements in this account in the previous study equaled $104,807,999, for an increase of 18 percent, with much of the retirement experience occurring earlier in the life of this account. The 47-year life still captures the initial retirements up until age 30. Discussions with FortisBC Energy operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for retirements in this account. The ages of plant in service that have experienced retirement activity have shown no material changes since the last study. There are earlier retirements occurring that will need to be monitored moving forward but the current experience does not constitute a change to what is currently approved. A review of peer Canadian natural gas distribution utilities indicates a life of between 45 and 70 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 47-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 47-R2 to represent the future expectations for the investment in this account.

FortisBC Energy has incurred over $152 million in cost of removal in this account between 2002-2022. The historical net salvage activity shows a range from negative 11 percent to negative 154 percent. A three-year band analysis shows a range from negative 11 percent to negative 322 percent. A five-year band analysis produces a range from negative 32 percent to negative 299 percent. The full-depth band for this account shows an amount of negative 154 percent. Canadian gas distribution peers have net salvage ranging from negative 32 to negative 125 percent. With increases to cost of removal since the previous study of over $58 million, Concentric views that a negative 85 percent net salvage percent would be reasonable at this time. Given the concept of gradualism, Concentric is recommending a net salvage rate of negative 85 percent. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

ACCOUNT 474.00 – DISTRIBUTION PLANT – METER/REGULATOR INSTALLATIONS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
165,174,993	1.98%	20-S0 & 23-SQ	23-SQ	-20%	-20%

The investment in Distribution Plant – Meter/Regulator Installations is approximately $165.2 million, representing 1.98 percent of the total depreciable plant studied.

Approximately 77 percent of this account relates to the installation costs of older gas meters, which are due to be completely retired in 2035. The remaining 23 percent is related to station regulator assets. The investment relating to installation of meters costs follow an amortization accounting method and are expected to be completely retired by 2035. The remaining 13 percent of this account, relating to installation of station regulators, follow traditional retirement accounting practices and are expected to be in service until the end-of-life of the asset. It has been confirmed by FortisBC Energy staff that these assets are almost fully amortized.

As the majority of the investment in this account currently relates to amortizated assets, there was no retirement rate analysis prepared. Concentric viewed that the comments from the operational and management staff were the most reasonable expectation for the equipment in this account. As such, the Iowa 23-SQ is recommended for the meter installation and station regulator assets based on the indications from management and operations, and on the professional judgement of Concentric.

FortisBC Energy has incurred almost $50 million in cost of removal in this account between 2002-2022. The historical net salvage activity shows a range from negative 1 percent to negative 46 percent. A three-year band analysis shows a range from negative 1 percent to negative 504 percent. A five-year band analysis produces a range from negative 2 percent to negative 433 percent. The full-depth band for this account shows an amount of negative 46 percent. Canadian natural gas distribution peers have net salvage ranging from negative 20 to negative 30 percent. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended salvage for this account is consistent with their opinion on the future cost of removal and retirement activity within this account. Concentric is recommending a net salvage percentage of negative 20 percent due to FortisBC Energy's recent experience and near-term requirements. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

ACCOUNT 475.00 – DISTRIBUTION PLANT – SYSTEMS - MAINS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
2,281,611,431	27.41%	65-R2.5	65-R2.5	-25%	-30%

The investment in Distribution Plant – Mains is approximately $2.3 billion, representing 18.44 percent of the total depreciable plant studied. This account contains steel and plastic distribution mains. The company has an ongoing replacement program which began in 2013. Currently, approximately seven kilometers per year are replaced on a proactive basis. These replacements are targeted based on age and risk of future problems. Almost all of the pipe being replaced is older vintage. This program is expected to be ongoing with no foreseeable plans to increase or decrease the retirements. FortisBC Energy began to install plastic mains in 1981.

The currently approved life parameter is an Iowa 65-R2.5. The retirements, additions and other plant transactions, for the period 1924 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1963 through 2022, of $61,988,407 were recorded. The currently approved Iowa 65-R2.5 produced a related residual measure of 1.2175, as depicted on page 6-85. Discussions with FortisBC Energy operational and management staff indicated that the currently approved life is still a good representation of the historical life and future expectations for retirements in this account. Since the previous study, the surviving plant balance has increased by almost 60 percent, due to large investment in FortisBC Energy's Lower Mainland Project. However, the ages of plant in service that have experienced retirement activity have shown no material changes since the last study. There are earlier retirements occurring that will need to be monitored moving forward but the current experience does not warrant a change to what is currently approved. A review of peer Canadian natural gas distribution utilities indicates a life of between 55 and 80 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 65-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 65-R2.5 to represent the future expectations for the investment in this account.

FortisBC Energy has incurred over $17 million in cost of removal in this account between 2002-2022. The historical net salvage activity shows a range from negative 1 percent to negative 39 percent. A three-year band analysis shows a range from negative 1 percent to negative 80 percent. A five-year band analysis produces a range from negative 7 percent to negative 74 percent. The full-depth band for this account shows an amount of negative 39 percent. Canadian natural gas distribution peers have net salvage ranging from negative 25 to negative 90 percent. With increases to cost of removal since the previous study of over $7 million, Concentric views that a negative 30 percent net salvage percent would be reasonable at this time. Given the concept of gradualism, Concentric is recommending a net salvage rate of negative 30 percent. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

ACCOUNT 477.10 – DISTRIBUTION PLANT – MEASURING AND REGULATING

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
227,560,333	2.73%	33-R2	34-R2.5	-12%	-12%

The investment in Distribution Plant – Measuring and Regulating is approximately $227.6 million, representing 2.71 percent of the total depreciable plant studied. This account contains a mix of measuring and regulating equipment including regulators, valves, line heaters, filters and process flow piping. This equipment is generally very easy to replace and size up or down as needed. Consequently, measuring and regulating stations are often built with the intention of being sized properly for the current need while being able to expand later; this means that there are many smaller value retirements to right size the equipment but far fewer large retirements due to stations no longer suiting the intended need.

The currently approved life parameter is an Iowa 33-R2. The retirements, additions and other plant transactions, for the period 1957 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1959 through 2022, of $24,623,938 were recorded. The currently approved Iowa 33-R2 produced a related residual measure of 0.8323. The proposed Iowa 34-R2.5 produces a better visual and mathematical fit with a residual measure of 0.8249 as depicted on page 6-95. Retirements in this account in the previous study equaled $17,828,251, and retirements in this account as at the time of the study equaled $24,623,939, for an increase of 38 percent. Much of this increase (approximately $6.8 million) occurred between ages 12 and 16. The overall exposure amount of roughly $252.2 million is, however, relatively unaffected by this increase in retirement experience, and as such, the proposed R2.5 mode curve does a better job of fitting the retirements from age 25 upwards. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion on the future retirement activity within this account. A review of peer Canadian natural gas distribution utilities indicates a life of between 30 and 45 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 34-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 34-R2.5 to represent the future expectations for the investment in this account.

FortisBC Energy incurred $2,769,121 in cost of removal in this account between 2002-2022. The historical net salvage activity shows a range from negative 1 percent to negative 16 percent. A three-year band analysis shows a range from negative 1 percent to negative 40 percent. A five-year band analysis produces a range from negative 6 percent to negative 35 percent. The full-depth band for this account shows an amount of negative 14 percent. Canadian natural gas distribution peers have net salvage ranging from negative 7 to negative 30 percent. Concentric is recommending a net salvage percentage of negative 12 percent due to FortisBC Energy's recent experience and near-term requirements.

ACCOUNT 477.20 – DISTRIBUTION PLANT – TELEMETRY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
29,036,466	0.35%	20-R3	20-R3	-5%	-5%

The investment in Distribution Plant – Telemetry is approximately $29 million, representing 0.35 percent of the total depreciable plant studied.

The currently approved life parameter is an Iowa 20-R3. The retirements, additions and other plant transactions, for the period 1958 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1971 through 2022, of $2,985,542 were recorded. The currently approved Iowa 20-R3 produced a related residual measure of 2.3505, as depicted on page 6-99. Retirements in this account in the previous study equaled $1,679,165 resulting in an increase of 78 percent. Much of this increase (approximately $1.3 million) occurred between ages 18 and 30. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion on the future retirement activity within this account. A review of peer Canadian natural gas distribution utilities indicates a life of 20 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 20-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 20-R3 to represent the future expectations for the investment in this account.

FortisBC Energy incurred $159,818 in cost of removal in this account between 2004-2022. The historical net salvage activity shows a range from negative 1 percent to negative 8 percent. A three-year band analysis shows a range from negative 1 percent to negative 259 percent. A five-year band analysis produces a range from negative 1 percent to negative 13 percent. The full-depth band for this account shows an amount of negative 6 percent. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended salvage for this account is consistent with their opinion on the future cost of removal and retirement activity within this account. Concentric is recommending a net salvage percentage of negative 5 percent due to FortisBC Energy's recent experience and near-term requirements.

ACCOUNT 478.10 – DISTRIBUTION PLANT - METERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
316,909,877	3.81%	18-R4	18-R4/5-SQ	0	0

The investment in Distribution Plant – Meters is approximately $316.9 million, representing 3.18 percent of the total depreciable plant studied. This account contains all commercial and residential meters. FortisBC Energy has a replacement program to replace all current meters and install new ultrasonic meters in 2025 and 2026. Measurement Canada standard S-S-06 has a large influence on the average service life of the units in this account. As consistent with the previous study, this standard still dictates that each vintage has significant testing after 10 years, then again after eight years, with the next testing following six more years.

Approximately 60 percent of this account relates to the meters subject to retirement under the AMI Project. The remaining 40 percent of this account follows traditional retirement accounting practices and the assets are expected to be in service until end-of-life. At this time, Concentric recommends that the annual depreciation accrual should be weighted in accordance with the retirement practices for each group of assets in this account. With this approach, the resultant depreciation accrual rate will recognize the straight-line amortization related to meters as well as the typical retirement pattern of the non-amortized metering assets.

As the majority of the investment in this account currently relates to amortized assets, there was no retirement rate analysis prepared for the assets expected to be retired as part of the AMI Project. The Iowa 5-SQ is recommended for the meter assets based on the indications from management and operations, and on the professional judgement of Concentric. When calculating the depreciation rate for this portion of the account, adjustments were made to the book reserve to account for accumulated depreciation shortfalls that FortisBC Energy has been approved to collect through a deferral account.[5]

FortisBC Energy incurred $1,505,949 in cost of removal in this account between 2008-2022. The historical net salvage activity shows a range from 1 percent to 2 percent. A three-year band analysis shows a range from negative 1 percent to 3 percent. A five-year band analysis produces a range from negative 1 percent to 2 percent. The full-depth band for this account shows an amount of 1 percent. Canadian natural gas distribution peers have net salvage ranging from 0 percent to 1 percent. Concentric is recommending a net salvage percentage of 0 percent due to FortisBC Energy's recent experience and near-term requirements.

ACCOUNT 482.20 – STRUCTURES - MASONRY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
132,011,784	1.59%	60-R2	65-R2	-4%	-10%

The investment in Structures - Masonry is approximately $132.0 million, representing 1.59 percent of the total depreciable plant studied. This account includes buildings in the FortisBC Energy portfolio, including the head office located in Surrey and purchases in Burnaby.

The currently approved life parameter is an Iowa 60-R2. The retirements, additions, and other plant transactions, for the period 1960 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1978 through 2022, of $2,995,148 were recorded. The currently approved Iowa 60-R2 produced a fit with a related residual measure of 1.0378. An Iowa 65-R2 produced a better fit with a related residual measure of 0.7720, as depicted on page 6-110. Retirements in this account in the previous study equaled $2,619,342, for an increase of 11 percent. Most of the retirement experience occurs before age 25. The overall exposure amount of roughly

[5] Refer to BCUC Order C-2-23 regarding FortisBC Energy's AMI Project Application where two deferral accounts were approved: Existing Meter Cost Recovery deferral account for the recovery of the remaining book value of existing meters replaced with new AMI meters; Previously Retired Meter Cost Recovery deferral account for the recovery of remaining rate base value for meters previously retired.

$135.0 million is, however, relatively unaffected by the increase in retirement experience, and as such, the proposed 65-year life does a better job of fitting the retirements from age 25 onwards. Conversations with FortisBC Energy staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion on the future retirement activity within this account. A review of peer Canadian natural gas utilities indicates a life of between 35 and 75 years. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 65-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 65-R2 to represent the future expectations for the investment in this account.

FortisBC Energy has incurred $490,682 in cost of removal in this account between 2008-2022. The historical net salvage activity shows a range from negative 7 percent to negative 17 percent. A three-year band analysis shows a range from negative 2 percent to negative 3,469 percent. A five-year band analysis produces a range from negative 3 percent to negative 254 percent. The full-depth band for this account shows an amount of negative 17 percent. Canadian natural gas peers have net salvage ranging from 0 to negative 15 percent. With increases to cost of removal of over $200,000 from the previous study, Concentric is recommending a net salvage percentage of negative 10 percent due to FortisBC Energy's recent experience and near-term requirements.

ACCOUNT 484.00 – GENERAL PLANT - VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
54,721,373	0.66%	7-L1	10-L1	15%	15%

The investment in General plant- vehicles is approximately $54.7 million, representing 0.66 percent of the total depreciable plant studied. This account contains vehicles ranging from on-call trucks to fleet vehicles that travel shorter distances, and are used less than average fleet vehicles.

The currently approved life parameter is an Iowa 7-L1. The retirements, additions, and other plant transactions, for the period 1957 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1962 through 2022, of $24,850,648 were recorded. The currently approved Iowa 7-L1 produced a fit with a related residual measure of 0.6832. An Iowa 10-L1 produced a better fit with a related residual measure of 0.1148, as depicted on page 6-114. Retirements in this account in the previous study equaled $22,057,466, for an increase of 12.7 percent. Most of the retirement experience occurs up until age 21. As a result, the fit to the historical data is made substantially better by lengthening the life by three years. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion on the future retirement activity within this account. A review of peer Canadian natural gas general plant accounts indicates a life of between 7 and 16 years. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 10-L1 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 10-L1 to represent the future expectations for the investment in this account.

FortisBC Energy has retained close to $580,000 in cost of removal in this account between 2008-2022. The historical net salvage activity shows a range from 1 percent to 42 percent. A three-year band analysis shows a range from 2 percent to 127 percent. A five-year band analysis produces a range from 2 percent to 131 percent. The full-depth band for this account shows an amount of 42 percent. Canadian natural gas peers have net salvage ranging from 0 to 25 percent. Concentric is recommending a net salvage percentage of 15 percent due to FortisBC's recent experience and near-term requirements.

ACCOUNT 485.20 – GENERAL PLANT – HEAVY MOBILE EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
12,179,351	0.15%	9-L1.5	10-L1.5	15%	0%

The investment in General Plant- Vehicles is approximately $12.2 million, representing 0.15 percent of the total depreciable plant studied. This account contains heavy-duty assets, including heavy mobile and bucket trucks.

The currently approved life parameter is an Iowa 9-L1.5. The retirements, additions, and other plant transactions, for the period 1957 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1969 through 2022, of $4,249,448 were recorded. The currently approved Iowa 9-L1.5 produced a fit with a related residual measure of 0.9579. An Iowa 10-L1.5 produced a better fit with a related residual measure of 0.7745, as depicted on page 6-120. Retirements in this account in the previous study equaled $3,375,229, for an increase of about 26 percent in the current study. Most of the retirement experience occurs before age 19. As a result, the fit to the historical data is made better by lengthening the life by one year. Conversations with FortisBC Energy operational staff and subject matter experts indicated that the recommended life for this account is consistent with their opinion on the future retirement activity within this account. A review of peer Canadian natural gas general plant accounts indicates a life of between 10 and 20 years. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 10-L1.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 10-L1.5 to represent the future expectations for the investment in this account.

Given the lack of salvage and cost of removal activity, Concentric is basing its net salvage recommendation on peers and operational and management personnel discussions. Canadian natural gas distribution peers have net salvage ranging from 0 to 30 percent Concentric is recommending a decrease in net salvage from 15 percent to 0 percent. Comments from operational and management personnel indicate that zero percent is an appropriate estimate due to the lack of cost of removal and salvage data.

3.3 Other Accounts

The above analysis provides the consideration relating to over 87 percent of the depreciable plant. Many of the accounts related to the remaining 13 percent of the depreciable plant studied, as of December 31, 2022, are subjected to amortization accounting. This is proposed for a number of accounts that represent numerous units of property but very small portions of depreciable gas plant in service.

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because (normally) all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group procedure (Also known as the Average Service Life procedure), the rate of annual depreciation is based on the average service life of the group - this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

In the determination of the depreciation rates in this study, the use of the Average Life Group procedure has been continued. While the Equal Life Group procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Average Life Group procedure was used in order to conform to past Company practices and approvals by the BCUC.

4.2 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts. The accounts and their amortization periods are as follows:

Account	Title	Amortization Period, Years	Net Salvage Percentage
402.01	Computer Software Applications – 8 Years	8	-
402.02	Computer Software Applications – 5 Years	5	-
474.02	Distribution Plant – New Meter Installations	22	-
483.10	Computer Hardware	4	-
483.20	Computer Software (12.5%)	8	-
483.30	Office Equipment	15	-
483.40	Furniture	20	-
486.00	Small Tools/Equipment	20	-
488.10	Telephone Equipment	15	-
488.20	Radio Equipment	15	-

For calculating annual amortization amounts, as of December 31, 2022, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. Any amount of book reserve in vintages older than the amortization period has been deducted from both the original cost as well as from accumulated depreciation. This approach assumes that the original costs of vintages, older than the chosen amortization period, will have been retired along with their accumulated depreciation.

The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age, to its amortization period. An annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

Amortization accounting is a widely used method across various regulated utilities, including electric and gas utilities.

5 RESULTS OF STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the Average Life Group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other gas distribution utilities. The results of the statistical analysis of service life are presented in Section 6, beginning on page 6-2 of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2022, are presented in account sequence starting on page 8-2 of the supporting documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

FortisBC Energy Inc.

TABLE 1 - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

TOTAL

Account	Account Description (1)	Survivor Curve (2)	Net Salvage Percent (3)	Original Cost as of Dec. 31, 2022 (4)	Book Depreciation Reserve (5)	Future Accruals (6)	Calculated Annual Accural Amount (7)	Calculated Annual Accural Rate (8)	Composite Remaining Life (9)
INTANGIBLE PLANT									
401.01	Franchises and Consents	40-SQ	0	196,933	139,813	57,120	4,923	2.50 *	8.85
402.01	Computer Software Application - 8 Years	8-SQ	0	77,966,230	27,328,837	50,637,394	9,745,779	12.50 *	5.20
402.02	Computer Software Application - 5 Years	5-SQ	0	25,937,204	9,246,051	16,691,153	5,187,441	20.00 *	3.22
402.03	Intangible Plant	40-SQ	0	1,906,591	1,293,414	613,177	47,665	2.50 *	15.99
TOTAL INTANGIBLE PLANT				**106,006,959**	**38,008,115**	**67,998,844**	**14,985,808**	**14.14**	
MANUFACTURING PLANT									
432.00	Structures	40-SQ	0	1,312,030	458,017	854,013	32,801	2.50 *	25.13
433.00	Equipment	20-SQ	0	1,201,139	353,228	847,910	60,057	5.00 *	14.86
434.00	Holders	40-SQ	0	2,948,088	944,289	2,003,799	73,702	2.50 *	27.39
436.00	Compressor Equipment	25-SQ	0	366,583	197,836	168,746	14,663	4.00 *	12.97
437.00	Measuring and Regulating Equipment	20-SQ	0	2,170,484	1,334,791	835,694	108,524	5.00 *	12.57
TOTAL MANUFACTURING PLANT				**7,998,323**	**3,288,162**	**4,710,161**	**289,747**	**3.62**	
LNG PLANT									
442.00	Structures and Improvements - Tilbury	28-L2	(10)	101,760,421	16,150,570	95,785,894	4,062,462	3.99	23.63
442.01	Structures and Improvements - Mt Hayes	28-L2	(10)	19,098,348	8,810,723	12,197,459	661,208	3.46	18.42
443.00	Gas Holders - Storage - Tilbury	57-S4	(20)	183,674,557	30,272,486	190,136,983	3,687,366	2.01	50.91
443.05	Gas Holders - Storage - Mt Hayes	60-R5	(20)	61,836,512	12,955,937	61,247,878	1,244,774	2.01	49.20
448.10	Piping - Mt Hayes	40-R3	(10)	12,714,468	3,621,715	10,364,199	344,785	2.71	30.05
448.11	Piping - Tilbury	40-R3	(10)	52,842,616	5,196,459	52,930,419	1,445,832	2.74	36.61
448.20	Pre-treatment - Mt Hayes	25-R3	(10)	29,347,745	14,031,839	18,250,681	1,231,063	4.19	14.82
448.21	Pre-treatment - Tilbury	25-R3	(10)	34,099,015	5,975,605	31,533,312	1,482,414	4.35	21.27
448.30	Liquefaction Equipment - Mt Hayes	40-R3	(20)	28,939,534	9,221,864	25,505,577	865,057	2.99	29.48
448.31	Liquefaction Equipment - Tilbury	40-R3	(20)	88,823,153	11,384,214	95,203,570	2,632,225	2.96	36.17
448.40	Send Out Equipment - Mt Hayes	40-R3	(10)	23,743,248	7,021,926	19,095,647	644,460	2.71	29.63
448.41	Send Out Equipment - Tilbury	40-R3	(10)	10,675,476	783,562	10,959,462	293,427	2.75	37.35
448.50	Substation and Electrical - Mt Hayes	40-R3	(20)	21,788,252	6,907,992	19,237,910	652,839	3.00	29.47
448.51	Substation and Electrical - Tilbury	40-R3	(20)	38,245,155	4,499,459	41,394,727	1,141,507	2.98	36.26
448.60	Control Room - Mt Hayes	15-R3	0	6,664,704	4,608,745	2,055,959	334,028	5.01	6.00
448.61	Control Room - Tilbury	15-R3	0	4,608,084	950,217	3,657,866	310,986	6.75	11.77
449.00	Local Storage Equipment - Tilbury	27-R3	(5)	28,955,236	21,298,708	9,104,290	559,503	1.93	10.95
449.01	Local Storage Equipment - Mt Hayes	30-R3	(5)	6,133,465	1,293,879	5,146,259	221,041	3.60	23.30
TOTAL LNG PLANT				**753,949,990**	**164,985,900**	**703,808,091**	**21,814,977**	**2.89**	
TRANSMISSION PLANT									
462.00	Compressor Structures	30-S4	(3)	46,138,194	22,921,083	24,601,257	1,426,386	3.09	16.20
463.00	Measuring and Regulating Structures	40-S2.5	(15)	25,989,383	9,762,187	20,125,603	688,952	2.65	28.32
464.00	Other Structures	30-R4	(5)	6,871,016	4,283,231	2,931,336	244,914	3.56	11.99
465.00	Transmission Pipeline	65-R4	(23)	1,679,785,040	533,624,429	1,532,511,171	32,690,223	1.95	47.20

FortisBC Energy Inc.

TABLE 1 - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

TOTAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
465.11	Intermediate Pipe - Whistler	65-R3	(20)	59,041,836	10,178,265	60,671,938	1,100,299	1.86	55.16
465.30	Mains - Mt. Hayes	65-SQ	(20)	6,306,953	1,292,471	6,275,872	116,436	1.85 *	54.01
466.00	Compressor Equipment	37-R4	(3)	203,053,266	114,478,511	94,666,354	4,892,736	2.41	18.48
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5	(5)	5,929,381	2,050,877	4,174,973	142,918	2.41	29.08
467.10	Measuring and Regulating Equipment	37-R1.5	(5)	93,258,936	33,326,963	64,594,919	2,245,126	2.41	27.37
467.20	Telemetry Equipment	10-L1.5	0	21,931,673	11,502,033	10,429,640	1,322,914	6.03	6.49
467.31	Measuring and Regulating Equipment - Whistler	37-R1.5	(7)	313,344	139,560	195,718	7,302	2.33	26.80
468.00	Communications Equipment	19-R3	0	3,327,075	4,092,061	- 764,986	-	0.00	4.04
TOTAL TRANSMISSION PLANT				**2,151,946,097**	**747,651,670**	**1,820,413,795**	**44,878,206**	**2.09**	
DISTRIBUTION PLANT									
472.00	Structures	45-R2.5	(20)	54,417,590	14,216,408	51,084,700	1,379,867	2.54	36.52
473.00	Services	47-R2	(85)	1,535,297,088	507,535,183	2,332,764,429	70,259,091	4.58	34.41
474.00	Meter/Regulator Installations	23-SQ	(20)	165,174,993	118,994,597	79,215,395	8,617,826	5.22 *	6.19
474.02	New Meter Installations	22-SQ	0	240,060,967	56,196,067	183,864,900	10,911,862	4.55 *	16.98
475.00	Systems - Mains	65-R2.5	(30)	2,281,611,431	647,924,161	2,318,170,700	44,976,399	1.97	51.38
476.00	NGV Fuel Equipment	7-L0	0	613,588	2,149,456	- 1,535,868	-	0.00	3.04
477.10	Measuring and Regulating	34-R2.5	(12)	227,560,333	74,278,132	180,589,440	6,967,763	3.06	25.17
477.20	Telemetry	20-R3	(5)	29,036,466	8,510,348	21,977,941	1,533,813	5.28	14.36
478.10	Meters	18-R4/5-SQ	0	316,909,877	201,108,391	86,566,002	10,147,315	3.20	**
478.20	Instruments	35-SQ	0	15,707,467	8,098,600	7,608,867	448,785	2.86 *	16.84
TOTAL DISTRIBUTION PLANT				**4,866,389,799**	**1,639,011,342**	**5,260,306,506**	**155,242,720**	**3.19**	
BIO GAS									
472.20	Structures and Improvements	36-R1.5	(10)	1,517,854	178,831	1,490,808	45,108	2.97	32.94
474.10	Meters/Regulator Installations	19-S0	(25)	802,187	142,755	859,979	51,119	6.37	16.73
475.10	Mains - Municipal Land	65-R2.5	(25)	1,752,805	243,121	1,947,886	33,748	1.93	57.72
475.20	Mains - Private Land	65-R2.5	(25)	410,314	22,688	490,204	7,877	1.92	62.23
477.40	Measuring and Regulating	30-R2	0	4,319,983	708,109	3,611,874	140,067	3.24	25.71
478.30	Meters	18-R2.5	0	84,213	17,680	66,533	4,355	5.17	14.93
418.10	Purification Overhauls	20-SQ	0	20,423	8,841	11,582	1,021	5.00 *	12.00
418.20	Purification Upgrader	20-SQ	(5)	10,051,967	3,994,609	6,559,957	527,728	5.25 *	12.48
TOTAL BIO GAS				**18,959,747**	**5,316,634**	**15,038,824**	**811,023**	**4.28**	
NG FOR TRANSPORTATION									
476.10	CNG Disp Equipment	20-SQ	0	17,120,865	4,254,815	12,866,050	856,043	5.00 *	15.02
476.20	LNG Disp Equipment	20-SQ	0	13,713,753	4,914,155	8,799,598	685,688	5.00 *	13.11
476.30	CNG Foundation	20-SQ	0	3,161,249	853,717	2,307,532	158,062	5.00 *	14.61
476.40	LNG Foundation	20-SQ	0	1,048,809	454,944	593,865	52,440	5.00 *	11.95
476.50	LNG Pumps	10-SQ	0	76,880	87,810	- 10,930	7,688	10.00 *	1.37
476.60	CNG Dehydrator	20-SQ	0	804,044	185,642	618,402	40,202	5.00 *	15.43

FortisBC Energy Inc.

TABLE 1 - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

TOTAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate		Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
TOTAL NG FOR TRANSPORTATION				**35,925,601**	**10,751,084**	**25,174,517**	**1,800,124**	**5.01**		
GENERAL PLANT										
482.10	Stuctures (Frame)	25-R2	(4)	27,203,434	13,853,295	14,438,276	851,471	3.13		14.98
482.20	Structures (Masonry)	65-R2	(10)	132,011,784	38,024,706	107,188,256	2,033,575	1.54		52.28
483.10	Computer Hardware	4-SQ	0	50,714,813	24,967,302	25,747,511	12,678,703	25.00	*	2.18
483.20	Computer Software (12.5%)	8-SQ	0	8,545,123	3,024,977	5,520,146	1,068,140	12.50	*	5.17
483.30	Office Equipment	15-SQ	0	2,303,282	1,322,912	980,371	153,552	6.67	*	6.26
483.40	Furniture	20-SQ	0	16,575,749	5,816,452	10,759,297	828,787	5.00	*	12.92
484.00	Vehicles	10-L1	15	54,721,373	21,834,231	24,678,936	3,062,072	5.60		7.40
485.10	Heavy Work Equipment	13-L0.5	5	722,832	467,317	219,373	27,901	3.86		6.91
485.20	Heavy Mobile Equipment	10-L1.5	0	12,179,351	3,741,657	8,437,694	1,245,553	10.23		6.82
486.00	Small Tools/Equipment	20-SQ	0	59,415,986	25,721,024	33,694,962	2,970,799	5.00	*	11.47
488.10	Telephone Equipment	15-SQ	0	1,223,235	1,070,502	152,733	81,549	6.67	*	2.01
488.20	Radio Equipment	15-SQ	0	17,066,740	6,703,380	10,363,360	1,137,783	6.67	*	9.13
TOTAL GENERAL PLANT				**382,683,701**	**146,547,755**	**242,180,914**	**26,139,886**	**6.83**		
TOTAL DEPRECIABLE PLANT				**8,323,860,216**	**2,755,560,663**	**8,139,631,652**	**265,962,492**	**3.20**		
PLANT NOT STUDIED										
175.00	Unamortized Conversion/Expense			108,669						
178.00	Organizational Costs			728,114						
430.00	Manufacturing Plant - Land			31,008						
440.00	LNG Gas - Land			15,164,215						
440.01	LNG Gas - Land - Mt. Hayes			1,082,611						
448.65	Inspections			1,571,861						
460.00	Transmission Plant - Land			11,270,594						
461.01	Transmission Plant - Land Rights			52,766,185						
461.02	Transmission Plant - Land Rights - Mt. Hayes			609,277						
461.12	Transmission Plant - Land Rights - Byron Creek			16,166						
461.13	IP Land Rights - Whistler			23,738						
465.10	Transmission Plant - Transmission Pipeline - Byron Creek			1,371,092						
465.20	Inspections			38,043,964						
466.10	Compressor Overhaul			8,713,431						
467.30	Transmission Plant - Measuring and Regulating Equipment - Byron Creek			291,409						
470.00	Distribution System - Land			6,058,088						
471.01	Distribution System - Land Rights			3,671,988						
471.11	Distribution System - Land Rights - Byron Creek			1,140						

FortisBC Energy Inc.

TABLE 1 - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
TOTAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
472.10	Distribution System - Structures - Byron Creek			123,615					
477.30	Measuring and Regulating Rquipment - Byron Creek			153,151					
480.00	General Plant - Land			31,944,352					
482.30	Structures (Leased)			3,474,736					
484.10	Capital Lease Vehicles			-					
TOTAL PLANT NOT STUDIED				**177,219,402**	**-**				
TOTAL PLANT				**8,501,079,618**	**2,755,560,663**				

FortisBC Energy Inc.

TABLE 1A - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

LIFE

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate		Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
INTANGIBLE PLANT										
401.01	Franchises and Consents	40-SQ	0	196,933	139,813	57,120	4,923	2.50	*	8.85
402.01	Computer Software Application - 8 Years	8-SQ	0	77,966,230	27,328,837	50,637,394	9,745,779	12.50	*	5.20
402.02	Computer Software Application - 5 Years	5-SQ	0	25,937,204	9,246,051	16,691,153	5,187,441	20.00	*	3.22
402.03	Intangible Plant	40-SQ	0	1,906,591	1,293,414	613,177	47,665	2.50	*	15.99
TOTAL INTANGIBLE PLANT				**106,006,959**	**38,008,115**	**67,998,844**	**14,985,808**	**14.14**		
MANUFACTURING PLANT										
432.00	Structures	40-SQ	0	1,312,030	458,017	854,013	32,801	2.50	*	25.13
433.00	Equipment	20-SQ	0	1,201,139	353,228	847,910	60,057	5.00	*	14.86
434.00	Holders	40-SQ	0	2,948,088	944,289	2,003,799	73,702	2.50	*	27.39
436.00	Compressor Equipment	25-SQ	0	366,583	197,836	168,746	14,663	4.00	*	12.97
437.00	Measuring and Regulating Equipment	20-SQ	0	2,170,484	1,356,910	813,574	108,524	5.00	*	12.57
TOTAL MANUFACTURING PLANT				**7,998,323**	**3,310,281**	**4,688,042**	**289,747**	**3.62**		
LNG PLANT										
442.00	Structures and Improvements - Tilbury	28-L2	0	101,760,421	13,292,385	88,468,036	3,762,127	3.70		23.63
442.01	Structures and Improvements - Mt Hayes	28-L2	0	19,098,348	8,297,078	10,801,269	585,328	3.06		18.42
443.00	Gas Holders - Storage - Tilbury	57-S4	0	183,674,557	22,679,902	160,994,655	3,140,895	1.71		50.91
443.05	Gas Holders - Storage - Mt Hayes	60-R5	0	61,836,512	11,657,601	50,178,912	1,019,761	1.65		49.20
448.10	Piping - Mt Hayes	40-R3	0	12,714,468	3,424,041	9,290,427	309,002	2.43		30.05
448.11	Piping - Tilbury	40-R3	0	52,842,616	4,490,048	48,352,568	1,320,827	2.50		36.61
448.20	Pre-treatment - Mt Hayes	25-R3	0	29,347,745	13,197,017	16,150,728	1,089,267	3.71		14.82
448.21	Pre-treatment - Tilbury	25-R3	0	34,099,015	5,030,620	29,068,395	1,366,642	4.01		21.27
448.30	Liquefaction Equipment - Mt Hayes	40-R3	0	28,939,534	8,262,865	20,676,669	701,256	2.42		29.48
448.31	Liquefaction Equipment - Tilbury	40-R3	0	88,823,153	8,531,394	80,291,759	2,219,971	2.50		36.17
448.40	Send Out Equipment - Mt Hayes	40-R3	0	23,743,248	6,638,110	17,105,138	577,244	2.43		29.63
448.41	Send Out Equipment - Tilbury	40-R3	0	10,675,476	698,766	9,976,710	267,124	2.50		37.35
448.50	Substation and Electrical - Mt Hayes	40-R3	0	21,788,252	6,191,317	15,596,934	529,275	2.43		29.47
448.51	Substation and Electrical - Tilbury	40-R3	0	38,245,155	3,508,365	34,736,790	957,933	2.50		36.26
448.60	Control Room - Mt Hayes	15-R3	0	6,664,704	4,608,745	2,055,959	334,028	5.01		6.00
448.61	Control Room - Tilbury	15-R3	0	4,608,084	950,217	3,657,866	310,986	6.75		11.77
449.00	Local Storage Equipment - Tilbury	27-R3	0	28,955,236	19,720,056	9,235,181	608,342	2.10		10.95
449.01	Local Storage Equipment - Mt Hayes	30-R3	0	6,133,465	1,185,442	4,948,023	212,568	3.47		23.30
TOTAL LNG PLANT				**753,949,990**	**142,363,970**	**611,586,020**	**19,312,576**	**2.56**		
TRANSMISSION PLANT										
462.00	Compressor Structures	30-S4	0	46,138,194	22,359,284	23,778,910	1,369,784	2.97		16.20
463.00	Measuring and Regulating Structures	40-S2.5	0	25,989,383	9,005,647	16,983,737	569,938	2.19		28.32

FortisBC Energy Inc.

TABLE 1A - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

LIFE

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
464.00	Other Structures	30-R4	0	6,871,016	4,135,437	2,735,579	227,441	3.31	11.99
465.00	Transmission Pipeline	65-R4	0	1,679,785,040	495,519,712	1,184,265,328	24,837,247	1.48	47.20
465.11	Intermediate Pipe - Whistler	65-R3	0	59,041,836	9,148,300	49,893,536	904,367	1.53	55.16
465.30	Mains - Mt. Hayes	65-SQ	0	6,306,953	1,175,242	5,131,711	97,030	1.54 *	54.01
466.00	Compressor Equipment	37-R4	0	203,053,266	111,901,530	91,151,736	4,695,524	2.31	18.48
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5	0	5,929,381	1,977,581	3,951,799	135,253	2.28	29.08
467.10	Measuring and Regulating Equipment	37-R1.5	0	93,258,936	32,157,644	61,101,292	2,117,010	2.27	27.37
467.20	Telemetry Equipment	10-L1.5	0	21,931,673	11,530,472	10,401,201	1,317,445	6.01	6.49
467.31	Measuring and Regulating Equipment - Whistler	37-R1.5	0	313,344	133,892	179,452	6,695	2.14	26.80
468.00	Communications Equipment	19-R3	0	3,327,075	3,691,189	- 364,114	-	0.00	4.04
TOTAL TRANSMISSION PLANT				**2,151,946,097**	**702,735,929**	**1,449,210,168**	**36,277,734**	**1.69**	
DISTRIBUTION PLANT									
472.00	Structures	45-R2.5	0	54,417,590	13,428,895	40,988,695	1,092,120	2.01	36.52
473.00	Services	47-R2	0	1,535,297,088	419,789,098	1,115,507,990	32,340,525	2.11	34.41
474.00	Meter/Regulator Installations	23-SQ	0	165,174,993	119,986,419	45,188,575	7,181,521	4.35 *	6.19
474.02	New Meter Installations	22-SQ	0	240,060,967	55,446,912	184,614,056	10,911,862	4.55 *	16.98
475.00	Systems - Mains	65-R2.5	0	2,281,611,431	590,416,786	1,691,194,645	32,305,708	1.42	51.38
476.00	NGV Fuel Equipment	7-L0	0	613,588	1,443,548	- 829,960	-	0.00	3.04
477.10	Measuring and Regulating	34-R2.5	0	227,560,333	68,931,535	158,628,797	6,052,078	2.66	25.17
477.20	Telemetry	20-R3	0	29,036,466	8,182,557	20,853,908	1,443,960	4.97	14.36
478.10	Meters	18-R4/5-SQ	0	316,909,877	198,357,366	89,317,027	10,697,520	3.38	**
478.20	Instruments	35-SQ	0	15,707,467	8,098,600	7,608,867	448,785	2.86 *	16.84
TOTAL DISTRIBUTION PLANT				**4,866,389,799**	**1,484,081,716**	**3,353,072,599**	**102,474,079**	**2.11**	
BIO GAS									
472.20	Structures and Improvements	36-R1.5	0	1,517,854	166,294	1,351,560	40,880	2.69	32.94
474.10	Meters/Regulator Installations	19-S0	0	802,187	116,096	686,091	40,758	5.08	16.73
475.10	Mains - Municipal Land	65-R2.5	0	1,752,805	193,184	1,559,621	27,021	1.54	57.72
475.20	Mains - Private Land	65-R2.5	0	410,314	19,451	390,863	6,279	1.53	62.23
477.40	Measuring and Regulating	30-R2	0	4,319,983	714,118	3,605,865	139,804	3.24	25.71
478.30	Meters	18-R2.5	0	84,213	17,502	66,712	4,372	5.19	14.93
418.10	Purification Overhauls	20-SQ	0	20,423	8,841	11,582	1,021	5.00 *	12.00
418.20	Purification Upgrader	20-SQ	0	10,051,967	3,846,766	6,205,202	502,598	5.00 *	12.48
TOTAL BIO GAS				**18,959,747**	**5,082,251**	**13,877,496**	**762,734**	**4.02**	
NG FOR TRANSPORTATION									
476.10	CNG Disp Equipment	20-SQ	0	17,120,865	4,256,263	12,864,602	856,043	5.00 *	15.02
476.20	LNG Disp Equipment	20-SQ	0	13,713,753	4,904,508	8,809,246	685,688	5.00 *	13.11
476.30	CNG Foundation	20-SQ	0	3,161,249	853,717	2,307,532	158,062	5.00 *	14.61

FortisBC Energy Inc.

TABLE 1A - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
LIFE

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate		Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
476.40	LNG Foundation	20-SQ	0	1,048,809	445,999	602,811	52,440	5.00	*	11.95
476.50	LNG Pumps	10-SQ	0	76,880	71,422	5,458	7,688	10.00	*	1.37
476.60	CNG Dehydrator	20-SQ	0	804,044	185,642	618,402	40,202	5.00	*	15.43
TOTAL NG FOR TRANSPORTATION				**35,925,601**	**10,717,550**	**25,208,051**	**1,800,124**	**5.01**		
GENERAL PLANT										
482.10	Stuctures (Frame)	25-R2	0	27,203,434	13,995,601	13,207,834	748,514	2.75		14.98
482.20	Structures (Masonry)	65-R2	0	132,011,784	36,990,572	95,021,212	1,798,110	1.36		52.28
483.10	Computer Hardware	4-SQ	0	50,714,813	24,967,302	25,747,511	12,678,703	25.00	*	2.18
483.20	Computer Software (12.5%)	8-SQ	0	8,545,123	3,024,977	5,520,146	1,068,140	12.50	*	5.17
483.30	Office Equipment	15-SQ	0	2,303,282	1,322,139	981,144	153,552	6.67	*	6.26
483.40	Furniture	20-SQ	0	16,575,749	5,910,797	10,664,952	828,787	5.00	*	12.92
484.00	Vehicles	10-L1	0	54,721,373	23,687,037	31,034,336	3,910,964	7.15		7.40
485.10	Heavy Work Equipment	13-L0.5	0	722,832	492,899	229,933	29,217	4.04		6.91
485.20	Heavy Mobile Equipment	10-L1.5	0	12,179,351	4,750,400	7,428,951	1,036,512	8.51		6.82
486.00	Small Tools/Equipment	20-SQ	0	59,415,986	25,669,378	33,746,608	2,970,799	5.00	*	11.47
488.10	Telephone Equipment	15-SQ	0	1,223,235	1,070,502	152,733	81,549	6.67	*	2.01
488.20	Radio Equipment	15-SQ	0	17,066,740	6,710,180	10,356,560	1,137,783	6.67	*	9.13
TOTAL GENERAL PLANT				**382,683,701**	**148,591,783**	**234,091,917**	**26,442,631**	**6.91**		
TOTAL DEPRECIABLE PLANT				**8,323,860,216**	**2,534,891,595**	**5,759,733,137**	**202,345,433**	**2.43**		
PLANT NOT STUDIED										
175.00	Unamortized Conversion/Expense			108,669						
178.00	Organizational Costs			728,114						
430.00	Manufacturing Plant - Land			31,008						
440.00	LNG Gas - Land			15,164,215						
440.01	LNG Gas - Land - Mt. Hayes			1,082,611						
448.65	Inspections			1,571,861						
460.00	Transmission Plant - Land			11,270,594						
461.01	Transmission Plant - Land Rights			52,766,185						
461.02	Transmission Plant - Land Rights - Mt. Hayes			609,277						
461.12	Transmission Plant - Land Rights - Byron Creek			16,166						
461.13	IP Land Rights - Whistler			23,738						
465.10	Transmission Plant - Transmission Pipeline - Byron Creek			1,371,092						
465.20	Inspections			38,043,964						
466.10	Compressor Overhaul			8,713,431						

FortisBC Energy Inc.

TABLE 1A - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT LIFE

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
467.30	Transmission Plant - Measuring and Regulating Equipment - Byron Creek			291,409					
470.00	Distribution System - Land			6,058,088					
471.01	Distribution System - Land Rights			3,671,988					
471.11	Distribution System - Land Rights - Byron Creek			1,140					
472.10	Distribution System - Structures - Byron Creek			123,615					
477.30	Measuring and Regulating Rquipment - Byron Creek			153,151					
480.00	General Plant - Land			31,944,352					
482.30	Structures (Leased)			3,474,736					
484.10	Capital Lease Vehicles								
TOTAL PLANT NOT STUDIED				**177,219,402**	**-**				
TOTAL PLANT				**8,501,079,618**	**2,534,891,595**				

FortisBC Energy Inc.

TABLE 1B - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
INTANGIBLE PLANT								
401.01	Franchises and Consents	40-SQ	0	196,933	-	-	-	0.00
402.01	Computer Software Application - 8 Years	8-SQ	0	77,966,230	-	-	-	0.00
402.02	Computer Software Application - 5 Years	5-SQ	0	25,937,204	-	-	-	0.00
402.03	Intangible Plant	40-SQ	0	1,906,591	-	-	-	0.00
TOTAL INTANGIBLE PLANT				**106,006,959**	**-**	-	**-**	**0.00**
MANUFACTURING PLANT						-		
432.00	Structures	40-SQ	0	1,312,030	-	-	-	0.00
433.00	Equipment	20-SQ	0	1,201,139	-	-	-	0.00
434.00	Holders	40-SQ	0	2,948,088	-	-	-	0.00
436.00	Compressor Equipment	25-SQ	0	366,583	-	-	-	0.00
437.00	Measuring and Regulating Equipment	20-SQ	0	2,170,484	(22,119)	22,119	-	0.00
TOTAL MANUFACTURING PLANT				**7,998,323**	**(22,119)**	**22,119**	**-**	**0.00**
LNG PLANT								
442.00	Structures and Improvements - Tilbury	28-L2	(10)	101,760,421	2,858,185	7,317,857	300,335	0.30
442.01	Structures and Improvements - Mt Hayes	28-L2	(10)	19,098,348	513,645	1,396,190	75,880	0.40
443.00	Gas Holders - Storage - Tilbury	57-S4	(20)	183,674,557	7,592,584	29,142,327	546,471	0.30
443.05	Gas Holders - Storage - Mt Hayes	60-R5	(20)	61,836,512	1,298,336	11,068,966	225,013	0.36
448.10	Piping - Mt Hayes	40-R3	(10)	12,714,468	197,675	1,073,772	35,783	0.28
448.11	Piping - Tilbury	40-R3	(10)	52,842,616	706,411	4,577,851	125,005	0.24
448.20	Pre-treatment - Mt Hayes	25-R3	(10)	29,347,745	834,822	2,099,953	141,796	0.48
448.21	Pre-treatment - Tilbury	25-R3	(10)	34,099,015	944,984	2,464,917	115,772	0.34
448.30	Liquefaction Equipment - Mt Hayes	40-R3	(20)	28,939,534	958,999	4,828,908	163,801	0.57
448.31	Liquefaction Equipment - Tilbury	40-R3	(20)	88,823,153	2,852,820	14,911,811	412,254	0.46
448.40	Send Out Equipment - Mt Hayes	40-R3	(10)	23,743,248	383,816	1,990,508	67,216	0.28
448.41	Send Out Equipment - Tilbury	40-R3	(10)	10,675,476	84,795	982,752	26,303	0.25
448.50	Substation and Electrical - Mt Hayes	40-R3	(20)	21,788,252	716,675	3,640,976	123,564	0.57
448.51	Substation and Electrical - Tilbury	40-R3	(20)	38,245,155	991,094	6,657,937	183,574	0.48
448.60	Control Room - Mt Hayes	15-R3	0	6,664,704	-	-	-	0.00
448.61	Control Room - Tilbury	15-R3	0	4,608,084	-	-	-	0.00
449.00	Local Storage Equipment - Tilbury	27-R3	(5)	28,955,236	1,578,653 -	130,891	(48,839)	(0.17)
449.01	Local Storage Equipment - Mt Hayes	30-R3	(5)	6,133,465	108,437	198,236	8,473	0.14
TOTAL LNG PLANT				**753,949,990**	**22,621,930**	**92,222,071**	**2,502,401**	**0.33**
TRANSMISSION PLANT								
462.00	Compressor Structures	30-S4	(3)	46,138,194	561,799	822,347	56,602	0.12
463.00	Measuring and Regulating Structures	40-S2.5	(15)	25,989,383	756,541	3,141,867	119,014	0.46

FortisBC Energy Inc.

TABLE 1B - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
464.00	Other Structures	30-R4	(5)	6,871,016	147,794	195,757	17,473	0.25
465.00	Transmission Pipeline	65-R4	(23)	1,679,785,040	38,104,716	348,245,843	7,852,976	0.47
465.11	Intermediate Pipe - Whistler	65-R3	(20)	59,041,836	1,029,965	10,778,402	195,932	0.33
465.30	Mains - Mt. Hayes	65-SQ	(20)	6,306,953	117,229	1,144,161	19,406	0.31
466.00	Compressor Equipment	37-R4	(3)	203,053,266	2,576,981	3,514,617	197,212	0.10
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5	(5)	5,929,381	73,296	223,173	7,665	0.13
467.10	Measuring and Regulating Equipment	37-R1.5	(5)	93,258,936	1,169,320	3,493,627	128,116	0.14
467.20	Telemetry Equipment	10-L1.5	0	21,931,673	(28,440)	28,440	5,469	0.02
467.31	Measuring and Regulating Equipment - Whistler	37-R1.5	(7)	313,344	5,668	16,266	607	0.19
468.00	Communications Equipment	19-R3	0	3,327,075	400,872	- 400,872	-	0.00
TOTAL TRANSMISSION PLANT				**2,151,946,097**	**44,915,742**	**371,203,627**	**8,600,472**	**0.40**
DISTRIBUTION PLANT								
472.00	Structures	45-R2.5	(20)	54,417,590	787,513	10,096,005	287,747	0.53
473.00	Services	47-R2	(85)	1,535,297,088	87,746,085	1,217,256,439	37,918,566	2.47
474.00	Meter/Regulator Installations	23-SQ	(20)	165,174,993	(991,822)	34,026,821	1,436,304	0.87
474.02	New Meter Installations	22-SQ	0	240,060,967	749,155	- 749,155	-	0.00
475.00	Systems - Mains	65-R2.5	(30)	2,281,611,431	57,507,375	626,976,055	12,670,691	0.56
476.00	NGV Fuel Equipment	7-L0	0	613,588	705,908	- 705,908	-	0.00
477.10	Measuring and Regulating	34-R2.5	(12)	227,560,333	5,346,597	21,960,643	915,685	0.40
477.20	Telemetry	20-R3	(5)	29,036,466	327,791	1,124,033	89,853	0.31
478.10	Meters	18-R4/5-SQ	0	316,909,877	2,751,025	- 2,751,025	(550,205)	(0.17)
478.20	Instruments	35-SQ	0	15,707,467	-	-	-	0.00
TOTAL DISTRIBUTION PLANT				**4,866,389,799**	**154,929,626**	**1,907,233,907**	**52,768,641**	**1.08**
BIO GAS								
472.20	Structures and Improvements	36-R1.5	(10)	1,517,854	12,537	139,248	4,228	0.28
474.10	Meters/Regulator Installations	19-S0	(25)	802,187	26,659	173,888	10,361	1.29
475.10	Mains - Municipal Land	65-R2.5	(25)	1,752,805	49,936	388,265	6,727	0.38
475.20	Mains - Private Land	65-R2.5	(25)	410,314	3,237	99,341	1,598	0.39
477.40	Measuring and Regulating	30-R2	0	4,319,983	(6,009)	6,009	263	0.01
478.30	Meters	18-R2.5	0	84,213	178	- 178	(17)	(0.02)
418.10	Purification Overhauls	20-SQ	0	20,423	-	-	-	0.00
418.20	Purification Upgrader	20-SQ	(5)	10,051,967	147,843	354,755	25,130	0.25
TOTAL BIO GAS				**18,959,747**	**234,382**	**1,161,328**	**48,290**	**0.25**
NG FOR TRANSPORTATION								
476.10	CNG Disp Equipment	20-SQ	0	17,120,865	(1,447)	1,447	-	0.00
476.20	LNG Disp Equipment	20-SQ	0	13,713,753	9,647	- 9,647	-	0.00

FortisBC Energy Inc.

TABLE 1B - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve		Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate
	(1)	(2)	(3)	(4)	(5)		(6)	(7)	(8)
476.30	CNG Foundation	20-SQ	0	3,161,249	-		-	-	0.00
476.40	LNG Foundation	20-SQ	0	1,048,809	8,946	-	8,946	-	0.00
476.50	LNG Pumps	10-SQ	0	76,880	16,389	-	16,389	-	0.00
476.60	CNG Dehydrator	20-SQ	0	804,044	-		-	-	0.00
TOTAL NG FOR TRANSPORTATION				**35,925,601**	**33,534**		**(33,534)**	**-**	**0.00**
GENERAL PLANT									
482.10	Stuctures (Frame)	25-R2	(4)	27,203,434	(142,305)		1,230,443	102,957	0.38
482.20	Structures (Masonry)	65-R2	(10)	132,011,784	1,034,135		12,167,044	235,465	0.18
483.10	Computer Hardware	4-SQ	0	50,714,813	-		-	-	0.00
483.20	Computer Software (12.5%)	8-SQ	0	8,545,123	-		-	-	0.00
483.30	Office Equipment	15-SQ	0	2,303,282	773	-	773	-	0.00
483.40	Furniture	20-SQ	0	16,575,749	(94,346)		94,346	-	0.00
484.00	Vehicles	10-L1	15	54,721,373	(1,852,806)	-	6,355,400	(848,892)	(1.55)
485.10	Heavy Work Equipment	13-L0.5	5	722,832	(25,582)	-	10,560	(1,316)	(0.18)
485.20	Heavy Mobile Equipment	10-L1.5	0	12,179,351	(1,008,744)		1,008,744	209,041	1.72
486.00	Small Tools/Equipment	20-SQ	0	59,415,986	51,646	-	51,646	-	0.00
488.10	Telephone Equipment	15-SQ	0	1,223,235	-		-	-	0.00
488.20	Radio Equipment	15-SQ	0	17,066,740	(6,800)		6,800	-	0.00
TOTAL GENERAL PLANT				**382,683,701**	**(2,044,028)**		**8,088,997**	**(302,745)**	**(0.08)**
TOTAL DEPRECIABLE PLANT				**8,323,860,216**	**220,669,067**		**2,379,898,516**	**63,617,059**	**0.76**
PLANT NOT STUDIED									
175.00	Unamortized Conversion/Expense			108,669					
178.00	Organizational Costs			728,114					
430.00	Manufacturing Plant - Land			31,008					
440.00	LNG Gas - Land			15,164,215					
440.01	LNG Gas - Land - Mt. Hayes			1,082,611					
448.65	Inspections			1,571,861					
460.00	Transmission Plant - Land			11,270,594					
461.01	Transmission Plant - Land Rights			52,766,185					
461.02	Transmission Plant - Land Rights - Mt. Hayes			609,277					
461.12	Transmission Plant - Land Rights - Byron Creek			16,166					
461.13	IP Land Rights - Whistler			23,738					
465.10	Transmission Plant - Transmission Pipeline - Byron Creek			1,371,092					

FortisBC Energy Inc.

TABLE 1B - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED
ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
465.20	Inspections			38,043,964				
466.10	Compressor Overhaul			8,713,431				
467.30	Transmission Plant - Measuring and Regulating Equipment - Byron Creek			291,409				
470.00	Distribution System - Land			6,058,088				
471.01	Distribution System - Land Rights			3,671,988				
471.11	Distribution System - Land Rights - Byron Creek			1,140				
472.10	Distribution System - Structures - Byron Creek			123,615				
477.30	Measuring and Regulating Rquipment - Byron Creek			153,151				
480.00	General Plant - Land			31,944,352				
482.30	Structures (Leased)			3,474,736				
484.10	Capital Lease Vehicles			-				
TOTAL PLANT NOT STUDIED				**177,219,402**	**-**			
TOTAL PLANT				**8,501,079,618**	**220,669,067**			

SECTION 6

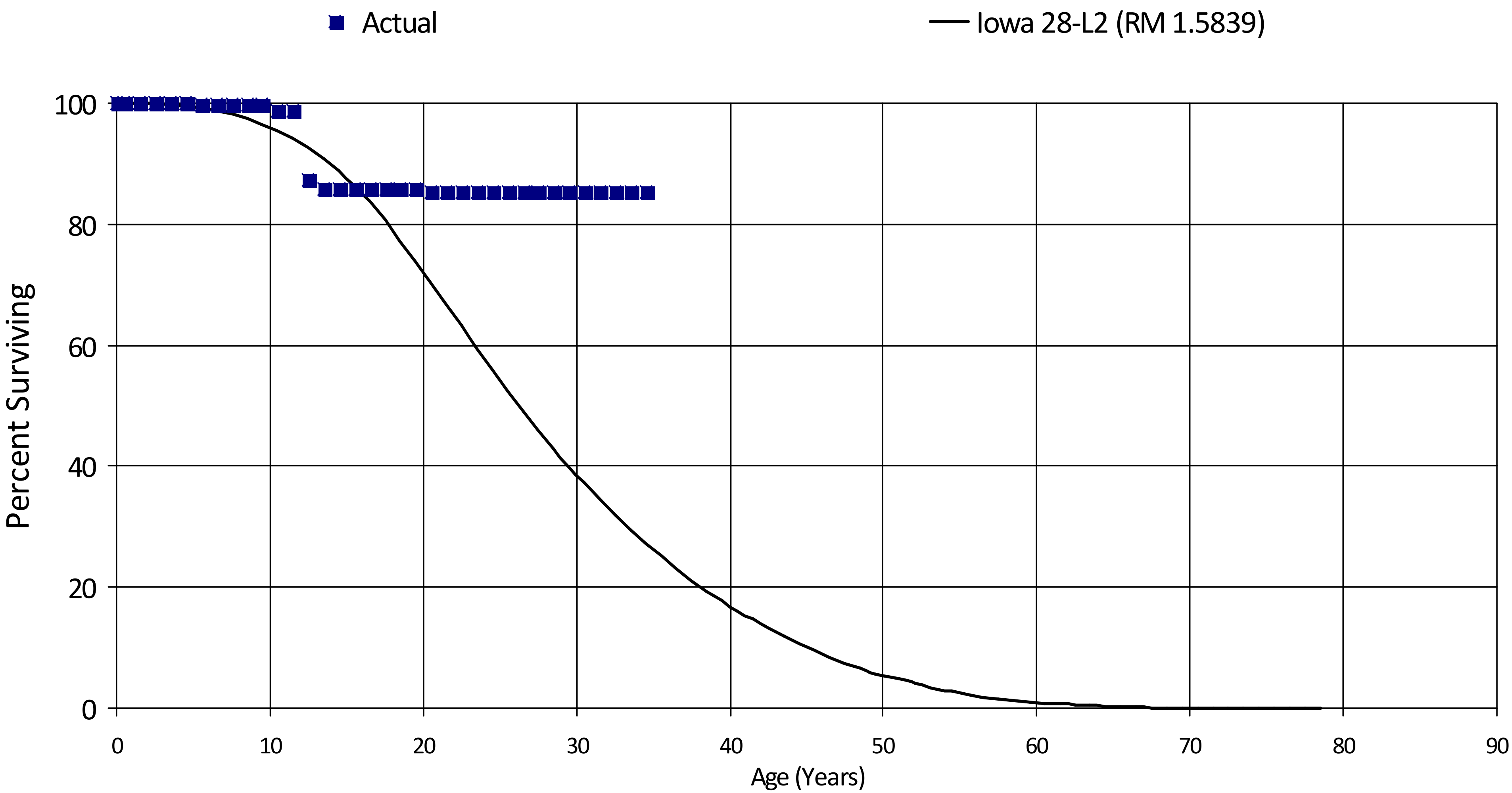
6 ACTUARIAL ANALYSIS CALCULATIONS

FortisBC

Account 442.00 - Structures - LNG Plant

Placement Band - 1972 - 2022   Experience Band - 1985 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 442.00 - Structures - LNG Plant

Placement Band - 1972 - 2022   Experience Band - 1985 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	102,599,121	0	0.00000	1.00000	100.00
0.5	100,869,824	0	0.00000	1.00000	100.00
1.5	100,412,935	0	0.00000	1.00000	100.00
2.5	98,579,606	0	0.00000	1.00000	100.00
3.5	94,889,447	0	0.00000	1.00000	100.00
4.5	6,051,283	11,458	0.00189	0.99811	100.00
5.5	6,038,264	0	0.00000	1.00000	99.81
6.5	6,011,319	0	0.00000	1.00000	99.81
7.5	5,996,197	0	0.00000	1.00000	99.81
8.5	5,789,277	1,000	0.00017	0.99983	99.81
9.5	5,788,277	61,358	0.01060	0.98940	99.79
10.5	5,726,357	0	0.00000	1.00000	98.73
11.5	5,724,347	669,121	0.11689	0.88311	98.73
12.5	4,980,343	74,954	0.01505	0.98495	87.19
13.5	4,905,388	0	0.00000	1.00000	85.88
14.5	4,875,027	2,477	0.00051	0.99949	85.88
15.5	4,601,948	0	0.00000	1.00000	85.84
16.5	4,588,336	0	0.00000	1.00000	85.84
17.5	3,799,878	1,959	0.00052	0.99948	85.84
18.5	3,780,923	6,000	0.00159	0.99841	85.80
19.5	3,070,667	10,373	0.00338	0.99662	85.66
20.5	3,023,760	0	0.00000	1.00000	85.37
21.5	2,928,941	0	0.00000	1.00000	85.37
22.5	2,610,192	0	0.00000	1.00000	85.37
23.5	2,476,299	0	0.00000	1.00000	85.37
24.5	2,079,553	0	0.00000	1.00000	85.37
25.5	1,833,440	0	0.00000	1.00000	85.37
26.5	1,790,660	0	0.00000	1.00000	85.37

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Account 442.00 - Structures - LNG Plant

Placement Band - 1972 - 2022   Experience Band - 1985 - 2022

27.5	1,658,079	0	0.00000	1.00000	85.37
28.5	1,573,517	0	0.00000	1.00000	85.37
29.5	1,565,423	0	0.00000	1.00000	85.37
30.5	1,454,996	0	0.00000	1.00000	85.37
31.5	1,453,071	0	0.00000	1.00000	85.37
32.5	1,453,071	0	0.00000	1.00000	85.37
33.5	1,453,071	0	0.00000	1.00000	85.37
34.5	0	0	0.00000	0.00000	85.37
	Totals:	838,700			

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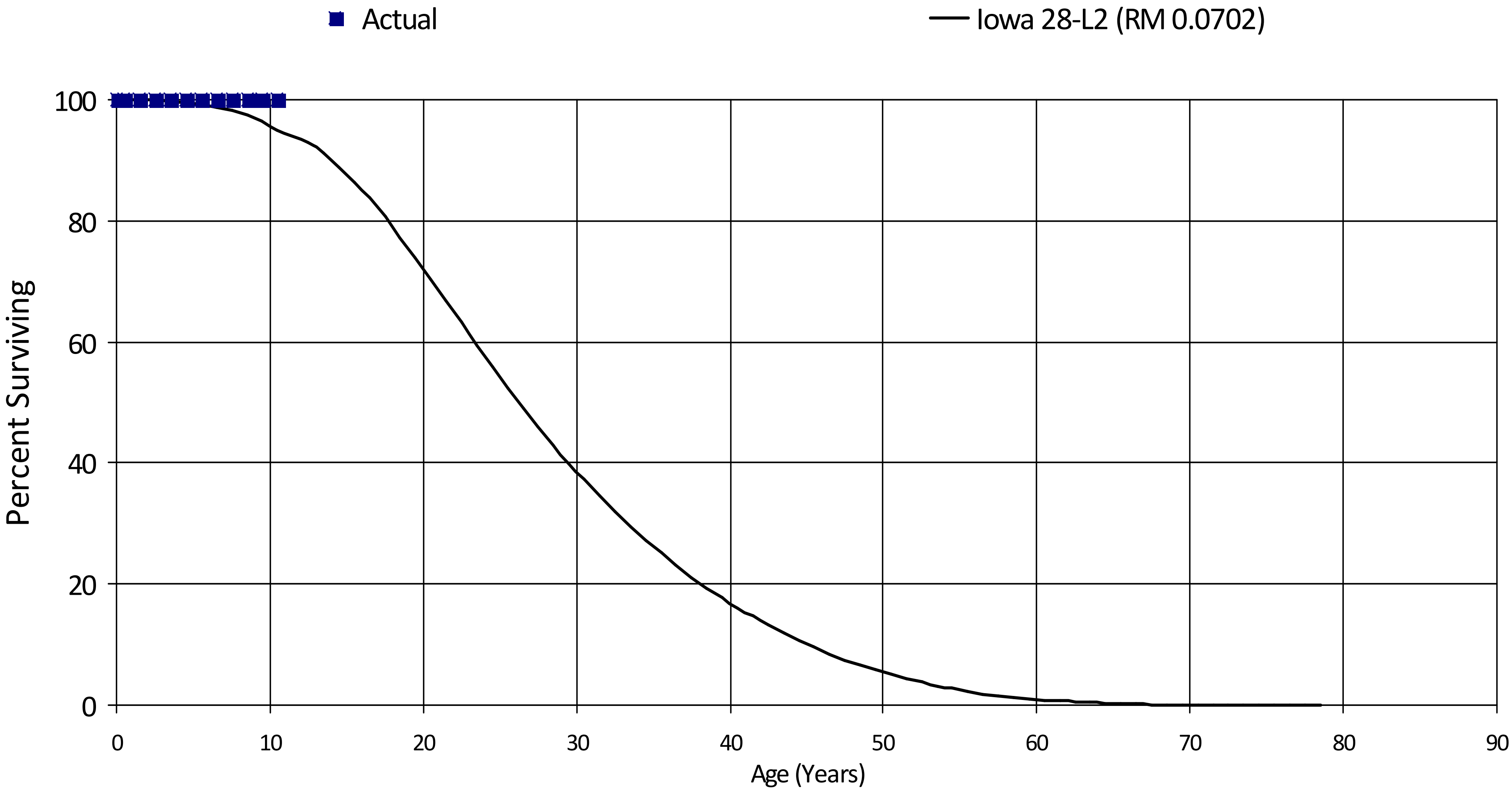
Account 442.01 - Structures - Mt. Hayes - LNG Plant

Placement Band - 2011 - 2021 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 442.01 - Structures - Mt. Hayes - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

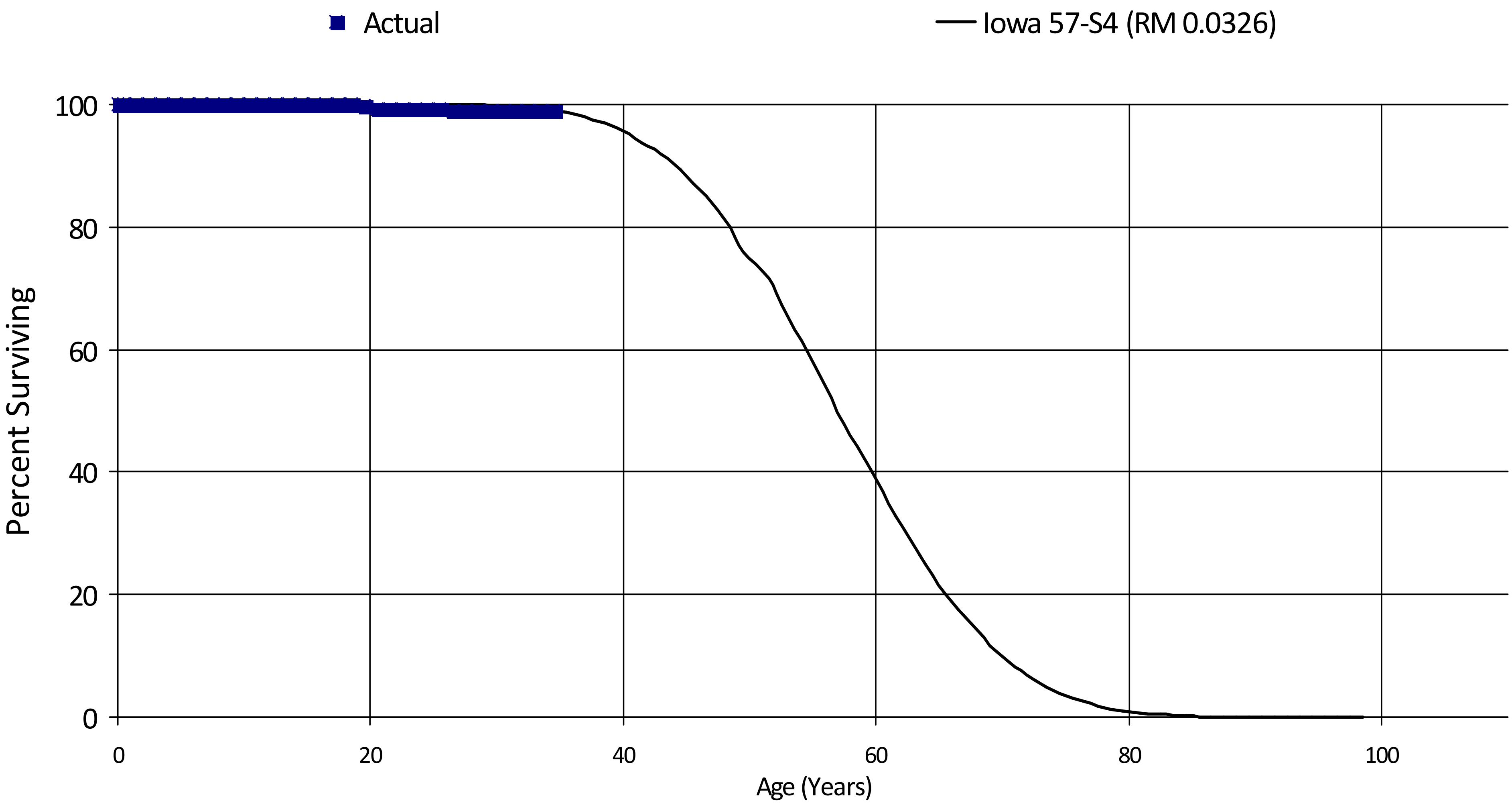
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	19,098,348	0	0.00000	1.00000	100.00
0.5	19,098,348	0	0.00000	1.00000	100.00
1.5	19,049,617	0	0.00000	1.00000	100.00
2.5	19,045,068	0	0.00000	1.00000	100.00
3.5	19,045,068	0	0.00000	1.00000	100.00
4.5	19,036,303	0	0.00000	1.00000	100.00
5.5	18,668,894	0	0.00000	1.00000	100.00
6.5	18,164,671	0	0.00000	1.00000	100.00
7.5	17,305,919	0	0.00000	1.00000	100.00
8.5	17,279,791	0	0.00000	1.00000	100.00
9.5	17,257,175	0	0.00000	1.00000	100.00
10.5	17,257,175	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 443.00 - Equipment - LNG Plant

Placement Band - 1972 - 2022   Experience Band - 1998 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 443.00 - Equipment - LNG Plant

Placement Band - 1972 - 2022   Experience Band - 1998 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	183,841,672	0	0.00000	1.00000	100.00
0.5	183,785,892	0	0.00000	1.00000	100.00
1.5	182,938,623	0	0.00000	1.00000	100.00
2.5	179,715,951	0	0.00000	1.00000	100.00
3.5	177,838,479	0	0.00000	1.00000	100.00
4.5	16,880,870	1,000	0.00006	0.99994	100.00
5.5	16,871,143	0	0.00000	1.00000	99.99
6.5	16,732,415	0	0.00000	1.00000	99.99
7.5	16,664,731	0	0.00000	1.00000	99.99
8.5	16,664,731	0	0.00000	1.00000	99.99
9.5	16,664,731	12,708	0.00076	0.99924	99.99
10.5	16,652,023	0	0.00000	1.00000	99.91
11.5	16,647,424	0	0.00000	1.00000	99.91
12.5	16,647,424	0	0.00000	1.00000	99.91
13.5	16,647,424	0	0.00000	1.00000	99.91
14.5	16,647,424	0	0.00000	1.00000	99.91
15.5	16,647,164	1,734	0.00010	0.99990	99.91
16.5	16,593,932	0	0.00000	1.00000	99.90
17.5	16,593,932	0	0.00000	1.00000	99.90
18.5	16,395,154	44,685	0.00273	0.99727	99.90
19.5	16,166,928	79,648	0.00493	0.99507	99.63
20.5	10,783,210	0	0.00000	1.00000	99.14
21.5	10,680,915	0	0.00000	1.00000	99.14
22.5	10,598,994	0	0.00000	1.00000	99.14
23.5	9,852,260	0	0.00000	1.00000	99.14
24.5	9,749,835	0	0.00000	1.00000	99.14
25.5	9,565,231	27,340	0.00286	0.99714	99.14
26.5	9,144,419	0	0.00000	1.00000	98.86

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Account 443.00 - Equipment - LNG Plant

Placement Band - 1972 - 2022   Experience Band - 1998 - 2022

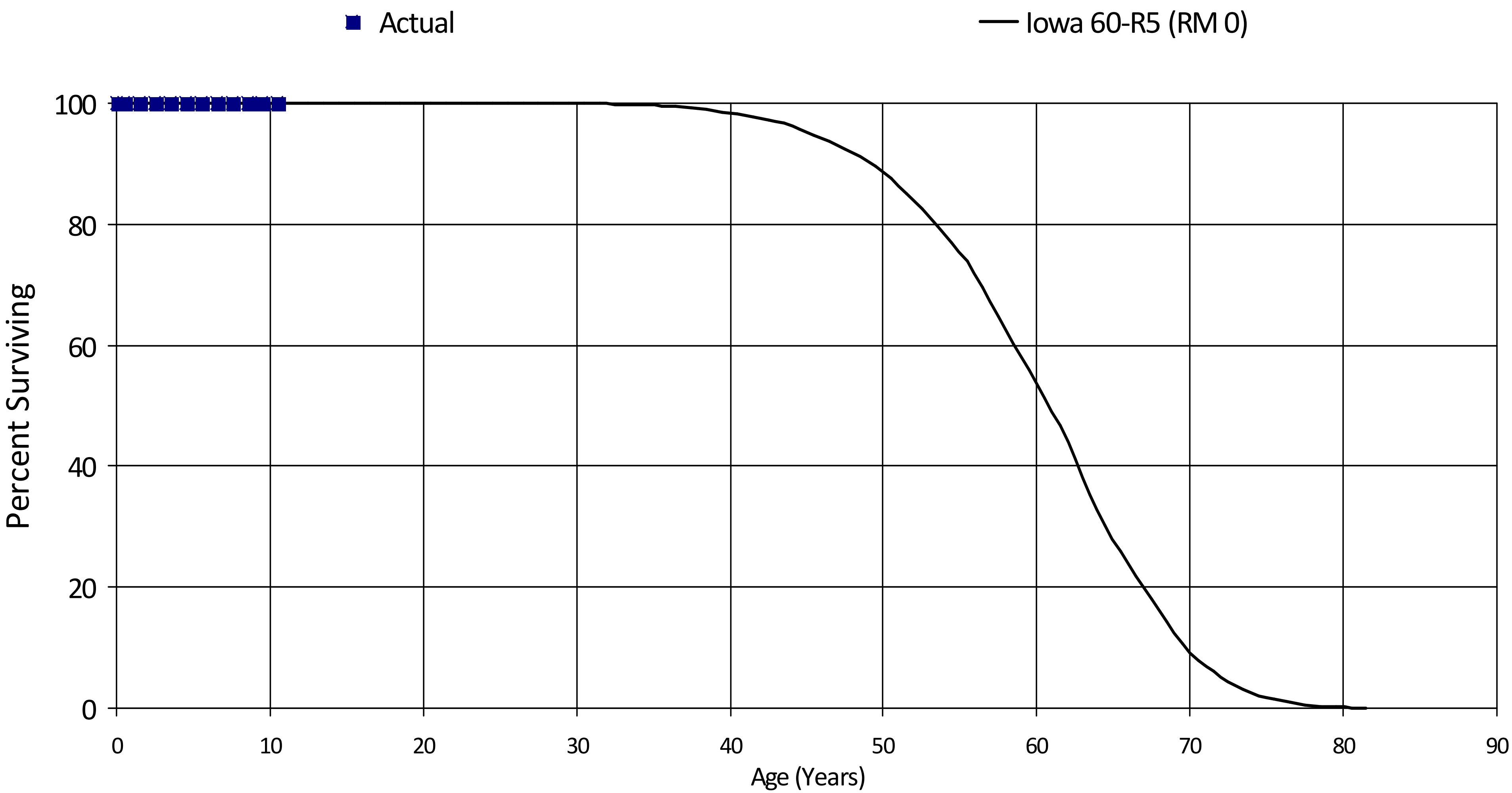
27.5	9,144,419	0	0.00000	1.00000	98.86
28.5	9,144,419	0	0.00000	1.00000	98.86
29.5	9,081,967	0	0.00000	1.00000	98.86
30.5	9,081,967	0	0.00000	1.00000	98.86
31.5	9,052,020	0	0.00000	1.00000	98.86
32.5	9,052,020	0	0.00000	1.00000	98.86
33.5	9,052,020	0	0.00000	1.00000	98.86
34.5	0	0	0.00000	0.00000	98.86
	Totals:	167,115			

FortisBC

Account 443.05 - Equipment - Mt. Hayes - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



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Account 443.05 - Equipment - Mt. Hayes - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

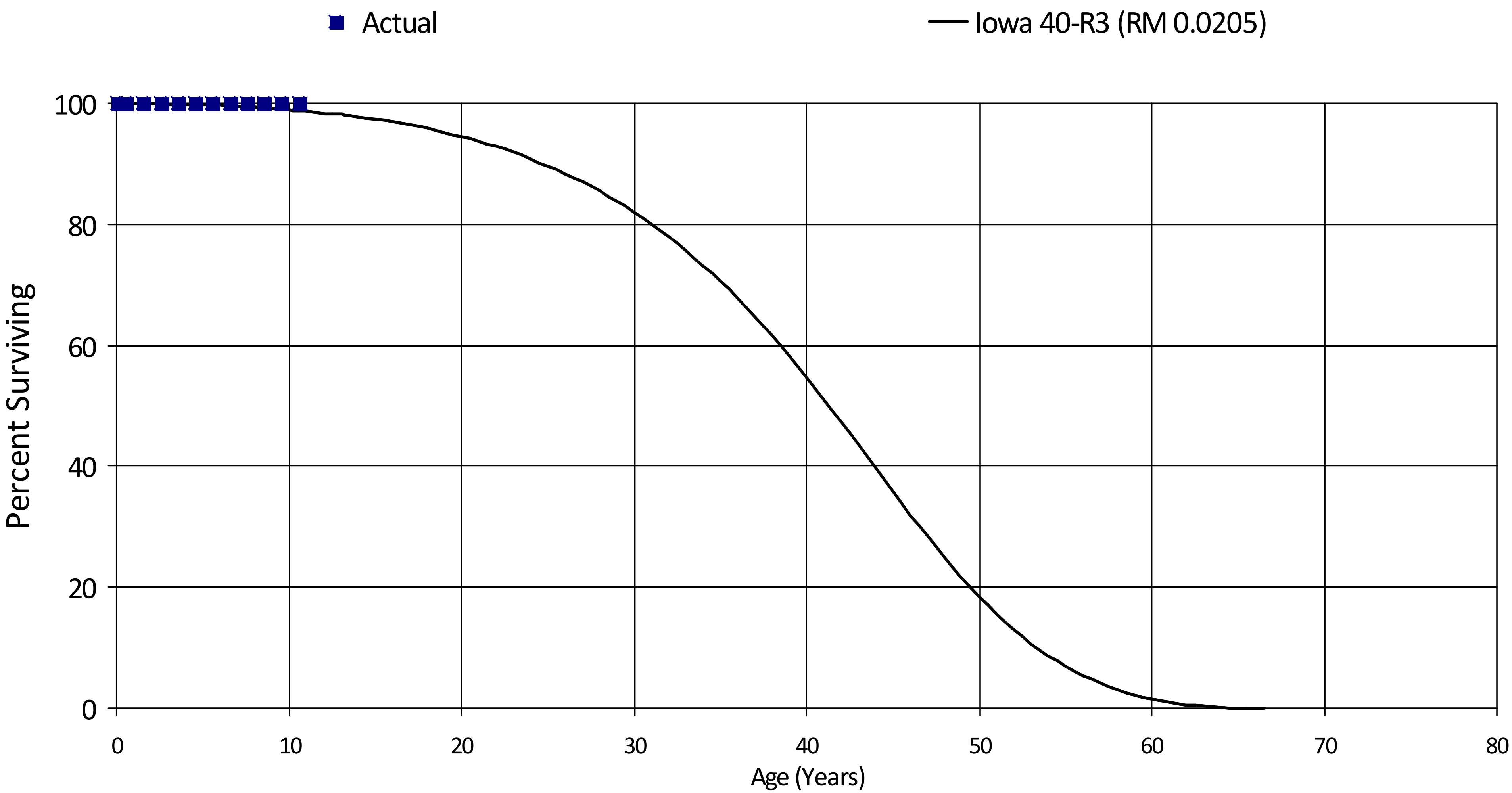
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	61,836,512	0	0.00000	1.00000	100.00
0.5	61,836,512	0	0.00000	1.00000	100.00
1.5	61,783,669	0	0.00000	1.00000	100.00
2.5	61,773,836	0	0.00000	1.00000	100.00
3.5	60,655,015	0	0.00000	1.00000	100.00
4.5	60,652,242	0	0.00000	1.00000	100.00
5.5	60,285,058	0	0.00000	1.00000	100.00
6.5	60,129,347	0	0.00000	1.00000	100.00
7.5	60,096,336	0	0.00000	1.00000	100.00
8.5	60,096,336	0	0.00000	1.00000	100.00
9.5	60,096,336	0	0.00000	1.00000	100.00
10.5	60,096,336	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.10 - Piping - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.10 - Piping - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

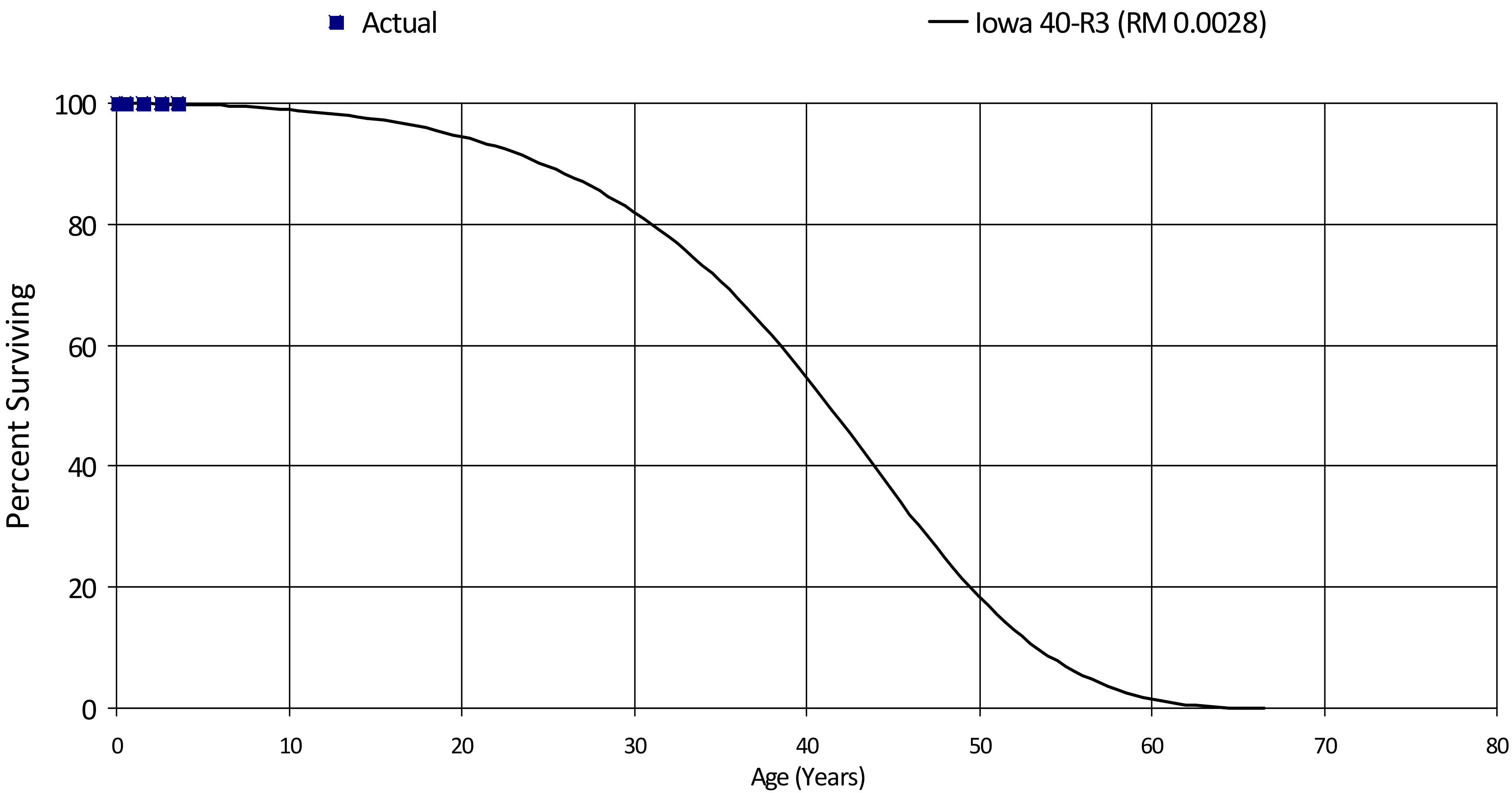
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,714,468	0	0.00000	1.00000	100.00
0.5	12,714,468	0	0.00000	1.00000	100.00
1.5	12,562,527	0	0.00000	1.00000	100.00
2.5	12,454,595	0	0.00000	1.00000	100.00
3.5	12,452,280	0	0.00000	1.00000	100.00
4.5	12,431,600	0	0.00000	1.00000	100.00
5.5	11,531,088	0	0.00000	1.00000	100.00
6.5	11,531,088	0	0.00000	1.00000	100.00
7.5	11,485,374	0	0.00000	1.00000	100.00
8.5	11,485,374	0	0.00000	1.00000	100.00
9.5	11,485,374	0	0.00000	1.00000	100.00
10.5	11,485,374	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.11 - Piping (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.11 - Piping (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

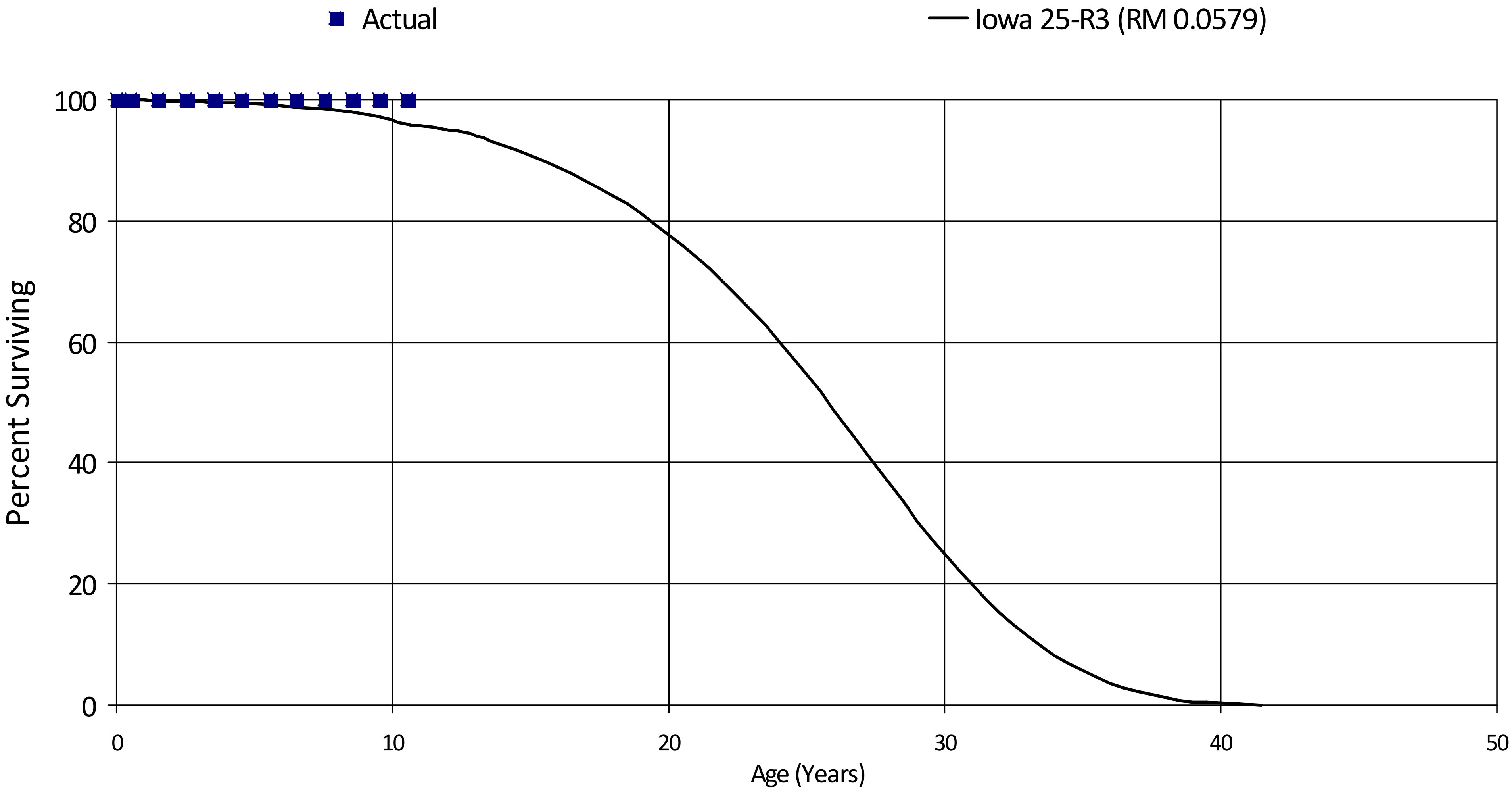
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	52,842,616	0	0.00000	1.00000	100.00
0.5	52,816,633	0	0.00000	1.00000	100.00
1.5	52,618,427	0	0.00000	1.00000	100.00
2.5	39,033,153	0	0.00000	1.00000	100.00
3.5	38,641,329	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.20 - Pre-Treatment - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.20 - Pre-Treatment - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

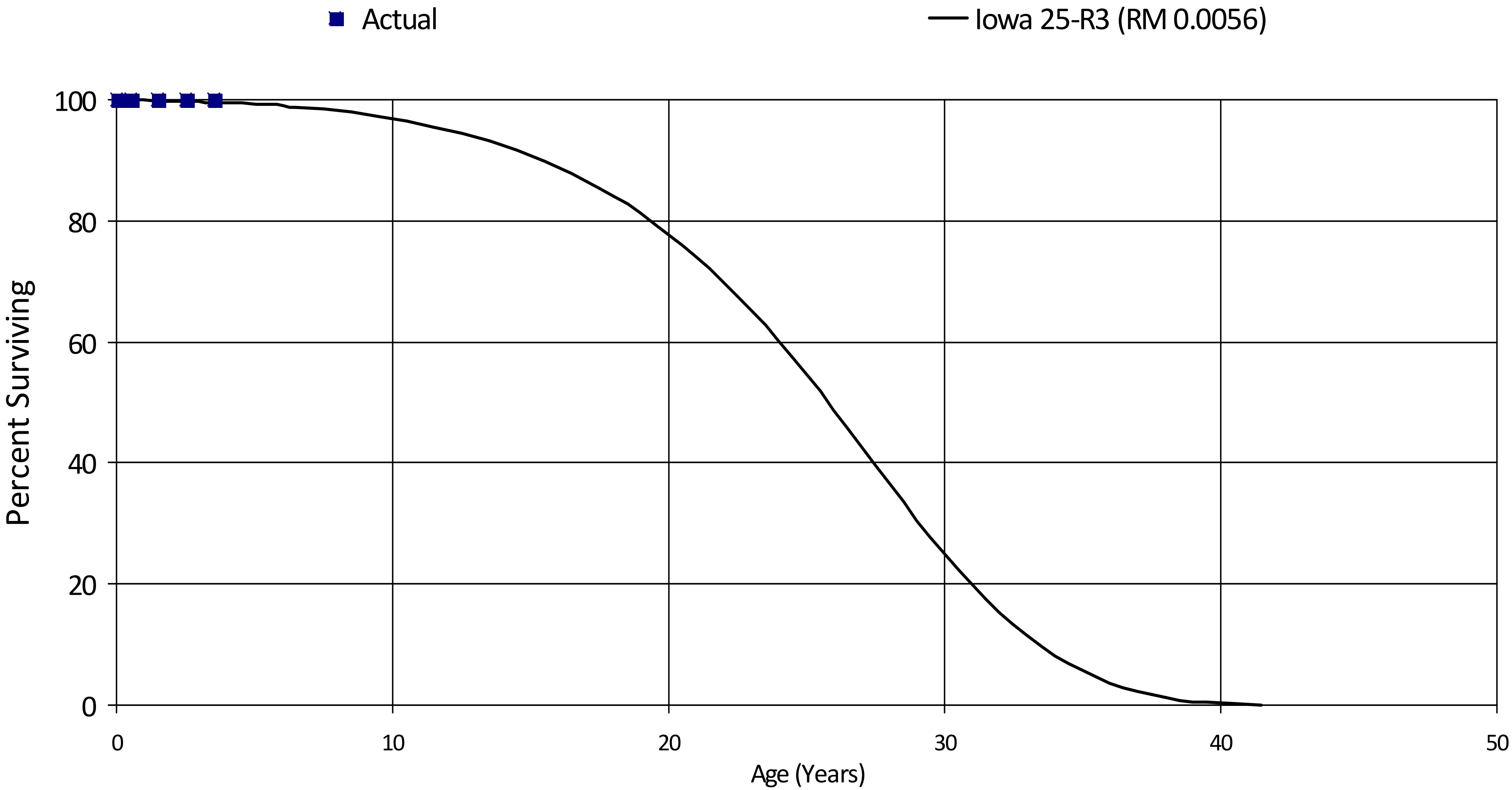
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	29,347,745	0	0.00000	1.00000	100.00
0.5	29,347,745	0	0.00000	1.00000	100.00
1.5	29,274,048	0	0.00000	1.00000	100.00
2.5	29,238,349	0	0.00000	1.00000	100.00
3.5	29,238,349	0	0.00000	1.00000	100.00
4.5	29,238,349	0	0.00000	1.00000	100.00
5.5	29,221,013	0	0.00000	1.00000	100.00
6.5	28,990,419	0	0.00000	1.00000	100.00
7.5	28,705,901	0	0.00000	1.00000	100.00
8.5	28,705,901	0	0.00000	1.00000	100.00
9.5	28,705,901	0	0.00000	1.00000	100.00
10.5	28,705,901	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.21 - Pre-treatment (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.21 - Pre-treatment (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

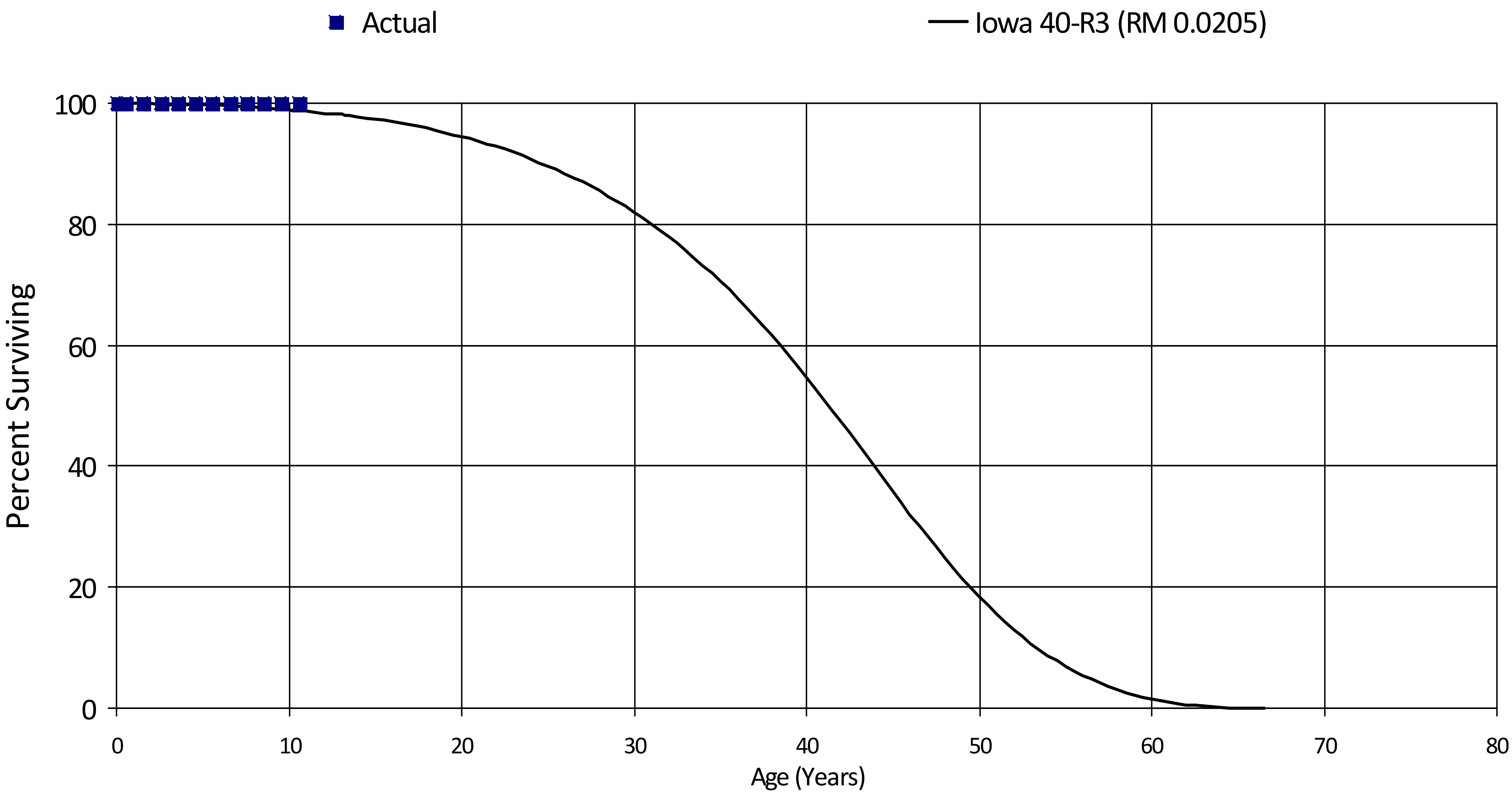
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	34,099,015	0	0.00000	1.00000	100.00
0.5	33,508,418	0	0.00000	1.00000	100.00
1.5	33,159,307	0	0.00000	1.00000	100.00
2.5	32,545,232	0	0.00000	1.00000	100.00
3.5	31,465,017	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.30 - Liquefaction Equipment - LNG Plant

Placement Band - 2011 - 2021 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.30 - Liquefaction Equipment - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

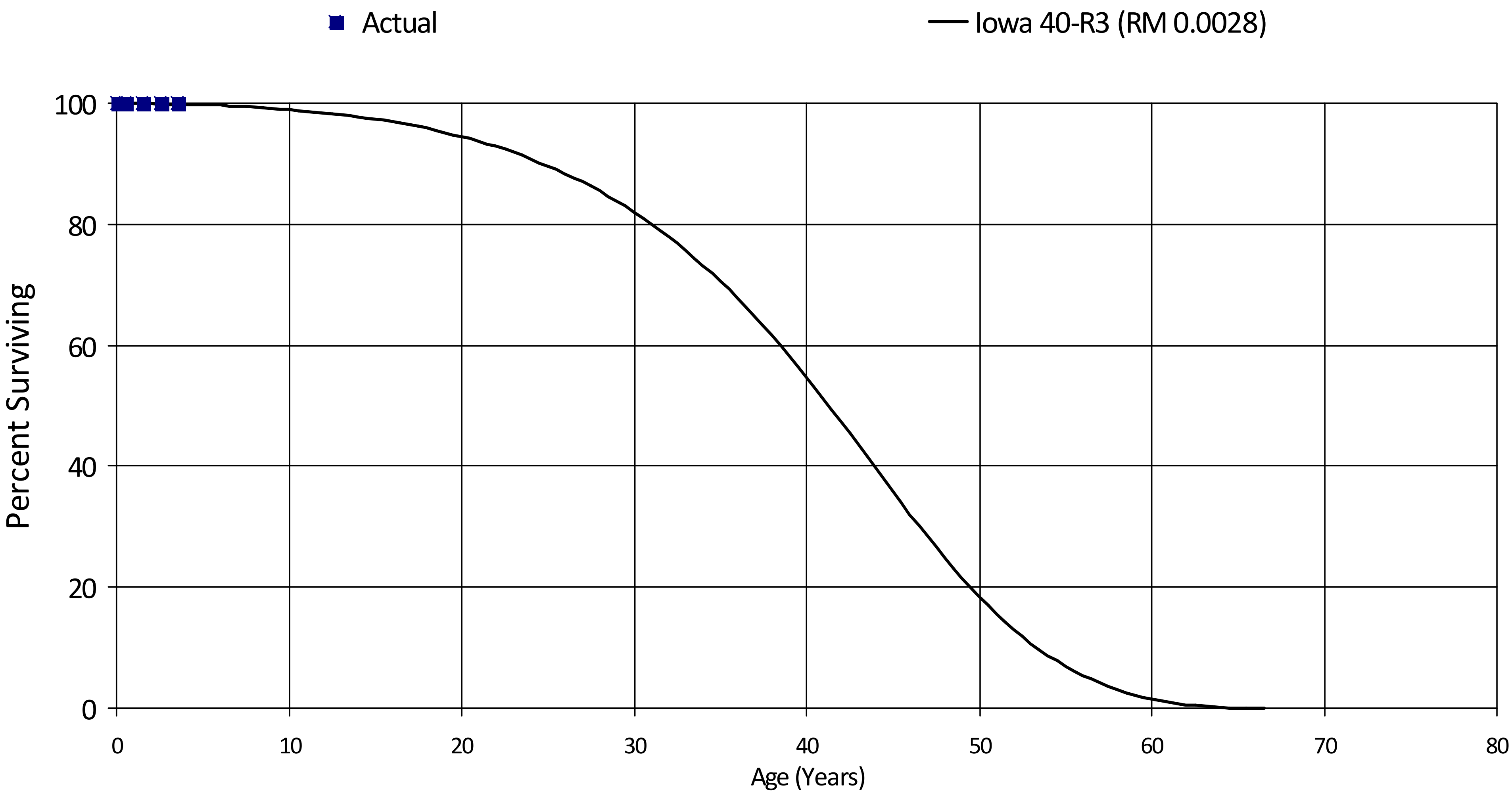
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	28,939,534	0	0.00000	1.00000	100.00
0.5	28,939,534	0	0.00000	1.00000	100.00
1.5	28,879,533	0	0.00000	1.00000	100.00
2.5	28,879,533	0	0.00000	1.00000	100.00
3.5	28,879,533	0	0.00000	1.00000	100.00
4.5	28,879,533	0	0.00000	1.00000	100.00
5.5	28,828,878	0	0.00000	1.00000	100.00
6.5	28,828,878	0	0.00000	1.00000	100.00
7.5	28,705,901	0	0.00000	1.00000	100.00
8.5	28,705,901	0	0.00000	1.00000	100.00
9.5	28,705,901	0	0.00000	1.00000	100.00
10.5	28,705,901	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.31 - Liquefacation Equipment (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.31 - Liquefacation Equipment (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

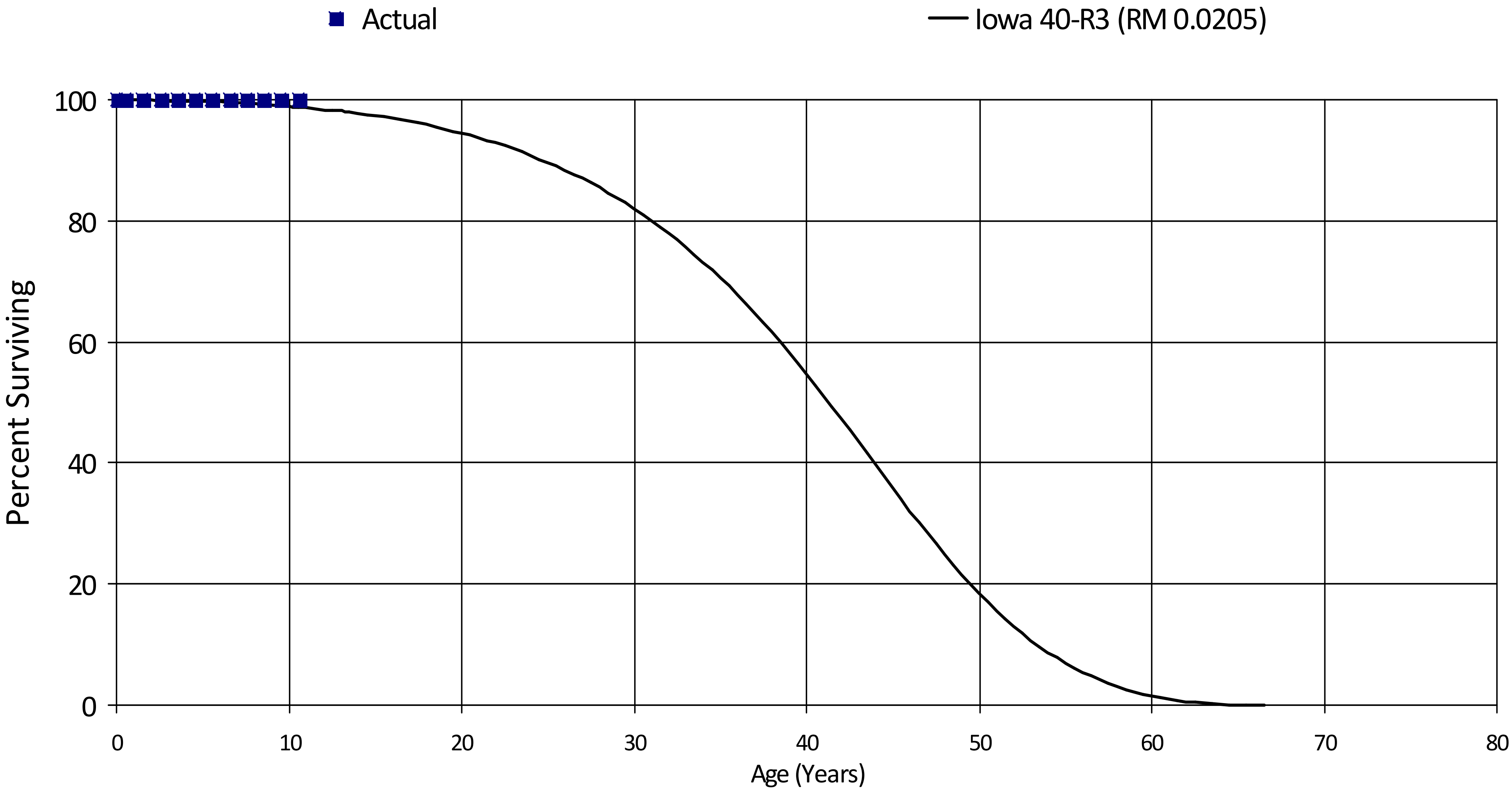
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	88,823,153	0	0.00000	1.00000	100.00
0.5	88,643,220	0	0.00000	1.00000	100.00
1.5	88,170,999	0	0.00000	1.00000	100.00
2.5	86,281,377	0	0.00000	1.00000	100.00
3.5	84,778,551	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.40 - Send Out Equipment - LNG Plant

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.40 - Send Out Equipment - LNG Plant

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

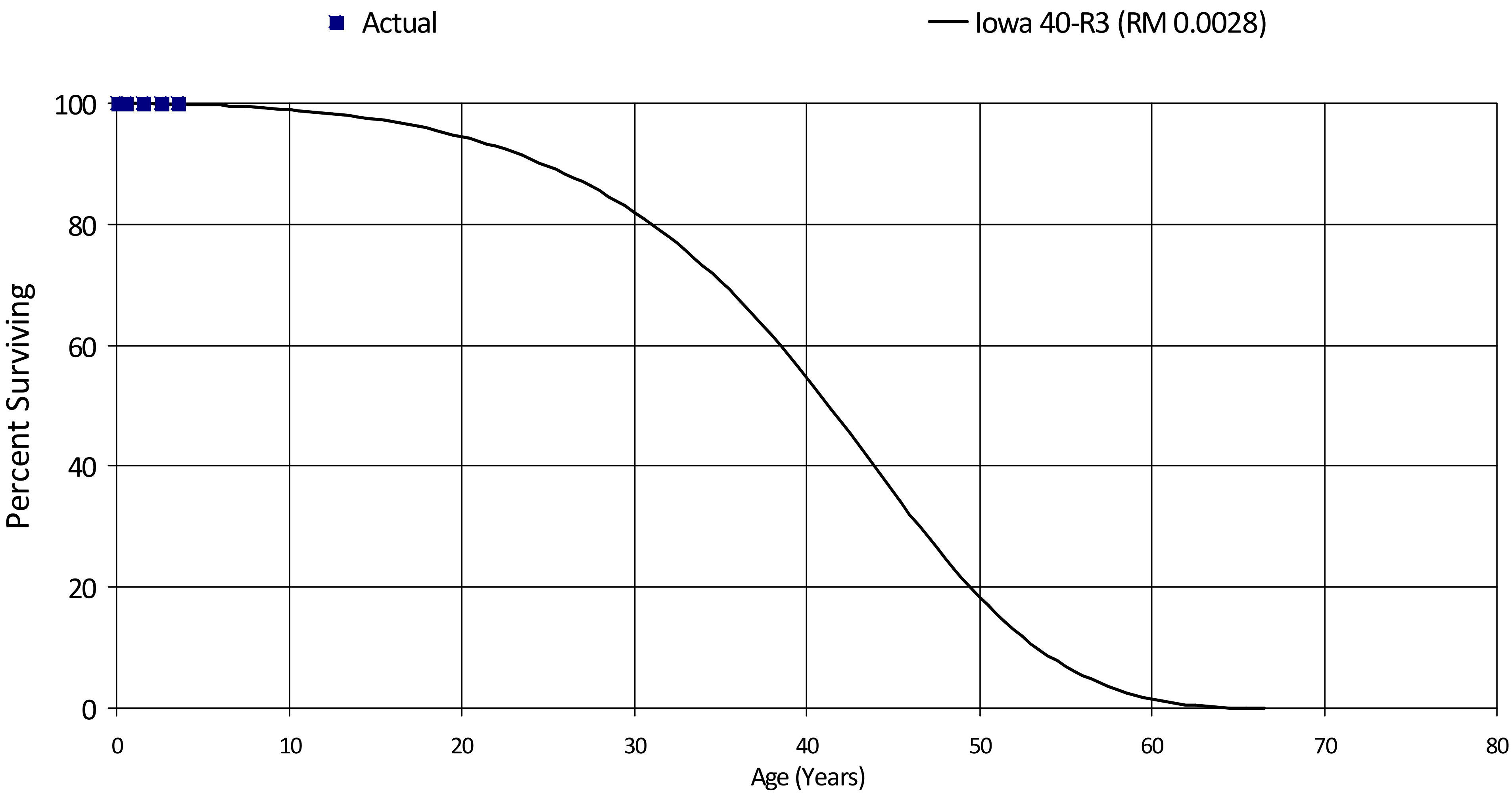
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,743,248	0	0.00000	1.00000	100.00
0.5	23,723,855	0	0.00000	1.00000	100.00
1.5	23,552,210	0	0.00000	1.00000	100.00
2.5	23,552,210	0	0.00000	1.00000	100.00
3.5	23,552,210	0	0.00000	1.00000	100.00
4.5	23,552,210	0	0.00000	1.00000	100.00
5.5	23,350,369	0	0.00000	1.00000	100.00
6.5	23,315,061	0	0.00000	1.00000	100.00
7.5	22,954,145	0	0.00000	1.00000	100.00
8.5	22,954,145	0	0.00000	1.00000	100.00
9.5	22,954,145	0	0.00000	1.00000	100.00
10.5	22,954,145	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.41 - Send Out Equipment (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.41 - Send Out Equipment (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

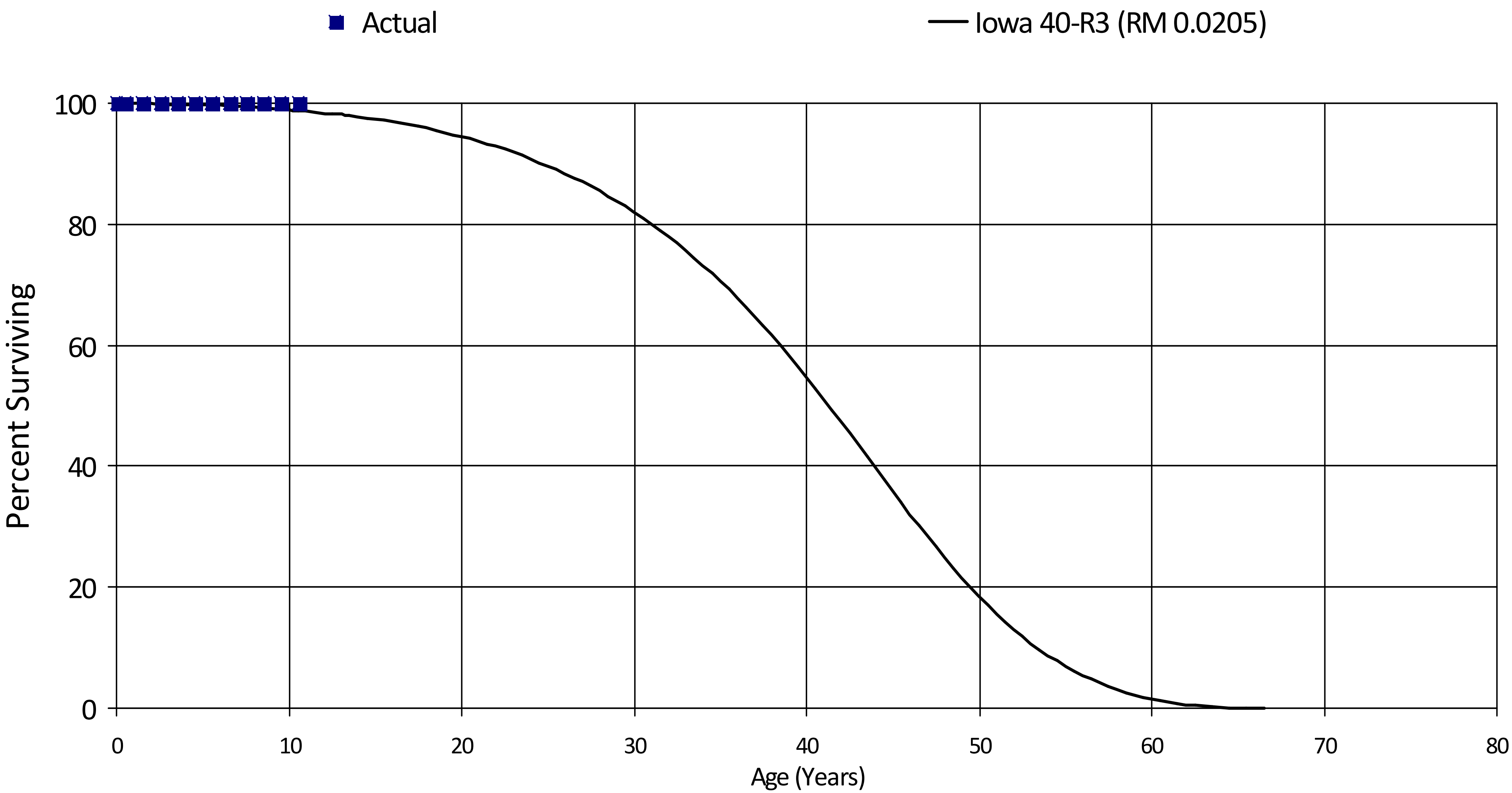
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	10,675,476	0	0.00000	1.00000	100.00
0.5	7,857,781	0	0.00000	1.00000	100.00
1.5	7,650,233	0	0.00000	1.00000	100.00
2.5	6,794,804	0	0.00000	1.00000	100.00
3.5	6,609,363	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.50 - Substation and Electrical - LNG Plant

Placement Band - 2011 - 2017   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.50 - Substation and Electrical - LNG Plant

Placement Band - 2011 - 2017   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

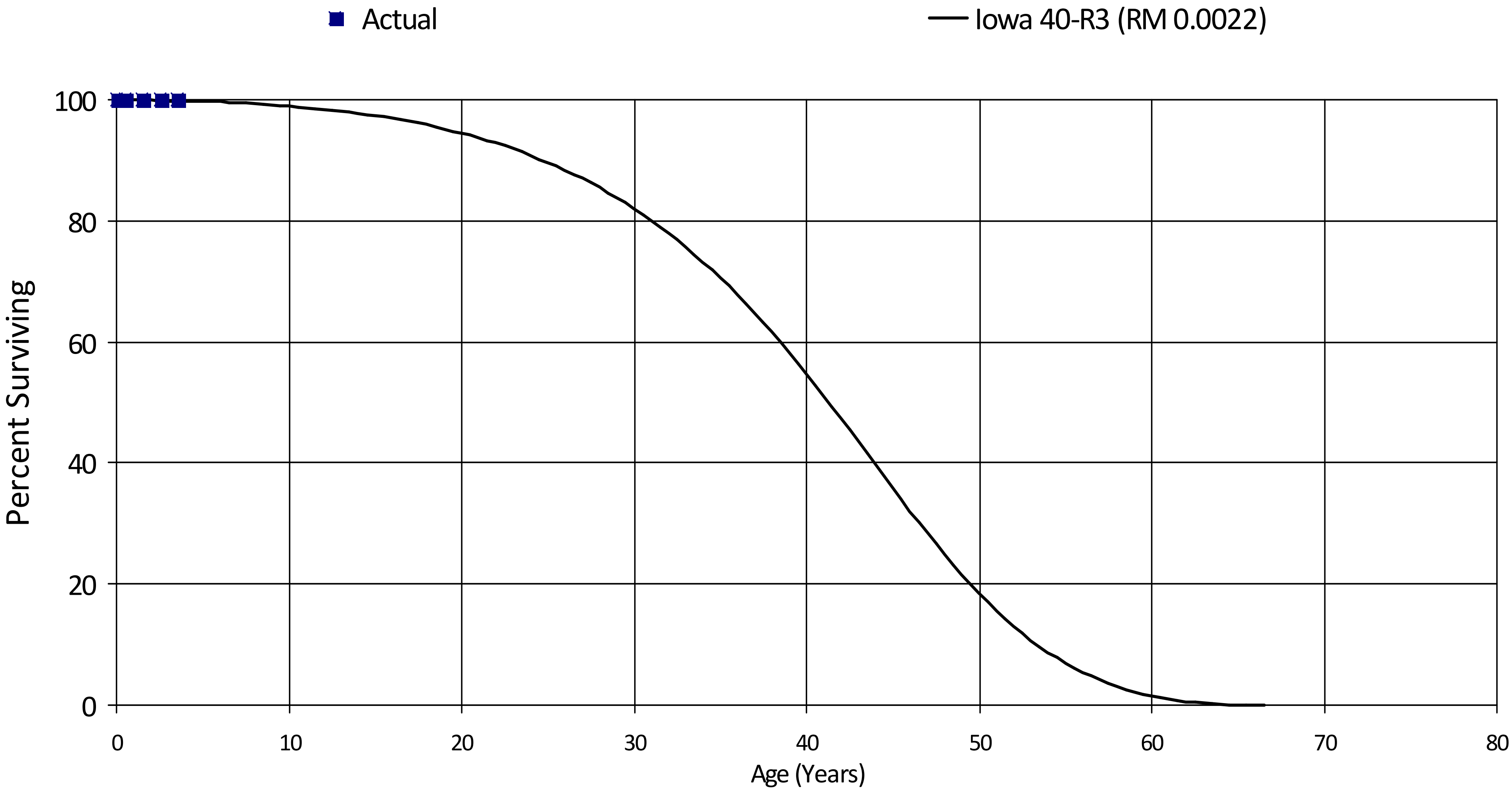
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	21,788,252	0	0.00000	1.00000	100.00
0.5	21,788,252	0	0.00000	1.00000	100.00
1.5	21,788,252	0	0.00000	1.00000	100.00
2.5	21,788,252	0	0.00000	1.00000	100.00
3.5	21,788,252	0	0.00000	1.00000	100.00
4.5	21,788,252	0	0.00000	1.00000	100.00
5.5	21,745,828	0	0.00000	1.00000	100.00
6.5	21,745,828	0	0.00000	1.00000	100.00
7.5	21,638,229	0	0.00000	1.00000	100.00
8.5	21,638,229	0	0.00000	1.00000	100.00
9.5	21,638,229	0	0.00000	1.00000	100.00
10.5	21,638,229	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.51 - Substation and Electrical (Tilbury)

Placement Band - 2018 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.51 - Substation and Electrical (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

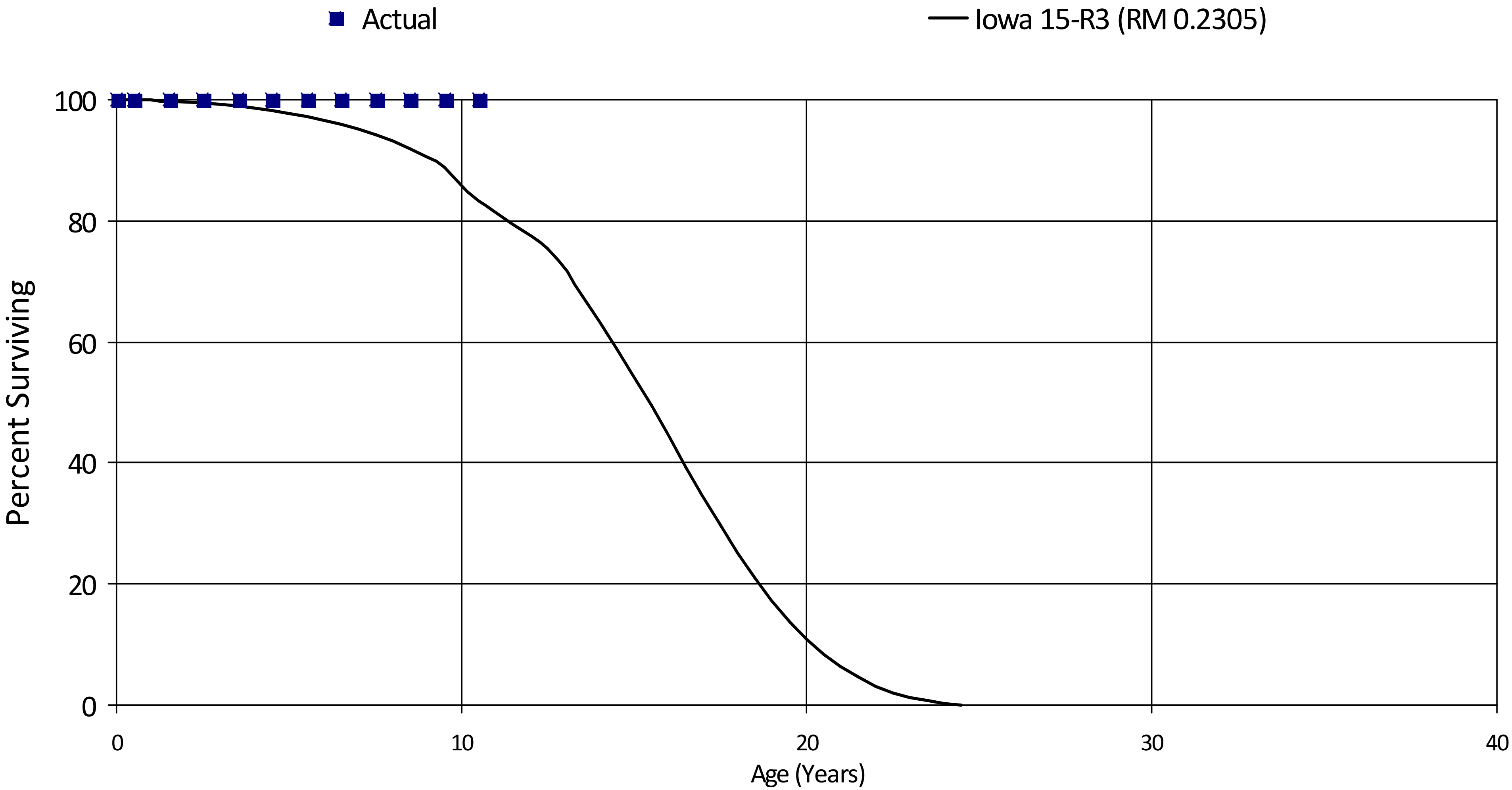
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	38,270,155	0	0.00000	1.00000	100.00
0.5	37,174,297	0	0.00000	1.00000	100.00
1.5	36,990,458	0	0.00000	1.00000	100.00
2.5	36,215,859	25,000	0.00069	0.99931	100.00
3.5	35,786,573	0	0.00000	1.00000	99.93
	Totals:	25,000			

FortisBC

Account 448.60 - Control Room - LNG Plant

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.60 - Control Room - LNG Plant

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

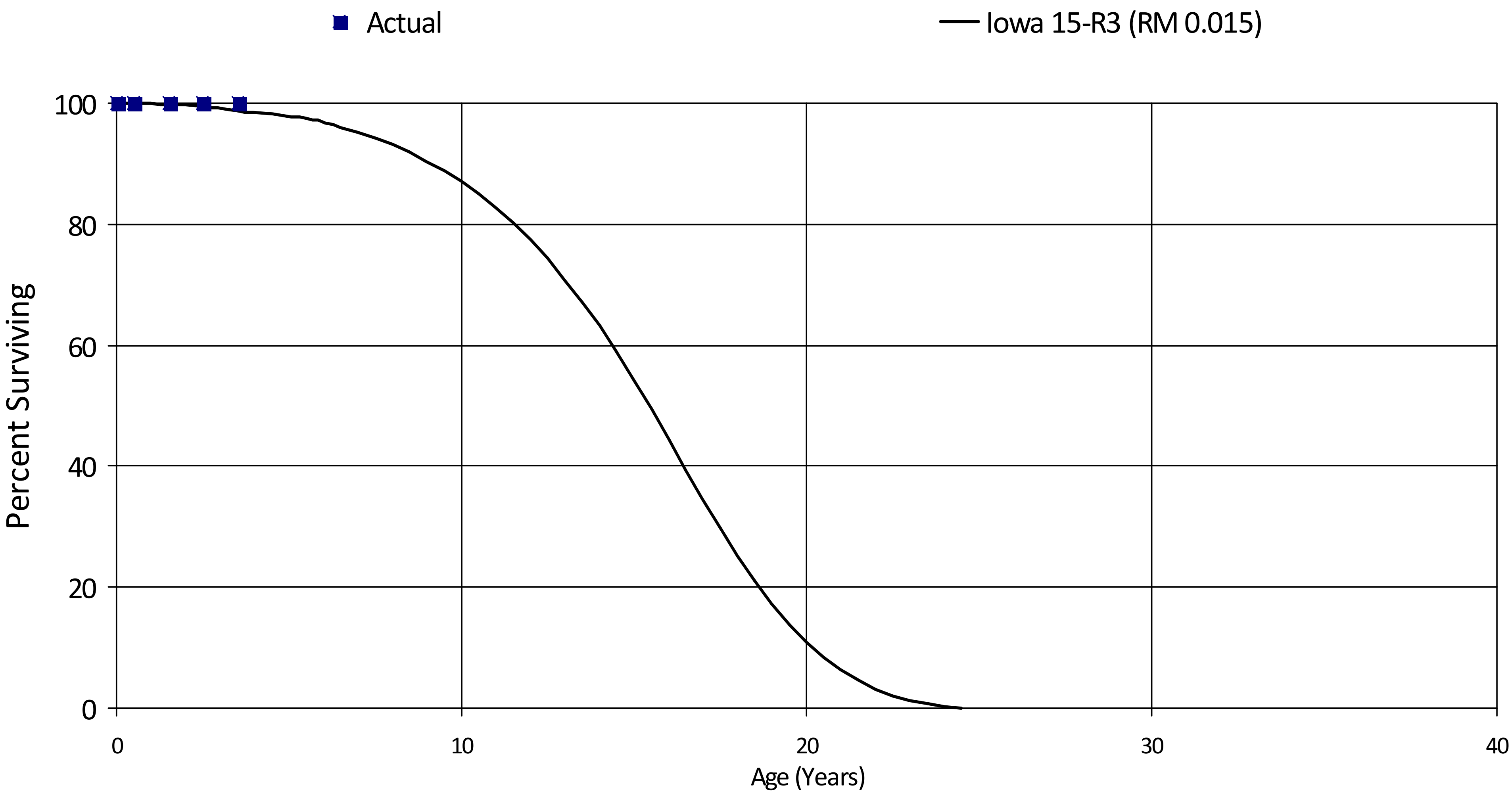
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,664,704	0	0.00000	1.00000	100.00
0.5	6,599,562	0	0.00000	1.00000	100.00
1.5	6,598,703	0	0.00000	1.00000	100.00
2.5	6,425,148	0	0.00000	1.00000	100.00
3.5	6,353,356	0	0.00000	1.00000	100.00
4.5	6,353,356	0	0.00000	1.00000	100.00
5.5	6,353,356	0	0.00000	1.00000	100.00
6.5	6,130,516	0	0.00000	1.00000	100.00
7.5	5,898,480	0	0.00000	1.00000	100.00
8.5	5,898,480	0	0.00000	1.00000	100.00
9.5	5,898,480	0	0.00000	1.00000	100.00
10.5	5,898,480	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 448.61 - Control Room (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 448.61 - Control Room (Tilbury)

Placement Band - 2018 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

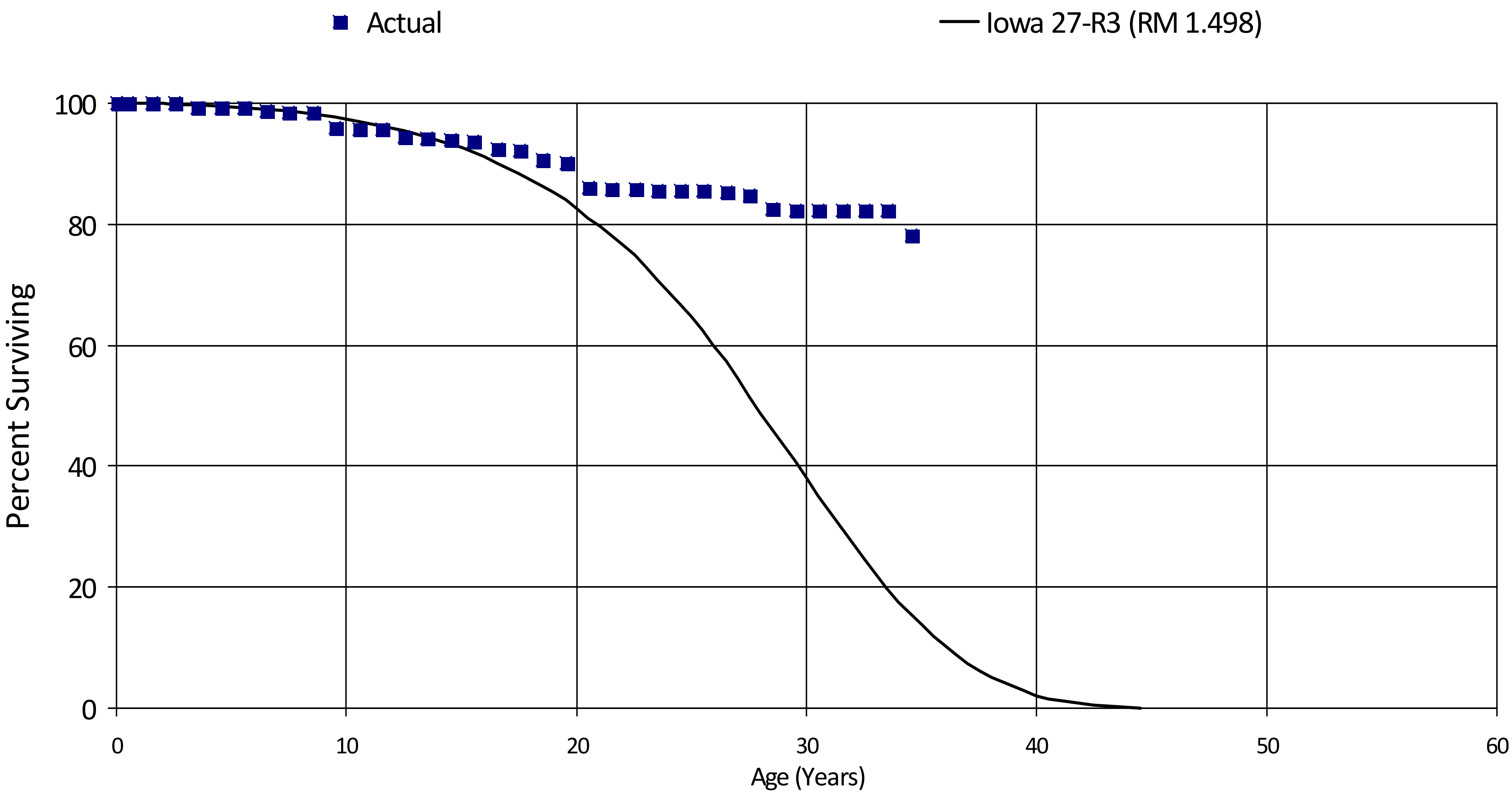
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,608,084	0	0.00000	1.00000	100.00
0.5	4,453,303	0	0.00000	1.00000	100.00
1.5	3,748,542	0	0.00000	1.00000	100.00
2.5	3,658,426	0	0.00000	1.00000	100.00
3.5	3,617,885	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 449.00 - Other Equipment - LNG Plant

Placement Band - 1970 - 2022   Experience Band - 1985 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 449.00 - Other Equipment - LNG Plant

Placement Band - 1970 - 2022   Experience Band - 1985 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,888,717	500	0.00002	0.99998	100.00
0.5	32,493,200	0	0.00000	1.00000	100.00
1.5	31,010,722	1	0.00000	1.00000	100.00
2.5	30,980,582	258,133	0.00833	0.99167	100.00
3.5	30,288,807	48	0.00000	1.00000	99.17
4.5	28,599,913	10,802	0.00038	0.99962	99.17
5.5	28,569,585	125,989	0.00441	0.99559	99.13
6.5	28,106,242	56,589	0.00201	0.99799	98.69
7.5	27,897,422	9,223	0.00033	0.99967	98.49
8.5	27,799,600	698,665	0.02513	0.97487	98.46
9.5	27,074,276	94,101	0.00348	0.99652	95.99
10.5	26,335,209	25,930	0.00098	0.99902	95.66
11.5	26,245,209	286,493	0.01092	0.98908	95.57
12.5	25,331,366	123,449	0.00487	0.99513	94.53
13.5	23,358,192	67,845	0.00290	0.99710	94.07
14.5	19,132,930	41,927	0.00219	0.99781	93.80
15.5	18,731,915	220,295	0.01176	0.98824	93.59
16.5	18,205,734	85,676	0.00471	0.99529	92.49
17.5	17,921,070	304,210	0.01697	0.98303	92.05
18.5	17,588,406	72,499	0.00412	0.99588	90.49
19.5	15,717,013	705,606	0.04489	0.95511	90.12
20.5	14,781,746	32,256	0.00218	0.99782	86.07
21.5	14,732,490	21,715	0.00147	0.99853	85.88
22.5	13,745,928	20,000	0.00145	0.99855	85.75
23.5	13,081,630	0	0.00000	1.00000	85.63
24.5	13,063,070	0	0.00000	1.00000	85.63
25.5	12,981,940	62,851	0.00484	0.99516	85.63
26.5	12,180,018	58,992	0.00484	0.99516	85.22

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Account 449.00 - Other Equipment - LNG Plant

Placement Band - 1970 - 2022 Experience Band - 1985 - 2022

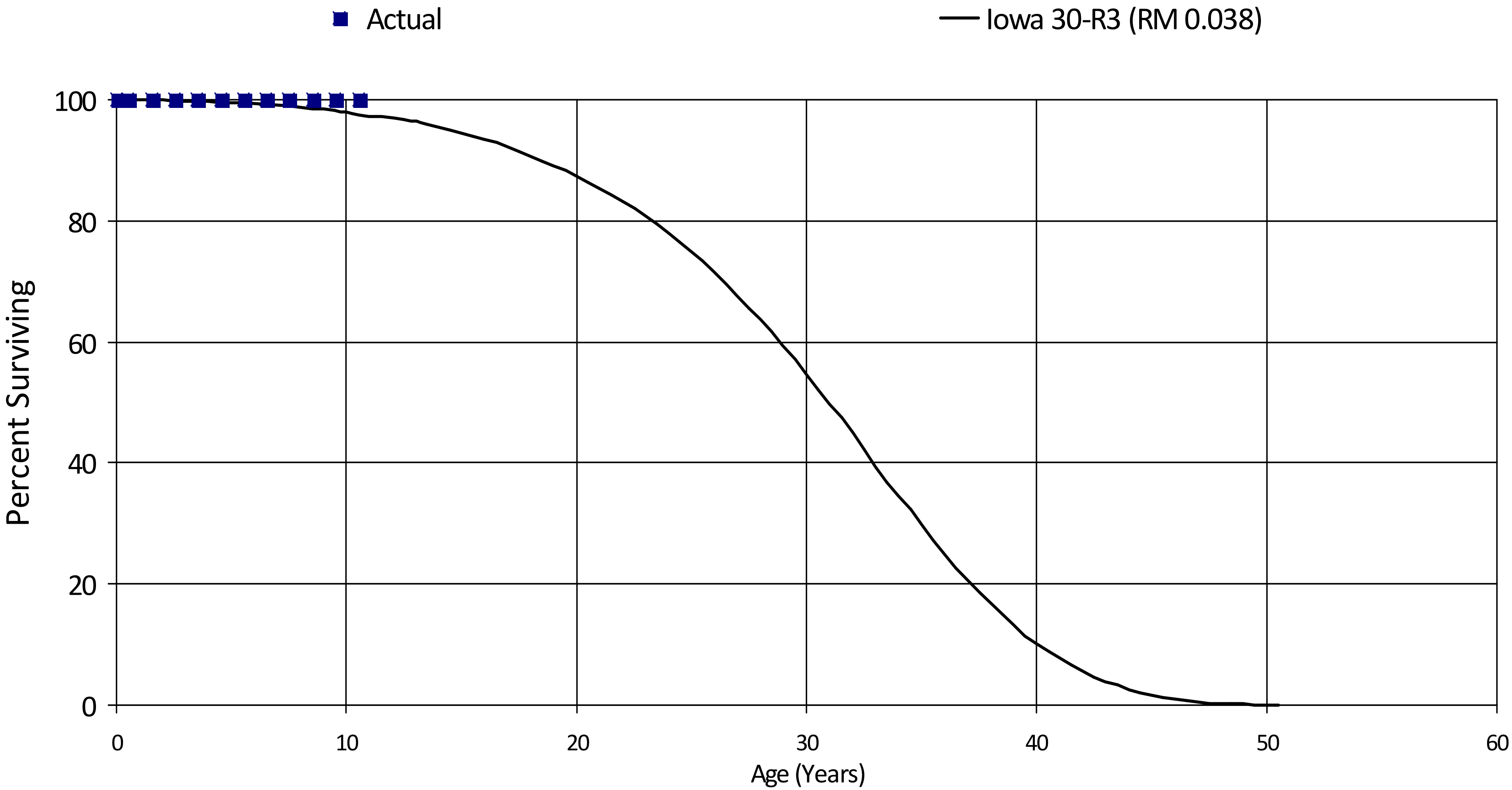
27.5	9,249,509	239,799	0.02593	0.97407	84.81
28.5	8,966,959	47,273	0.00527	0.99473	82.61
29.5	6,628,203	3,500	0.00053	0.99947	82.17
30.5	6,091,400	0	0.00000	1.00000	82.13
31.5	5,536,937	0	0.00000	1.00000	82.13
32.5	5,536,937	0	0.00000	1.00000	82.13
33.5	5,536,937	259,113	0.04680	0.95320	82.13
34.5	0	0	0.00000	0.00000	78.29
	Totals:	3,933,480			

FortisBC

Account 449.01 - Other Equipment - Mt. Hayes - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 449.01 - Other Equipment - Mt. Hayes - LNG Plant

Placement Band - 2011 - 2021   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

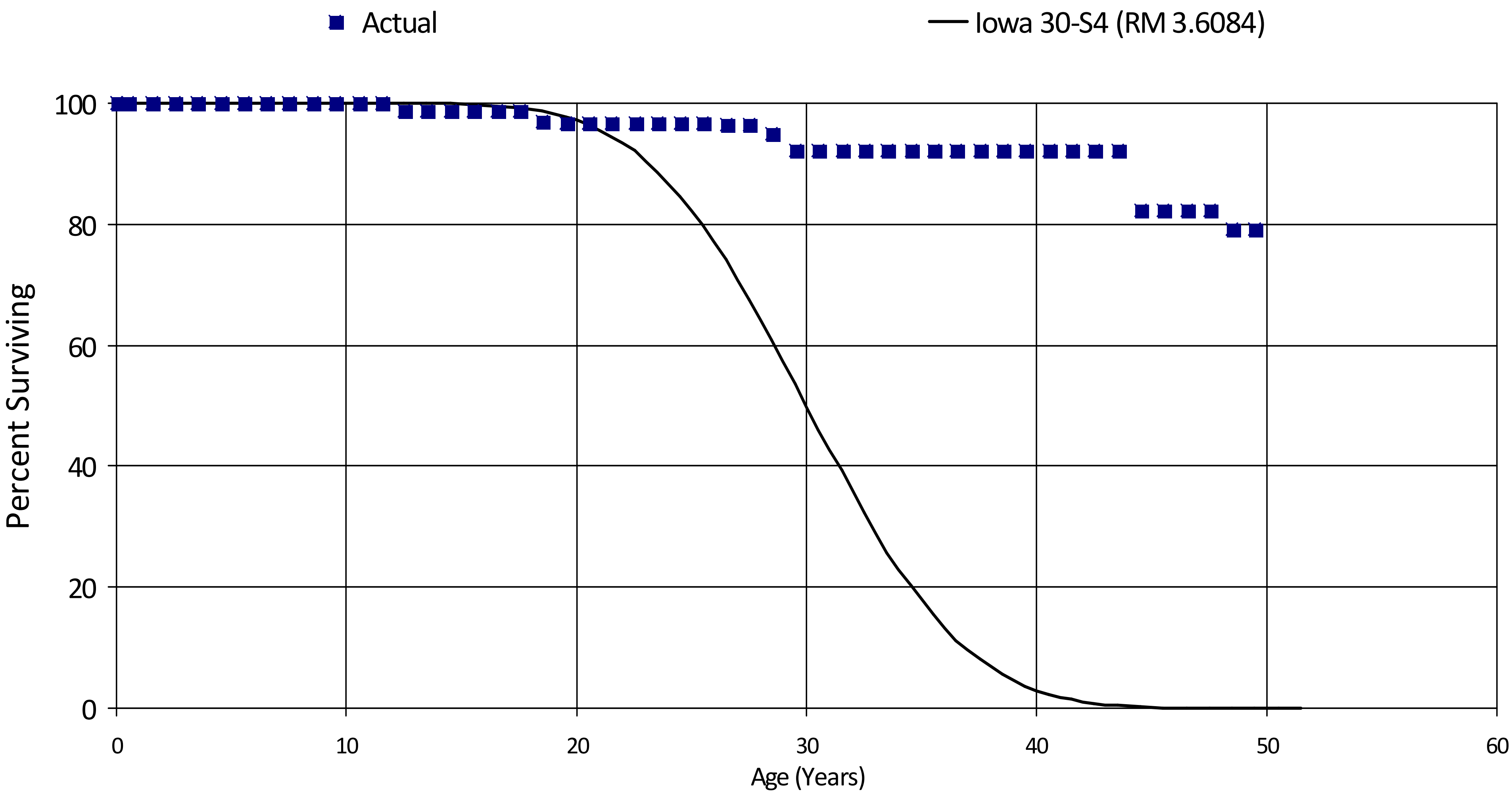
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,133,465	0	0.00000	1.00000	100.00
0.5	6,133,465	0	0.00000	1.00000	100.00
1.5	5,736,853	0	0.00000	1.00000	100.00
2.5	5,727,459	0	0.00000	1.00000	100.00
3.5	5,600,432	0	0.00000	1.00000	100.00
4.5	5,600,432	0	0.00000	1.00000	100.00
5.5	5,592,016	0	0.00000	1.00000	100.00
6.5	5,232,908	0	0.00000	1.00000	100.00
7.5	2,958,915	0	0.00000	1.00000	100.00
8.5	33,236	0	0.00000	1.00000	100.00
9.5	33,236	0	0.00000	1.00000	100.00
10.5	33,236	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 462.00 - Compressor Structures - Transmission Plant

Placement Band - 1965 - 2022   Experience Band - 1974 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 462.00 - Compressor Structures - Transmission Plant

Placement Band - 1965 - 2022   Experience Band - 1974 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	47,235,674	458	0.00001	0.99999	100.00
0.5	44,095,638	0	0.00000	1.00000	100.00
1.5	35,029,759	1,338	0.00004	0.99996	100.00
2.5	33,700,623	0	0.00000	1.00000	100.00
3.5	32,626,559	1,225	0.00004	0.99996	100.00
4.5	32,401,712	7,893	0.00024	0.99976	100.00
5.5	32,125,260	6,379	0.00020	0.99980	99.98
6.5	30,805,058	2,414	0.00008	0.99992	99.96
7.5	30,380,065	659	0.00002	0.99998	99.95
8.5	30,221,717	3,363	0.00011	0.99989	99.95
9.5	29,556,282	3,380	0.00011	0.99989	99.94
10.5	27,621,163	6,438	0.00023	0.99977	99.93
11.5	27,048,205	288,000	0.01065	0.98935	99.91
12.5	26,534,887	1,162	0.00004	0.99996	98.85
13.5	26,083,969	15,868	0.00061	0.99939	98.85
14.5	25,891,301	13,625	0.00053	0.99947	98.79
15.5	24,216,412	1,961	0.00008	0.99992	98.74
16.5	24,161,606	3,140	0.00013	0.99987	98.73
17.5	24,158,466	458,159	0.01896	0.98104	98.72
18.5	23,532,586	8,000	0.00034	0.99966	96.85
19.5	23,413,210	10,000	0.00043	0.99957	96.82
20.5	21,482,736	16,000	0.00074	0.99926	96.78
21.5	20,681,058	0	0.00000	1.00000	96.71
22.5	16,359,176	0	0.00000	1.00000	96.71
23.5	13,808,955	0	0.00000	1.00000	96.71
24.5	10,479,906	8,000	0.00076	0.99924	96.71
25.5	10,076,974	16,000	0.00159	0.99841	96.64
26.5	9,636,000	5,000	0.00052	0.99948	96.49

FortisBC

Account 462.00 - Compressor Structures - Transmission Plant

Placement Band - 1965 - 2022   Experience Band - 1974 - 2022

27.5	5,027,371	85,423	0.01699	0.98301	96.44
28.5	3,580,341	98,347	0.02747	0.97253	94.80
29.5	2,389,634	0	0.00000	1.00000	92.20
30.5	2,146,598	0	0.00000	1.00000	92.20
31.5	293,960	0	0.00000	1.00000	92.20
32.5	262,661	0	0.00000	1.00000	92.20
33.5	260,102	0	0.00000	1.00000	92.20
34.5	257,546	0	0.00000	1.00000	92.20
35.5	257,546	0	0.00000	1.00000	92.20
36.5	257,546	0	0.00000	1.00000	92.20
37.5	257,546	0	0.00000	1.00000	92.20
38.5	256,651	0	0.00000	1.00000	92.20
39.5	256,651	0	0.00000	1.00000	92.20
40.5	255,405	0	0.00000	1.00000	92.20
41.5	255,405	0	0.00000	1.00000	92.20
42.5	254,790	0	0.00000	1.00000	92.20
43.5	254,790	27,247	0.10694	0.89306	92.20
44.5	221,626	0	0.00000	1.00000	82.34
45.5	221,559	0	0.00000	1.00000	82.34
46.5	221,559	0	0.00000	1.00000	82.34
47.5	215,401	8,000	0.03714	0.96286	82.34
48.5	207,401	0	0.00000	1.00000	79.28
49.5	0	0	0.00000	0.00000	79.28
	Totals:	1,097,479			

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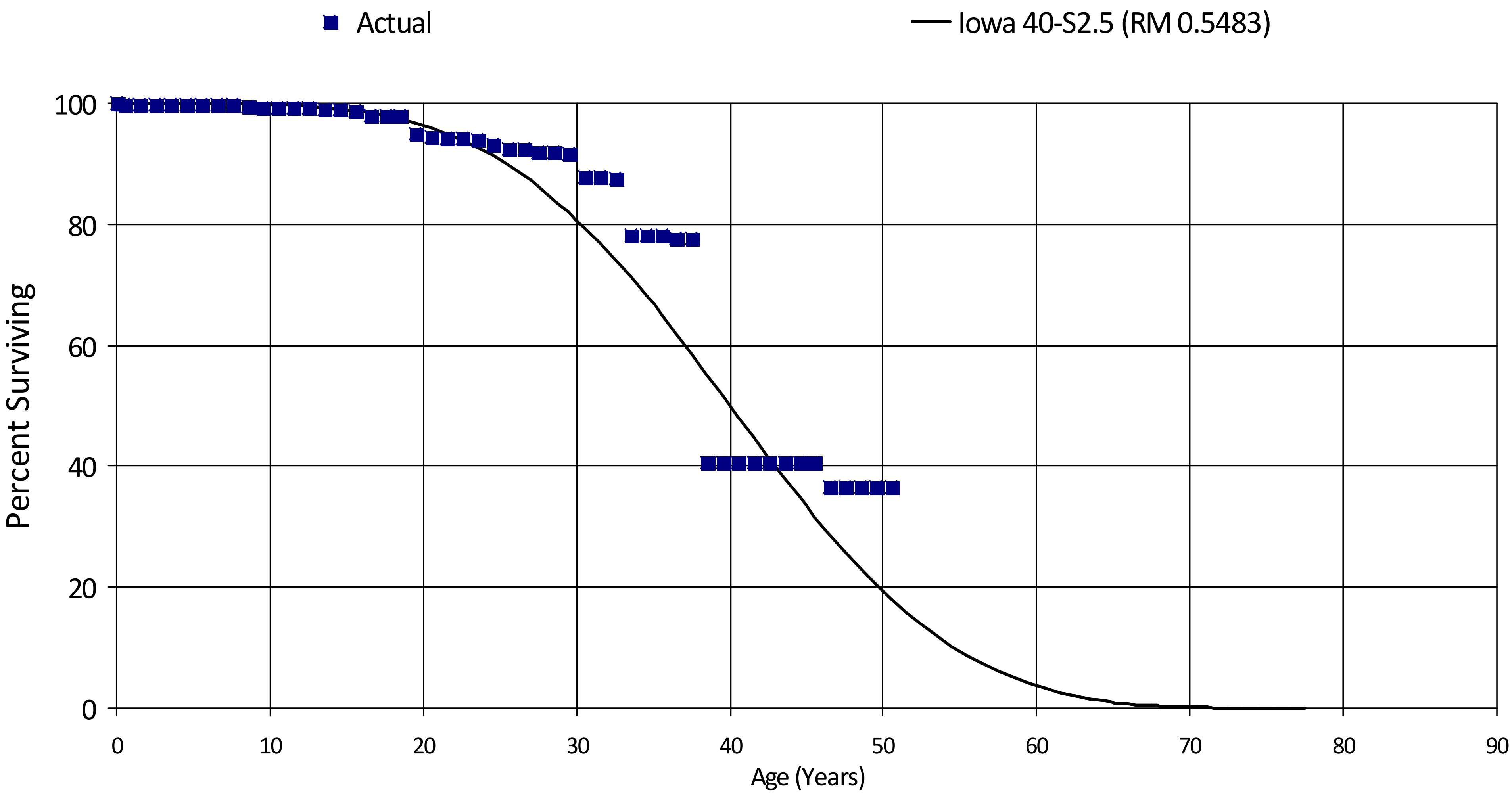
Account 463.00 - Measuring and Regulating Structures - Transmission Plant

Placement Band - 1956 - 2022   Experience Band - 1968 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 463.00 - Measuring and Regulating Structures - Transmission Plant

Placement Band - 1956 - 2022   Experience Band - 1968 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,047,665	53,753	0.00199	0.99801	100.00
0.5	25,460,123	3	0.00000	1.00000	99.80
1.5	24,509,883	4,023	0.00016	0.99984	99.80
2.5	20,991,732	142	0.00001	0.99999	99.78
3.5	16,521,960	167	0.00001	0.99999	99.78
4.5	15,844,122	2,546	0.00016	0.99984	99.78
5.5	15,482,210	597	0.00004	0.99996	99.76
6.5	15,214,902	6,386	0.00042	0.99958	99.76
7.5	14,794,161	17,727	0.00120	0.99880	99.72
8.5	14,650,711	48,726	0.00333	0.99667	99.60
9.5	13,703,607	4,013	0.00029	0.99971	99.27
10.5	13,565,136	544	0.00004	0.99996	99.24
11.5	13,414,288	437	0.00003	0.99997	99.24
12.5	13,075,349	36,190	0.00277	0.99723	99.24
13.5	12,825,491	1,380	0.00011	0.99989	98.97
14.5	12,714,805	22,233	0.00175	0.99825	98.96
15.5	10,935,126	100,090	0.00915	0.99085	98.79
16.5	9,049,965	113	0.00001	0.99999	97.89
17.5	8,895,287	59	0.00001	0.99999	97.89
18.5	8,528,965	265,851	0.03117	0.96883	97.89
19.5	8,059,165	41,957	0.00521	0.99479	94.84
20.5	7,206,747	10,416	0.00145	0.99855	94.35
21.5	7,090,471	6,227	0.00088	0.99912	94.21
22.5	6,685,067	18,950	0.00283	0.99717	94.13
23.5	6,045,928	49,497	0.00819	0.99181	93.86
24.5	5,875,899	37,213	0.00633	0.99367	93.09
25.5	5,644,165	3,000	0.00053	0.99947	92.50
26.5	5,293,684	33,393	0.00631	0.99369	92.45

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Account 463.00 - Measuring and Regulating Structures - Transmission Plant

Placement Band - 1956 - 2022   Experience Band - 1968 - 2022

27.5	4,817,309	0	0.00000	1.00000	91.87
28.5	4,746,113	14,938	0.00315	0.99685	91.87
29.5	4,557,120	187,045	0.04104	0.95896	91.58
30.5	4,123,359	0	0.00000	1.00000	87.82
31.5	283,541	622	0.00219	0.99781	87.82
32.5	277,670	29,850	0.10750	0.89250	87.63
33.5	245,917	0	0.00000	1.00000	78.21
34.5	127,995	0	0.00000	1.00000	78.21
35.5	119,591	1,000	0.00836	0.99164	78.21
36.5	117,227	0	0.00000	1.00000	77.56
37.5	114,183	54,267	0.47526	0.52474	77.56
38.5	51,000	230	0.00451	0.99549	40.70
39.5	50,770	0	0.00000	1.00000	40.52
40.5	49,524	0	0.00000	1.00000	40.52
41.5	49,524	0	0.00000	1.00000	40.52
42.5	47,862	0	0.00000	1.00000	40.52
43.5	47,862	0	0.00000	1.00000	40.52
44.5	47,862	0	0.00000	1.00000	40.52
45.5	47,862	4,697	0.09814	0.90186	40.52
46.5	43,165	0	0.00000	1.00000	36.54
47.5	43,165	0	0.00000	1.00000	36.54
48.5	30,628	0	0.00000	1.00000	36.54
49.5	30,628	0	0.00000	1.00000	36.54
50.5	0	0	0.00000	0.00000	36.54
	Totals:	1,058,282			

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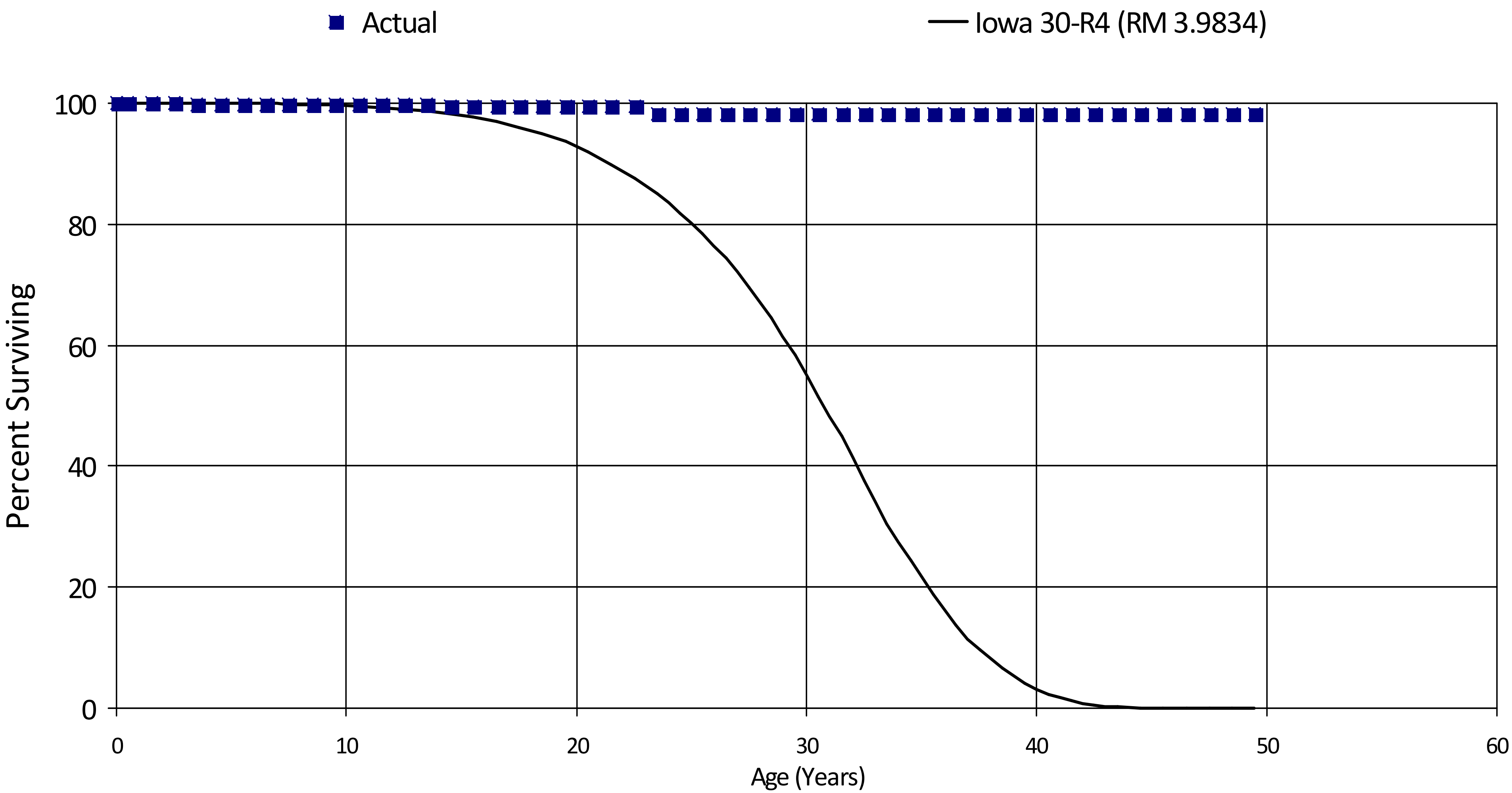
Account 464.00 - Other Structures - Transmission Plant

Placement Band - 1968 - 2019   Experience Band - 1970 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 464.00 - Other Structures - Transmission Plant

Placement Band - 1968 - 2019   Experience Band - 1970 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,913,829	0	0.00000	1.00000	100.00
0.5	6,913,829	0	0.00000	1.00000	100.00
1.5	6,913,829	7,358	0.00106	0.99894	100.00
2.5	6,906,471	4,055	0.00059	0.99941	99.89
3.5	6,847,862	7,453	0.00109	0.99891	99.83
4.5	6,787,369	0	0.00000	1.00000	99.72
5.5	6,787,369	0	0.00000	1.00000	99.72
6.5	6,592,843	0	0.00000	1.00000	99.72
7.5	6,521,926	0	0.00000	1.00000	99.72
8.5	6,503,246	0	0.00000	1.00000	99.72
9.5	6,171,389	643	0.00010	0.99990	99.72
10.5	6,163,454	0	0.00000	1.00000	99.71
11.5	6,163,454	70	0.00001	0.99999	99.71
12.5	6,163,384	0	0.00000	1.00000	99.71
13.5	6,140,392	8,017	0.00131	0.99869	99.71
14.5	6,132,212	3,713	0.00061	0.99939	99.58
15.5	6,024,118	0	0.00000	1.00000	99.52
16.5	5,785,917	0	0.00000	1.00000	99.52
17.5	5,497,503	0	0.00000	1.00000	99.52
18.5	4,942,708	0	0.00000	1.00000	99.52
19.5	4,931,879	6,746	0.00137	0.99863	99.52
20.5	4,387,425	0	0.00000	1.00000	99.38
21.5	554,137	0	0.00000	1.00000	99.38
22.5	448,712	4,757	0.01060	0.98940	99.38
23.5	252,148	0	0.00000	1.00000	98.33
24.5	249,138	0	0.00000	1.00000	98.33
25.5	236,882	0	0.00000	1.00000	98.33
26.5	159,999	0	0.00000	1.00000	98.33

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Account 464.00 - Other Structures - Transmission Plant

Placement Band - 1968 - 2019   Experience Band - 1970 - 2022

27.5	159,433	0	0.00000	1.00000	98.33
28.5	115,691	0	0.00000	1.00000	98.33
29.5	106,136	0	0.00000	1.00000	98.33
30.5	106,136	0	0.00000	1.00000	98.33
31.5	80,005	0	0.00000	1.00000	98.33
32.5	75,828	0	0.00000	1.00000	98.33
33.5	70,582	0	0.00000	1.00000	98.33
34.5	57,683	0	0.00000	1.00000	98.33
35.5	39,047	0	0.00000	1.00000	98.33
36.5	39,047	0	0.00000	1.00000	98.33
37.5	39,047	0	0.00000	1.00000	98.33
38.5	35,848	0	0.00000	1.00000	98.33
39.5	26,979	0	0.00000	1.00000	98.33
40.5	26,979	0	0.00000	1.00000	98.33
41.5	26,979	0	0.00000	1.00000	98.33
42.5	26,979	0	0.00000	1.00000	98.33
43.5	16,153	0	0.00000	1.00000	98.33
44.5	9,838	0	0.00000	1.00000	98.33
45.5	9,838	0	0.00000	1.00000	98.33
46.5	9,838	0	0.00000	1.00000	98.33
47.5	7,845	0	0.00000	1.00000	98.33
48.5	7,845	0	0.00000	1.00000	98.33
49.5	0	0	0.00000	0.00000	98.33
	Totals:	42,812			

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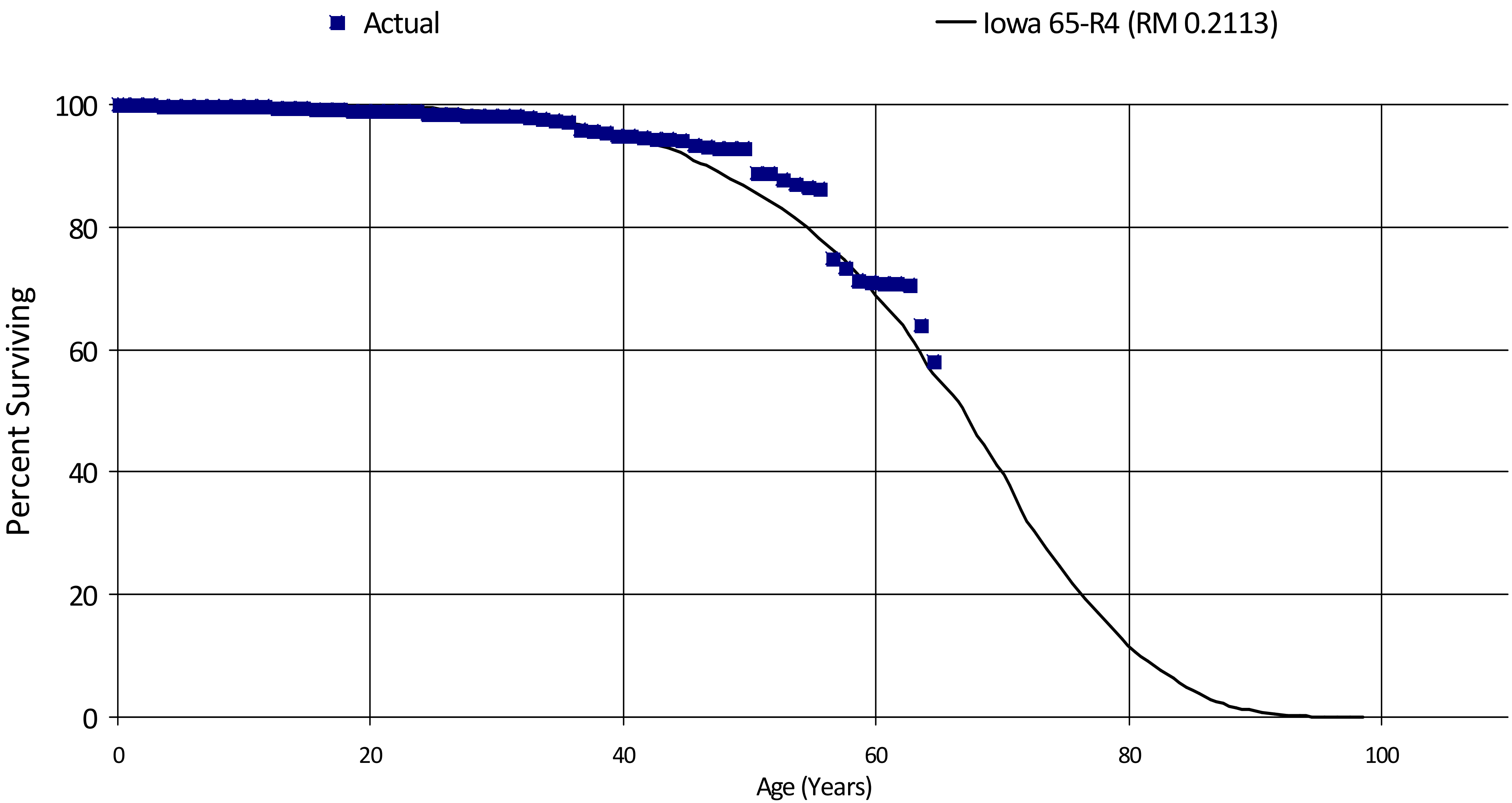
Account 465.00 - Transmission Pipeline

Placement Band - 1957 - 2022   Experience Band - 1962 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 465.00 - Transmission Pipeline

Placement Band - 1957 - 2022   Experience Band - 1962 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,706,849,588	120,950	0.00007	0.99993	100.00
0.5	1,586,320,296	240,793	0.00015	0.99985	99.99
1.5	1,513,370,837	211,413	0.00014	0.99986	99.98
2.5	1,448,817,688	2,231,944	0.00154	0.99846	99.97
3.5	1,423,608,480	342,123	0.00024	0.99976	99.82
4.5	1,389,263,634	377,896	0.00027	0.99973	99.80
5.5	1,223,990,086	128,677	0.00011	0.99989	99.77
6.5	1,202,786,896	235,985	0.00020	0.99980	99.76
7.5	1,177,520,602	242,657	0.00021	0.99979	99.74
8.5	1,154,442,230	523,204	0.00045	0.99955	99.72
9.5	1,133,204,087	343,780	0.00030	0.99970	99.68
10.5	1,117,679,299	254,709	0.00023	0.99977	99.65
11.5	1,060,524,403	718,705	0.00068	0.99932	99.63
12.5	1,051,325,296	935,791	0.00089	0.99911	99.56
13.5	1,041,181,676	224,828	0.00022	0.99978	99.47
14.5	1,029,022,826	1,831,328	0.00178	0.99822	99.45
15.5	1,016,785,582	129,888	0.00013	0.99987	99.27
16.5	1,004,142,591	377,583	0.00038	0.99962	99.26
17.5	992,444,410	1,173,298	0.00118	0.99882	99.22
18.5	977,822,523	172,866	0.00018	0.99982	99.10
19.5	959,710,481	800,024	0.00083	0.99917	99.08
20.5	932,995,893	22,452	0.00002	0.99998	99.00
21.5	886,745,780	79,329	0.00009	0.99991	99.00
22.5	568,613,831	195,019	0.00034	0.99966	98.99
23.5	555,995,961	2,360,277	0.00425	0.99575	98.96
24.5	553,635,684	637,492	0.00115	0.99885	98.54
25.5	544,629,692	242,810	0.00045	0.99955	98.43
26.5	531,613,470	404,531	0.00076	0.99924	98.39

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Account 465.00 - Transmission Pipeline

Placement Band - 1957 - 2022 Experience Band - 1962 - 2022

27.5	497,987,533	88,602	0.00018	0.99982	98.32
28.5	495,000,076	262,511	0.00053	0.99947	98.30
29.5	487,827,534	98,370	0.00020	0.99980	98.25
30.5	430,326,090	322,180	0.00075	0.99925	98.23
31.5	106,374,628	289,715	0.00272	0.99728	98.16
32.5	99,432,321	291,782	0.00293	0.99707	97.89
33.5	98,448,874	80,632	0.00082	0.99918	97.60
34.5	63,283,631	259,998	0.00411	0.99589	97.52
35.5	61,214,862	819,472	0.01339	0.98661	97.12
36.5	56,899,097	119,234	0.00210	0.99790	95.82
37.5	55,701,891	47,051	0.00084	0.99916	95.62
38.5	55,172,554	325,751	0.00590	0.99410	95.54
39.5	54,531,741	91,157	0.00167	0.99833	94.98
40.5	53,796,342	98,214	0.00183	0.99817	94.82
41.5	52,366,359	65,377	0.00125	0.99875	94.65
42.5	51,571,709	54,236	0.00105	0.99895	94.53
43.5	51,470,174	213,536	0.00415	0.99585	94.43
44.5	50,906,381	389,123	0.00764	0.99236	94.04
45.5	50,244,652	42,188	0.00084	0.99916	93.32
46.5	32,846,764	80,260	0.00244	0.99756	93.24
47.5	32,705,348	19,361	0.00059	0.99941	93.01
48.5	32,653,283	48,002	0.00147	0.99853	92.96
49.5	32,195,826	1,389,659	0.04316	0.95684	92.82
50.5	23,161,727	10,775	0.00047	0.99953	88.81
51.5	22,219,506	246,850	0.01111	0.98889	88.77
52.5	21,609,749	183,267	0.00848	0.99152	87.78
53.5	19,851,326	126,738	0.00638	0.99362	87.04
54.5	18,956,235	27,670	0.00146	0.99854	86.48
55.5	18,506,412	2,453,062	0.13255	0.86745	86.35
56.5	15,863,874	315,574	0.01989	0.98011	74.90
57.5	15,548,299	457,914	0.02945	0.97055	73.41

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Account 465.00 - Transmission Pipeline

Placement Band - 1957 - 2022   Experience Band - 1962 - 2022

58.5	15,042,618	38,215	0.00254	0.99746	71.25
59.5	14,911,874	28,968	0.00194	0.99806	71.07
60.5	12,477,559	26,703	0.00214	0.99786	70.93
61.5	12,323,051	22,104	0.00179	0.99821	70.78
62.5	12,283,339	1,171,559	0.09538	0.90462	70.65
63.5	9,980,580	898,385	0.09001	0.90999	63.91
64.5	12,047	0	0.00000	1.00000	58.16
	Totals:	27,064,547			

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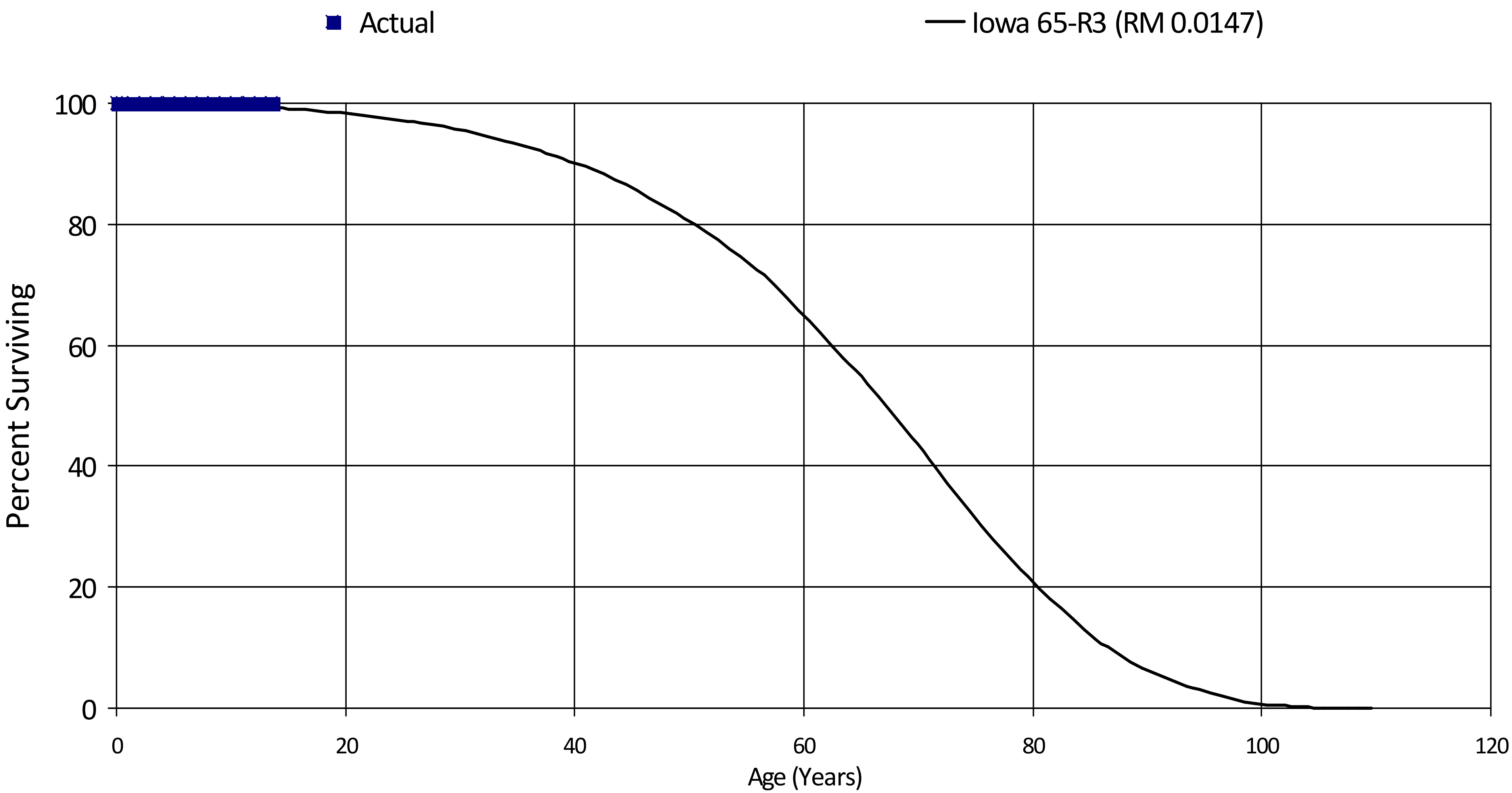
Account 465.11 - Intermediate Pipe - Whistler - Transmission Plant

Placement Band - 2008 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 465.11 - Intermediate Pipe - Whistler - Transmission Plant

Placement Band - 2008 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	59,041,836	0	0.00000	1.00000	100.00
0.5	58,915,597	0	0.00000	1.00000	100.00
1.5	58,861,224	0	0.00000	1.00000	100.00
2.5	58,689,399	0	0.00000	1.00000	100.00
3.5	42,338,129	0	0.00000	1.00000	100.00
4.5	42,320,235	0	0.00000	1.00000	100.00
5.5	42,315,506	0	0.00000	1.00000	100.00
6.5	42,315,506	0	0.00000	1.00000	100.00
7.5	42,311,922	0	0.00000	1.00000	100.00
8.5	42,172,895	0	0.00000	1.00000	100.00
9.5	42,172,895	0	0.00000	1.00000	100.00
10.5	42,172,895	0	0.00000	1.00000	100.00
11.5	42,172,895	0	0.00000	1.00000	100.00
12.5	42,039,067	0	0.00000	1.00000	100.00
13.5	8,227	0	0.00000	1.00000	100.00
	Totals:	0			

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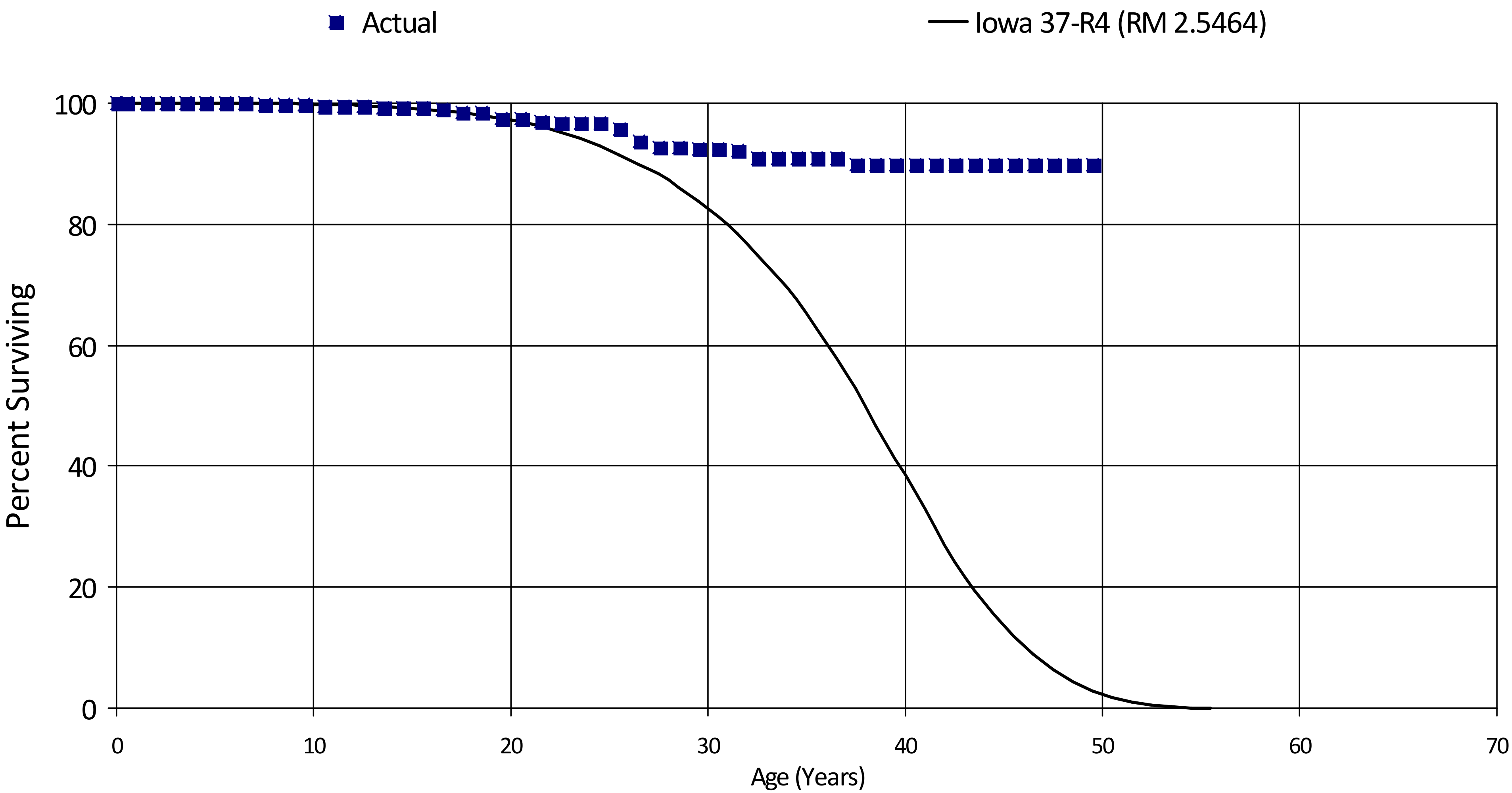
Account 466.00 - Compressor Equipment - Transmission Plant

Placement Band - 1965 - 2022   Experience Band - 1973 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 466.00 - Compressor Equipment - Transmission Plant

Placement Band - 1965 - 2022   Experience Band - 1973 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	210,357,112	35	0.00000	1.00000	100.00
0.5	204,713,664	556	0.00000	1.00000	100.00
1.5	202,620,994	19,727	0.00010	0.99990	100.00
2.5	201,128,536	2,978	0.00001	0.99999	99.99
3.5	198,378,662	1,513	0.00001	0.99999	99.99
4.5	196,257,913	16,949	0.00009	0.99991	99.99
5.5	188,872,508	23,569	0.00012	0.99988	99.98
6.5	182,201,105	206,181	0.00113	0.99887	99.97
7.5	178,479,960	275,835	0.00155	0.99845	99.86
8.5	177,382,139	112,784	0.00064	0.99936	99.71
9.5	175,849,406	305,855	0.00174	0.99826	99.65
10.5	172,635,861	144,174	0.00084	0.99916	99.48
11.5	168,673,763	11,150	0.00007	0.99993	99.40
12.5	168,662,613	149,215	0.00088	0.99912	99.39
13.5	163,889,193	6,869	0.00004	0.99996	99.30
14.5	160,566,476	121,794	0.00076	0.99924	99.30
15.5	142,072,369	255,037	0.00180	0.99820	99.22
16.5	141,377,422	677,697	0.00479	0.99521	99.04
17.5	138,841,949	287,088	0.00207	0.99793	98.57
18.5	136,302,073	1,241,034	0.00911	0.99089	98.37
19.5	134,362,301	135,051	0.00101	0.99899	97.47
20.5	127,739,462	694,340	0.00544	0.99456	97.37
21.5	121,421,951	29,010	0.00024	0.99976	96.84
22.5	70,764,549	170,085	0.00240	0.99760	96.82
23.5	63,581,643	9,084	0.00014	0.99986	96.59
24.5	57,463,431	500,374	0.00871	0.99129	96.58
25.5	53,490,910	1,151,548	0.02153	0.97847	95.74
26.5	50,332,227	551,260	0.01095	0.98905	93.68

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Account 466.00 - Compressor Equipment - Transmission Plant

Placement Band - 1965 - 2022   Experience Band - 1973 - 2022

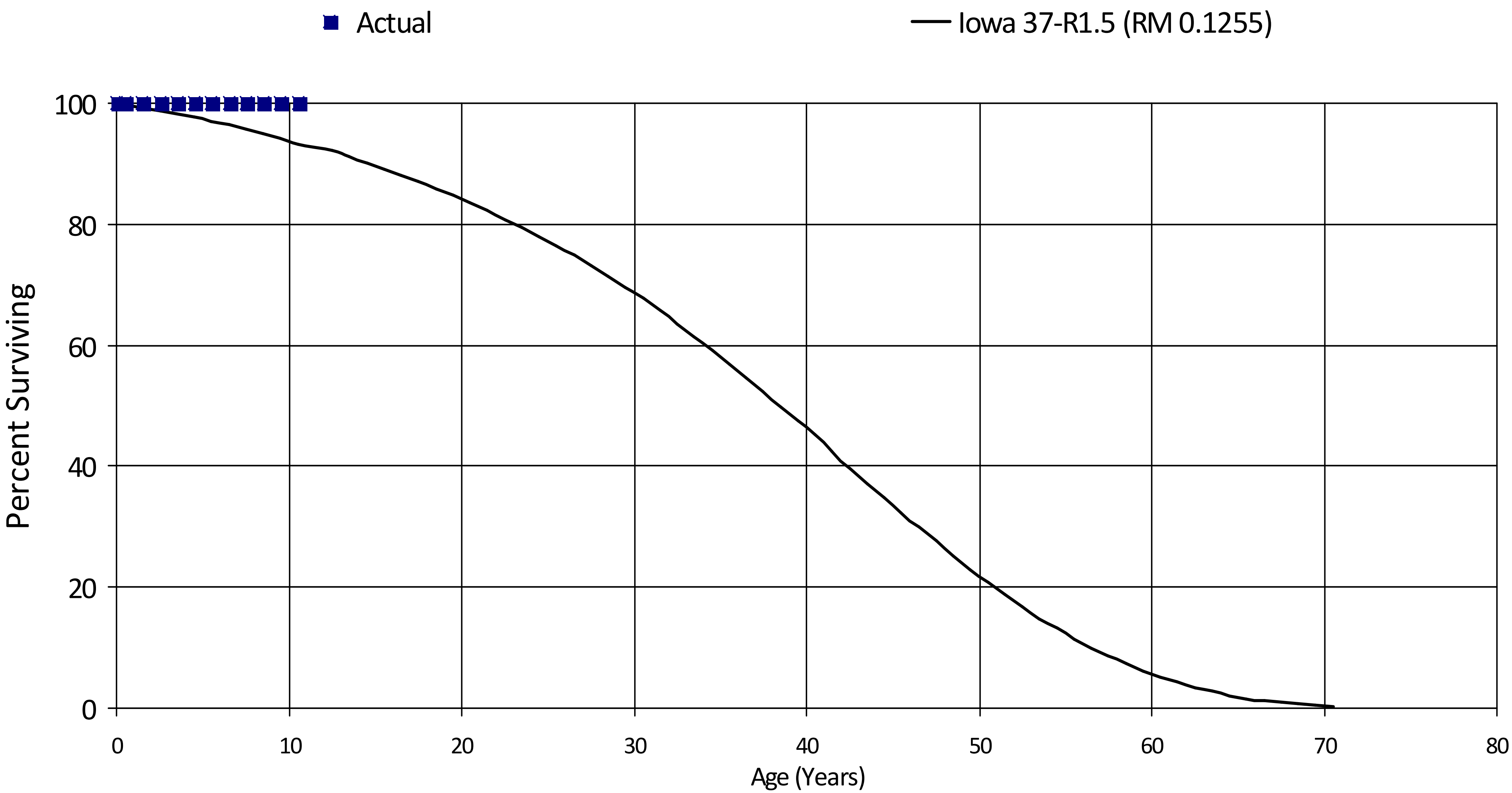
27.5	44,947,007	9,049	0.00020	0.99980	92.65
28.5	26,224,834	52,073	0.00199	0.99801	92.63
29.5	21,668,822	0	0.00000	1.00000	92.45
30.5	18,918,960	79,374	0.00420	0.99580	92.45
31.5	2,555,189	29,977	0.01173	0.98827	92.06
32.5	2,494,739	0	0.00000	1.00000	90.98
33.5	2,474,657	0	0.00000	1.00000	90.98
34.5	2,461,151	0	0.00000	1.00000	90.98
35.5	2,373,556	0	0.00000	1.00000	90.98
36.5	2,365,946	32,582	0.01377	0.98623	90.98
37.5	2,332,077	0	0.00000	1.00000	89.73
38.5	2,328,602	0	0.00000	1.00000	89.73
39.5	2,297,560	0	0.00000	1.00000	89.73
40.5	2,297,560	0	0.00000	1.00000	89.73
41.5	2,294,550	0	0.00000	1.00000	89.73
42.5	2,294,550	0	0.00000	1.00000	89.73
43.5	2,291,709	0	0.00000	1.00000	89.73
44.5	1,513,636	0	0.00000	1.00000	89.73
45.5	1,464,608	0	0.00000	1.00000	89.73
46.5	1,452,220	0	0.00000	1.00000	89.73
47.5	1,449,467	0	0.00000	1.00000	89.73
48.5	1,161,436	0	0.00000	1.00000	89.73
49.5	0	0	0.00000	0.00000	89.73
	Totals:	7,303,847			

FortisBC

Account 467.00 - Measuring and Regulating Equipment - Mt. Hayes - Transmission Plant

Placement Band - 2011 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



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Account 467.00 - Measuring and Regulating Equipment - Mt. Hayes - Transmission Plant

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

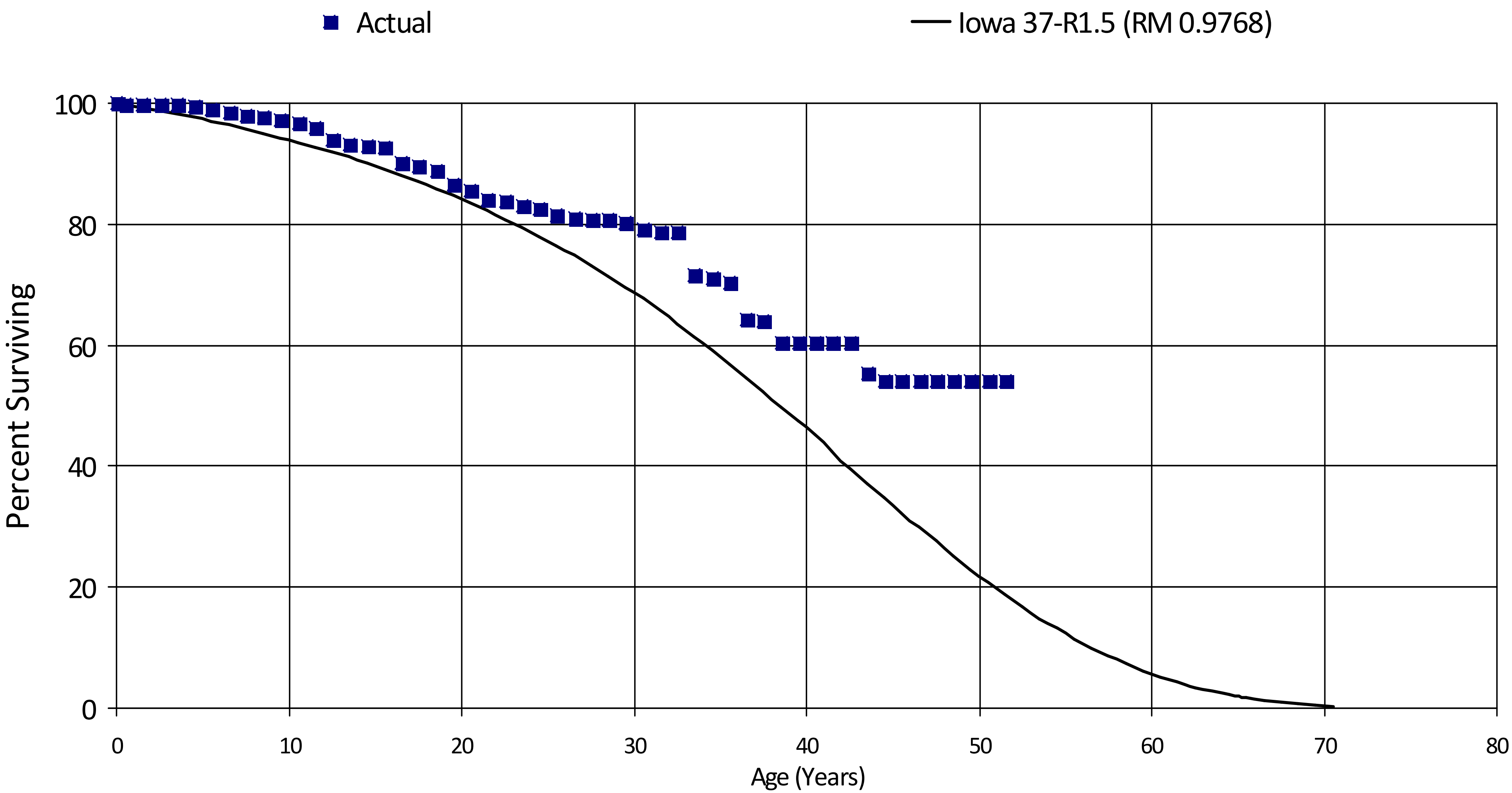
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,929,381	0	0.00000	1.00000	100.00
0.5	5,914,289	0	0.00000	1.00000	100.00
1.5	5,340,256	0	0.00000	1.00000	100.00
2.5	5,340,256	0	0.00000	1.00000	100.00
3.5	5,340,256	0	0.00000	1.00000	100.00
4.5	5,340,256	0	0.00000	1.00000	100.00
5.5	5,340,256	0	0.00000	1.00000	100.00
6.5	5,340,256	0	0.00000	1.00000	100.00
7.5	5,340,256	0	0.00000	1.00000	100.00
8.5	5,340,256	0	0.00000	1.00000	100.00
9.5	5,340,256	0	0.00000	1.00000	100.00
10.5	5,340,256	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 467.10 - Measuring and Regulating Equipment - Transmission Plant

Placement Band - 1959 - 2022   Experience Band - 1968 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 467.10 - Measuring and Regulating Equipment - Transmission Plant

Placement Band - 1959 - 2022   Experience Band - 1968 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	102,234,083	178,113	0.00174	0.99826	100.00
0.5	97,946,329	12,228	0.00012	0.99988	99.83
1.5	89,965,652	75,124	0.00084	0.99916	99.82
2.5	87,244,533	68,444	0.00078	0.99922	99.74
3.5	80,049,400	109,969	0.00137	0.99863	99.66
4.5	68,934,806	405,262	0.00588	0.99412	99.52
5.5	65,599,721	322,834	0.00492	0.99508	98.93
6.5	63,475,704	288,042	0.00454	0.99546	98.44
7.5	56,064,942	229,247	0.00409	0.99591	97.99
8.5	54,567,976	151,312	0.00277	0.99723	97.59
9.5	52,123,743	297,211	0.00570	0.99430	97.32
10.5	48,382,811	421,211	0.00871	0.99129	96.77
11.5	46,577,352	1,040,584	0.02234	0.97766	95.93
12.5	44,988,836	307,634	0.00684	0.99316	93.79
13.5	44,012,861	99,387	0.00226	0.99774	93.15
14.5	42,480,293	127,175	0.00299	0.99701	92.94
15.5	41,330,091	1,152,627	0.02789	0.97211	92.66
16.5	38,102,870	189,463	0.00497	0.99503	90.08
17.5	37,472,644	284,804	0.00760	0.99240	89.63
18.5	36,118,360	987,721	0.02735	0.97265	88.95
19.5	30,979,287	318,688	0.01029	0.98971	86.52
20.5	28,369,601	517,601	0.01824	0.98176	85.63
21.5	26,933,078	99,648	0.00370	0.99630	84.07
22.5	23,241,308	180,659	0.00777	0.99223	83.76
23.5	21,230,051	136,221	0.00642	0.99358	83.11
24.5	20,080,475	258,703	0.01288	0.98712	82.58
25.5	16,916,930	125,845	0.00744	0.99256	81.52
26.5	15,906,479	42,919	0.00270	0.99730	80.91

FortisBC

Account 467.10 - Measuring and Regulating Equipment - Transmission Plant

Placement Band - 1959 - 2022 Experience Band - 1968 - 2022

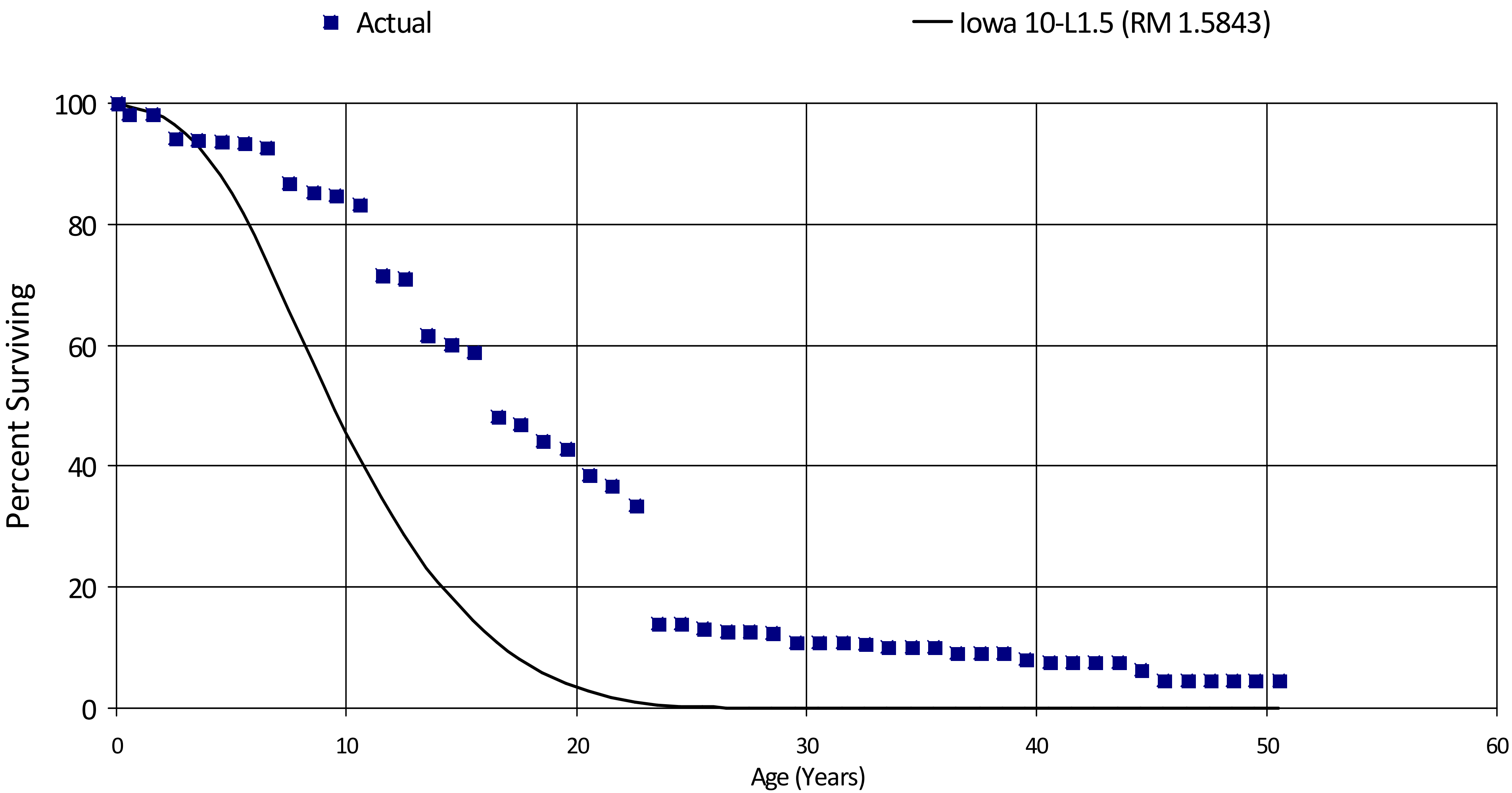
27.5	14,585,754	15,462	0.00106	0.99894	80.69
28.5	13,711,015	77,212	0.00563	0.99437	80.60
29.5	12,216,731	144,909	0.01186	0.98814	80.15
30.5	10,576,962	69,710	0.00659	0.99341	79.20
31.5	1,612,800	800	0.00050	0.99950	78.68
32.5	1,612,000	145,893	0.09050	0.90950	78.64
33.5	1,434,427	10,000	0.00697	0.99303	71.52
34.5	462,982	4,450	0.00961	0.99039	71.02
35.5	447,695	38,600	0.08622	0.91378	70.34
36.5	371,285	2,124	0.00572	0.99428	64.28
37.5	261,731	14,139	0.05402	0.94598	63.91
38.5	219,540	0	0.00000	1.00000	60.46
39.5	219,540	0	0.00000	1.00000	60.46
40.5	219,540	670	0.00305	0.99695	60.46
41.5	217,036	0	0.00000	1.00000	60.28
42.5	217,036	17,501	0.08064	0.91936	60.28
43.5	199,534	5,000	0.02506	0.97494	55.42
44.5	191,047	0	0.00000	1.00000	54.03
45.5	190,008	0	0.00000	1.00000	54.03
46.5	190,008	0	0.00000	1.00000	54.03
47.5	189,010	0	0.00000	1.00000	54.03
48.5	172,419	0	0.00000	1.00000	54.03
49.5	172,419	0	0.00000	1.00000	54.03
50.5	47,395	0	0.00000	1.00000	54.03
51.5	0	0	0.00000	0.00000	54.03
	Totals:	8,975,146			

FortisBC

Account 467.20 - Telemetry Equipment - Transmission Plant

Placement Band - 1968 - 2022   Experience Band - 1973 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 467.20 - Telemetry Equipment - Transmission Plant

Placement Band - 1968 - 2022   Experience Band - 1973 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	33,923,168	567,491	0.01673	0.98327	100.00
0.5	32,992,295	45,109	0.00137	0.99863	98.33
1.5	24,243,113	978,712	0.04037	0.95963	98.20
2.5	22,813,836	83,362	0.00365	0.99635	94.24
3.5	22,268,670	53,988	0.00242	0.99758	93.90
4.5	21,488,673	64,024	0.00298	0.99702	93.67
5.5	21,110,874	185,424	0.00878	0.99122	93.39
6.5	20,159,608	1,242,116	0.06161	0.93839	92.57
7.5	15,382,226	261,440	0.01700	0.98300	86.87
8.5	14,362,918	95,520	0.00665	0.99335	85.39
9.5	12,838,739	235,495	0.01834	0.98166	84.82
10.5	11,935,794	1,660,503	0.13912	0.86088	83.26
11.5	8,627,881	83,774	0.00971	0.99029	71.68
12.5	8,438,869	1,100,548	0.13041	0.86959	70.98
13.5	7,331,821	200,956	0.02741	0.97259	61.72
14.5	7,012,005	137,601	0.01962	0.98038	60.03
15.5	6,804,094	1,225,875	0.18017	0.81983	58.85
16.5	5,578,186	138,388	0.02481	0.97519	48.25
17.5	5,417,421	335,172	0.06187	0.93813	47.05
18.5	4,940,762	152,884	0.03094	0.96906	44.14
19.5	4,708,487	459,765	0.09765	0.90235	42.77
20.5	4,133,888	191,431	0.04631	0.95369	38.59
21.5	3,720,182	325,906	0.08760	0.91240	36.80
22.5	3,317,201	1,936,773	0.58386	0.41614	33.58
23.5	1,380,428	12,282	0.00890	0.99110	13.97
24.5	1,300,059	52,873	0.04067	0.95933	13.85
25.5	1,043,341	38,146	0.03656	0.96344	13.29
26.5	897,009	2,674	0.00298	0.99702	12.80

FortisBC

Account 467.20 - Telemetry Equipment - Transmission Plant

Placement Band - 1968 - 2022 Experience Band - 1973 - 2022

27.5	650,244	11,015	0.01694	0.98306	12.76
28.5	500,007	61,082	0.12216	0.87784	12.54
29.5	323,893	0	0.00000	1.00000	11.01
30.5	231,842	480	0.00207	0.99793	11.01
31.5	151,673	3,077	0.02029	0.97971	10.99
32.5	148,596	6,891	0.04637	0.95363	10.77
33.5	141,225	526	0.00372	0.99628	10.27
34.5	135,381	503	0.00372	0.99628	10.23
35.5	133,769	13,019	0.09732	0.90268	10.19
36.5	120,751	0	0.00000	1.00000	9.20
37.5	86,946	0	0.00000	1.00000	9.20
38.5	86,946	11,208	0.12891	0.87109	9.20
39.5	75,738	2,683	0.03542	0.96458	8.01
40.5	64,648	0	0.00000	1.00000	7.73
41.5	62,993	0	0.00000	1.00000	7.73
42.5	37,841	0	0.00000	1.00000	7.73
43.5	36,401	6,935	0.19052	0.80948	7.73
44.5	22,750	5,845	0.25692	0.74308	6.26
45.5	16,905	0	0.00000	1.00000	4.65
46.5	16,905	0	0.00000	1.00000	4.65
47.5	16,905	0	0.00000	1.00000	4.65
48.5	14,813	0	0.00000	1.00000	4.65
49.5	14,813	0	0.00000	1.00000	4.65
50.5	0	0	0.00000	0.00000	4.65
	Totals:	11,991,496			

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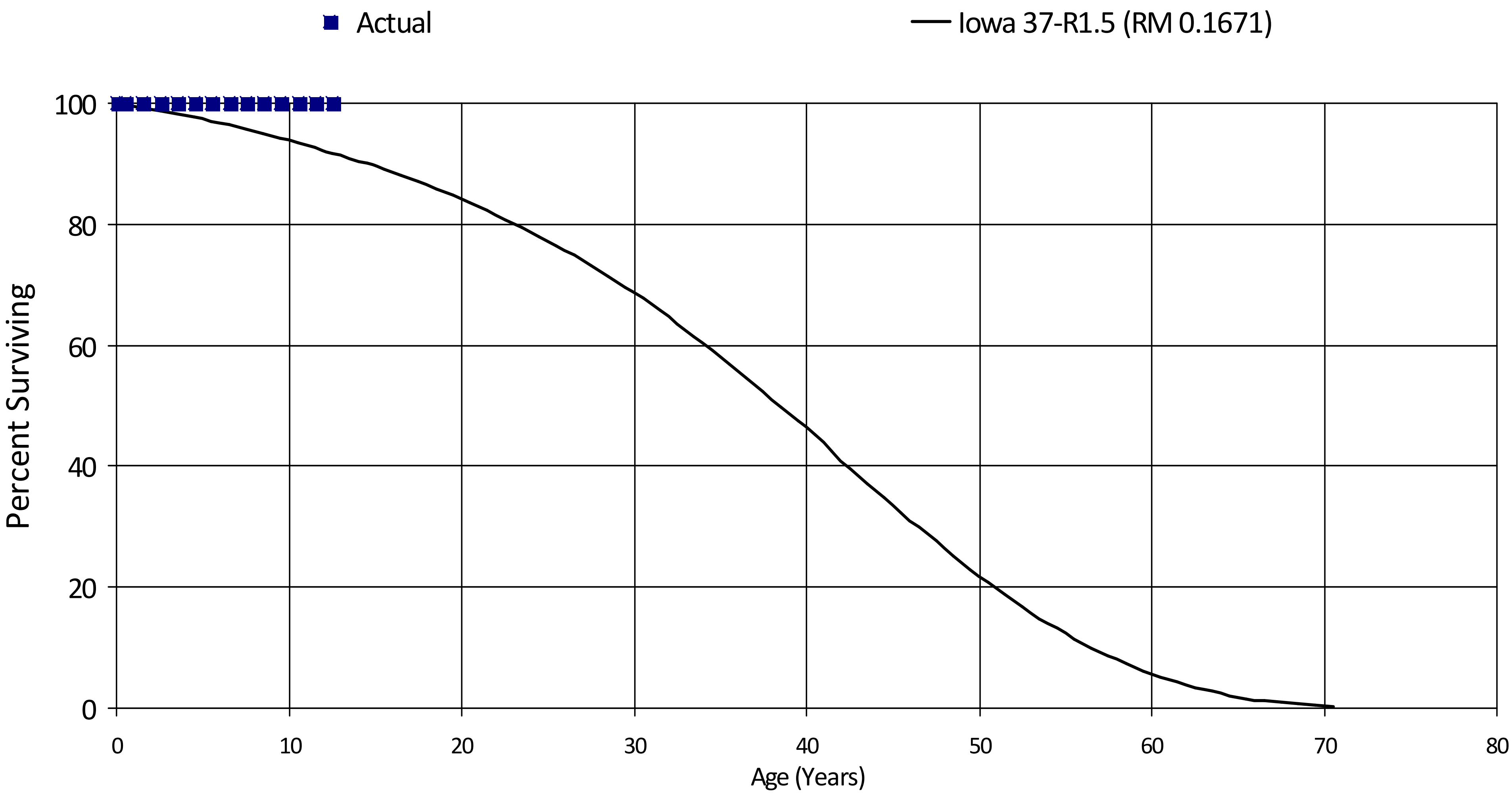
Account 467.31 - Measuring and Regulating Equipment - Whistler - Transmission Plant

Placement Band - 2009 - 2009   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 467.31 - Measuring and Regulating Equipment - Whistler - Transmission Plant

Placement Band - 2009 - 2009   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

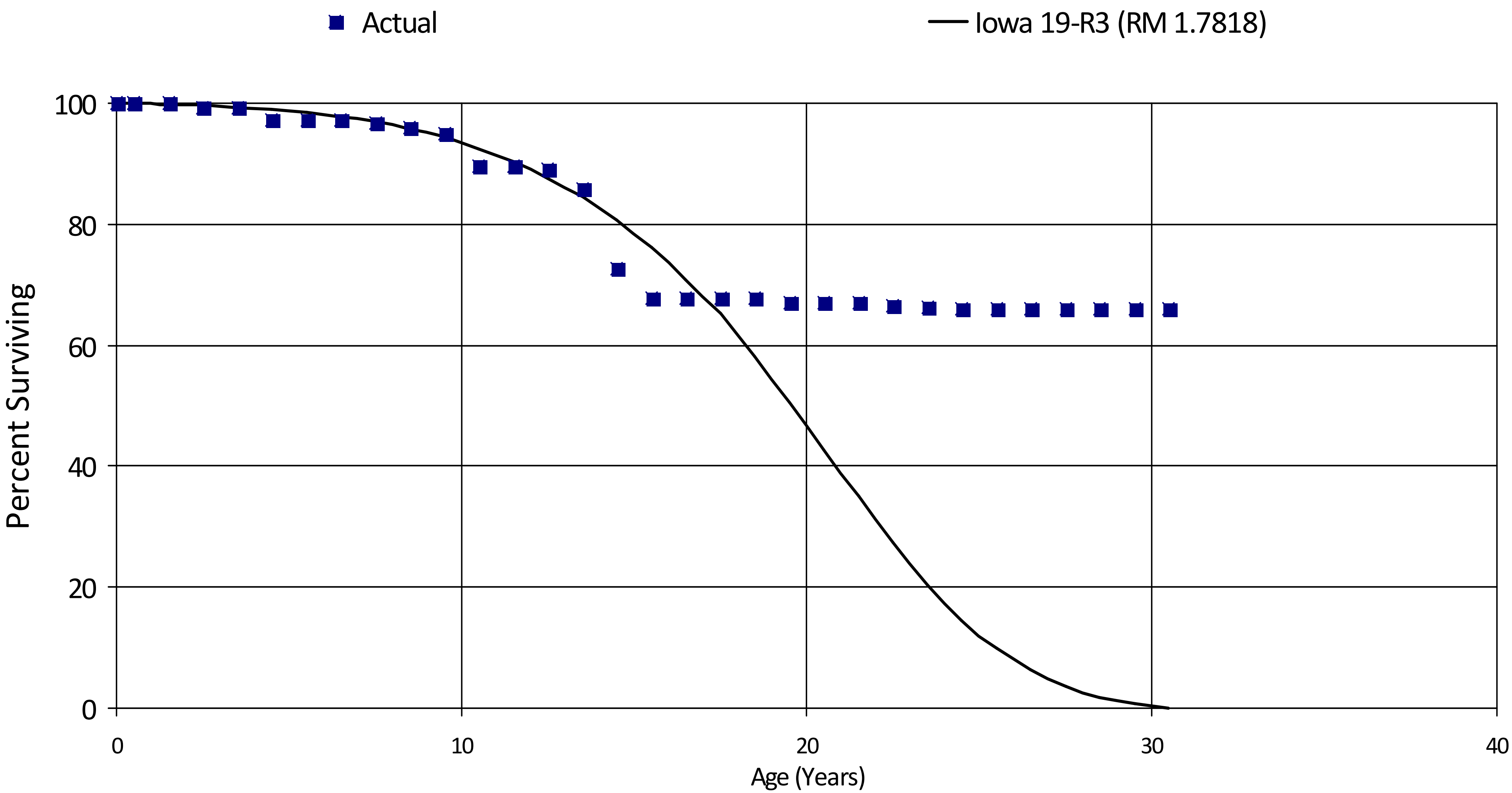
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	313,344	0	0.00000	1.00000	100.00
0.5	313,344	0	0.00000	1.00000	100.00
1.5	313,344	0	0.00000	1.00000	100.00
2.5	313,344	0	0.00000	1.00000	100.00
3.5	313,344	0	0.00000	1.00000	100.00
4.5	313,344	0	0.00000	1.00000	100.00
5.5	313,344	0	0.00000	1.00000	100.00
6.5	313,344	0	0.00000	1.00000	100.00
7.5	313,344	0	0.00000	1.00000	100.00
8.5	313,344	0	0.00000	1.00000	100.00
9.5	313,344	0	0.00000	1.00000	100.00
10.5	313,344	0	0.00000	1.00000	100.00
11.5	313,344	0	0.00000	1.00000	100.00
12.5	313,344	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 468.00 - Communications Equipment - Transmission Plant

Placement Band - 1991 - 2018   Experience Band - 1995 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 468.00 - Communications Equipment - Transmission Plant

Placement Band - 1991 - 2018   Experience Band - 1995 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,635,689	0	0.00000	1.00000	100.00
0.5	4,635,689	0	0.00000	1.00000	100.00
1.5	4,635,689	30,284	0.00653	0.99347	100.00
2.5	4,605,405	106	0.00002	0.99998	99.35
3.5	4,605,299	101,196	0.02197	0.97803	99.35
4.5	4,359,791	0	0.00000	1.00000	97.17
5.5	4,359,791	849	0.00019	0.99981	97.17
6.5	4,358,942	19,964	0.00458	0.99542	97.15
7.5	4,338,978	37,386	0.00862	0.99138	96.71
8.5	4,301,592	37,644	0.00875	0.99125	95.88
9.5	3,999,108	225,386	0.05636	0.94364	95.04
10.5	3,773,709	7,378	0.00196	0.99804	89.68
11.5	3,471,618	17,333	0.00499	0.99501	89.50
12.5	3,453,345	122,320	0.03542	0.96458	89.05
13.5	3,104,504	476,973	0.15364	0.84636	85.90
14.5	2,609,330	180,769	0.06928	0.93072	72.70
15.5	2,171,073	0	0.00000	1.00000	67.66
16.5	2,167,724	0	0.00000	1.00000	67.66
17.5	2,167,724	0	0.00000	1.00000	67.66
18.5	2,162,803	22,940	0.01061	0.98939	67.66
19.5	2,136,962	417	0.00020	0.99980	66.94
20.5	2,132,668	0	0.00000	1.00000	66.93
21.5	2,037,387	10,144	0.00498	0.99502	66.93
22.5	2,024,835	12,206	0.00603	0.99397	66.60
23.5	2,009,615	5,319	0.00265	0.99735	66.20
24.5	1,993,069	0	0.00000	1.00000	66.02
25.5	1,988,812	0	0.00000	1.00000	66.02
26.5	1,985,004	0	0.00000	1.00000	66.02

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Account 468.00 - Communications Equipment - Transmission Plant

Placement Band - 1991 - 2018   Experience Band - 1995 - 2022

27.5	1,964,612	0	0.00000	1.00000	66.02
28.5	1,958,059	0	0.00000	1.00000	66.02
29.5	1,958,059	0	0.00000	1.00000	66.02
30.5	1,958,059	0	0.00000	1.00000	66.02
	Totals:	1,308,614			

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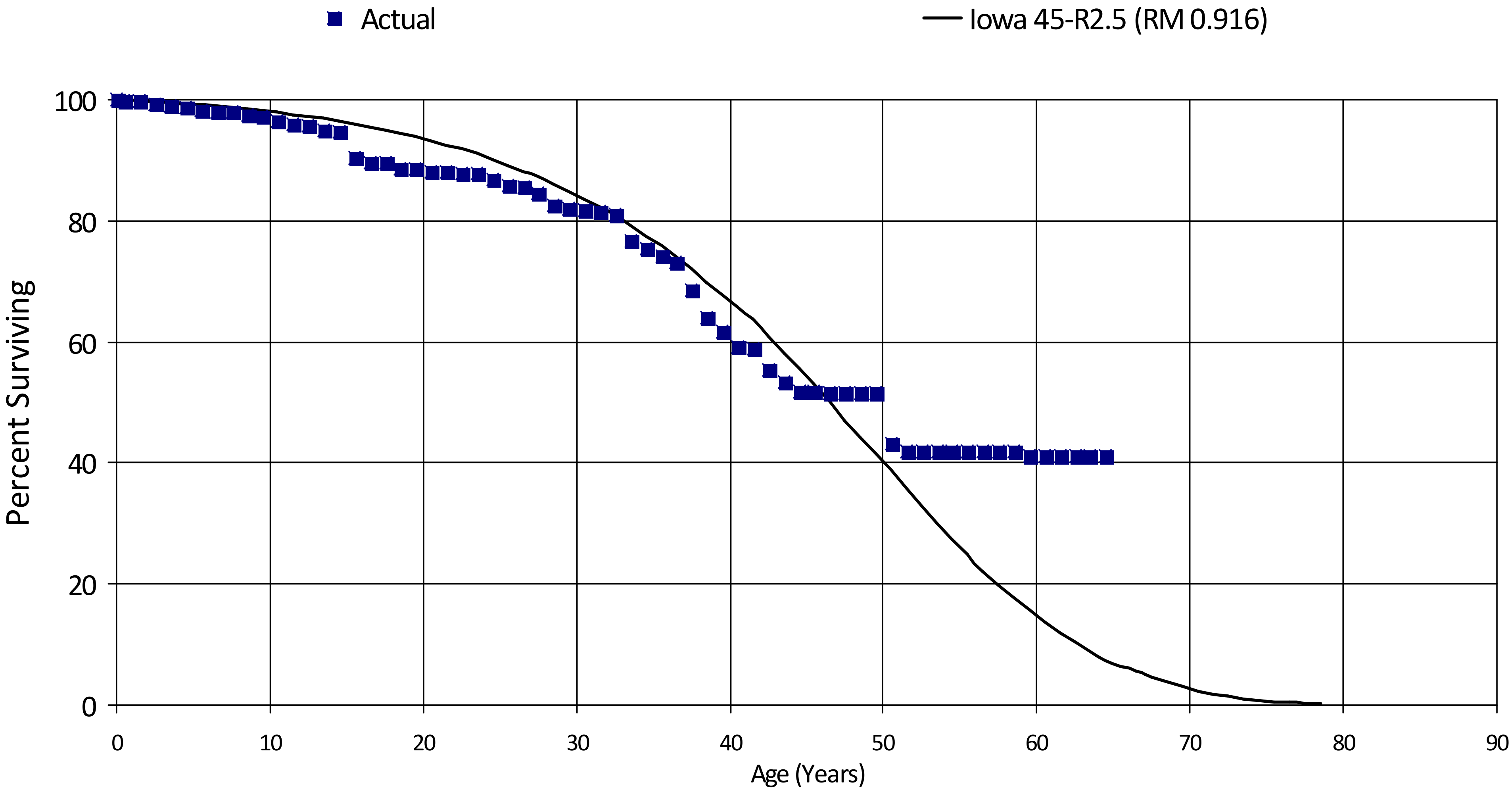
Account 472.00 - Structures - Distribution Plant

Placement Band - 1957 - 2022   Experience Band - 1959 - 2022

Actual and Smooth Survivor Curves



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Account 472.00 - Structures - Distribution Plant

Placement Band - 1957 - 2022 Experience Band - 1959 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	57,577,962	91,687	0.00159	0.99841	100.00
0.5	56,934,326	75,898	0.00133	0.99867	99.84
1.5	56,069,704	203,022	0.00362	0.99638	99.71
2.5	49,634,124	117,864	0.00237	0.99763	99.35
3.5	36,596,794	126,511	0.00346	0.99654	99.11
4.5	27,268,288	177,984	0.00653	0.99347	98.77
5.5	26,150,456	22,826	0.00087	0.99913	98.13
6.5	25,248,751	38,537	0.00153	0.99847	98.04
7.5	23,833,265	76,370	0.00320	0.99680	97.89
8.5	23,335,486	109,255	0.00468	0.99532	97.58
9.5	22,311,498	184,497	0.00827	0.99173	97.12
10.5	21,142,283	59,169	0.00280	0.99720	96.32
11.5	19,111,869	89,505	0.00468	0.99532	96.05
12.5	18,545,657	136,275	0.00735	0.99265	95.60
13.5	17,866,257	59,759	0.00334	0.99666	94.90
14.5	16,761,242	756,788	0.04515	0.95485	94.58
15.5	15,096,015	114,488	0.00758	0.99242	90.31
16.5	12,595,101	13,759	0.00109	0.99891	89.63
17.5	10,444,178	108,652	0.01040	0.98960	89.53
18.5	9,163,808	8,815	0.00096	0.99904	88.60
19.5	8,864,468	33,860	0.00382	0.99618	88.51
20.5	8,608,261	18,346	0.00213	0.99787	88.17
21.5	8,044,908	14,988	0.00186	0.99814	87.98
22.5	7,497,166	5,722	0.00076	0.99924	87.82
23.5	7,044,824	73,298	0.01040	0.98960	87.75
24.5	6,503,676	71,924	0.01106	0.98894	86.84
25.5	5,499,829	20,987	0.00382	0.99618	85.88
26.5	4,474,293	47,407	0.01060	0.98940	85.55

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Account 472.00 - Structures - Distribution Plant

Placement Band - 1957 - 2022 Experience Band - 1959 - 2022

27.5	3,508,633	91,941	0.02620	0.97380	84.64
28.5	2,679,144	13,601	0.00508	0.99492	82.42
29.5	2,447,282	7,625	0.00312	0.99688	82.00
30.5	1,802,719	6,871	0.00381	0.99619	81.74
31.5	797,840	5,674	0.00711	0.99289	81.43
32.5	748,103	38,266	0.05115	0.94885	80.85
33.5	689,965	12,424	0.01801	0.98199	76.71
34.5	660,104	11,325	0.01716	0.98284	75.33
35.5	502,996	7,192	0.01430	0.98570	74.04
36.5	386,734	23,097	0.05972	0.94028	72.98
37.5	351,851	23,397	0.06650	0.93350	68.62
38.5	301,744	11,575	0.03836	0.96164	64.06
39.5	249,096	10,276	0.04125	0.95875	61.60
40.5	231,177	365	0.00158	0.99842	59.06
41.5	154,380	9,320	0.06037	0.93963	58.97
42.5	137,864	5,444	0.03949	0.96051	55.41
43.5	131,386	3,313	0.02522	0.97478	53.22
44.5	128,058	0	0.00000	1.00000	51.88
45.5	128,058	728	0.00568	0.99432	51.88
46.5	125,508	0	0.00000	1.00000	51.59
47.5	118,770	0	0.00000	1.00000	51.59
48.5	114,715	0	0.00000	1.00000	51.59
49.5	100,735	16,702	0.16580	0.83420	51.59
50.5	79,978	2,101	0.02627	0.97373	43.04
51.5	77,192	0	0.00000	1.00000	41.91
52.5	76,819	0	0.00000	1.00000	41.91
53.5	74,985	0	0.00000	1.00000	41.91
54.5	59,496	0	0.00000	1.00000	41.91
55.5	59,496	0	0.00000	1.00000	41.91
56.5	59,496	0	0.00000	1.00000	41.91
57.5	58,937	0	0.00000	1.00000	41.91

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Account 472.00 - Structures - Distribution Plant

Placement Band - 1957 - 2022   Experience Band - 1959 - 2022

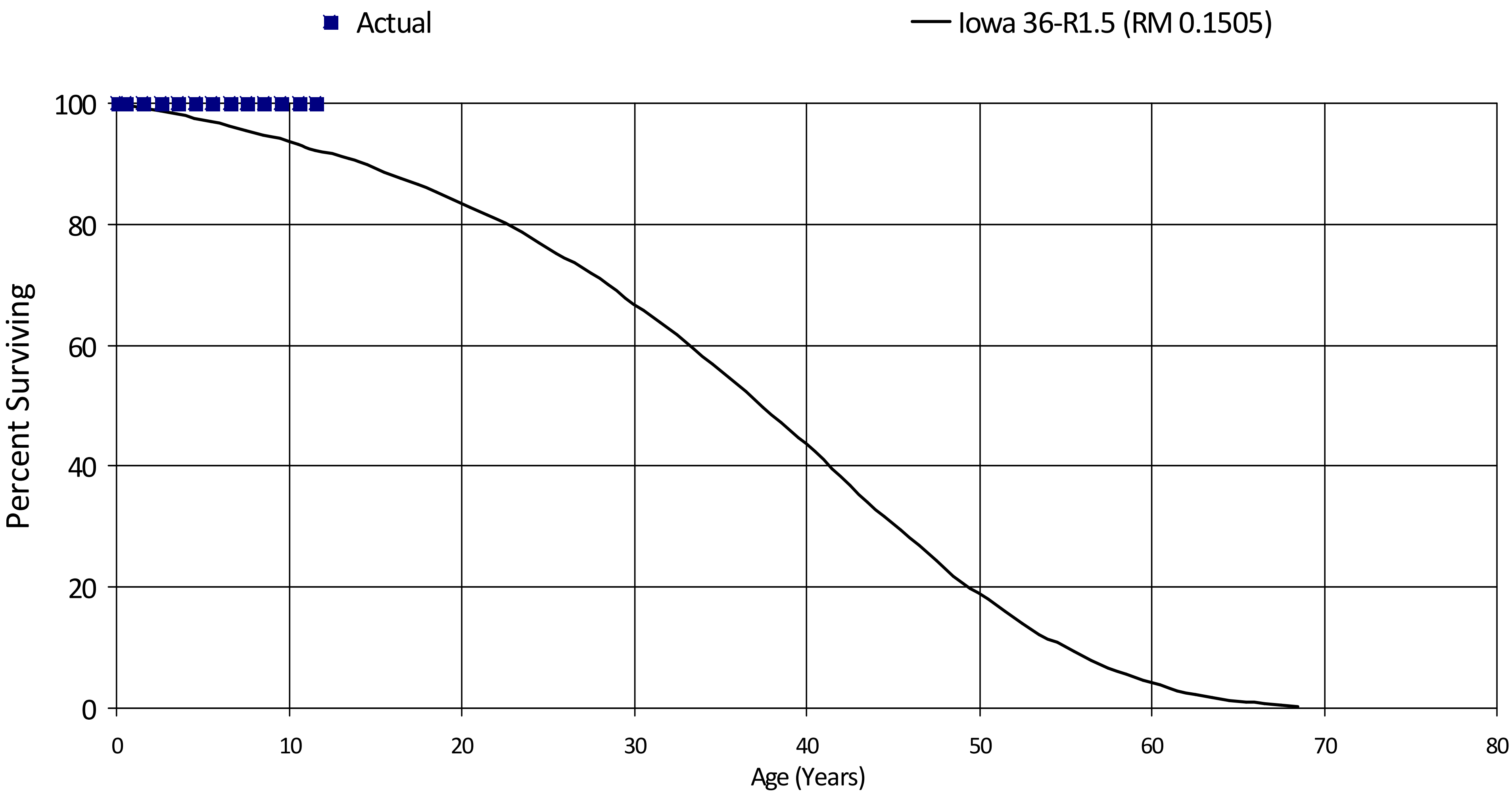
58.5	58,937	943	0.01600	0.98400	41.91
59.5	57,994	0	0.00000	1.00000	41.24
60.5	42,586	0	0.00000	1.00000	41.24
61.5	20,875	0	0.00000	1.00000	41.24
62.5	20,875	0	0.00000	1.00000	41.24
63.5	20,875	0	0.00000	1.00000	41.24
64.5	0	0	0.00000	0.00000	41.24
	Totals:	3,160,373			

FortisBC

Account 472.20 - Structures and Improvements - Bio Gas

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 472.20 - Structures and Improvements - Bio Gas

Placement Band - 2010 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,517,854	0	0.00000	1.00000	100.00
0.5	710,255	0	0.00000	1.00000	100.00
1.5	710,255	0	0.00000	1.00000	100.00
2.5	710,255	0	0.00000	1.00000	100.00
3.5	710,255	0	0.00000	1.00000	100.00
4.5	654,898	0	0.00000	1.00000	100.00
5.5	654,898	0	0.00000	1.00000	100.00
6.5	622,023	0	0.00000	1.00000	100.00
7.5	462,387	0	0.00000	1.00000	100.00
8.5	184,972	0	0.00000	1.00000	100.00
9.5	136,986	0	0.00000	1.00000	100.00
10.5	136,986	0	0.00000	1.00000	100.00
11.5	136,986	0	0.00000	1.00000	100.00
	Totals:	0			

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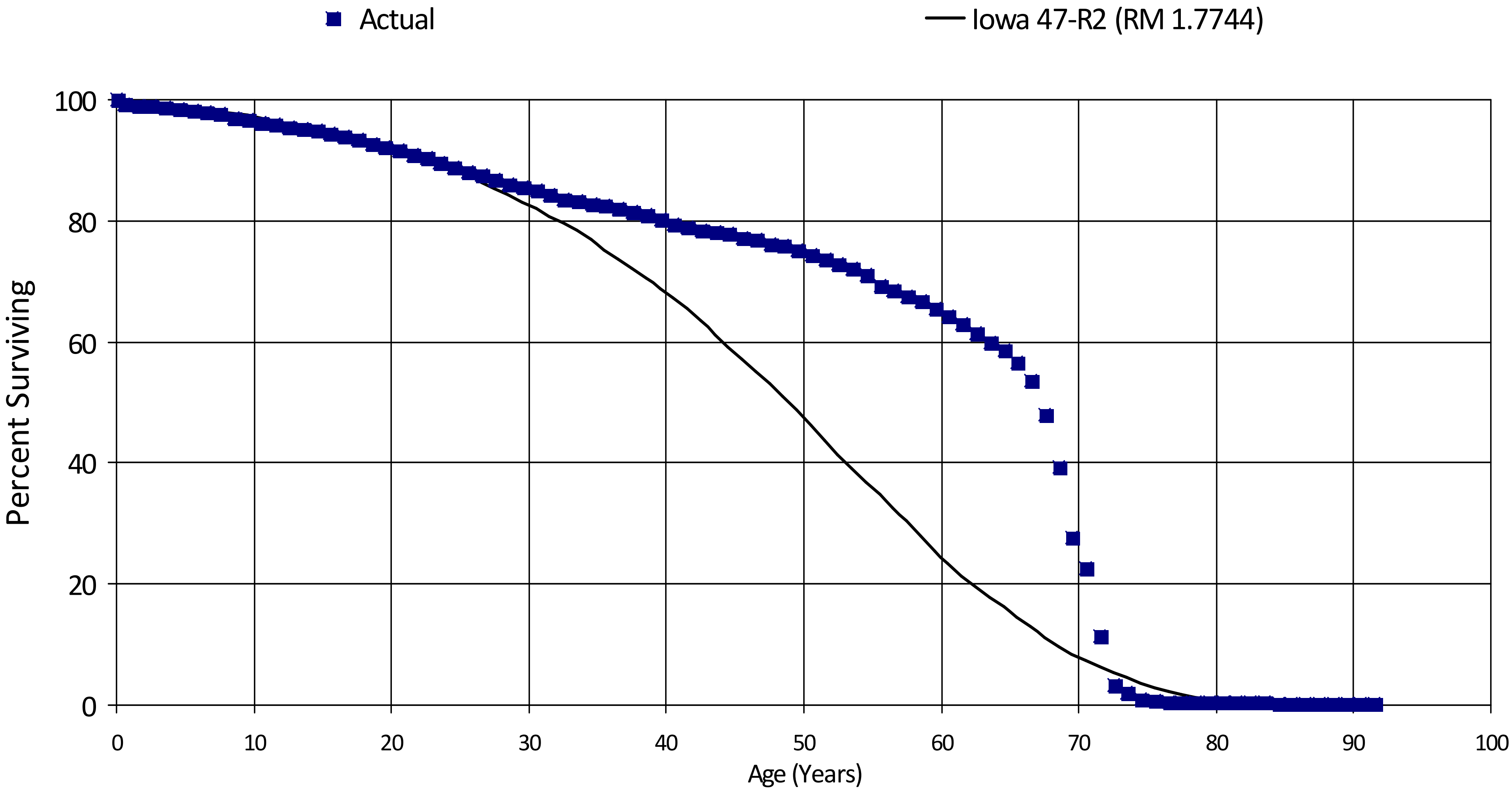
Account 473.00 - Services - Distribution Plant

Placement Band - 1900 - 2022   Experience Band - 1963 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 473.00 - Services - Distribution Plant

Placement Band - 1900 - 2022   Experience Band - 1963 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,659,615,312	12,126,777	0.00731	0.99269	100.00
0.5	1,561,689,305	3,126,240	0.00200	0.99800	99.27
1.5	1,465,803,069	3,147,963	0.00215	0.99785	99.07
2.5	1,389,086,729	2,877,047	0.00207	0.99793	98.86
3.5	1,315,493,206	2,767,031	0.00210	0.99790	98.66
4.5	1,242,496,524	3,777,301	0.00304	0.99696	98.45
5.5	1,184,771,791	3,078,127	0.00260	0.99740	98.15
6.5	1,139,966,572	2,849,046	0.00250	0.99750	97.89
7.5	1,093,964,959	9,054,924	0.00828	0.99172	97.65
8.5	1,039,942,727	2,676,813	0.00257	0.99743	96.84
9.5	994,134,170	3,424,015	0.00344	0.99656	96.59
10.5	948,598,244	3,721,126	0.00392	0.99608	96.26
11.5	908,706,112	3,604,871	0.00397	0.99603	95.88
12.5	870,616,694	2,512,327	0.00289	0.99711	95.50
13.5	835,472,301	3,624,992	0.00434	0.99566	95.22
14.5	787,036,534	3,453,266	0.00439	0.99561	94.81
15.5	740,934,888	3,483,893	0.00470	0.99530	94.39
16.5	702,010,539	4,181,683	0.00596	0.99404	93.95
17.5	663,860,655	4,637,378	0.00699	0.99301	93.39
18.5	631,645,410	4,833,453	0.00765	0.99235	92.74
19.5	602,399,137	3,409,443	0.00566	0.99434	92.03
20.5	575,302,510	3,872,686	0.00673	0.99327	91.51
21.5	550,250,875	3,659,254	0.00665	0.99335	90.89
22.5	518,630,249	3,656,260	0.00705	0.99295	90.29
23.5	489,713,239	4,897,282	0.01000	0.99000	89.65
24.5	456,172,770	3,248,584	0.00712	0.99288	88.75
25.5	419,409,047	2,854,469	0.00681	0.99319	88.12
26.5	380,605,977	2,983,710	0.00784	0.99216	87.52

FortisBC

Account 473.00 - Services - Distribution Plant

Placement Band - 1900 - 2022   Experience Band - 1963 - 2022

27.5	341,305,325	2,746,076	0.00805	0.99195	86.83
28.5	302,185,607	1,950,926	0.00646	0.99354	86.13
29.5	260,760,095	1,767,605	0.00678	0.99322	85.57
30.5	221,897,576	1,991,019	0.00897	0.99103	84.99
31.5	195,980,527	1,517,194	0.00774	0.99226	84.23
32.5	48,850,439	215,840	0.00442	0.99558	83.58
33.5	44,606,234	206,981	0.00464	0.99536	83.21
34.5	41,545,540	220,923	0.00532	0.99468	82.82
35.5	36,077,264	205,734	0.00570	0.99430	82.38
36.5	33,696,946	185,035	0.00549	0.99451	81.91
37.5	28,152,442	203,603	0.00723	0.99277	81.46
38.5	24,878,623	201,463	0.00810	0.99190	80.87
39.5	21,304,625	200,476	0.00941	0.99059	80.21
40.5	18,329,489	140,500	0.00767	0.99233	79.46
41.5	15,268,873	71,596	0.00469	0.99531	78.85
42.5	13,236,594	46,431	0.00351	0.99649	78.48
43.5	11,832,023	39,954	0.00338	0.99662	78.20
44.5	10,365,223	108,964	0.01051	0.98949	77.94
45.5	8,984,586	36,513	0.00406	0.99594	77.12
46.5	7,575,735	54,931	0.00725	0.99275	76.81
47.5	6,567,557	41,718	0.00635	0.99365	76.25
48.5	5,542,907	46,415	0.00837	0.99163	75.77
49.5	4,737,141	46,275	0.00977	0.99023	75.14
50.5	4,171,168	42,235	0.01013	0.98987	74.41
51.5	3,708,184	42,821	0.01155	0.98845	73.66
52.5	3,280,434	34,937	0.01065	0.98935	72.81
53.5	3,060,043	36,468	0.01192	0.98808	72.03
54.5	2,769,132	70,997	0.02564	0.97436	71.17
55.5	2,465,754	27,611	0.01120	0.98880	69.35
56.5	2,223,201	30,438	0.01369	0.98631	68.57
57.5	2,018,364	27,274	0.01351	0.98649	67.63

FortisBC

Account 473.00 - Services - Distribution Plant

Placement Band - 1900 - 2022   Experience Band - 1963 - 2022

58.5	1,782,587	30,167	0.01692	0.98308	66.72
59.5	1,525,495	29,571	0.01938	0.98062	65.59
60.5	1,334,480	29,207	0.02189	0.97811	64.32
61.5	1,305,272	28,917	0.02215	0.97785	62.91
62.5	1,152,986	31,261	0.02711	0.97289	61.52
63.5	70,188	1,480	0.02109	0.97891	59.85
64.5	68,708	2,377	0.03460	0.96540	58.59
65.5	66,331	3,544	0.05343	0.94657	56.56
66.5	62,787	6,635	0.10567	0.89433	53.54
67.5	56,152	10,001	0.17811	0.82189	47.88
68.5	46,151	13,679	0.29640	0.70360	39.35
69.5	32,472	5,866	0.18065	0.81935	27.69
70.5	26,606	13,087	0.49188	0.50812	22.69
71.5	13,519	9,566	0.70760	0.29240	11.53
72.5	3,953	1,500	0.37946	0.62054	3.37
73.5	2,453	1,200	0.48920	0.51080	2.09
74.5	1,253	287	0.22905	0.77095	1.07
75.5	966	400	0.41408	0.58592	0.82
76.5	566	0	0.00000	1.00000	0.48
77.5	566	0	0.00000	1.00000	0.48
78.5	566	0	0.00000	1.00000	0.48
79.5	566	0	0.00000	1.00000	0.48
80.5	566	0	0.00000	1.00000	0.48
81.5	566	0	0.00000	1.00000	0.48
82.5	566	0	0.00000	1.00000	0.48
83.5	566	300	0.53004	0.46996	0.48
84.5	266	0	0.00000	1.00000	0.23
85.5	266	0	0.00000	1.00000	0.23
86.5	266	0	0.00000	1.00000	0.23
87.5	266	0	0.00000	1.00000	0.23
88.5	266	0	0.00000	1.00000	0.23

FortisBC

Account 473.00 - Services - Distribution Plant

Placement Band - 1900 - 2022   Experience Band - 1963 - 2022

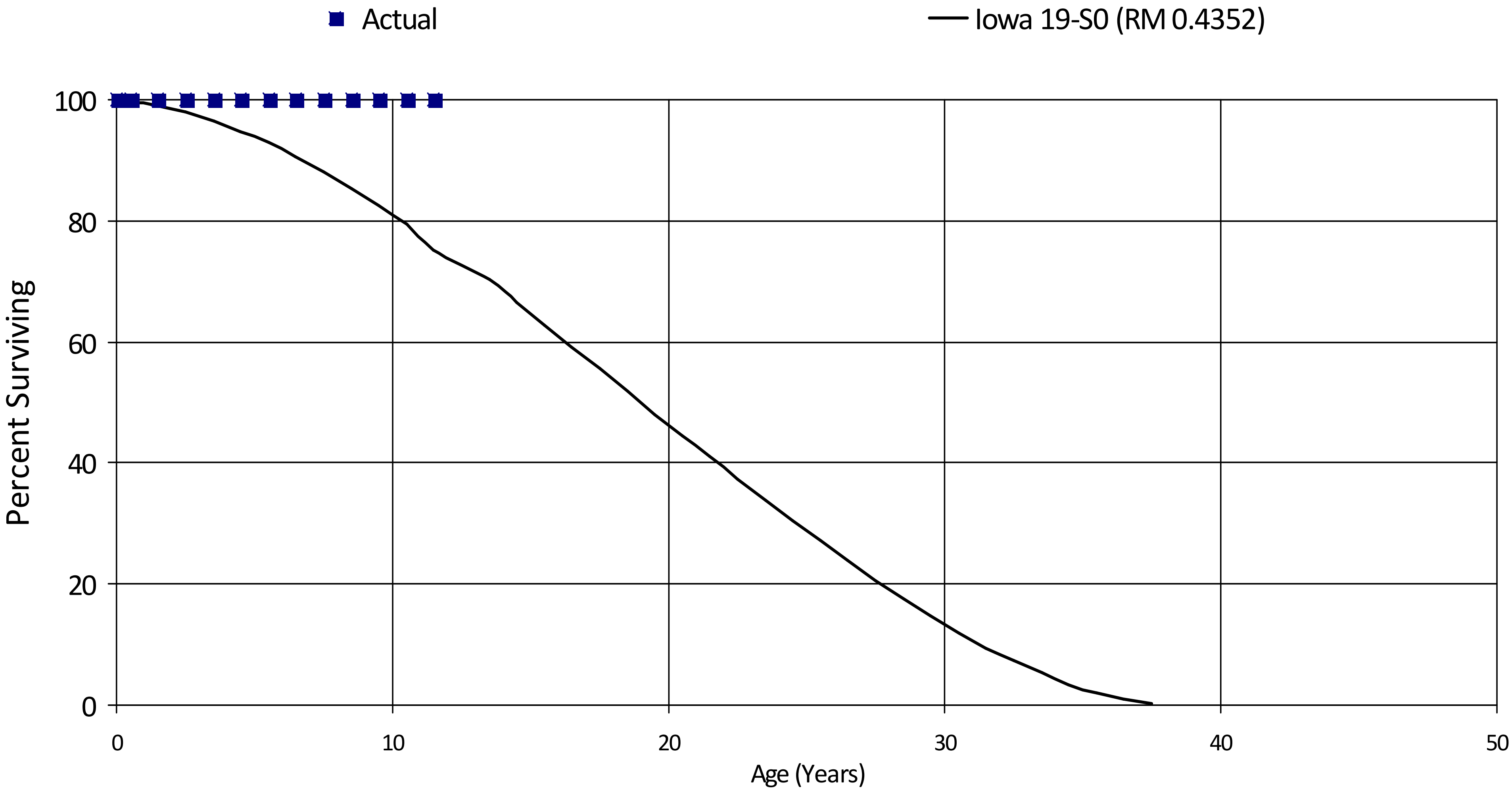
89.5	266	0	0.00000	1.00000	0.23
90.5	266	0	0.00000	1.00000	0.23
91.5	266	266	1.00000		0.23
	Totals:	124,318,225			

FortisBC

Account 474.10 - Meters/Regulator Installations - Bio Gas

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 474.10 - Meters/Regulator Installations - Bio Gas

Placement Band - 2010 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	802,187	0	0.00000	1.00000	100.00
0.5	740,766	0	0.00000	1.00000	100.00
1.5	226,218	0	0.00000	1.00000	100.00
2.5	226,054	0	0.00000	1.00000	100.00
3.5	226,054	0	0.00000	1.00000	100.00
4.5	226,054	0	0.00000	1.00000	100.00
5.5	226,054	0	0.00000	1.00000	100.00
6.5	218,581	0	0.00000	1.00000	100.00
7.5	177,183	0	0.00000	1.00000	100.00
8.5	21,780	0	0.00000	1.00000	100.00
9.5	21,780	0	0.00000	1.00000	100.00
10.5	21,780	0	0.00000	1.00000	100.00
11.5	21,780	0	0.00000	1.00000	100.00
	Totals:	0			

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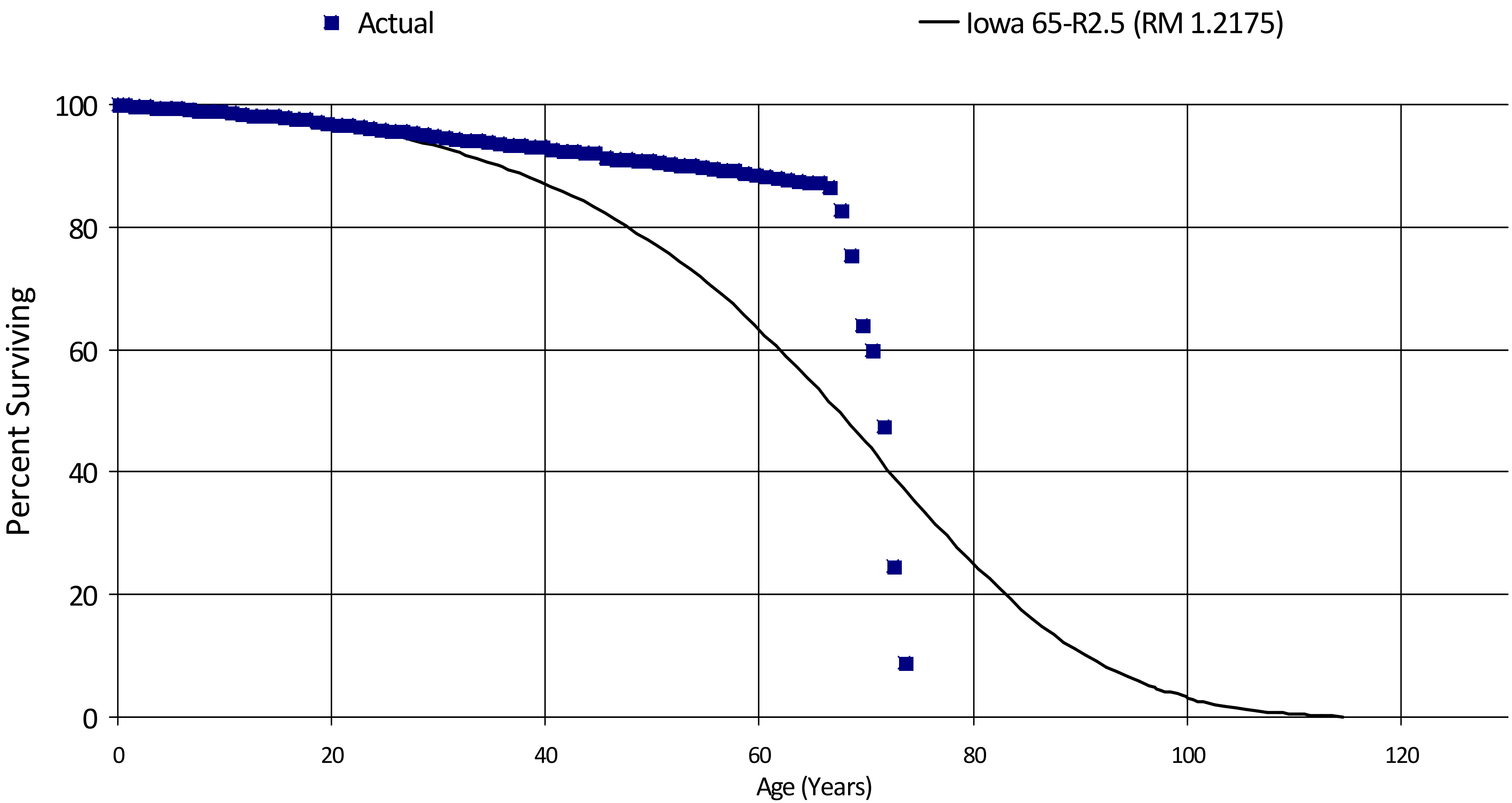
Account 475.00 - Systems - Mains - Distribution Plant

Placement Band - 1924 - 2022 Experience Band - 1963 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 475.00 - Systems - Mains - Distribution Plant

Placement Band - 1924 - 2022 Experience Band - 1963 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,343,599,841	574,233	0.00025	0.99975	100.00
0.5	2,109,278,049	5,093,197	0.00241	0.99759	99.98
1.5	2,006,821,245	1,800,953	0.00090	0.99910	99.74
2.5	1,928,049,539	1,130,807	0.00059	0.99941	99.65
3.5	1,592,648,882	1,310,283	0.00082	0.99918	99.59
4.5	1,468,106,454	1,655,496	0.00113	0.99887	99.51
5.5	1,426,446,471	1,535,746	0.00108	0.99892	99.40
6.5	1,392,188,303	2,770,106	0.00199	0.99801	99.29
7.5	1,346,623,217	2,039,862	0.00151	0.99849	99.09
8.5	1,307,392,257	982,348	0.00075	0.99925	98.94
9.5	1,271,254,745	2,606,661	0.00205	0.99795	98.87
10.5	1,243,079,582	2,208,598	0.00178	0.99822	98.67
11.5	1,216,807,556	1,785,298	0.00147	0.99853	98.49
12.5	1,191,096,393	1,080,754	0.00091	0.99909	98.35
13.5	1,154,106,183	1,673,609	0.00145	0.99855	98.26
14.5	1,113,270,795	1,463,298	0.00131	0.99869	98.12
15.5	1,074,802,084	1,896,703	0.00176	0.99824	97.99
16.5	1,039,752,579	2,098,908	0.00202	0.99798	97.82
17.5	1,009,572,932	3,049,992	0.00302	0.99698	97.62
18.5	979,925,473	3,379,166	0.00345	0.99655	97.33
19.5	945,721,099	2,154,567	0.00228	0.99772	96.99
20.5	916,656,004	1,322,235	0.00144	0.99856	96.77
21.5	882,539,016	2,371,656	0.00269	0.99731	96.63
22.5	847,933,071	1,936,554	0.00228	0.99772	96.37
23.5	806,901,781	2,573,309	0.00319	0.99681	96.15
24.5	765,158,558	1,317,858	0.00172	0.99828	95.84
25.5	720,675,367	743,207	0.00103	0.99897	95.68
26.5	676,567,233	1,299,378	0.00192	0.99808	95.58

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Account 475.00 - Systems - Mains - Distribution Plant

Placement Band - 1924 - 2022   Experience Band - 1963 - 2022

27.5	625,309,026	1,428,484	0.00228	0.99772	95.40
28.5	574,976,788	1,374,069	0.00239	0.99761	95.18
29.5	529,965,788	979,734	0.00185	0.99815	94.95
30.5	450,747,744	1,358,099	0.00301	0.99699	94.77
31.5	397,393,677	1,239,000	0.00312	0.99688	94.48
32.5	70,131,653	105,952	0.00151	0.99849	94.19
33.5	67,271,553	160,008	0.00238	0.99762	94.05
34.5	64,876,332	144,905	0.00223	0.99777	93.83
35.5	60,267,093	61,638	0.00102	0.99898	93.62
36.5	57,341,496	74,087	0.00129	0.99871	93.52
37.5	53,983,169	92,944	0.00172	0.99828	93.40
38.5	49,483,642	86,756	0.00175	0.99825	93.24
39.5	40,209,443	173,845	0.00432	0.99568	93.08
40.5	34,067,718	62,580	0.00184	0.99816	92.68
41.5	30,472,467	48,249	0.00158	0.99842	92.51
42.5	27,308,504	31,043	0.00114	0.99886	92.36
43.5	24,489,899	14,072	0.00057	0.99943	92.25
44.5	22,737,922	189,252	0.00832	0.99168	92.20
45.5	20,757,731	47,940	0.00231	0.99769	91.43
46.5	18,796,804	21,032	0.00112	0.99888	91.22
47.5	17,499,500	30,928	0.00177	0.99823	91.12
48.5	15,506,775	30,238	0.00195	0.99805	90.96
49.5	13,925,951	36,225	0.00260	0.99740	90.78
50.5	12,629,992	29,246	0.00232	0.99768	90.54
51.5	11,740,147	20,118	0.00171	0.99829	90.33
52.5	9,950,401	13,736	0.00138	0.99862	90.18
53.5	8,635,970	14,881	0.00172	0.99828	90.06
54.5	7,814,652	27,764	0.00355	0.99645	89.91
55.5	7,236,977	12,199	0.00169	0.99831	89.59
56.5	6,336,021	14,768	0.00233	0.99767	89.44
57.5	5,892,357	20,010	0.00340	0.99660	89.23

FortisBC

Account 475.00 - Systems - Mains - Distribution Plant

Placement Band - 1924 - 2022 Experience Band - 1963 - 2022

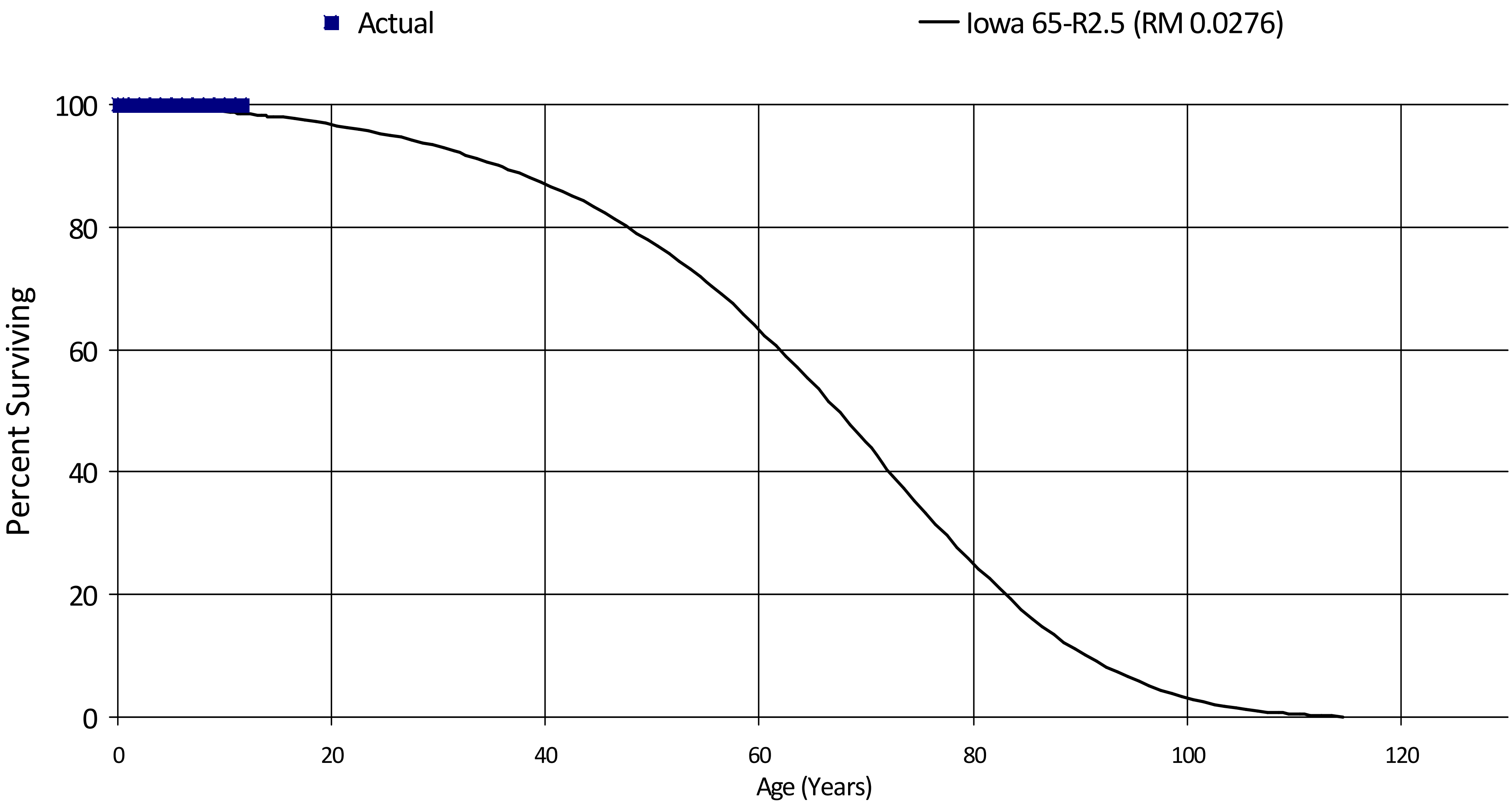
58.5	5,313,835	19,679	0.00370	0.99630	88.93
59.5	4,665,081	12,640	0.00271	0.99729	88.60
60.5	4,355,692	11,661	0.00268	0.99732	88.36
61.5	4,248,142	17,133	0.00403	0.99597	88.12
62.5	4,138,980	13,451	0.00325	0.99675	87.76
63.5	115,259	104	0.00090	0.99910	87.47
64.5	115,155	0	0.00000	1.00000	87.39
65.5	115,155	1,051	0.00913	0.99087	87.39
66.5	114,104	5,097	0.04467	0.95533	86.59
67.5	109,007	9,619	0.08824	0.91176	82.72
68.5	99,388	15,233	0.15327	0.84673	75.42
69.5	84,155	5,371	0.06382	0.93618	63.86
70.5	78,784	16,139	0.20485	0.79515	59.78
71.5	62,645	30,099	0.48047	0.51953	47.53
72.5	32,546	20,729	0.63691	0.36309	24.69
73.5	11,817	11,817	1.00000		8.96
	Totals:	61,988,407			

FortisBC

Account 475.10 - Mains - Municipal Land - Bio Gas

Placement Band - 2010 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 475.10 - Mains - Municipal Land - Bio Gas

Placement Band - 2010 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

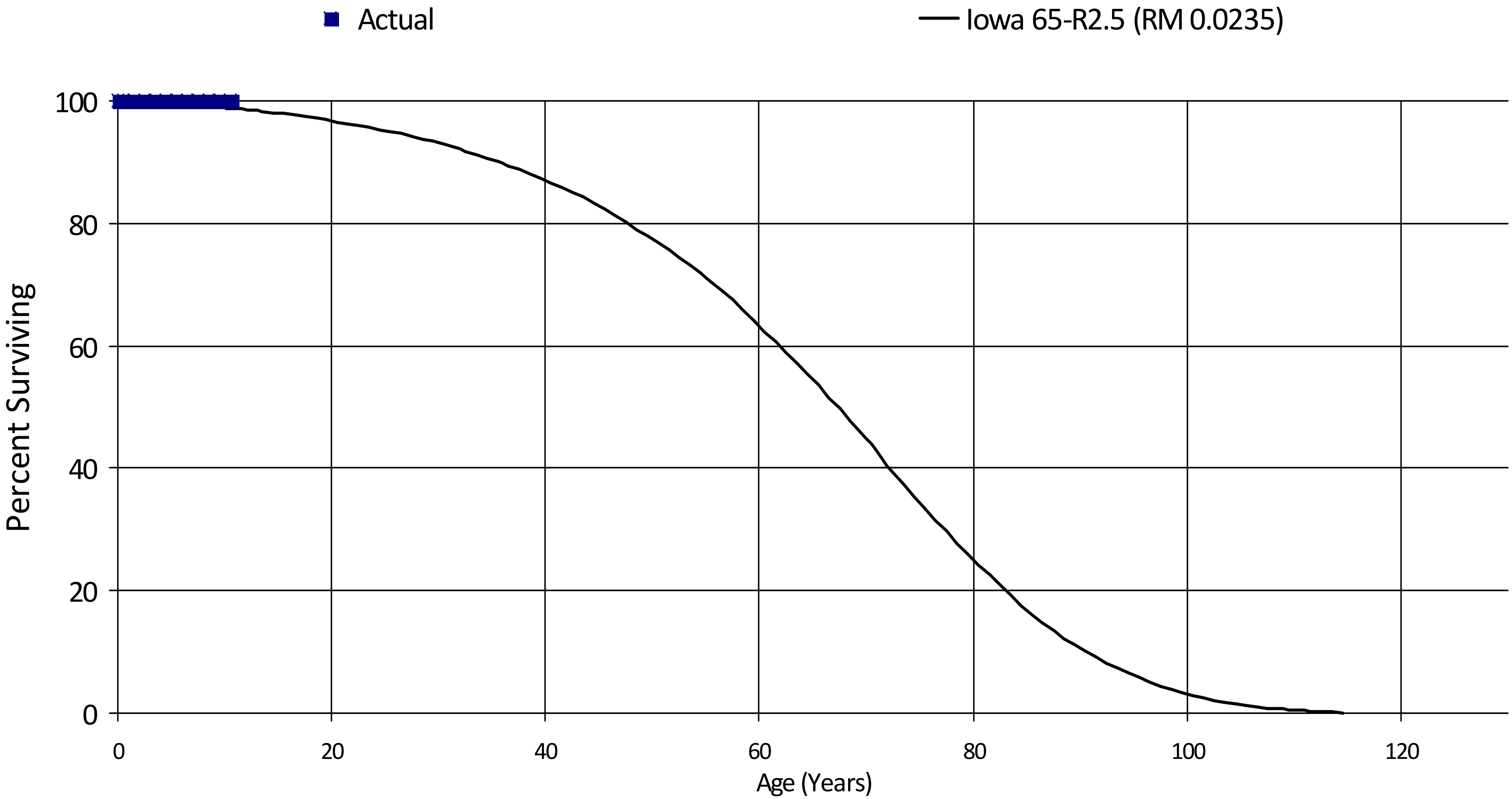
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,752,805	0	0.00000	1.00000	100.00
0.5	1,611,725	0	0.00000	1.00000	100.00
1.5	1,605,025	0	0.00000	1.00000	100.00
2.5	1,600,648	0	0.00000	1.00000	100.00
3.5	1,600,648	0	0.00000	1.00000	100.00
4.5	1,600,648	0	0.00000	1.00000	100.00
5.5	1,600,648	0	0.00000	1.00000	100.00
6.5	1,599,670	0	0.00000	1.00000	100.00
7.5	1,331,426	0	0.00000	1.00000	100.00
8.5	490,005	0	0.00000	1.00000	100.00
9.5	490,005	0	0.00000	1.00000	100.00
10.5	78,295	0	0.00000	1.00000	100.00
11.5	73,653	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 475.20 - Bio Gas Mains – Private Land

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 475.20 - Bio Gas Mains – Private Land

Placement Band - 2011 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

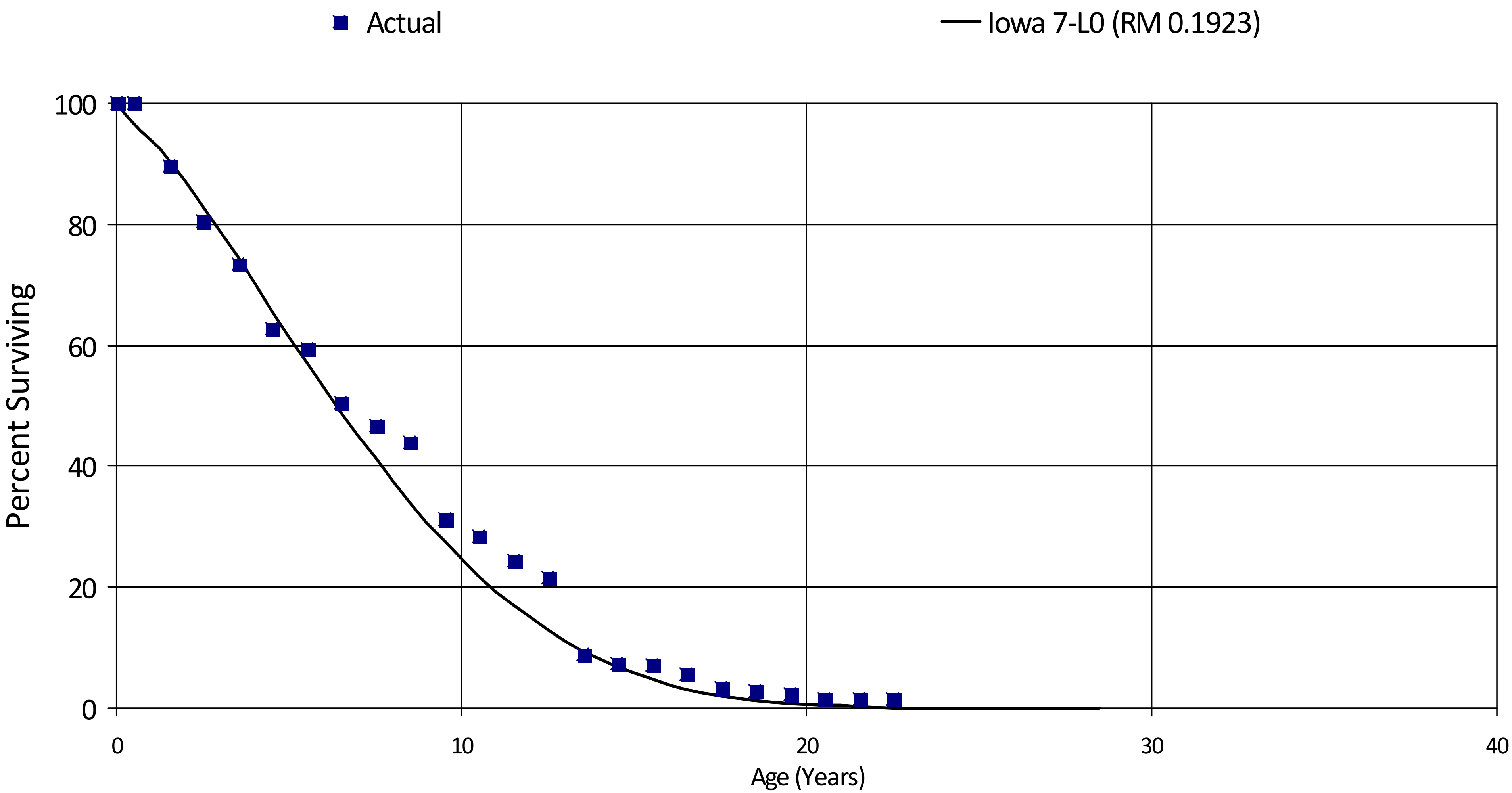
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	410,314	0	0.00000	1.00000	100.00
0.5	398,046	0	0.00000	1.00000	100.00
1.5	338,869	0	0.00000	1.00000	100.00
2.5	55,167	0	0.00000	1.00000	100.00
3.5	55,167	0	0.00000	1.00000	100.00
4.5	55,167	0	0.00000	1.00000	100.00
5.5	55,167	0	0.00000	1.00000	100.00
6.5	55,167	0	0.00000	1.00000	100.00
7.5	55,167	0	0.00000	1.00000	100.00
8.5	51,795	0	0.00000	1.00000	100.00
9.5	51,795	0	0.00000	1.00000	100.00
10.5	41,239	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 476.00 - NGV Fuel Equipment

Placement Band - 1983 - 2015   Experience Band - 1985 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 476.00 - NGV Fuel Equipment

Placement Band - 1983 - 2015   Experience Band - 1985 - 2022

RETIREMENT RATE ANALYSIS

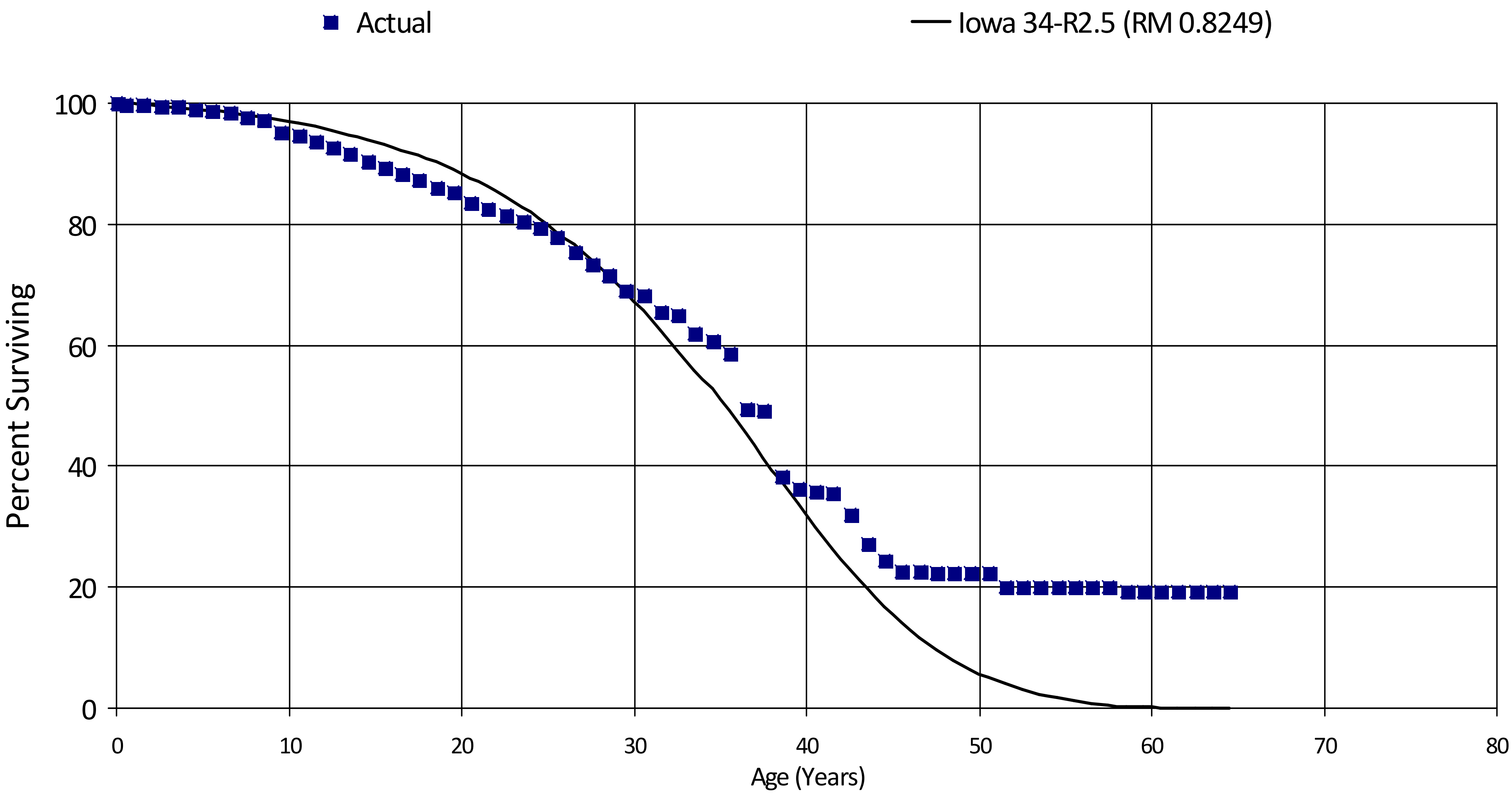
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	10,642,311	100	0.00001	0.99999	100.00
0.5	10,642,211	1,096,943	0.10307	0.89693	100.00
1.5	9,545,267	969,105	0.10153	0.89847	89.69
2.5	8,576,162	765,596	0.08927	0.91073	80.58
3.5	7,810,566	1,127,045	0.14430	0.85570	73.39
4.5	6,683,521	353,582	0.05290	0.94710	62.80
5.5	6,329,938	951,620	0.15034	0.84966	59.48
6.5	5,378,318	407,191	0.07571	0.92429	50.54
7.5	4,696,205	278,800	0.05937	0.94063	46.71
8.5	4,417,406	1,279,856	0.28973	0.71027	43.94
9.5	3,137,549	278,533	0.08877	0.91123	31.21
10.5	2,859,016	399,241	0.13964	0.86036	28.44
11.5	2,262,504	273,868	0.12105	0.87895	24.47
12.5	1,988,635	1,159,465	0.58305	0.41695	21.51
13.5	829,170	142,747	0.17216	0.82784	8.97
14.5	686,423	40,654	0.05923	0.94077	7.43
15.5	645,769	125,269	0.19398	0.80602	6.99
16.5	520,500	209,271	0.40206	0.59794	5.63
17.5	311,229	50,154	0.16115	0.83885	3.37
18.5	261,075	56,248	0.21545	0.78455	2.83
19.5	204,827	63,432	0.30969	0.69031	2.22
20.5	141,395	0	0.00000	1.00000	1.53
21.5	141,395	0	0.00000	1.00000	1.53
22.5	0	0	0.00000	0.00000	1.53
	Totals:	10,028,720			

FortisBC

Account 477.10 - Measuring and Regulating - Distribution Plant

Placement Band - 1957 - 2022   Experience Band - 1959 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 477.10 - Measuring and Regulating - Distribution Plant

Placement Band - 1957 - 2022   Experience Band - 1959 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	252,184,272	340,158	0.00135	0.99865	100.00
0.5	227,230,225	268,045	0.00118	0.99882	99.86
1.5	218,401,135	400,725	0.00183	0.99817	99.74
2.5	206,429,639	343,049	0.00166	0.99834	99.56
3.5	172,108,853	526,460	0.00306	0.99694	99.39
4.5	159,259,870	432,647	0.00272	0.99728	99.09
5.5	144,930,935	601,087	0.00415	0.99585	98.82
6.5	131,052,583	844,967	0.00645	0.99355	98.41
7.5	121,172,010	744,962	0.00615	0.99385	97.78
8.5	118,318,465	2,563,553	0.02167	0.97833	97.18
9.5	108,122,696	594,025	0.00549	0.99451	95.07
10.5	103,351,447	1,120,468	0.01084	0.98916	94.55
11.5	98,168,398	943,522	0.00961	0.99039	93.53
12.5	93,897,480	1,139,182	0.01213	0.98787	92.63
13.5	87,968,594	1,226,662	0.01394	0.98606	91.51
14.5	83,473,843	862,463	0.01033	0.98967	90.23
15.5	77,276,277	916,346	0.01186	0.98814	89.30
16.5	68,700,539	733,907	0.01068	0.98932	88.24
17.5	63,333,699	901,227	0.01423	0.98577	87.30
18.5	59,071,901	503,412	0.00852	0.99148	86.06
19.5	51,325,626	1,124,011	0.02190	0.97810	85.33
20.5	47,369,940	537,447	0.01135	0.98865	83.46
21.5	42,514,666	472,303	0.01111	0.98889	82.51
22.5	38,962,305	580,595	0.01490	0.98510	81.59
23.5	36,107,185	368,152	0.01020	0.98980	80.37
24.5	33,425,295	720,797	0.02156	0.97844	79.55
25.5	29,333,244	886,313	0.03022	0.96978	77.83
26.5	25,366,809	688,159	0.02713	0.97287	75.48

FortisBC

Account 477.10 - Measuring and Regulating - Distribution Plant

Placement Band - 1957 - 2022   Experience Band - 1959 - 2022

27.5	20,123,826	538,521	0.02676	0.97324	73.43
28.5	16,900,583	578,325	0.03422	0.96578	71.47
29.5	14,711,499	179,029	0.01217	0.98783	69.02
30.5	12,389,307	487,308	0.03933	0.96067	68.18
31.5	9,288,237	78,554	0.00846	0.99154	65.50
32.5	9,168,010	437,439	0.04771	0.95229	64.95
33.5	8,517,523	148,949	0.01749	0.98251	61.85
34.5	2,495,126	91,330	0.03660	0.96340	60.77
35.5	1,941,098	299,653	0.15437	0.84563	58.55
36.5	1,093,586	5,707	0.00522	0.99478	49.51
37.5	1,015,312	227,074	0.22365	0.77635	49.25
38.5	666,327	33,251	0.04990	0.95010	38.24
39.5	448,667	7,444	0.01659	0.98341	36.33
40.5	390,644	3,208	0.00821	0.99179	35.73
41.5	379,530	36,842	0.09707	0.90293	35.44
42.5	265,618	40,489	0.15243	0.84757	32.00
43.5	220,494	22,444	0.10179	0.89821	27.12
44.5	193,710	14,082	0.07270	0.92730	24.36
45.5	172,557	0	0.00000	1.00000	22.59
46.5	152,995	2,101	0.01373	0.98627	22.59
47.5	148,516	0	0.00000	1.00000	22.28
48.5	147,460	0	0.00000	1.00000	22.28
49.5	60,868	130	0.00214	0.99786	22.28
50.5	60,739	6,204	0.10214	0.89786	22.23
51.5	49,080	0	0.00000	1.00000	19.96
52.5	44,906	0	0.00000	1.00000	19.96
53.5	43,262	0	0.00000	1.00000	19.96
54.5	43,262	0	0.00000	1.00000	19.96
55.5	43,262	0	0.00000	1.00000	19.96
56.5	42,851	0	0.00000	1.00000	19.96
57.5	42,066	1,210	0.02876	0.97124	19.96

FortisBC

Account 477.10 - Measuring and Regulating - Distribution Plant

Placement Band - 1957 - 2022   Experience Band - 1959 - 2022

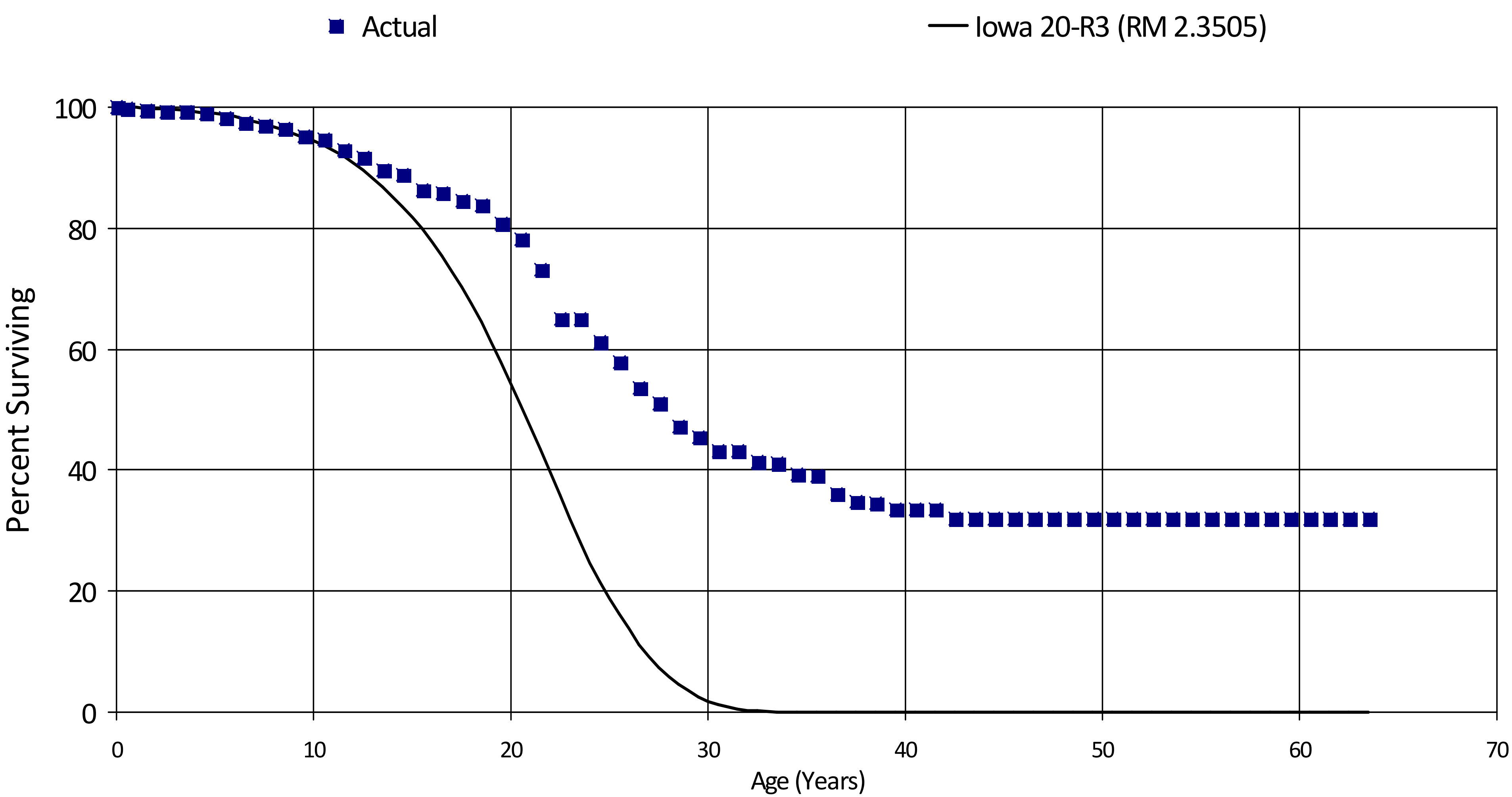
58.5	40,642	0	0.00000	1.00000	19.39
59.5	39,803	0	0.00000	1.00000	19.39
60.5	39,803	0	0.00000	1.00000	19.39
61.5	39,803	0	0.00000	1.00000	19.39
62.5	39,803	0	0.00000	1.00000	19.39
63.5	39,803	0	0.00000	1.00000	19.39
64.5	0	0	0.00000	0.00000	19.39
	Totals:	24,623,938			

FortisBC

Account 477.20 - Telemetry - Distribution Plant

Placement Band - 1958 - 2022 Experience Band - 1971 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 477.20 - Telemetry - Distribution Plant

Placement Band - 1958 - 2022   Experience Band - 1971 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,022,009	106,907	0.00334	0.99666	100.00
0.5	29,120,099	25,599	0.00088	0.99912	99.67
1.5	25,204,354	59,012	0.00234	0.99766	99.58
2.5	23,522,888	15,986	0.00068	0.99932	99.35
3.5	18,538,150	67,437	0.00364	0.99636	99.28
4.5	16,362,523	118,513	0.00724	0.99276	98.92
5.5	14,322,404	108,028	0.00754	0.99246	98.20
6.5	12,413,564	51,317	0.00413	0.99587	97.46
7.5	11,161,923	84,070	0.00753	0.99247	97.06
8.5	9,532,228	108,882	0.01142	0.98858	96.33
9.5	7,949,421	56,669	0.00713	0.99287	95.23
10.5	6,803,180	111,082	0.01633	0.98367	94.55
11.5	6,350,953	94,430	0.01487	0.98513	93.01
12.5	5,813,445	137,238	0.02361	0.97639	91.63
13.5	5,571,692	39,781	0.00714	0.99286	89.47
14.5	5,340,511	151,414	0.02835	0.97165	88.83
15.5	5,141,282	30,125	0.00586	0.99414	86.31
16.5	4,921,596	69,667	0.01416	0.98584	85.80
17.5	4,821,168	49,491	0.01027	0.98973	84.59
18.5	4,687,869	164,819	0.03516	0.96484	83.72
19.5	4,197,758	138,876	0.03308	0.96692	80.78
20.5	3,933,891	254,027	0.06457	0.93543	78.11
21.5	3,410,057	371,815	0.10903	0.89097	73.07
22.5	2,811,953	7,673	0.00273	0.99727	65.10
23.5	2,633,526	154,963	0.05884	0.94116	64.92
24.5	2,238,146	113,943	0.05091	0.94909	61.10
25.5	1,754,591	134,759	0.07680	0.92320	57.99
26.5	713,896	34,253	0.04798	0.95202	53.54

FortisBC

Account 477.20 - Telemetry - Distribution Plant

Placement Band - 1958 - 2022   Experience Band - 1971 - 2022

27.5	558,824	40,814	0.07304	0.92696	50.97
28.5	414,045	15,565	0.03759	0.96241	47.25
29.5	366,624	18,697	0.05100	0.94900	45.47
30.5	317,105	0	0.00000	1.00000	43.15
31.5	274,713	10,900	0.03968	0.96032	43.15
32.5	249,764	1,200	0.00480	0.99520	41.44
33.5	244,546	11,698	0.04784	0.95216	41.24
34.5	201,282	1,075	0.00534	0.99466	39.27
35.5	199,600	15,708	0.07870	0.92130	39.06
36.5	129,869	4,696	0.03616	0.96384	35.99
37.5	96,205	493	0.00512	0.99488	34.69
38.5	93,346	2,595	0.02780	0.97220	34.51
39.5	44,283	0	0.00000	1.00000	33.55
40.5	26,615	0	0.00000	1.00000	33.55
41.5	26,615	1,325	0.04978	0.95022	33.55
42.5	25,290	0	0.00000	1.00000	31.88
43.5	11,404	0	0.00000	1.00000	31.88
44.5	11,404	0	0.00000	1.00000	31.88
45.5	11,404	0	0.00000	1.00000	31.88
46.5	11,208	0	0.00000	1.00000	31.88
47.5	11,208	0	0.00000	1.00000	31.88
48.5	11,208	0	0.00000	1.00000	31.88
49.5	9,820	0	0.00000	1.00000	31.88
50.5	9,820	0	0.00000	1.00000	31.88
51.5	9,679	0	0.00000	1.00000	31.88
52.5	9,679	0	0.00000	1.00000	31.88
53.5	203	0	0.00000	1.00000	31.88
54.5	203	0	0.00000	1.00000	31.88
55.5	203	0	0.00000	1.00000	31.88
56.5	203	0	0.00000	1.00000	31.88
57.5	203	0	0.00000	1.00000	31.88

FortisBC

Account 477.20 - Telemetry - Distribution Plant

Placement Band - 1958 - 2022   Experience Band - 1971 - 2022

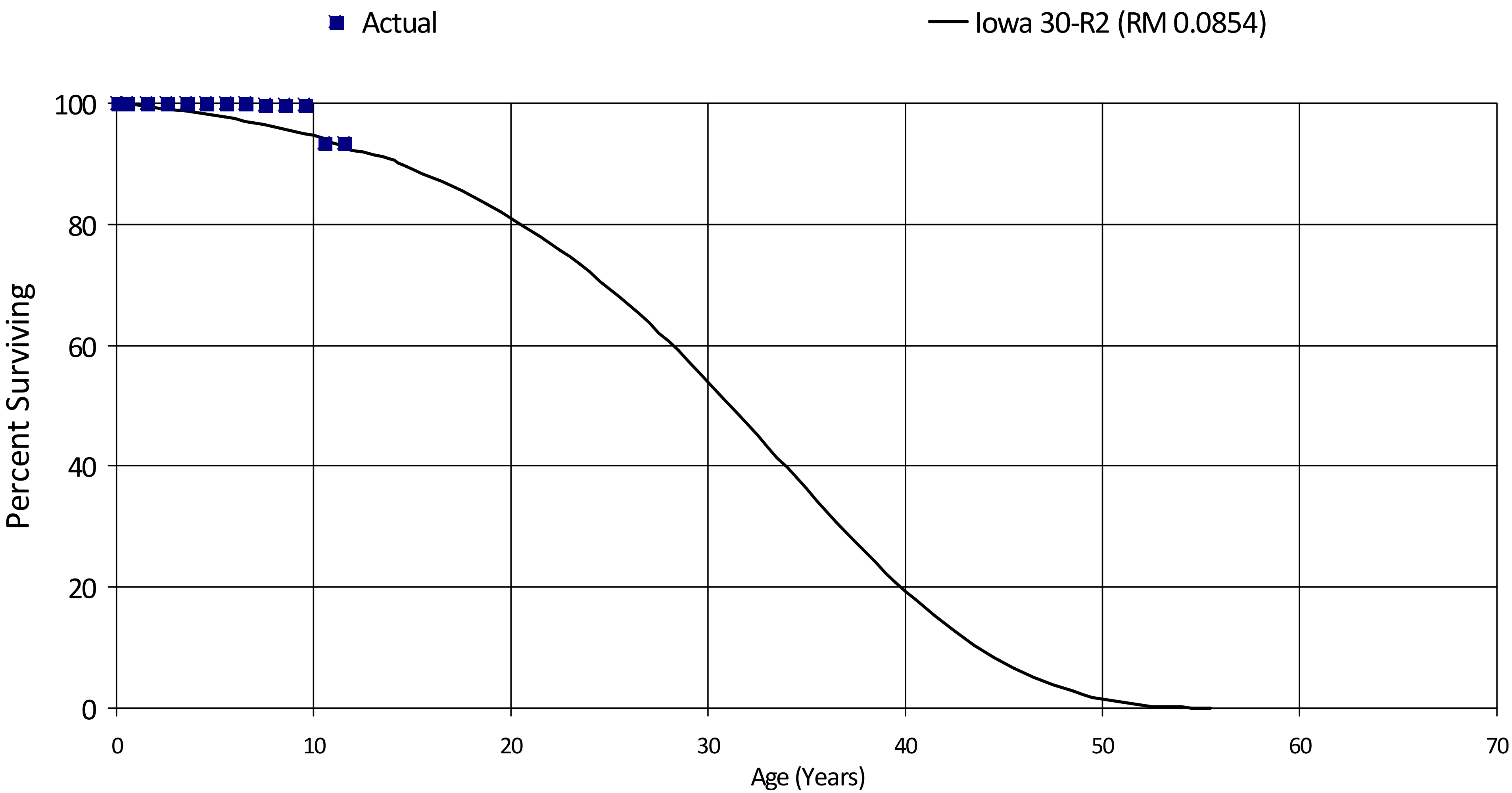
58.5	203	0	0.00000	1.00000	31.88
59.5	203	0	0.00000	1.00000	31.88
60.5	203	0	0.00000	1.00000	31.88
61.5	203	0	0.00000	1.00000	31.88
62.5	203	0	0.00000	1.00000	31.88
63.5	0	0	0.00000	0.00000	31.88
	Totals:	2,985,542			

FortisBC

Account 477.40 - Measuring and Regulating - Bio Gas

Placement Band - 2010 - 2022 Experience Band - 2020 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 477.40 - Measuring and Regulating - Bio Gas

Placement Band - 2010 - 2022   Experience Band - 2020 - 2022

RETIREMENT RATE ANALYSIS

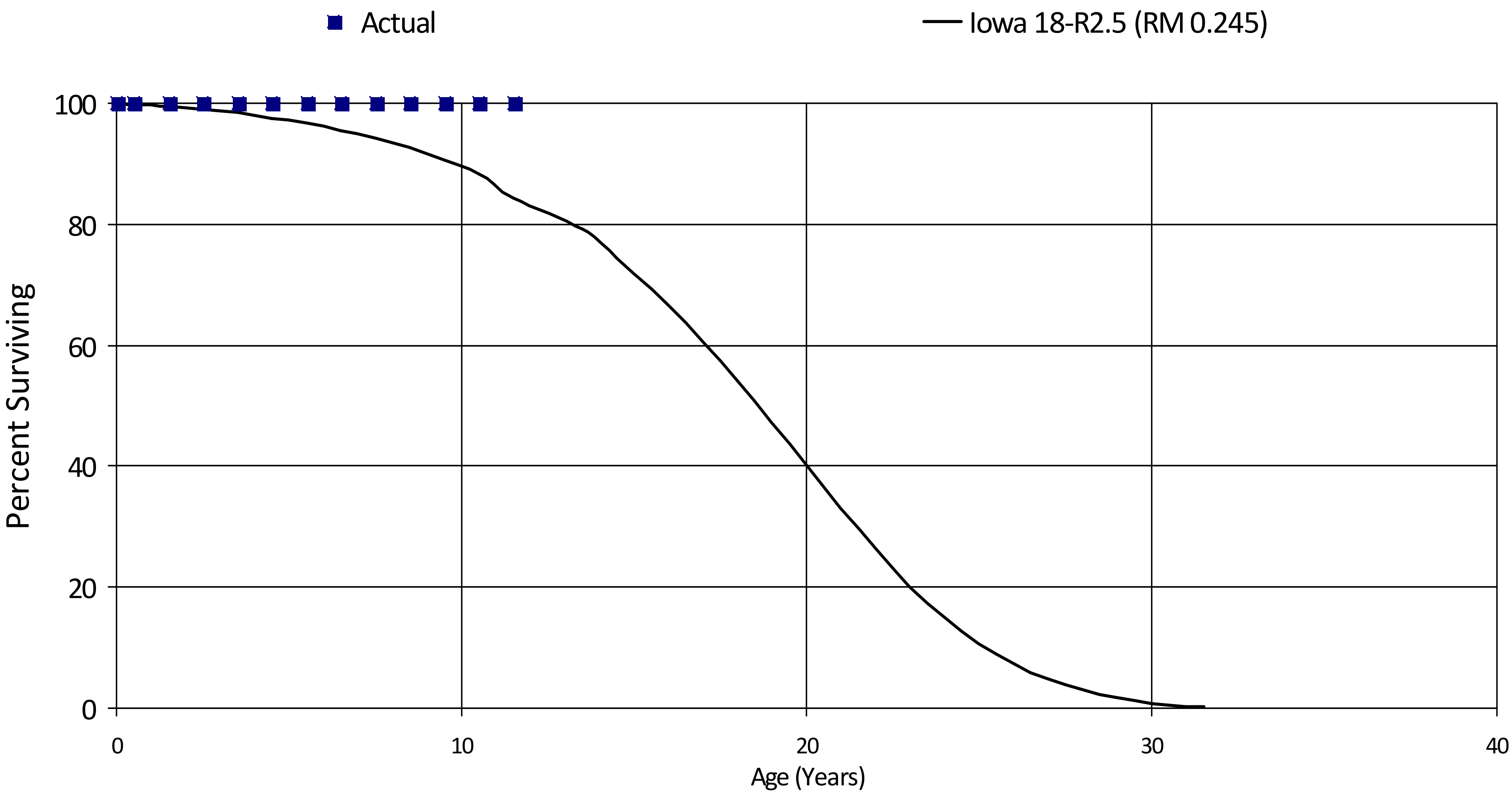
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	4,342,839	0	0.00000	1.00000	100.00
0.5	3,540,072	0	0.00000	1.00000	100.00
1.5	2,859,695	0	0.00000	1.00000	100.00
2.5	2,750,563	0	0.00000	1.00000	100.00
3.5	2,728,078	0	0.00000	1.00000	100.00
4.5	2,565,623	0	0.00000	1.00000	100.00
5.5	2,046,129	0	0.00000	1.00000	100.00
6.5	1,917,323	5,000	0.00261	0.99739	100.00
7.5	1,427,698	0	0.00000	1.00000	99.74
8.5	853,254	0	0.00000	1.00000	99.74
9.5	279,916	17,856	0.06379	0.93621	99.74
10.5	261,744	0	0.00000	1.00000	93.38
11.5	257,694	0	0.00000	1.00000	93.38
	Totals:	22,856			

FortisBC

Account 478.30 - Meters - Bio Gas

Placement Band - 2010 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 478.30 - Meters - Bio Gas

Placement Band - 2010 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	84,213	0	0.00000	1.00000	100.00
0.5	39,538	0	0.00000	1.00000	100.00
1.5	36,644	0	0.00000	1.00000	100.00
2.5	36,492	0	0.00000	1.00000	100.00
3.5	36,492	0	0.00000	1.00000	100.00
4.5	35,277	0	0.00000	1.00000	100.00
5.5	35,277	0	0.00000	1.00000	100.00
6.5	30,794	0	0.00000	1.00000	100.00
7.5	10,298	0	0.00000	1.00000	100.00
8.5	10,298	0	0.00000	1.00000	100.00
9.5	7,334	0	0.00000	1.00000	100.00
10.5	7,334	0	0.00000	1.00000	100.00
11.5	7,334	0	0.00000	1.00000	100.00
	Totals:	0			

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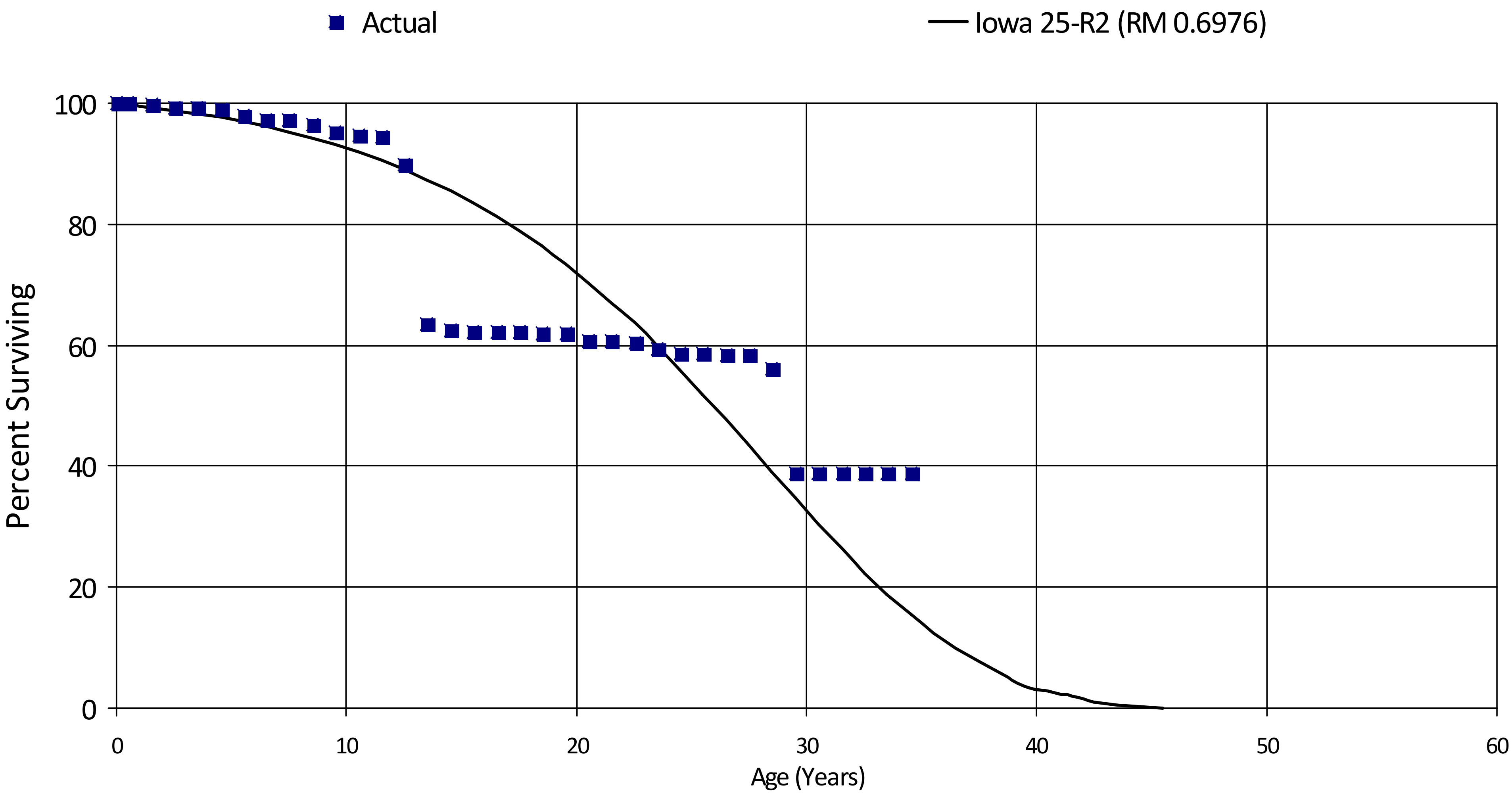
Account 482.10 - Stuctures (Frame) - General Plant

Placement Band - 1982 - 2022 Experience Band - 2000 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 482.10 - Stuctures (Frame) - General Plant

Placement Band - 1982 - 2022   Experience Band - 2000 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	35,368,587	1,593	0.00005	0.99995	100.00
0.5	35,366,994	68,135	0.00193	0.99807	100.00
1.5	33,873,990	186,822	0.00552	0.99448	99.81
2.5	32,721,597	19,013	0.00058	0.99942	99.26
3.5	31,537,558	86,901	0.00276	0.99724	99.20
4.5	30,517,335	257,957	0.00845	0.99155	98.93
5.5	28,693,756	234,553	0.00817	0.99183	98.09
6.5	26,380,163	41,932	0.00159	0.99841	97.29
7.5	25,850,390	167,296	0.00647	0.99353	97.14
8.5	25,045,208	370,654	0.01480	0.98520	96.51
9.5	22,294,937	75,021	0.00336	0.99664	95.08
10.5	21,276,344	51,084	0.00240	0.99760	94.76
11.5	18,432,507	911,273	0.04944	0.95056	94.53
12.5	15,842,226	4,637,978	0.29276	0.70724	89.86
13.5	9,666,197	168,025	0.01738	0.98262	63.55
14.5	9,393,174	42,282	0.00450	0.99550	62.45
15.5	9,239,884	0	0.00000	1.00000	62.17
16.5	9,077,517	12,595	0.00139	0.99861	62.17
17.5	8,874,560	5,958	0.00067	0.99933	62.08
18.5	8,740,190	28,873	0.00330	0.99670	62.04
19.5	8,482,201	154,898	0.01826	0.98174	61.84
20.5	7,439,358	12,909	0.00174	0.99826	60.71
21.5	6,461,426	14,630	0.00226	0.99774	60.60
22.5	6,234,746	100,748	0.01616	0.98384	60.46
23.5	6,005,664	78,380	0.01305	0.98695	59.48
24.5	5,509,673	5,816	0.00106	0.99894	58.70
25.5	5,406,366	35,240	0.00652	0.99348	58.64
26.5	4,414,253	0	0.00000	1.00000	58.26

FortisBC

Account 482.10 - Stuctures (Frame) - General Plant

Placement Band - 1982 - 2022   Experience Band - 2000 - 2022

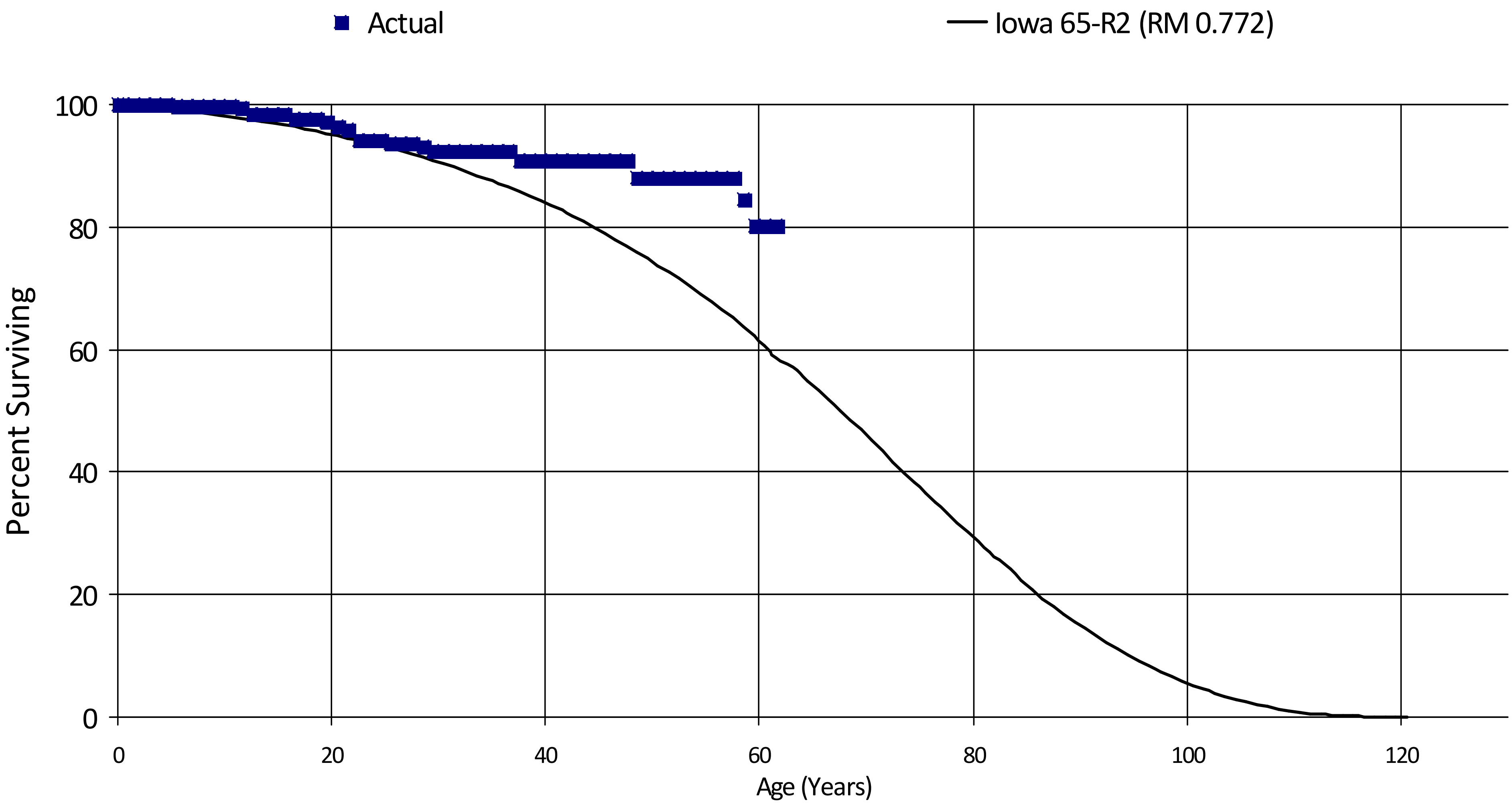
27.5	1,996,385	77,333	0.03874	0.96126	58.26
28.5	1,034,124	316,554	0.30611	0.69389	56.00
29.5	713,513	700	0.00098	0.99902	38.86
30.5	705,715	0	0.00000	1.00000	38.82
31.5	580,948	0	0.00000	1.00000	38.82
32.5	580,627	0	0.00000	1.00000	38.82
33.5	580,627	0	0.00000	1.00000	38.82
34.5	0	0	0.00000	0.00000	38.82
	Totals:	8,165,153			

FortisBC

Account 482.20 - Structures (Masonry) - General Plant

Placement Band - 1960 - 2022   Experience Band - 1978 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 482.20 - Structures (Masonry) - General Plant

Placement Band - 1960 - 2022   Experience Band - 1978 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	135,006,932	11,358	0.00008	0.99992	100.00
0.5	129,090,727	69,205	0.00054	0.99946	99.99
1.5	126,171,920	52,031	0.00041	0.99959	99.94
2.5	122,599,925	0	0.00000	1.00000	99.90
3.5	120,796,248	6,229	0.00005	0.99995	99.90
4.5	116,605,499	32,473	0.00028	0.99972	99.90
5.5	113,790,868	4,411	0.00004	0.99996	99.87
6.5	110,910,805	86,056	0.00078	0.99922	99.87
7.5	109,488,297	63,830	0.00058	0.99942	99.79
8.5	109,376,724	38,626	0.00035	0.99965	99.73
9.5	108,111,023	3,340	0.00003	0.99997	99.70
10.5	94,702,027	115,397	0.00122	0.99878	99.70
11.5	86,383,794	889,442	0.01030	0.98970	99.58
12.5	84,140,284	72,348	0.00086	0.99914	98.55
13.5	82,446,733	26,208	0.00032	0.99968	98.47
14.5	81,432,538	1,080	0.00001	0.99999	98.44
15.5	78,196,658	489,860	0.00626	0.99374	98.44
16.5	76,582,015	11,500	0.00015	0.99985	97.82
17.5	25,001,178	4,200	0.00017	0.99983	97.81
18.5	23,998,184	138,039	0.00575	0.99425	97.79
19.5	22,374,303	160,000	0.00715	0.99285	97.23
20.5	21,721,655	154,813	0.00713	0.99287	96.53
21.5	20,276,106	344,721	0.01700	0.98300	95.84
22.5	19,407,080	5,800	0.00030	0.99970	94.21
23.5	19,174,140	0	0.00000	1.00000	94.18
24.5	17,797,796	100,000	0.00562	0.99438	94.18
25.5	17,251,066	0	0.00000	1.00000	93.65
26.5	13,051,246	2,400	0.00018	0.99982	93.65

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Account 482.20 - Structures (Masonry) - General Plant

Placement Band - 1960 - 2022 Experience Band - 1978 - 2022

27.5	9,134,300	42,784	0.00468	0.99532	93.63
28.5	5,427,551	41,157	0.00758	0.99242	93.19
29.5	5,244,601	0	0.00000	1.00000	92.48
30.5	1,933,996	0	0.00000	1.00000	92.48
31.5	1,906,372	0	0.00000	1.00000	92.48
32.5	1,791,533	0	0.00000	1.00000	92.48
33.5	1,360,471	0	0.00000	1.00000	92.48
34.5	852,822	0	0.00000	1.00000	92.48
35.5	849,472	0	0.00000	1.00000	92.48
36.5	849,226	15,000	0.01766	0.98234	92.48
37.5	833,139	0	0.00000	1.00000	90.85
38.5	787,601	0	0.00000	1.00000	90.85
39.5	776,560	0	0.00000	1.00000	90.85
40.5	768,805	0	0.00000	1.00000	90.85
41.5	759,836	0	0.00000	1.00000	90.85
42.5	754,915	0	0.00000	1.00000	90.85
43.5	449,087	0	0.00000	1.00000	90.85
44.5	428,730	0	0.00000	1.00000	90.85
45.5	419,803	0	0.00000	1.00000	90.85
46.5	171,033	0	0.00000	1.00000	90.85
47.5	170,852	5,000	0.02927	0.97073	90.85
48.5	165,163	0	0.00000	1.00000	88.19
49.5	165,163	0	0.00000	1.00000	88.19
50.5	165,163	0	0.00000	1.00000	88.19
51.5	165,163	0	0.00000	1.00000	88.19
52.5	156,331	0	0.00000	1.00000	88.19
53.5	156,331	0	0.00000	1.00000	88.19
54.5	156,331	0	0.00000	1.00000	88.19
55.5	85,734	0	0.00000	1.00000	88.19
56.5	85,734	0	0.00000	1.00000	88.19
57.5	85,734	3,643	0.04249	0.95751	88.19

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Account 482.20 - Structures (Masonry) - General Plant

Placement Band - 1960 - 2022   Experience Band - 1978 - 2022

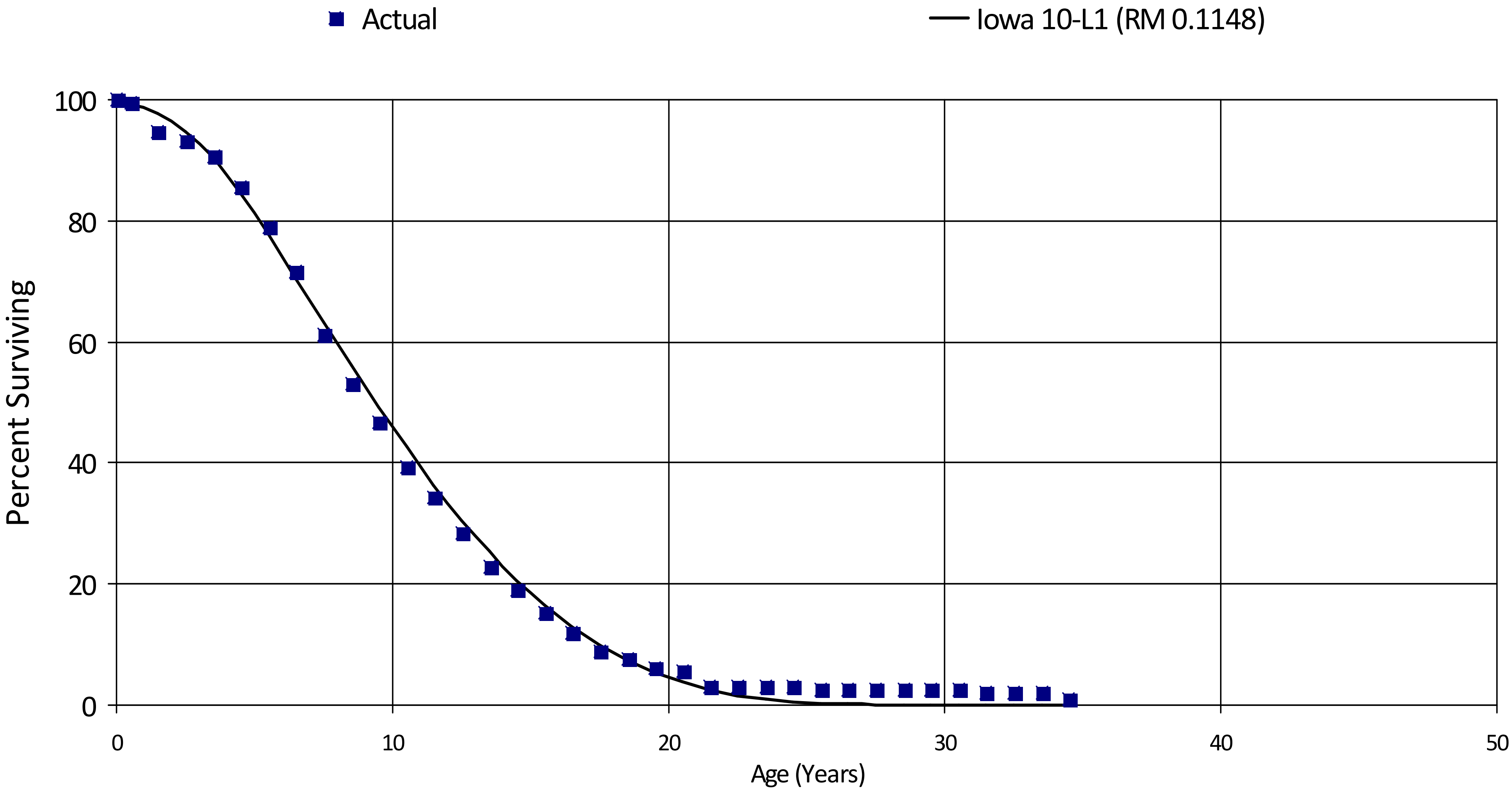
58.5	82,091	4,197	0.05113	0.94887	84.44
59.5	77,894	0	0.00000	1.00000	80.12
60.5	77,894	0	0.00000	1.00000	80.12
61.5	77,894	0	0.00000	1.00000	80.12
	Totals:	2,995,148			

FortisBC

Account 484.00 - Vehicles - General Plant

Placement Band - 1957 - 2022   Experience Band - 1962 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 484.00 - Vehicles - General Plant

Placement Band - 1957 - 2022   Experience Band - 1962 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	79,572,021	386,315	0.00485	0.99515	100.00
0.5	72,223,432	3,431,357	0.04751	0.95249	99.52
1.5	62,486,141	1,100,175	0.01761	0.98239	94.79
2.5	53,880,499	1,484,555	0.02755	0.97245	93.12
3.5	45,769,211	2,527,223	0.05522	0.94478	90.55
4.5	33,625,341	2,623,468	0.07802	0.92198	85.55
5.5	26,209,633	2,439,393	0.09307	0.90693	78.88
6.5	20,206,458	2,943,310	0.14566	0.85434	71.54
7.5	14,497,549	1,914,137	0.13203	0.86797	61.12
8.5	10,936,590	1,324,476	0.12111	0.87889	53.05
9.5	8,457,503	1,337,194	0.15811	0.84189	46.63
10.5	6,364,975	827,235	0.12997	0.87003	39.26
11.5	4,833,434	812,622	0.16813	0.83187	34.16
12.5	3,268,455	653,773	0.20003	0.79997	28.42
13.5	1,998,401	334,424	0.16735	0.83265	22.74
14.5	1,303,176	261,253	0.20047	0.79953	18.93
15.5	948,976	204,563	0.21556	0.78444	15.14
16.5	470,167	117,244	0.24937	0.75063	11.88
17.5	227,262	30,379	0.13367	0.86633	8.92
18.5	195,819	40,074	0.20465	0.79535	7.73
19.5	109,987	12,011	0.10920	0.89080	6.15
20.5	45,467	19,252	0.42343	0.57657	5.48
21.5	26,215	1,254	0.04784	0.95216	3.16
22.5	24,961	367	0.01470	0.98530	3.01
23.5	24,594	0	0.00000	1.00000	2.97
24.5	24,594	3,721	0.15130	0.84870	2.97
25.5	20,873	0	0.00000	1.00000	2.52
26.5	20,873	0	0.00000	1.00000	2.52

FortisBC

Account 484.00 - Vehicles - General Plant

Placement Band - 1957 - 2022 Experience Band - 1962 - 2022

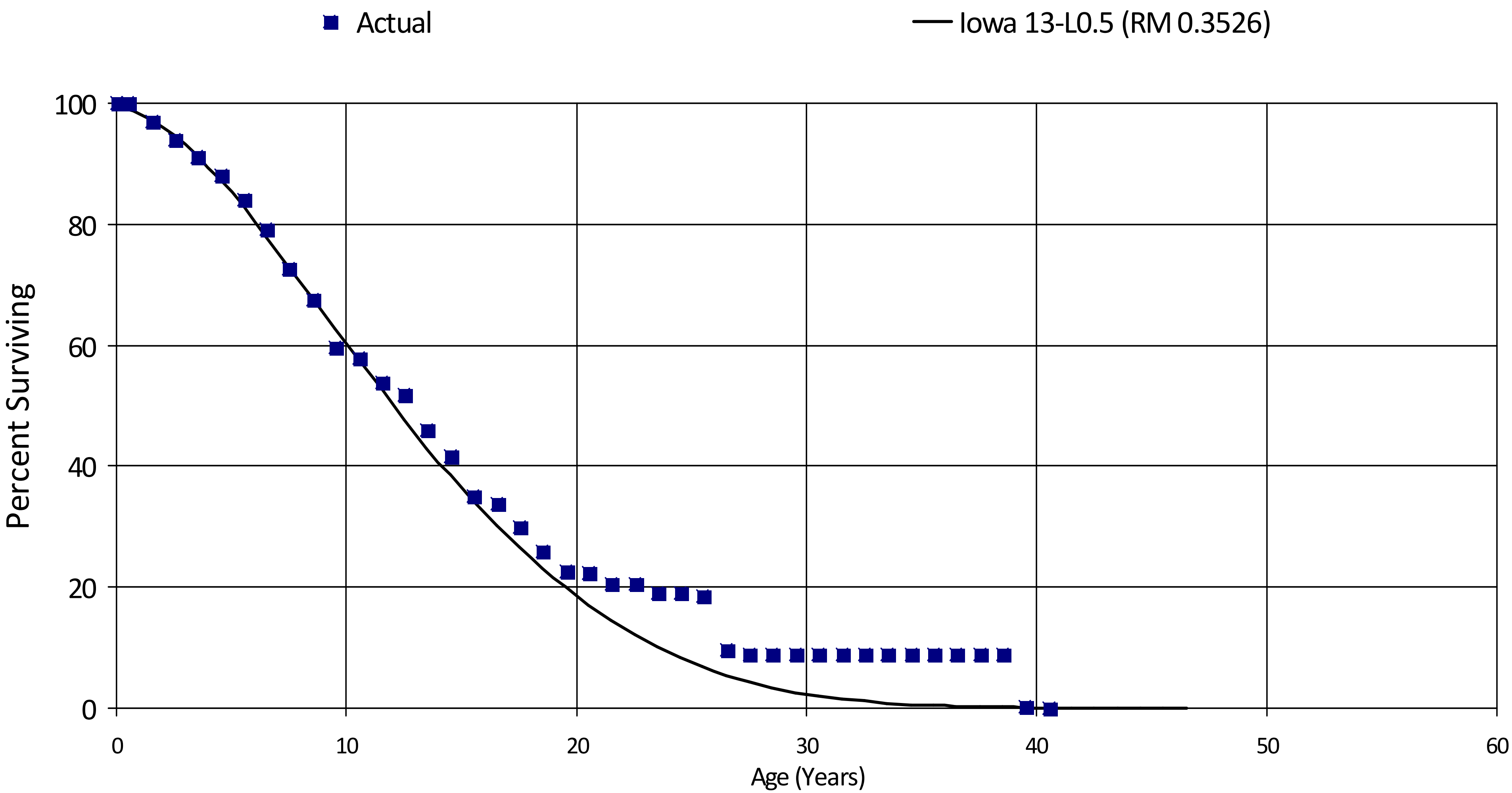
27.5	20,873	384	0.01840	0.98160	2.52
28.5	20,489	0	0.00000	1.00000	2.47
29.5	20,489	0	0.00000	1.00000	2.47
30.5	20,489	3,441	0.16794	0.83206	2.47
31.5	17,048	0	0.00000	1.00000	2.06
32.5	17,048	385	0.02258	0.97742	2.06
33.5	16,663	7,823	0.46948	0.53052	2.01
34.5	8,840	8,840	1.00000		1.07
	Totals:	24,850,648			

FortisBC

Account 485.10 - Heavy Work Equipment - General Plant

Placement Band - 1958 - 2020   Experience Band - 1970 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 485.10 - Heavy Work Equipment - General Plant

Placement Band - 1958 - 2020   Experience Band - 1970 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,289,740	325	0.00014	0.99986	100.00
0.5	2,289,415	67,561	0.02951	0.97049	99.99
1.5	2,221,854	74,412	0.03349	0.96651	97.04
2.5	2,143,939	61,430	0.02865	0.97135	93.79
3.5	2,067,924	70,598	0.03414	0.96586	91.10
4.5	1,997,326	92,838	0.04648	0.95352	87.99
5.5	1,898,582	108,380	0.05708	0.94292	83.90
6.5	1,790,202	146,018	0.08157	0.91843	79.11
7.5	1,577,753	109,889	0.06965	0.93035	72.66
8.5	1,422,301	167,517	0.11778	0.88222	67.60
9.5	1,251,681	36,534	0.02919	0.97081	59.64
10.5	962,224	67,289	0.06993	0.93007	57.90
11.5	812,729	32,253	0.03968	0.96032	53.85
12.5	754,754	83,378	0.11047	0.88953	51.71
13.5	671,376	62,849	0.09361	0.90639	46.00
14.5	608,527	98,676	0.16216	0.83784	41.69
15.5	509,308	18,288	0.03591	0.96409	34.93
16.5	481,797	54,188	0.11247	0.88753	33.68
17.5	398,788	51,939	0.13024	0.86976	29.89
18.5	346,849	45,845	0.13218	0.86782	26.00
19.5	301,004	2,493	0.00828	0.99172	22.56
20.5	284,434	22,597	0.07945	0.92055	22.37
21.5	249,330	0	0.00000	1.00000	20.59
22.5	236,348	16,706	0.07068	0.92932	20.59
23.5	203,393	0	0.00000	1.00000	19.13
24.5	150,606	4,653	0.03090	0.96910	19.13
25.5	113,224	54,451	0.48091	0.51909	18.54
26.5	38,244	3,200	0.08367	0.91633	9.62

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Account 485.10 - Heavy Work Equipment - General Plant

Placement Band - 1958 - 2020   Experience Band - 1970 - 2022

27.5	15,802	0	0.00000	1.00000	8.82
28.5	15,802	0	0.00000	1.00000	8.82
29.5	15,802	0	0.00000	1.00000	8.82
30.5	12,602	0	0.00000	1.00000	8.82
31.5	12,602	0	0.00000	1.00000	8.82
32.5	12,602	0	0.00000	1.00000	8.82
33.5	12,602	0	0.00000	1.00000	8.82
34.5	12,602	0	0.00000	1.00000	8.82
35.5	12,602	0	0.00000	1.00000	8.82
36.5	12,602	0	0.00000	1.00000	8.82
37.5	12,602	0	0.00000	1.00000	8.82
38.5	12,602	12,109	0.96090	0.03910	8.82
39.5	493	493	1.00049	-0.00049	0.34
40.5	0	0	0.00000	0.00000	0.00
	Totals:	1,566,909			

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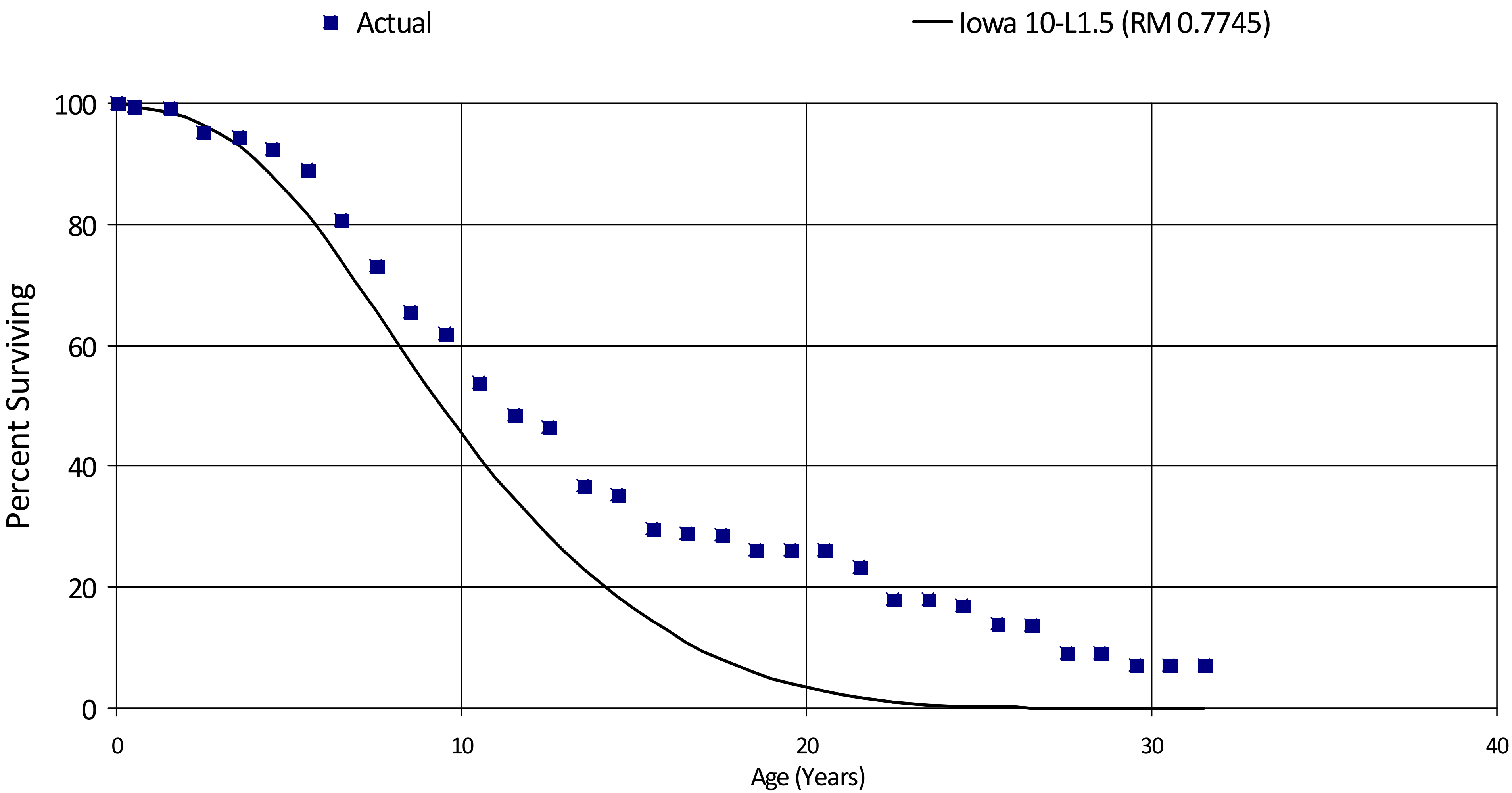
Account 485.20 - Heavy Mobile Equipment - General Plant

Placement Band - 1957 - 2022 Experience Band - 1969 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 485.20 - Heavy Mobile Equipment - General Plant

Placement Band - 1957 - 2022   Experience Band - 1969 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,428,798	95,257	0.00580	0.99420	100.00
0.5	15,647,432	36,764	0.00235	0.99765	99.42
1.5	13,219,645	540,398	0.04088	0.95912	99.19
2.5	11,267,341	84,272	0.00748	0.99252	95.14
3.5	10,051,246	220,140	0.02190	0.97810	94.43
4.5	7,893,301	290,837	0.03685	0.96315	92.36
5.5	6,224,155	575,157	0.09241	0.90759	88.96
6.5	5,424,706	516,381	0.09519	0.90481	80.74
7.5	4,615,129	479,903	0.10398	0.89602	73.05
8.5	3,305,628	183,288	0.05545	0.94455	65.45
9.5	3,039,918	397,386	0.13072	0.86928	61.82
10.5	2,558,915	245,374	0.09589	0.90411	53.74
11.5	2,100,885	92,740	0.04414	0.95586	48.59
12.5	1,360,787	279,250	0.20521	0.79479	46.45
13.5	878,749	41,190	0.04687	0.95313	36.92
14.5	711,290	112,277	0.15785	0.84215	35.19
15.5	572,006	15,220	0.02661	0.97339	29.64
16.5	476,020	1,419	0.00298	0.99702	28.85
17.5	326,131	29,983	0.09194	0.90806	28.76
18.5	110,547	0	0.00000	1.00000	26.12
19.5	41,676	1	0.00002	0.99998	26.12
20.5	41,675	4,280	0.10270	0.89730	26.12
21.5	7,931	1,812	0.22847	0.77153	23.44
22.5	6,119	0	0.00000	1.00000	18.08
23.5	6,119	323	0.05279	0.94721	18.08
24.5	5,796	1,079	0.18616	0.81384	17.13
25.5	4,717	74	0.01569	0.98431	13.94
26.5	4,643	1,509	0.32501	0.67499	13.72

FortisBC

Account 485.20 - Heavy Mobile Equipment - General Plant

Placement Band - 1957 - 2022   Experience Band - 1969 - 2022

27.5	3,134	0	0.00000	1.00000	9.26
28.5	3,134	729	0.23261	0.76739	9.26
29.5	2,405	0	0.00000	1.00000	7.11
30.5	2,405	0	0.00000	1.00000	7.11
31.5	2,405	2,405	1.00000		7.11
	Totals:	4,249,448			

SECTION 7

7 NET SALVAGE CALCULATION

FortisBC Energy Inc.
ACCOUNT 432.00 - Manufacturing Plant - Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2004		13,473	0		0	-13,473	0					-13,473	0
2005		583	0		0	-583	0					-7,028	0
2006	14,056		0		0	0	0	-4,685	-100			-7,028	-100
2007			0		0	0	0	-194	-4			-7,028	-100
2008			0		0	0	0	0	0	-2,811	-100	-7,028	-100
2009			0		0	0	0	0	0	-117	-4	-7,028	-100
2010		86,809	0		0	-86,809	0	-28,936	0	-17,362	-618	-33,622	-718
2011		-86,320	0		0	86,320	0	-163	0	-98	0	-3,636	-103
2012			0		0	0	0	-163	0	-98	0	-3,636	-103
2013			0		0	0	0	28,773	0	-98	0	-3,636	-103
2014	6,075		0		0	0	0	0	0	-98	-8	-3,636	-72
2015			0		0	0	0	0	0	17,264	1,421	-3,636	-72
2016			0		0	0	0	0	0	0	0	-3,636	-72
2017			0		0	0	0	0	0	0	0	-3,636	-72
2018			0		0	0	0	0	0	0	0	-3,636	-72
2019			0		0	0	0	0	0	0	0	-3,636	-72
2020			0		0	0	0	0	0	0	0	-3,636	-72
2021			0		0	0	0	0	0	0	0	-3,636	-72
2022			0		0	0	0	0	0	0	0	-3,636	-72
TOTAL	**20,130**	**14,544**	**72**	**0**	**0**	**-14,544**	**-72**						

FortisBC Energy Inc.
ACCOUNT 433.00 - Manufacturing Plant - Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010		50,733	0		0	-50,733	0					-50,733	0
2011		-50,478	0		0	50,478	0					-128	0
2012			0		0	0	0	-85	0			-128	0
2013			0		0	0	0	16,826	0			-128	0
2014			0		0	0	0	0	0	-51	0	-128	0
2015			0		0	0	0	0	0	10,096	0	-128	0
2016			0		0	0	0	0	0	0	0	-128	0
2017			0		0	0	0	0	0	0	0	-128	0
2018			0		0	0	0	0	0	0	0	-128	0
2019			0		0	0	0	0	0	0	0	-128	0
2020			0		0	0	0	0	0	0	0	-128	0
2021	25,612		0		0	0	0	0	0	0	0	-128	-1
2022			0		0	0	0	0	0	0	0	-128	-1
TOTAL	**25,612**	**255**	**1.00**	**0**	**0.00**	**-255**	**(1.00)**						

FortisBC Energy Inc.
ACCOUNT 434.00 - Manufacturing Plant - Holders
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2010		82,642	0		0	-82,642	0					-82,642	0
2011		-82,173	0		0	82,173	0					-234	0
2012			0		0	0	0	-156	0			-234	0
2013			0		0	0	0	27,391	0			-234	0
2014	1,000		0		0	0	0	0	0	-94	-47	-234	-47
2015			0		0	0	0	0	0	16,435	8,217	-234	-47
2016			0		0	0	0	0	0	0	0	-234	-47
2017			0		0	0	0	0	0	0	0	-234	-47
2018			0		0	0	0	0	0	0	0	-234	-47
2019			0		0	0	0	0	0	0	0	-234	-47
2020			0		0	0	0	0	0	0	0	-234	-47
2021	5,000		0		0	0	0	0	0	0	0	-234	-8
2022	1,800		0		0	0	0	0	0	0	0	-234	-6
TOTAL	**7,800**	**469**	**6.01**	**0**	**0.00**	**-469**	**(6)**						

FortisBC Energy Inc.

ACCOUNT 437.00 - Manufacturing Plant - Measuring and Regulating Equipment

SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	27,548		0		0	0	0						0
2002			0		0	0	0						0
2003			0		0	0	0	0	0				0
2004			0		0	0	0	0	0				0
2005			0		0	0	0	0	0	0	0		0
2006			0		0	0	0	0	0	0	0		0
2007			0		0	0	0	0	0	0	0		0
2008			0		0	0	0	0	0	0	0		0
2009			0		0	0	0	0	0	0	0		0
2010		11,574	0		0	-11,574	0	-3,858	0	-2,315	0	-11,574	-42
2011		-11,476	0		0	11,476	0	-32	0	-19	0	-49	0
2012			0		0	0	0	-32	0	-19	0	-49	0
2013			0		0	0	0	3,825	0	-19	0	-49	0
2014	4,012	-4,903	-122		0	4,903	122	1,634	122	961	120	1,602	15
2015	15,000	18,109	121		0	-18,109	-121	-4,402	-69	-346	-9	-3,326	-29
2016			0		0	0	0	-4,402	-69	-2,641	-69	-3,326	-29
2017			0		0	0	0	-6,036	-121	-2,641	-69	-3,326	-29
2018			0		0	0	0	0	0	-2,641	-69	-3,326	-29
2019			0		0	0	0	0	0	-3,622	-121	-3,326	-29
2020		157	0		0	-157	0	-52	0	-31	0	-2,692	-29
2021	4,000		0		0	0	0	-52	-4	-31	-4	-2,692	-27
2022			0		0	0	0	-52	-4	-31	-4	-2,692	-27
TOTAL	**50,559**	**13,461**	**26.62**	**0**	**0.00**	**-13,461**	**(27)**						

FortisBC Energy Inc.
ACCOUNT 442.00 - LNG Plant - Structures and Improvements - Tilbury
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2006	1,959		0		0	0	0						0
2007	17,458		0		0	0	0						0
2008	6,000	2,000	33		0	-2,000	-33	-667	-8			-2,000	-8
2009			0		0	0	0	-667	-9			-2,000	-8
2010			0		0	0	0	-667	-33	-400	-8	-2,000	-8
2011			0		0	0	0	0	0	-400	-9	-2,000	-8
2012			0		0	0	0	0	0	-400	-33	-2,000	-8
2013			0		0	0	0	0	0	0	0	-2,000	-8
2014			0		0	0	0	0	0	0	0	-2,000	-8
2015			0		0	0	0	0	0	0	0	-2,000	-8
2016			0		0	0	0	0	0	0	0	-2,000	-8
2017			0		0	0	0	0	0	0	0	-2,000	-8
2018			0		0	0	0	0	0	0	0	-2,000	-8
2019			0		0	0	0	0	0	0	0	-2,000	-8
2020			0		0	0	0	0	0	0	0	-2,000	-8
2021			0		0	0	0	0	0	0	0	-2,000	-8
2022			0		0	0	0	0	0	0	0	-2,000	-8
TOTAL	**25,417**	**2,000**	**7.87**	**0**	**0.00**	**-2,000**	**(8)**						

FortisBC Energy Inc.
ACCOUNT 443.00 - LNG Plant - Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2002		3,000	0		0	-3,000	0					-3,000	0
2003	12,708		0		0	0	0					-3,000	-24
2004			0		0	0	0	-1,000	-24			-3,000	-24
2005			0		0	0	0	0	0			-3,000	-24
2006	44,685		0		0	0	0	0	0	-600	-5	-3,000	-5
2007	80,648		0		0	0	0	0	0	0	0	-3,000	-2
2008	1,734		0		0	0	0	0	0	0	0	-3,000	-2
2009			0		0	0	0	0	0	0	0	-3,000	-2
2010			0		0	0	0	0	0	0	0	-3,000	-2
2011			0		0	0	0	0	0	0	0	-3,000	-2
2012			0		0	0	0	0	0	0	0	-3,000	-2
2013			0		0	0	0	0	0	0	0	-3,000	-2
2014			0		0	0	0	0	0	0	0	-3,000	-2
2015			0		0	0	0	0	0	0	0	-3,000	-2
2016			0		0	0	0	0	0	0	0	-3,000	-2
2017			0		0	0	0	0	0	0	0	-3,000	-2
2018			0		0	0	0	0	0	0	0	-3,000	-2
2019			0		0	0	0	0	0	0	0	-3,000	-2
2020			0		0	0	0	0	0	0	0	-3,000	-2
2021			0		0	0	0	0	0	0	0	-3,000	-2
2022			0		0	0	0	0	0	0	0	-3,000	-2
TOTAL	**139,775**	**3,000**	**2.15**	**0**	**0.00**	**-3,000**	**(2)**						

FortisBC Energy Inc.
ACCOUNT 448.51 - LNG Plant - Sub-station and Electric (Tilbury)
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2018			0		0	0	0						0
2019			0		0	0	0						0
2020			0		0	0	0	0	0				0
2021			0		0	0	0	0	0				0
2022	25,000	74,662	299		0	-74,662	-299	-24,887	-299	-14,932	-299	-74,662	-299
TOTAL	**25,000**	**74,662**	**298.65**	**0**	**0.00**	**-74,662**	**(299)**						

FortisBC Energy Inc.
ACCOUNT 449.00 - LNG Plant - Other Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	30,000		0		0	0	0						0
2002			0		0	0	0						0
2003	96,616		0		0	0	0	0	0				0
2004			0		0	0	0	0	0				0
2005	214,983		0		0	0	0	0	0	0	0		0
2006	111,600		0		0	0	0	0	0	0	0		0
2007	196,414		0		0	0	0	0	0	0	0		0
2008	1,297,755	283,859	22	-79,166	-6	-204,693	-16	-68,231	-13	-40,939	-11	-204,693	-11
2009	82,431		0		0	0	0	-68,231	-13	-40,939	-12	-204,693	-10
2010		552	0		0	-552	0	-68,415	-15	-41,049	-12	-102,622	-10
2011		8,558	0		0	-8,558	0	-3,037	-11	-42,761	-14	-71,268	-11
2012			0		0	0	0	-3,037	0	-42,761	-15	-71,268	-11
2013		1,802	0		0	-1,802	0	-3,453	0	-2,182	-13	-53,901	-11
2014			0		0	0	0	-601	0	-2,182	0	-53,901	-11
2015	5,000		0		0	0	0	-601	-36	-2,072	-207	-53,901	-11
2016			0		0	0	0	0	0	-360	-36	-53,901	-11
2017			0		0	0	0	0	0	-360	-36	-53,901	-11
2018			0		0	0	0	0	0	0	0	-53,901	-11
2019			0		0	0	0	0	0	0	0	-53,901	-11
2020			0		0	0	0	0	0	0	0	-53,901	-11
2021	54,904		0		0	0	0	0	0	0	0	-53,901	-10
2022	759,890		0		0	0	0	0	0	0	0	-53,901	-8
TOTAL	**2,849,593**	**294,771**	**10.34**	**-79,166**	**(2.78)**	**-215,605**	**(8)**						

FortisBC Energy Inc.
ACCOUNT 462.00 - Transmission Plant - Compressor Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2008	13,400		0		0	0	0						0
2009	40,138		0		0	0	0						0
2010			0		0	0	0	0	0				0
2011		173	0		0	-173	0	-58	0			-173	0
2012	349,500	8,368	2		0	-8,368	-2	-2,847	-2	-1,708	-2	-4,270	-2
2013		1,391	0		0	-1,391	0	-3,311	-3	-1,986	-3	-3,311	-2
2014			0		0	0	0	-3,253	-3	-1,986	-3	-3,311	-2
2015			0		0	0	0	-464	0	-1,986	-3	-3,311	-2
2016			0		0	0	0	0	0	-1,952	-3	-3,311	-2
2017			0		0	0	0	0	0	-278	0	-3,311	-2
2018			0		0	0	0	0	0	0	0	-3,311	-2
2019			0		0	0	0	0	0	0	0	-3,311	-2
2020	10,000	1,244	12		0	-1,244	-12	-415	-12	-249	-12	-2,794	-3
2021	64,000		0		0	0	0	-415	-2	-249	-2	-2,794	-2
2022	180,770		0		0	0	0	-415	0	-249	0	-2,794	-2
TOTAL	**657,809**	**11,175**	**1.70**	**0**	**0.00**	**-11,175**	**(2)**						

FortisBC Energy Inc.
ACCOUNT 463.00 - Transmission Plant - Measuring and Regulating Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	26,672		0		0	0	0						0
2002			0		0	0	0						0
2003	75,177		0		0	0	0	0	0				0
2004	86,997	15,037	17		0	-15,037	-17	-5,012	-9			-15,037	-8
2005			0		0	0	0	-5,012	-9	-3,007	-8	-15,037	-8
2006	50,237		0		0	0	0	-5,012	-11	-3,007	-7	-15,037	-6
2007	40,820		0		0	0	0	0	0	-3,007	-6	-15,037	-5
2008			0		0	0	0	0	0	-3,007	-8	-15,037	-5
2009	4,405		0		0	0	0	0	0	0	0	-15,037	-5
2010	219,500	181,034	82		0	-181,034	-82	-60,345	-81	-36,207	-57	-98,035	-39
2011	10,000	-4,137	-41		0	4,137	41	-58,966	-76	-35,379	-64	-63,978	-37
2012	7,325	7,669	105		0	-7,669	-105	-61,522	-78	-36,913	-77	-49,901	-38
2013	4,641		0		0	0	0	-1,177	-16	-36,913	-75	-49,901	-38
2014			0		0	0	0	-2,556	-64	-36,913	-76	-49,901	-38
2015	32,532		0		0	0	0	0	0	-706	-6	-49,901	-36
2016			0		0	0	0	0	0	-1,534	-17	-49,901	-36
2017			0		0	0	0	0	0	0	0	-49,901	-36
2018	7,856		0		0	0	0	0	0	0	0	-49,901	-35
2019			0		0	0	0	0	0	0	0	-49,901	-35
2020	32,163		0		0	0	0	0	0	0	0	-49,901	-33
2021	259,759		0		0	0	0	0	0	0	0	-49,901	-23
2022			0		0	0	0	0	0	0	0	-49,901	-23
TOTAL	**858,084**	**199,602**	**23.26**	**0**	**0.00**	**-199,602**	**(23)**						

FortisBC Energy Inc.
ACCOUNT 464.00 - Transmission Plant - Other Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	70		0		0	0	0						0
2002			0		0	0	0						0
2003		15,490	0		0	-15,490	0	-5,163	-22,129			-15,490	-22,129
2004			0		0	0	0	-5,163	0			-15,490	-22,129
2005			0		0	0	0	-5,163	0	-3,098	-22,129	-15,490	-22,129
2006			0		0	0	0	0	0	-3,098	0	-15,490	-22,129
2007	6,746		0		0	0	0	0	0	-3,098	-230	-15,490	-227
2008			0		0	0	0	0	0	0	0	-15,490	-227
2009	11,730		0		0	0	0	0	0	0	0	-15,490	-84
2010			0		0	0	0	0	0	0	0	-15,490	-84
2011			0		0	0	0	0	0	0	0	-15,490	-84
2012			0		0	0	0	0	0	0	0	-15,490	-84
2013		14,534	0		0	-14,534	0	-4,845	0	-2,907	-124	-15,012	-162
2014	643		0		0	0	0	-4,845	-2,259	-2,907	-2,259	-15,012	-156
2015			0		0	0	0	-4,845	-2,259	-2,907	-2,259	-15,012	-156
2016			0		0	0	0	0	0	-2,907	-2,259	-15,012	-156
2017			0		0	0	0	0	0	-2,907	-2,259	-15,012	-156
2018			0		0	0	0	0	0	0	0	-15,012	-156
2019			0		0	0	0	0	0	0	0	-15,012	-156
2020	4,757		0		0	0	0	0	0	0	0	-15,012	-125
2021			0		0	0	0	0	0	0	0	-15,012	-125
2022			0		0	0	0	0	0	0	0	-15,012	-125
TOTAL	**23,947**	**30,025**	**125.38**	**0**	**0.00**	**-30,025**	**(125)**						

FortisBC Energy Inc.
ACCOUNT 465.00 - Transmission Plant -Transmission Pipeline
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	719		0		0	0	0						0
2001	1,219,906		0		0	0	0						0
2002	657,746	5,259	1		0	-5,259	-1	-1,753	0			-5,259	0
2003	1,850,075		0		0	0	0	-1,753	0			-5,259	0
2004	682,967	80,507	12		0	-80,507	-12	-28,589	-3	-17,153	-2	-42,883	-2
2005	749,466	36,935	5		0	-36,935	-5	-39,147	-4	-24,540	-2	-40,900	-2
2006	576,912	7,635	1		0	-7,635	-1	-41,692	-6	-26,067	-3	-32,584	-2
2007	134,227		0		0	0	0	-14,857	-3	-25,015	-3	-32,584	-2
2008	67,495	47,528	70		0	-47,528	-70	-18,388	-7	-34,521	-8	-35,573	-3
2009	693,373	752,187	108		0	-752,187	-108	-266,572	-89	-168,857	-38	-155,008	-14
2010	321,324	171,010	53		0	-171,010	-53	-323,575	-90	-195,672	-55	-157,294	-16
2011	861,075	845,270	98		0	-845,270	-98	-589,489	-94	-363,199	-87	-243,291	-25
2012	3,131,294	154,110	5		0	-154,110	-5	-390,130	-27	-394,021	-39	-233,382	-19
2013	488,034	129,806	27		0	-129,806	-27	-376,395	-25	-410,477	-37	-223,025	-20
2014	4,026,900	1,486,283	37		0	-1,486,283	-37	-590,066	-23	-557,296	-32	-337,866	-24
2015	329,683	388,897	118		0	-388,897	-118	-668,328	-41	-600,873	-34	-342,119	-26
2016	585,429	552,303	94		0	-552,303	-94	-809,161	-49	-542,279	-32	-358,287	-28
2017	659,382	103,473	16		0	-103,473	-16	-348,224	-66	-532,152	-44	-340,086	-28
2018	1,250,924	417,726	33		0	-417,726	-33	-357,834	-43	-589,736	-43	-345,262	-28
2019	242,072	343,425	142		0	-343,425	-142	-288,208	-40	-361,165	-59	-345,147	-30
2020	672,527	327,792	49		0	-327,792	-49	-362,981	-50	-348,944	-51	-344,126	-30
2021	3,021,290	365,385	12		0	-365,385	-12	-345,534	-26	-311,560	-27	-345,307	-28
2022	953,967	758,645	80		0	-758,645	-80	-483,941	-31	-442,595	-36	-367,062	-30
TOTAL	**23,176,789**	**6,974,175**	**30.09**	**0**	**0.00**	**-6,974,175**	**(30)**						

FortisBC Energy Inc.
ACCOUNT 466.00 - Transmission Plant -Compressor Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	10,826		0		0	0	0						0
2002			0		0	0	0						0
2003	57,131	12,923	23		0	-12,923	-23	-4,308	-19			-12,923	-19
2004		2,000	0		0	-2,000	0	-4,974	-26			-7,461	-22
2005	67,044		0		0	0	0	-4,974	-12	-2,985	-11	-7,461	-11
2006			0		0	0	0	-667	-3	-2,985	-12	-7,461	-11
2007			0		0	0	0	0	0	-2,985	-12	-7,461	-11
2008	62,641	3,523	6		0	-3,523	-6	-1,174	-6	-1,105	-4	-6,149	-9
2009		19,228	0		0	-19,228	0	-7,584	-36	-4,550	-18	-9,418	-19
2010	449,859	2,280	1		0	-2,280	-1	-8,344	-5	-5,006	-5	-7,991	-6
2011	714,672	19,452	3		0	-19,452	-3	-13,654	-4	-8,897	-4	-9,901	-4
2012	94,949	5,542	6		0	-5,542	-6	-9,091	-2	-10,005	-4	-9,278	-4
2013	1,329,229	1,566	0		0	-1,566	0	-8,853	-1	-9,614	-2	-8,314	-2
2014	160,000		0		0	0	0	-2,369	0	-5,768	-1	-8,314	-2
2015	200,000	30,786	15		0	-30,786	-15	-10,784	-2	-11,469	-2	-10,811	-3
2016	568,000	20,052	4		0	-20,052	-4	-16,946	-5	-11,589	-2	-11,735	-3
2017	500,000	20,662	4		0	-20,662	-4	-23,833	-6	-14,613	-3	-12,547	-3
2018	263,141		0		0	0	0	-13,571	-3	-14,300	-4	-12,547	-3
2019	234,817		0		0	0	0	-6,887	-2	-14,300	-4	-12,547	-3
2020	925,832	20,506	2		0	-20,506	-2	-6,835	-1	-12,244	-2	-13,210	-3
2021	55,000		0		0	0	0	-6,835	-2	-8,234	-2	-13,210	-3
2022	52,473		0		0	0	0	-6,835	-2	-4,101	-1	-13,210	-3
TOTAL	**5,745,614**	**158,521**	**2.76**	**0**	**0.00**	**-158,521**	**(3)**						

FortisBC Energy Inc.
ACCOUNT 467.10 - Transmission Plant -Measuring and Regulating Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	251,311		0		0	0	0						0
2002	178,402		0		0	0	0						0
2003	309,532		0		0	0	0	0	0				0
2004	1,928,908	77,340	4		0	-77,340	-4	-25,780	-3			-77,340	-3
2005	139,586	9,763	7		0	-9,763	-7	-29,034	-4	-17,421	-3	-43,551	-3
2006	206,490	47,392	23		0	-47,392	-23	-44,831	-6	-26,899	-5	-44,831	-4
2007	275,309		0		0	0	0	-19,052	-9	-26,899	-5	-44,831	-4
2008	26,600	6,720	25		0	-6,720	-25	-18,037	-11	-28,243	-5	-35,304	-4
2009	231,628	2,015	1		0	-2,015	-1	-2,912	-2	-13,178	-7	-28,646	-4
2010	737,851	4,685	1		0	-4,685	-1	-4,473	-1	-12,162	-4	-24,652	-3
2011	127,225	1,442	1		0	-1,442	-1	-2,714	-1	-2,972	-1	-21,337	-3
2012	283,137	32,994	12		0	-32,994	-12	-13,040	-3	-9,571	-3	-22,794	-4
2013	214,307	102,828	48		0	-102,828	-48	-45,755	-22	-28,793	-9	-31,687	-6
2014	75,754	43,173	57		0	-43,173	-57	-59,665	-31	-37,025	-13	-32,835	-7
2015	39,528	2,837	7		0	-2,837	-7	-49,613	-45	-36,655	-25	-30,108	-7
2016	281,090		0		0	0	0	-15,337	-12	-36,367	-20	-30,108	-6
2017	282,595		0		0	0	0	-946	0	-29,768	-17	-30,108	-6
2018	114,134	0	0	-600	-1	600	1	200	0	-9,082	-6	-27,549	-6
2019	93,225	0	0		0	0	0	200	0	-447	0	-27,549	-6
2020	344,397	0	0		0	0	0	200	0	120	0	-27,549	-5
2021	777,226	0	0		0	0	0	0	0	120	0	-27,549	-5
2022	184,276	7,673	4		0	-7,673	-4	-2,558	-1	-1,415	0	-26,020	-5
TOTAL	**7,102,514**	**338,863**	**4.77**	**-600**	**(0.01)**	**-338,263**	**(5)**						

FortisBC Energy Inc.
ACCOUNT 467.20 - Transmission Plant -Telemetry Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	121,625		0		0	0	0						0
2001	1,877,759		0		0	0	0						0
2002			0		0	0	0	0	0				0
2003	72,642		0		0	0	0	0	0				0
2004	47,359		0		0	0	0	0	0	0	0		0
2005	57,476		0		0	0	0	0	0	0	0		0
2006	1,337,511		0		0	0	0	0	0	0	0		0
2007	300		0		0	0	0	0	0	0	0		0
2008			0		0	0	0	0	0	0	0		0
2009	7,104		0		0	0	0	0	0	0	0		0
2010			0		0	0	0	0	0	0	0		0
2011	7,903	500	6		0	-500	-6	-167	-3	-100	-3	-500	0
2012	5,000		0		0	0	0	-167	-4	-100	-2	-500	0
2013	37,706		0		0	0	0	-167	-1	-100	-1	-500	0
2014			0		0	0	0	0	0	-100	-1	-500	0
2015	61,761	153	0		0	-153	0	-51	0	-131	-1	-326	0
2016	2,060	25,589	1,242		0	-25,589	-1,242	-8,580	-40	-5,148	-24	-8,747	-1
2017	92,022		0		0	0	0	-8,580	-17	-5,148	-13	-8,747	-1
2018	44,407		0		0	0	0	-8,530	-18	-5,148	-13	-8,747	-1
2019			0		0	0	0	0	0	-5,148	-13	-8,747	-1
2020	96,563	2,431	3		0	-2,431	-3	-810	-2	-5,604	-12	-7,168	-1
2021	117,226		0		0	0	0	-810	-1	-486	-1	-7,168	-1
2022	6,319,383	498	0		0	-498	0	-976	0	-586	0	-5,834	0
TOTAL	**10,305,808**	**29,170**	**0.28**	**0**	**0.00**	**-29,170**	**(0)**						

FortisBC Energy Inc.
ACCOUNT 468.00 - Transmission Plant -Communication Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	13,824		0	-9,443	-68	9,443	68					9,443	68
2002			0		0	0	0					9,443	68
2003	211,562		0		0	0	0	3,148	4			9,443	4
2004			0		0	0	0	0	0			9,443	4
2005			0		0	0	0	0	0	1,889	4	9,443	4
2006	8,844		0		0	0	0	0	0	0	0	9,443	4
2007			0		0	0	0	0	0	0	0	9,443	4
2008			0		0	0	0	0	0	0	0	9,443	4
2009			0		0	0	0	0	0	0	0	9,443	4
2010	33,038		0		0	0	0	0	0	0	0	9,443	4
2011	229,969	13,103	6		0	-13,103	-6	-4,368	-5	-2,621	-5	-1,830	-1
2012			0		0	0	0	-4,368	-5	-2,621	-5	-1,830	-1
2013	225,244		0		0	0	0	-4,368	-3	-2,621	-3	-1,830	-1
2014			0		0	0	0	0	0	-2,621	-3	-1,830	-1
2015			0		0	0	0	0	0	-2,621	-3	-1,830	-1
2016	191,721		0		0	0	0	0	0	0	0	-1,830	0
2017	287,887		0		0	0	0	0	0	0	0	-1,830	0
2018			0		0	0	0	0	0	0	0	-1,830	0
2019			0		0	0	0	0	0	0	0	-1,830	0
2020			0		0	0	0	0	0	0	0	-1,830	0
2021			0		0	0	0	0	0	0	0	-1,830	0
2022			0		0	0	0	0	0	0	0	-1,830	0
TOTAL	**1,202,089**	**13,103**	**1.09**	**-9,443**	**(0.79)**	**-3,660**	**(0)**						

FortisBC Energy Inc.
ACCOUNT 472.00 - Distribution Plant - Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	13,168		0		0	0	0						0
2001	104,190		0		0	0	0						0
2002	40,060		0		0	0	0	0	0				0
2003	78,668		0		0	0	0	0	0				0
2004	953		0		0	0	0	0	0	0	0		0
2005		3,678	0		0	-3,678	0	-1,226	-5	-736	-2	-3,678	-2
2006	50,994	4,276	8		0	-4,276	-8	-2,652	-15	-1,591	-5	-3,977	-3
2007	54,534		0		0	0	0	-2,652	-8	-1,591	-4	-3,977	-2
2008	80,293	26,516	33		0	-26,516	-33	-10,264	-17	-6,894	-18	-11,490	-8
2009	35,094	39,152	112		0	-39,152	-112	-21,889	-39	-14,725	-33	-18,406	-16
2010	3,308	243	7		0	-243	-7	-21,970	-56	-14,037	-31	-14,773	-16
2011	18,155	4,133	23		0	-4,133	-23	-14,509	-77	-14,009	-37	-13,000	-16
2012		187	0		0	-187	0	-1,521	-21	-14,046	-51	-11,169	-16
2013	92,192	2,400	3		0	-2,400	-3	-2,240	-6	-9,223	-31	-10,073	-14
2014	66,668		0		0	0	0	-862	-2	-1,392	-4	-10,073	-13
2015	24,177	7,356	30		0	-7,356	-30	-3,252	-5	-2,815	-7	-9,771	-13
2016	131,900	47,671	36		0	-47,671	-36	-18,342	-25	-11,523	-18	-13,561	-17
2017	79,665	4,368	5		0	-4,368	-5	-19,799	-25	-12,359	-16	-12,725	-16
2018	142,969	48,350	34		0	-48,350	-34	-33,463	-28	-21,549	-24	-15,694	-19
2019	124,658	240,083	193		0	-240,083	-193	-97,600	-84	-69,566	-69	-32,955	-38
2020	93,251	17	0		0	-17	0	-96,150	-80	-68,098	-59	-30,602	-35
2021	91,204	66,683	73		0	-66,683	-73	-102,261	-99	-71,900	-68	-33,007	-37
2022	63,630	25,036	39		0	-25,036	-39	-30,578	-37	-76,034	-74	-32,509	-37
TOTAL	**1,389,730**	**520,148**	**37.43**	**0**	**0.00**	**-520,148**	**(37)**						

FortisBC Energy Inc.
ACCOUNT 473.00 - Distribution Plant - Services
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	1,800,475		0		0	0	0						0
2001	1,098,971		0		0	0	0						0
2002	2,474,792	588,456	24		0	-588,456	-24	-196,152	-11			-588,456	-11
2003	343,211	211,987	62		0	-211,987	-62	-266,814	-20			-400,222	-14
2004	2,332,842	3,531,097	151		0	-3,531,097	-151	-1,443,847	-84	-866,308	-54	-1,443,847	-54
2005	2,485,696	3,551,042	143		0	-3,551,042	-143	-2,431,375	-141	-1,576,517	-90	-1,970,646	-75
2006	13,164,951	1,630,153	12		0	-1,630,153	-12	-2,904,098	-48	-1,902,547	-46	-1,902,547	-40
2007	9,140,075		0		0	0	0	-1,727,065	-21	-1,784,856	-32	-1,902,547	-29
2008	3,702,055	5,404,860	146		0	-5,404,860	-146	-2,345,004	-27	-2,823,431	-46	-2,486,266	-41
2009	4,319,221	5,440,566	126		0	-5,440,566	-126	-3,615,142	-63	-3,205,324	-49	-2,908,309	-50
2010	3,171,509	7,393,063	233		0	-7,393,063	-233	-6,079,496	-163	-3,973,729	-59	-3,468,903	-63
2011	4,414,701	12,179,045	276		0	-12,179,045	-276	-8,337,558	-210	-6,083,507	-123	-4,436,697	-82
2012	5,320,515	11,036,649	207		0	-11,036,649	-207	-10,202,919	-237	-8,290,837	-198	-5,096,692	-95
2013	5,105,091	10,120,174	198		0	-10,120,174	-198	-11,111,956	-225	-9,233,900	-207	-5,553,372	-104
2014	9,452,463	8,438,368	89		0	-8,438,368	-89	-9,865,064	-149	-9,833,460	-179	-5,793,788	-102
2015	4,068,251	8,758,515	215		0	-8,758,515	-215	-9,105,685	-147	-10,106,550	-178	-6,021,844	-108
2016	3,070,108	7,093,819	231		0	-7,093,819	-231	-8,096,900	-146	-9,089,505	-168	-6,098,414	-113
2017	4,282,805	9,156,900	214		0	-9,156,900	-214	-8,336,411	-219	-8,713,555	-168	-6,302,313	-119
2018	4,299,889	10,574,332	246		0	-10,574,332	-246	-8,941,684	-230	-8,804,387	-175	-6,569,314	-125
2019	3,461,687	9,920,485	287		0	-9,920,485	-287	-9,883,906	-246	-9,100,810	-237	-6,766,442	-131
2020	3,187,021	9,657,013	303		0	-9,657,013	-303	-10,050,610	-275	-9,280,510	-254	-6,927,029	-137
2021	4,245,588	13,119,854	309		0	-13,119,854	-309	-10,899,117	-300	-10,485,717	-269	-7,252,967	-145
2022	4,316,041	15,041,226	348		0	-15,041,226	-348	-12,606,031	-322	-11,662,582	-299	-7,642,380	-154
TOTAL	**99,257,959**	**152,847,604**	**153.99**	**0**	**0.00**	**-152,847,604**	**(154)**						

FortisBC Energy Inc.
ACCOUNT 474.00 - Distribution Plant - Meter and Regulator
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	95,683		0		0	0	0						0
2001	2,428,481		0		0	0	0						0
2002	6,270,257	53,023	1		0	-53,023	-1	-17,674	-1			-53,023	-1
2003	3,267,469	14,989	0		0	-14,989	0	-22,671	-1			-34,006	-1
2004	4,930,968	247,468	5		0	-247,468	-5	-105,160	-2	-63,096	-2	-105,160	-2
2005	6,813,560	217,139	3		0	-217,139	-3	-159,865	-3	-106,524	-2	-133,155	-2
2006	8,240,670	211,256	3		0	-211,256	-3	-225,288	-3	-148,775	-3	-148,775	-2
2007	5,860,519		0		0	0	0	-142,798	-2	-138,170	-2	-148,775	-2
2008	7,010,448	900,663	13		0	-900,663	-13	-370,639	-5	-315,305	-5	-274,090	-4
2009	7,349,546	1,320,731	18	-12,236	0	-1,308,495	-18	-736,386	-11	-527,510	-7	-421,862	-6
2010	17,660,406	2,490,045	14		0	-2,490,045	-14	-1,566,401	-15	-982,092	-11	-680,385	-8
2011	68,245	2,717,111	3,981		0	-2,717,111	-3,981	-2,171,884	-26	-1,483,263	-20	-906,688	-12
2012	1,078,773	2,994,079	278		0	-2,994,079	-278	-2,733,745	-44	-2,082,078	-31	-1,115,427	-16
2013	851,997	3,478,502	408		0	-3,478,502	-408	-3,063,231	-460	-2,597,646	-48	-1,330,252	-20
2014	899,228	3,679,458	409		0	-3,679,458	-409	-3,384,013	-359	-3,071,839	-75	-1,526,019	-25
2015	1,666,771	4,528,155	272		0	-4,528,155	-272	-3,895,372	-342	-3,479,461	-381	-1,756,952	-31
2016	85,085	5,146,762	6,049		0	-5,146,762	-6,049	-4,451,458	-504	-3,965,391	-433	-1,999,082	-38
2017	9,228,784	4,244,562	46		0	-4,244,562	-46	-4,639,826	-127	-4,215,488	-166	-2,148,780	-38
2018	7,138,914	3,501,854	49		0	-3,501,854	-49	-4,297,726	-78	-4,220,158	-111	-2,233,348	-39
2019	4,054,715	3,441,172	85		0	-3,441,172	-85	-3,729,196	-55	-4,172,501	-94	-2,304,396	-41
2020	4,317,204	2,769,876	64		0	-2,769,876	-64	-3,237,634	-63	-3,820,845	-77	-2,330,256	-42
2021	5,415,390	4,588,766	85		0	-4,588,766	-85	-3,599,938	-78	-3,709,246	-62	-2,449,125	-44
2022	2,286,123	2,930,929	128		0	-2,930,929	-128	-3,429,857	-86	-3,446,520	-74	-2,473,215	-46
TOTAL	**107,019,236**	**49,476,540**	**46.23**	**-12,236**	**(0.01)**	**-49,464,303**	**(46)**						

FortisBC Energy Inc.
ACCOUNT 475.00 - Distribution Plant - Mains
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	4,430,340		0		0	0	0						0
2001	485,250		0		0	0	0						0
2002	1,000,236	63,210	6		0	-63,210	-6	-21,070	-1			-63,210	-1
2003	96,226	23,024	24		0	-23,024	-24	-28,745	-5			-43,117	-1
2004	424,865	364,611	86		0	-364,611	-86	-150,282	-30	-90,169	-7	-150,282	-7
2005	816,133	532,849	65		0	-532,849	-65	-306,828	-69	-196,739	-35	-245,923	-14
2006	2,701,842	139,634	5		0	-139,634	-5	-345,698	-26	-224,666	-22	-224,666	-11
2007	2,163,435		0		0	0	0	-224,161	-12	-212,023	-17	-224,666	-9
2008	2,444,452	474,834	19		0	-474,834	-19	-204,823	-8	-302,386	-18	-266,360	-11
2009	3,350,956	592,027	18		0	-592,027	-18	-355,620	-13	-347,869	-15	-312,884	-12
2010	1,212,065	531,511	44		0	-531,511	-44	-532,791	-23	-347,601	-15	-340,212	-14
2011	1,414,525	766,407	54		0	-766,407	-54	-629,981	-32	-472,956	-22	-387,567	-17
2012	1,563,776	1,311,699	84		0	-1,311,699	-84	-869,872	-62	-735,295	-37	-479,980	-22
2013	1,683,240	620,950	37		0	-620,950	-37	-899,685	-58	-764,519	-41	-492,796	-23
2014	4,103,990	1,357,998	33		0	-1,357,998	-33	-1,096,882	-45	-917,713	-46	-564,896	-24
2015	1,378,697	985,915	72		0	-985,915	-72	-988,288	-41	-1,008,594	-50	-597,282	-27
2016	632,513	915,916	145		0	-915,916	-145	-1,086,610	-53	-1,038,496	-55	-620,042	-29
2017	2,116,939	852,928	40		0	-852,928	-40	-918,253	-67	-946,742	-48	-635,568	-30
2018	1,845,199	1,165,773	63		0	-1,165,773	-63	-978,206	-64	-1,055,706	-52	-668,705	-32
2019	1,593,284	1,516,563	95		0	-1,516,563	-95	-1,178,422	-64	-1,087,419	-72	-718,579	-34
2020	1,234,160	1,058,016	86		0	-1,058,016	-86	-1,246,784	-80	-1,101,840	-74	-737,437	-36
2021	4,780,318	2,024,435	42		0	-2,024,435	-42	-1,533,005	-60	-1,323,543	-57	-805,174	-37
2022	2,414,196	1,812,740	75		0	-1,812,740	-75	-1,631,730	-58	-1,515,506	-64	-855,552	-39
TOTAL	**43,886,635**	**17,111,041**	**38.99**	**0**	**0.00**	**-17,111,041**	**(39)**						

FortisBC Energy Inc.
ACCOUNT 476.00 - Distribution Plant - NGV Fuel Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	7,475,766		0		0	0	0						0
2001	91		0		0	0	0						0
2002			0		0	0	0	0	0				0
2003			0		0	0	0	0	0				0
2004			0		0	0	0	0	0	0	0		0
2005			0		0	0	0	0	0	0	0		0
2006			0		0	0	0	0	0	0	0		0
2007			0		0	0	0	0	0	0	0		0
2008			0		0	0	0	0	0	0	0		0
2009			0		0	0	0	0	0	0	0		0
2010			0		0	0	0	0	0	0	0		0
2011			0		0	0	0	0	0	0	0		0
2012			0		0	0	0	0	0	0	0		0
2013			0		0	0	0	0	0	0	0		0
2014			0		0	0	0	0	0	0	0		0
2015			0		0	0	0	0	0	0	0		0
2016	771,459	5,250	1		0	-5,250	-1	-1,750	-1	-1,050	-1	-5,250	0
2017			0		0	0	0	-1,750	-1	-1,050	-1	-5,250	0
2018			0		0	0	0	-1,750	-1	-1,050	-1	-5,250	0
2019			0		0	0	0	0	0	-1,050	-1	-5,250	0
2020			0		0	0	0	0	0	-1,050	-1	-5,250	0
2021			0		0	0	0	0	0	0	0	-5,250	0
2022			0		0	0	0	0	0	0	0	-5,250	0
TOTAL	**8,247,316**	**5,250**	**0.06**	**0**	**0.00**	**-5,250**	**(0)**						

FortisBC Energy Inc.
ACCOUNT 476.10 - NG For Transportation - CNG Disp Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2014		1,447	0		0	-1,447	0					-1,447	0
2015			0		0	0	0					-1,447	0
2016			0		0	0	0	-482	0			-1,447	0
2017			0		0	0	0	0	0			-1,447	0
2018			0		0	0	0	0	0	-289	0	-1,447	0
2019			0		0	0	0	0	0	0	0	-1,447	0
2020	272,364		0		0	0	0	0	0	0	0	-1,447	-1
2021			0		0	0	0	0	0	0	0	-1,447	-1
2022	887,578		0		0	0	0	0	0	0	0	-1,447	0
TOTAL	**1,159,942**	**1,447**	**0.12**	**0**	**0.00**	**-1,447**	**(0)**						

FortisBC Energy Inc.
ACCOUNT 476.20 - NG For Transportation - LNG Disp Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2021	352,027	4,453	1	-15,672	-4	11,220	3					11,220	3
2022	0	1,572	0		0	-1,572	0					4,824	3
TOTAL	**352,027**	**6,025**	**1.71**	**-15,672**	**(4.45)**	**9,647**	**3**						

FortisBC Energy Inc.
ACCOUNT 476.40 - NG For Transportation - LNG Foundation
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2021	327,053	4,137	1	-14,544	-4	10,406	3					10,406	3
2022	0	1,461	0		0	-1,461	0					4,473	3
TOTAL	**327,053**	**5,598**	**1.71**	**-14,544**	**(4.45)**	**8,946**	**3**						

FortisBC Energy Inc.
ACCOUNT 476.50 - NG For Transportation - LNG Pumps
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2021	1,417,230	17,931	1	-40,650	-3	22,719	2					22,719	2
2022	0	6,330	0		0	-6,330	0					8,194	1
TOTAL	**1,417,230**	**24,261**	**1.71**	**-40,650**	**(2.87)**	**16,389**	**1**						

FortisBC Energy Inc.
ACCOUNT 477.10 - Distribution Plant - Measuring and Regulating
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	346,633		0		0	0	0						0
2001	2,262,537		0		0	0	0						0
2002	799,436	43,803	5		0	-43,803	-5	-14,601	-1			-43,803	-1
2003	1,025,334	45,686	4		0	-45,686	-4	-29,830	-2			-44,745	-2
2004	63,872	158,470	248		0	-158,470	-248	-82,653	-13	-49,592	-6	-82,653	-6
2005	527,761	40,275	8		0	-40,275	-8	-81,477	-15	-57,647	-6	-72,059	-6
2006	1,045,949	34,302	3		0	-34,302	-3	-77,682	-14	-64,507	-9	-64,507	-5
2007	563,389		0		0	0	0	-24,859	-3	-55,747	-9	-64,507	-5
2008	901,908	356,214	39		0	-356,214	-39	-130,172	-16	-117,852	-19	-113,125	-9
2009	521,037	104,228	20		0	-104,228	-20	-153,480	-23	-107,004	-15	-111,854	-10
2010	277,280	23,126	8		0	-23,126	-8	-161,189	-28	-103,574	-16	-100,763	-10
2011	392,040	42,042	11		0	-42,042	-11	-56,465	-14	-105,122	-20	-94,238	-10
2012	1,101,785	59,878	5		0	-59,878	-5	-41,682	-7	-117,098	-18	-90,802	-9
2013	422,122	50,946	12		0	-50,946	-12	-50,955	-8	-56,044	-10	-87,179	-9
2014	483,083	21,385	4		0	-21,385	-4	-44,070	-7	-39,475	-7	-81,696	-9
2015	517,505	73,153	14		0	-73,153	-14	-48,495	-10	-49,481	-8	-81,039	-9
2016	662,008	208,155	31		0	-208,155	-31	-100,898	-18	-82,703	-13	-90,119	-11
2017	812,103	276,306	34		0	-276,306	-34	-185,871	-28	-125,989	-22	-102,531	-12
2018	1,318,622	504,654	38		0	-504,654	-38	-329,705	-35	-216,730	-29	-127,664	-15
2019	872,273	408,317	47		0	-408,317	-47	-396,425	-40	-294,117	-35	-144,173	-16
2020	945,037	96,913	10		0	-96,913	-10	-336,628	-32	-298,869	-32	-141,547	-16
2021	2,401,089	165,802	7		0	-165,802	-7	-223,677	-16	-290,398	-23	-142,824	-15
2022	1,258,667	55,467	4		0	-55,467	-4	-106,060	-7	-246,230	-18	-138,456	-14
TOTAL	**19,521,471**	**2,769,121**	**14.19**	**0**	**0.00**	**-2,769,121**	**(14)**						

FortisBC Energy Inc.
ACCOUNT 477.20 - Distribution Plant -Telemetry
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	17,499		0		0	0	0						0
2001	80,431		0		0	0	0						0
2002	251,623		0		0	0	0	0	0				0
2003	68,932		0		0	0	0	0	0				0
2004		227	0		0	-227	0	-76	0	-45	0	-227	0
2005			0		0	0	0	-76	0	-45	0	-227	0
2006	1,008	2,382	236		0	-2,382	-236	-870	-259	-522	-1	-1,305	-1
2007	32,413		0		0	0	0	-794	-7	-522	-3	-1,305	-1
2008	5,000		0		0	0	0	-794	-6	-522	-7	-1,305	-1
2009	54,840		0		0	0	0	0	0	-476	-3	-1,305	-1
2010	3,222		0		0	0	0	0	0	-476	-2	-1,305	-1
2011	149,241	831	1		0	-831	-1	-277	0	-166	0	-1,147	-1
2012	85,025	15	0		0	-15	0	-282	0	-169	0	-864	0
2013	9,941	11,533	116		0	-11,533	-116	-4,126	-5	-2,476	-4	-2,997	-2
2014	108,594		0		0	0	0	-3,849	-6	-2,476	-3	-2,997	-2
2015	98,393	9,533	10		0	-9,533	-10	-7,022	-10	-4,382	-5	-4,087	-3
2016	147,084	8,947	6		0	-8,947	-6	-6,160	-5	-6,006	-7	-4,781	-3
2017	49,210		0		0	0	0	-6,160	-6	-6,003	-7	-4,781	-3
2018	422,986	0	0		0	0	0	-2,982	-1	-3,696	-2	-4,781	-2
2019	312,586	120,285	38		0	-120,285	-38	-40,095	-15	-27,753	-13	-19,219	-8
2020	208,294	5,274	3		0	-5,274	-3	-41,853	-13	-26,901	-12	-17,670	-8
2021	271,405	792	0		0	-792	0	-42,117	-16	-25,270	-10	-15,982	-7
2022	91,108	0	0		0	0	0	-2,022	-1	-25,270	-10	-15,982	-6
TOTAL	**2,468,837**	**159,818**	**6.47**	**0**	**0.00**	**-159,818**	**(6)**						

FortisBC Energy Inc.
ACCOUNT 478.10 - Distribution Plant -Meters
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	679,275		0		0	0	0						0
2001	2,117,588		0		0	0	0						0
2002	3,437,049		0		0	0	0	0	0				0
2003	2,018,918		0		0	0	0	0	0				0
2004	2,729,515	0	0	-78,811	-3	78,811	3	26,270	1	15,762	1	78,811	1
2005	4,879,690		0		0	0	0	26,270	1	15,762	1	78,811	0
2006	3,821,305		0		0	0	0	26,270	1	15,762	0	78,811	0
2007	3,118,099		0		0	0	0	0	0	15,762	0	78,811	0
2008	4,782,171	-69,432	-1	-284,774	-6	354,206	7	118,069	3	86,603	2	216,508	2
2009	4,143,930	71,292	2	-66,136	-2	-5,156	0	116,350	3	69,810	2	142,620	1
2010	6,433,600	147,607	2	-136,306	-2	-11,301	0	112,583	2	67,550	2	104,140	1
2011	4,759,675	135,914	3	-241,924	-5	106,011	2	29,851	1	88,752	2	104,514	1
2012	8,509,300	117,023	1	-172,166	-2	55,143	1	49,951	1	99,781	2	96,286	1
2013	8,250,035	211,511	3	-360,326	-4	148,815	2	103,323	1	58,702	1	103,790	1
2014	6,633,512	153,078	2	-329,250	-5	176,172	3	126,710	2	94,968	1	112,838	1
2015	6,571,396	33,108	1		0	-33,108	-1	97,293	1	90,607	1	96,621	1
2016	6,771,458	90,997	1		0	-90,997	-1	17,356	0	51,205	1	77,860	1
2017	6,005,393	91,232	2		0	-91,232	-2	-71,779	-1	21,930	0	62,488	1
2018	7,553,177	162,460	2	-236,495	-3	74,035	1	-36,065	-1	6,974	0	63,450	1
2019	4,239,686	121,390	3	-78,486	-2	-42,904	-1	-20,034	0	-36,841	-1	55,269	1
2020	4,796,752	98,958	2	-43,372	-1	-55,586	-1	-8,152	0	-41,337	-1	47,351	1
2021	6,476,582	56,493	1	-27,143	0	-29,350	0	-42,613	-1	-29,008	0	42,237	1
2022	2,999,046	84,317	3	-45,569	-2	-38,748	-1	-41,228	-1	-18,511	0	37,176	1
TOTAL	**111,727,151**	**1,505,949**	**1.35**	**-2,100,759**	**(1.88)**	**594,810**	**1**						

FortisBC Energy Inc.
ACCOUNT 482.10 - General Plant - Structures (Frame)
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	1,255,720		0		0	0	0						0
2001	5,565,513		0		0	0	0						0
2002	40,469	613	2		0	-613	-2	-204	0			-613	0
2003	87,243		0		0	0	0	-204	0			-613	0
2004			0	-800	0	800	0	62	0	37	0	93	0
2005	1,200		0		0	0	0	267	1	37	0	93	0
2006	28,003		0		0	0	0	267	3	37	0	93	0
2007	6,655		0		0	0	0	0	0	160	1	93	0
2008	258,882	11,410	4		0	-11,410	-4	-3,803	-4	-2,122	-4	-3,741	0
2009	1,909	450	24		0	-450	-24	-3,953	-4	-2,372	-4	-2,918	0
2010	4,888		0		0	0	0	-3,953	-4	-2,372	-4	-2,918	0
2011	154,534		0		0	0	0	-150	0	-2,372	-3	-2,918	0
2012			0		0	0	0	0	0	-2,372	-3	-2,918	0
2013			0		0	0	0	0	0	-90	0	-2,918	0
2014			0		0	0	0	0	0	0	0	-2,918	0
2015		128,381	0		0	-128,381	0	-42,794	0	-25,676	-83	-28,011	-2
2016	113,059	149,152	132		0	-149,152	-132	-92,511	-245	-55,507	-245	-48,201	-4
2017	165,136	6,163	4		0	-6,163	-4	-94,565	-102	-56,739	-102	-42,196	-4
2018	12,324		0		0	0	0	-51,772	-53	-56,739	-98	-42,196	-4
2019	15,715	3,702	24		0	-3,702	-24	-3,288	-5	-57,480	-94	-37,384	-4
2020	407,165	13,009	3		0	-13,009	-3	-5,571	-4	-34,405	-24	-34,676	-4
2021	7,070		0		0	0	0	-5,571	-4	-4,575	-4	-34,676	-4
2022	39,668	31,069	78		0	-31,069	-78	-14,693	-10	-9,556	-10	-34,315	-4
TOTAL	**8,165,153**	**343,950**	**4.21**	**-800**	**(0.01)**	**-343,150**	**(4)**						

FortisBC Energy Inc.
ACCOUNT 482.20 - General Plant - Structures (Masonry)
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	876,365		0		0	0	0						0
2001	213,291		0		0	0	0						0
2002	5,545		0		0	0	0	0	0				0
2003	60,624		0		0	0	0	0	0				0
2004			0		0	0	0	0	0	0	0		0
2005			0		0	0	0	0	0	0	0		0
2006	106,637		0		0	0	0	0	0	0	0		0
2007	26,805		0		0	0	0	0	0	0	0		0
2008	511,877	134,252	26		0	-134,252	-26	-44,751	-21	-26,850	-21	-134,252	-7
2009	40,000	100,978	252		0	-100,978	-252	-78,410	-41	-47,046	-34	-117,615	-13
2010			0		0	0	0	-78,410	-43	-47,046	-34	-117,615	-13
2011			0		0	0	0	-33,659	-252	-47,046	-41	-117,615	-13
2012		-45	0		0	45	0	15	0	-47,037	-43	-78,395	-13
2013		547	0		0	-547	0	-167	0	-20,296	-254	-58,933	-13
2014			0		0	0	0	-167	0	-100	0	-58,933	-13
2015		53,733	0		0	-53,733	0	-18,093	0	-10,847	0	-57,893	-16
2016	339,032		0		0	0	0	-17,911	-16	-10,847	-16	-57,893	-13
2017	377,325		0		0	0	0	-17,911	-8	-10,856	-8	-57,893	-11
2018	33,755	11,471	34		0	-11,471	-34	-3,824	-2	-13,041	-9	-50,156	-12
2019	256,636	6,882	3		0	-6,882	-3	-6,118	-3	-14,417	-7	-43,974	-11
2020		15,490	0		0	-15,490	0	-11,281	-12	-6,769	-3	-40,413	-11
2021			0		0	0	0	-7,457	-9	-6,769	-5	-40,413	-11
2022	5,271	167,374	3,175		0	-167,374	-3,175	-60,955	-3,469	-40,243	-68	-54,520	-17
TOTAL	**2,853,163**	**490,682**	**17.20**	**0**	**0.00**	**-490,682**	**(17)**						

FortisBC Energy Inc.
ACCOUNT 484.00 - General Plant - Vehicles
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	1,582,820		0		0	0	0						0
2001	34,001		0		0	0	0						0
2002	239,632		0		0	0	0	0	0				0
2003	30,578		0		0	0	0	0	0				0
2004	260,925		0		0	0	0	0	0	0	0		0
2005	14,890		0		0	0	0	0	0	0	0		0
2006	7,381		0		0	0	0	0	0	0	0		0
2007	93,297		0		0	0	0	0	0	0	0		0
2008	40,268	-7,617	-19	-4,000	-10	11,617	29	3,872	8	2,323	3	11,617	1
2009	32,635	1,081	3	-13,825	-42	12,744	39	8,120	15	4,872	13	12,180	1
2010	169,164	0	0	-29,791	-18	29,791	18	18,050	22	10,830	16	18,050	2
2011	872,023		0		0	0	0	14,178	4	10,830	4	18,050	2
2012	580,467		0		0	0	0	9,930	2	10,830	3	18,050	1
2013	300,515		0		0	0	0	0	0	8,507	2	18,050	1
2014	376,446	0	0	-145,085	-39	145,085	39	48,362	12	34,975	8	49,809	4
2015	681,831	-184,494	-27		0	184,494	27	109,860	24	65,916	12	76,746	7
2016	429,629	-132,603	-31		0	132,603	31	154,061	31	92,436	20	86,056	9
2017	166,615	-254,696	-153		0	254,696	153	190,597	45	143,376	37	110,147	13
2018	166,303	0	0	-231,749	-139	231,749	139	206,349	81	189,725	52	125,347	16
2019	675,883	0	0	-628,658	-93	628,658	93	371,701	111	286,440	68	181,271	24
2020	90,414	0	0	-257,153	-284	257,153	284	372,520	120	300,972	98	188,859	28
2021	620,344	0	0	-874,877	-141	874,877	141	586,896	127	449,427	131	251,224	37
2022	1,240,238	741	0	-861,467	-69	860,725	69	664,252	102	570,632	102	302,016	42
TOTAL	**8,706,301**	**(577,587)**	**(6.63)**	**-3,046,605**	**(34.99)**	**3,624,191**	**42**						

FortisBC Energy Inc.
ACCOUNT 485.10 - General Plant - Heavy Work Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	13,523		0		0	0	0						0
2001			0		0	0	0						0
2002	6,318		0		0	0	0	0	0				0
2003			0		0	0	0	0	0				0
2004			0		0	0	0	0	0	0	0		0
2005			0		0	0	0	0	0	0	0		0
2006	26,600		0		0	0	0	0	0	0	0		0
2007			0		0	0	0	0	0	0	0		0
2008			0		0	0	0	0	0	0	0		0
2009			0		0	0	0	0	0	0	0		0
2010	12,429		0		0	0	0	0	0	0	0		0
2011	45,146		0		0	0	0	0	0	0	0		0
2012	46,290		0		0	0	0	0	0	0	0		0
2013	66,483		0		0	0	0	0	0	0	0		0
2014	24,491		0		0	0	0	0	0	0	0		0
2015			0		0	0	0	0	0	0	0		0
2016	63,971	-6,997	-11		0	6,997	11	2,332	8	1,399	3	6,997	2
2017			0		0	0	0	2,332	11	1,399	5	6,997	2
2018			0		0	0	0	2,332	11	1,399	8	6,997	2
2019	114,876		0		0	0	0	0	0	1,399	4	6,997	2
2020	21,307		0		0	0	0	0	0	1,399	3	6,997	2
2021	7,439		0		0	0	0	0	0	0	0	6,997	2
2022	1,819		0		0	0	0	0	0	0	0	6,997	2
TOTAL	**450,693**	**(6,997)**	**(1.55)**	**0**	**0.00**	**6,997**	**2**						

FortisBC Energy Inc.
ACCOUNT 485.20 - General Plant - Heavy Mobile Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000			0		0	0	0						0
2001			0		0	0	0						0
2002			0		0	0	0	0	0				0
2003			0		0	0	0	0	0				0
2004			0		0	0	0	0	0	0	0		0
2005	4,280		0		0	0	0	0	0	0	0		0
2006	35,407		0		0	0	0	0	0	0	0		0
2007	1		0		0	0	0	0	0	0	0		0
2008			0		0	0	0	0	0	0	0		0
2009			0		0	0	0	0	0	0	0		0
2010			0		0	0	0	0	0	0	0		0
2011	5,699		0		0	0	0	0	0	0	0		0
2012	19,035		0		0	0	0	0	0	0	0		0
2013	79,630		0		0	0	0	0	0	0	0		0
2014			0		0	0	0	0	0	0	0		0
2015			0		0	0	0	0	0	0	0		0
2016			0		0	0	0	0	0	0	0		0
2017	1,758		0		0	0	0	0	0	0	0		0
2018			0		0	0	0	0	0	0	0		0
2019	216,762		0		0	0	0	0	0	0	0		0
2020	164,250		0		0	0	0	0	0	0	0		0
2021	5,826		0		0	0	0	0	0	0	0		0
2022	487,380		0		0	0	0	0	0	0	0		0
TOTAL	**1,020,028**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATION

FortisBC

Account #: 401.01 - Franchises and Consents

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1987	8,238.78	7,209	6,571	0.7976	1,668	5.00	334	35.0
1991	186,139.77	144,258	131,495	0.7064	54,644	9.00	6,072	31.0
1992	2,554.74	1,916	1,747	0.6836	808	10.00	81	30.0
TOTAL	196,933.29	153,383	139,813		57,120		6,487	

COMPOSITE ANNUAL ACCRUAL RATE	3.29%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.71
COMPOSITE AVERAGE AGE (YEARS)	31.15
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	8.85

FortisBC

Account #: 402.01 - Computer Software Application - 8 Years

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 8
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2015	5,983,783.40	5,235,810	5,235,811	0.8750	747,973	1.00	747,973	7.0
2016	7,330,845.15	5,498,134	5,498,134	0.7500	1,832,711	2.00	916,356	6.0
2017	9,629,842.10	6,018,651	6,018,651	0.6250	3,611,191	3.00	1,203,730	5.0
2018	7,338,086.79	3,669,043	3,669,043	0.5000	3,669,043	4.00	917,261	4.0
2019	7,059,752.74	2,647,407	2,647,407	0.3750	4,412,345	5.00	882,469	3.0
2020	14,822,720.09	3,705,680	3,705,680	0.2500	11,117,040	6.00	1,852,840	2.0
2021	4,432,882.56	554,110	554,110	0.1250	3,878,772	7.00	554,110	1.0
2022	21,368,317.44	0	0	0.0000	21,368,317	8.00	2,671,040	0.0
TOTAL	77,966,230.27	27,328,837	27,328,837		50,637,393		9,745,779	

COMPOSITE ANNUAL ACCRUAL RATE	12.50%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	2.80
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.20

FortisBC

Account #: 402.02 - Computer Software Application - 5 Years

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 5
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	4,136,749.88	3,309,400	3,309,400	0.8000	827,350	1.00	827,350	4.0
2019	4,456,242.30	2,673,745	2,673,745	0.6000	1,782,497	2.00	891,248	3.0
2020	5,220,627.65	2,088,251	2,088,251	0.4000	3,132,377	3.00	1,044,126	2.0
2021	5,873,271.60	1,174,654	1,174,654	0.2000	4,698,617	4.00	1,174,654	1.0
2022	6,250,312.37	0	0	0.0000	6,250,312	5.00	1,250,062	0.0
TOTAL	25,937,203.80	9,246,051	9,246,051		16,691,153		5,187,440	

COMPOSITE ANNUAL ACCRUAL RATE 20.00%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.36

COMPOSITE AVERAGE AGE (YEARS) 1.78

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 3.22

FortisBC

Account #: 402.03 - Intangible Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1991	694,036.53	537,878	607,880	0.8759	86,157	9.00	9,573	31.0
2001	687,554.78	360,966	407,943	0.5933	279,611	19.00	14,716	21.0
2003	500,000.00	237,500	268,409	0.5368	231,591	21.00	11,028	19.0
2009	25,000.00	8,125	9,182	0.3673	15,818	27.00	586	13.0
TOTAL	1,906,591.31	1,144,470	1,293,414		613,177		35,903	

COMPOSITE ANNUAL ACCRUAL RATE	1.88%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.68
COMPOSITE AVERAGE AGE (YEARS)	24.01
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	15.99

FortisBC

Account #: 418.10 - Purification Overhauls - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life

Survivor Curve: SQ

ASL: 20

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	20,423.22	8,169	8,841	0.4329	11,582	12.00	965	8.0
TOTAL	20,423.22	8,169	8,841		11,582		965	

COMPOSITE ANNUAL ACCRUAL RATE	4.73%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.43
COMPOSITE AVERAGE AGE (YEARS)	8.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.00

FortisBC

Account #: 418.20 - Purification Upgrader - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	2,444,884.49	1,155,208	1,162,255	0.4527	1,404,874	11.00	127,716	9.0
2014	4,572,331.59	1,920,379	1,932,094	0.4024	2,868,854	12.00	239,071	8.0
2015	1,058,217.27	388,895	391,267	0.3521	719,861	13.00	55,374	7.0
2016	268,063.29	84,440	84,955	0.3018	196,511	14.00	14,037	6.0
2017	1,451,373.70	380,986	383,310	0.2515	1,140,633	15.00	76,042	5.0
2019	256,868.25	40,457	40,704	0.1509	229,008	17.00	13,471	3.0
2020	228.76	24	24	0.1006	216	18.00	12	2.0
TOTAL	10,051,967.35	3,970,388	3,994,609		6,559,957		525,723	

COMPOSITE ANNUAL ACCRUAL RATE	5.23%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.40
COMPOSITE AVERAGE AGE (YEARS)	7.52
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.48

FortisBC

Account #: 432.00 - Structures - Manufacturing Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1990	358,775.13	287,020	269,574	0.7514	89,201	8.00	11,150	32.0
1992	1,967.78	1,476	1,386	0.7044	582	10.00	58	30.0
1996	899.39	585	549	0.6105	350	14.00	25	26.0
1997	797.53	498	468	0.5870	329	15.00	22	25.0
1998	2,668.96	1,601	1,504	0.5635	1,165	16.00	73	24.0
1999	6,436.48	3,701	3,476	0.5400	2,960	17.00	174	23.0
2000	13,624.40	7,493	7,038	0.5166	6,586	18.00	366	22.0
2001	1,019.52	535	503	0.4931	517	19.00	27	21.0
2002	44,609.77	22,305	20,949	0.4696	23,661	20.00	1,183	20.0
2004	437.00	197	185	0.4227	252	22.00	11	18.0
2005	11,641.25	4,948	4,647	0.3992	6,994	23.00	304	17.0
2006	1,293.03	517	486	0.3757	807	24.00	34	16.0
2007	666.81	250	235	0.3522	432	25.00	17	15.0
2008	12,597.36	4,409	4,141	0.3287	8,456	26.00	325	14.0
2009	0.95	0	0	0.3053	1	27.00	0	13.0
2010	763.11	229	215	0.2818	548	28.00	20	12.0
2011	20,591.32	5,663	5,318	0.2583	15,273	29.00	527	11.0
2012	488,711.14	122,178	114,752	0.2348	373,960	30.00	12,465	10.0
2013	24,703.50	5,558	5,220	0.2113	19,483	31.00	628	9.0
2014	189.09	38	36	0.1878	154	32.00	5	8.0
2019	206,434.13	15,483	14,541	0.0704	191,893	37.00	5,186	3.0
2020	19,309.86	965	907	0.0470	18,403	38.00	484	2.0
2021	80,355.99	2,009	1,887	0.0235	78,469	39.00	2,012	1.0
2022	13,536.48	0	0	0.0000	13,536	40.00	338	0.0

FortisBC

Account #: 432.00 - Structures - Manufacturing Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	1,312,029.98	487,658	458,017		854,013		35,434	

COMPOSITE ANNUAL ACCRUAL RATE	2.70%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	14.87
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	25.13

FortisBC

Account #: 433.00 - Equipment - Manufacturing Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1994	5,018.55	5,019	5,019	1.0000	0	1.00	0	28.0
1997	3,352.69	3,353	3,353	1.0000	0	1.00	0	25.0
1999	99,809.18	99,809	99,809	1.0000	0	1.00	0	23.0
2000	5,687.97	5,688	5,688	1.0000	0	1.00	0	22.0
2005	6,458.40	5,490	6,458	1.0000	0	3.00	0	17.0
2012	310,358.83	155,179	188,350	0.6069	122,008	10.00	12,201	10.0
2013	2,914.86	1,312	1,475	0.5060	1,440	11.00	131	9.0
2015	57,135.77	19,998	22,484	0.3935	34,652	13.00	2,666	7.0
2019	93,635.20	14,045	15,792	0.1687	77,843	17.00	4,579	3.0
2020	5,999.70	600	675	0.1124	5,325	18.00	296	2.0
2021	73,389.10	3,669	4,126	0.0562	69,263	19.00	3,645	1.0
2022	537,378.35	0	0	0.0000	537,378	20.00	26,869	0.0
TOTAL	1,201,138.60	314,161	353,228		847,910		50,387	

COMPOSITE ANNUAL ACCRUAL RATE 4.19%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.29

COMPOSITE AVERAGE AGE (YEARS) 5.54

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 14.86

FortisBC

Account #: 434.00 - Holders - Manufacturing Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1990	238,142.82	190,514	193,619	0.8130	44,523	8.00	5,565	32.0
1992	102,238.92	76,679	77,929	0.7622	24,310	10.00	2,431	30.0
1996	860.87	560	569	0.6606	292	14.00	21	26.0
1997	763.37	477	485	0.6352	278	15.00	19	25.0
1998	680.66	408	415	0.6098	266	16.00	17	24.0
1999	681.40	392	398	0.5844	283	17.00	17	23.0
2000	544.40	299	304	0.5590	240	18.00	13	22.0
2001	10,282.20	5,398	5,486	0.5336	4,796	19.00	252	21.0
2002	590.33	295	300	0.5082	290	20.00	15	20.0
2011	330,932.50	91,006	92,490	0.2795	238,443	29.00	8,222	11.0
2012	2,167,248.27	541,812	550,642	0.2541	1,616,606	30.00	53,887	10.0
2013	91,239.63	20,529	20,863	0.2287	70,376	31.00	2,270	9.0
2014	3,882.60	777	789	0.2033	3,093	32.00	97	8.0
TOTAL	2,948,087.97	929,147	944,289		2,003,799		72,826	

COMPOSITE ANNUAL ACCRUAL RATE	2.47%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	12.61
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	27.39

FortisBC

Account #: 436.00 - Compressor Equipment - Manufacturing Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 25
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1992	1,382.72	1,383	1,383	1.0000	0	1.00	0	30.0
1995	51,896.50	51,897	51,897	1.0000	0	1.00	0	27.0
1996	5.50	6	6	1.0000	0	1.00	0	26.0
1997	4.88	5	5	1.0000	0	1.00	0	25.0
1998	4.35	4	4	1.0000	0	1.00	0	24.0
1999	4.36	4	4	1.0000	0	2.00	0	23.0
2000	3.48	3	3	1.0000	0	3.00	0	22.0
2001	3.35	3	3	1.0000	0	4.00	0	21.0
2002	3.77	3	4	1.0000	0	5.00	0	20.0
2012	310,358.83	124,144	143,365	0.4619	166,994	15.00	11,133	10.0
2013	2,914.86	1,049	1,163	0.3990	1,752	16.00	109	9.0
TOTAL	366,582.60	178,500	197,836		168,746		11,242	

COMPOSITE ANNUAL ACCRUAL RATE 3.07%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.54

COMPOSITE AVERAGE AGE (YEARS) 12.48

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 12.97

FortisBC

Account #: 437.00 - Measuring and Regulating Equipment - Manufacturing Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1992	280,389.70	280,390	280,390	1.0000	0	1.00	0	30.0
1996	789.15	789	789	1.0000	0	1.00	0	26.0
1997	699.77	700	700	1.0000	0	1.00	0	25.0
1998	623.95	624	624	1.0000	0	1.00	0	24.0
1999	624.63	625	625	1.0000	0	1.00	0	23.0
2000	499.05	499	499	1.0000	0	1.00	0	22.0
2001	1,086.26	1,086	1,086	1.0000	0	1.00	0	21.0
2002	541.14	541	541	1.0000	0	1.00	0	20.0
2003	10,181.08	9,672	10,181	1.0000	0	1.00	0	19.0
2011	119,082.62	65,495	119,083	1.0000	0	9.00	0	11.0
2012	306,357.95	153,179	306,358	1.0000	0	10.00	0	10.0
2013	132,273.32	59,523	132,273	1.0000	0	11.00	0	9.0
2014	262,190.11	104,876	249,472	0.9515	12,718	12.00	1,060	8.0
2015	111,539.56	39,039	63,488	0.5692	48,051	13.00	3,696	7.0
2019	482,871.56	72,431	117,793	0.2439	365,078	17.00	21,475	3.0
2020	198,632.69	19,863	32,303	0.1626	166,329	18.00	9,241	2.0
2021	228,559.13	11,428	18,585	0.0813	209,974	19.00	11,051	1.0
2022	33,542.45	0	0	0.0000	33,542	20.00	1,677	0.0
TOTAL	2,170,484.12	820,760	1,334,791		835,694		48,200	

COMPOSITE ANNUAL ACCRUAL RATE	2.22%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.61
COMPOSITE AVERAGE AGE (YEARS)	8.86
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.57

FortisBC

Account #: 442.00 - Structures - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L2
ASL: 28
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	1,453,071.43	1,059,093	979,949	0.6131	618,430	9.45	65,463	34.0
1991	1,924.79	1,347	1,247	0.5888	871	10.18	86	31.0
1992	110,426.95	76,249	70,551	0.5808	50,918	10.42	4,885	30.0
1993	8,093.70	5,513	5,101	0.5729	3,802	10.66	357	29.0
1994	84,561.94	56,799	52,554	0.5650	40,464	10.90	3,711	28.0
1995	132,581.49	87,800	81,239	0.5570	64,601	11.14	5,797	27.0
1996	42,779.92	27,919	25,833	0.5490	21,225	11.39	1,864	26.0
1997	246,113.24	158,196	146,374	0.5407	124,351	11.64	10,684	25.0
1998	396,745.70	250,963	232,209	0.5321	204,211	11.90	17,163	24.0
1999	133,892.83	83,257	77,036	0.5230	70,247	12.17	5,771	23.0
2000	318,749.06	194,571	180,031	0.5135	170,593	12.46	13,689	22.0
2001	94,819.16	56,719	52,481	0.5032	51,820	12.77	4,057	21.0
2002	36,534.09	21,370	19,773	0.4920	20,415	13.11	1,557	20.0
2003	704,255.73	401,753	371,730	0.4798	402,951	13.48	29,895	19.0
2004	16,996.28	9,426	8,722	0.4665	9,974	13.88	718	18.0
2005	788,457.87	423,513	391,865	0.4518	475,439	14.33	33,184	17.0
2006	13,612.01	7,050	6,523	0.4357	8,450	14.82	570	16.0
2007	270,602.22	134,425	124,379	0.4179	173,283	15.36	11,285	15.0
2008	30,361.26	14,379	13,304	0.3984	20,093	15.94	1,260	14.0
2009	0.84	0	0	0.3788	1	16.59	0	13.0
2010	74,883.19	31,523	29,167	0.3541	53,204	17.28	3,078	12.0
2011	2,009.60	787	728	0.3295	1,482	18.03	82	11.0
2012	562.15	203	188	0.3035	431	18.81	23	10.0
2014	206,919.61	61,176	56,605	0.2487	171,007	20.47	8,352	8.0
2015	15,121.82	3,957	3,661	0.2201	12,973	21.34	608	7.0
2016	26,945.83	6,110	5,653	0.1907	23,987	22.23	1,079	6.0
2017	1,560.68	298	276	0.1606	1,441	23.14	62	5.0
2018	88,838,164.07	13,689,585	12,666,583	0.1296	85,055,397	24.08	3,532,558	4.0

FortisBC

Account #: 442.00 - Structures - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L2
ASL: 28
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2019	3,690,158.43	429,816	397,697	0.0980	3,661,478	25.04	146,253	3.0
2020	1,833,329.78	143,236	132,532	0.0657	1,884,131	26.01	72,435	2.0
2021	456,888.98	17,919	16,580	0.0330	485,998	27.00	17,999	1.0
2022	1,729,296.64	0	0	0.0000	1,902,226	28.00	67,937	0.0
TOTAL	101,760,421.29	17,454,952	16,150,570		95,785,893		4,062,462	

COMPOSITE ANNUAL ACCRUAL RATE	3.99%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.16
COMPOSITE AVERAGE AGE (YEARS)	4.85
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	23.63

FortisBC

Account #: 442.01 - Structures - Mt. Hayes - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L2
ASL: 28
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	17,257,174.99	6,759,841	8,286,154	0.4365	10,696,739	18.03	593,302	11.0
2013	22,616.08	7,435	9,113	0.3663	15,764	19.63	803	9.0
2014	26,128.07	7,725	9,469	0.3295	19,272	20.47	941	8.0
2015	858,751.90	224,712	275,451	0.2916	669,177	21.34	31,359	7.0
2016	504,223.29	114,325	140,139	0.2527	414,507	22.23	18,647	6.0
2017	367,408.17	70,129	85,964	0.2127	318,185	23.14	13,750	5.0
2018	8,765.54	1,351	1,656	0.1717	7,986	24.08	332	4.0
2020	4,549.32	355	436	0.0871	4,569	26.01	176	2.0
2021	48,730.22	1,911	2,343	0.0437	51,261	27.00	1,898	1.0
TOTAL	19,098,347.58	7,187,785	8,810,723		12,197,459		661,208	

COMPOSITE ANNUAL ACCRUAL RATE 3.46%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.46

COMPOSITE AVERAGE AGE (YEARS) 10.54

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 18.42

FortisBC

Account #: 443.00 - Equipment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S4
ASL: 57
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	9,052,020.29	6,437,194	8,271,581	0.7615	2,590,844	23.22	111,573	34.0
1991	29,946.64	19,490	25,044	0.6969	10,892	26.09	418	31.0
1993	62,452.26	38,075	48,925	0.6528	26,018	28.04	928	29.0
1996	393,472.04	215,281	276,629	0.5859	195,537	31.01	6,305	26.0
1997	184,604.19	97,134	124,814	0.5634	96,712	32.01	3,022	25.0
1998	102,424.92	51,743	66,488	0.5409	56,422	33.00	1,710	24.0
1999	746,733.77	361,541	464,568	0.5184	431,513	34.00	12,691	23.0
2000	81,921.07	37,940	48,752	0.4959	49,553	35.00	1,416	22.0
2001	102,295.11	45,224	58,111	0.4734	64,643	36.00	1,796	21.0
2002	5,304,069.89	2,233,259	2,869,664	0.4509	3,495,220	37.00	94,465	20.0
2003	183,540.37	73,416	94,337	0.4283	125,912	38.00	3,313	19.0
2004	198,778.25	75,326	96,792	0.4058	141,742	39.00	3,634	18.0
2006	51,498.10	17,347	22,290	0.3607	39,508	41.00	964	16.0
2007	260.44	82	106	0.3381	207	42.00	5	15.0
2011	4,599.00	1,065	1,369	0.2480	4,150	46.00	90	11.0
2015	67,683.59	9,974	12,817	0.1578	68,404	50.00	1,368	7.0
2016	138,728.33	17,524	22,517	0.1353	143,957	51.00	2,823	6.0
2017	8,726.97	919	1,180	0.1127	9,292	52.00	179	5.0
2018	160,957,608.60	13,554,324	17,416,858	0.0902	175,732,273	53.00	3,315,703	4.0
2019	1,877,471.88	118,577	152,368	0.0676	2,100,599	54.00	38,900	3.0
2020	3,222,672.00	135,691	174,359	0.0451	3,692,847	55.00	67,143	2.0
2021	847,269.01	17,837	22,920	0.0225	993,803	56.00	17,746	1.0
2022	55,780.20	0	0	0.0000	66,936	57.00	1,174	0.0

FortisBC

Account #: 443.00 - Equipment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S4
ASL: 57
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	183,674,556.92	23,558,961	30,272,486		190,136,982		3,687,366	

COMPOSITE ANNUAL ACCRUAL RATE	2.01%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.16
COMPOSITE AVERAGE AGE (YEARS)	6.10
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	50.91

FortisBC

Account #: 443.05 - Equipment - Mt. Hayes - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R5
ASL: 60
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	60,096,336.36	13,221,722	12,830,904	0.1779	59,284,700	49.00	1,209,903	11.0
2015	33,011.11	4,622	4,485	0.1132	35,128	53.00	663	7.0
2016	155,710.19	18,687	18,134	0.0971	168,718	54.00	3,124	6.0
2017	367,184.08	36,722	35,636	0.0809	404,985	55.00	7,363	5.0
2018	2,773.52	222	215	0.0647	3,113	56.00	56	4.0
2019	1,118,820.39	67,139	65,155	0.0485	1,277,430	57.00	22,411	3.0
2020	9,833.71	393	382	0.0324	11,419	58.00	197	2.0
2021	52,842.82	1,057	1,026	0.0162	62,385	59.00	1,057	1.0
TOTAL	61,836,512.18	13,350,564	12,955,937		61,247,878		1,244,774	

COMPOSITE ANNUAL ACCRUAL RATE	2.01%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.21
COMPOSITE AVERAGE AGE (YEARS)	10.79
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	49.20

FortisBC

Account #: 448.10 - Piping - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	11,485,373.91	3,335,852	3,474,056	0.2750	9,159,855	29.44	311,153	11.0
2015	45,714.55	8,550	8,904	0.1771	41,382	33.20	1,246	7.0
2017	900,511.97	120,883	125,891	0.1271	864,672	35.12	24,621	5.0
2018	20,679.67	2,226	2,318	0.1019	20,430	36.09	566	4.0
2019	2,314.60	187	195	0.0766	2,351	37.06	63	3.0
2020	107,932.57	5,830	6,071	0.0511	112,655	38.04	2,962	2.0
2021	151,940.28	4,110	4,280	0.0256	162,854	39.02	4,174	1.0
TOTAL	12,714,467.55	3,477,637	3,621,715		10,364,199		344,785	

COMPOSITE ANNUAL ACCRUAL RATE	2.71%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.28
COMPOSITE AVERAGE AGE (YEARS)	10.35
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	30.05

FortisBC

Account #: 448.11 - Piping (Tilbury)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	38,641,329.44	4,158,643	4,383,879	0.1031	38,121,583	36.09	1,056,395	4.0
2019	391,823.71	31,687	33,404	0.0775	397,602	37.06	10,729	3.0
2020	13,585,274.27	733,782	773,524	0.0518	14,170,277	38.04	372,550	2.0
2021	198,205.63	5,361	5,652	0.0259	212,375	39.02	5,443	1.0
2022	25,983.05	0	0	0.0000	28,581	40.00	715	0.0
TOTAL	52,842,616.10	4,929,474	5,196,459		52,930,419		1,445,832	

COMPOSITE ANNUAL ACCRUAL RATE	2.74%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.10
COMPOSITE AVERAGE AGE (YEARS)	3.47
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	36.61

FortisBC

Account #: 448.20 - Pre-Treatment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 25
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	28,705,900.92	12,990,396	13,868,754	0.4392	17,707,737	14.72	1,203,369	11.0
2015	284,517.80	84,081	89,766	0.2868	223,203	18.28	12,208	7.0
2016	230,594.41	58,715	62,685	0.2471	190,969	19.21	9,940	6.0
2017	17,335.95	3,696	3,946	0.2069	15,124	20.15	750	5.0
2020	35,699.10	3,078	3,287	0.0837	35,982	23.04	1,562	2.0
2021	73,697.12	3,187	3,402	0.0420	77,665	24.02	3,234	1.0
TOTAL	29,347,745.30	13,143,153	14,031,839		18,250,681		1,231,063	

COMPOSITE ANNUAL ACCRUAL RATE	4.19%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.48
COMPOSITE AVERAGE AGE (YEARS)	10.88
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.82

FortisBC

Account #: 448.21 - Pre-treatment (Tilbury)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 25
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	31,465,017.20	5,388,760	5,754,231	0.1663	28,857,288	21.11	1,367,146	4.0
2019	1,080,214.44	139,266	148,712	0.1252	1,039,524	22.07	47,101	3.0
2020	614,075.45	52,952	56,544	0.0837	618,939	23.04	26,863	2.0
2021	349,110.61	15,095	16,119	0.0420	367,903	24.02	15,318	1.0
2022	590,597.62	0	0	0.0000	649,657	25.00	25,986	0.0
TOTAL	34,099,015.32	5,596,074	5,975,605		31,533,312		1,482,414	

COMPOSITE ANNUAL ACCRUAL RATE	4.35%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.18
COMPOSITE AVERAGE AGE (YEARS)	3.83
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	21.27

FortisBC

Account #: 448.30 - Liquefaction Equipment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	28,705,900.92	9,095,392	9,187,238	0.2667	25,259,843	29.44	858,057	11.0
2015	122,976.78	25,092	25,345	0.1717	122,227	33.20	3,682	7.0
2017	50,655.29	7,418	7,493	0.1233	53,293	35.12	1,518	5.0
2021	60,001.45	1,771	1,788	0.0248	70,213	39.02	1,800	1.0
TOTAL	28,939,534.44	9,129,673	9,221,864		25,505,577		865,057	

COMPOSITE ANNUAL ACCRUAL RATE	2.99%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	10.95
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.48

FortisBC

Account #: 448.31 - Liquefaction Eqpt (Tilbury)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	84,778,550.96	9,953,462	11,096,734	0.1091	90,637,527	36.09	2,511,675	4.0
2019	1,502,826.10	132,585	147,814	0.0820	1,655,577	37.06	44,674	3.0
2020	1,889,622.26	111,343	124,132	0.0547	2,143,415	38.04	56,352	2.0
2021	472,220.47	13,934	15,535	0.0274	551,130	39.02	14,126	1.0
2022	179,933.37	0	0	0.0000	215,920	40.00	5,398	0.0
TOTAL	88,823,153.16	10,211,324	11,384,214		95,203,570		2,632,225	

COMPOSITE ANNUAL ACCRUAL RATE	2.96%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.13
COMPOSITE AVERAGE AGE (YEARS)	3.92
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	36.17

FortisBC

Account #: 448.40 - Send Out Equipment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	22,954,144.52	6,666,882	6,913,135	0.2738	18,336,424	29.44	622,874	11.0
2015	360,916.00	67,504	69,997	0.1763	327,010	33.20	9,850	7.0
2016	35,308.30	5,675	5,884	0.1515	32,955	34.16	965	6.0
2017	201,840.73	27,095	28,095	0.1265	193,929	35.12	5,522	5.0
2021	171,645.16	4,643	4,814	0.0255	183,995	39.02	4,716	1.0
2022	19,393.30	0	0	0.0000	21,333	40.00	533	0.0
TOTAL	23,743,248.01	6,771,798	7,021,926		19,095,647		644,460	

COMPOSITE ANNUAL ACCRUAL RATE	2.71%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	10.80
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.63

FortisBC

Account #: 448.41 - Send out eqpt (Tilbury)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	6,609,363.49	711,311	716,280	0.0985	6,554,020	36.09	181,620	4.0
2019	185,440.98	14,997	15,102	0.0740	188,883	37.06	5,097	3.0
2020	855,428.44	46,204	46,527	0.0494	894,444	38.04	23,516	2.0
2021	207,548.57	5,614	5,653	0.0248	222,650	39.02	5,707	1.0
2022	2,817,694.96	0	0	0.0000	3,099,464	40.00	77,487	0.0
TOTAL	10,675,476.44	778,126	783,562		10,959,462		293,427	

COMPOSITE ANNUAL ACCRUAL RATE 2.75%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.07

COMPOSITE AVERAGE AGE (YEARS) 2.71

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 37.35

FortisBC

Account #: 448.50 - Substation and Electrical - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	21,638,229.37	6,856,018	6,879,728	0.2650	19,086,147	29.44	648,341	11.0
2015	107,598.77	21,954	22,030	0.1706	107,088	33.20	3,226	7.0
2017	42,423.46	6,213	6,234	0.1225	44,674	35.12	1,272	5.0
TOTAL	21,788,251.60	6,884,185	6,907,992		19,237,910		652,839	

COMPOSITE ANNUAL ACCRUAL RATE	3.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	10.97
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.47

FortisBC

Account #: 448.51 - Sub-station and Electric (Tilbury)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	35,786,573.31	4,201,538	4,408,453	0.1027	38,535,435	36.09	1,067,863	4.0
2019	404,285.80	35,668	37,424	0.0771	447,719	37.06	12,081	3.0
2020	774,598.65	45,642	47,890	0.0515	881,629	38.04	23,179	2.0
2021	183,839.54	5,425	5,692	0.0258	214,916	39.02	5,508	1.0
2022	1,095,858.11	0	0	0.0000	1,315,030	40.00	32,876	0.0
TOTAL	38,245,155.41	4,288,272	4,499,459		41,394,727		1,141,507	

COMPOSITE ANNUAL ACCRUAL RATE	2.98%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	3.82
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	36.26

FortisBC

Account #: 448.60 - Control Room - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	5,898,480.31	3,778,901	4,353,900	0.7381	1,544,580	5.39	286,556	11.0
2015	232,036.04	100,713	116,038	0.5001	115,998	8.49	13,664	7.0
2016	222,839.89	83,934	96,706	0.4340	126,134	9.35	13,490	6.0
2019	71,792.15	13,912	16,029	0.2233	55,763	12.09	4,611	3.0
2020	173,554.83	22,572	26,007	0.1498	147,548	13.05	11,307	2.0
2021	858.76	56	65	0.0753	794	14.02	57	1.0
2022	65,141.64	0	0	0.0000	65,142	15.00	4,343	0.0
TOTAL	6,664,703.62	4,000,089	4,608,745		2,055,959		334,028	

COMPOSITE ANNUAL ACCRUAL RATE	5.01%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	10.26
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.00

FortisBC

Account #: 448.61 - Control Room (Tilbury)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	3,617,885.03	927,236	887,383	0.2453	2,730,502	11.16	244,765	4.0
2019	40,540.87	7,856	7,519	0.1855	33,022	12.09	2,731	3.0
2020	90,116.54	11,721	11,217	0.1245	78,900	13.05	6,046	2.0
2021	704,761.05	46,080	44,099	0.0626	660,662	14.02	47,125	1.0
2022	154,780.06	0	0	0.0000	154,780	15.00	10,319	0.0
TOTAL	4,608,083.55	992,892	950,217		3,657,866		310,986	

COMPOSITE ANNUAL ACCRUAL RATE	6.75%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.21
COMPOSITE AVERAGE AGE (YEARS)	3.36
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.77

FortisBC

Account #: 449.00 - Other Equipment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 27
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	5,277,823.88	4,936,636	5,541,715	1.0000	0	2.95	0	34.0
1991	554,462.83	499,087	582,186	1.0000	0	3.85	0	31.0
1992	533,303.62	472,744	559,969	1.0000	0	4.21	0	30.0
1993	2,291,482.42	1,997,160	2,400,458	0.9977	5,598	4.59	1,220	29.0
1994	42,751.39	36,569	43,953	0.9791	936	5.00	187	28.0
1995	2,871,517.51	2,405,898	2,891,736	0.9591	123,357	5.46	22,612	27.0
1996	739,070.38	605,245	727,466	0.9374	48,558	5.94	8,172	26.0
1997	81,130.05	64,794	77,878	0.9142	7,308	6.46	1,131	25.0
1998	18,560.60	14,422	17,334	0.8895	2,154	7.02	307	24.0
1999	644,297.54	485,867	583,981	0.8632	92,531	7.61	12,161	23.0
2000	964,847.19	704,298	846,521	0.8356	166,569	8.23	20,240	22.0
2001	17,000.51	11,980	14,399	0.8066	3,452	8.88	389	21.0
2002	229,659.96	155,783	187,241	0.7765	53,902	9.56	5,640	20.0
2003	1,798,894.31	1,170,992	1,407,457	0.7451	481,382	10.26	46,913	19.0
2004	28,454.19	17,717	21,295	0.7128	8,582	10.99	781	18.0
2005	198,987.18	118,099	141,948	0.6794	66,989	11.74	5,707	17.0
2006	305,886.62	172,367	207,175	0.6450	114,006	12.51	9,113	16.0
2007	359,087.89	191,292	229,921	0.6098	147,122	13.30	11,060	15.0
2008	4,157,417.12	2,083,629	2,504,389	0.5737	1,860,899	14.11	131,862	14.0
2009	1,849,724.98	867,374	1,042,529	0.5368	899,683	14.94	60,212	13.0
2010	627,350.21	273,499	328,728	0.4990	329,990	15.79	20,899	12.0
2011	64,069.35	25,778	30,983	0.4606	36,290	16.65	2,179	11.0
2012	644,965.41	237,404	285,345	0.4214	391,869	17.53	22,348	10.0
2013	26,659.00	8,884	10,678	0.3815	17,314	18.43	939	9.0
2014	88,599.02	26,387	31,716	0.3409	61,313	19.34	3,170	8.0
2015	152,230.67	39,871	47,923	0.2998	111,919	20.27	5,523	7.0
2016	337,354.21	76,082	91,446	0.2582	262,776	21.20	12,395	6.0
2017	19,526.33	3,685	4,429	0.2160	16,074	22.15	726	5.0

FortisBC

Account #: 449.00 - Other Equipment - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 27
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	1,688,845.57	255,928	307,609	0.1735	1,465,678	23.10	63,440	4.0
2019	433,642.17	49,450	59,436	0.1305	395,888	24.07	16,449	3.0
2020	30,138.31	2,298	2,762	0.0873	28,883	25.04	1,154	2.0
2021	1,482,478.70	56,662	68,104	0.0438	1,488,499	26.02	57,212	1.0
2022	395,017.11	0	0	0.0000	414,768	27.00	15,362	0.0
TOTAL	28,955,236.23	18,067,883	21,298,708		9,104,290		559,503	

COMPOSITE ANNUAL ACCRUAL RATE 1.93%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.74

COMPOSITE AVERAGE AGE (YEARS) 20.01

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 10.95

FortisBC

Account #: 449.01 - Other Equipment - Mt. Hayes - LNG Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 30
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	33,236.49	12,119	10,896	0.3122	24,003	19.58	1,226	11.0
2014	2,925,678.44	787,403	707,923	0.2304	2,364,039	22.31	105,961	8.0
2015	2,273,993.41	537,774	483,492	0.2025	1,904,202	23.24	81,925	7.0
2016	359,107.68	73,076	65,700	0.1742	311,363	24.19	12,874	6.0
2017	8,415.58	1,432	1,288	0.1457	7,549	25.14	300	5.0
2019	127,026.90	13,049	11,732	0.0880	121,646	27.06	4,495	3.0
2020	9,394.56	645	580	0.0588	9,284	28.04	331	2.0
2021	396,611.85	13,646	12,269	0.0295	404,174	29.02	13,929	1.0
TOTAL	6,133,464.91	1,439,144	1,293,879		5,146,259		221,041	

COMPOSITE ANNUAL ACCRUAL RATE	3.60%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.21
COMPOSITE AVERAGE AGE (YEARS)	6.96
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	23.30

FortisBC

Account #: 462.00 - Compressor Structures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S4
ASL: 30
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1973	207,401.10	208,161	213,623	1.0000	0	1.00	0	49.0
1975	6,158.28	6,145	6,343	1.0000	0	1.00	0	47.0
1977	67.03	66	69	1.0000	0	1.14	0	45.0
1978	5,916.53	5,840	6,094	1.0000	0	1.25	0	44.0
1980	614.64	601	631	0.9962	2	1.50	2	42.0
1982	1,246.15	1,207	1,266	0.9864	17	1.78	10	40.0
1984	895.28	857	899	0.9748	23	2.12	11	38.0
1988	2,555.92	2,372	2,488	0.9449	145	2.97	49	34.0
1989	2,559.08	2,351	2,466	0.9356	170	3.24	52	33.0
1990	31,298.71	28,445	29,832	0.9254	2,406	3.53	682	32.0
1991	1,852,637.56	1,663,218	1,744,313	0.9141	163,904	3.85	42,553	31.0
1992	243,036.89	215,219	225,712	0.9017	24,616	4.21	5,850	30.0
1993	1,092,359.31	952,588	999,033	0.8879	126,097	4.60	27,409	29.0
1994	1,361,607.07	1,167,090	1,223,994	0.8728	178,461	5.03	35,446	28.0
1995	4,603,628.27	3,870,304	4,059,010	0.8560	682,727	5.51	123,831	27.0
1996	424,974.21	349,571	366,615	0.8376	71,108	6.04	11,770	26.0
1997	394,931.89	317,003	332,459	0.8173	74,321	6.62	11,225	25.0
1998	3,329,048.96	2,599,843	2,726,605	0.7952	702,315	7.25	96,822	24.0
1999	2,550,221.28	1,931,298	2,025,463	0.7711	601,265	7.94	75,702	23.0
2000	4,321,881.76	3,162,835	3,317,047	0.7451	1,134,492	8.68	130,628	22.0
2001	785,677.98	553,567	580,557	0.7174	228,691	9.48	24,127	21.0
2002	1,920,474.22	1,297,563	1,360,829	0.6880	617,260	10.32	59,806	20.0
2003	111,375.93	71,871	75,376	0.6571	39,342	11.20	3,511	19.0
2004	167,721.21	102,942	107,962	0.6249	64,791	12.12	5,344	18.0
2006	52,844.97	28,963	30,375	0.5580	24,056	14.04	1,714	16.0
2007	1,661,264.19	854,538	896,203	0.5238	814,899	15.02	54,262	15.0
2008	176,799.50	84,934	89,075	0.4891	93,028	16.01	5,811	14.0
2009	449,756.30	200,693	210,479	0.4544	252,770	17.00	14,866	13.0

FortisBC

Account #: 462.00 - Compressor Structures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S4
ASL: 30
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	225,317.46	92,823	97,349	0.4195	134,728	18.00	7,484	12.0
2011	566,520.02	213,950	224,381	0.3845	359,134	19.00	18,901	11.0
2012	1,931,739.12	663,226	695,563	0.3496	1,294,128	20.00	64,706	10.0
2013	662,072.62	204,580	214,555	0.3146	467,380	21.00	22,256	9.0
2014	157,689.11	43,312	45,424	0.2797	116,996	22.00	5,318	8.0
2015	422,578.72	101,560	106,512	0.2447	328,745	23.00	14,293	7.0
2016	1,313,823.08	270,648	283,844	0.2098	1,069,394	24.00	44,558	6.0
2017	268,558.82	46,103	48,350	0.1748	228,265	25.00	9,131	5.0
2018	223,622.32	30,711	32,208	0.1398	198,123	26.00	7,620	4.0
2019	1,074,063.66	110,629	116,023	0.1049	990,263	27.00	36,676	3.0
2020	1,327,798.03	91,175	95,621	0.0699	1,272,011	28.00	45,429	2.0
2021	9,065,878.74	311,262	326,438	0.0350	9,011,417	29.00	310,739	1.0
2022	3,139,578.50	0	0	0.0000	3,233,766	30.00	107,792	0.0
TOTAL	46,138,194.42	21,860,062	22,921,083		24,601,257		1,426,386	

COMPOSITE ANNUAL ACCRUAL RATE 3.09%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.50

COMPOSITE AVERAGE AGE (YEARS) 14.80

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 16.20

FortisBC

Account #: 463.00 - Measuring and Regulating Structures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S2.5
ASL: 40
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1972	30,628.34	30,000	33,543	0.9523	1,679	5.93	283	50.0
1974	12,536.32	12,090	13,518	0.9377	899	6.46	139	48.0
1980	1,662.26	1,517	1,696	0.8874	215	8.26	26	42.0
1982	1,246.15	1,110	1,241	0.8658	192	9.03	21	40.0
1984	8,916.23	7,736	8,649	0.8435	1,604	9.82	163	38.0
1985	3,043.26	2,603	2,911	0.8317	589	10.25	57	37.0
1986	1,364.56	1,150	1,286	0.8194	283	10.69	27	36.0
1987	8,403.96	6,970	7,794	0.8064	1,871	11.15	168	35.0
1988	117,922.23	96,170	107,530	0.7929	28,080	11.63	2,414	34.0
1989	1,902.24	1,524	1,704	0.7788	484	12.14	40	33.0
1990	5,248.61	4,125	4,612	0.7641	1,424	12.67	112	32.0
1991	3,839,818.01	2,956,751	3,306,014	0.7487	1,109,776	13.22	83,969	31.0
1992	246,715.93	185,908	207,868	0.7326	75,855	13.79	5,501	30.0
1993	174,055.32	128,158	143,296	0.7159	56,867	14.39	3,952	29.0
1994	71,195.96	51,147	57,189	0.6985	24,686	15.01	1,644	28.0
1995	442,981.68	309,974	346,589	0.6803	162,840	15.66	10,398	27.0
1996	347,481.11	236,425	264,352	0.6615	135,251	16.33	8,280	26.0
1997	194,521.74	128,440	143,612	0.6420	80,088	17.03	4,702	25.0
1998	120,531.61	77,079	86,184	0.6218	52,428	17.76	2,953	24.0
1999	620,189.29	383,244	428,514	0.6008	284,703	18.51	15,384	23.0
2000	399,176.78	237,806	265,896	0.5792	193,157	19.28	10,019	22.0
2001	105,859.77	60,639	67,801	0.5569	53,937	20.08	2,687	21.0
2002	810,460.26	445,169	497,754	0.5341	434,276	20.89	20,784	20.0
2003	203,948.97	107,090	119,740	0.5105	114,802	21.74	5,282	19.0
2004	366,262.99	183,250	204,896	0.4865	216,307	22.60	9,572	18.0
2005	154,564.20	73,415	82,087	0.4618	95,661	23.48	4,074	17.0
2006	1,785,071.88	801,775	896,484	0.4367	1,156,349	24.38	47,436	16.0
2007	1,757,445.92	743,113	830,892	0.4111	1,190,170	25.29	47,056	15.0

FortisBC

Account #: 463.00 - Measuring and Regulating Structures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S2.5
ASL: 40
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2008	109,305.21	43,297	48,412	0.3851	77,289	26.22	2,947	14.0
2009	213,669.11	78,843	88,156	0.3588	157,564	27.17	5,800	13.0
2010	338,501.84	115,618	129,275	0.3321	260,002	28.12	9,246	12.0
2011	150,303.34	47,168	52,740	0.3051	120,109	29.08	4,130	11.0
2012	134,458.66	38,434	42,974	0.2779	111,653	30.06	3,715	10.0
2013	898,378.10	231,473	258,816	0.2505	774,319	31.04	24,947	9.0
2014	125,722.51	28,830	32,235	0.2230	112,346	32.02	3,508	8.0
2015	414,354.64	83,214	93,043	0.1953	383,464	33.01	11,615	7.0
2016	266,712.24	45,941	51,368	0.1675	255,351	34.01	7,508	6.0
2017	359,365.54	51,604	57,699	0.1396	355,571	35.01	10,158	5.0
2018	677,671.29	77,863	87,061	0.1117	692,261	36.00	19,228	4.0
2019	4,469,630.60	385,147	430,642	0.0838	4,709,434	37.00	127,272	3.0
2020	3,514,127.64	201,805	225,643	0.0558	3,815,603	38.00	100,404	2.0
2021	950,237.13	27,251	30,470	0.0279	1,062,303	39.00	27,237	1.0
2022	1,533,789.67	0	0	0.0000	1,763,858	40.00	44,094	0.0
TOTAL	25,989,383.10	8,730,862	9,762,187		20,125,603		688,952	

COMPOSITE ANNUAL ACCRUAL RATE 2.65%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.38

COMPOSITE AVERAGE AGE (YEARS) 12.69

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 28.32

FortisBC

Account #: 464.00 - Other Structures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1973	7,845.44	8,238	8,146	0.9889	91	1.00	91	49.0
1975	1,992.26	2,092	2,069	0.9889	23	1.00	23	47.0
1978	6,315.00	6,512	6,439	0.9712	191	1.00	191	44.0
1979	10,826.17	11,108	10,984	0.9663	383	1.00	383	43.0
1983	8,868.78	8,832	8,734	0.9379	578	1.55	374	39.0
1984	3,199.30	3,158	3,123	0.9297	236	1.80	131	38.0
1987	18,636.05	17,868	17,670	0.9030	1,898	2.61	728	35.0
1988	12,898.76	12,234	12,098	0.8932	1,446	2.90	498	34.0
1989	5,246.07	4,917	4,862	0.8827	646	3.22	201	33.0
1990	4,177.22	3,864	3,821	0.8711	565	3.57	158	32.0
1991	26,130.83	23,813	23,548	0.8583	3,889	3.96	981	31.0
1993	9,555.00	8,397	8,304	0.8277	1,729	4.89	353	29.0
1994	43,742.33	37,606	37,189	0.8097	8,741	5.44	1,608	28.0
1995	565.90	475	469	0.7900	125	6.03	21	27.0
1996	76,883.05	62,772	62,075	0.7689	18,652	6.67	2,795	26.0
1997	12,255.54	9,719	9,611	0.7469	3,258	7.34	444	25.0
1998	3,010.54	2,314	2,289	0.7240	872	8.04	109	24.0
1999	191,806.97	142,630	141,046	0.7003	60,351	8.75	6,894	23.0
2000	105,424.54	75,658	74,818	0.6759	35,878	9.50	3,778	22.0
2001	3,833,288.66	2,648,125	2,618,720	0.6506	1,406,234	10.26	137,031	21.0
2002	537,707.52	356,545	352,586	0.6245	212,007	11.05	19,178	20.0
2003	10,828.76	6,871	6,795	0.5976	4,576	11.87	385	19.0
2004	554,794.63	335,698	331,971	0.5699	250,564	12.71	19,711	18.0
2005	288,414.54	165,802	163,960	0.5414	138,875	13.58	10,230	17.0
2006	238,200.38	129,568	128,129	0.5123	121,981	14.46	8,437	16.0
2007	104,381.11	53,481	52,887	0.4825	56,713	15.36	3,692	15.0
2008	163.42	78	78	0.4522	94	16.28	6	14.0
2009	22,991.57	10,288	10,174	0.4214	13,967	17.22	811	13.0

FortisBC

Account #: 464.00 - Other Structures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	7,291.71	2,530	2,501	0.3267	5,155	20.09	257	10.0
2013	331,857.79	103,798	102,646	0.2946	245,805	21.06	11,670	9.0
2014	18,679.57	5,201	5,143	0.2622	14,470	22.04	656	8.0
2015	70,917.02	17,298	17,106	0.2297	57,357	23.03	2,490	7.0
2016	194,526.30	40,709	40,257	0.1971	163,995	24.02	6,827	6.0
2018	53,039.31	7,410	7,328	0.1316	48,364	26.01	1,860	4.0
2019	54,554.08	5,719	5,655	0.0987	51,627	27.00	1,912	3.0
TOTAL	6,871,016.12	4,331,327	4,283,231		2,931,336		244,914	

COMPOSITE ANNUAL ACCRUAL RATE	3.56%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.62
COMPOSITE AVERAGE AGE (YEARS)	19.18
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.99

FortisBC

Account #: 465.00 - Transmission Pipeline

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 65
Net Salvage: -23%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	12,047.23	12,648	11,932	0.8053	2,886	9.52	303	65.0
1958	9,070,147.52	9,440,704	8,906,208	0.7983	2,250,074	10.00	225,109	64.0
1959	1,131,199.57	1,166,680	1,100,627	0.7910	290,748	10.50	27,698	63.0
1960	17,607.69	17,984	16,966	0.7834	4,692	11.03	426	62.0
1961	127,805.46	129,200	121,885	0.7753	35,316	11.58	3,050	61.0
1962	2,405,347.05	2,405,303	2,269,124	0.7670	689,453	12.16	56,720	60.0
1963	92,529.62	91,478	86,299	0.7583	27,513	12.76	2,157	59.0
1964	47,767.60	46,664	44,022	0.7493	14,732	13.38	1,101	58.0
1966	189,476.66	180,459	170,242	0.7305	62,814	14.67	4,282	56.0
1967	422,153.62	396,722	374,261	0.7208	144,988	15.34	9,453	55.0
1968	768,351.72	712,193	671,872	0.7109	273,201	16.02	17,057	54.0
1969	1,575,155.87	1,439,443	1,357,947	0.7009	579,494	16.71	34,685	53.0
1970	362,907.47	326,837	308,333	0.6907	138,043	17.41	7,930	52.0
1971	931,446.08	826,317	779,534	0.6804	366,144	18.12	20,208	51.0
1972	7,644,439.27	6,677,278	6,299,236	0.6699	3,103,424	18.84	164,722	50.0
1973	409,455.57	351,964	332,037	0.6593	171,593	19.57	8,766	49.0
1974	32,703.80	27,651	26,086	0.6485	14,140	20.32	696	48.0
1975	61,155.51	50,831	47,953	0.6375	27,268	21.08	1,294	47.0
1976	17,355,699.80	14,173,467	13,371,021	0.6264	7,976,490	21.84	365,159	46.0
1977	272,605.58	218,599	206,223	0.6150	129,082	22.62	5,706	45.0
1978	350,257.34	275,621	260,016	0.6035	170,800	23.42	7,294	44.0
1979	47,298.96	36,502	34,435	0.5919	23,743	24.22	980	43.0
1980	729,273.32	551,553	520,326	0.5801	376,680	25.03	15,048	42.0
1981	1,331,768.41	986,434	930,586	0.5681	707,489	25.86	27,361	41.0
1982	644,241.64	466,984	440,545	0.5560	351,872	26.69	13,181	40.0
1983	315,062.27	223,330	210,686	0.5437	176,840	27.54	6,421	39.0
1984	482,286.28	334,036	315,124	0.5312	278,088	28.40	9,792	38.0
1985	1,077,972.54	728,933	687,664	0.5186	638,242	29.27	21,809	37.0

FortisBC

Account #: 465.00 - Transmission Pipeline

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 65
Net Salvage: -23%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1986	3,496,292.38	2,306,175	2,175,608	0.5059	2,124,832	30.14	70,492	36.0
1987	1,808,770.65	1,162,755	1,096,925	0.4930	1,127,863	31.03	36,349	35.0
1988	35,084,611.21	21,959,574	20,716,309	0.4801	22,437,763	31.92	702,854	34.0
1989	691,664.91	421,092	397,252	0.4669	453,496	32.83	13,815	33.0
1990	6,652,592.02	3,935,424	3,712,616	0.4537	4,470,073	33.74	132,491	32.0
1991	323,629,281.70	185,818,423	175,298,111	0.4404	222,765,905	34.66	6,427,611	31.0
1992	57,403,074.66	31,953,252	30,144,184	0.4269	40,461,598	35.58	1,137,083	30.0
1993	6,910,030.80	3,724,437	3,513,574	0.4134	4,985,764	36.52	136,533	29.0
1994	2,898,855.51	1,510,946	1,425,402	0.3998	2,140,190	37.46	57,139	28.0
1995	33,221,405.82	16,721,403	15,774,702	0.3860	25,087,627	38.40	653,304	27.0
1996	12,773,412.24	6,199,579	5,848,583	0.3723	9,862,714	39.35	250,632	26.0
1997	8,368,500.04	3,910,267	3,688,883	0.3584	6,604,372	40.31	163,850	25.0
1999	12,422,850.75	5,352,186	5,049,166	0.3304	10,230,941	42.23	242,254	23.0
2000	318,052,620.60	131,198,973	123,771,001	0.3164	267,433,723	43.20	6,190,475	22.0
2001	46,227,661.10	18,218,732	17,187,259	0.3023	39,672,764	44.17	898,120	21.0
2002	25,914,563.36	9,734,824	9,183,677	0.2881	22,691,236	45.15	502,591	20.0
2003	17,939,175.58	6,406,721	6,043,998	0.2739	16,021,188	46.13	347,328	19.0
2004	13,448,588.68	4,553,288	4,295,499	0.2597	12,246,265	47.11	259,961	18.0
2005	11,320,597.83	3,622,136	3,417,065	0.2454	10,507,270	48.09	218,485	17.0
2006	12,513,103.54	3,770,288	3,556,829	0.2311	11,834,289	49.08	241,136	16.0
2007	10,405,916.18	2,940,925	2,774,421	0.2168	10,024,856	50.06	200,238	15.0
2008	11,934,020.82	3,149,376	2,971,070	0.2024	11,707,775	51.05	229,321	14.0
2009	9,207,830.20	2,257,316	2,129,516	0.1880	9,196,115	52.04	176,696	13.0
2010	8,480,401.21	1,919,763	1,811,074	0.1736	8,619,820	53.04	162,525	12.0
2011	56,900,186.45	11,811,423	11,142,707	0.1592	58,844,523	54.03	1,089,103	11.0
2012	15,181,008.20	2,865,653	2,703,411	0.1448	15,969,229	55.02	290,220	10.0
2013	20,714,939.46	3,520,179	3,320,880	0.1303	22,158,495	56.02	395,548	9.0
2014	22,835,714.67	3,450,197	3,254,860	0.1159	24,833,069	57.02	435,548	8.0

FortisBC

Account #: 465.00 - Transmission Pipeline

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 65
Net Salvage: -23%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2015	25,030,309.76	3,309,737	3,122,353	0.1014	27,664,928	58.01	476,881	7.0
2016	21,074,513.45	2,389,000	2,253,744	0.0869	23,667,907	59.01	401,087	6.0
2017	164,895,651.30	15,579,523	14,697,472	0.0725	188,124,179	60.01	3,135,032	5.0
2018	34,002,723.88	2,570,434	2,424,906	0.0580	39,398,444	61.01	645,822	4.0
2019	22,977,263.68	1,302,856	1,229,094	0.0435	27,032,941	62.00	435,990	3.0
2020	64,341,736.28	2,432,364	2,294,653	0.0290	76,845,683	63.00	1,219,729	2.0
2021	72,708,666.54	1,374,238	1,296,434	0.0145	88,135,226	64.00	1,377,087	1.0
2022	120,408,341.00	0	0	0.0000	148,102,259	65.00	2,278,485	0.0
TOTAL	1,679,785,039.91	565,649,277	533,624,429		1,532,511,170		32,690,223	

COMPOSITE ANNUAL ACCRUAL RATE	1.95%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	18.17
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	47.20

FortisBC

Account #: 465.11 - Intermediate Pipe - Whistler - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 65
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2008	8,227.20	2,057	1,952	0.1977	7,921	51.46	154	14.0
2009	42,030,839.72	9,775,121	9,276,830	0.1839	41,160,178	52.40	785,463	13.0
2010	133,828.28	28,778	27,311	0.1701	133,283	53.35	2,498	12.0
2014	139,026.93	20,050	19,028	0.1141	147,805	57.19	2,585	8.0
2015	3,584.26	453	430	0.0999	3,871	58.16	67	7.0
2017	4,728.66	428	406	0.0716	5,268	60.10	88	5.0
2018	17,893.93	1,297	1,231	0.0573	20,242	61.07	331	4.0
2019	16,351,269.82	889,566	844,220	0.0430	18,777,304	62.05	302,600	3.0
2020	171,824.83	6,238	5,920	0.0287	200,269	63.03	3,177	2.0
2021	54,372.97	988	938	0.0144	64,310	64.02	1,005	1.0
2022	126,239.39	0	0	0.0000	151,487	65.00	2,331	0.0
TOTAL	59,041,835.99	10,724,975	10,178,265		60,671,938		1,100,299	

COMPOSITE ANNUAL ACCRUAL RATE	1.86%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	10.14
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	55.16

FortisBC

Account #: 465.30 - Mains - Mt. Hayes - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 65
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	6,296,993.66	1,278,774	1,291,357	0.1709	6,265,035	54.00	116,019	11.0
2016	9,959.04	1,103	1,114	0.0932	10,837	59.00	184	6.0
TOTAL	6,306,952.70	1,279,877	1,292,471		6,275,872		116,203	

COMPOSITE ANNUAL ACCRUAL RATE	1.84%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.20
COMPOSITE AVERAGE AGE (YEARS)	10.99
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	54.01

FortisBC

Account #: 466.00 - Compressor Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 37
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1973	1,161,436.28	1,142,386	1,196,279	1.0000	0	1.67	0	49.0
1974	288,030.63	281,321	296,672	1.0000	0	1.91	0	48.0
1975	2,752.84	2,669	2,835	1.0000	0	2.17	0	47.0
1976	12,388.65	11,923	12,760	1.0000	0	2.43	0	46.0
1977	49,027.94	46,822	50,499	1.0000	0	2.69	0	45.0
1978	778,072.63	737,103	801,415	1.0000	0	2.97	0	44.0
1979	2,841.36	2,669	2,920	0.9979	6	3.25	2	43.0
1981	3,009.83	2,776	3,037	0.9797	63	3.87	16	41.0
1983	31,042.02	28,019	30,653	0.9587	1,320	4.58	289	39.0
1984	3,474.57	3,097	3,388	0.9468	191	4.98	38	38.0
1985	1,287.81	1,132	1,238	0.9337	88	5.42	16	37.0
1986	7,609.26	6,586	7,205	0.9193	633	5.91	107	36.0
1987	87,594.98	74,519	81,526	0.9036	8,697	6.44	1,350	35.0
1988	13,505.80	11,274	12,334	0.8867	1,577	7.01	225	34.0
1989	20,082.21	16,421	17,965	0.8685	2,719	7.63	357	33.0
1990	30,473.35	24,371	26,662	0.8494	4,726	8.27	571	32.0
1991	16,284,396.01	12,719,737	13,915,676	0.8297	2,857,252	8.94	319,565	31.0
1992	2,749,861.98	2,095,197	2,292,192	0.8093	540,165	9.63	56,093	30.0
1993	4,503,939.66	3,342,949	3,657,261	0.7884	981,797	10.34	94,975	29.0
1994	18,713,123.59	13,510,812	14,781,130	0.7669	4,493,388	11.06	406,120	28.0
1995	4,833,959.75	3,389,643	3,708,345	0.7448	1,270,634	11.81	107,583	27.0
1996	2,007,135.76	1,364,533	1,492,830	0.7221	574,520	12.58	45,675	26.0
1997	3,472,147.04	2,284,346	2,499,125	0.6988	1,077,186	13.37	80,589	25.0
1998	6,109,127.88	3,881,853	4,246,834	0.6749	2,045,568	14.17	144,315	24.0
1999	7,012,821.35	4,294,487	4,698,264	0.6504	2,524,942	15.00	168,307	23.0
2000	50,628,392.07	29,810,257	32,613,086	0.6254	19,534,158	15.85	1,232,536	22.0
2001	5,623,170.57	3,175,648	3,474,229	0.5998	2,317,636	16.71	138,672	21.0
2002	6,487,787.69	3,504,795	3,834,324	0.5738	2,848,097	17.59	161,877	20.0

FortisBC

Account #: 466.00 - Compressor Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 37
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	698,737.94	360,016	393,866	0.5473	325,834	18.49	17,621	19.0
2004	2,252,788.46	1,103,570	1,207,330	0.5203	1,113,042	19.40	57,365	18.0
2005	1,857,776.67	862,269	943,341	0.4930	970,168	20.33	47,728	17.0
2006	439,909.77	192,714	210,833	0.4653	242,274	21.26	11,394	16.0
2007	18,372,313.14	7,564,334	8,275,550	0.4373	10,647,933	22.21	479,423	15.0
2008	3,315,847.99	1,277,004	1,397,071	0.4091	2,018,253	23.17	87,123	14.0
2009	4,624,205.10	1,656,826	1,812,604	0.3806	2,950,327	24.13	122,272	13.0
2011	3,817,924.42	1,161,018	1,270,179	0.3230	2,662,283	26.08	102,097	11.0
2012	2,907,689.35	804,800	880,469	0.2940	2,114,451	27.06	78,147	10.0
2013	1,419,948.95	354,071	387,362	0.2649	1,075,186	28.04	38,341	9.0
2014	821,986.80	182,346	199,491	0.2356	647,156	29.03	22,292	8.0
2015	3,514,964.29	682,758	746,953	0.2063	2,873,461	30.02	95,711	7.0
2016	6,647,833.37	1,107,464	1,211,590	0.1769	5,635,678	31.02	181,704	6.0
2017	7,368,456.39	1,023,409	1,119,632	0.1475	6,469,878	32.01	202,116	5.0
2018	2,119,235.64	235,564	257,712	0.1181	1,925,101	33.01	58,324	4.0
2019	2,746,896.22	229,068	250,605	0.0886	2,578,698	34.00	75,834	3.0
2020	1,472,730.93	81,894	89,593	0.0591	1,427,319	35.00	40,778	2.0
2021	2,092,113.93	58,174	63,644	0.0295	2,091,234	36.00	58,088	1.0
2022	5,643,413.51	0	0	0.0000	5,812,716	37.00	157,100	0.0
TOTAL	203,053,266.38	104,704,645	114,478,511		94,666,354		4,892,736	

COMPOSITE ANNUAL ACCRUAL RATE	2.41%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.56
COMPOSITE AVERAGE AGE (YEARS)	19.62
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	18.48

FortisBC

Account #: 467.00 - Measuring and Regulating Equipment - Mt. Hayes - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	5,340,255.96	1,318,511	2,030,199	0.3621	3,577,070	28.30	126,400	11.0
2021	574,032.55	13,430	20,678	0.0343	582,056	36.18	16,090	1.0
2022	15,092.18	0	0	0.0000	15,847	37.00	428	0.0
TOTAL	5,929,380.69	1,331,941	2,050,877		4,174,973		142,918	

COMPOSITE ANNUAL ACCRUAL RATE	2.41%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	10.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.08

FortisBC

Account #: 467.10 - Measuring and Regulating Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1971	47,395.12	40,929	49,765	1.0000	0	6.57	0	51.0
1972	125,024.32	106,857	131,276	1.0000	0	6.88	0	50.0
1974	16,590.56	13,874	17,420	1.0000	0	7.53	0	48.0
1975	998.36	825	1,048	1.0000	0	7.87	0	47.0
1977	1,038.54	838	1,090	1.0000	0	8.57	0	45.0
1978	3,487.48	2,777	3,632	0.9918	30	8.94	3	44.0
1981	1,834.03	1,399	1,829	0.9500	96	10.13	10	41.0
1984	28,053.01	20,356	26,625	0.9039	2,831	11.43	248	38.0
1985	107,429.56	76,546	100,116	0.8875	12,685	11.89	1,067	37.0
1986	37,810.22	26,429	34,567	0.8707	5,134	12.37	415	36.0
1987	10,836.18	7,423	9,709	0.8533	1,669	12.86	130	35.0
1988	961,445.42	644,870	843,443	0.8355	166,075	13.36	12,426	34.0
1989	31,680.46	20,782	27,182	0.8171	6,083	13.88	438	33.0
1991	8,894,452.59	5,562,221	7,274,976	0.7790	2,064,199	14.96	137,948	31.0
1992	1,494,859.61	911,064	1,191,605	0.7592	377,998	15.52	24,350	30.0
1993	1,417,071.72	840,588	1,099,427	0.7389	388,499	16.10	24,134	29.0
1994	859,276.43	495,412	647,963	0.7182	254,277	16.68	15,241	28.0
1995	1,277,806.36	714,998	935,165	0.6970	406,531	17.28	23,523	27.0
1996	884,605.60	479,628	627,318	0.6754	301,518	17.89	16,850	26.0
1997	2,904,842.74	1,523,587	1,992,740	0.6533	1,057,345	18.52	57,099	25.0
1998	1,013,355.44	513,243	671,284	0.6309	392,740	19.15	20,506	24.0
1999	1,830,598.22	893,572	1,168,727	0.6080	753,402	19.80	38,052	23.0
2000	3,592,121.91	1,686,395	2,205,680	0.5848	1,566,048	20.46	76,554	22.0
2001	918,920.96	413,987	541,465	0.5612	423,402	21.12	20,043	21.0
2002	2,290,997.97	988,043	1,292,288	0.5372	1,113,260	21.80	51,060	20.0
2003	4,151,351.75	1,709,287	2,235,622	0.5129	2,123,298	22.49	94,407	19.0
2004	1,069,479.89	419,184	548,262	0.4882	574,692	23.19	24,784	18.0
2005	440,763.58	163,925	214,401	0.4633	248,401	23.89	10,396	17.0

FortisBC

Account #: 467.10 - Measuring and Regulating Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2006	2,074,593.79	729,464	954,085	0.4380	1,224,239	24.61	49,746	16.0
2007	1,023,026.17	338,719	443,019	0.4124	631,158	25.33	24,915	15.0
2008	1,433,181.46	444,796	581,760	0.3866	923,081	26.06	35,416	14.0
2009	668,341.23	193,420	252,979	0.3605	448,779	26.80	16,744	13.0
2010	547,931.90	146,981	192,240	0.3341	383,089	27.55	13,906	12.0
2011	1,384,247.08	341,771	447,011	0.3076	1,006,448	28.30	35,564	11.0
2012	3,443,721.24	776,112	1,015,097	0.2807	2,600,810	29.06	89,503	10.0
2013	2,292,921.04	466,949	610,735	0.2537	1,796,832	29.82	60,248	9.0
2014	1,267,718.85	230,404	301,352	0.2264	1,029,753	30.60	33,657	8.0
2015	7,122,720.10	1,137,266	1,487,460	0.1989	5,991,396	31.37	190,969	7.0
2016	1,801,183.27	247,485	323,692	0.1712	1,567,550	32.16	48,745	6.0
2017	2,929,822.63	336,799	440,509	0.1432	2,635,805	32.95	79,996	5.0
2018	11,004,625.06	1,016,099	1,328,982	0.1150	10,225,874	33.75	303,022	4.0
2019	7,126,688.85	495,539	648,128	0.0866	6,834,895	34.55	197,827	3.0
2020	2,645,995.07	123,173	161,101	0.0580	2,617,194	35.36	74,016	2.0
2021	7,968,448.43	186,423	243,828	0.0291	8,123,043	36.18	224,545	1.0
2022	4,109,641.52	0	361	0.0001	4,314,762	37.00	116,623	0.0
TOTAL	93,258,935.72	25,490,439	33,326,963		64,594,919		2,245,126	

COMPOSITE ANNUAL ACCRUAL RATE	2.41%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	12.87
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	27.37

FortisBC

Account #: 467.20 - Telemetry Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1972	14,813.00	14,813	14,813	1.0000	0	1.00	0	50.0
1974	2,092.39	2,092	2,092	1.0000	0	1.00	0	48.0
1978	6,715.46	6,715	6,715	1.0000	0	1.00	0	44.0
1979	1,440.46	1,440	1,440	1.0000	0	1.00	0	43.0
1980	25,152.16	25,152	25,152	1.0000	0	1.00	0	42.0
1981	1,654.26	1,654	1,654	1.0000	0	1.00	0	41.0
1982	8,407.98	8,408	8,408	1.0000	0	1.00	0	40.0
1985	33,804.31	33,804	33,804	1.0000	0	1.00	0	37.0
1987	1,108.53	1,109	1,109	1.0000	0	1.00	0	35.0
1988	5,317.37	5,317	5,317	1.0000	0	1.00	0	34.0
1989	480.06	480	480	1.0000	0	1.00	0	33.0
1991	79,689.42	79,689	79,689	1.0000	0	1.00	0	31.0
1992	92,050.16	92,050	92,050	1.0000	0	1.00	0	30.0
1993	115,032.72	109,281	115,033	1.0000	0	1.00	0	29.0
1994	139,221.61	126,074	139,222	1.0000	0	1.00	0	28.0
1995	244,090.68	220,145	244,091	1.0000	0	1.00	0	27.0
1996	108,186.46	96,408	108,186	1.0000	0	1.09	0	26.0
1997	203,844.96	179,097	203,845	1.0000	0	1.21	0	25.0
1998	68,087.09	58,903	68,087	1.0000	0	1.35	0	24.0
2000	77,074.99	64,373	77,075	1.0000	0	1.65	0	22.0
2001	222,275.69	181,972	222,276	1.0000	0	1.81	0	21.0
2002	114,833.41	91,992	114,833	1.0000	0	1.99	0	20.0
2003	79,391.21	62,120	79,391	1.0000	0	2.18	0	19.0
2004	141,487.44	107,917	141,487	1.0000	0	2.37	0	18.0
2005	22,377.46	16,602	22,377	1.0000	0	2.58	0	17.0
2006	32.66	24	33	1.0000	0	2.80	0	16.0
2007	70,310.25	48,991	70,310	1.0000	0	3.03	0	15.0
2008	118,860.22	79,941	118,860	1.0000	0	3.27	0	14.0

FortisBC

Account #: 467.20 - Telemetry Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	6,499.63	4,208	6,500	1.0000	0	3.53	0	13.0
2010	105,237.56	65,431	103,323	0.9818	1,915	3.78	506	12.0
2011	1,647,410.34	981,329	1,549,624	0.9406	97,786	4.04	24,185	11.0
2012	667,450.32	379,941	599,968	0.8989	67,482	4.31	15,666	10.0
2013	1,428,659.05	774,237	1,222,602	0.8558	206,057	4.58	44,984	9.0
2014	757,868.05	388,463	613,424	0.8094	144,444	4.87	29,634	8.0
2015	3,535,266.23	1,694,499	2,675,795	0.7569	859,471	5.21	165,065	7.0
2016	765,841.80	336,871	531,955	0.6946	233,887	5.60	41,756	6.0
2017	313,775.31	122,924	194,111	0.6186	119,664	6.08	19,674	5.0
2018	726,008.77	241,349	381,115	0.5249	344,894	6.68	51,664	4.0
2019	461,803.01	121,098	191,227	0.4141	270,576	7.38	36,675	3.0
2020	450,566.05	82,426	130,160	0.2889	320,406	8.17	39,214	2.0
2021	8,704,073.28	826,034	1,304,397	0.1499	7,399,677	9.05	817,555	1.0
2022	363,381.03	0	0	0.0000	363,381	10.00	36,336	0.0
TOTAL	21,931,672.84	7,735,376	11,502,033		10,429,640		1,322,914	

COMPOSITE ANNUAL ACCRUAL RATE	6.03%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	6.31
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.49

FortisBC

Account #: 467.31 - Measuring and Regulating Equipment - Whistler - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -7%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	313,343.70	92,410	139,560	0.4163	195,718	26.80	7,302	13.0
TOTAL	313,343.70	92,410	139,560		195,718		7,302	

COMPOSITE ANNUAL ACCRUAL RATE	2.33%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	13.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	26.80

FortisBC

Account #: 468.00 - Communications Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 19
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1991	1,958,059.29	1,906,234	1,958,059	1.0000	0	1.00	0	31.0
1994	6,552.41	6,187	6,552	1.0000	0	1.06	0	28.0
1995	20,392.63	18,992	20,393	1.0000	0	1.31	0	27.0
1996	3,807.61	3,496	3,808	1.0000	0	1.55	0	26.0
1997	4,256.87	3,852	4,257	1.0000	0	1.81	0	25.0
1998	11,227.62	10,005	11,228	1.0000	0	2.07	0	24.0
1999	3,013.81	2,641	3,014	1.0000	0	2.35	0	23.0
2000	2,407.88	2,071	2,408	1.0000	0	2.66	0	22.0
2001	95,281.20	80,190	95,281	1.0000	0	3.01	0	21.0
2002	3,877.00	3,183	3,877	1.0000	0	3.40	0	20.0
2003	2,901.26	2,314	2,901	1.0000	0	3.84	0	19.0
2004	4,920.95	3,798	4,921	1.0000	0	4.34	0	18.0
2006	3,348.48	2,384	3,348	1.0000	0	5.47	0	16.0
2007	257,488.01	174,762	257,488	1.0000	0	6.10	0	15.0
2008	18,201.05	11,707	18,201	1.0000	0	6.78	0	14.0
2009	226,521.39	137,226	226,521	1.0000	0	7.49	0	13.0
2010	939.84	533	940	1.0000	0	8.23	0	12.0
2011	294,713.93	154,991	294,714	1.0000	0	9.01	0	11.0
2012	12.65	6	13	1.0000	0	9.81	0	10.0
2013	264,839.14	116,529	264,839	1.0000	0	10.64	0	9.0
2018	144,312.11	29,404	144,312	1.0000	0	15.13	0	4.0

FortisBC

Account #: 468.00 - Communications Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 19
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	3,327,075.13	2,670,505	3,327,075		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	23.32
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.04

FortisBC

Account #: 472.00 - Structures - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1958	20,875.29	22,367	25,050	1.0000	0	4.82	0	64.0
1961	21,710.46	22,856	26,053	1.0000	0	5.52	0	61.0
1962	15,408.41	16,122	18,490	1.0000	0	5.76	0	60.0
1965	559.36	574	663	0.9876	8	6.53	1	57.0
1968	15,488.52	15,539	17,950	0.9658	636	7.38	86	54.0
1969	1,834.27	1,825	2,108	0.9579	93	7.69	12	53.0
1970	373.23	368	425	0.9496	23	8.01	3	52.0
1971	684.49	669	773	0.9409	49	8.35	6	51.0
1972	4,054.62	3,925	4,534	0.9318	332	8.70	38	50.0
1973	13,979.73	13,392	15,471	0.9222	1,305	9.08	144	49.0
1974	4,055.06	3,842	4,439	0.9122	427	9.47	45	48.0
1975	6,738.60	6,311	7,291	0.9016	796	9.88	81	47.0
1976	1,822.60	1,686	1,948	0.8906	239	10.31	23	46.0
1978	15.33	14	16	0.8670	2	11.22	0	44.0
1979	1,034.00	918	1,060	0.8545	181	11.71	15	43.0
1980	7,195.67	6,290	7,266	0.8415	1,369	12.22	112	42.0
1981	76,431.46	65,742	75,944	0.8280	15,774	12.74	1,238	41.0
1982	7,643.54	6,464	7,467	0.8140	1,706	13.29	128	40.0
1983	41,072.00	34,116	39,410	0.7996	9,876	13.85	713	39.0
1984	26,710.02	21,773	25,152	0.7847	6,900	14.43	478	38.0
1985	11,785.99	9,420	10,882	0.7694	3,261	15.03	217	37.0
1986	109,069.59	85,398	98,650	0.7537	32,233	15.64	2,061	36.0
1987	145,783.14	111,700	129,035	0.7376	45,905	16.27	2,822	35.0
1988	17,436.24	13,061	15,088	0.7211	5,836	16.91	345	34.0
1989	19,872.92	14,538	16,794	0.7042	7,054	17.57	402	33.0
1990	44,063.07	31,445	36,325	0.6870	16,551	18.24	907	32.0
1991	998,008.24	693,994	801,694	0.6694	395,916	18.92	20,922	31.0
1992	636,938.25	431,062	497,959	0.6515	266,367	19.62	13,576	30.0

FortisBC

Account #: 472.00 - Structures - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1993	218,260.59	143,580	165,863	0.6333	96,050	20.33	4,724	29.0
1994	737,547.92	470,990	544,083	0.6147	340,975	21.05	16,196	28.0
1995	918,253.56	568,428	656,641	0.5959	445,263	21.79	20,438	27.0
1996	1,004,548.70	601,879	695,285	0.5768	510,174	22.53	22,642	26.0
1997	931,923.87	539,572	623,307	0.5574	495,002	23.29	21,256	25.0
1998	467,849.49	261,311	301,864	0.5377	259,556	24.05	10,790	24.0
1999	446,619.81	240,196	277,472	0.5177	258,472	24.83	10,409	23.0
2000	532,753.60	275,329	318,057	0.4975	321,247	25.62	12,539	22.0
2001	545,007.88	270,066	311,977	0.4770	342,032	26.42	12,947	21.0
2002	222,346.98	105,391	121,747	0.4563	145,070	27.23	5,329	20.0
2003	290,525.14	131,379	151,767	0.4353	196,863	28.04	7,020	19.0
2004	1,171,717.94	504,055	582,279	0.4141	823,783	28.87	28,536	18.0
2005	2,137,164.59	871,764	1,007,052	0.3927	1,557,546	29.70	52,436	17.0
2006	2,386,425.14	919,728	1,062,460	0.3710	1,801,250	30.55	58,966	16.0
2007	908,438.66	329,465	380,594	0.3491	709,532	31.40	22,597	15.0
2008	1,045,256.32	355,103	410,211	0.3270	844,097	32.26	26,165	14.0
2009	543,124.93	171,937	198,620	0.3047	453,130	33.13	13,678	13.0
2010	476,707.19	139,774	161,466	0.2823	410,583	34.00	12,074	12.0
2011	1,971,245.33	531,553	614,044	0.2596	1,751,451	34.89	50,202	11.0
2012	984,718.01	242,157	279,737	0.2367	901,925	35.78	25,209	10.0
2013	914,732.57	203,071	234,585	0.2137	863,094	36.67	23,534	9.0
2014	421,409.01	83,400	96,343	0.1905	409,348	37.58	10,893	8.0
2015	1,376,948.94	239,114	276,222	0.1672	1,376,117	38.49	35,754	7.0
2016	878,878.77	131,173	151,529	0.1437	903,125	39.40	22,920	6.0
2017	939,848.46	117,200	135,388	0.1200	992,430	40.32	24,612	5.0
2018	9,201,995.45	920,291	1,063,110	0.0963	9,979,284	41.25	241,924	4.0
2019	12,919,465.20	971,364	1,122,108	0.0724	14,381,250	42.18	340,945	3.0
2020	6,232,558.36	313,123	361,717	0.0484	7,117,353	43.12	165,075	2.0

FortisBC

Account #: 472.00 - Structures - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 45
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2021	788,723.01	19,859	22,941	0.0242	923,527	44.06	20,963	1.0
2022	551,950.09	0	5	0.0000	662,335	45.00	14,719	0.0
TOTAL	54,417,589.61	12,307,662	14,216,408		51,084,700		1,379,867	

COMPOSITE ANNUAL ACCRUAL RATE	2.54%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.26
COMPOSITE AVERAGE AGE (YEARS)	9.53
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	36.52

FortisBC

Account #: 472.20 - Structures and Improvements - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 36
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	136,986.21	39,511	49,743	0.3301	100,942	26.56	3,800	12.0
2013	47,985.30	10,511	13,234	0.2507	39,550	28.83	1,372	9.0
2014	277,415.78	54,239	68,286	0.2238	236,871	29.60	8,002	8.0
2015	159,635.24	27,422	34,524	0.1966	141,075	30.38	4,644	7.0
2016	32,875.21	4,860	6,119	0.1692	30,044	31.16	964	6.0
2018	55,357.52	5,501	6,926	0.1137	53,968	32.75	1,648	4.0
2022	807,598.69	0	0	0.0000	888,359	36.00	24,678	0.0
TOTAL	1,517,853.95	142,045	178,831		1,490,808		45,108	

COMPOSITE ANNUAL ACCRUAL RATE	2.97%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	3.84
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	32.94

FortisBC

Account #: 473.00 - Services - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 47
Net Salvage: -85%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1959	1,051,536.91	1,661,122	1,107,739	0.5694	837,604	6.87	121,978	63.0
1960	123,369.20	193,365	128,948	0.5650	99,285	7.18	13,827	62.0
1962	161,444.33	248,932	166,003	0.5558	132,669	7.83	16,950	60.0
1963	226,924.94	346,903	231,336	0.5510	188,475	8.16	23,090	59.0
1964	208,502.82	315,918	210,673	0.5462	175,057	8.51	20,579	58.0
1965	174,399.52	261,820	174,598	0.5412	148,042	8.86	16,709	57.0
1966	214,942.01	319,611	213,137	0.5360	184,506	9.22	20,005	56.0
1967	232,381.93	342,126	228,151	0.5307	201,756	9.60	21,023	55.0
1968	254,442.04	370,754	247,241	0.5252	223,476	9.98	22,390	54.0
1969	185,453.77	267,340	178,279	0.5196	164,811	10.38	15,882	53.0
1970	384,928.77	548,718	365,919	0.5138	346,199	10.78	32,102	52.0
1971	420,748.97	592,833	395,338	0.5079	383,048	11.20	34,189	51.0
1972	519,698.47	723,423	482,423	0.5018	479,019	11.64	41,169	50.0
1973	759,350.55	1,043,750	696,037	0.4955	708,761	12.08	58,675	49.0
1974	982,932.76	1,333,412	889,201	0.4890	929,224	12.54	74,125	48.0
1975	953,245.88	1,275,542	850,610	0.4823	912,895	13.00	70,196	47.0
1976	1,372,338.37	1,810,298	1,207,218	0.4755	1,331,608	13.49	98,734	46.0
1977	1,271,673.05	1,652,748	1,102,155	0.4685	1,250,441	13.98	89,435	45.0
1978	1,426,845.91	1,825,930	1,217,643	0.4613	1,422,022	14.49	98,146	44.0
1979	1,358,140.63	1,710,214	1,140,476	0.4539	1,372,084	15.01	91,419	43.0
1980	1,960,682.97	2,427,862	1,619,048	0.4464	2,008,215	15.54	129,219	42.0
1981	2,920,115.42	3,553,269	2,369,540	0.4386	3,032,674	16.09	188,528	41.0
1982	2,774,660.43	3,315,416	2,210,924	0.4307	2,922,197	16.64	175,578	40.0
1983	3,372,535.73	3,954,208	2,636,910	0.4226	3,602,281	17.21	209,279	39.0
1984	3,070,216.07	3,529,418	2,353,634	0.4144	3,326,265	17.79	186,924	38.0
1985	5,359,468.44	6,035,794	4,025,041	0.4060	5,889,976	18.39	320,306	37.0
1986	2,174,584.39	2,397,171	1,598,582	0.3974	2,424,399	18.99	127,639	36.0
1987	5,247,352.75	5,657,015	3,772,447	0.3886	5,935,155	19.61	302,641	35.0

FortisBC

Account #: 473.00 - Services - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 47
Net Salvage: -85%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	2,853,713.39	3,005,921	2,004,534	0.3797	3,274,836	20.24	161,804	34.0
1989	4,028,365.29	4,141,825	2,762,025	0.3706	4,690,451	20.88	224,649	33.0
1990	145,612,893.74	145,986,208	97,352,629	0.3614	172,031,224	21.53	7,990,503	32.0
1991	23,926,028.80	23,364,597	15,580,958	0.3520	28,682,195	22.19	1,292,530	31.0
1992	37,094,914.63	35,243,167	23,502,323	0.3425	45,123,270	22.86	1,973,654	30.0
1993	39,474,585.32	36,443,815	24,302,989	0.3328	48,724,994	23.55	2,069,427	29.0
1994	36,373,642.82	32,589,578	21,732,745	0.3230	45,558,494	24.24	1,879,662	28.0
1995	36,316,941.94	31,534,815	21,029,364	0.3130	46,156,978	24.94	1,850,727	27.0
1996	35,948,601.80	30,207,495	20,144,226	0.3029	46,360,688	25.65	1,807,299	26.0
1997	33,515,138.33	27,210,860	18,145,884	0.2927	43,857,122	26.37	1,662,929	25.0
1998	28,643,187.09	22,431,401	14,958,645	0.2823	38,031,251	27.10	1,403,149	24.0
1999	25,260,749.84	19,046,620	12,701,464	0.2718	34,030,923	27.84	1,222,186	23.0
2000	27,961,371.90	20,258,314	13,509,496	0.2612	38,219,042	28.59	1,336,633	22.0
2001	21,178,948.24	14,712,532	9,811,226	0.2504	29,369,828	29.35	1,000,626	21.0
2002	23,687,183.94	15,740,297	10,496,603	0.2395	33,324,687	30.12	1,106,473	20.0
2003	24,412,820.37	15,477,883	10,321,609	0.2285	34,842,109	30.89	1,127,839	19.0
2004	27,577,867.11	16,634,479	11,092,899	0.2174	39,926,155	31.68	1,260,458	18.0
2005	33,968,201.52	19,431,203	12,957,928	0.2062	49,883,245	32.47	1,536,426	17.0
2006	35,440,455.92	19,158,716	12,776,217	0.1949	52,788,627	33.27	1,586,859	16.0
2007	42,648,381.02	21,700,533	14,471,257	0.1834	64,428,248	34.07	1,890,882	15.0
2008	44,810,774.60	21,363,894	14,246,765	0.1719	68,653,168	34.89	1,967,829	14.0
2009	32,632,066.13	14,501,705	9,670,633	0.1602	50,698,689	35.71	1,419,741	13.0
2010	34,484,546.25	14,199,277	9,468,956	0.1484	54,327,455	36.54	1,486,829	12.0
2011	36,171,007.21	13,702,881	9,137,928	0.1366	57,778,435	37.38	1,545,890	11.0
2012	42,111,909.94	14,555,618	9,706,586	0.1246	68,200,447	38.22	1,784,472	10.0
2013	43,131,743.38	13,464,865	8,979,204	0.1125	70,814,521	39.07	1,812,553	9.0
2014	44,967,308.44	12,521,497	8,350,109	0.1004	74,839,412	39.93	1,874,469	8.0
2015	43,152,566.63	10,549,644	7,035,155	0.0881	72,797,093	40.79	1,784,721	7.0

FortisBC

Account #: 473.00 - Services - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 47
Net Salvage: -85%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2016	41,727,091.97	8,772,676	5,850,163	0.0758	71,344,957	41.66	1,712,603	6.0
2017	53,947,432.45	9,482,032	6,323,206	0.0634	93,479,545	42.53	2,197,728	5.0
2018	70,229,651.72	9,906,203	6,606,069	0.0508	123,318,787	43.42	2,840,370	4.0
2019	70,716,476.11	7,504,140	5,004,225	0.0383	125,821,256	44.30	2,839,947	3.0
2020	73,568,376.65	5,220,066	3,481,063	0.0256	132,620,434	45.20	2,934,252	2.0
2021	92,759,996.48	3,300,304	2,200,846	0.0128	169,405,147	46.10	3,675,043	1.0
2022	85,799,229.74	0	0	0.0000	158,728,575	47.00	3,377,192	0.0
TOTAL	1,535,297,087.74	761,079,973	507,535,183		2,332,764,429		70,259,091	

COMPOSITE ANNUAL ACCRUAL RATE	4.58%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	15.26
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	34.41

FortisBC

Account #: 474.00 - Meter/Regulator Installations - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 23
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1968	83,278.65	99,934	80,851	0.8090	19,083	1.00	19,083	54.0
1972	30,530.56	36,637	29,641	0.8090	6,996	1.00	6,996	50.0
1973	12,356.90	14,828	11,997	0.8090	2,832	1.00	2,832	49.0
1974	14,528.69	17,434	14,105	0.8090	3,329	1.00	3,329	48.0
1975	2,700.12	3,240	2,621	0.8090	619	1.00	619	47.0
1977	8,986.39	10,784	8,724	0.8090	2,059	1.00	2,059	45.0
1978	99,941.85	119,930	97,028	0.8090	22,902	1.00	22,902	44.0
1979	906.16	1,087	880	0.8090	208	1.00	208	43.0
1980	515.70	619	501	0.8090	118	1.00	118	42.0
1981	131,804.92	158,166	127,963	0.8090	30,203	1.00	30,203	41.0
1982	183,521.08	220,225	178,171	0.8090	42,054	1.00	42,054	40.0
1983	24,854.31	29,825	24,130	0.8090	5,695	1.00	5,695	39.0
1984	4,751,642.88	5,701,971	4,613,122	0.8090	1,088,849	1.00	1,088,849	38.0
1985	96,470.92	115,765	93,659	0.8090	22,107	1.00	22,107	37.0
1986	204,733.50	245,680	198,765	0.8090	46,915	1.00	46,915	36.0
1987	158,778.06	190,534	154,149	0.8090	36,384	1.00	36,384	35.0
1988	266,888.54	320,266	259,108	0.8090	61,158	1.00	61,158	34.0
1989	387,906.45	465,488	376,598	0.8090	88,890	1.00	88,890	33.0
1990	264,482.20	317,379	256,772	0.8090	60,607	1.00	60,607	32.0
1991	171,688.61	206,026	166,684	0.8090	39,343	1.00	39,343	31.0
1992	519,111.24	622,933	503,978	0.8090	118,955	1.00	118,955	30.0
1993	1,045,372.00	1,254,446	1,014,897	0.8090	239,549	1.00	239,549	29.0
1994	729,960.29	875,952	708,680	0.8090	167,272	1.00	167,272	28.0
1995	11,828,795.58	14,194,555	11,483,960	0.8090	2,710,595	1.00	2,710,595	27.0
1996	5,454,784.85	6,545,742	5,295,766	0.8090	1,249,976	1.00	1,249,976	26.0
1997	5,625,918.64	6,751,102	5,461,911	0.8090	1,289,192	1.00	1,289,192	25.0
1998	3,676,908.33	4,412,290	3,569,718	0.8090	842,572	1.00	842,572	24.0
1999	6,190,168.61	7,428,202	6,009,712	0.8090	1,418,491	1.00	1,418,491	23.0

FortisBC

Account #: 474.00 - Meter/Regulator Installations - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 23
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2000	5,481,970.87	6,292,349	5,090,761	0.7739	1,487,604	1.00	1,487,604	22.0
2001	5,638,504.93	6,177,840	4,998,119	0.7387	1,768,087	2.00	884,044	21.0
2002	6,279,697.84	6,552,728	5,301,418	0.7035	2,234,219	3.00	744,740	20.0
2003	6,034,611.56	5,982,137	4,839,787	0.6683	2,401,747	4.00	600,437	19.0
2004	8,449,103.56	7,934,810	6,419,578	0.6332	3,719,347	5.00	743,869	18.0
2005	9,132,267.78	8,099,924	6,553,162	0.5980	4,405,560	6.00	734,260	17.0
2006	9,889,120.93	8,255,266	6,678,839	0.5628	5,188,106	7.00	741,158	16.0
2007	11,275,945.63	8,824,653	7,139,496	0.5276	6,391,639	8.00	798,955	15.0
2008	9,119,921.62	6,661,508	5,389,425	0.4925	5,554,481	9.00	617,165	14.0
2009	12,381,906.76	8,398,163	6,794,448	0.4573	8,063,840	10.00	806,384	13.0
2010	16,430,896.51	10,287,170	8,322,730	0.4221	11,394,346	11.00	1,035,850	12.0
2011	23,093,509.34	13,253,666	10,722,744	0.3869	16,989,467	12.00	1,415,789	11.0
TOTAL	165,174,993.36	147,081,259	118,994,597		79,215,395		20,227,208	

COMPOSITE ANNUAL ACCRUAL RATE 12.25%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.72

COMPOSITE AVERAGE AGE (YEARS) 18.23

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 6.19

FortisBC

Account #: 474.02 - New Meter Installations - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 22
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	20,022,156.64	9,100,980	9,336,895	0.4663	10,685,262	12.00	890,438	10.0
2013	27,372,039.35	11,197,652	11,487,917	0.4197	15,884,123	13.00	1,221,856	9.0
2014	20,967,654.18	7,624,602	7,822,246	0.3731	13,145,409	14.00	938,958	8.0
2015	20,316,882.03	6,464,462	6,632,034	0.3264	13,684,848	15.00	912,323	7.0
2016	22,558,412.60	6,152,294	6,311,773	0.2798	16,246,639	16.00	1,015,415	6.0
2017	20,797,287.36	4,726,656	4,849,180	0.2332	15,948,107	17.00	938,124	5.0
2018	19,530,585.93	3,551,016	3,643,065	0.1865	15,887,521	18.00	882,640	4.0
2019	20,858,443.52	2,844,333	2,918,064	0.1399	17,940,380	19.00	944,231	3.0
2020	20,762,539.40	1,887,504	1,936,431	0.0933	18,826,108	20.00	941,305	2.0
2021	26,986,641.19	1,226,666	1,258,463	0.0466	25,728,178	21.00	1,225,151	1.0
2022	19,888,325.08	0	0	0.0000	19,888,325	22.00	904,015	0.0
TOTAL	240,060,967.28	54,776,165	56,196,067		183,864,900		10,814,456	

COMPOSITE ANNUAL ACCRUAL RATE	4.50%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	5.02
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.98

FortisBC

Account #: 474.10 - Meters/Regulator Installations - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S0
ASL: 19
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	21,779.73	11,578	13,818	0.5076	13,407	10.92	1,228	12.0
2014	155,403.41	59,973	71,575	0.3685	122,680	13.13	9,341	8.0
2015	41,398.32	14,332	17,105	0.3305	34,643	13.74	2,522	7.0
2016	7,472.09	2,278	2,718	0.2910	6,622	14.37	461	6.0
2020	164.90	19	23	0.1112	183	17.23	11	2.0
2021	514,547.11	31,435	37,516	0.0583	605,668	18.07	33,515	1.0
2022	61,421.77	0	0	0.0000	76,777	19.00	4,041	0.0
TOTAL	802,187.33	119,615	142,755		859,979		51,119	

COMPOSITE ANNUAL ACCRUAL RATE	6.37%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.18
COMPOSITE AVERAGE AGE (YEARS)	2.93
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.73

FortisBC

Account #: 475.00 - Systems - Mains - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1959	4,010,269.66	3,891,763	4,056,653	0.7781	1,156,698	16.48	70,198	63.0
1960	92,028.84	88,402	92,148	0.7702	27,490	16.97	1,620	62.0
1961	95,888.13	91,140	95,002	0.7621	29,653	17.48	1,697	61.0
1962	296,749.29	278,976	290,796	0.7538	94,978	17.99	5,278	60.0
1963	629,074.32	584,710	609,483	0.7453	208,313	18.53	11,244	59.0
1964	558,511.79	513,044	534,781	0.7365	191,285	19.07	10,030	58.0
1965	428,895.56	389,203	405,693	0.7276	151,871	19.63	7,738	57.0
1966	888,757.21	796,398	830,140	0.7185	325,244	20.20	16,104	56.0
1967	549,911.09	486,372	506,979	0.7092	207,905	20.78	10,006	55.0
1968	806,436.37	703,710	733,525	0.6997	314,842	21.37	14,733	54.0
1969	1,300,694.54	1,119,284	1,166,707	0.6900	524,196	21.97	23,856	53.0
1970	1,769,628.45	1,501,079	1,564,677	0.6801	735,840	22.59	32,577	52.0
1971	860,598.15	719,215	749,687	0.6701	369,090	23.21	15,899	51.0
1972	1,259,734.16	1,036,763	1,080,690	0.6599	556,965	23.85	23,353	50.0
1973	1,550,585.67	1,256,072	1,309,290	0.6495	706,471	24.50	28,839	49.0
1974	1,961,796.87	1,563,438	1,629,679	0.6390	920,657	25.15	36,602	48.0
1975	1,276,272.17	1,000,107	1,042,481	0.6283	616,673	25.82	23,884	47.0
1976	1,912,987.64	1,473,208	1,535,626	0.6175	951,258	26.49	35,904	46.0
1977	1,790,938.63	1,354,692	1,412,089	0.6065	916,131	27.18	33,707	45.0
1978	1,737,904.66	1,290,464	1,345,139	0.5954	914,137	27.87	32,797	44.0
1979	2,787,562.40	2,030,729	2,116,768	0.5841	1,507,063	28.58	52,740	43.0
1980	3,115,714.04	2,225,466	2,319,756	0.5727	1,730,672	29.29	59,095	42.0
1981	3,532,670.69	2,472,494	2,577,250	0.5612	2,015,222	30.01	67,162	41.0
1982	5,967,880.39	4,089,992	4,263,280	0.5495	3,494,964	30.73	113,719	40.0
1983	9,187,442.84	6,161,428	6,422,480	0.5377	5,521,195	31.47	175,453	39.0
1984	4,406,583.36	2,889,640	3,012,070	0.5258	2,716,488	32.21	84,331	38.0
1985	3,284,240.97	2,104,348	2,193,507	0.5138	2,076,006	32.96	62,980	37.0
1986	2,863,958.98	1,791,575	1,867,482	0.5016	1,855,665	33.72	55,028	36.0

FortisBC

Account #: 475.00 - Systems - Mains - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1987	4,464,333.58	2,724,319	2,839,745	0.4893	2,963,889	34.49	85,940	35.0
1988	2,235,212.81	1,329,432	1,385,758	0.4769	1,520,018	35.26	43,107	34.0
1989	2,754,148.92	1,595,081	1,662,663	0.4644	1,917,731	36.04	53,208	33.0
1990	326,023,023.51	183,681,654	191,464,024	0.4517	232,365,907	36.83	6,309,155	32.0
1991	51,995,968.05	28,468,086	29,674,245	0.4390	37,920,514	37.62	1,007,862	31.0
1992	78,238,309.91	41,581,992	43,343,771	0.4262	58,366,032	38.43	1,518,918	30.0
1993	43,636,930.62	22,486,535	23,439,263	0.4132	33,288,747	39.23	848,456	29.0
1994	48,903,754.59	24,403,950	25,437,916	0.4001	38,136,965	40.05	952,258	28.0
1995	49,958,828.48	24,109,492	25,130,982	0.3869	39,815,495	40.87	974,183	27.0
1996	43,364,927.60	20,209,962	21,066,234	0.3737	35,308,172	41.70	846,763	26.0
1997	43,165,331.66	19,396,665	20,218,478	0.3603	35,896,453	42.53	843,984	25.0
1998	39,169,914.22	16,943,536	17,661,414	0.3468	33,259,475	43.37	766,847	24.0
1999	39,094,735.94	16,249,373	16,937,839	0.3333	33,885,318	44.22	766,325	23.0
2000	32,234,289.04	12,848,905	13,393,297	0.3196	28,511,279	45.07	632,607	22.0
2001	32,794,752.93	12,509,832	13,039,859	0.3059	29,593,320	45.93	644,354	21.0
2002	26,910,527.90	9,800,805	10,216,053	0.2920	24,767,633	46.79	529,336	20.0
2003	30,825,208.47	10,691,144	11,144,115	0.2781	28,928,656	47.66	607,000	19.0
2004	26,597,466.79	8,760,039	9,131,191	0.2641	25,445,515	48.53	524,302	18.0
2005	28,080,740.16	8,755,060	9,126,001	0.2500	27,378,961	49.41	554,108	17.0
2006	33,152,801.63	9,750,304	10,163,413	0.2358	32,935,229	50.29	654,842	16.0
2007	37,005,412.76	10,225,803	10,659,058	0.2216	37,447,979	51.18	731,643	15.0
2008	39,161,779.80	10,121,749	10,550,595	0.2072	40,359,719	52.08	775,001	14.0
2009	35,909,456.12	8,636,468	9,002,385	0.1928	37,679,908	52.97	711,282	13.0
2010	23,925,864.61	5,322,379	5,547,882	0.1784	25,555,742	53.88	474,332	12.0
2011	24,063,427.84	4,916,737	5,125,053	0.1638	26,157,403	54.78	477,466	11.0
2012	25,568,502.11	4,758,409	4,960,017	0.1492	28,279,036	55.69	507,750	10.0
2013	35,155,163.45	5,899,426	6,149,378	0.1346	39,552,334	56.61	698,688	9.0
2014	37,191,097.56	5,557,716	5,793,189	0.1198	42,555,238	57.53	739,729	8.0

FortisBC

Account #: 475.00 - Systems - Mains - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2015	42,794,980.75	5,605,747	5,843,256	0.1050	49,790,219	58.45	851,836	7.0
2016	32,722,421.39	3,680,373	3,836,306	0.0902	38,702,842	59.38	651,822	6.0
2017	40,004,486.21	3,755,823	3,914,952	0.0753	48,090,880	60.31	797,451	5.0
2018	123,232,145.80	9,271,169	9,663,977	0.0603	150,537,812	61.24	2,458,228	4.0
2019	334,269,849.60	18,891,297	19,691,698	0.0453	414,859,106	62.17	6,672,523	3.0
2020	76,970,753.66	2,904,905	3,027,982	0.0303	97,033,997	63.11	1,537,465	2.0
2021	97,363,607.08	1,840,339	1,918,312	0.0152	124,654,377	64.05	1,946,055	1.0
2022	233,747,558.70	0	0	0.0000	303,871,826	65.00	4,674,999	0.0
TOTAL	2,281,611,431.12	621,588,217	647,924,161		2,318,170,699		44,976,399	

COMPOSITE ANNUAL ACCRUAL RATE	1.97%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.28
COMPOSITE AVERAGE AGE (YEARS)	15.26
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	51.38

FortisBC

Account #: 475.10 - Mains - Municipal Land - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life

Survivor Curve: R2.5

ASL: 65

Net Salvage: -25%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	73,652.86	15,754	15,607	0.1695	76,459	53.88	1,419	12.0
2011	4,642.53	912	904	0.1557	4,900	54.78	89	11.0
2012	411,709.24	73,674	72,985	0.1418	441,651	55.69	7,930	10.0
2014	841,421.31	120,903	119,773	0.1139	932,004	57.53	16,201	8.0
2015	268,244.23	33,786	33,470	0.0998	301,835	58.45	5,164	7.0
2016	977.33	106	105	0.0857	1,117	59.38	19	6.0
2020	4,377.41	159	157	0.0288	5,314	63.11	84	2.0
2021	6,700.20	122	121	0.0144	8,255	64.05	129	1.0
2022	141,080.37	0	0	0.0000	176,350	65.00	2,713	0.0
TOTAL	1,752,805.48	245,416	243,121		1,947,886		33,748	

COMPOSITE ANNUAL ACCRUAL RATE	1.93%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.14
COMPOSITE AVERAGE AGE (YEARS)	7.81
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	57.72

FortisBC

Account #: 475.20 - Bio Gas Mains – Private Land

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	41,238.83	8,102	8,414	0.1632	43,134	54.78	787	11.0
2012	10,556.56	1,889	1,962	0.1487	11,234	55.69	202	10.0
2014	3,371.78	484	503	0.1194	3,712	57.53	65	8.0
2020	283,701.67	10,295	10,692	0.0301	343,935	63.11	5,450	2.0
2021	59,176.96	1,076	1,117	0.0151	72,854	64.05	1,137	1.0
2022	12,267.88	0	0	0.0000	15,335	65.00	236	0.0
TOTAL	410,313.68	21,846	22,688		490,204		7,877	

COMPOSITE ANNUAL ACCRUAL RATE 1.92%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.06

COMPOSITE AVERAGE AGE (YEARS) 2.96

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 62.23

FortisBC

Account #: 476.00 - NGV Fuel Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L0
ASL: 7
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2000	141,394.58	118,413	141,395	1.0000	0	1.14	0	22.0
2011	197,271.37	112,673	197,271	1.0000	0	3.00	0	11.0
2015	274,921.70	116,456	274,922	1.0000	0	4.03	0	7.0
TOTAL	613,587.65	347,543	613,588		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	11.74
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	3.04

FortisBC

Account #: 476.10 - CNG Disp Equipment - NG For Transportation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	339,749.44	220,837	220,442	0.6488	119,308	7.00	17,044	13.0
2011	132,172.10	72,695	72,564	0.5490	59,608	9.00	6,623	11.0
2012	1,252,036.26	626,018	624,897	0.4991	627,140	10.00	62,714	10.0
2013	971,702.35	437,266	436,483	0.4492	535,220	11.00	48,656	9.0
2014	1,054,059.26	421,624	420,868	0.3993	633,191	12.00	52,766	8.0
2015	1,991,623.47	697,068	695,819	0.3494	1,295,804	13.00	99,677	7.0
2016	2,137,163.60	641,149	640,000	0.2995	1,497,163	14.00	106,940	6.0
2017	2,787,241.98	696,811	695,562	0.2496	2,091,680	15.00	139,445	5.0
2018	377,228.58	75,446	75,311	0.1996	301,918	16.00	18,870	4.0
2019	1,525,266.84	228,790	228,380	0.1497	1,296,887	17.00	76,287	3.0
2020	507,718.94	50,772	50,681	0.0998	457,038	18.00	25,391	2.0
2021	1,879,526.25	93,976	93,808	0.0499	1,785,718	19.00	93,985	1.0
2022	2,165,375.98	0	0	0.0000	2,165,376	20.00	108,269	0.0
TOTAL	17,120,865.05	4,262,451	4,254,815		12,866,050		856,667	

COMPOSITE ANNUAL ACCRUAL RATE	5.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	4.98
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	15.02

FortisBC

Account #: 476.20 - LNG Disp Equipment - NG For Transportation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	584,763.04	321,620	334,694	0.5724	250,069	9.00	27,785	11.0
2012	34,417.99	17,209	17,909	0.5203	16,509	10.00	1,651	10.0
2013	2,471,637.07	1,112,237	1,157,450	0.4683	1,314,187	11.00	119,472	9.0
2014	2,610,768.92	1,044,308	1,086,760	0.4163	1,524,009	12.00	127,001	8.0
2015	2,385,608.80	834,963	868,905	0.3642	1,516,704	13.00	116,670	7.0
2016	2,861,325.61	858,398	893,292	0.3122	1,968,033	14.00	140,574	6.0
2017	349,603.03	87,401	90,954	0.2602	258,649	15.00	17,243	5.0
2018	1,674,303.48	334,861	348,473	0.2081	1,325,830	16.00	82,864	4.0
2019	741,325.48	111,199	115,719	0.1561	625,606	17.00	36,800	3.0
TOTAL	13,713,753.42	4,722,194	4,914,155		8,799,598		670,060	

COMPOSITE ANNUAL ACCRUAL RATE	4.89%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	6.89
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	13.11

FortisBC

Account #: 476.30 - CNG Foundation - NG For Transportation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	375,339.17	187,670	188,068	0.5011	187,272	10.00	18,727	10.0
2013	160,698.23	72,314	72,468	0.4510	88,231	11.00	8,021	9.0
2014	142,333.63	56,933	57,054	0.4008	85,279	12.00	7,107	8.0
2015	546,001.10	191,100	191,506	0.3507	354,495	13.00	27,269	7.0
2016	447,942.39	134,383	134,668	0.3006	313,275	14.00	22,377	6.0
2017	515,413.64	128,853	129,127	0.2505	386,287	15.00	25,752	5.0
2018	53,137.04	10,627	10,650	0.2004	42,487	16.00	2,655	4.0
2019	370,265.65	55,540	55,658	0.1503	314,608	17.00	18,506	3.0
2020	5,585.00	559	560	0.1002	5,025	18.00	279	2.0
2021	278,608.57	13,930	13,960	0.0501	264,649	19.00	13,929	1.0
2022	265,924.48	0	0	0.0000	265,924	20.00	13,296	0.0
TOTAL	3,161,248.90	851,910	853,717		2,307,532		157,918	

COMPOSITE ANNUAL ACCRUAL RATE	5.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.27
COMPOSITE AVERAGE AGE (YEARS)	5.39
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.61

FortisBC

Account #: 476.40 - LNG Foundation - NG For Transportation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	4,372.08	2,405	2,590	0.5925	1,782	9.00	198	11.0
2013	581,529.49	261,688	281,891	0.4847	299,638	11.00	27,240	9.0
2014	311,561.09	124,624	134,246	0.4309	177,315	12.00	14,776	8.0
2015	86,846.19	30,396	32,743	0.3770	54,103	13.00	4,162	7.0
2021	64,500.28	3,225	3,474	0.0539	61,026	19.00	3,212	1.0
TOTAL	1,048,809.13	422,339	454,944		593,865		49,588	

COMPOSITE ANNUAL ACCRUAL RATE 4.73%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.43

COMPOSITE AVERAGE AGE (YEARS) 8.05

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 11.95

FortisBC

Account #: 476.50 - LNG Pumps - NG For Transportation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	62,632.40	56,369	62,632	1.0000	0	1.00	0	9.0
2015	14,247.61	9,973	14,248	1.0000	0	3.00	0	7.0
TOTAL	76,880.01	66,342	76,880		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	8.63
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	1.37

FortisBC

Account #: 476.60 - CNG Dehydrator - NG For Transportation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	52,224.55	26,112	26,391	0.5053	25,834	10.00	2,583	10.0
2013	70,880.43	31,896	32,236	0.4548	38,644	11.00	3,513	9.0
2014	53,098.84	21,240	21,466	0.4043	31,633	12.00	2,636	8.0
2015	81,898.65	28,665	28,970	0.3537	52,929	13.00	4,071	7.0
2016	138,189.72	41,457	41,899	0.3032	96,291	14.00	6,878	6.0
2017	14,348.13	3,587	3,625	0.2527	10,723	15.00	715	5.0
2018	6,460.99	1,292	1,306	0.2021	5,155	16.00	322	4.0
2019	59,295.55	8,894	8,989	0.1516	50,306	17.00	2,959	3.0
2020	155,677.20	15,568	15,734	0.1011	139,944	18.00	7,775	2.0
2021	99,471.49	4,974	5,027	0.0505	94,445	19.00	4,971	1.0
2022	72,498.65	0	0	0.0000	72,499	20.00	3,625	0.0
TOTAL	804,044.20	183,684	185,642		618,402		40,048	

COMPOSITE ANNUAL ACCRUAL RATE	4.98%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	4.57
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	15.43

FortisBC

Account #: 477.10 - Measuring and Regulating - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 34
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1958	39,802.79	44,579	44,579	1.0000	0	1.00	0	64.0
1963	838.85	921	940	1.0000	0	1.00	0	59.0
1964	214.27	232	240	1.0000	0	1.12	0	58.0
1965	784.71	838	879	1.0000	0	1.59	0	57.0
1966	410.59	434	460	1.0000	0	1.88	0	56.0
1969	1,644.28	1,700	1,842	1.0000	0	2.62	0	53.0
1970	4,174.35	4,285	4,675	1.0000	0	2.84	0	52.0
1971	5,454.34	5,559	6,109	1.0000	0	3.06	0	51.0
1973	86,591.83	86,993	96,983	1.0000	0	3.50	0	49.0
1974	1,055.44	1,052	1,181	0.9993	1	3.73	0	48.0
1975	2,378.93	2,354	2,642	0.9916	22	3.96	6	47.0
1976	19,561.97	19,204	21,554	0.9838	355	4.20	85	46.0
1977	7,070.53	6,884	7,727	0.9757	192	4.44	43	45.0
1978	4,340.83	4,191	4,703	0.9674	158	4.69	34	44.0
1979	4,634.28	4,434	4,976	0.9588	214	4.96	43	43.0
1980	77,069.66	73,040	81,979	0.9497	4,339	5.23	830	42.0
1981	7,906.43	7,418	8,326	0.9402	530	5.52	96	41.0
1982	50,578.92	46,943	52,687	0.9301	3,961	5.83	680	40.0
1983	184,408.23	169,171	189,874	0.9193	16,663	6.15	2,709	39.0
1984	121,911.52	110,444	123,960	0.9079	12,581	6.50	1,936	38.0
1985	72,567.14	64,856	72,793	0.8956	8,483	6.87	1,235	37.0
1986	547,859.30	482,517	541,567	0.8826	72,036	7.26	9,917	36.0
1987	462,697.16	401,112	450,200	0.8687	68,021	7.68	8,853	35.0
1988	5,873,448.38	5,005,502	5,618,070	0.8540	960,192	8.13	118,121	34.0
1989	213,048.52	178,257	200,072	0.8385	38,542	8.60	4,482	33.0
1990	41,673.47	34,186	38,369	0.8221	8,305	9.10	913	32.0
1991	2,613,762.06	2,099,189	2,356,085	0.8048	571,328	9.62	59,394	31.0
1992	2,143,162.88	1,682,661	1,888,583	0.7868	511,760	10.17	50,342	30.0

FortisBC

Account #: 477.10 - Measuring and Regulating - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 34
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1993	1,610,758.11	1,234,414	1,385,480	0.7680	418,569	10.74	38,989	29.0
1994	2,684,722.33	2,005,060	2,250,437	0.7484	756,452	11.33	66,777	28.0
1995	4,554,823.88	3,309,619	3,714,646	0.7282	1,386,757	11.94	116,125	27.0
1996	3,080,121.42	2,173,714	2,439,731	0.7072	1,010,005	12.58	80,311	26.0
1997	3,371,254.64	2,306,578	2,588,855	0.6856	1,186,951	13.23	89,717	25.0
1998	2,313,738.02	1,531,809	1,719,270	0.6635	872,117	13.90	62,733	24.0
1999	2,274,524.46	1,454,174	1,632,135	0.6407	915,333	14.59	62,730	23.0
2000	3,080,058.10	1,897,505	2,129,720	0.6174	1,319,945	15.30	86,281	22.0
2001	4,317,827.21	2,557,293	2,870,252	0.5935	1,965,715	16.02	122,699	21.0
2002	2,831,674.79	1,608,275	1,805,094	0.5692	1,366,382	16.76	81,534	20.0
2003	7,242,862.51	3,934,073	4,415,520	0.5443	3,696,486	17.51	211,094	19.0
2004	3,360,571.40	1,740,440	1,953,432	0.5190	1,810,407	18.28	99,048	18.0
2005	4,632,933.00	2,280,227	2,559,278	0.4932	2,629,607	19.06	137,973	17.0
2006	7,659,392.11	3,569,352	4,006,165	0.4670	4,572,354	19.85	230,307	16.0
2007	5,335,102.52	2,344,325	2,631,221	0.4403	3,344,094	20.66	161,858	15.0
2008	3,268,089.25	1,347,788	1,512,728	0.4133	2,147,532	21.48	99,976	14.0
2009	4,789,704.79	1,844,056	2,069,729	0.3858	3,294,740	22.31	147,664	13.0
2010	3,327,395.30	1,188,604	1,334,064	0.3580	2,392,619	23.16	103,327	12.0
2011	4,062,581.25	1,336,851	1,500,454	0.3298	3,049,637	24.01	127,012	11.0
2012	4,177,223.06	1,255,511	1,409,159	0.3012	3,269,331	24.88	131,426	10.0
2013	7,632,216.61	2,073,858	2,327,655	0.2723	6,220,428	25.75	241,558	9.0
2014	2,108,582.90	511,481	574,075	0.2431	1,787,537	26.64	67,109	8.0
2015	9,035,605.64	1,925,653	2,161,312	0.2136	7,958,566	27.53	289,083	7.0
2016	13,277,265.16	2,434,838	2,732,811	0.1838	12,137,726	28.43	426,889	6.0
2017	13,896,287.47	2,131,484	2,392,333	0.1537	13,171,509	29.34	448,871	5.0
2018	12,322,524.10	1,517,383	1,703,079	0.1234	12,098,148	30.26	399,782	4.0
2019	33,977,736.25	3,148,453	3,533,757	0.0929	34,521,307	31.19	1,106,912	3.0
2020	11,570,771.41	717,053	804,806	0.0621	12,154,458	32.12	378,423	2.0

FortisBC

Account #: 477.10 - Measuring and Regulating - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 34
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2021	8,561,044.19	266,090	298,654	0.0311	9,289,716	33.06	281,026	1.0
2022	24,613,889.21	0	226	0.0000	27,567,330	34.00	810,810	0.0
TOTAL	227,560,332.75	66,184,920	74,278,132		180,589,440		6,967,763	

COMPOSITE ANNUAL ACCRUAL RATE 3.06%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.33

COMPOSITE AVERAGE AGE (YEARS) 10.31

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 25.17

FortisBC

Account #: 477.20 - Telemetry - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 20
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1959	202.89	213	211	0.9886	2	1.00	2	63.0
1969	9,476.34	9,950	9,837	0.9886	113	1.00	113	53.0
1971	140.82	148	146	0.9886	2	1.00	2	51.0
1973	1,388.40	1,458	1,441	0.9886	17	1.00	17	49.0
1976	195.90	206	203	0.9886	2	1.00	2	46.0
1979	13,885.50	14,580	14,414	0.9886	166	1.00	166	43.0
1982	17,668.21	18,552	18,341	0.9886	211	1.00	211	40.0
1983	46,467.78	48,791	48,236	0.9886	555	1.00	555	39.0
1984	2,366.11	2,484	2,456	0.9886	28	1.00	28	38.0
1985	28,968.47	30,417	30,071	0.9886	346	1.00	346	37.0
1986	54,022.68	56,724	56,079	0.9886	645	1.00	645	36.0
1987	606.69	637	630	0.9886	7	1.00	7	35.0
1988	31,566.07	33,144	32,768	0.9886	377	1.00	377	34.0
1989	4,017.83	4,113	4,066	0.9639	152	1.00	152	33.0
1990	14,049.49	14,329	14,166	0.9603	586	1.00	586	32.0
1991	42,391.77	42,820	42,333	0.9511	2,178	1.00	2,178	31.0
1992	30,822.33	30,772	30,422	0.9400	1,941	1.00	1,941	30.0
1993	31,855.60	31,401	31,044	0.9281	2,404	1.22	1,964	29.0
1994	103,964.92	101,128	99,978	0.9159	9,185	1.47	6,239	28.0
1995	120,820.24	115,930	114,612	0.9034	12,249	1.72	7,108	27.0
1996	905,935.67	857,105	847,361	0.8908	103,872	1.98	52,485	26.0
1997	369,611.60	344,509	340,592	0.8776	47,500	2.25	21,148	25.0
1998	240,416.42	220,461	217,954	0.8634	34,483	2.53	13,611	24.0
1999	170,753.75	153,739	151,991	0.8477	27,300	2.85	9,578	23.0
2000	226,288.92	199,532	197,264	0.8302	40,340	3.20	12,588	22.0
2001	269,806.57	232,278	229,637	0.8106	53,660	3.60	14,898	21.0
2002	124,991.38	104,694	103,504	0.7887	27,737	4.05	6,856	20.0
2003	325,292.37	264,073	261,071	0.7644	80,486	4.54	17,740	19.0

FortisBC

Account #: 477.20 - Telemetry - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 20
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2004	83,809.10	65,665	64,918	0.7377	23,082	5.08	4,547	18.0
2005	30,760.95	23,157	22,894	0.7088	9,405	5.66	1,661	17.0
2006	189,560.91	136,463	134,911	0.6778	64,127	6.29	10,199	16.0
2007	47,814.20	32,749	32,377	0.6449	17,828	6.95	2,564	15.0
2008	191,400.25	124,048	122,638	0.6102	78,332	7.66	10,233	14.0
2009	104,514.64	63,712	62,988	0.5740	46,753	8.39	5,573	13.0
2010	443,077.92	252,346	249,477	0.5362	215,755	9.15	23,575	12.0
2011	341,144.36	180,127	178,079	0.4971	180,123	9.94	18,116	11.0
2012	1,089,572.03	528,570	522,561	0.4568	621,490	10.76	57,761	10.0
2013	1,473,925.41	649,900	642,511	0.4152	905,110	11.60	78,018	9.0
2014	1,545,624.89	611,333	604,383	0.3724	1,018,523	12.47	81,703	8.0
2015	1,200,323.25	418,888	414,126	0.3286	846,214	13.35	63,374	7.0
2016	1,800,811.80	542,742	536,572	0.2838	1,354,281	14.26	94,975	6.0
2017	1,921,606.49	485,883	480,359	0.2381	1,537,328	15.18	101,248	5.0
2018	2,108,189.97	428,988	424,111	0.1916	1,789,488	16.12	110,982	4.0
2019	4,968,751.26	762,234	753,568	0.1444	4,463,621	17.08	261,367	3.0
2020	1,622,453.81	166,666	164,771	0.0967	1,538,805	18.04	85,284	2.0
2021	3,890,146.47	200,554	198,274	0.0485	3,886,380	19.02	204,353	1.0
2022	2,795,003.07	0	0	0.0000	2,934,753	20.00	146,737	0.0
TOTAL	29,036,465.50	8,608,215	8,510,348		21,977,941		1,533,813	

COMPOSITE ANNUAL ACCRUAL RATE	5.28%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	6.69
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.36

FortisBC

Account #: 477.40 - Measuring and Regulating - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	257,693.82	87,455	100,319	0.3893	157,375	19.82	7,941	12.0
2011	4,049.98	1,268	1,455	0.3592	2,595	20.61	126	11.0
2012	316.05	91	104	0.3286	212	21.41	10	10.0
2013	573,338.21	148,746	170,624	0.2976	402,714	22.22	18,127	9.0
2014	574,444.01	133,265	152,866	0.2661	421,578	23.04	18,297	8.0
2015	484,624.43	98,946	113,499	0.2342	371,125	23.87	15,545	7.0
2016	128,806.43	22,669	26,003	0.2019	102,803	24.72	4,159	6.0
2017	519,493.78	76,601	87,868	0.1691	431,626	25.58	16,876	5.0
2018	162,455.04	19,264	22,098	0.1360	140,357	26.44	5,308	4.0
2019	22,485.17	2,010	2,306	0.1025	20,180	27.32	739	3.0
2020	109,132.51	6,535	7,496	0.0687	101,637	28.20	3,604	2.0
2021	680,376.70	20,463	23,472	0.0345	656,904	29.10	22,576	1.0
2022	802,767.00	0	0	0.0000	802,767	30.00	26,759	0.0
TOTAL	4,319,983.13	617,312	708,109		3,611,874		140,067	

COMPOSITE ANNUAL ACCRUAL RATE	3.24%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.16
COMPOSITE AVERAGE AGE (YEARS)	4.92
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	25.71

FortisBC

Account #: 478.20 - Instruments - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1983	361,761.94	361,762	358,826	0.9919	2,936	1.00	2,936	39.0
1984	2,933.10	2,933	2,909	0.9919	24	1.00	24	38.0
1985	5,631.05	5,631	5,585	0.9919	46	1.00	46	37.0
1986	23,355.78	23,356	23,166	0.9919	190	1.00	190	36.0
1987	96,807.57	96,808	96,022	0.9919	786	1.00	786	35.0
1988	115,160.76	111,870	110,962	0.9635	4,198	1.00	4,198	34.0
1989	93,986.33	88,616	87,896	0.9352	6,090	2.00	3,045	33.0
1990	165,438.23	151,258	150,030	0.9069	15,408	3.00	5,136	32.0
1991	344,502.95	305,131	302,655	0.8785	41,848	4.00	10,462	31.0
1992	754,659.62	646,851	641,601	0.8502	113,059	5.00	22,612	30.0
1993	835,661.00	692,405	686,785	0.8218	148,876	6.00	24,813	29.0
1994	901,190.00	720,952	715,100	0.7935	186,090	7.00	26,584	28.0
1995	785,627.00	606,055	601,136	0.7652	184,491	8.00	23,061	27.0
1996	655,670.92	487,070	483,117	0.7368	172,554	9.00	19,173	26.0
1997	407,431.51	291,023	288,660	0.7085	118,771	10.00	11,877	25.0
1998	53,827.57	36,910	36,611	0.6801	17,217	11.00	1,565	24.0
1999	354,932.07	233,241	231,348	0.6518	123,584	12.00	10,299	23.0
2000	253,791.63	159,526	158,231	0.6235	95,560	13.00	7,351	22.0
2001	375,867.06	225,520	223,690	0.5951	152,177	14.00	10,870	21.0
2002	356,603.79	203,774	202,120	0.5668	154,484	15.00	10,299	20.0
2003	1,390,662.14	754,931	748,804	0.5385	641,859	16.00	40,116	19.0
2004	1,363,377.05	701,165	695,474	0.5101	667,903	17.00	39,288	18.0
2005	288,290.84	140,027	138,890	0.4818	149,400	18.00	8,300	17.0
2006	508,057.41	232,255	230,370	0.4534	277,688	19.00	14,615	16.0
2007	447,712.81	191,877	190,320	0.4251	257,393	20.00	12,870	15.0
2008	308,436.81	123,375	122,373	0.3968	186,063	21.00	8,860	14.0
2009	53,796.50	19,982	19,819	0.3684	33,977	22.00	1,544	13.0
2010	174,068.52	59,681	59,196	0.3401	114,872	23.00	4,994	12.0

FortisBC

Account #: 478.20 - Instruments - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	291,813.18	91,713	90,968	0.3117	200,845	24.00	8,369	11.0
2012	118,228.13	33,779	33,505	0.2834	84,723	25.00	3,389	10.0
2013	55,114.41	14,172	14,057	0.2551	41,057	26.00	1,579	9.0
2014	198,933.39	45,470	45,101	0.2267	153,832	27.00	5,697	8.0
2015	229,700.63	45,940	45,567	0.1984	184,133	28.00	6,576	7.0
2016	583,753.69	100,072	99,260	0.1700	484,494	29.00	16,707	6.0
2017	445,044.83	63,578	63,062	0.1417	381,983	30.00	12,733	5.0
2018	262,960.10	30,053	29,809	0.1134	233,151	31.00	7,521	4.0
2019	338,968.09	29,054	28,819	0.0850	310,150	32.00	9,692	3.0
2020	430,688.12	24,611	24,411	0.0567	406,277	33.00	12,311	2.0
2021	435,523.74	12,444	12,343	0.0283	423,181	34.00	12,447	1.0
2022	837,496.49	0	0	0.0000	837,496	35.00	23,928	0.0
TOTAL	15,707,466.76	8,164,869	8,098,600		7,608,867		446,863	

COMPOSITE ANNUAL ACCRUAL RATE	2.84%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	18.29
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.84

FortisBC

Account #: 478.30 - Meters - Bio Gas

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life

Survivor Curve: R2.5

ASL: 18

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	7,334.33	4,135	5,090	0.6940	2,245	7.85	286	12.0
2013	2,963.75	1,302	1,603	0.5408	1,361	10.09	135	9.0
2015	20,495.49	7,157	8,808	0.4298	11,687	11.71	998	7.0
2016	4,483.34	1,355	1,667	0.3719	2,816	12.56	224	6.0
2018	1,214.66	249	306	0.2522	908	14.31	63	4.0
2020	152.23	16	19	0.1279	133	16.13	8	2.0
2021	2,894.21	151	186	0.0643	2,708	17.06	159	1.0
2022	44,675.25	0	0	0.0000	44,675	18.00	2,482	0.0
TOTAL	84,213.26	14,365	17,680		66,533		4,355	

COMPOSITE ANNUAL ACCRUAL RATE	5.17%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.21
COMPOSITE AVERAGE AGE (YEARS)	3.48
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.93

FortisBC

Account #: 482.10 - Stuctures (Frame) - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 25
Net Salvage: -4%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	580,626.78	519,007	603,852	1.0000	0	3.51	0	34.0
1990	321.21	279	334	1.0000	0	4.14	0	32.0
1991	124,767.12	106,499	129,758	1.0000	0	4.48	0	31.0
1992	7,098.31	5,954	7,293	0.9879	89	4.84	18	30.0
1993	4,057.00	3,340	4,091	0.9696	128	5.21	25	29.0
1994	884,927.35	714,070	874,585	0.9503	45,739	5.60	8,164	28.0
1995	2,417,868.71	1,909,157	2,338,314	0.9299	176,269	6.02	29,285	27.0
1996	956,872.12	738,057	903,964	0.9084	91,183	6.46	14,118	26.0
1997	97,491.90	73,320	89,801	0.8857	11,590	6.92	1,675	25.0
1998	417,610.66	305,609	374,306	0.8618	60,009	7.41	8,100	24.0
1999	128,334.49	91,188	111,686	0.8368	21,782	7.92	2,750	23.0
2000	212,050.32	145,957	178,766	0.8106	41,766	8.45	4,940	22.0
2001	965,021.89	641,833	786,110	0.7833	217,513	9.01	24,136	21.0
2002	887,944.35	569,109	697,038	0.7548	226,424	9.59	23,603	20.0
2003	229,116.44	141,097	172,814	0.7253	65,467	10.20	6,421	19.0
2004	128,412.11	75,741	92,767	0.6946	40,781	10.82	3,769	18.0
2005	190,362.28	107,166	131,256	0.6630	66,721	11.47	5,818	17.0
2006	162,367.17	86,906	106,441	0.6303	62,421	12.13	5,144	16.0
2007	111,007.99	56,250	68,894	0.5967	46,555	12.82	3,632	15.0
2008	104,998.31	50,127	61,395	0.5622	47,803	13.52	3,535	14.0
2009	1,538,051.38	688,045	842,710	0.5268	756,864	14.25	53,127	13.0
2010	1,679,007.35	699,417	856,638	0.4906	889,529	14.99	59,356	12.0
2011	2,792,753.56	1,075,455	1,317,206	0.4535	1,587,258	15.74	100,823	11.0
2012	943,571.42	333,024	407,885	0.4157	573,430	16.52	34,720	10.0
2013	2,379,616.42	761,831	933,082	0.3770	1,541,719	17.30	89,095	9.0
2014	637,885.58	182,906	224,021	0.3377	439,380	18.11	24,265	8.0
2015	487,841.47	123,293	151,008	0.2976	356,348	18.92	18,830	7.0
2016	2,079,040.07	453,548	555,500	0.2569	1,606,701	19.76	81,327	6.0

FortisBC

Account #: 482.10 - Stuctures (Frame) - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 25
Net Salvage: -4%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	1,565,622.27	286,548	350,961	0.2155	1,277,286	20.60	62,003	5.0
2018	933,321.44	137,546	168,465	0.1736	802,189	21.46	37,385	4.0
2019	1,165,026.87	129,573	158,699	0.1310	1,052,929	22.33	47,161	3.0
2020	965,570.69	72,019	88,208	0.0878	915,986	23.21	39,470	2.0
2021	1,424,869.46	53,435	65,447	0.0442	1,416,417	24.10	58,776	1.0
TOTAL	27,203,434.49	11,337,307	13,853,295		14,438,276		851,471	

COMPOSITE ANNUAL ACCRUAL RATE 3.13%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.51

COMPOSITE AVERAGE AGE (YEARS) 13.00

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 14.98

FortisBC

Account #: 482.20 - Structures (Masonry) - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 65
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	77,894.37	60,042	80,316	0.9373	5,368	19.45	276	62.0
1967	70,596.50	49,943	66,807	0.8603	10,850	23.20	468	55.0
1970	8,832.70	5,989	8,011	0.8245	1,705	24.93	68	52.0
1974	688.62	438	587	0.7743	171	27.37	6	48.0
1975	181.34	114	152	0.7614	48	28.00	2	47.0
1976	248,769.72	153,067	204,751	0.7482	68,896	28.64	2,405	46.0
1977	8,927.00	5,395	7,217	0.7349	2,603	29.29	89	45.0
1978	20,357.44	12,078	16,156	0.7215	6,237	29.94	208	44.0
1979	305,827.48	178,020	238,128	0.7079	98,282	30.60	3,211	43.0
1980	4,921.37	2,809	3,757	0.6941	1,656	31.27	53	42.0
1981	8,968.67	5,016	6,710	0.6801	3,156	31.95	99	41.0
1982	7,755.47	4,248	5,682	0.6660	2,849	32.63	87	40.0
1983	11,041.06	5,918	7,917	0.6518	4,229	33.33	127	39.0
1984	45,537.81	23,870	31,930	0.6374	18,162	34.03	534	38.0
1985	1,086.55	557	745	0.6229	451	34.73	13	37.0
1986	246.00	123	165	0.6082	106	35.44	3	36.0
1987	3,350.06	1,635	2,187	0.5934	1,498	36.16	41	35.0
1988	507,648.78	241,477	323,012	0.5784	235,401	36.89	6,381	34.0
1989	431,062.55	199,696	267,124	0.5634	207,045	37.63	5,503	33.0
1990	114,839.26	51,763	69,240	0.5481	57,083	38.37	1,488	32.0
1991	27,623.86	12,102	16,188	0.5328	14,198	39.11	363	31.0
1992	3,310,605.15	1,408,210	1,883,694	0.5173	1,757,971	39.86	44,098	30.0
1993	141,792.70	58,491	78,240	0.5016	77,732	40.62	1,913	29.0
1994	3,663,964.63	1,463,972	1,958,284	0.4859	2,072,078	41.39	50,063	28.0
1995	3,914,546.17	1,512,950	2,023,800	0.4700	2,282,201	42.16	54,130	27.0
1996	4,199,819.35	1,567,964	2,097,389	0.4540	2,522,413	42.94	58,744	26.0
1997	446,730.18	160,854	215,167	0.4379	276,236	43.72	6,318	25.0
1998	1,376,344.34	477,199	638,326	0.4216	875,653	44.51	19,672	24.0

FortisBC

Account #: 482.20 - Structures (Masonry) - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 65
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1999	227,140.28	75,695	101,253	0.4052	148,601	45.31	3,280	23.0
2000	524,305.01	167,620	224,216	0.3888	352,519	46.11	7,645	22.0
2001	1,290,736.18	395,024	528,405	0.3722	891,405	46.92	19,000	21.0
2002	492,648.17	144,003	192,625	0.3555	349,288	47.73	7,318	20.0
2003	1,485,841.92	413,759	553,465	0.3386	1,080,961	48.55	22,267	19.0
2004	998,794.21	264,222	353,436	0.3217	745,237	49.37	15,096	18.0
2005	51,569,336.48	12,919,525	17,281,819	0.3047	39,444,451	50.20	785,807	17.0
2006	1,124,782.67	265,923	355,712	0.2875	881,549	51.03	17,275	16.0
2007	3,234,800.57	718,890	961,624	0.2702	2,596,657	51.87	50,063	15.0
2008	987,986.97	205,459	274,832	0.2529	811,953	52.71	15,404	14.0
2009	1,621,202.30	313,873	419,853	0.2354	1,363,470	53.56	25,457	13.0
2010	1,354,068.57	242,594	324,506	0.2179	1,164,970	54.41	21,410	12.0
2011	8,202,835.99	1,350,535	1,806,545	0.2002	7,216,574	55.27	130,567	11.0
2012	13,405,655.92	2,011,364	2,690,504	0.1825	12,055,717	56.13	214,766	10.0
2013	1,227,074.37	166,100	222,184	0.1646	1,127,597	57.00	19,782	9.0
2014	47,743.01	5,758	7,702	0.1467	44,815	57.87	774	8.0
2015	1,336,452.62	141,367	189,100	0.1286	1,280,998	58.75	21,804	7.0
2016	2,875,651.84	261,325	349,562	0.1105	2,813,655	59.63	47,185	6.0
2017	2,782,157.94	211,164	282,463	0.0923	2,777,910	60.52	45,904	5.0
2018	4,184,520.45	254,650	340,633	0.0740	4,262,340	61.40	69,415	4.0
2019	1,803,676.78	82,497	110,352	0.0556	1,873,692	62.30	30,077	3.0
2020	3,519,963.02	107,567	143,887	0.0372	3,728,073	63.19	58,994	2.0
2021	2,849,602.64	43,619	58,347	0.0186	3,076,216	64.10	47,994	1.0
2022	5,904,846.93	0	0	0.0000	6,495,332	65.00	99,928	0.0

FortisBC

Account #: 482.20 - Structures (Masonry) - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 65
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	132,011,783.97	28,426,471	38,024,706		107,188,256		2,033,575	

COMPOSITE ANNUAL ACCRUAL RATE	1.54%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	14.71
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	52.28

FortisBC

Account #: 483.10 - Computer Hardware - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	9,246,992.32	9,246,992	9,078,868	0.9818	168,124	1.00	168,124	4.0
2019	10,427,011.43	7,820,259	7,678,074	0.7364	2,748,937	1.00	2,748,937	3.0
2020	12,047,039.51	6,023,520	5,914,003	0.4909	6,133,037	2.00	3,066,518	2.0
2021	9,355,525.33	2,338,881	2,296,357	0.2455	7,059,168	3.00	2,353,056	1.0
2022	9,638,244.54	0	0	0.0000	9,638,245	4.00	2,409,561	0.0
TOTAL	50,714,813.13	25,429,652	24,967,302		25,747,511		10,746,196	

COMPOSITE ANNUAL ACCRUAL RATE	21.19%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	2.01
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.18

FortisBC

Account #: 483.20 - Computer Software (12.5%) - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life

Survivor Curve: SQ

ASL: 8

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2015	634,939.21	555,572	555,572	0.8750	79,367	1.00	79,367	7.0
2016	777,670.56	583,253	583,253	0.7500	194,418	2.00	97,209	6.0
2017	1,037,873.74	648,671	648,671	0.6250	389,203	3.00	129,734	5.0
2018	662,440.09	331,220	331,220	0.5000	331,220	4.00	82,805	4.0
2019	1,047,205.88	392,702	392,702	0.3750	654,504	5.00	130,901	3.0
2020	1,223,393.48	305,848	305,848	0.2500	917,545	6.00	152,924	2.0
2021	1,661,681.56	207,710	207,710	0.1250	1,453,971	7.00	207,710	1.0
2022	1,499,917.99	0	0	0.0000	1,499,918	8.00	187,490	0.0
TOTAL	8,545,122.51	3,024,977	3,024,977		5,520,146		1,068,140	

COMPOSITE ANNUAL ACCRUAL RATE	12.50%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	2.83
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.17

FortisBC

Account #: 483.30 - Office Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	41,659.52	41,660	40,977	0.9836	683	1.00	683	15.0
2008	73,406.61	68,513	67,390	0.9180	6,017	1.00	6,017	14.0
2009	189,359.45	164,112	161,421	0.8525	27,938	2.00	13,969	13.0
2010	109,842.14	87,874	86,433	0.7869	23,409	3.00	7,803	12.0
2011	532,856.02	390,761	384,356	0.7213	148,500	4.00	37,125	11.0
2012	92,948.69	61,966	60,950	0.6557	31,999	5.00	6,400	10.0
2013	391,007.25	234,604	230,759	0.5902	160,248	6.00	26,708	9.0
2014	122,225.95	65,187	64,119	0.5246	58,107	7.00	8,301	8.0
2015	207,179.22	96,684	95,099	0.4590	112,080	8.00	14,010	7.0
2016	31,031.03	12,412	12,209	0.3934	18,822	9.00	2,091	6.0
2017	218,652.35	72,884	71,689	0.3279	146,963	10.00	14,696	5.0
2018	107,176.46	28,580	28,112	0.2623	79,065	11.00	7,188	4.0
2019	28,591.75	5,718	5,625	0.1967	22,967	12.00	1,914	3.0
2020	105,022.31	14,003	13,773	0.1311	91,249	13.00	7,019	2.0
2022	52,323.53	0	0	0.0000	52,324	15.00	3,488	0.0
TOTAL	2,303,282.28	1,344,958	1,322,912		980,370		157,412	

COMPOSITE ANNUAL ACCRUAL RATE 6.83%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.57

COMPOSITE AVERAGE AGE (YEARS) 8.76

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 6.26

FortisBC

Account #: 483.40 - Furniture - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2001	71,013.15	71,013	70,322	0.9903	691	1.00	691	21.0
2002	79,930.14	79,930	79,152	0.9903	778	1.00	778	20.0
2003	260,885.66	247,841	245,430	0.9408	15,456	1.00	15,456	19.0
2004	55,485.42	49,937	49,451	0.8912	6,034	2.00	3,017	18.0
2005	166,338.89	141,388	140,012	0.8417	26,326	3.00	8,775	17.0
2006	111,369.74	89,096	88,229	0.7922	23,141	4.00	5,785	16.0
2007	198,349.07	148,762	147,314	0.7427	51,035	5.00	10,207	15.0
2008	811,571.21	568,100	562,573	0.6932	248,999	6.00	41,500	14.0
2009	252,686.89	164,246	162,648	0.6437	90,038	7.00	12,863	13.0
2010	867,395.67	520,437	515,374	0.5942	352,022	8.00	44,003	12.0
2011	2,817,871.93	1,549,830	1,534,751	0.5446	1,283,121	9.00	142,569	11.0
2012	527,329.58	263,665	261,099	0.4951	266,230	10.00	26,623	10.0
2013	1,224,286.02	550,929	545,569	0.4456	678,718	11.00	61,702	9.0
2014	518,167.21	207,267	205,250	0.3961	312,917	12.00	26,076	8.0
2015	350,164.46	122,558	121,365	0.3466	228,799	13.00	17,600	7.0
2016	635,737.10	190,721	188,866	0.2971	446,872	14.00	31,919	6.0
2017	1,213,001.85	303,250	300,300	0.2476	912,702	15.00	60,847	5.0
2018	531,705.31	106,341	105,306	0.1981	426,399	16.00	26,650	4.0
2019	1,904,856.71	285,729	282,949	0.1485	1,621,908	17.00	95,406	3.0
2020	1,881,059.26	188,106	186,276	0.0990	1,694,783	18.00	94,155	2.0
2021	489,062.99	24,453	24,215	0.0495	464,848	19.00	24,466	1.0
2022	1,607,480.67	0	0	0.0000	1,607,481	20.00	80,374	0.0

FortisBC

Account #: 483.40 - Furniture - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	16,575,748.93	5,873,599	5,816,452		10,759,297		831,462	

COMPOSITE ANNUAL ACCRUAL RATE	5.02%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	7.09
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.92

FortisBC

Account #: 484.00 - Vehicles - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1
ASL: 10
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	52,508.80	34,906	44,632	1.0000	0	2.18	0	20.0
2003	45,758.07	29,614	38,894	1.0000	0	2.39	0	19.0
2004	1,064.25	669	905	1.0000	0	2.60	0	18.0
2005	125,661.45	76,641	106,812	1.0000	0	2.82	0	17.0
2006	274,245.05	161,834	233,108	1.0000	0	3.06	0	16.0
2007	92,947.39	52,930	79,005	1.0000	0	3.30	0	15.0
2008	360,800.01	197,683	306,680	1.0000	0	3.55	0	14.0
2009	616,281.25	323,765	523,839	1.0000	0	3.82	0	13.0
2010	752,357.78	377,481	639,504	1.0000	0	4.10	0	12.0
2011	704,305.34	335,917	598,660	1.0000	0	4.39	0	11.0
2012	755,333.88	340,587	624,042	0.9720	17,992	4.70	3,832	10.0
2013	1,154,611.48	488,987	895,948	0.9129	85,472	5.02	17,035	9.0
2014	1,646,822.30	649,884	1,190,752	0.8507	209,047	5.36	39,021	8.0
2015	2,765,598.00	1,007,096	1,845,256	0.7850	505,502	5.72	88,438	7.0
2016	3,563,782.30	1,182,974	2,167,508	0.7155	861,707	6.09	141,384	6.0
2017	4,792,239.30	1,423,859	2,608,872	0.6405	1,464,532	6.50	225,157	5.0
2018	9,616,647.52	2,463,840	4,514,381	0.5523	3,659,770	6.99	523,886	4.0
2019	6,626,732.74	1,368,055	2,506,625	0.4450	3,126,098	7.57	412,891	3.0
2020	7,505,467.10	1,100,721	2,016,800	0.3161	4,362,847	8.27	527,255	2.0
2021	6,305,934.13	486,835	892,006	0.1664	4,468,038	9.09	491,440	1.0
2022	6,962,274.44	0	0	0.0000	5,917,933	10.00	591,733	0.0

FortisBC

Account #: 484.00 - Vehicles - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1
ASL: 10
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	54,721,372.58	12,104,278	21,834,231		24,678,936		3,062,072	

COMPOSITE ANNUAL ACCRUAL RATE	5.60%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.40
COMPOSITE AVERAGE AGE (YEARS)	3.93
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	7.40

FortisBC

Account #: 485.10 - Heavy Work Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L0.5
ASL: 13
Net Salvage: 5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1992	3,200.00	2,270	3,040	1.0000	0	3.29	0	30.0
1995	19,242.50	13,096	18,280	1.0000	0	3.69	0	27.0
1996	20,529.03	13,742	19,503	1.0000	0	3.84	0	26.0
1997	32,729.25	21,518	31,093	1.0000	0	4.00	0	25.0
1998	52,786.37	34,033	49,609	0.9893	538	4.18	129	24.0
1999	16,249.22	10,257	14,952	0.9686	485	4.36	111	23.0
2000	12,982.28	8,011	11,677	0.9468	656	4.56	144	22.0
2001	12,506.95	7,530	10,977	0.9238	905	4.76	190	21.0
2002	14,077.43	8,255	12,033	0.8997	1,341	4.98	269	20.0
2005	28,821.00	15,412	22,465	0.8205	4,915	5.68	865	17.0
2006	9,223.44	4,759	6,937	0.7917	1,825	5.94	307	16.0
2007	542.75	269	393	0.7616	123	6.21	20	15.0
2010	25,722.00	11,117	16,205	0.6631	8,231	7.09	1,162	12.0
2011	82,206.26	33,615	49,000	0.6274	29,096	7.40	3,930	11.0
2012	252,922.43	97,278	141,800	0.5902	98,476	7.74	12,728	10.0
2013	3,103.00	1,115	1,625	0.5512	1,323	8.08	164	9.0
2014	45,562.75	15,162	22,101	0.5106	21,183	8.45	2,508	8.0
2015	66,430.41	20,261	29,534	0.4680	33,575	8.83	3,804	7.0
2017	5,906.05	1,427	2,080	0.3707	3,531	9.69	364	5.0
2019	14,585.00	2,355	3,433	0.2478	10,422	10.79	966	3.0
2020	3,503.53	399	582	0.1747	2,747	11.44	240	2.0

FortisBC

Account #: 485.10 - Heavy Work Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L0.5
ASL: 13
Net Salvage: 5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	722,831.65	321,880	467,317		219,373		27,901	

COMPOSITE ANNUAL ACCRUAL RATE	3.86%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.65
COMPOSITE AVERAGE AGE (YEARS)	13.51
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.91

FortisBC

Account #: 485.20 - Heavy Mobile Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2001	29,463.87	24,121	23,292	0.7905	6,172	1.81	3,404	21.0
2003	68,871.57	53,889	52,035	0.7555	16,836	2.18	7,739	19.0
2004	185,600.95	141,564	136,696	0.7365	48,905	2.37	20,612	18.0
2005	148,469.18	110,150	106,362	0.7164	42,107	2.58	16,315	17.0
2006	80,766.65	58,146	56,146	0.6952	24,621	2.80	8,791	16.0
2007	27,006.80	18,818	18,171	0.6728	8,836	3.03	2,914	15.0
2008	126,269.42	84,924	82,003	0.6494	44,266	3.27	13,519	14.0
2009	202,788.53	131,297	126,781	0.6252	76,007	3.53	21,560	13.0
2010	647,358.18	402,494	388,652	0.6004	258,707	3.78	68,395	12.0
2011	212,655.54	126,675	122,318	0.5752	90,337	4.04	22,343	11.0
2012	83,617.38	47,599	45,962	0.5497	37,656	4.31	8,742	10.0
2013	82,422.15	44,667	43,131	0.5233	39,291	4.58	8,578	9.0
2014	829,598.04	425,230	410,605	0.4949	418,993	4.87	85,960	8.0
2015	293,195.91	140,533	135,700	0.4628	157,496	5.21	30,248	7.0
2016	224,292.11	98,659	95,266	0.4247	129,026	5.60	23,035	6.0
2017	1,378,308.37	539,965	521,395	0.3783	856,913	6.08	140,884	5.0
2018	1,937,804.85	644,188	622,034	0.3210	1,315,771	6.68	197,099	4.0
2019	1,131,822.53	296,797	286,590	0.2532	845,233	7.38	114,566	3.0
2020	1,411,907.24	258,293	249,410	0.1766	1,162,497	8.17	142,278	2.0
2021	2,391,022.25	226,913	219,109	0.0916	2,171,913	9.05	239,964	1.0
2022	686,109.45	0	0	0.0000	686,109	10.00	68,607	0.0

FortisBC

Account #: 485.20 - Heavy Mobile Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	12,179,350.97	3,874,920	3,741,657		8,437,694		1,245,553	

COMPOSITE ANNUAL ACCRUAL RATE	10.23%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	4.83
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.82

FortisBC

Account #: 486.00 - Small Tools/Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2001	57,288.26	57,288	57,288	1.0000	0	1.00	0	21.0
2002	1,299,889.10	1,299,889	1,299,889	1.0000	0	1.00	0	20.0
2003	2,509,723.31	2,384,237	2,431,798	0.9690	77,925	1.00	77,925	19.0
2004	1,617,392.96	1,455,654	1,474,158	0.9114	143,235	2.00	71,618	18.0
2005	2,698,821.42	2,293,998	2,323,160	0.8608	375,662	3.00	125,221	17.0
2006	1,734,308.07	1,387,446	1,405,084	0.8102	329,224	4.00	82,306	16.0
2007	2,289,647.01	1,717,235	1,739,065	0.7595	550,582	5.00	110,116	15.0
2008	2,226,660.29	1,558,662	1,578,476	0.7089	648,184	6.00	108,031	14.0
2009	2,869,637.60	1,865,264	1,888,976	0.6583	980,662	7.00	140,095	13.0
2010	2,761,291.71	1,656,775	1,677,836	0.6076	1,083,456	8.00	135,432	12.0
2011	2,551,651.70	1,403,408	1,421,249	0.5570	1,130,403	9.00	125,600	11.0
2012	3,750,938.74	1,875,469	1,899,310	0.5064	1,851,628	10.00	185,163	10.0
2013	2,899,024.09	1,304,561	1,321,144	0.4557	1,577,880	11.00	143,444	9.0
2014	2,621,793.74	1,048,718	1,062,049	0.4051	1,559,745	12.00	129,979	8.0
2015	2,315,802.18	810,531	820,834	0.3544	1,494,968	13.00	114,998	7.0
2016	2,362,370.53	708,711	717,720	0.3038	1,644,650	14.00	117,475	6.0
2017	2,473,284.85	618,321	626,181	0.2532	1,847,104	15.00	123,140	5.0
2018	2,520,424.24	504,085	510,493	0.2025	2,009,931	16.00	125,621	4.0
2019	4,054,320.45	608,148	615,879	0.1519	3,438,442	17.00	202,261	3.0
2020	5,846,540.94	584,654	592,086	0.1013	5,254,455	18.00	291,914	2.0
2021	5,102,122.10	255,106	258,349	0.0506	4,843,773	19.00	254,935	1.0
2022	2,853,052.45	0	0	0.0000	2,853,052	20.00	142,653	0.0

FortisBC

Account #: 486.00 - Small Tools/Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	59,415,985.74	25,398,162	25,721,024		33,694,962		2,807,927	

COMPOSITE ANNUAL ACCRUAL RATE	4.73%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.43
COMPOSITE AVERAGE AGE (YEARS)	8.55
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.47

FortisBC

Account #: 488.10 - Telephone Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	120,133.21	120,133	120,133	1.0000	0	1.00	0	15.0
2008	394,398.82	368,106	369,609	0.9371	24,790	1.00	24,790	14.0
2009	391,239.67	339,074	340,119	0.8693	51,121	2.00	25,560	13.0
2010	173,004.31	138,403	138,830	0.8025	34,175	3.00	11,392	12.0
2011	77,889.91	57,119	57,295	0.7356	20,595	4.00	5,149	11.0
2012	66,568.88	44,379	44,516	0.6687	22,053	5.00	4,411	10.0
TOTAL	1,223,234.80	1,067,215	1,070,502		152,733		71,302	

COMPOSITE ANNUAL ACCRUAL RATE	5.83%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.88
COMPOSITE AVERAGE AGE (YEARS)	13.09
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.01

FortisBC

Account #: 488.20 - Radio Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life

Survivor Curve: SQ

ASL: 15

Net Salvage: 0%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	767,616.96	665,268	668,085	0.8703	99,532	2.00	49,766	13.0
2010	226,477.52	181,182	181,949	0.8034	44,528	3.00	14,843	12.0
2011	247,246.38	181,314	182,082	0.7364	65,165	4.00	16,291	11.0
2012	117,516.31	78,344	78,676	0.6695	38,840	5.00	7,768	10.0
2013	146,339.47	87,804	88,175	0.6025	58,164	6.00	9,694	9.0
2014	4,285,036.52	2,285,353	2,295,029	0.5356	1,990,007	7.00	284,287	8.0
2015	1,933,165.31	902,144	905,964	0.4686	1,027,202	8.00	128,400	7.0
2016	1,800,384.90	720,154	723,203	0.4017	1,077,182	9.00	119,687	6.0
2017	1,986,975.87	662,325	665,130	0.3347	1,321,846	10.00	132,185	5.0
2018	1,753,664.15	467,644	469,624	0.2678	1,284,040	11.00	116,731	4.0
2019	1,183,472.69	236,695	237,697	0.2008	945,776	12.00	78,815	3.0
2020	1,157,325.99	154,310	154,963	0.1339	1,002,363	13.00	77,105	2.0
2021	788,715.64	52,581	52,804	0.0669	735,912	14.00	52,565	1.0
2022	672,801.95	0	0	0.0000	672,802	15.00	44,853	0.0
TOTAL	17,066,739.66	6,675,117	6,703,380		10,363,360		1,132,990	

COMPOSITE ANNUAL ACCRUAL RATE	6.64%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	5.87
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	9.13

SECTION 9

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service".[6] All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age".[7] To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1, shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age."[8] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve.[9] Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

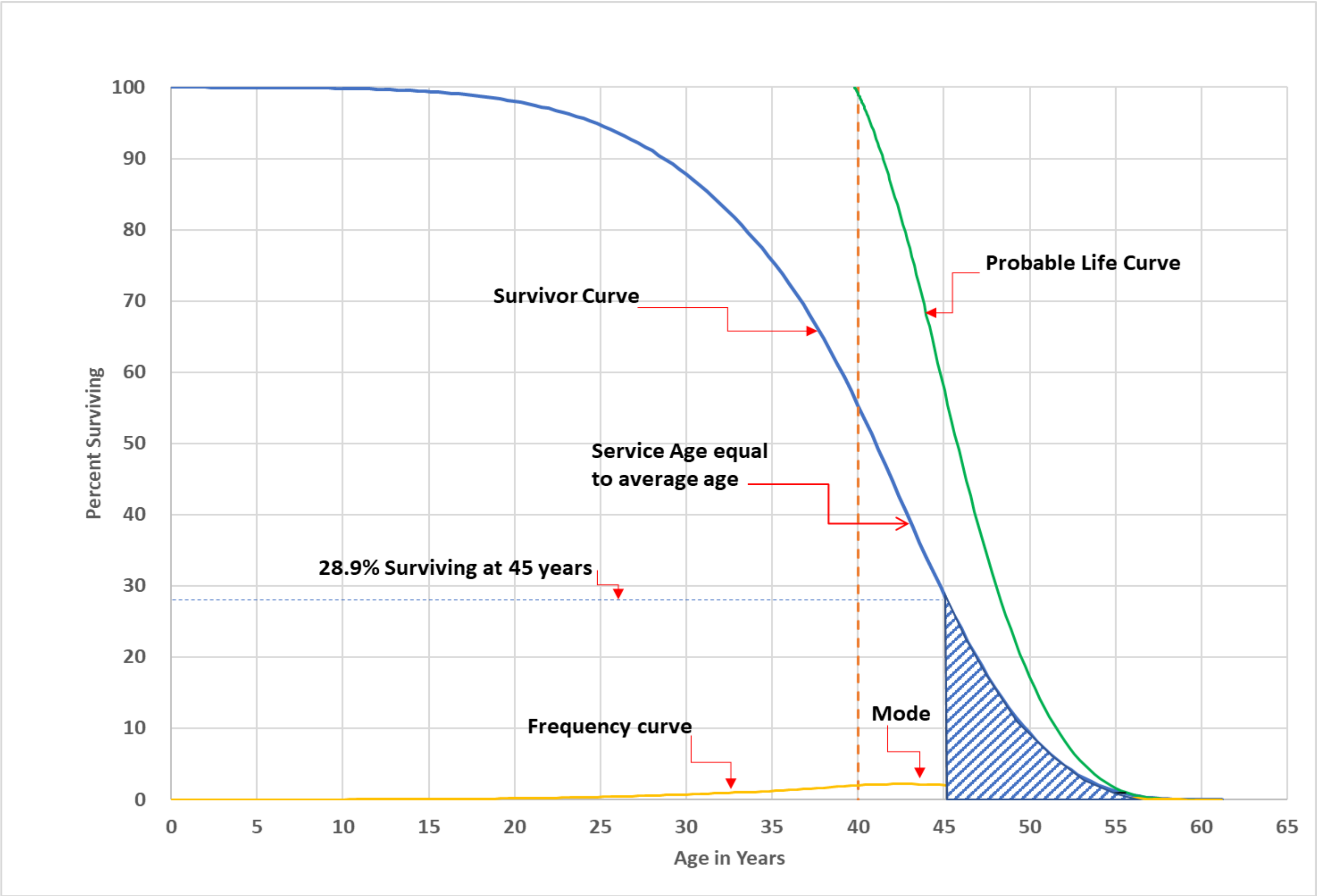
[6] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21

[7] *Ibid*, 23.

[8] *Ibid*, 29.

[9] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment".[10] The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation.[11] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[12] presenting his development of the fourth family consisting of the four O-type survivor curves.

[10] *Ibid*, 21

[11] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[12] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

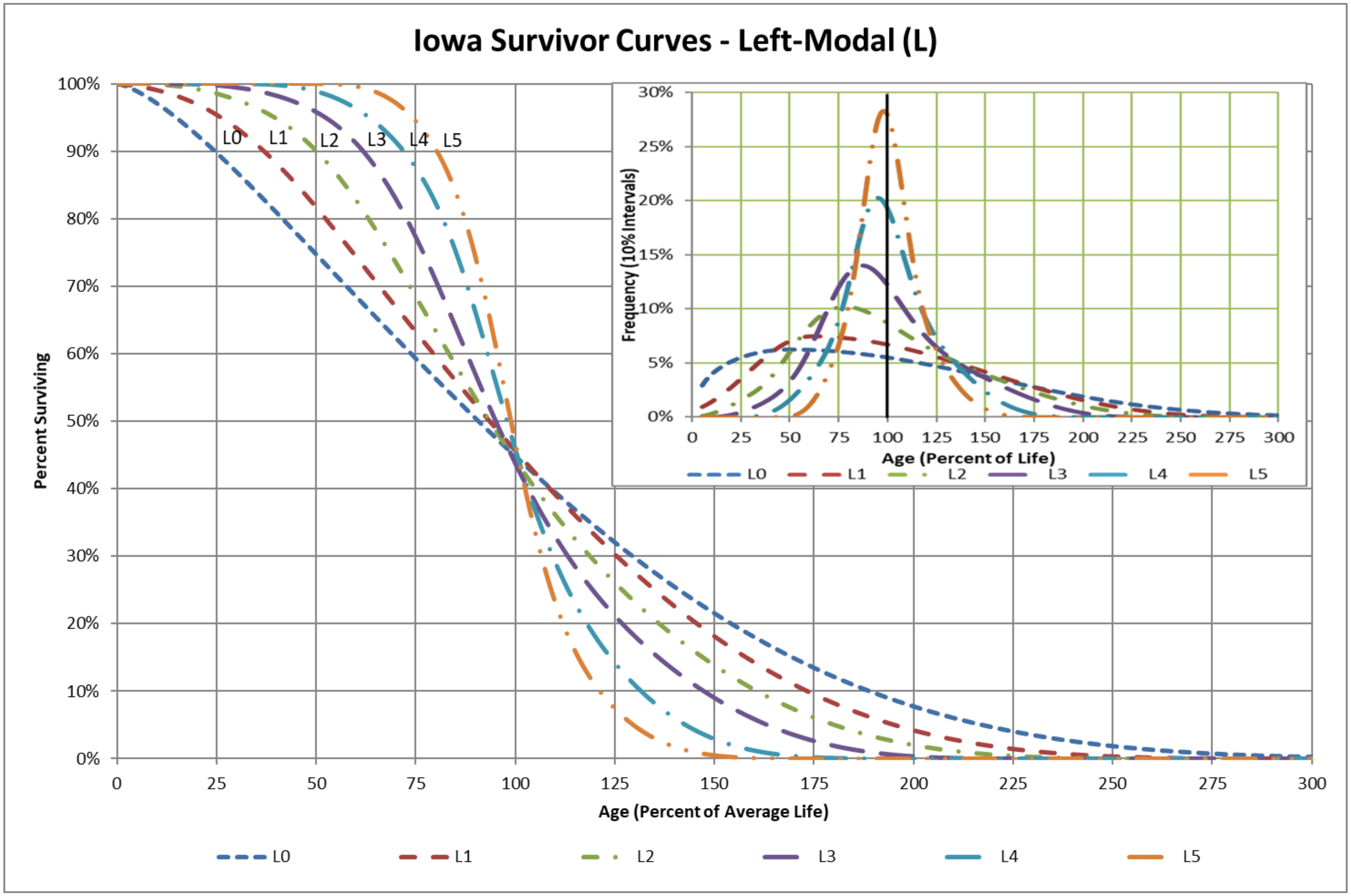


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

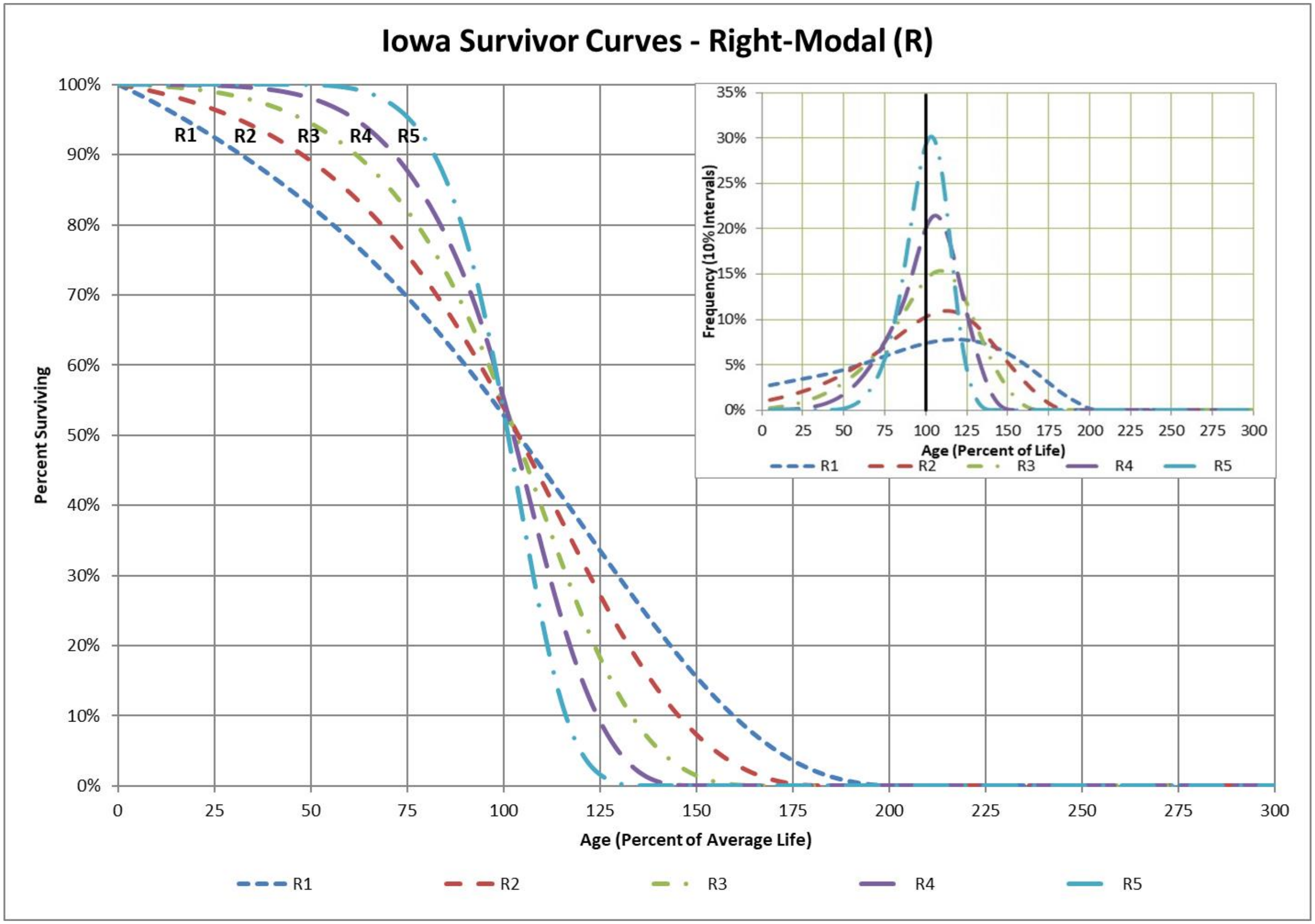


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

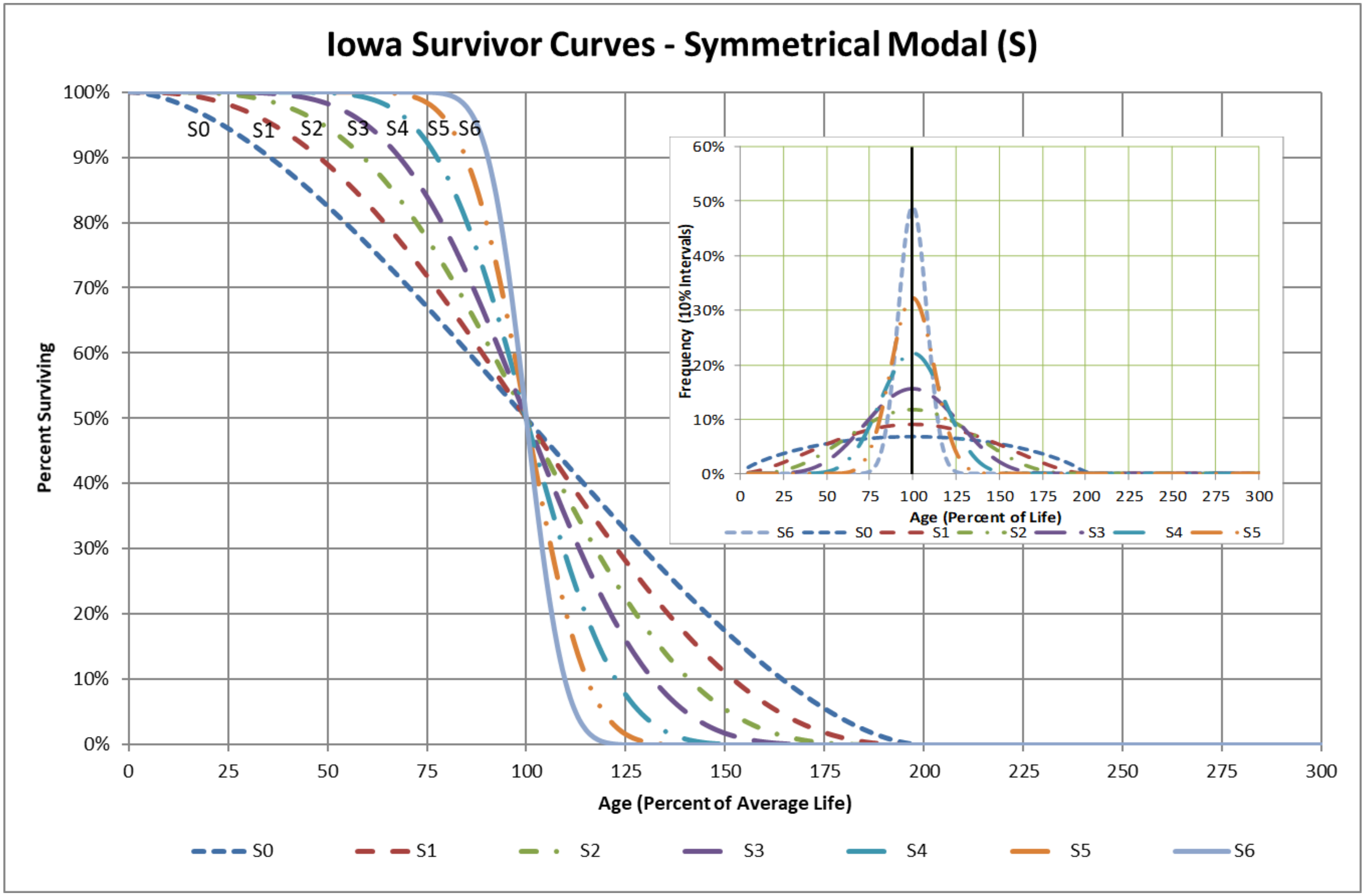
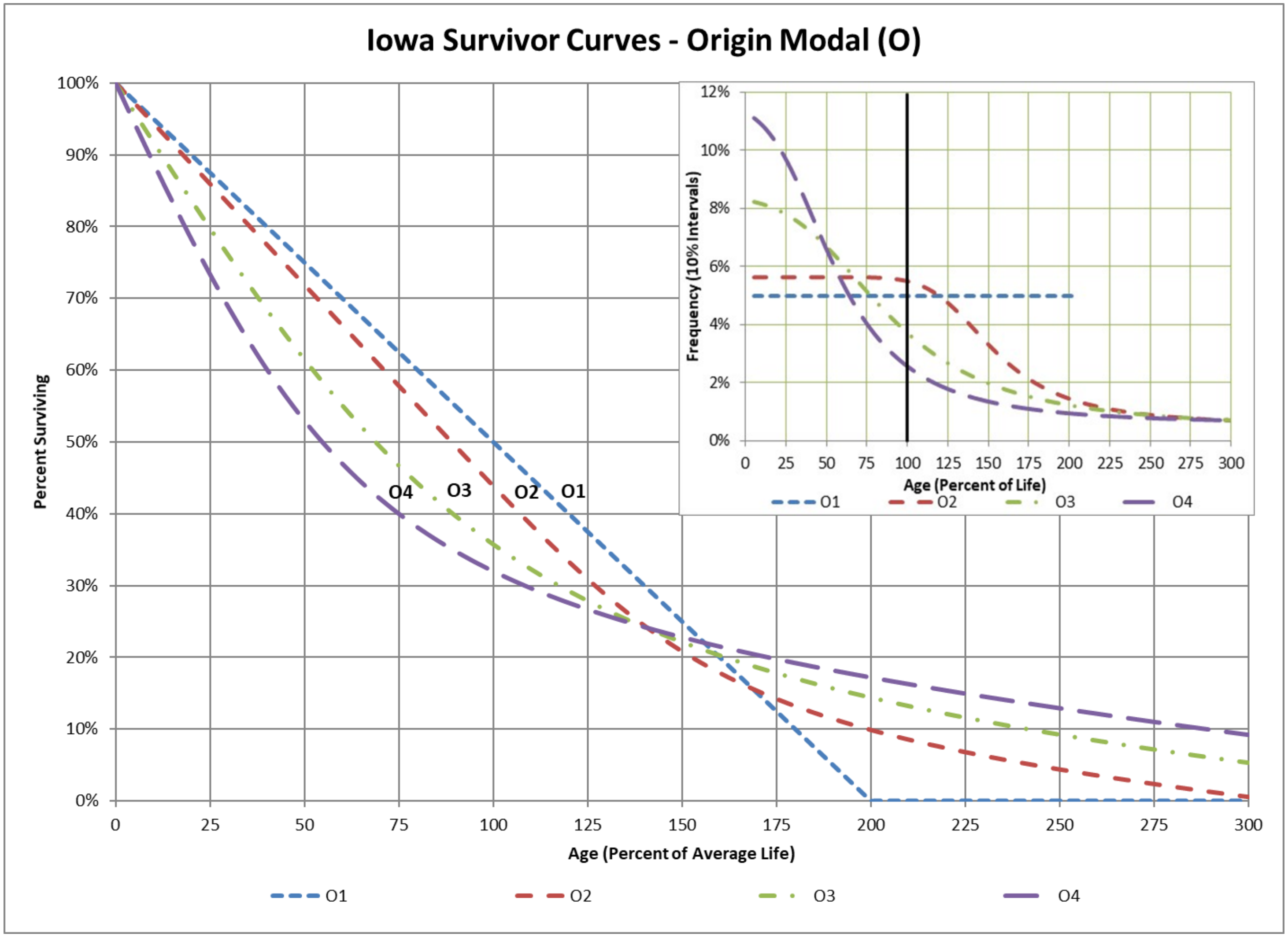


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements, [13] Engineering Valuation and Depreciation [14] and Depreciation Systems. [15]

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[13] Anson, Winfrey & Hempstead, *supra* note 3

[14] Anson, Winfrey & Hempstead, *supra* note 3

[15] Wolf & Fitch, supra note 1

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2022 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2022 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2008 through 2017 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2022, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2022 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

	1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
	420	460	510	580	660	750	850	960	1080	1220	0
	1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 41: ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017				Placement Band 2003-2017	
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

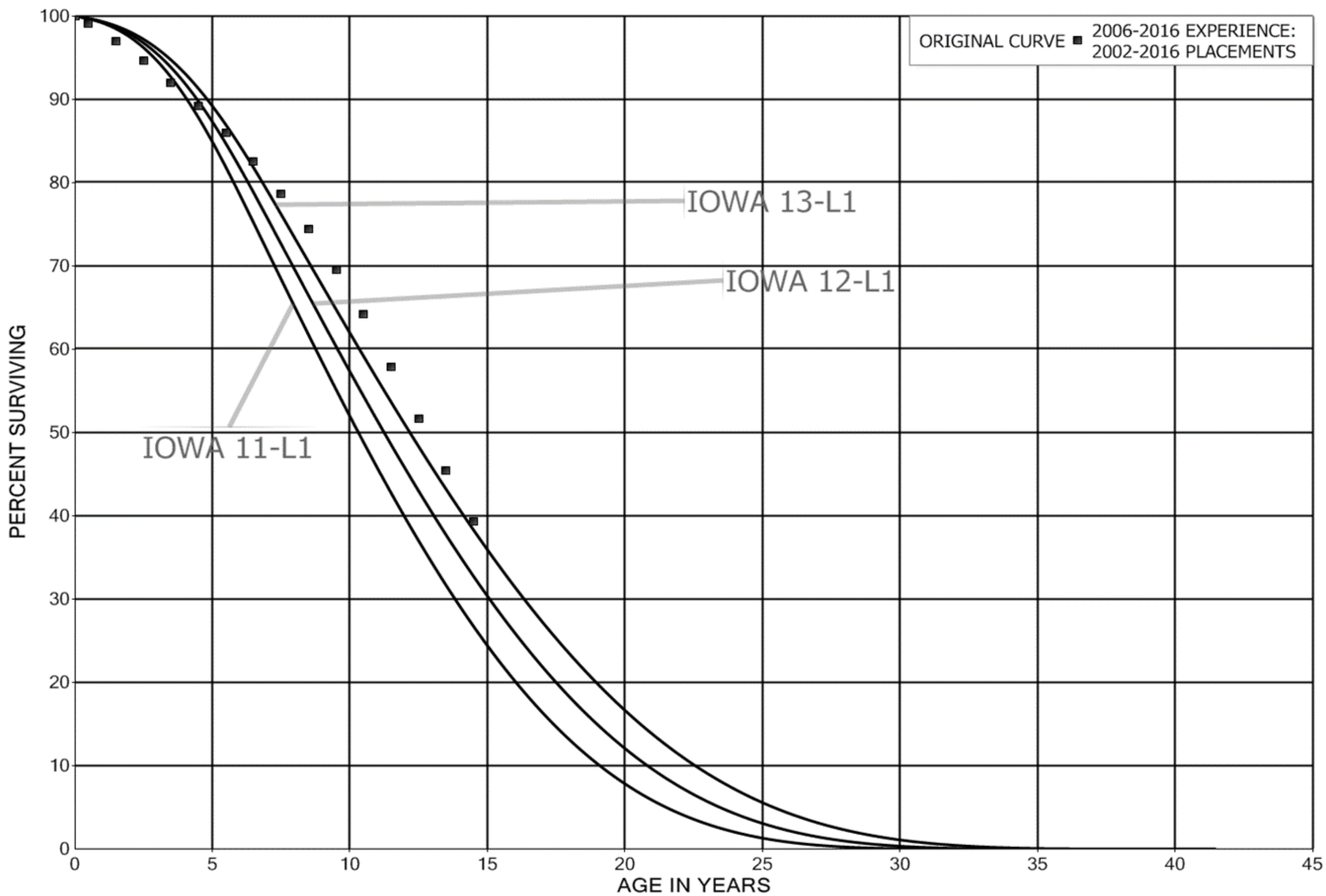


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

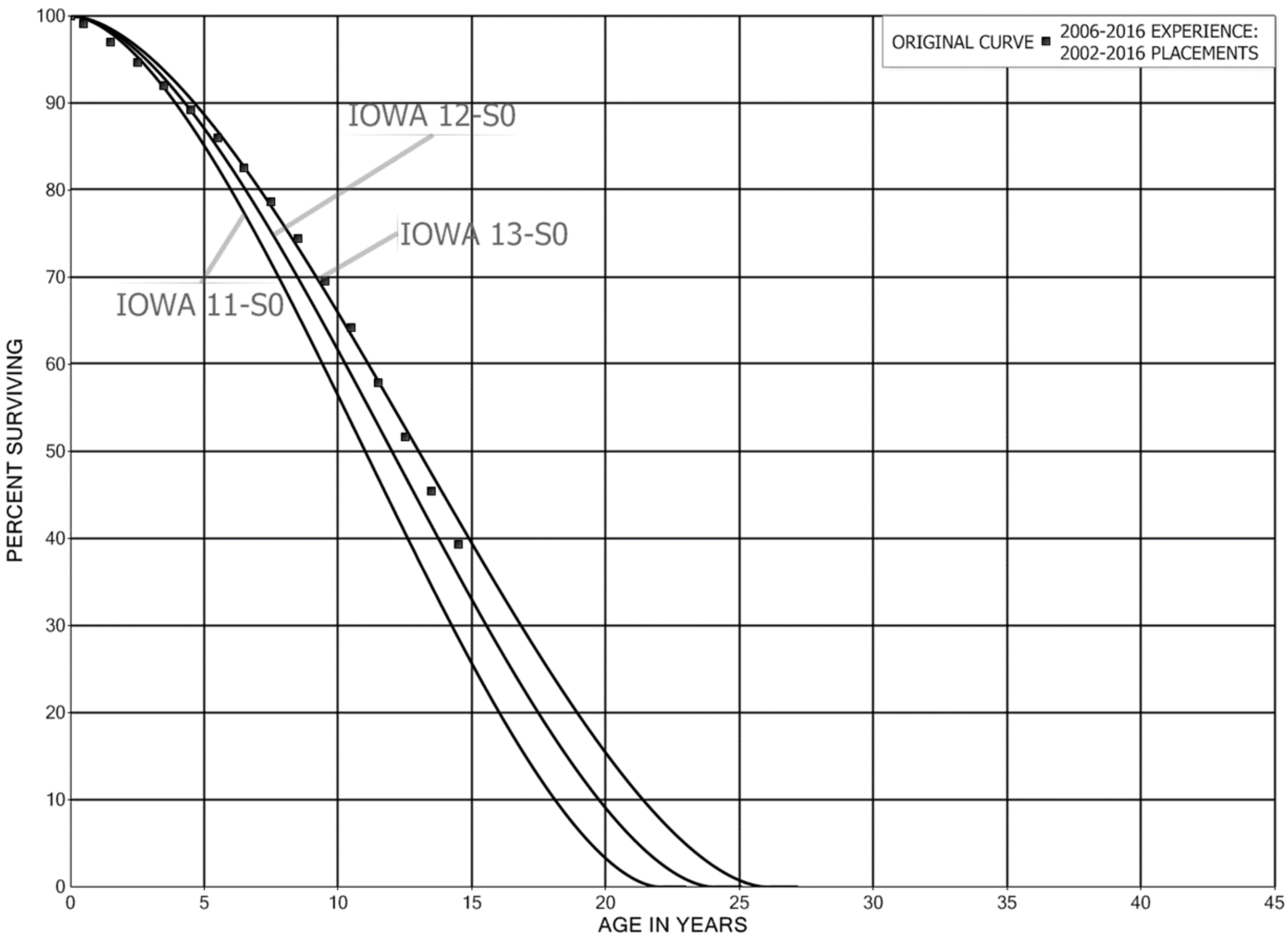


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

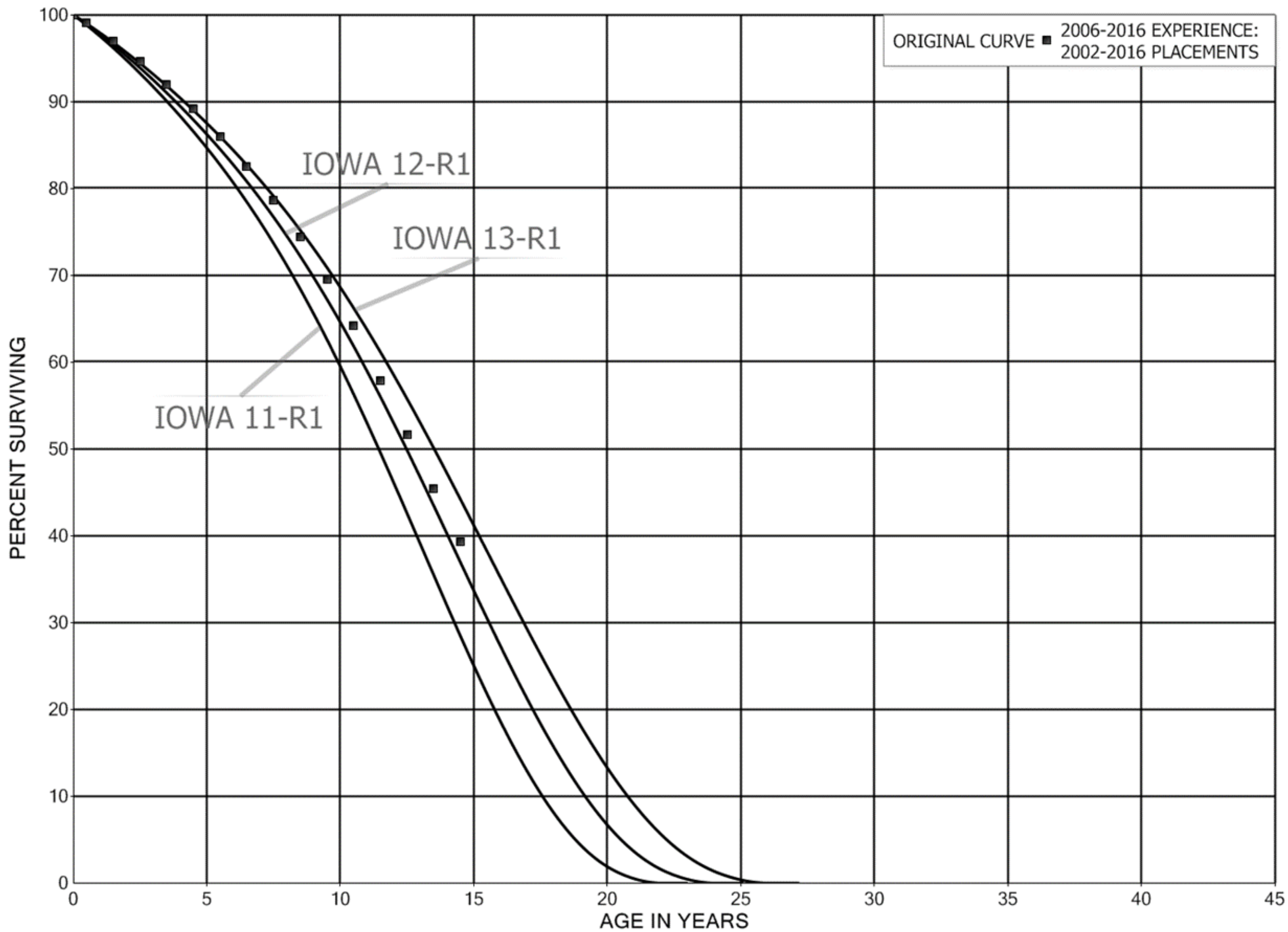
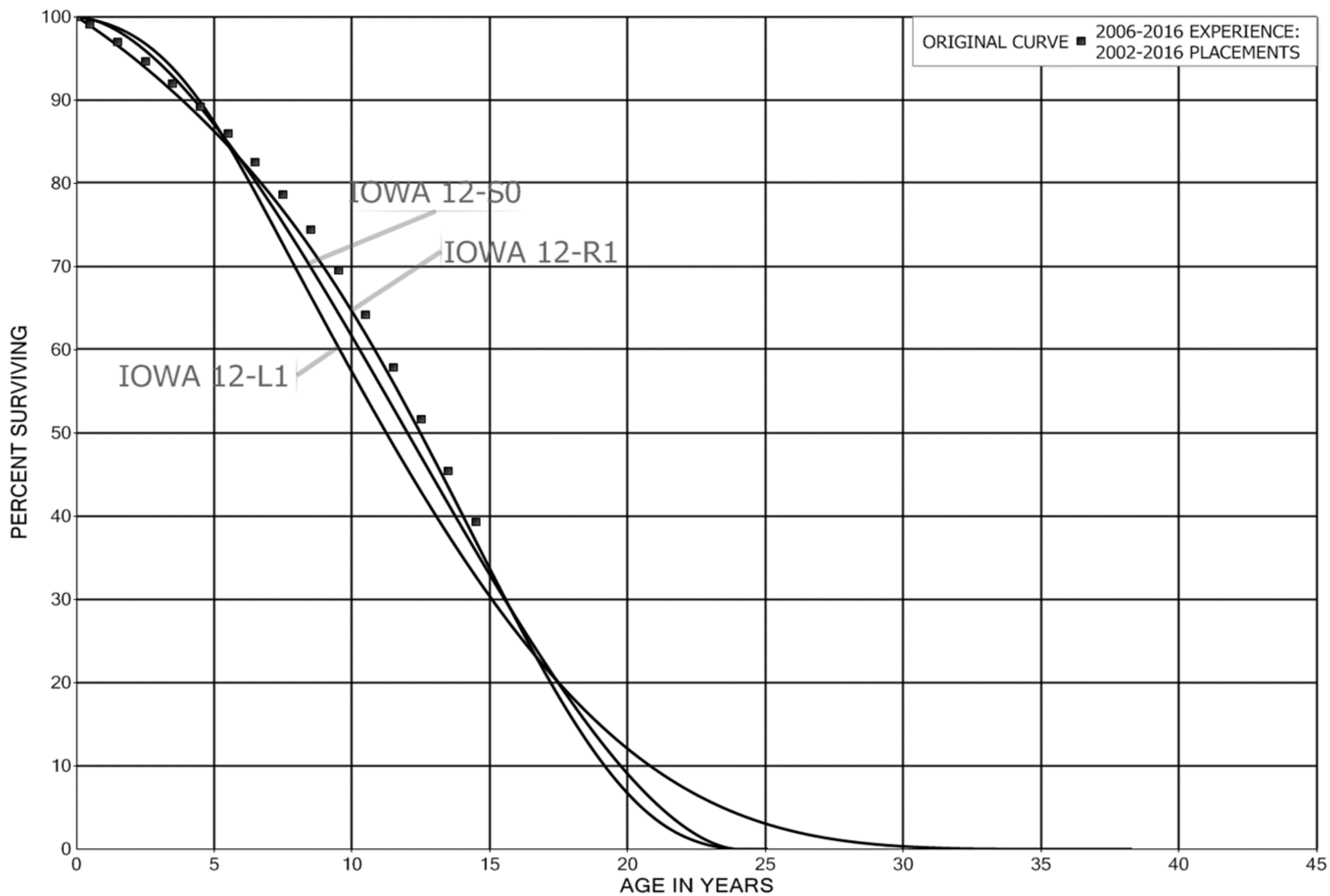


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated is usually determined using the "Traditional Approach" for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

Appendix D2-2

FBC DEPRECIATION STUDY

2022 DEPRECIATION STUDY

Calculated Annual Depreciation Accrual Rates
As of December 31, 2022

Headquarters
293 Boston Post Rd West, Ste 500
Marlborough, MA, USA 01752
508.263.6200

Washington, D.C. Office
1300 19th St NW, Ste 620
Washington, DC, USA 20036
202.587.4470

Concentric Advisors, ULC
200 Rivercrest Drive SE, Ste 277
Calgary, AB, Canada T2C 2X5
403.257.5946

January 16, 2024

FortisBC - Electricity
Suite 100, 1975 Springfield Road
Kelowna, British Columbia V1Y 7P7

Attention: Lilyana Tabakova
Asset Accounting Manager

Dear Lilyana;

Pursuant to your request, we have conducted a depreciation study related to the electric generation, transmission, distribution, and general plant assets of FortisBC – Electricity, as of December 31, 2022. Our report presents a description of the methods used in the estimation of depreciation and net salvage, the statistical analyses of service life and the summary and detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of December 31, 2022. The depreciation rates are based on the Straight-Line method, the remaining life basis, using the average life group procedure. An annual review of the depreciation rates using the same estimates and methods is recommended.

Yours truly,

CONCENTRIC ADVISORS, ULC

Larry E. Kennedy
Senior Vice President

Donna Bourne
Project Manager

Project: 100196

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to FortisBC – Electricity's ("FortisBC" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the electric generation, transmission, distribution and general plant accounts, as of December 31, 2022. The purpose of the study is to determine the annual depreciation accrual rates and amounts applicable to the original cost of electric plant, as of December 31, 2022. Concentric acknowledges that it has a duty to provide opinion evidence to the British Columbia Utilities Commission (BCUC) that is fair, objective and non-partisan. This study determines annual depreciation accrual rates for assets in service as of December 31, 2022.

This study utilizes the Straight-Line method and the Average Life Group ("ALG") procedure applied on a remaining life basis for each depreciable group of assets. The calculations were based on attained ages and estimated average service life and forecasting net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2022, are amortized over the remaining life of assets.

FortisBC's accounting policy has not changed since the last depreciation study was prepared. It continues to recognize the recovery of future costs of removal over the average service of the assets, and therefore includes estimated costs of removal percentages into the depreciation rate calculations costs of removal.

These estimates of salvage values present the continuation of a moderated process to full cost recovery to avoid sharp increases in costs of removal recovery.

Concentric recommends the calculated annual depreciation accrual rates set forth in this study apply specifically to plant in service, as of December 31, 2022, as summarized by Tables 1, 1A, and 1B (pages 5-2 to 5-7). Supporting data and calculations are provided within this study.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $72.3 million, when applied to depreciable plant balances as of December 31, 2022 of $2.4 billion. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group	Original Cost	Annual Accrual	
Generation	$359,528,354	2.11%	$7,571,994
Transmission	$541,268,000	2.55%	$13,817,632
Distribution	$1,253,610,393	2.85%	$35,751,764
General	$218,013,675	6.95%	$15,144,464
TOTAL PLANT IN SERVICE	**$2,372,420,422**	**3.05%**	**$72,285,854**

SECTION 2

2 INTRODUCTION

2.1 Scope

This report sets forth the results of the depreciation study for assets of FortisBC to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of FortisBC's electric plant assets as of December 31, 2022. The rates and amounts are based on the Straight-Line method of depreciation, incorporating the ALG procedure applied on a remaining life basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the electric plant in service as of December 31, 2022.

The service life estimates resulting from this study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2022;
- a review of FortisBC's practices and outlooks as they relate to plant operation and retirement;
- review of the Company's upcoming capital and retirement projects; and
- consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

The depreciation accrual rates presented in this study are based on generally-accepted methods and procedures for calculating depreciation. The estimated survivor curves used in this study are based on studies incorporating actual data through 2022 for most accounts.

2.2 Plan of Study

This study is presented in the following order:

Section 1	Study Highlights, presents a brief summary of the depreciation study and results
Section 2	Introduction, contains statements with respect to the plan and the basis of the study
Section 3	Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.
Section 4	Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation
Section 5	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1, 1A, and 1B
Section 6	Show the results of the Retirement Rate Analysis
Section 7	Presents the Net Salvage Calculations
Section 8	Presents Detailed Depreciation Calculations
Section 9	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10	Estimation of Net Salvage is an overview of the Net Salvage Analysis

2.3 Depreciation

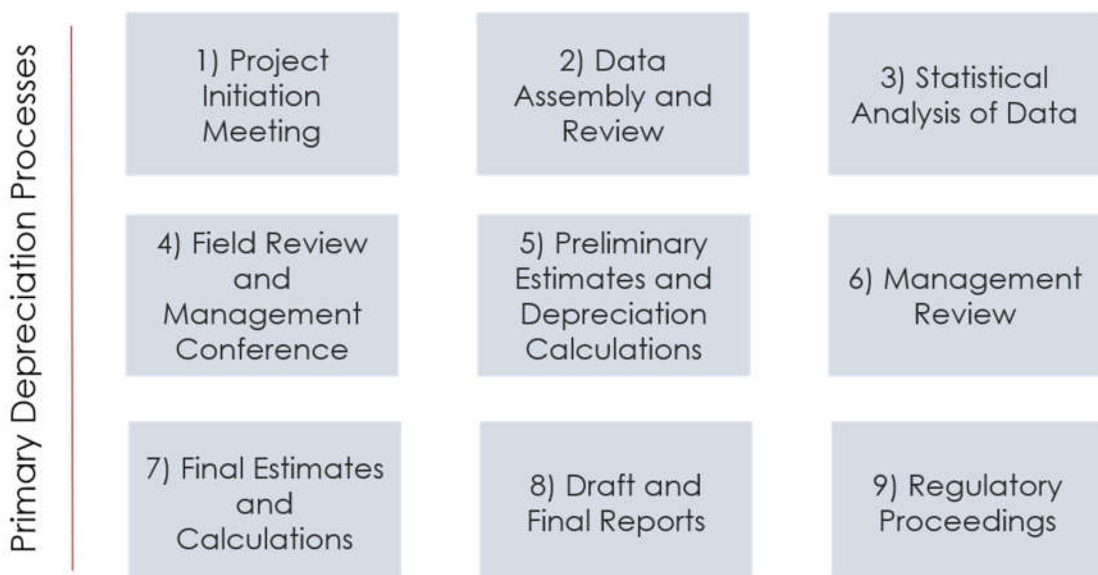
A full and comprehensive depreciation study includes the following components:

1. Supported recommendations regarding Average Service Life estimates for each account;
2. supported recommendations regarding estimated Net Salvage requirements for each account;
3. detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
4. a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

A diagram of the nine primary processes followed by Concentric in the development of the depreciation study is provided below. Each of the steps is undertaken by Concentric using proprietary software.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

Consistent with the current FortisBC practice, amortization accounting continues to be recommended for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts.



2.4 Service Life and Net salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of the Company's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other natural electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for electric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in Tables 1, 1A, and 1B (Section 5, pages 5-2 – 5-7) of this study. The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

2.5 Information Provided by FortisBC

FortisBC has provided Concentric with the required information, as of December 31, 2022, for all accounts being studied. This information has been compiled from the plant accounting records and includes the following:

- current balances by vintage year for each account (aged balances). The balances provide the amount of investment sorted by installation year currently in operation. This file is only inclusive of current plant in service and does not include any retirement information;
- detailed retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired as well as the original cost of the asset being retired; and
- detailed cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.6 Data Reconciliation

The above data was reviewed and reconciled to FortisBC's control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;

- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that the cost of removal, retirement and gross salvage data over time corresponds to plant and accounting records and their analyses reflects an accurate representation of net salvage.

SECTION 3

3 DEVELOPMENT OF DEPRECIATION RATES

3.1 Depreciation

The development of the depreciation calculations requires the input of an average service life, a retirement dispersion curve (i.e., Iowa curve) and net salvage recommendations. Together, the average service life, retirement dispersion curve, and net salvage recommendation are referred to as the depreciation parameters. Additionally, to complete the depreciation calculations, the calculation methods must be established. Specifically, the selection of the depreciation method must establish three types of additional input:

1. the choice of a depreciation method;
2. a basis upon which to apply the method, and
3. in the case of group assets, a procedure to use in grouping the assets.

In this study, the depreciation rates for FortisBC have been calculated in accordance with the Straight-Line method, the ALG procedure and applied using the Remaining Life technique where any accumulated depreciation variances are trued-up within the depreciation rate calculations over the composite remaining life of each account.

Depreciation, as applied to depreciable plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art and changes in demand and requirements of public authorities.[1]

When considering the action of the elements, the average service life and net salvage calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utility plant has been influenced by events including:

- forest fires;
- earthquakes;
- tornadoes;
- ice storms;
- wind-storms;
- large scale flooding;
- fires;
- lightning;
- intentional actions of third parties;
- hoar frost; and
- other natural forces of nature.

.

[1] The National Association of Railroad and Utilities Commissioners, Uniform System of Accounts for Class A and B Electric Utilities. The Definition used by the Federal Energy Regulatory Commission for Electric is essentially the same.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.2 Depreciation Methods and Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group (ALG) and Equal Life Group (ELG) procedures.

In the ALG Procedure, the rate of annual depreciation is based on the average service life of the group. This rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group Procedure, also known as the Unit Summation Procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line Method using the ALG Procedure. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and an estimate of service lives.

While the Equal Life Group Procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Straight-Line Method, Average Life Group Procedure is a commonly used depreciation calculation that has been widely accepted in jurisdictions throughout North America. Concentric recommends its continued use.

Amortization accounting is used for certain general plant accounts because of the disproportionate plant accounting effort required in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. This study calculates the annual and accrued depreciation using the Straight-Line Method and ALG Procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. Concentric has determined an amortization amount to correct the present variance with the calculated accrued depreciation (theoretical reserve) over the composite remaining life of each account.

3.3 Estimation of Survivor Curves

3.3.1 Survivor Curves

The use of an Average Service Life Group for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves "…were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."[2] The Iowa curves are described as L-type (i.e., left-moded), R-type (i.e., right-moded), and S-type (i.e., symmetrical). Further development resulted in the introduction of O-type (i.e., origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion which is the residual measure. This residual measure is calculated as a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the residual measure, the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely-used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process.

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life. A discussion of the general concept of survivor curves and retirement rate method, and net salvage are presented in Sections 9 and 10 of this report.

3.3.2 Survivor Curve and Net Salvage Judgments

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from Concentric's studies of other electric utilities. A detailed peer review is compiled to establish a range of reasonableness for the Iowa curve and net salvage estimate for each account. While the peer review is considered an appropriate test of the estimates, it should never be viewed as conclusive. Differences in characteristics such as the account structure, climate conditions, regulatory environment, and area of service must always be considered when reviewing a peer study.

Concentric has maintained an extensive database of electric utility depreciation studies completed throughout North America. In preparing the FortisBC Depreciation Study, Concentric views the following utilities with similar characteristics to FortisBC to be the most relevant peer utilities. As such, the following utilities were considered in the peer review:

- BC Hydro - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, BC Hydro has an electric transmission, distribution, and generation network located throughout the province of BC and is therefore subject to similar forces of retirement and cost of removal.
- FortisAlberta - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, FortisAlberta has an extensive distribution network throughout rural areas within the province of Alberta and is therefore subject to similar forces of retirement and cost of removal.
- ENMAX Power - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, ENMAX has an extensive transmission and distribution network throughout the metro area of the City of Calgary and is therefore subject to similar forces of retirement and cost of removal.
- ATCO Electric Transmission and ATCO Electric Distribution - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, ATCO has an extensive transmission and distribution network located in large municipalities in Western Canada and is therefore subject to similar forces of retirement and cost of removal.
- SaskPower - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, SaskPower has a distribution network located throughout the province of Saskatchewan including both urban and rural areas and is therefore subject to similar forces of retirement and cost of removal.
- Manitoba Hydro - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, Manitoba Hydro has a transmission and distribution

network located in Manitoba including both urban and metro areas and is therefore subject to similar forces of retirement and cost of removal.

- Northwest Territories Power Corporation (NTPC) - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, NTPC has an extensive generation, transmission, and distribution network located in the Northwest Territories and is therefore subject to similar forces of retirement and cost of removal.
- Newfoundland and Labrador Hydro - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, Newfoundland and Labrador Hydro has a transmission and distribution network located throughout the province of Newfoundland and Labrador and is therefore subject to similar forces of retirement and cost of removal.
- New Brunswick Power (Transmission and Distribution) - Selected for peer review as the most recent depreciation study was completed by Concentric. Additionally, New Brunswick Power has a distribution network located throughout the province of New Brunswick, and is therefore subject to similar forces of retirement and cost of removal.

The use of survivor curves, to reflect the expected dispersion of retirement, provides a consistent method of estimating depreciation for electric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data and the probable future. The forecasting of a probable future included management and operational staff interviews. The combination of the historical experience and the probable future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in the applicable tables of this study (Section 5). The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

The estimates of net salvage for the mass property accounts were based mostly in part on historical data related to actual retirement activity for the years 1995 through 2022, for most accounts. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements were used. Percentages of the cost of plant retired were calculated for each component of net salvage on an annual, three-year, and on a cumulative moving average basis.

The following discussion, dealing with a number of accounts that comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 332.00 – GENERATION PLANT – RESERVOIRS, DAMS AND WATERWAYS

Investment $	Investment %	Previously Approved Curves	Concentric Recommended Curves	Previously Approved Salvage	Concentric Recommended Salvage
$116,281,849	4.90%	70-S2	75-S2	-25%	-30%

The investment in Generation Plant – Reservoirs, Dams and Waterways is approximately $116.3 million, representing 4.90 percent of the total depreciable plant studied. This account includes the facilities and structures used in diverting and impounding waterways, as well as the necessary assets for storage and regulation of water needed in the generation of power. The facilities include dams, spillways, foundations, tunnels, gates, bridges and culverts as well as associated control and monitoring systems.

The currently approved life parameter is an Iowa 70-S2. The retirements, additions and other plant transactions, for the period 1950 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1977 through 2022, of $2,173,104 were recorded. The currently approved Iowa 70-S2 produced a related residual measure of 1.3188. The proposed Iowa 75-S2 produces a better visual and mathematical fit with a residual measure of 1.3911 as depicted on page 6-8. Since the previous study, the surviving plant balance has increased by 242 percent. Large additions of new plant, such as dams, gates and spillways, have led to the increase in average service life of this account. Conversations with operational staff and subject matter experts indicated that the recommended life of 75 years is consistent with their opinion that the large additions for refurbishments and improvements of various parts of the older plant may contribute towards longer life characteristics. However, the ages of plant in service that have experienced retirement activity have shown no material changes since the last study and there are earlier retirements occurring that will need to be monitored moving forward. A review of peer Canadian hydro-electric generation, and electric transmission and distribution utilities indicates a life of between 100 and 125 years. FortisBC is on the lower end of the range due to the forces of retirement related to geological risks in British Columbia that are not experienced in other jurisdictions. Based on the above discussion and considerations, and on Concentrics's experience, an Iowa 75-S2 is a reasonable expectation for the investment in this account. As such, and based upon the increase in plant balance, natural disaster mitigation, and the concept of gradualism, Concentric recommends an Iowa 75-S2 to represent the future expectations for the investment in this account.

FortisBC has incurred over $14 million in cost of removal in this account between 2004-2022. The historical net salvage activity shows a range from negative 1 percent to over negative 600 percent. A three-year band analysis shows a range from negative one percent to over negative 2000 percent. A five-year band analysis produces a range from negative one percent to over negative 1000 percent. The full-depth band for this account shows an amount of negative 691 percent. Canadian hydro-electric generation, and electric transmission and distribution peers have net salvage ranging from negative 8 to over negative 100 percent. FortisBC has also seen large costs of removal since 2018 of over $13 million. Given the concept of gradualism, Concentric is recommending a net salvage rate of negative 30 percent to reflect actual experience and near-term requirements.

ACCOUNT 333.00 – GENERATION PLANT – WATER WHEELS, TURBINES AND GENERATORS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$122,271,003	5.15%	70-R2.5	70-R2.5	-25%	-30%

The investment in Generation Plant – Water Wheels, Turbines, and Generators is approximately $122.3 million, representing 5.15 percent of the total depreciable plant studied. This account includes the necessary hydraulic components, pumps, motors and generators used to generate electricity. This encompasses exciter sets, water wheels, gates, governors, penstocks, oil pumps and their associated foundation works as well as regulators, cooling and monitoring equipment.

The currently approved life parameter is an Iowa 70-R2.5. The retirements, additions and other plant transactions, for the period 1960 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1979 through 2022, of $1,849,089 were recorded. The currently approved Iowa 70-R2.5 produced a related residual measure of 0.2453, as depicted on page 6-11. Discussions with FortisBC operational and management staff indicated that a 70-year life is still a good representation of the historical life and future expectations for retirements in this account. There has been an increase of approximately 17 percent in the retirement experience in this account, up from $1,569,495 in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs at the same age of plant as it did previously. A review of peer Canadian hydro-electric generation, and electric transmission and distribution utilities indicates a life of between 25 and 65 years, placing FortisBC on the long end of Canadian peers. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 70-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 70-R2.5 to continue to represent the future expectations for this account.

FortisBC has incurred over $2 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from negative 1 percent to over negative 400 percent. A three-year band analysis shows a range from negative one percent to over negative 3000 percent. A five-year band analysis produces a range from negative 3 percent to over negative 500 percent. The full-depth band for this account shows an amount of negative 214 percent. Canadian hydro-electric generation, and electric transmission and distribution peers have net salvage ranging from negative 1 to negative 12 percent. Costs of removal for this account have been sporadic, but high as a function of original costs as shown on page 7-4. Historical net salvage percentages have trended well above the previous study's recommendation, with the last five years averaging almost negative 250 percent. It is recommended that a gradual increase in negative net salvage is continued from the amounts recommended in the previous study. Concentric views that it would be reasonable to increase the net salvage rate at this time. Given the concept of gradualism, Concentric is recommending a net salvage rate of negative 30 percent to reflect actual experience and near-term requirements.

ACCOUNT 334.00 – GENERATION PLANT – ACCESSORY ELECTRICAL EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$51,723,325	2.18%	40-R2.5	42-R2.5	-20%	-25%

The investment in Generation Plant – Accessory Electrical Equipment is approximately $51.7 million and represents 2.18 percent of the total depreciable plant studied. This account includes the auxiliary, control, switching and conversion equipment associated with hydro-electric generation equipment or motors.

The currently approved life parameter is an Iowa 40-R2.5. The retirements, additions and other plant transactions, for the period 1950 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1978 through 2022, of $4,656,557 were recorded. The currently approved Iowa 40-R2.5 produced a related residual measure of 2.1156. The proposed Iowa 42-R2.5 produces a better visual and mathematical fit with a residual measure of 1.8488, as depicted on page 6-15. Operations personnel indicated that the control equipment included in this account has been mostly replaced with digital technology. Newer digital equipment provides for better condition assessments of the assets being protected, however, the technological nature and reliance on vendor support for the technology included in these assets may cause retirement at an earlier age than previously experienced with the older generation mechanical protection equipment. It is too soon to know if these potential life decreases will be seen, and as such, Concentric recommends a small life lengthening at this time to better match the historical data. The Iowa 42-R2.5 does a better job of picking up retirements up until age 30, where most of the experience occurs. A review of peer Canadian hydro-electric generation, and electric transmission and distribution utilities indicates a life of between 35 and 50 years. FortisBC is on the lower end of other Canadian hydro-electric generation and electric distribution utilities. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 42-R2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 42-R2.5 to represent the future expectations for the investment in this account.

FortisBC has incurred over $1.6 million in cost of removal in this account between 1999-2022. The historical net salvage activity shows a range from negative 2 percent to negative 45 percent. A three-year band analysis shows a range from negative one percent to negative 195 percent. A five-year band analysis produces a range from 0 percent to over negative 150 percent. The full-depth band for this account shows an amount of negative 37 percent. Canadian hydro-electric generation, and electric transmission and distribution peers have net salvage ranging from negative 8 to negative 63 percent. Concentric views that it would be reasonable to increase negative net salvage at this time. Given the concept of gradualism and an increase in cost of removal since the previous study, Concentric is recommending a net salvage rate of negative 25 percent to reflect actual experience and near-term requirements.

ACCOUNT 335.00 – GENERATION PLANT – OTHER POWER PLANT EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$45,994,334	1.94%	51-R4	45-R4	-15%	-5%

The investment in Generation Plant – Other Power Plant Equipment is approximately $46.0 million and represents 1.94 percent of the total depreciable plant studied. This account includes miscellaneous equipment associated with generation of power which are not included in other, more identifiable accounts.

The currently approved life parameter is an Iowa 51-R4. The retirements, additions and other plant transactions, for the period 1957 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1977 through 2022, of $2,173,116 were recorded. The currently approved Iowa 51-R4 produced a related residual measure of 1.1202. The proposed Iowa 45-R4 produces a better visual and mathematical fit with a residual measure of 0.9642 as depicted on page 6-19. The 45-R4 produced a better statistical fit to the data due to an increase in retirements from age interval 18 to 26, indicating a need to shorten the service life for this account to consider early to mid-term retirements. Discussions with management and operational staff indicated that the reduction in service life for this account is justified as changes in technology drive retirements of shorter-lived power plant equipment. A review of peer Canadian hydro-electric generation, and electric transmission and distribution utilities indicates a life of between 23 and 40 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 45-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 45-R4 to represent the future expectations for the investment in this account.

FortisBC has incurred $144,625 in cost of removal in this account between 2000-2022. The historical net salvage activity shows a range from negative 1 percent to negative 7 percent. A three-year band analysis shows a range from negative one percent to negative 87 percent. A five-year band analysis produces a range from negative 1 percent to negative 35 percent. The full-depth band for this account shows an amount of negative 7 percent. Canadian hydro-electric generation, and electric transmission and distribution peers have net salvage ranging from 0 percent to over negative 200 percent. Concentric views that it would be reasonable to decrease the negative net salvage rate at this time. Given the decreases in cost of removal within the past 5 years since the previous study, Concentric is recommending a net salvage rate of negative 5 percent to reflect actual experience and near-term requirements.

ACCOUNT 353.00 – TRANSMISSION PLANT – SUBSTATION EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$274,187,157	11.56%	50-R4	52-R4	-25%	-30%

The investment in Transmission Plant – Substation Equipment is approximately $274.2 million and represents 11.56 percent of the total depreciable plant studied. Substation equipment within the transmission group includes the installed cost of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits.

The currently approved life parameter is an Iowa 50-R4. The retirements, additions and other plant transactions, for the period 1940 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $5,124,464 were recorded. The currently approved Iowa 50-R4 produced a fit with a related residual measure of 0.8126. An Iowa 52-R4 produced a better fit with a related residual measure of 0.5238, as depicted on page 6-30. As a result, the curve fit to the data by lengthening the life by two years is substantially better. The 52-year life, along with the R4 curve captures the initial retirements up until age 40. Also, by moving to a 52-year life, the curve captures more of the gradual retirements from age 40 onwards. Discussions with FortisBC operational and management staff indicated that a 52-year life is a good representation of the historical life and future expectations of retirements. A review of peer Canadian electric transmission utilities indicates a life of between 32 and 52 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 52-R4 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 52-R4 to represent the future expectations for the investment in this account.

FortisBC has incurred over $3 million in cost of removal in this account between 1998-2022. The historical net salvage activity shows a range from negative 1 percent to negative 70 percent. A three-year band analysis shows a range from negative one percent to over negative 1000 percent. A five-year band analysis produces a range from negative 1 percent to over negative 150 percent. The full-depth band for this account shows an amount of negative 69 percent. Canadian electric transmission peers have net salvage ranging from negative 10 to negative 30 percent. FortisBC has also seen large costs of removal since 2018 of over $1 million. Concentric views that it would be reasonable to increase the negative net salvage rate at this time. Given the concept of gradualism and an increase in cost of removal since the previous, Concentric is recommending a net salvage rate of negative 30 percent to reflect actual experience and near-term requirements.

ACCOUNT 355.00 – TRANSMISSION PLANT – POLES, TOWERS AND FIXTURES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$129,864,752	5.47%	50-R1.5	50-R2	-35%	-40%

The investment in Transmission Plant – Poles, Towers and Fixtures is approximately $129.9 million and represents 5.47 percent of the total depreciable plant studied. This account reflects the installed costs of electric transmission poles and towers. The associated components include guy wires, crossarms, brackets, insulators, and excavation and backfill material used in the installation of these structures.

The currently approved life parameter is an Iowa 50-R1.5. The retirements, additions and other plant transactions, for the period 1950 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $10,110,715 were recorded. The currently approved Iowa 50-R1.5 produced a fit with a related residual measure of 0.4581. An Iowa 50-R2 produced a better fit with a related residual measure of 0.4222, as depicted on page 6-34. The R2 curve captures the initial retirements from age 0 through age 40 better than the R1.5 does, and over half of the retirement dollars are experienced within this range. Also, by moving from a R1.5 to an R2, the curve captures more of the gradual retirements from age 40 onwards. As there is not a large record of retirements, capturing the gradual nature of them in that age range is important. This is consistent with the management and operational staff interviews from the previous studies, which indicated that shorter lives can occur when temporary services related to highway construction are put in place and removed after a few years. Additionally, staff indicated the program to replace pole and tower components is still on-going, lasting for a minimum of 40 years. Staff also indicated that the practice of using of steel stub supports for selected newer poles that show early signs of deterioration remains part of FortisBC's maintenance program and is meant to offset any decrease in service life. Discussions with FortisBC operational and management staff indicated that a 50-year life is a good representation of the historical life and future expectations of retirements. A review of peer Canadian electric transmission utilities indicates a life of between 40 and 65 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 50-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 50-R2 to represent the future expectations for the investment in this account.

FortisBC has incurred over $10 million in cost of removal in this account between 1998-2022. The historical net salvage activity shows a range from negative 1 percent to over negative 100 percent. A three-year band analysis shows a range from negative one percent to over negative 700 percent. A five-year band analysis produces a range from negative 1 percent to over negative 400 percent. The full-depth band for this account shows an amount of negative 106 percent. Canadian electric transmission peers have net salvage ranging from negative 10 to negative 90 percent. FortisBC has also seen an increase in costs of removal since 2018 of over $3 million. Concentric views that it would be reasonable to increase the negative net salvage rate at this time. Given the concept of gradualism and an increase in cost of removal since the previous study, Concentric is recommending a net salvage rate of negative 40 percent to reflect actual experience and near-term requirements.

ACCOUNT 356.00 – TRANSMISSION PLANT – CONDUCTORS AND DEVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$127,644,855	5.38%	51-R1.5	51-R2	-30%	-35%

The investment in Transmission Plant – Conductors and Devices is approximately $127.6 million and represents 5.38 percent of the total depreciable plant studied. This account includes investment related to the overhead conductors and devices used at a transmission voltage. The components include the conductors, circuit breakers, insulating wires, cables and ground wires, and lightning arresters and associated switches.

The currently approved life parameter is an Iowa 51-R1.5. The retirements, additions and other plant transactions, for the period 1940 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $9,175,802 were recorded. The currently approved Iowa 51-R1.5 produced a fit with a related residual measure of 0.4448. An Iowa 51-R2 produced a better fit with a related residual measure of 0.4118, as depicted on page 6-38. The R2 curve captures the initial retirements from age 0 through age 40 better than the R1.5 does, and over half of the retirement dollars are experienced within this range. Also, by moving from a R1.5 to an R2, the curve captures more of the gradual retirements from age 40 onwards. As there is not a large record of retirements, capturing the gradual nature of them in that age range is important. Discussions with FortisBC operational and management staff indicated that a 51-year life is a good representation of the historical life and future expectations of retirements. A review of peer Canadian electric transmission utilities indicates a life of between 45 and 85 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 51-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 51-R2 to represent the future expectations for the investment in this account.

FortisBC has incurred over $10 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from negative 1 percent to over negative 100 percent. A three-year band analysis shows a range from negative one percent to over negative 900 percent. A five-year band analysis produces a range from negative 1 percent to over negative 400 percent. The full-depth band for this account shows an amount of negative 117 percent. Canadian electric transmission peers have net salvage ranging from negative 13 to negative 50 percent. FortisBC has also seen increase in costs of removal since 2018 of over $3 million. Concentric views that it would be reasonable to increase the negative net salvage rate at this time. Given the concept of gradualism and an increase in cost of removal since the previous study, Concentric is recommending a net salvage rate of negative 35 percent to reflect actual experience and near-term requirements.

ACCOUNT 362.00 – DISTRIBUTION PLANT – SUBSTATION EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$290,961,496	12.26%	50-R3	50-R3	-30%	-30%

The investment in Distribution Plant – Substation Equipment is approximately $291.0 million and represents 12.26 percent of the total depreciable plant studied. This account includes the station equipment related to electric distribution service. Components include control equipment, transformers, switches, cooling equipment and ducting in the substation at the lower distribution level.

The currently approved life parameter is an Iowa 50-R3. The retirements, additions and other plant transactions, for the period 1950 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $14,600,387 were recorded. The currently approved Iowa 50-R3 produced a related residual measure of 0.9672, as depicted on page 6-50. Discussions with FortisBC operational and management staff indicated that a 50-year life is still a good representation of the historical life and future expectations for retirements in this account. There has been an increase of approximately 65 percent in the retirement experience in this account, up from $8,831,733 in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same age range of plant as it did previously. A review of peer Canadian electric distribution utilities indicates a life of between 25 and 55 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 50-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 50-R3 to continue to represent the future expectations for this account.

FortisBC has incurred over $4 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from negative 1 percent to over negative 40 percent. A three-year band analysis shows a range from negative 1 percent to negative 94 percent. A five-year band analysis produces a range from negative 1 percent to negative 86 percent. The full-depth band for this account shows an amount of negative 32 percent. Canadian electric distribution peers have net salvage of negative 5 percent. At this time, Concentric recommends a negative 30 percent net salvage estimate be used in the depreciation calculations within this study due to FortisBC's recent experience and near-term requirements.

ACCOUNT 364.00 – DISTRIBUTION PLANT – POLES, TOWERS AND FIXTURES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$262,331,266	11.06%	50-R3	50-R3	-35%	-40%

The investment in Distribution Plant – Poles, Towers, and Fixtures is approximately $262.3 million and represents 11.06 percent of the total depreciable plant studied. This account reflects the installed costs of poles or towers and support fixtures that carry overhead conductors at a distribution level. Equipment in this account includes guy wires, crossarms, brackets and the excavation and backfill of materials associated with their installation.

The currently approved life parameter is an Iowa 50-R3. The retirements, additions and other plant transactions, for the period 1940 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $10,905,848 were recorded. The currently approved Iowa 50-R3 produced a related residual measure of 1.0289, as depicted on page 6-54. Discussions with FortisBC operational and management staff indicated that a 50-year life is still a good representation of the historical life and future expectations for retirements in this account. There has been an increase of approximately 18 percent in the retirement experience in this account, up from $9,189,981 in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same age range of plant as it did previously. A review of peer Canadian electric distribution utilities indicates a life of between 43 and 60 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 50-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 50-R3 to continue to represent the future expectations for this account.

FortisBC has incurred over $12 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from 0 percent to over negative 100 percent. A three-year band analysis shows a range from 0 percent to over negative 600 percent. A five-year band analysis produces a range from 0 percent to over negative 300 percent. The full-depth band for this account shows an amount of negative 126 percent. Canadian electric distribution peers have net salvage ranging from negative 5 percent to negative 65 percent. FortisBC has also seen an increase in cost of removal since 2018 of over $5 million. Costs of removal for poles, towers and fixtures have increased over the last 14 years as compared to the original cost retired. Concentric views that it would be reasonable to increase the negative net salvage rate at this time. Given the concept of gradualism and an increase in cost of removal since the previous study, Concentric is recommending a net salvage rate of negative 40 percent to reflect actual experience and near-term requirements.

ACCOUNT 365.00 – DISTRIBUTION PLANT – CONDUCTORS AND DEVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$421,758,681	17.78%	55-R2.5	55-R3	-35%	-35%

The investment in Distribution Plant – Conductors and Devices is approximately $421.8 million and represents 17.78 percent of the total depreciable plant studied. This account reflects the installed costs of distribution overhead conductors. The components include pole top circuit breakers, conductors, ground wires, insulators, lightning arresters and associated tie wires or clamps.

The currently approved life parameter is an Iowa 55-R2.5. The retirements, additions and other plant transactions, for the period 1950 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $17,179,597 were recorded. The currently approved Iowa 55-R2.5 produced a fit with a related residual measure of 0.5073. An Iowa 55-R3 produced a better fit with a related residual measure of 0.4132, as depicted on page 6-58. The R3 curve captures the initial retirements from age 0 through age 40 better than the R2.5 does, and over half of the retirement dollars are experienced within this range. Also, by moving from a R2.5 to an R3, the curve captures more of the gradual retirements from age 40 onwards. Discussions with FortisBC operational and management staff indicated that a 55-year life is a good representation of the historical life and future expectations of retirements. A review of peer Canadian electric distribution utilities indicates a life of between 48 and 65 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 55-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 55-R3 to represent the future expectations for the investment in this account.

FortisBC has incurred over $19 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from negative 1 percent to over negative 100 percent. A three-year band analysis shows a range from negative one percent to over negative 400 percent. A five-year band analysis produces a range from negative 1 percent to over negative 300 percent. The full-depth band for this account shows an amount of negative 142 percent. Canadian electric distribution peers have net salvage ranging from negative 5 to negative 65 percent. The data indicates net salvage costs for distribution conductors and devices are significantly more negative than the same types of devices at the transmission level. Operations staff confirmed that cost of removal for distribution conductors are not necessarily the same as experienced for transmission conductors. At this time, Concentric recommends a negative 35 percent net salvage estimate be used in the depreciation calculations within this study due to FortisBC's recent experience and near-term requirements.

ACCOUNT 368.00 – DISTRIBUTION PLANT – LINE TRANSFORMERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$206,615,205	8.71%	42-R3	40-R3	-25%	-30%

The investment in Distribution Plant – Line Transformers is approximately $206.6 million and represents 8.71 percent of the total depreciable plant studied. This account reflects the installed costs of distribution line transformers, either overhead or underground, as well as voltage regulators. Components of these costs include the transformer cut-out boxes, capacitors, transformer lightning arrestors and the labour associated with their installation.

The currently approved life parameter is an Iowa 42-R3. The retirements, additions and other plant transactions, for the period 1940 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1975 through 2022, of $25,920,730 were recorded. The currently approved Iowa 42-R3 produced a related residual measure of 1.1163. The proposed Iowa 40-R3 produces a better visual and mathematical fit with a residual measure of 0.8246 as depicted on page 6-62. The 40-R3 produced a better statistical fit to the data due to an increase in retirements from age interval 25 onwards, indicating a need to shorten the service life for this account to consider early to mid-term retirements. A review of peer Canadian electric distribution utilities indicates a life of between 30 and 50 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 40-R3 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 40-R3 to represent the future expectations for the investment in this account.

FortisBC has incurred over $8 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from negative 1 percent to negative 37 percent. A three-year band analysis shows a range from negative one percent to negative 65 percent. A five-year band analysis produces a range from negative 1 percent to negative 58 percent. The full-depth band for this account shows an amount of negative 37 percent. Canadian electric distribution peers have net salvage ranging from 5 percent to negative 5 percent. FortisBC has also consistent increases in costs of removal since the previous study. As such, Concentric views that it would be reasonable to increase the negative net salvage rate at this time. Given the concept of gradualism, Concentric is recommending an increase in the net salvage rate to negative 30 percent to reflect actual experience and near-term requirements.

ACCOUNT 390.10 – GENERAL PLANT – STRUCTURES MASONRY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$51,640,669	2.18%	35-S1	35-R2	-5%	-5%

The investment in General Plant – Structures Masonry is approximately $51.6 million and represents 2.18 percent of the total depreciable plant studied. This account includes any masonry structures or improvements used for general purposes and not directly for specific generation or operations purposes. The components may be the buildings, fencing, landscaping, sewage, roads and any associated improvements.

The currently approved life parameter is an Iowa 35-S1. The retirements, additions and other plant transactions, for the period 1940 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1977 through 2022, of $2,758,849 were recorded. The currently approved Iowa 35-S1 produced a fit with a related residual measure of 0.8758. An Iowa 35-R2 produced a better fit with a related residual measure of 0.7490, as depicted on page 6-72. The R2 curve captures the retirements from age 18 onwards better than the S1 does, and over half of the retirement dollars are experienced after this range. Discussions with FortisBC operational and management staff indicated that a 35-year life is a good representation of the historical life and future expectations of retirements. A review of peer Canadian electric utilities indicates a life of between 20 and 65 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 35-R2 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 35-R2 to represent the future expectations for the investment in this account.

FortisBC has incurred over $1 million in cost of removal in this account between 1995-2022. The historical net salvage activity shows a range from negative 1 percent to negative 60 percent. A three-year band analysis shows a range from negative one percent to over negative 300 percent. A five-year band analysis produces a range from negative 1 percent to over negative 300 percent. The full-depth band for this account shows an amount of negative 52 percent. Canadian electric peers have net salvage ranging from 0 percent to negative 5 percent. Net salvage data for the Structures Masonry account has been historically very sparse. At this time, Concentric recommends a negative 5 percent net salvage estimate be maintained to address any near-term requirements.

ACCOUNT 392.10 – GENERAL PLANT - LIGHT DUTY VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$4,778,115	0.20%	12-L1	12-L1	15%	10%

The investment in General Plant – Light Duty Vehicles is approximately $4.8 million and represents 0.20 percent of the total depreciable plant studied. This account contains vehicles ranging from on-call trucks to fleet vehicles (cars and light duty trucks) that are used in various roles as well as within the general pool for employee use.

The currently approved life parameter is an Iowa 12-L1. The retirements, additions and other plant transactions, for the period 1966 through 2022, were analyzed by the retirement rate method. Retirements, for the period 2006 through 2022, of $18,568,396, were recorded. The currently approved Iowa 12-L1 produced a related residual measure of 0.2483, as depicted on page 6-78. Discussions with FortisBC operational and management staff indicated that a 12-year life is still a good representation of the historical life and future expectations for retirements in this account. There has been an increase of approximately 20 percent in the retirement experience in this account, up from $15,473,384 in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same age range of plant as it did previously. A review of peer Canadian electric utilities indicates a life of between 6 and 14 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 12-L1 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 12-L1 to continue to represent the future expectations for this account.

FortisBC has retained $40,200 in net salvage in this account between 2016-2022. The historical net salvage activity shows a range from 1 percent to 5 percent. A three-year band analysis shows a range from 0 percent to 70 percent. A five-year band analysis produces a range from 0 percent to 27 percent. The full-depth band for this account shows an amount of 5 percent. Canadian electric peers have net salvage ranging from 5 percent to 15 percent. At the time of this study, FortisBC had experienced anomalous data over the past 3 years with decreases in salvage. Discussions with FortisBC operational and management staff confirmed this trend is expected to continue. Concentric views that it would be reasonable to decrease the net salvage rate at this time. Given the concept of gradualism and limited cost of removal data, Concentric is recommending a net salvage rate of 10 percent to reflect actual experience and near-term expectations.

ACCOUNT 392.20 – GENERAL PLANT - HEAVY DUTY VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$30,246,074	1.27%	16-L2.5	16-L2.5	15%	10%

The investment in General Plant – Heavy Duty Vehicles is approximately $30.2 million and represents 1.27 percent of the total depreciable plant studied. This account includes bigger trucks and rolling equipment used in heavier duty environments.

The currently approved life parameter is an Iowa 16-L2.5. The retirements, additions and other plant transactions, for the period 1972 through 2022, were analyzed by the retirement rate method. Retirements, for the period 1990 through 2022, of $21,573,478 were recorded. The currently approved Iowa 16-L2.5 produced a related residual measure of 0.4406, as depicted on page 6-81. Discussions with FortisBC operational and management staff indicated that a 16-year life is still a good representation of the historical life and future expectations for retirements in this account. There has been an increase of approximately 15 percent in the retirement experience in this account, up from $18,696,095 in the previous study. However, the additional data since the last study has not indicated a need to change the recommended life for this account as most of the retirement experience occurs within the same age range of plant as it did previously. A review of peer Canadian electric utilities indicates a life of between 5 and 20 years. Based on the above discussion and considerations, and on Concentric's experience, an Iowa 16-L2.5 is a reasonable expectation for the investment in this account. As such, Concentric recommends an Iowa 16-L2.5 to continue to represent the future expectations for this account.

FortisBC has incurred $36,031 in salvage in this account between 2010-2022. The historical net salvage activity shows a range from 1 percent to 3 percent. A three-year band analysis shows a range from 1 percent to 55 percent. A five-year band analysis produces a range from 1 percent to 23 percent. The full-depth band for this account shows an amount of 3 percent. Canadian electric peers have net salvage ranging from 5 percent to 15 percent. Recent data points to lower gross salvage proceeds combined with no costs of removal, resulting in a reduction in the recent five-year and three-year moving averages. Concentric views that it would be reasonable to decrease the net salvage rate to 10 percent at this time. Given the concept of gradualism and limited cost of removal data, Concentric is recommending a net salvage rate of 10 percent to reflect actual experience and near-term expectations.

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because (normally) all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group procedure, the rate of annual depreciation is based on the average service life of the group - this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

In the determination of the depreciation rates in this study, the use of the Average Life Group procedure has been continued. While the Equal Life Group procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Average Life Group procedure was used in order to conform to past Company practices and approvals by the BCUC.

4.2 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amounts over the life of the asset to which it is expected to apply. The distribution of the amount is in equal amounts to each year of the amortization period.

Group systems of accounting depreciation is one of two systems used to determine depreciation of assets. The other is the unit system of accounting depreciation where depreciation is calculated for large, identifiable pieces of equipment that are easy to identify, have a lot of capital in each unit and are rather unique.[3] Examples include large excavators, a large reservoir or large dam.

The group system chooses to combine several similar units that are smaller into groups which then are analyzed according to their common traits. Examples include many individual meters, transformers or similar substation equipment that would share the same life span, cost of removal and dispersion of retirements. The assets in group accounting are often tracked as soon as one item

[3] Anson Marston, R. W., *Engineering Valuation and Depreciation* (Iowa State University Press,1982), 224

is purchased, and then retired when the asset being removed from service. All of this takes some effort but leads to the ultimate dispersion of retirements and retirement rate analyses.

Within the group system of accounting, there are classes of equipment that are very numerous but represent a small portion of overall depreciable plant. Tracking the individual purchases and retirements of each item in the class would require effort and cost that would not be justified in relation to the level of accuracy in the results. Even if such an effort was optimized and made effective, sometimes retirements of small items in the group would be missed. Examples may include the many pieces of furniture, computer hardware, software licenses, communication equipment and small tools. The system would depend on utilization and retirement notifications of disparate small items and entries to ensure surviving balances of old vintages are still in service.

To minimize this extra cost to the rate payers and estimation and notification errors, amortization accounting places an estimated life span to the entire class and automatically retires the asset at the end of a selected amortization period. This takes group accounting to a higher, more simplified level by treating all items belonging to a certain vintage year as one asset. Rather than tracking the many individual parts through their acquisition and retirements through labour intensive notifications and accounting entries, amortization accounting simplifies retirements while still adhering to proper depreciation principles.

Concentric continues to recommend the practice of using amortization accounting for selected accounts (mainly general plant accounts) because of the disproportionate plant accounting effort required when compared to the large number of small cost items in these accounts as discussed above.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment that incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for the following accounts:

Account	Title	Amortization Period in Years
370.10	AMI Meters	18
391.00	Office Furniture and Equipment	15
391.10	Computer Hardware	4
391.20	Computer Software	8
391.60	AMI Computer Software	10
394.00	Tools and Work Equipment	15
397.00	Communications Structures and Equipment	15

397.10	Fiber	15
397.20	Communications Structures and Equipment	15

For calculating annual amortization amounts, as of December 31, 2022, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. Any amount of book reserve in vintages older than the amortization period has been deducted from both the original cost as well as from accumulated depreciation. This approach assumes that the original costs of vintages, older than the chosen amortization period, will have been retired along with their accumulated depreciation.

The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age, to its amortization period. An annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

As shown in Section 5, there are a number of General Plant accounts in which the depreciation rate is not yet indicative of an amortized account. This is due to the true up inherent in the depreciation rate calculation as a result of historical differences between the book reserve and the calculated accrued amortization for those accounts.

SECTION 5

5 RESULTS OF THE STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the average life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in Section 6 of this report.

For each depreciable group analyzed by the Retirement Rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2022 are presented in account sequence in Section 8 of the supporting documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation and the calculated annual accrual.

FortisBC - Electricity

TABLE 1 - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
TOTAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate		Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
GENERATION PLANT										
330.10	Land Rights	75-R4	-	961,358	380,204	581,154	9,770	1.02		57.53
331.00	Structures and Improvements	60-S1.5	(10)	21,009,050	6,707,897	16,402,059	360,339	1.72		45.07
332.00	Reservoirs, Dams and Waterways	75-S2	(30)	116,281,849	(1,389,971)	152,556,375	2,313,932	1.99		68.35
333.00	Water Wheels, Turbines and Generators	70-R2.5	(30)	122,271,003	29,148,212	129,804,093	2,279,083	1.86		56.99
334.00	Accessory Electrical Equipment	42-R2.5	(25)	51,723,325	18,760,437	45,893,719	1,551,824	3.00		29.69
335.00	Other Power Plant Equipment	45-R4	(5)	45,994,334	19,797,799	28,496,252	1,038,706	2.26		27.18
336.00	Roads, Railroads and Bridges	75-R4	-	1,287,434	477,231	810,203	18,340	1.42		44.45
TOTAL GENERATION PLANT				**359,528,354**	**73,881,808**	**374,543,854**	**7,571,994**	**2.11**		
TRANSMISSION PLANT										
350.20	Surface and Mineral	75-R4	-	8,449,306	2,468,250	5,981,056	107,273	1.27		55.23
353.00	Substation Equipment	52-R4	(30)	274,187,157	106,016,347	250,426,957	6,529,938	2.38		37.87
355.00	Poles, Towers and Fixtures	50-R2	(40)	129,864,752	45,300,443	136,510,211	3,639,516	2.80		37.52
356.00	Conductors and Devices	51-R2	(35)	127,644,855	38,579,901	133,740,653	3,520,057	2.76		38.35
359.00	Roads and Trails	50-R3	-	1,121,930	435,601	686,328	20,848	1.86		32.48
TOTAL TRANSMISSION PLANT				**541,268,000**	**192,800,542**	**527,345,205**	**13,817,632**	**2.55**		
DISTRIBUTION PLANT										
360.20	Surface and Mineral	75-R4	-	12,557,004	2,962,387	9,594,617	157,463	1.25		60.32
362.00	Substation Equipment	50-R3	(30)	290,961,496	93,948,266	284,301,679	7,647,376	2.63		37.27
364.00	Poles, Towers and Fixtures	50-R3	(40)	262,331,266	86,982,832	280,280,940	7,658,201	2.92		37.07
365.00	Conductors and Devices	55-R3	(35)	421,758,681	138,745,441	430,628,778	10,385,741	2.46		41.50
368.00	Line Transformers	40-R3	(30)	206,615,205	51,432,973	217,166,794	7,383,637	3.57		30.12
369.00	Services	70-R4	-	3,431,459	632,042	2,799,417	61,886	1.80		46.68
370.10	AMI Meters	18-SQ	-	41,935,015	9,037,025	32,897,991	1,827,666	5.56	*	11.74
373.00	Street Lighting and Signal Systems	25-R2	(15)	14,020,267	7,002,353	9,120,954	629,794	4.49		14.42
TOTAL DISTRIBUTION PLANT				**1,253,610,393**	**390,743,318**	**1,266,791,170**	**35,751,764**	**2.85**		
GENERAL PLANT										
390.10	Structures - Masonry	35-R2	(5)	51,640,669	12,987,032	41,235,671	1,424,873	2.76		28.06
390.20	Operations Buildings	50-R4	(5)	18,051,672	6,975,330	11,978,926	313,669	1.74		37.18
391.00	Office Furniture and Equipment	15-SQ	-	5,180,462	1,511,742	3,668,720	451,493	5.54	**	9.37
391.10	Computer Hardware	4-SQ	-	13,092,326	4,708,913	8,383,413	2,095,853	25.00	*	2.44
391.20	Computer Software	8-SQ	-	48,334,443	17,139,671	31,194,771	6,689,920	10.73	**	4.91
391.60	AMI Computer Software	10-SQ	-	9,581,690	7,227,836	2,353,854	235,385	10.00	*	2.46
392.10	Light Duty Vehicles	12-L1	10	4,778,115	1,436,356	2,863,947	326,358	6.83		8.63
392.20	Heavy Duty Vehicles	16-L2.5	10	30,246,074	9,174,671	18,046,795	1,812,046	5.99		10.14
394.00	Tools and Work Equipment	15-SQ	-	8,433,816	3,516,168	4,917,648	658,381	5.39	**	8.25
397.00	Communications Structures and Equipment	15-SQ	-	13,389,020	5,022,993	8,366,027	749,395	5.05	**	9.71
397.10	Fiber	15-SQ	-	10,315,657	7,085,073	3,230,584	215,372	6.67	*	4.99
397.20	AMI Communications Structure and Equipment	15-SQ	-	4,969,732	2,393,958	2,575,774	171,718	6.67	*	7.78
TOTAL GENERAL PLANT				**218,013,675**	**79,179,743**	**138,816,130**	**15,144,464**	**6.95**		
TOTAL DEPRECIABLE PLANT				**2,372,420,422**	**736,605,412**	**2,307,496,359**	**72,285,854**	**3.05**		

FortisBC - Electricity

TABLE 1 - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
TOTAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
PLANT NOT STUDIED									
114.00	Utility Plant Acquisition Adjustment			11,912,000					
350.10	Land Rights Transmission			9,219,544					
360.10	Land Rights Distribution			8,888,837					
360.20	Distribution Station Equipment - Non-Regulated			65,734					
370.00	Meters			-					
389.00	Land			11,192,370					
390.90	Leasehold Improvements			3,618,765					
999.90	Contribution in Aid of Construction			-					
107.10	Work-In-Progress - Asset Management			-					
TOTAL NON - DEPRECIABLE PLANT				**44,897,251**	**-**				
TOTAL PLANT				**2,417,317,672**	**736,605,412**	**2,307,496,359**	**72,285,854**		

* Amortization Accouting Proposed

** Amortized accounts with a gain/loss calculated by taking the half-way point between the full amortized rate and the previous study accrual rate

FortisBC - Electricity

TABLE 1A - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
LIFE

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate		Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
GENERATION PLANT										
330.10	Land Rights	75-R4	-	961,358	380,204	581,154	9,770	1.02		57.53
331.00	Structures and Improvements	60-S1.5	-	21,009,050	7,213,801	13,795,250	298,699	1.42		45.07
332.00	Reservoirs, Dams and Waterways	75-S2	-	116,281,849	10,920,102	105,361,746	1,538,056	1.32		68.35
333.00	Water Wheels, Turbines and Generators	70-R2.5	-	122,271,003	26,676,930	95,594,074	1,665,587	1.36		56.99
334.00	Accessory Electrical Equipment	42-R2.5	-	51,723,325	17,084,874	34,638,451	1,111,253	2.15		29.69
335.00	Other Power Plant Equipment	45-R4	-	45,994,334	18,856,517	27,137,817	989,184	2.15		27.18
336.00	Roads, Railroads and Bridges	75-R4	-	1,287,434	477,231	810,203	18,340	1.42		44.45
TOTAL GENERATION PLANT				**359,528,354**	**81,609,659**	**277,918,695**	**5,630,889**	**1.57**		
TRANSMISSION PLANT										
350.20	Surface and Mineral	75-R4	-	8,449,306	2,468,250	5,981,056	107,273	1.27		55.23
353.00	Substation Equipment	52-R4	-	274,187,157	96,376,585	177,810,573	4,514,604	1.65		37.87
355.00	Poles, Towers and Fixtures	50-R2	-	129,864,752	43,401,101	86,463,652	2,227,031	1.71		37.52
356.00	Conductors and Devices	51-R2	-	127,644,855	37,482,584	90,162,270	2,305,857	1.81		38.35
359.00	Roads and Trails	50-R3	-	1,121,930	435,601	686,328	20,848	1.86		32.48
TOTAL TRANSMISSION PLANT				**541,268,000**	**180,164,121**	**361,103,879**	**9,175,613**	**1.70**		
DISTRIBUTION PLANT										
360.20	Surface and Mineral	75-R4	-	12,557,004	2,945,937	9,611,067	157,786	1.26		60.32
362.00	Substation Equipment	50-R3	-	290,961,496	82,785,071	208,176,425	5,513,540	1.89		37.27
364.00	Poles, Towers and Fixtures	50-R3	-	262,331,266	80,644,791	181,686,474	4,747,752	1.81		37.07
365.00	Conductors and Devices	55-R3	-	421,758,681	129,075,969	292,682,712	6,796,713	1.61		41.50
368.00	Line Transformers	40-R3	-	206,615,205	48,718,132	157,897,074	5,268,987	2.55		30.12
369.00	Services	70-R4	-	3,431,459	632,042	2,799,417	61,886	1.80		46.68
370.10	AMI Meters	18-SQ	-	41,935,015	9,109,949	32,825,066	1,823,615	5.56	*	11.74
373.00	Street Lighting and Signal Systems	25-R2	-	14,020,267	6,373,831	7,646,436	523,342	3.73		14.42
TOTAL DISTRIBUTION PLANT				**1,253,610,393**	**360,285,721**	**893,324,671**	**24,893,621**	**1.99**		
GENERAL PLANT										
390.10	Structures - Masonry	35-R2	-	51,640,669	14,001,946	37,638,723	1,275,869	2.47		28.06
390.20	Operations Buildings	50-R4	-	18,051,672	6,910,807	11,140,865	290,473	1.61		37.18
391.00	Office Furniture and Equipment	15-SQ	-	5,180,462	1,511,742	3,668,720	451,493	5.54	**	9.37
391.10	Computer Hardware	4-SQ	-	13,092,326	4,708,913	8,383,413	2,095,853	25.00	*	2.44
391.20	Computer Software	8-SQ	-	48,334,443	17,139,671	31,194,771	6,689,920	10.73	**	4.91
391.60	AMI Computer Software	10-SQ	-	9,581,690	7,227,836	2,353,854	235,385	10.00	*	2.46
392.10	Light Duty Vehicles	12-L1	-	4,778,115	370,889	4,407,226	533,583	11.17		8.63
392.20	Heavy Duty Vehicles	16-L2.5	-	30,246,074	9,174,671	21,071,402	2,155,450	7.13		10.14
394.00	Tools and Work Equipment	15-SQ	-	8,433,816	3,516,168	4,917,648	658,381	5.39	**	8.25
397.00	Communications Structures and Equipment	15-SQ	-	13,389,020	5,437,707	7,951,313	634,122	4.75	**	9.71
397.10	Fiber	15-SQ	-	10,315,657	7,085,073	3,230,584	215,372	6.67	*	4.99
397.20	AMI Communications Structure and Equipment	15-SQ	-	4,969,732	2,393,958	2,575,774	171,718	6.67	*	7.78
TOTAL GENERAL PLANT				**218,013,675**	**79,479,381**	**138,534,294**	**15,407,620**	**7.07**		
TOTAL DEPRECIABLE PLANT				**2,372,420,422**	**701,538,883**	**1,670,881,539**	**55,107,743**	**2.32**		

FortisBC - Electricity

TABLE 1A - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT
LIFE

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
PLANT NOT STUDIED									
114.00	Utility Plant Acquisition Adjustment			11,912,000					
350.10	Land Rights Transmission			9,219,544					
360.10	Land Rights Distribution			8,888,837					
360.20	Distribution Station Equipment - Non-Regulated			65,734					
370.00	Meters			-					
389.00	Land			11,192,370					
390.90	Leasehold Improvements			3,618,765					
999.90	Contribution in Aid of Construction			-					
107.10	Work-In-Progress - Asset Management			-					
TOTAL NON - DEPRECIABLE PLANT				**44,897,251**	**-**				
TOTAL PLANT				**2,417,317,672**	**701,538,883**	**1,670,881,539**	**55,107,743**		

* Amortization Accouting Proposed

** Amortized accounts with a gain/loss calculated by taking the half-way point between the full amortized rate and the previous study accrual rate

FortisBC - Electricity

TABLE 1B - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
GENERATION PLANT								
330.10	Land Rights	75-R4	-	961,358	-	-	-	-
331.00	Structures and Improvements	60-S1.5	(10)	21,009,050	(505,904)	2,606,809	61,640	0.29
332.00	Reservoirs, Dams and Waterways	75-S2	(30)	116,281,849	(12,310,074)	47,194,628	775,876	0.67
333.00	Water Wheels, Turbines and Generators	70-R2.5	(30)	122,271,003	2,471,282	34,210,019	613,496	0.50
334.00	Accessory Electrical Equipment	42-R2.5	(25)	51,723,325	1,675,563	11,255,268	440,571	0.85
335.00	Other Power Plant Equipment	45-R4	(5)	45,994,334	941,282	1,358,435	49,522	0.11
336.00	Roads, Railroads and Bridges	75-R4	-	1,287,434	-	-	-	-
TOTAL GENERATION PLANT				**359,528,354**	**(7,727,851)**	**96,625,159**	**1,941,105**	**0.54**
TRANSMISSION PLANT								
350.20	Surface and Mineral	75-R4	-	8,449,306	-	-	-	-
353.00	Substation Equipment	52-R4	(30)	274,187,157	9,639,762	72,616,385	2,015,334	0.74
355.00	Poles, Towers and Fixtures	50-R2	(40)	129,864,752	1,899,342	50,046,559	1,412,485	1.09
356.00	Conductors and Devices	51-R2	(35)	127,644,855	1,097,317	43,578,382	1,214,200	0.95
359.00	Roads and Trails	50-R3	-	1,121,930	-	-	-	-
TOTAL TRANSMISSION PLANT				**541,268,000**	**12,636,421**	**166,241,326**	**4,642,019**	**0.86**
DISTRIBUTION PLANT								
360.20	Surface and Mineral	75-R4	-	12,557,004	16,450	(16,450)	(323)	(0.00)
362.00	Substation Equipment	50-R3	(30)	290,961,496	11,163,195	76,125,254	2,133,836	0.73
364.00	Poles, Towers and Fixtures	50-R3	(40)	262,331,266	6,338,041	98,594,466	2,910,449	1.11
365.00	Conductors and Devices	55-R3	(35)	421,758,681	9,669,472	137,946,066	3,589,028	0.85
368.00	Line Transformers	40-R3	(30)	206,615,205	2,714,842	59,269,720	2,114,650	1.02
369.00	Services	70-R4	-	3,431,459	-	-	-	-
370.10	AMI Meters	18-SQ	-	41,935,015	(72,924)	72,924	4,051	0.01
373.00	Street Lighting and Signal Systems	25-R2	(15)	14,020,267	628,522	1,474,518	106,452	0.76
TOTAL DISTRIBUTION PLANT				**1,253,610,393**	**30,457,597**	**373,466,498**	**10,858,143**	**0.87**
GENERAL PLANT								
390.10	Structures - Masonry	35-R2	(5)	51,640,669	(1,014,914)	3,596,947	149,004	0.29
390.20	Operations Buildings	50-R4	(5)	18,051,672	64,522	838,062	23,196	0.13
391.00	Office Furniture and Equipment	15-SQ	-	5,180,462	-	-	-	-
391.10	Computer Hardware	4-SQ	-	13,092,326	-	-	-	-
391.20	Computer Software	8-SQ	-	48,334,443	-	-	-	-
391.60	AMI Computer Software	10-SQ	-	9,581,690	-	-	-	-
392.10	Light Duty Vehicles	12-L1	10	4,778,115	1,065,468	(1,543,279)	(207,225)	(4.34)
392.20	Heavy Duty Vehicles	16-L2.5	10	30,246,074	-	(3,024,607)	(343,404)	(1.14)
394.00	Tools and Work Equipment	15-SQ	-	8,433,816	-	-	-	-
397.00	Communications Structures and Equipment	15-SQ	-	13,389,020	(414,714)	414,714	115,273	0.86
397.10	Fiber	15-SQ	-	10,315,657	-	-	-	-
397.20	AMI Communications Structure and Equipment	15-SQ	-	4,969,732	-	-	-	-
TOTAL GENERAL PLANT				**218,013,675**	**(299,638)**	**281,836**	**(263,156)**	**(0.12)**
TOTAL DEPRECIABLE PLANT				**2,372,420,422**	**35,066,529**	**636,614,820**	**17,178,111**	**0.72**

FortisBC - Electricity

TABLE 1B - ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DEC 31, 2022

DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2022	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PLANT NOT STUDIED								
114.00	Utility Plant Acquisition Adjustment			11,912,000				
350.10	Land Rights Transmission			9,219,544				
360.10	Land Rights Distribution			8,888,837				
360.20	Distribution Station Equipment - Non-Regulated			65,734				
370.00	Meters			-				
389.00	Land			11,192,370				
390.90	Leasehold Improvements			3,618,765				
999.90	Contribution in Aid of Construction			-				
107.10	Work-In-Progress - Asset Management			-				
TOTAL NON - DEPRECIABLE PLANT				**44,897,251**	**-**	**-**	**-**	
TOTAL PLANT				**2,417,317,672**	**35,066,529**	**636,614,820**	**17,178,111**	

SECTION 6

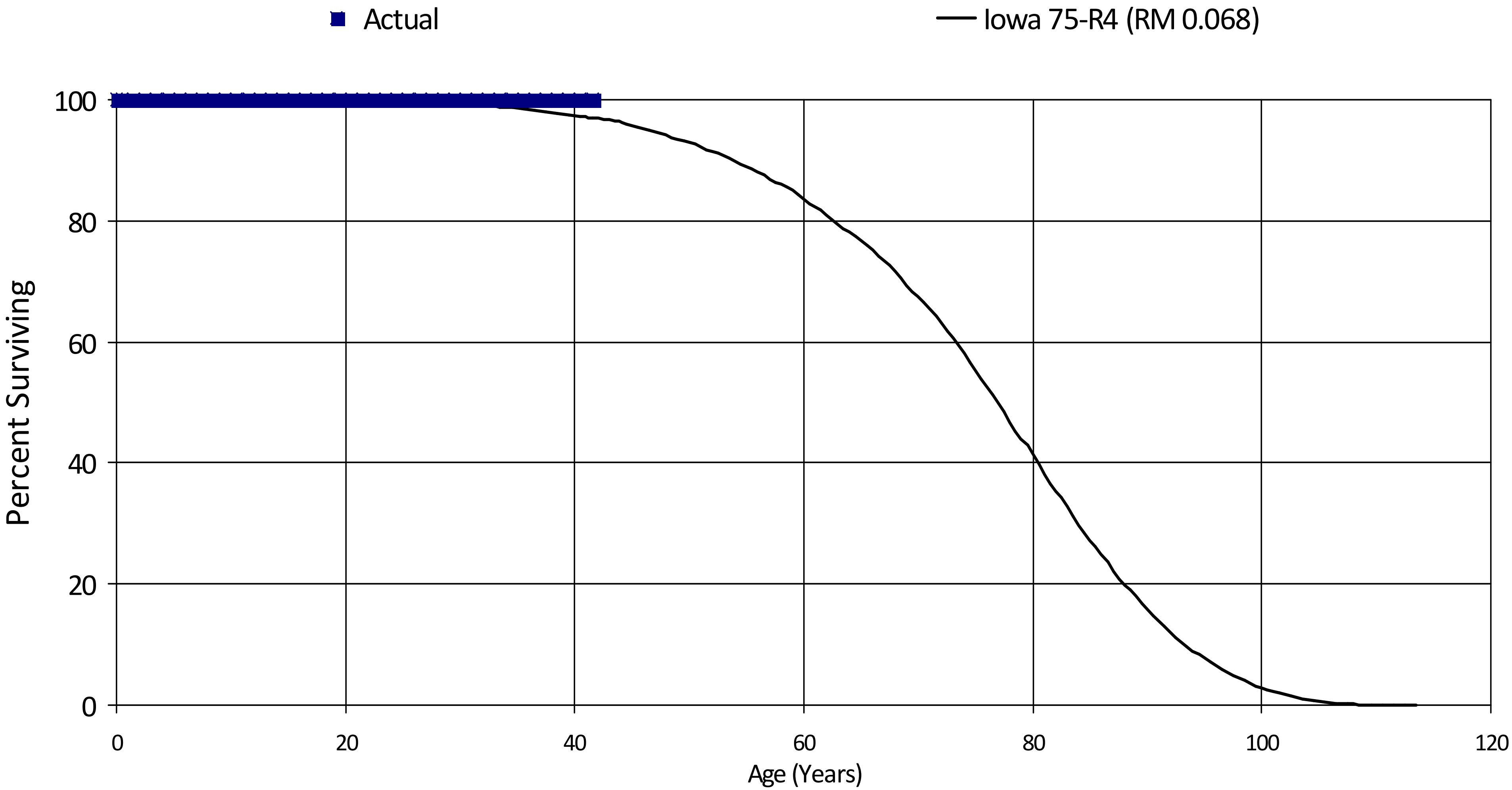
6 RETIREMENT RATE ANALYSIS

FortisBC

Account 33010 - Land Rights - Generation Plant

Placement Band - 1980 - 2008   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 33010 - Land Rights - Generation Plant

Placement Band - 1980 - 2008   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	961,358	0	0.00000	1.00000	100.00
0.5	961,358	0	0.00000	1.00000	100.00
1.5	961,358	0	0.00000	1.00000	100.00
2.5	961,358	0	0.00000	1.00000	100.00
3.5	961,358	0	0.00000	1.00000	100.00
4.5	961,358	0	0.00000	1.00000	100.00
5.5	961,358	0	0.00000	1.00000	100.00
6.5	961,358	0	0.00000	1.00000	100.00
7.5	961,358	0	0.00000	1.00000	100.00
8.5	961,358	0	0.00000	1.00000	100.00
9.5	961,358	0	0.00000	1.00000	100.00
10.5	961,358	0	0.00000	1.00000	100.00
11.5	961,358	0	0.00000	1.00000	100.00
12.5	961,358	0	0.00000	1.00000	100.00
13.5	961,358	0	0.00000	1.00000	100.00
14.5	846,775	0	0.00000	1.00000	100.00
15.5	119,897	0	0.00000	1.00000	100.00
16.5	119,897	0	0.00000	1.00000	100.00
17.5	98,939	0	0.00000	1.00000	100.00
18.5	98,939	0	0.00000	1.00000	100.00
19.5	98,939	0	0.00000	1.00000	100.00
20.5	98,939	0	0.00000	1.00000	100.00
21.5	98,939	0	0.00000	1.00000	100.00
22.5	98,939	0	0.00000	1.00000	100.00
23.5	98,939	0	0.00000	1.00000	100.00
24.5	98,939	0	0.00000	1.00000	100.00
25.5	98,939	0	0.00000	1.00000	100.00
26.5	98,939	0	0.00000	1.00000	100.00

FortisBC

Account 33010 - Land Rights - Generation Plant

Placement Band - 1980 - 2008 Experience Band - 2022 - 2022

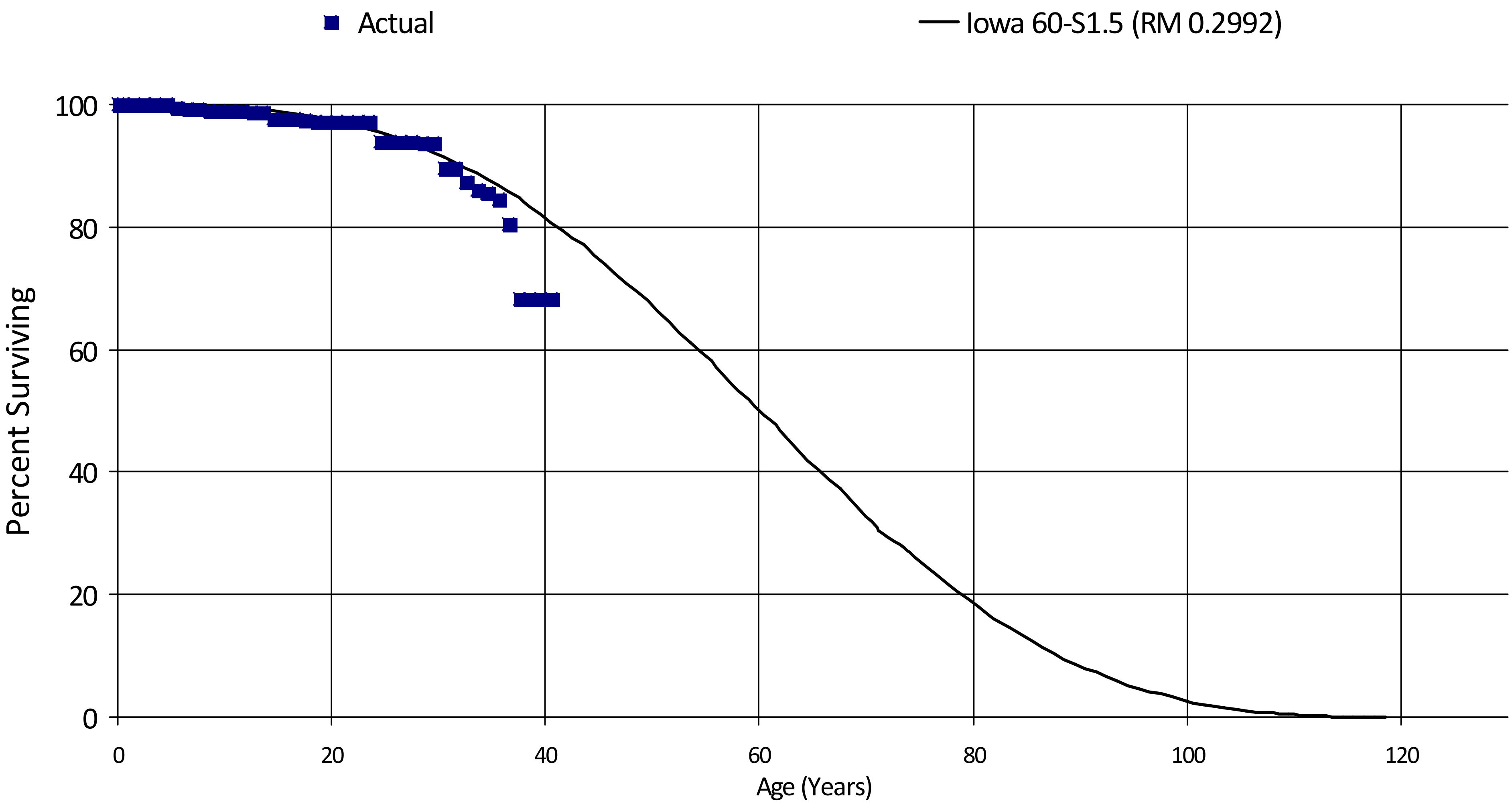
27.5	98,939	0	0.00000	1.00000	100.00
28.5	98,939	0	0.00000	1.00000	100.00
29.5	98,939	0	0.00000	1.00000	100.00
30.5	98,939	0	0.00000	1.00000	100.00
31.5	98,939	0	0.00000	1.00000	100.00
32.5	98,939	0	0.00000	1.00000	100.00
33.5	98,939	0	0.00000	1.00000	100.00
34.5	98,939	0	0.00000	1.00000	100.00
35.5	98,939	0	0.00000	1.00000	100.00
36.5	98,939	0	0.00000	1.00000	100.00
37.5	98,939	0	0.00000	1.00000	100.00
38.5	98,939	0	0.00000	1.00000	100.00
39.5	83,965	0	0.00000	1.00000	100.00
40.5	83,965	0	0.00000	1.00000	100.00
41.5	83,965	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 33100 - Structures and Improvements - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1978 - 2022

Actual and Smooth Survivor Curves



RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	21,790,087	5	0.00000	1.00000	100.00
0.5	21,703,244	2	0.00000	1.00000	100.00
1.5	20,759,323	0	0.00000	1.00000	100.00
2.5	20,156,585	1	0.00000	1.00000	100.00
3.5	20,044,088	4,556	0.00023	0.99977	100.00
4.5	18,964,983	101,831	0.00537	0.99463	99.98
5.5	17,726,331	27,959	0.00158	0.99842	99.44
6.5	16,566,804	3,658	0.00022	0.99978	99.28
7.5	15,227,299	24,712	0.00162	0.99838	99.26
8.5	14,300,967	4,112	0.00029	0.99971	99.10
9.5	14,120,702	7,531	0.00053	0.99947	99.07
10.5	13,189,430	20,649	0.00157	0.99843	99.02
11.5	13,012,571	10,523	0.00081	0.99919	98.86
12.5	12,406,095	8,326	0.00067	0.99933	98.78
13.5	12,102,321	109,018	0.00901	0.99099	98.71
14.5	11,221,346	12,106	0.00108	0.99892	97.82
15.5	10,588,232	0	0.00000	1.00000	97.71
16.5	10,370,802	39,184	0.00378	0.99622	97.71
17.5	9,930,267	6,088	0.00061	0.99939	97.34
18.5	9,714,230	2,932	0.00030	0.99970	97.28
19.5	9,244,124	0	0.00000	1.00000	97.25
20.5	8,877,110	0	0.00000	1.00000	97.25
21.5	7,855,719	0	0.00000	1.00000	97.25
22.5	7,390,748	0	0.00000	1.00000	97.25
23.5	7,320,444	247,630	0.03383	0.96617	97.25
24.5	6,617,386	3,630	0.00055	0.99945	93.96
25.5	6,519,060	0	0.00000	1.00000	93.91
26.5	6,362,886	7,026	0.00110	0.99890	93.91

FortisBC

Account 33100 - Structures and Improvements - Generation Plant

Placement Band - 1950 - 2022 Experience Band - 1978 - 2022

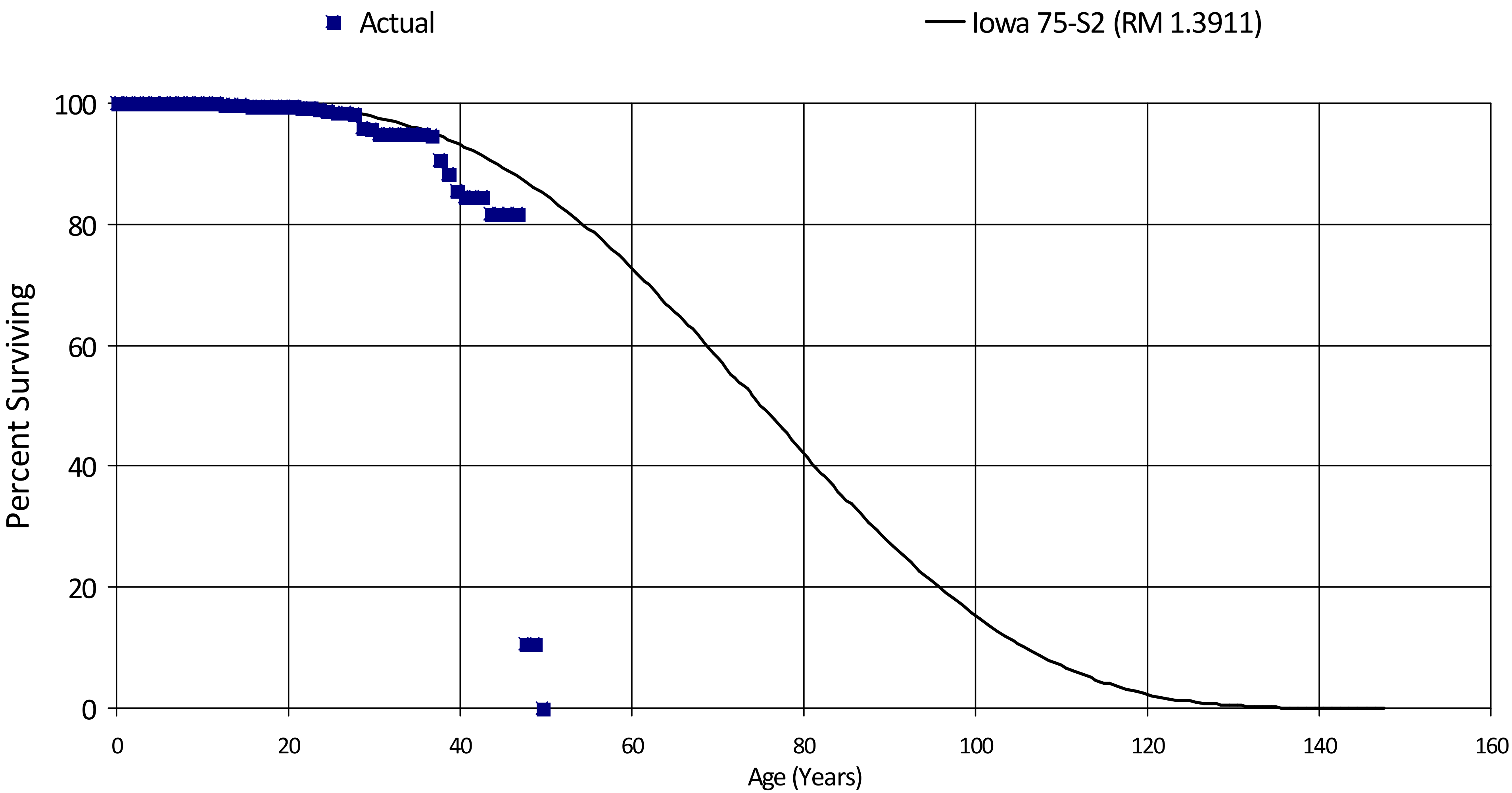
27.5	4,170,692	3,599	0.00086	0.99914	93.81
28.5	2,763,322	0	0.00000	1.00000	93.73
29.5	1,603,078	69,778	0.04353	0.95647	93.73
30.5	1,265,703	0	0.00000	1.00000	89.65
31.5	454,619	12,123	0.02667	0.97333	89.65
32.5	350,110	4,865	0.01390	0.98610	87.26
33.5	316,206	1,489	0.00471	0.99529	86.05
34.5	293,860	4,096	0.01394	0.98606	85.64
35.5	274,123	12,676	0.04624	0.95376	84.45
36.5	204,884	30,931	0.15097	0.84903	80.55
37.5	145,065	0	0.00000	1.00000	68.39
38.5	141,407	0	0.00000	1.00000	68.39
39.5	141,407	0	0.00000	1.00000	68.39
40.5	0	0	0.00000	0.00000	68.39
	Totals:	781,036			

FortisBC

Account 33200 - Reservoirs, Dams and Waterways - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1977 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 33200 - Reservoirs, Dams and Waterways - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1977 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	118,454,954	0	0.00000	1.00000	100.00
0.5	102,130,108	8,191	0.00008	0.99992	100.00
1.5	76,331,475	13	0.00000	1.00000	99.99
2.5	51,344,386	859	0.00002	0.99998	99.99
3.5	36,063,128	6	0.00000	1.00000	99.99
4.5	34,995,368	145	0.00000	1.00000	99.99
5.5	34,344,974	108	0.00000	1.00000	99.99
6.5	33,666,733	23,135	0.00069	0.99931	99.99
7.5	32,653,525	3,130	0.00010	0.99990	99.92
8.5	30,486,052	1	0.00000	1.00000	99.91
9.5	30,254,016	2,949	0.00010	0.99990	99.91
10.5	28,170,370	2,491	0.00009	0.99991	99.90
11.5	27,462,531	8,049	0.00029	0.99971	99.89
12.5	25,244,645	14	0.00000	1.00000	99.86
13.5	23,696,072	0	0.00000	1.00000	99.86
14.5	20,209,680	72,363	0.00358	0.99642	99.86
15.5	17,948,584	88	0.00000	1.00000	99.50
16.5	15,051,124	698	0.00005	0.99995	99.50
17.5	14,811,819	167	0.00001	0.99999	99.50
18.5	13,707,281	3,289	0.00024	0.99976	99.50
19.5	12,856,226	0	0.00000	1.00000	99.48
20.5	12,856,226	20,086	0.00156	0.99844	99.48
21.5	12,836,140	26,030	0.00203	0.99797	99.32
22.5	12,810,110	33,578	0.00262	0.99738	99.12
23.5	12,776,532	12,826	0.00100	0.99900	98.86
24.5	11,680,173	26,598	0.00228	0.99772	98.76
25.5	11,622,117	0	0.00000	1.00000	98.53
26.5	11,603,139	25,909	0.00223	0.99777	98.53

FortisBC

Account 33200 - Reservoirs, Dams and Waterways - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1977 - 2022

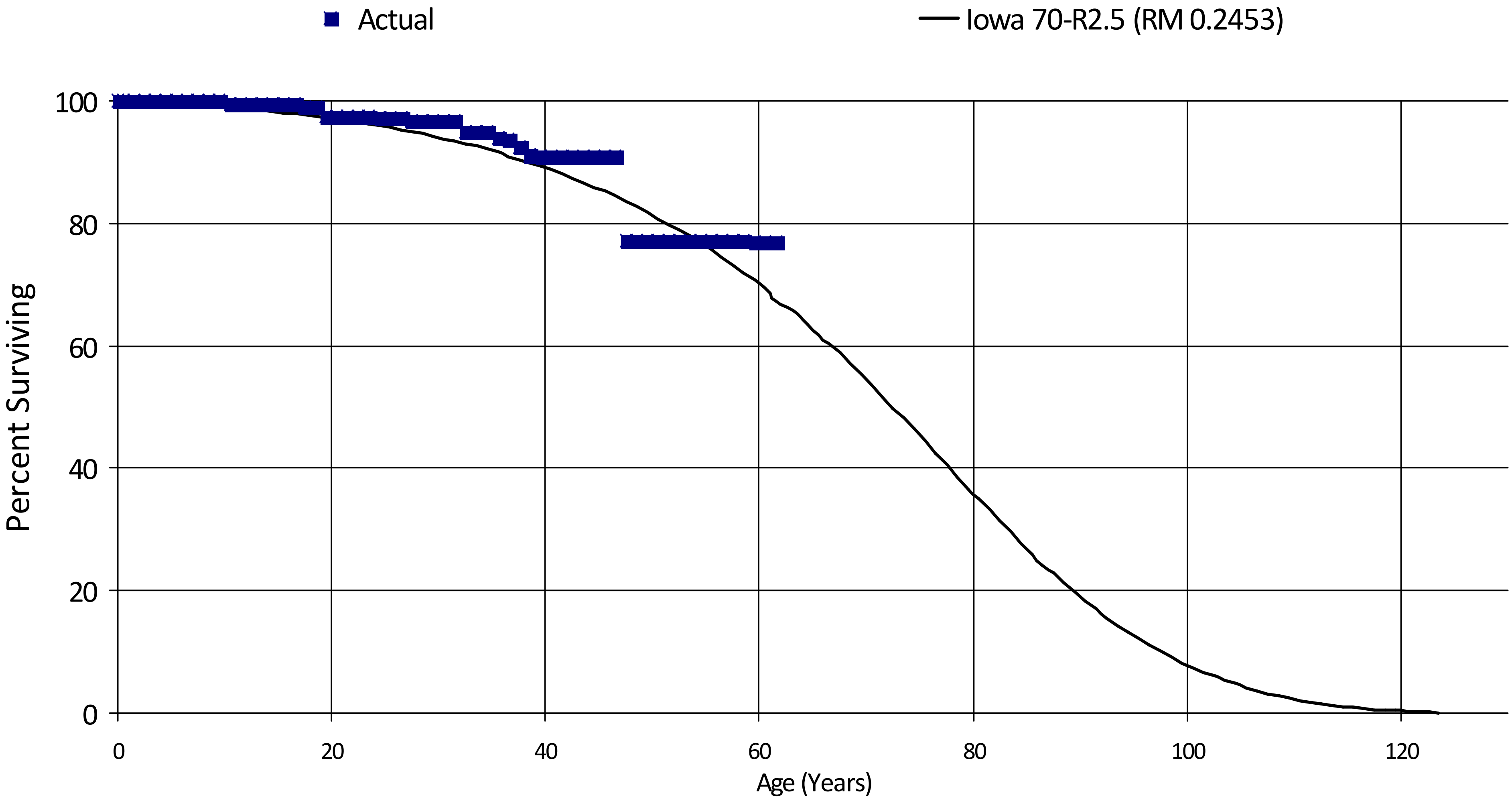
27.5	11,577,230	285,568	0.02467	0.97533	98.31
28.5	10,784,501	17,674	0.00164	0.99836	95.88
29.5	10,167,004	85,735	0.00843	0.99157	95.72
30.5	10,081,268	50	0.00000	1.00000	94.91
31.5	10,065,868	1,528	0.00015	0.99985	94.91
32.5	10,064,341	764	0.00008	0.99992	94.90
33.5	9,998,509	2,026	0.00020	0.99980	94.89
34.5	9,996,483	0	0.00000	1.00000	94.87
35.5	9,908,700	23,066	0.00233	0.99767	94.87
36.5	9,885,634	414,453	0.04192	0.95808	94.65
37.5	9,471,181	250,154	0.02641	0.97359	90.68
38.5	9,221,026	289,214	0.03136	0.96864	88.29
39.5	8,931,812	94,246	0.01055	0.98945	85.52
40.5	437,902	0	0.00000	1.00000	84.62
41.5	437,902	0	0.00000	1.00000	84.62
42.5	437,902	15,405	0.03518	0.96482	84.62
43.5	422,498	0	0.00000	1.00000	81.64
44.5	422,498	0	0.00000	1.00000	81.64
45.5	422,498	0	0.00000	1.00000	81.64
46.5	422,498	367,027	0.86871	0.13129	81.64
47.5	55,471	0	0.00000	1.00000	10.72
48.5	55,471	55,471	1.00001	-0.00001	10.72
49.5	0	0	0.00000	0.00000	0.00
	Totals:	2,173,104			

FortisBC

Account 33300 - Water Wheels, Turbines and Generators - Generation Plant

Placement Band - 1960 - 2022   Experience Band - 1979 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 33300 - Water Wheels, Turbines and Generators - Generation Plant

Placement Band - 1960 - 2022   Experience Band - 1979 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	124,120,092	2	0.00000	1.00000	100.00
0.5	123,360,651	81	0.00000	1.00000	100.00
1.5	122,247,917	0	0.00000	1.00000	100.00
2.5	116,632,792	11,780	0.00010	0.99990	100.00
3.5	109,825,854	143	0.00000	1.00000	99.99
4.5	99,126,595	54,623	0.00055	0.99945	99.99
5.5	98,805,686	0	0.00000	1.00000	99.94
6.5	98,565,523	442	0.00000	1.00000	99.94
7.5	98,198,601	919	0.00001	0.99999	99.94
8.5	97,080,672	13,082	0.00013	0.99987	99.94
9.5	96,841,036	357,852	0.00370	0.99630	99.93
10.5	95,138,430	0	0.00000	1.00000	99.56
11.5	74,473,909	0	0.00000	1.00000	99.56
12.5	62,146,437	0	0.00000	1.00000	99.56
13.5	53,890,394	3,850	0.00007	0.99993	99.56
14.5	53,886,544	34	0.00000	1.00000	99.55
15.5	46,907,475	200	0.00000	1.00000	99.55
16.5	36,769,618	169,288	0.00460	0.99540	99.55
17.5	36,373,684	1,844	0.00005	0.99995	99.09
18.5	22,561,747	370,968	0.01644	0.98356	99.09
19.5	22,079,238	0	0.00000	1.00000	97.46
20.5	21,911,296	11,543	0.00053	0.99947	97.46
21.5	20,222,243	0	0.00000	1.00000	97.41
22.5	11,238,251	0	0.00000	1.00000	97.41
23.5	11,062,668	27,172	0.00246	0.99754	97.41
24.5	10,471,552	0	0.00000	1.00000	97.17
25.5	10,229,081	8,624	0.00084	0.99916	97.17
26.5	9,610,673	26,293	0.00274	0.99726	97.09

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Account 33300 - Water Wheels, Turbines and Generators - Generation Plant

Placement Band - 1960 - 2022   Experience Band - 1979 - 2022

27.5	9,343,514	0	0.00000	1.00000	96.82
28.5	9,141,167	0	0.00000	1.00000	96.82
29.5	9,066,168	0	0.00000	1.00000	96.82
30.5	8,989,405	0	0.00000	1.00000	96.82
31.5	8,724,727	166,278	0.01906	0.98094	96.82
32.5	8,488,251	0	0.00000	1.00000	94.97
33.5	8,363,411	0	0.00000	1.00000	94.97
34.5	8,343,078	100,970	0.01210	0.98790	94.97
35.5	8,218,869	22,935	0.00279	0.99721	93.82
36.5	8,054,261	110,074	0.01367	0.98633	93.56
37.5	7,919,925	109,823	0.01387	0.98613	92.28
38.5	7,733,705	8,565	0.00111	0.99889	91.00
39.5	7,725,114	2,889	0.00037	0.99963	90.90
40.5	1,778,514	0	0.00000	1.00000	90.87
41.5	1,778,514	0	0.00000	1.00000	90.87
42.5	1,778,514	0	0.00000	1.00000	90.87
43.5	1,778,514	0	0.00000	1.00000	90.87
44.5	1,778,514	0	0.00000	1.00000	90.87
45.5	1,773,062	0	0.00000	1.00000	90.87
46.5	1,773,062	266,032	0.15004	0.84996	90.87
47.5	1,507,030	0	0.00000	1.00000	77.24
48.5	1,507,030	0	0.00000	1.00000	77.24
49.5	1,507,030	0	0.00000	1.00000	77.24
50.5	1,507,030	0	0.00000	1.00000	77.24
51.5	1,506,710	0	0.00000	1.00000	77.24
52.5	1,506,710	0	0.00000	1.00000	77.24
53.5	1,506,414	0	0.00000	1.00000	77.24
54.5	1,506,414	0	0.00000	1.00000	77.24
55.5	1,506,414	0	0.00000	1.00000	77.24
56.5	1,506,414	0	0.00000	1.00000	77.24
57.5	1,506,148	435	0.00029	0.99971	77.24

58.5	671,514	2,348	0.00350	0.99650	77.22
59.5	7,238	0	0.00000	1.00000	76.95
60.5	7,238	0	0.00000	1.00000	76.95
61.5	7,238	0	0.00000	1.00000	76.95
	Totals:	1,849,089			

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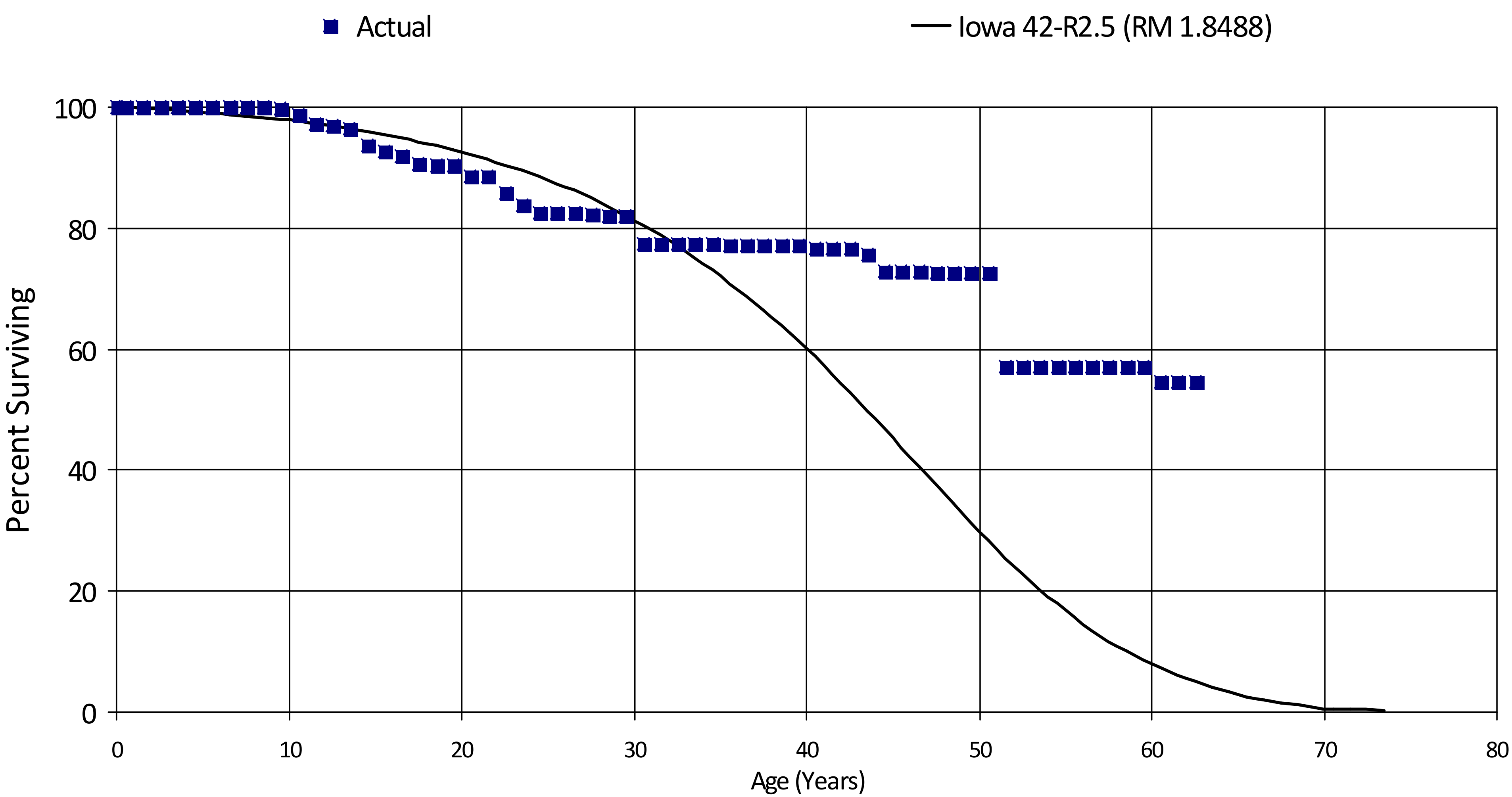
Account 33400 - Accessory Electrical Equipment - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1978 - 2022

Actual and Smooth Survivor Curves



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Account 33400 - Accessory Electrical Equipment - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1978 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	56,379,882	8	0.00000	1.00000	100.00
0.5	55,577,821	0	0.00000	1.00000	100.00
1.5	55,024,158	11,938	0.00022	0.99978	100.00
2.5	52,969,565	6,685	0.00013	0.99987	99.98
3.5	51,207,136	1	0.00000	1.00000	99.97
4.5	47,360,129	0	0.00000	1.00000	99.97
5.5	46,937,591	12,203	0.00026	0.99974	99.97
6.5	46,808,620	6	0.00000	1.00000	99.94
7.5	46,257,737	16,472	0.00036	0.99964	99.94
8.5	45,350,658	102,496	0.00226	0.99774	99.90
9.5	44,706,356	444,870	0.00995	0.99005	99.67
10.5	40,787,777	611,492	0.01499	0.98501	98.68
11.5	33,527,529	65,309	0.00195	0.99805	97.20
12.5	27,642,919	133,290	0.00482	0.99518	97.01
13.5	22,626,561	658,675	0.02911	0.97089	96.54
14.5	21,440,342	276,096	0.01288	0.98712	93.73
15.5	18,391,701	135,363	0.00736	0.99264	92.52
16.5	16,155,529	213,003	0.01318	0.98682	91.84
17.5	15,837,572	33,268	0.00210	0.99790	90.63
18.5	10,545,177	5,911	0.00056	0.99944	90.44
19.5	10,342,943	206,860	0.02000	0.98000	90.39
20.5	9,849,715	7,707	0.00078	0.99922	88.58
21.5	6,511,916	196,419	0.03016	0.96984	88.51
22.5	5,114,312	127,633	0.02496	0.97504	85.84
23.5	4,949,911	78,207	0.01580	0.98420	83.70
24.5	4,574,418	0	0.00000	1.00000	82.38
25.5	4,574,418	0	0.00000	1.00000	82.38
26.5	4,373,906	11,492	0.00263	0.99737	82.38

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Account 33400 - Accessory Electrical Equipment - Generation Plant

Placement Band - 1950 - 2022   Experience Band - 1978 - 2022

27.5	4,362,414	7,386	0.00169	0.99831	82.16
28.5	4,354,795	0	0.00000	1.00000	82.02
29.5	4,278,846	241,006	0.05633	0.94367	82.02
30.5	3,989,914	0	0.00000	1.00000	77.40
31.5	3,855,459	4,594	0.00119	0.99881	77.40
32.5	3,816,614	0	0.00000	1.00000	77.31
33.5	3,761,636	0	0.00000	1.00000	77.31
34.5	3,758,446	5,466	0.00145	0.99855	77.31
35.5	3,752,980	0	0.00000	1.00000	77.20
36.5	3,655,989	0	0.00000	1.00000	77.20
37.5	3,655,989	0	0.00000	1.00000	77.20
38.5	3,614,697	0	0.00000	1.00000	77.20
39.5	3,614,697	21,593	0.00597	0.99403	77.20
40.5	3,593,105	0	0.00000	1.00000	76.74
41.5	3,593,105	0	0.00000	1.00000	76.74
42.5	3,593,105	56,212	0.01564	0.98436	76.74
43.5	3,534,568	130,039	0.03679	0.96321	75.54
44.5	3,392,019	0	0.00000	1.00000	72.76
45.5	3,387,820	0	0.00000	1.00000	72.76
46.5	3,377,730	4,140	0.00123	0.99877	72.76
47.5	3,373,349	0	0.00000	1.00000	72.67
48.5	3,367,186	0	0.00000	1.00000	72.67
49.5	3,364,142	0	0.00000	1.00000	72.67
50.5	3,364,142	717,072	0.21315	0.78685	72.67
51.5	2,481,029	0	0.00000	1.00000	57.18
52.5	2,481,029	0	0.00000	1.00000	57.18
53.5	2,476,497	0	0.00000	1.00000	57.18
54.5	2,473,347	0	0.00000	1.00000	57.18
55.5	2,473,347	2,232	0.00090	0.99910	57.18
56.5	2,470,181	603	0.00024	0.99976	57.13
57.5	2,469,578	0	0.00000	1.00000	57.12

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Account 33400 - Accessory Electrical Equipment - Generation Plant

Placement Band - 1950 - 2022 Experience Band - 1978 - 2022

58.5	2,465,202	0	0.00000	1.00000	57.12
59.5	2,429,193	110,810	0.04562	0.95438	57.12
60.5	2,318,383	0	0.00000	1.00000	54.51
61.5	2,318,383	0	0.00000	1.00000	54.51
62.5	0	0	0.00000	0.00000	54.51
	Totals:	4,656,557			

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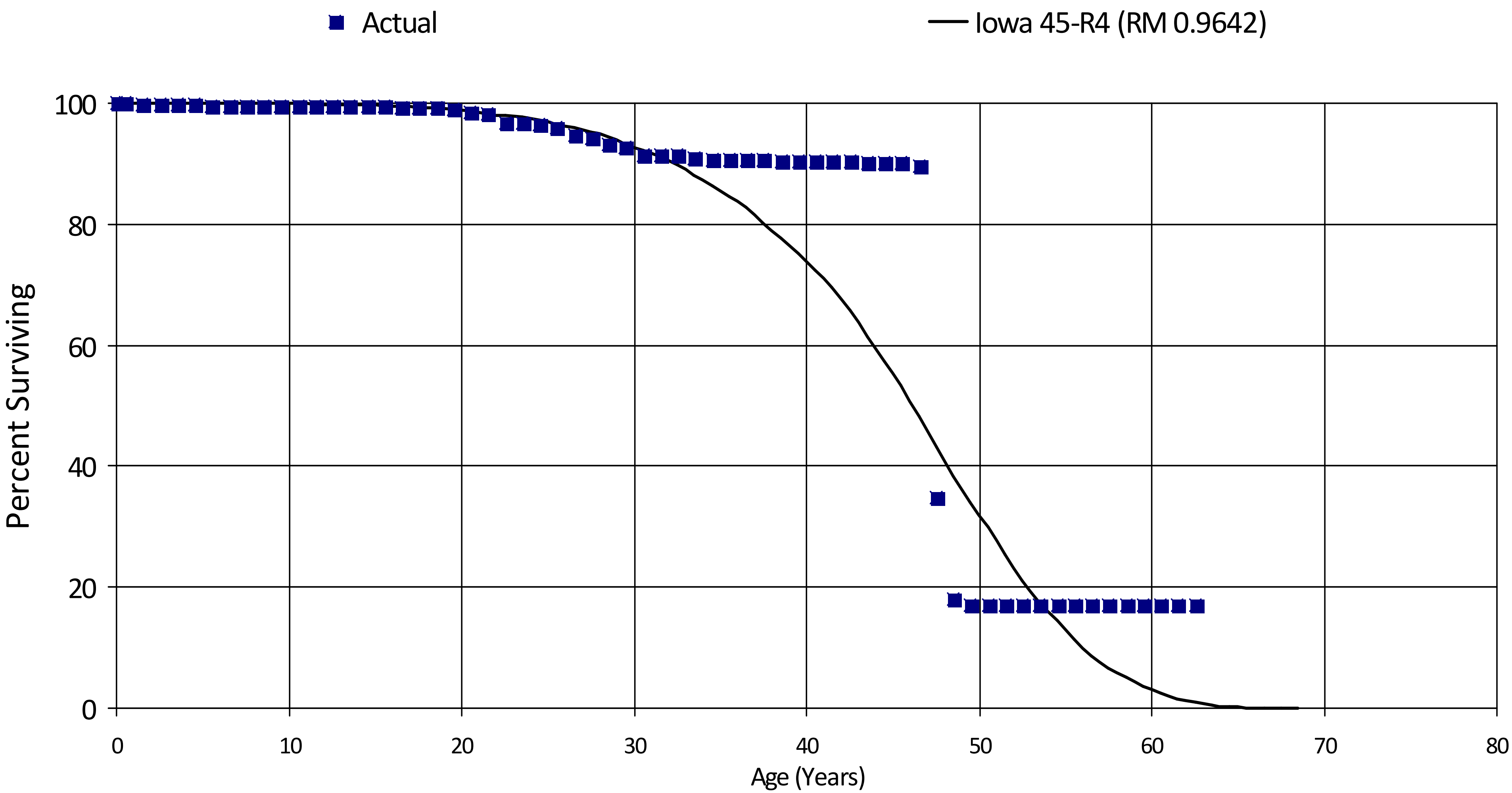
Account 33500 - Other Power Plant Equipment - Generation Plant

Placement Band - 1957 - 2022   Experience Band - 1977 - 2022

Actual and Smooth Survivor Curves



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Account 33500 - Other Power Plant Equipment - Generation Plant

Placement Band - 1957 - 2022   Experience Band - 1977 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	48,167,451	272	0.00001	0.99999	100.00
0.5	48,167,145	95,862	0.00199	0.99801	100.00
1.5	48,066,574	0	0.00000	1.00000	99.80
2.5	47,719,142	2,565	0.00005	0.99995	99.80
3.5	47,366,939	81,442	0.00172	0.99828	99.80
4.5	46,846,322	36,311	0.00078	0.99922	99.63
5.5	46,347,987	2,919	0.00006	0.99994	99.55
6.5	46,317,449	2,315	0.00005	0.99995	99.54
7.5	45,979,673	680	0.00001	0.99999	99.54
8.5	44,747,009	3,046	0.00007	0.99993	99.54
9.5	44,617,860	9,262	0.00021	0.99979	99.53
10.5	43,104,737	0	0.00000	1.00000	99.51
11.5	42,845,523	60,396	0.00141	0.99859	99.51
12.5	42,029,198	1,580	0.00004	0.99996	99.37
13.5	39,719,180	0	0.00000	1.00000	99.37
14.5	39,345,889	0	0.00000	1.00000	99.37
15.5	38,661,734	25,182	0.00065	0.99935	99.37
16.5	37,858,941	0	0.00000	1.00000	99.31
17.5	36,936,831	24,244	0.00066	0.99934	99.31
18.5	26,509,248	85,952	0.00324	0.99676	99.24
19.5	8,184,688	33,337	0.00407	0.99593	98.92
20.5	7,656,241	18,043	0.00236	0.99764	98.52
21.5	7,638,198	125,203	0.01639	0.98361	98.29
22.5	7,512,994	2,250	0.00030	0.99970	96.68
23.5	7,510,744	8,048	0.00107	0.99893	96.65
24.5	5,335,028	38,524	0.00722	0.99278	96.55
25.5	4,725,731	63,163	0.01337	0.98663	95.85
26.5	4,284,416	19,333	0.00451	0.99549	94.57

Account 33500 - Other Power Plant Equipment - Generation Plant

Placement Band - 1957 - 2022   Experience Band - 1977 - 2022

27.5	4,006,940	45,281	0.01130	0.98870	94.14
28.5	3,726,876	13,370	0.00359	0.99641	93.08
29.5	3,523,359	48,223	0.01369	0.98631	92.75
30.5	3,434,195	0	0.00000	1.00000	91.48
31.5	3,266,721	0	0.00000	1.00000	91.48
32.5	2,883,129	16,256	0.00564	0.99436	91.48
33.5	2,717,525	6,745	0.00248	0.99752	90.96
34.5	2,562,006	0	0.00000	1.00000	90.73
35.5	2,411,112	0	0.00000	1.00000	90.73
36.5	2,114,757	0	0.00000	1.00000	90.73
37.5	2,031,412	6,310	0.00311	0.99689	90.73
38.5	1,963,936	0	0.00000	1.00000	90.45
39.5	1,963,936	0	0.00000	1.00000	90.45
40.5	1,654,880	0	0.00000	1.00000	90.45
41.5	1,654,880	0	0.00000	1.00000	90.45
42.5	1,654,880	6,006	0.00363	0.99637	90.45
43.5	1,648,869	0	0.00000	1.00000	90.12
44.5	1,628,034	0	0.00000	1.00000	90.12
45.5	1,607,004	7,418	0.00462	0.99538	90.12
46.5	1,586,552	970,828	0.61191	0.38809	89.70
47.5	614,164	297,278	0.48404	0.51596	34.81
48.5	315,965	15,472	0.04897	0.95103	17.96
49.5	300,493	0	0.00000	1.00000	17.08
50.5	300,493	0	0.00000	1.00000	17.08
51.5	300,493	0	0.00000	1.00000	17.08
52.5	300,493	0	0.00000	1.00000	17.08
53.5	300,493	0	0.00000	1.00000	17.08
54.5	300,493	0	0.00000	1.00000	17.08
55.5	300,493	0	0.00000	1.00000	17.08
56.5	296,699	0	0.00000	1.00000	17.08
57.5	296,699	0	0.00000	1.00000	17.08

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Account 33500 - Other Power Plant Equipment - Generation Plant

Placement Band - 1957 - 2022   Experience Band - 1977 - 2022

58.5	296,699	0	0.00000	1.00000	17.08
59.5	296,699	0	0.00000	1.00000	17.08
60.5	296,699	0	0.00000	1.00000	17.08
61.5	296,699	0	0.00000	1.00000	17.08
62.5	0	0	0.00000	0.00000	17.08
	Totals:	2,173,116			

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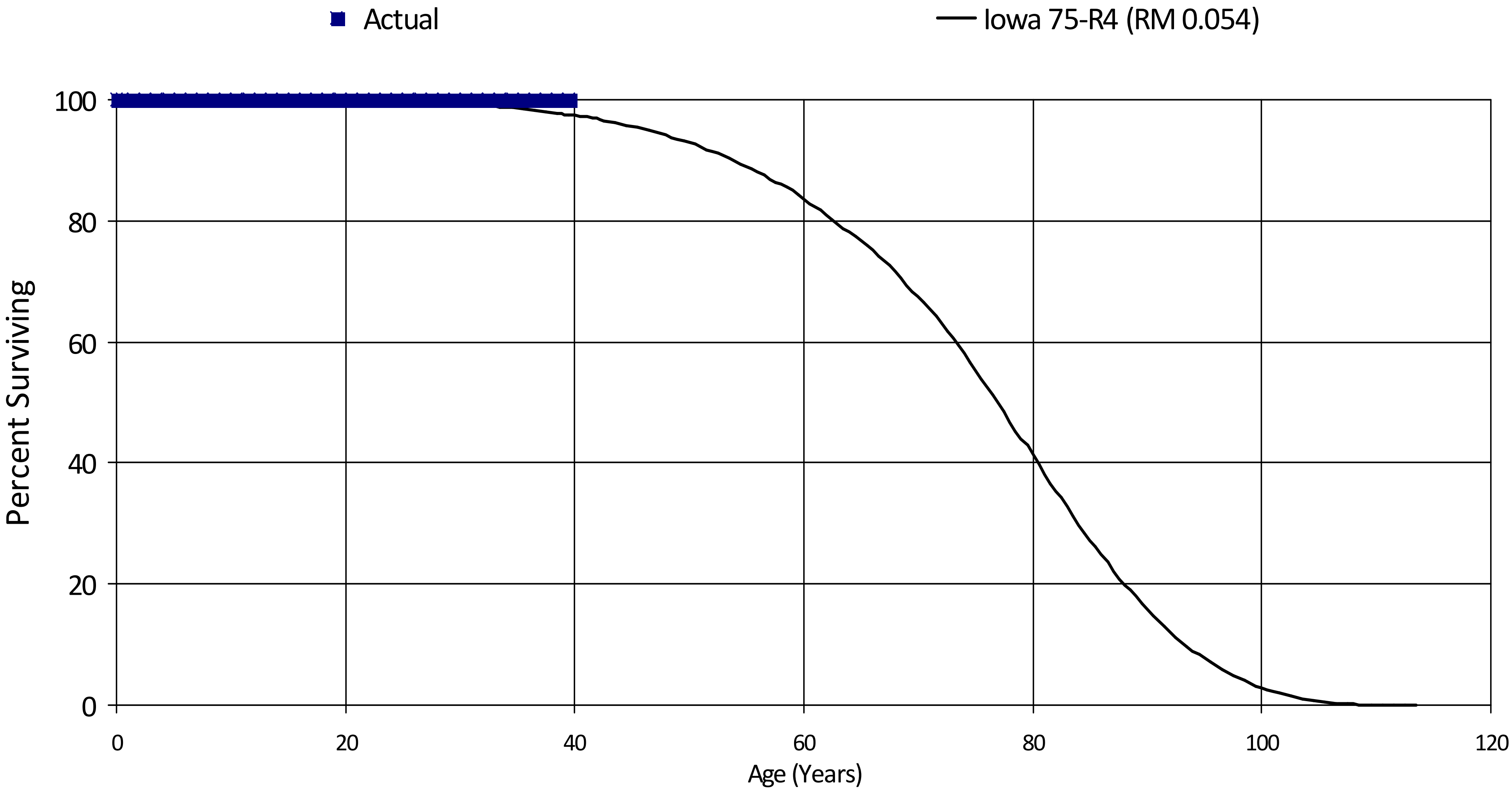
Account 33600 - Roads, Railroads and Bridges - Generation Plant

Placement Band - 1982 - 2008   Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



Account 33600 - Roads, Railroads and Bridges - Generation Plant

Placement Band - 1982 - 2008   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,287,434	0	0.00000	1.00000	100.00
0.5	1,287,434	0	0.00000	1.00000	100.00
1.5	1,287,434	0	0.00000	1.00000	100.00
2.5	1,287,434	0	0.00000	1.00000	100.00
3.5	1,287,434	0	0.00000	1.00000	100.00
4.5	1,287,434	0	0.00000	1.00000	100.00
5.5	1,287,434	0	0.00000	1.00000	100.00
6.5	1,287,434	0	0.00000	1.00000	100.00
7.5	1,287,434	0	0.00000	1.00000	100.00
8.5	1,287,434	0	0.00000	1.00000	100.00
9.5	1,287,434	0	0.00000	1.00000	100.00
10.5	1,287,434	0	0.00000	1.00000	100.00
11.5	1,287,434	0	0.00000	1.00000	100.00
12.5	1,287,434	0	0.00000	1.00000	100.00
13.5	1,287,434	0	0.00000	1.00000	100.00
14.5	1,053,045	0	0.00000	1.00000	100.00
15.5	1,053,045	0	0.00000	1.00000	100.00
16.5	1,046,226	0	0.00000	1.00000	100.00
17.5	1,046,226	0	0.00000	1.00000	100.00
18.5	1,045,307	0	0.00000	1.00000	100.00
19.5	1,043,069	0	0.00000	1.00000	100.00
20.5	1,043,069	0	0.00000	1.00000	100.00
21.5	1,043,069	0	0.00000	1.00000	100.00
22.5	1,043,069	0	0.00000	1.00000	100.00
23.5	895,359	0	0.00000	1.00000	100.00
24.5	895,359	0	0.00000	1.00000	100.00
25.5	895,359	0	0.00000	1.00000	100.00
26.5	895,359	0	0.00000	1.00000	100.00

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Account 33600 - Roads, Railroads and Bridges - Generation Plant

Placement Band - 1982 - 2008 Experience Band - 2022 - 2022

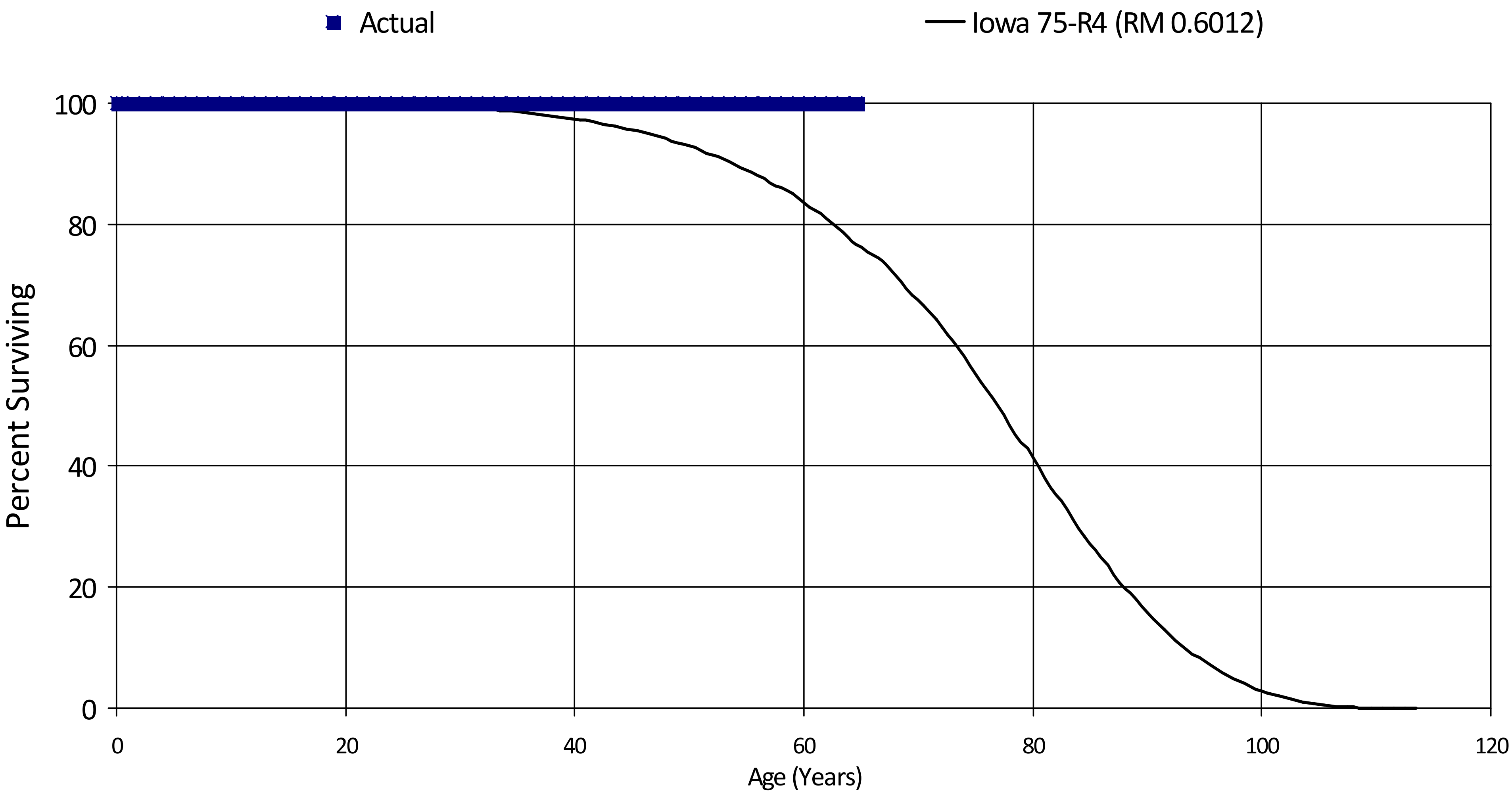
27.5	895,359	0	0.00000	1.00000	100.00
28.5	895,359	0	0.00000	1.00000	100.00
29.5	895,359	0	0.00000	1.00000	100.00
30.5	794,709	0	0.00000	1.00000	100.00
31.5	783,776	0	0.00000	1.00000	100.00
32.5	659,334	0	0.00000	1.00000	100.00
33.5	625,867	0	0.00000	1.00000	100.00
34.5	613,505	0	0.00000	1.00000	100.00
35.5	613,505	0	0.00000	1.00000	100.00
36.5	613,505	0	0.00000	1.00000	100.00
37.5	613,505	0	0.00000	1.00000	100.00
38.5	589,100	0	0.00000	1.00000	100.00
39.5	589,100	0	0.00000	1.00000	100.00
	Totals:	0			

FortisBC

Account 35020 - Surface and Mineral - Transmission Plant

Placement Band - 1957 - 2022 Experience Band - 2022 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 35020 - Surface and Mineral - Transmission Plant

Placement Band - 1957 - 2022   Experience Band - 2022 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,449,306	0	0.00000	1.00000	100.00
0.5	8,417,175	0	0.00000	1.00000	100.00
1.5	8,305,997	0	0.00000	1.00000	100.00
2.5	8,233,924	0	0.00000	1.00000	100.00
3.5	8,217,107	0	0.00000	1.00000	100.00
4.5	8,173,036	0	0.00000	1.00000	100.00
5.5	8,124,049	0	0.00000	1.00000	100.00
6.5	8,089,300	0	0.00000	1.00000	100.00
7.5	8,046,804	0	0.00000	1.00000	100.00
8.5	7,993,273	0	0.00000	1.00000	100.00
9.5	7,980,696	0	0.00000	1.00000	100.00
10.5	7,936,064	0	0.00000	1.00000	100.00
11.5	7,849,780	0	0.00000	1.00000	100.00
12.5	7,412,230	0	0.00000	1.00000	100.00
13.5	6,961,797	0	0.00000	1.00000	100.00
14.5	5,847,236	0	0.00000	1.00000	100.00
15.5	4,363,677	0	0.00000	1.00000	100.00
16.5	4,292,061	0	0.00000	1.00000	100.00
17.5	3,202,451	0	0.00000	1.00000	100.00
18.5	3,032,990	0	0.00000	1.00000	100.00
19.5	2,743,465	0	0.00000	1.00000	100.00
20.5	2,743,465	0	0.00000	1.00000	100.00
21.5	2,623,386	0	0.00000	1.00000	100.00
22.5	2,398,250	0	0.00000	1.00000	100.00
23.5	2,320,120	0	0.00000	1.00000	100.00
24.5	2,107,190	0	0.00000	1.00000	100.00
25.5	2,032,945	0	0.00000	1.00000	100.00
26.5	1,716,420	0	0.00000	1.00000	100.00

FortisBC

Account 35020 - Surface and Mineral - Transmission Plant

Placement Band - 1957 - 2022 Experience Band - 2022 - 2022

27.5	1,665,506	0	0.00000	1.00000	100.00
28.5	1,355,675	0	0.00000	1.00000	100.00
29.5	1,294,168	0	0.00000	1.00000	100.00
30.5	1,244,067	0	0.00000	1.00000	100.00
31.5	1,178,569	0	0.00000	1.00000	100.00
32.5	1,119,640	0	0.00000	1.00000	100.00
33.5	1,070,424	0	0.00000	1.00000	100.00
34.5	973,976	0	0.00000	1.00000	100.00
35.5	893,749	0	0.00000	1.00000	100.00
36.5	762,809	0	0.00000	1.00000	100.00
37.5	658,417	0	0.00000	1.00000	100.00
38.5	520,434	0	0.00000	1.00000	100.00
39.5	470,331	0	0.00000	1.00000	100.00
40.5	428,696	0	0.00000	1.00000	100.00
41.5	408,973	0	0.00000	1.00000	100.00
42.5	357,588	0	0.00000	1.00000	100.00
43.5	331,094	0	0.00000	1.00000	100.00
44.5	320,262	0	0.00000	1.00000	100.00
45.5	310,199	0	0.00000	1.00000	100.00
46.5	224,331	0	0.00000	1.00000	100.00
47.5	216,135	0	0.00000	1.00000	100.00
48.5	211,637	0	0.00000	1.00000	100.00
49.5	210,804	0	0.00000	1.00000	100.00
50.5	210,325	0	0.00000	1.00000	100.00
51.5	208,682	0	0.00000	1.00000	100.00
52.5	207,813	0	0.00000	1.00000	100.00
53.5	206,616	0	0.00000	1.00000	100.00
54.5	206,020	0	0.00000	1.00000	100.00
55.5	203,661	0	0.00000	1.00000	100.00
56.5	199,710	0	0.00000	1.00000	100.00
57.5	180,436	0	0.00000	1.00000	100.00

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Account 35020 - Surface and Mineral - Transmission Plant

Placement Band - 1957 - 2022   Experience Band - 2022 - 2022

58.5	163,443	0	0.00000	1.00000	100.00
59.5	132,182	0	0.00000	1.00000	100.00
60.5	112,026	0	0.00000	1.00000	100.00
61.5	109,176	0	0.00000	1.00000	100.00
62.5	108,593	0	0.00000	1.00000	100.00
63.5	105,830	0	0.00000	1.00000	100.00
64.5	71,278	0	0.00000	1.00000	100.00
	Totals:	0			

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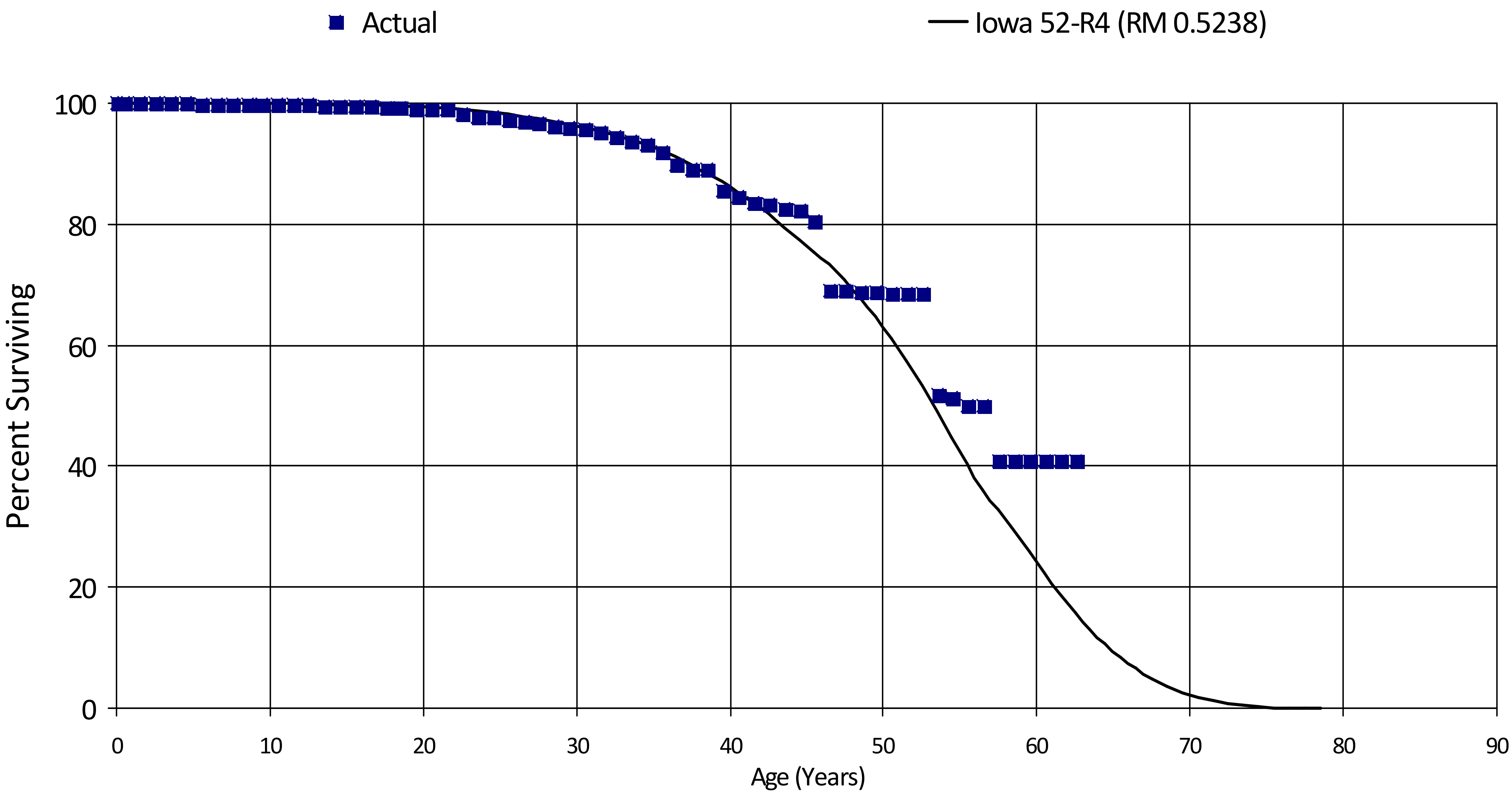
Account 35300 - Substation Equipment - Transmission Plant

Placement Band - 1940 - 2022 Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



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Account 35300 - Substation Equipment - Transmission Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	279,311,624	61,913	0.00022	0.99978	100.00
0.5	255,909,576	12,672	0.00005	0.99995	99.98
1.5	247,632,214	889	0.00000	1.00000	99.98
2.5	245,504,363	1,895	0.00001	0.99999	99.98
3.5	242,811,576	3,359	0.00001	0.99999	99.98
4.5	235,535,092	311,171	0.00132	0.99868	99.98
5.5	231,770,731	60,553	0.00026	0.99974	99.85
6.5	230,036,754	226,116	0.00098	0.99902	99.82
7.5	228,077,123	33,372	0.00015	0.99985	99.72
8.5	218,247,197	11,949	0.00005	0.99995	99.71
9.5	216,569,228	6,909	0.00003	0.99997	99.71
10.5	210,259,159	162,000	0.00077	0.99923	99.71
11.5	169,035,139	12,448	0.00007	0.99993	99.63
12.5	158,877,058	115,272	0.00073	0.99927	99.62
13.5	155,912,324	22,693	0.00015	0.99985	99.55
14.5	153,668,711	78,209	0.00051	0.99949	99.54
15.5	144,027,441	90,650	0.00063	0.99937	99.49
16.5	125,009,267	164,264	0.00131	0.99869	99.43
17.5	74,808,360	92,108	0.00123	0.99877	99.30
18.5	64,986,048	62,754	0.00097	0.99903	99.18
19.5	32,286,068	10,705	0.00033	0.99967	99.08
20.5	32,231,611	510	0.00002	0.99998	99.05
21.5	30,795,129	251,691	0.00817	0.99183	99.05
22.5	29,945,632	150,320	0.00502	0.99498	98.24
23.5	29,445,112	28,687	0.00097	0.99903	97.75
24.5	28,606,738	115,416	0.00403	0.99597	97.66
25.5	28,033,916	82,673	0.00295	0.99705	97.27
26.5	24,244,723	60,709	0.00250	0.99750	96.98

27.5	22,767,061	137,497	0.00604	0.99396	96.74
28.5	21,970,682	64,044	0.00291	0.99709	96.16
29.5	20,471,198	56,088	0.00274	0.99726	95.88
30.5	19,847,002	75,617	0.00381	0.99619	95.62
31.5	19,030,941	162,320	0.00853	0.99147	95.26
32.5	18,669,723	162,209	0.00869	0.99131	94.45
33.5	18,273,159	92,236	0.00505	0.99495	93.63
34.5	18,145,763	248,330	0.01369	0.98631	93.16
35.5	15,384,150	320,603	0.02084	0.97916	91.88
36.5	14,576,258	154,491	0.01060	0.98940	89.97
37.5	10,811,049	0	0.00000	1.00000	89.02
38.5	10,126,158	392,505	0.03876	0.96124	89.02
39.5	9,657,105	112,909	0.01169	0.98831	85.57
40.5	6,824,759	95,628	0.01401	0.98599	84.57
41.5	6,713,195	2,588	0.00039	0.99961	83.39
42.5	6,542,342	60,124	0.00919	0.99081	83.36
43.5	4,902,439	27,753	0.00566	0.99434	82.59
44.5	3,516,375	73,764	0.02098	0.97902	82.12
45.5	2,096,236	299,212	0.14274	0.85726	80.40
46.5	1,785,006	323	0.00018	0.99982	68.92
47.5	1,700,090	2,276	0.00134	0.99866	68.91
48.5	1,696,342	93	0.00005	0.99995	68.82
49.5	1,692,243	8,693	0.00514	0.99486	68.82
50.5	1,300,000	0	0.00000	1.00000	68.47
51.5	1,283,730	0	0.00000	1.00000	68.47
52.5	1,273,767	312,038	0.24497	0.75503	68.47
53.5	503,383	3,189	0.00634	0.99366	51.70
54.5	500,146	13,920	0.02783	0.97217	51.37
55.5	460,956	0	0.00000	1.00000	49.94
56.5	77,863	14,107	0.18118	0.81882	49.94
57.5	56,984	0	0.00000	1.00000	40.89

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Account 35300 - Substation Equipment - Transmission Plant

Placement Band - 1940 - 2022 Experience Band - 1975 - 2022

58.5	56,972	0	0.00000	1.00000	40.89
59.5	56,972	0	0.00000	1.00000	40.89
60.5	56,972	0	0.00000	1.00000	40.89
61.5	56,830	0	0.00000	1.00000	40.89
62.5	0	0	0.00000	0.00000	40.89
	Totals:	5,124,464			

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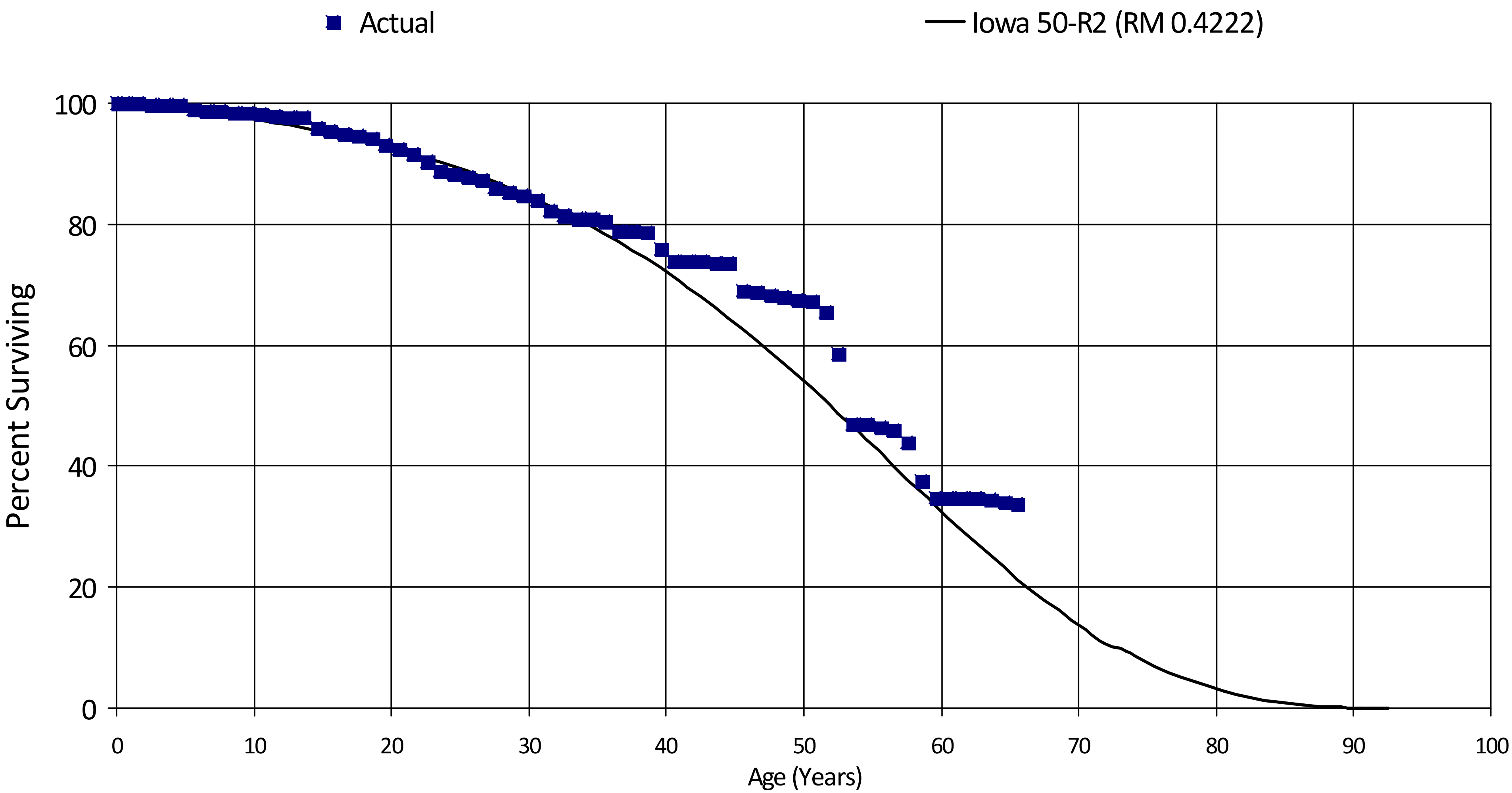
Account 35500 - Poles, Towers and Fixtures - Transmission Plant

Placement Band - 1950 - 2022 Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



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Account 35500 - Poles, Towers and Fixtures - Transmission Plant

Placement Band - 1950 - 2022   Experience Band - 1975 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	139,975,470	3,015	0.00002	0.99998	100.00
0.5	134,638,195	68,974	0.00051	0.99949	100.00
1.5	128,516,297	150,928	0.00117	0.99883	99.95
2.5	124,657,407	23,901	0.00019	0.99981	99.83
3.5	122,442,928	48,875	0.00040	0.99960	99.81
4.5	119,533,340	882,493	0.00738	0.99262	99.77
5.5	116,536,432	237,858	0.00204	0.99796	99.03
6.5	112,849,408	100,379	0.00089	0.99911	98.83
7.5	109,544,055	355,616	0.00325	0.99675	98.74
8.5	100,341,732	37,735	0.00038	0.99962	98.42
9.5	99,724,111	150,135	0.00151	0.99849	98.38
10.5	97,339,721	294,780	0.00303	0.99697	98.23
11.5	94,199,455	179,698	0.00191	0.99809	97.93
12.5	73,644,530	105,721	0.00144	0.99856	97.74
13.5	69,040,474	1,086,100	0.01573	0.98427	97.60
14.5	64,883,520	444,152	0.00685	0.99315	96.06
15.5	57,152,274	207,404	0.00363	0.99637	95.40
16.5	54,184,787	206,018	0.00380	0.99620	95.05
17.5	48,301,038	331,399	0.00686	0.99314	94.69
18.5	40,988,512	414,764	0.01012	0.98988	94.04
19.5	32,110,521	215,793	0.00672	0.99328	93.09
20.5	31,459,935	253,220	0.00805	0.99195	92.46
21.5	29,839,649	456,665	0.01530	0.98470	91.72
22.5	26,806,656	447,689	0.01670	0.98330	90.32
23.5	25,513,466	148,742	0.00583	0.99417	88.81
24.5	22,972,450	93,694	0.00408	0.99592	88.29
25.5	22,041,009	169,379	0.00768	0.99232	87.93
26.5	18,242,590	231,880	0.01271	0.98729	87.25

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Account 35500 - Poles, Towers and Fixtures - Transmission Plant

Placement Band - 1950 - 2022   Experience Band - 1975 - 2022

27.5	17,444,337	177,215	0.01016	0.98984	86.14
28.5	13,848,754	94,634	0.00683	0.99317	85.26
29.5	13,291,231	86,245	0.00649	0.99351	84.68
30.5	12,802,042	279,317	0.02182	0.97818	84.13
31.5	12,049,965	106,858	0.00887	0.99113	82.29
32.5	11,448,858	90,978	0.00795	0.99205	81.56
33.5	11,027,665	5,236	0.00047	0.99953	80.91
34.5	10,237,650	65,836	0.00643	0.99357	80.87
35.5	9,676,542	170,902	0.01766	0.98234	80.35
36.5	8,100,778	1,470	0.00018	0.99982	78.93
37.5	7,112,161	28,595	0.00402	0.99598	78.92
38.5	5,686,856	190,679	0.03353	0.96647	78.60
39.5	4,925,634	139,194	0.02826	0.97174	75.96
40.5	4,362,949	1,995	0.00046	0.99954	73.81
41.5	4,194,177	391	0.00009	0.99991	73.78
42.5	3,755,035	12,618	0.00336	0.99664	73.77
43.5	3,691,069	134	0.00004	0.99996	73.52
44.5	3,604,316	216,188	0.05998	0.94002	73.52
45.5	3,334,407	11,960	0.00359	0.99641	69.11
46.5	2,350,588	19,500	0.00830	0.99170	68.86
47.5	2,238,810	6,212	0.00277	0.99723	68.29
48.5	2,202,527	20,411	0.00927	0.99073	68.10
49.5	2,181,068	6,492	0.00298	0.99702	67.47
50.5	2,170,757	54,431	0.02507	0.97493	67.27
51.5	2,114,008	223,774	0.10585	0.89415	65.58
52.5	1,889,632	372,514	0.19714	0.80286	58.64
53.5	1,516,047	3,273	0.00216	0.99784	47.08
54.5	1,509,815	17,595	0.01165	0.98835	46.98
55.5	1,473,129	17,557	0.01192	0.98808	46.43
56.5	1,422,485	63,314	0.04451	0.95549	45.88
57.5	1,334,077	192,299	0.14414	0.85586	43.84

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Account 35500 - Poles, Towers and Fixtures - Transmission Plant

Placement Band - 1950 - 2022   Experience Band - 1975 - 2022

58.5	1,026,695	71,881	0.07001	0.92999	37.52
59.5	681,831	44	0.00006	0.99994	34.89
60.5	505,465	0	0.00000	1.00000	34.89
61.5	502,479	701	0.00140	0.99860	34.89
62.5	491,944	5,844	0.01188	0.98812	34.84
63.5	395,669	6,168	0.01559	0.98441	34.43
64.5	220,504	1,253	0.00568	0.99432	33.89
65.5	0	0	0.00000	0.00000	33.70
	Totals:	10,110,715			

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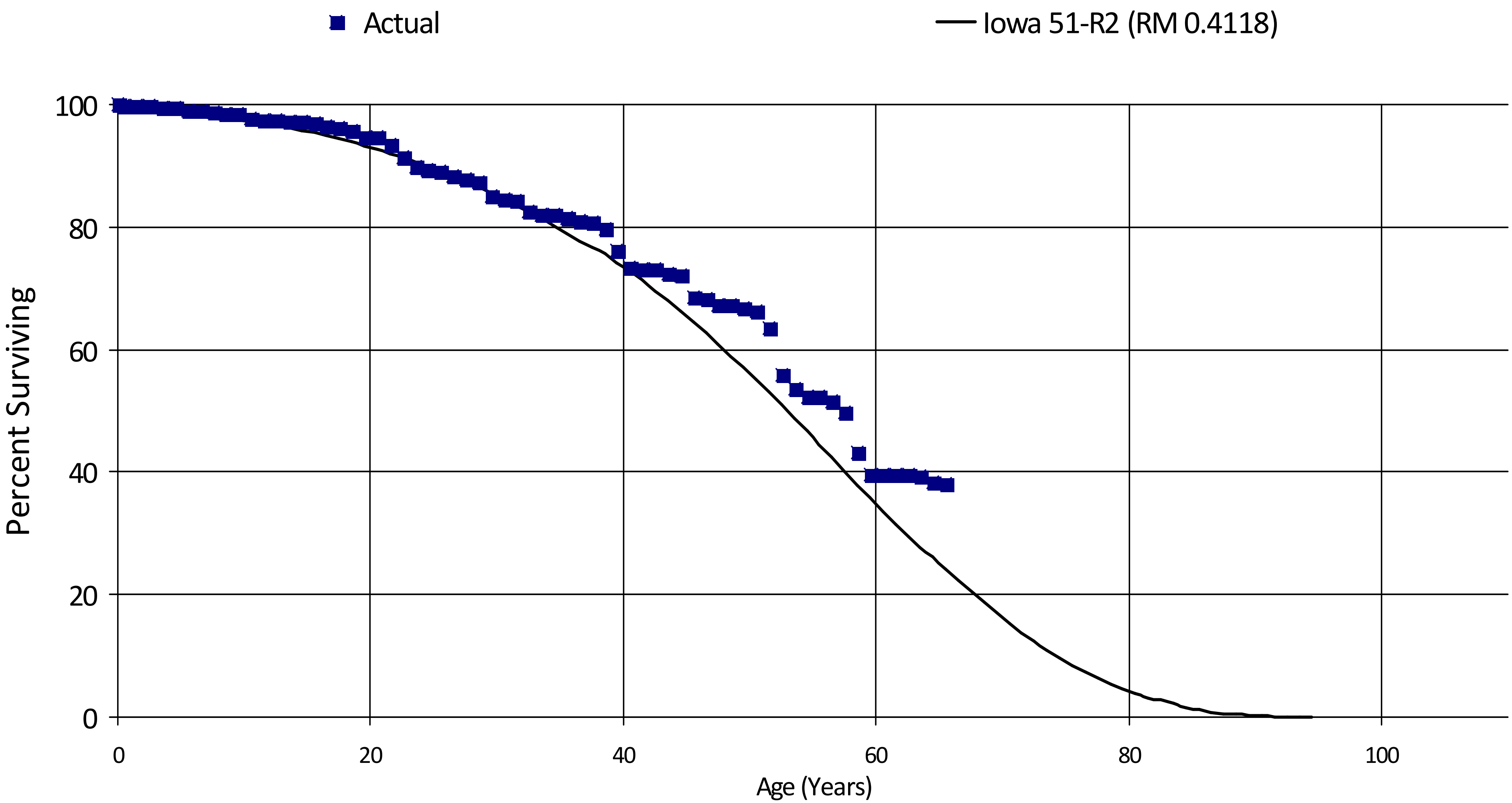
Account 35600 - Conductors and Devices - Transmission Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	136,820,654	333,465	0.00244	0.99756	100.00
0.5	131,152,940	65,274	0.00050	0.99950	99.76
1.5	125,034,747	13,498	0.00011	0.99989	99.71
2.5	121,313,295	124,592	0.00103	0.99897	99.70
3.5	118,998,131	15,210	0.00013	0.99987	99.60
4.5	116,122,231	643,958	0.00555	0.99445	99.59
5.5	113,363,566	176,181	0.00155	0.99845	99.04
6.5	109,707,035	48,893	0.00045	0.99955	98.89
7.5	106,246,356	412,526	0.00388	0.99612	98.85
8.5	98,223,162	77,249	0.00079	0.99921	98.47
9.5	97,166,436	677,234	0.00697	0.99303	98.39
10.5	94,253,758	126,572	0.00134	0.99866	97.70
11.5	91,329,103	94,584	0.00104	0.99896	97.57
12.5	70,859,176	122,916	0.00173	0.99827	97.47
13.5	66,001,644	107,027	0.00162	0.99838	97.30
14.5	62,827,565	126,883	0.00202	0.99798	97.14
15.5	57,132,133	241,238	0.00422	0.99578	96.94
16.5	54,337,289	178,869	0.00329	0.99671	96.53
17.5	49,944,385	294,825	0.00590	0.99410	96.21
18.5	42,425,821	397,152	0.00936	0.99064	95.64
19.5	33,559,830	46,487	0.00139	0.99861	94.74
20.5	33,061,021	389,112	0.01177	0.98823	94.61
21.5	31,287,231	702,270	0.02245	0.97755	93.50
22.5	27,941,657	496,031	0.01775	0.98225	91.40
23.5	26,540,930	122,800	0.00463	0.99537	89.78
24.5	23,954,995	53,935	0.00225	0.99775	89.36
25.5	23,038,755	191,794	0.00832	0.99168	89.16
26.5	19,073,503	113,133	0.00593	0.99407	88.42

FortisBC

Account 35600 - Conductors and Devices - Transmission Plant

Placement Band - 1940 - 2022 Experience Band - 1975 - 2022

27.5	18,377,393	111,931	0.00609	0.99391	87.90
28.5	14,600,924	388,618	0.02662	0.97338	87.36
29.5	13,735,847	82,566	0.00601	0.99399	85.03
30.5	13,238,525	35,427	0.00268	0.99732	84.52
31.5	12,716,480	268,073	0.02108	0.97892	84.29
32.5	11,939,669	74,713	0.00626	0.99374	82.51
33.5	11,525,061	4,141	0.00036	0.99964	81.99
34.5	10,714,498	53,145	0.00496	0.99504	81.96
35.5	10,108,868	63,260	0.00626	0.99374	81.55
36.5	8,602,010	24,429	0.00284	0.99716	81.04
37.5	7,473,524	104,568	0.01399	0.98601	80.81
38.5	5,930,675	258,299	0.04355	0.95645	79.68
39.5	5,076,728	196,475	0.03870	0.96130	76.21
40.5	4,444,348	9,111	0.00205	0.99795	73.26
41.5	4,263,571	3,147	0.00074	0.99926	73.11
42.5	3,704,380	31,945	0.00862	0.99138	73.06
43.5	3,552,801	12,108	0.00341	0.99659	72.43
44.5	3,485,867	182,165	0.05226	0.94774	72.18
45.5	3,253,709	4,873	0.00150	0.99850	68.41
46.5	2,242,445	31,823	0.01419	0.98581	68.31
47.5	2,114,979	6,176	0.00292	0.99708	67.34
48.5	2,077,849	14,481	0.00697	0.99303	67.14
49.5	2,062,290	13,128	0.00637	0.99363	66.67
50.5	2,045,231	89,575	0.04380	0.95620	66.25
51.5	1,953,270	234,151	0.11988	0.88012	63.35
52.5	1,718,500	67,947	0.03954	0.96046	55.76
53.5	1,649,450	42,812	0.02596	0.97404	53.56
54.5	1,603,593	374	0.00023	0.99977	52.17
55.5	1,580,728	17,442	0.01103	0.98897	52.16
56.5	1,528,285	51,874	0.03394	0.96606	51.58
57.5	1,450,279	192,066	0.13243	0.86757	49.83

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Account 35600 - Conductors and Devices - Transmission Plant

Placement Band - 1940 - 2022 Experience Band - 1975 - 2022

58.5	1,138,224	92,364	0.08115	0.91885	43.23
59.5	769,148	46	0.00006	0.99994	39.72
60.5	593,959	0	0.00000	1.00000	39.72
61.5	586,828	722	0.00123	0.99877	39.72
62.5	575,354	6,015	0.01045	0.98955	39.67
63.5	472,653	10,207	0.02160	0.97840	39.26
64.5	283,075	1,897	0.00670	0.99330	38.41
65.5	0	0	0.00000	0.00000	38.15
	Totals:	9,175,802			

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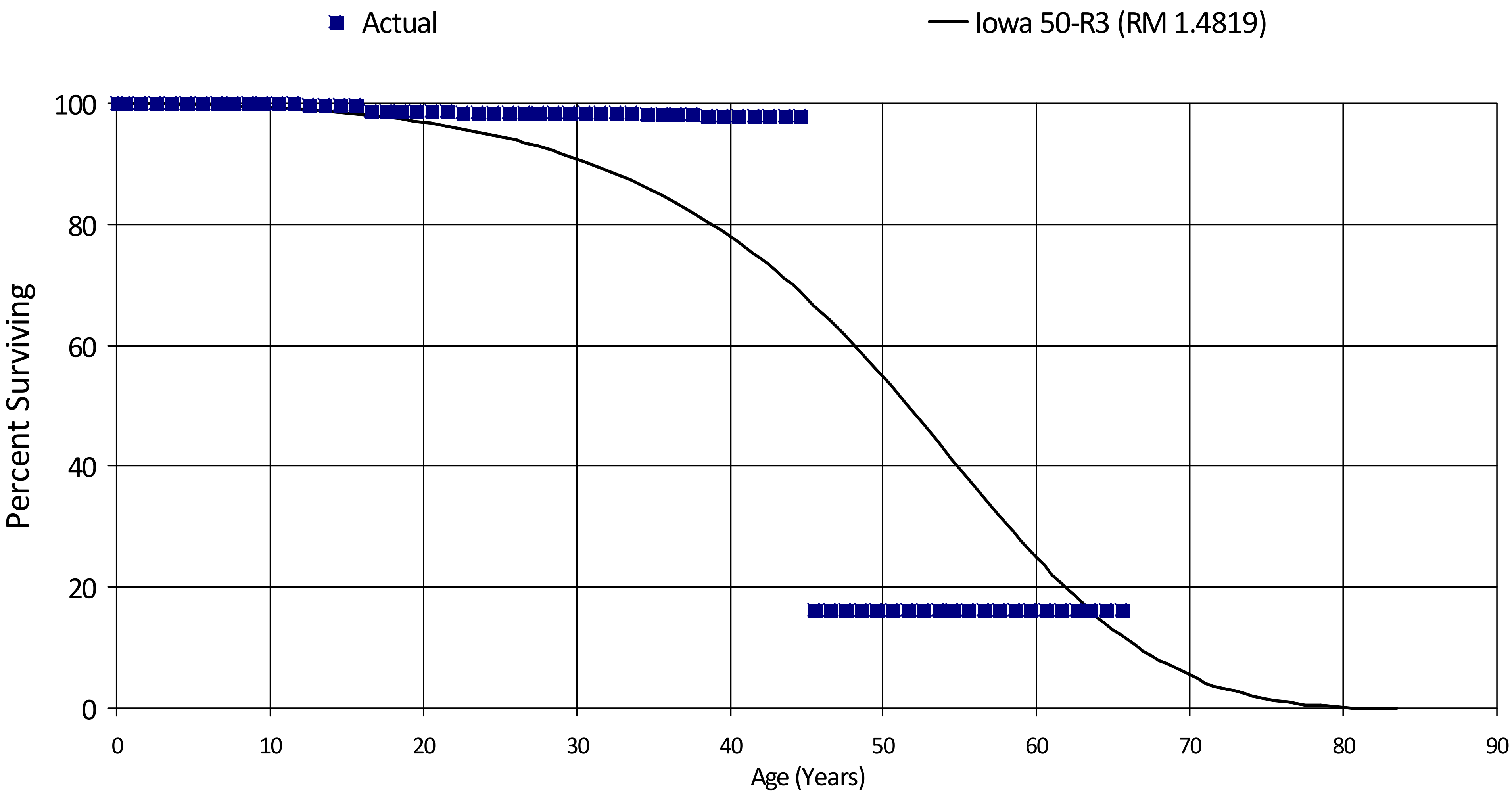
Account 35900 - Roads and Trails - Transmission Plant

Placement Band - 1950 - 2009   Experience Band - 1982 - 2022

Actual and Smooth Survivor Curves



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Account 35900 - Roads and Trails - Transmission Plant

Placement Band - 1950 - 2009   Experience Band - 1982 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,230,779	34	0.00003	0.99997	100.00
0.5	1,230,745	0	0.00000	1.00000	100.00
1.5	1,230,745	5	0.00000	1.00000	100.00
2.5	1,230,740	145	0.00012	0.99988	100.00
3.5	1,230,595	59	0.00005	0.99995	99.99
4.5	1,230,536	36	0.00003	0.99997	99.99
5.5	1,230,500	256	0.00021	0.99979	99.99
6.5	1,230,245	281	0.00023	0.99977	99.97
7.5	1,229,964	239	0.00019	0.99981	99.95
8.5	1,229,725	36	0.00003	0.99997	99.93
9.5	1,229,689	4	0.00000	1.00000	99.93
10.5	1,229,685	20	0.00002	0.99998	99.93
11.5	1,229,665	786	0.00064	0.99936	99.93
12.5	1,228,878	5	0.00000	1.00000	99.87
13.5	924,623	16	0.00002	0.99998	99.87
14.5	924,607	4	0.00000	1.00000	99.87
15.5	924,604	10,710	0.01158	0.98842	99.87
16.5	913,894	0	0.00000	1.00000	98.71
17.5	856,407	376	0.00044	0.99956	98.71
18.5	455,254	0	0.00000	1.00000	98.67
19.5	251,439	59	0.00023	0.99977	98.67
20.5	251,380	0	0.00000	1.00000	98.65
21.5	244,913	511	0.00209	0.99791	98.65
22.5	231,667	0	0.00000	1.00000	98.44
23.5	227,161	0	0.00000	1.00000	98.44
24.5	215,075	0	0.00000	1.00000	98.44
25.5	210,854	0	0.00000	1.00000	98.44
26.5	192,842	0	0.00000	1.00000	98.44

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Account 35900 - Roads and Trails - Transmission Plant

Placement Band - 1950 - 2009   Experience Band - 1982 - 2022

27.5	189,948	36	0.00019	0.99981	98.44
28.5	172,299	0	0.00000	1.00000	98.42
29.5	168,802	0	0.00000	1.00000	98.42
30.5	166,553	0	0.00000	1.00000	98.42
31.5	162,829	0	0.00000	1.00000	98.42
32.5	159,479	0	0.00000	1.00000	98.42
33.5	156,681	235	0.00150	0.99850	98.42
34.5	150,963	0	0.00000	1.00000	98.27
35.5	146,378	0	0.00000	1.00000	98.27
36.5	138,934	0	0.00000	1.00000	98.27
37.5	133,000	363	0.00273	0.99727	98.27
38.5	124,793	52	0.00042	0.99958	98.00
39.5	121,748	0	0.00000	1.00000	97.96
40.5	119,381	0	0.00000	1.00000	97.96
41.5	118,260	0	0.00000	1.00000	97.96
42.5	115,339	0	0.00000	1.00000	97.96
43.5	113,832	0	0.00000	1.00000	97.96
44.5	113,217	94,582	0.83541	0.16459	97.96
45.5	18,062	0	0.00000	1.00000	16.12
46.5	13,181	0	0.00000	1.00000	16.12
47.5	12,715	0	0.00000	1.00000	16.12
48.5	12,459	0	0.00000	1.00000	16.12
49.5	12,412	0	0.00000	1.00000	16.12
50.5	12,385	0	0.00000	1.00000	16.12
51.5	12,291	0	0.00000	1.00000	16.12
52.5	12,242	0	0.00000	1.00000	16.12
53.5	12,174	0	0.00000	1.00000	16.12
54.5	12,140	0	0.00000	1.00000	16.12
55.5	12,006	0	0.00000	1.00000	16.12
56.5	11,778	0	0.00000	1.00000	16.12
57.5	10,682	0	0.00000	1.00000	16.12

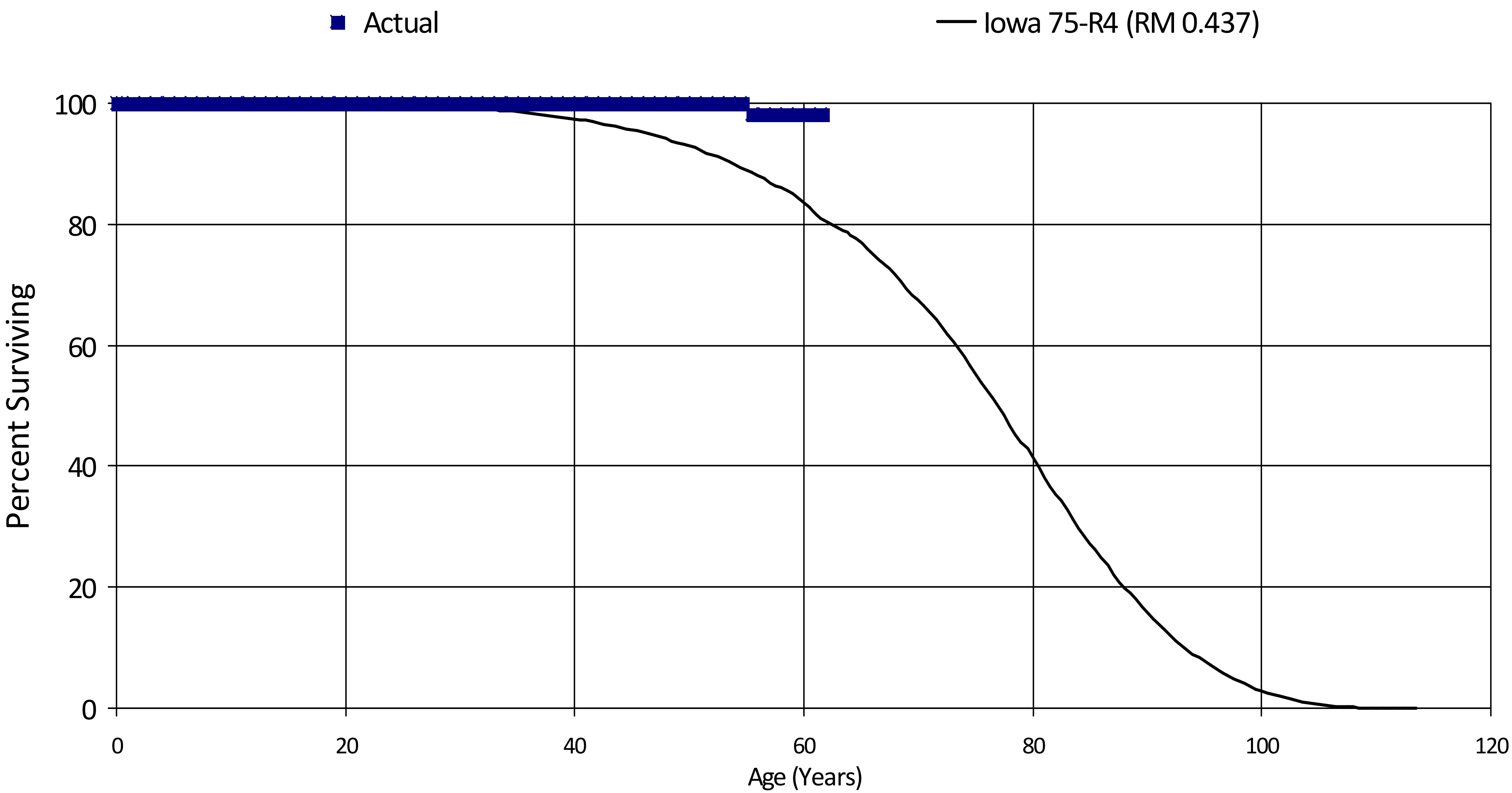
58.5	9,716	0	0.00000	1.00000	16.12
59.5	7,939	0	0.00000	1.00000	16.12
60.5	6,793	0	0.00000	1.00000	16.12
61.5	6,631	0	0.00000	1.00000	16.12
62.5	6,557	0	0.00000	1.00000	16.12
63.5	6,016	0	0.00000	1.00000	16.12
64.5	4,052	0	0.00000	1.00000	16.12
65.5	0	0	0.00000	0.00000	16.12
	Totals:	108,850			

FortisBC

Account 36020 - Surface and Mineral - Distribution Plant

Placement Band - 1960 - 2022   Experience Band - 2020 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 36020 - Surface and Mineral - Distribution Plant

Placement Band - 1960 - 2022   Experience Band - 2020 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,557,279	0	0.00000	1.00000	100.00
0.5	12,094,100	0	0.00000	1.00000	100.00
1.5	11,742,933	0	0.00000	1.00000	100.00
2.5	11,629,742	0	0.00000	1.00000	100.00
3.5	11,545,712	0	0.00000	1.00000	100.00
4.5	11,319,973	0	0.00000	1.00000	100.00
5.5	11,069,749	0	0.00000	1.00000	100.00
6.5	10,992,084	0	0.00000	1.00000	100.00
7.5	10,455,571	0	0.00000	1.00000	100.00
8.5	10,322,155	0	0.00000	1.00000	100.00
9.5	10,211,459	0	0.00000	1.00000	100.00
10.5	10,016,627	0	0.00000	1.00000	100.00
11.5	9,963,382	0	0.00000	1.00000	100.00
12.5	8,477,100	0	0.00000	1.00000	100.00
13.5	6,363,966	0	0.00000	1.00000	100.00
14.5	5,855,771	0	0.00000	1.00000	100.00
15.5	4,153,141	0	0.00000	1.00000	100.00
16.5	3,157,778	0	0.00000	1.00000	100.00
17.5	2,794,268	0	0.00000	1.00000	100.00
18.5	1,982,774	0	0.00000	1.00000	100.00
19.5	940,523	0	0.00000	1.00000	100.00
20.5	940,523	0	0.00000	1.00000	100.00
21.5	924,593	0	0.00000	1.00000	100.00
22.5	909,112	0	0.00000	1.00000	100.00
23.5	895,131	0	0.00000	1.00000	100.00
24.5	883,134	0	0.00000	1.00000	100.00
25.5	864,561	0	0.00000	1.00000	100.00
26.5	852,301	0	0.00000	1.00000	100.00

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Account 36020 - Surface and Mineral - Distribution Plant

Placement Band - 1960 - 2022   Experience Band - 2020 - 2022

27.5	834,833	0	0.00000	1.00000	100.00
28.5	817,578	0	0.00000	1.00000	100.00
29.5	804,698	0	0.00000	1.00000	100.00
30.5	794,798	0	0.00000	1.00000	100.00
31.5	784,102	0	0.00000	1.00000	100.00
32.5	773,933	0	0.00000	1.00000	100.00
33.5	765,495	0	0.00000	1.00000	100.00
34.5	758,072	0	0.00000	1.00000	100.00
35.5	752,064	0	0.00000	1.00000	100.00
36.5	745,108	0	0.00000	1.00000	100.00
37.5	738,140	0	0.00000	1.00000	100.00
38.5	731,645	0	0.00000	1.00000	100.00
39.5	725,086	0	0.00000	1.00000	100.00
40.5	716,930	0	0.00000	1.00000	100.00
41.5	707,810	0	0.00000	1.00000	100.00
42.5	700,954	0	0.00000	1.00000	100.00
43.5	695,723	0	0.00000	1.00000	100.00
44.5	689,807	0	0.00000	1.00000	100.00
45.5	685,551	0	0.00000	1.00000	100.00
46.5	681,222	0	0.00000	1.00000	100.00
47.5	24,741	0	0.00000	1.00000	100.00
48.5	22,375	0	0.00000	1.00000	100.00
49.5	20,903	0	0.00000	1.00000	100.00
50.5	19,522	0	0.00000	1.00000	100.00
51.5	18,470	0	0.00000	1.00000	100.00
52.5	17,492	0	0.00000	1.00000	100.00
53.5	16,460	0	0.00000	1.00000	100.00
54.5	15,447	275	0.01780	0.98220	100.00
55.5	14,215	0	0.00000	1.00000	98.22
56.5	13,273	0	0.00000	1.00000	98.22
57.5	11,575	0	0.00000	1.00000	98.22

58.5	10,897	0	0.00000	1.00000	98.22
59.5	10,064	0	0.00000	1.00000	98.22
60.5	9,375	0	0.00000	1.00000	98.22
61.5	8,862	0	0.00000	1.00000	98.22
	Totals:	275			

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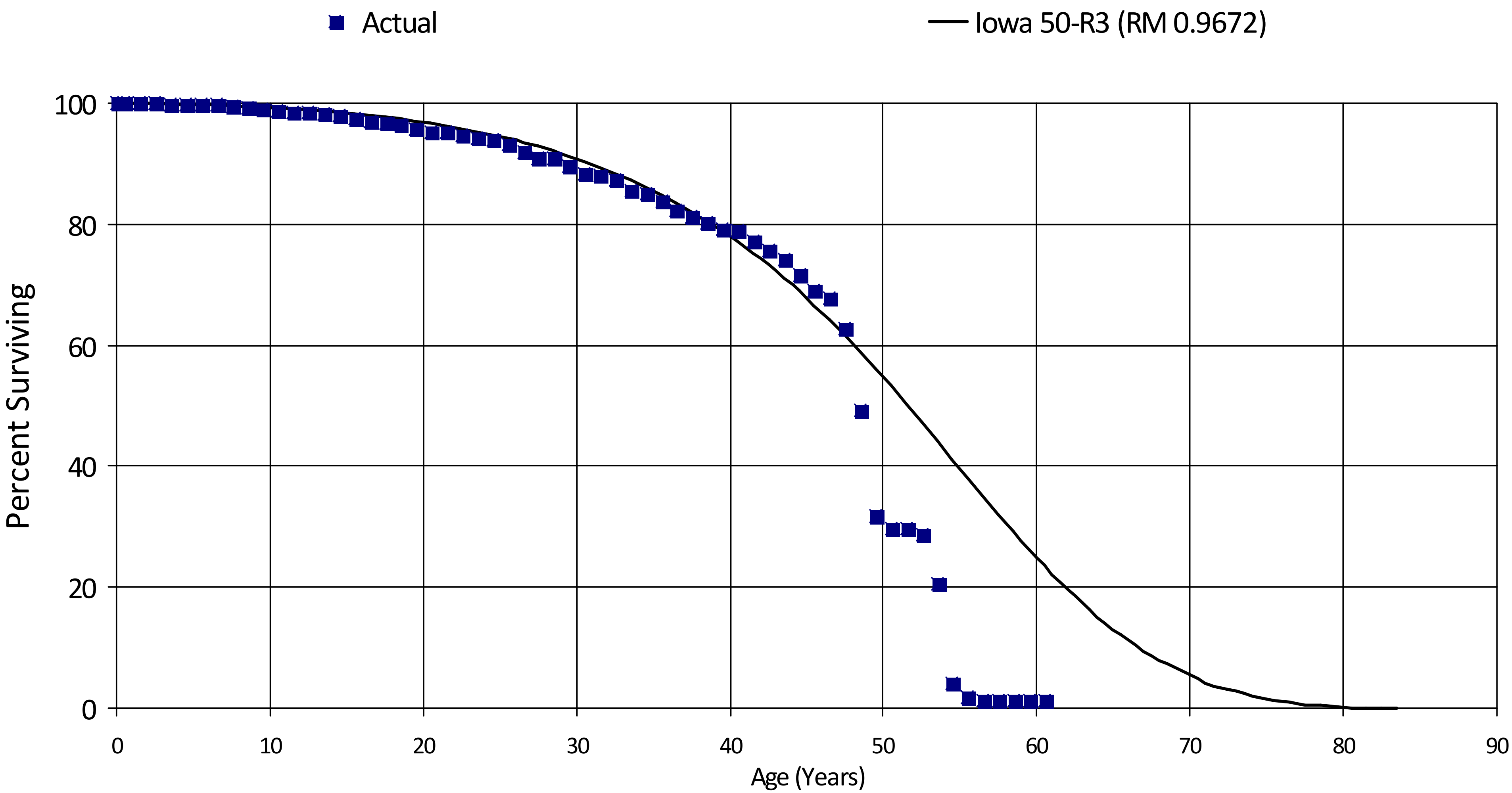
Account 36200 - Substation Equipment - Distribution Plant

Placement Band - 1950 - 2022   Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 36200 - Substation Equipment - Distribution Plant

Placement Band - 1950 - 2022 Experience Band - 1975 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	305,561,881	217,478	0.00071	0.99929	100.00
0.5	287,789,595	40,832	0.00014	0.99986	99.93
1.5	275,526,604	79,416	0.00029	0.99971	99.92
2.5	264,112,219	91,857	0.00035	0.99965	99.89
3.5	259,841,649	158,431	0.00061	0.99939	99.86
4.5	250,401,051	158,882	0.00063	0.99937	99.80
5.5	247,084,489	90,042	0.00036	0.99964	99.74
6.5	243,590,731	619,993	0.00255	0.99745	99.70
7.5	234,136,448	488,172	0.00208	0.99792	99.45
8.5	219,930,028	329,288	0.00150	0.99850	99.24
9.5	217,232,244	837,021	0.00385	0.99615	99.09
10.5	212,471,219	256,501	0.00121	0.99879	98.71
11.5	194,325,359	226,287	0.00116	0.99884	98.59
12.5	174,092,142	291,214	0.00167	0.99833	98.48
13.5	142,613,774	337,862	0.00237	0.99763	98.32
14.5	108,161,741	784,724	0.00726	0.99274	98.09
15.5	86,039,827	273,798	0.00318	0.99682	97.38
16.5	69,204,929	242,357	0.00350	0.99650	97.07
17.5	61,956,868	259,303	0.00419	0.99581	96.73
18.5	60,885,737	436,683	0.00717	0.99283	96.32
19.5	56,951,060	253,135	0.00444	0.99556	95.63
20.5	55,909,707	84,638	0.00151	0.99849	95.21
21.5	53,583,198	208,244	0.00389	0.99611	95.07
22.5	52,138,814	294,846	0.00566	0.99434	94.70
23.5	48,837,853	135,531	0.00278	0.99722	94.16
24.5	46,734,827	314,912	0.00674	0.99326	93.90
25.5	44,258,938	629,960	0.01423	0.98577	93.27
26.5	39,816,438	502,841	0.01263	0.98737	91.94

Account 36200 - Substation Equipment - Distribution Plant

Placement Band - 1950 - 2022 Experience Band - 1975 - 2022

27.5	35,074,275	11,455	0.00033	0.99967	90.78
28.5	32,030,679	394,190	0.01231	0.98769	90.75
29.5	30,053,820	474,679	0.01579	0.98421	89.63
30.5	29,018,913	61,370	0.00211	0.99789	88.21
31.5	25,488,722	230,887	0.00906	0.99094	88.02
32.5	22,843,223	431,305	0.01888	0.98112	87.22
33.5	20,766,388	145,175	0.00699	0.99301	85.57
34.5	19,829,181	294,167	0.01484	0.98516	84.97
35.5	17,804,943	288,202	0.01619	0.98381	83.71
36.5	15,290,246	207,913	0.01360	0.98640	82.35
37.5	13,941,270	167,733	0.01203	0.98797	81.23
38.5	13,257,201	173,377	0.01308	0.98692	80.25
39.5	10,708,448	52,699	0.00492	0.99508	79.20
40.5	7,806,924	167,962	0.02151	0.97849	78.81
41.5	7,014,013	133,631	0.01905	0.98095	77.11
42.5	4,721,114	102,993	0.02182	0.97818	75.64
43.5	4,565,778	155,659	0.03409	0.96591	73.99
44.5	3,726,825	120,788	0.03241	0.96759	71.47
45.5	3,120,164	64,405	0.02064	0.97936	69.15
46.5	2,741,009	203,520	0.07425	0.92575	67.72
47.5	2,328,909	504,130	0.21647	0.78353	62.69
48.5	1,696,254	602,940	0.35545	0.64455	49.12
49.5	1,088,608	67,715	0.06220	0.93780	31.66
50.5	1,017,102	3,426	0.00337	0.99663	29.69
51.5	970,850	29,493	0.03038	0.96962	29.59
52.5	920,737	264,704	0.28749	0.71251	28.69
53.5	642,344	512,348	0.79762	0.20238	20.44
54.5	127,223	75,061	0.59000	0.41000	4.14
55.5	51,038	14,212	0.27846	0.72154	1.70
56.5	4,708	0	0.00000	1.00000	1.23
57.5	2,945	0	0.00000	1.00000	1.23

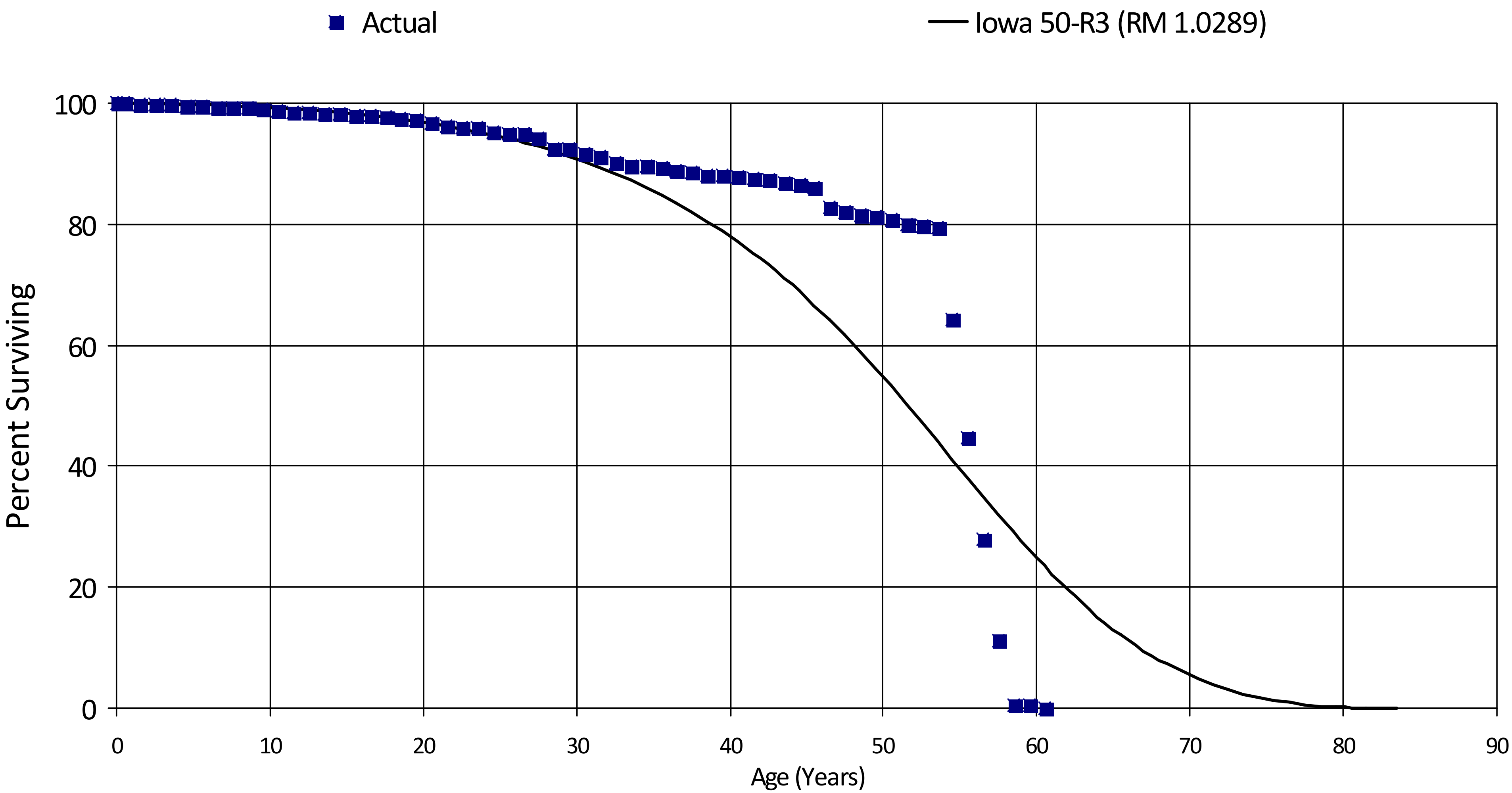
58.5	2,945	0	0.00000	1.00000	1.23
59.5	2,829	0	0.00000	1.00000	1.23
60.5	0	0	0.00000	0.00000	1.23
	Totals:	14,600,387			

FortisBC

Account 36400 - Poles, Towers and Fixtures - Distribution Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 36400 - Poles, Towers and Fixtures - Distribution Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	273,237,115	261,252	0.00096	0.99904	100.00
0.5	260,273,383	141,200	0.00054	0.99946	99.90
1.5	247,161,431	118,051	0.00048	0.99952	99.85
2.5	235,442,425	381,616	0.00162	0.99838	99.80
3.5	224,839,065	266,382	0.00118	0.99882	99.64
4.5	213,821,716	178,671	0.00084	0.99916	99.52
5.5	202,943,048	170,857	0.00084	0.99916	99.44
6.5	193,763,300	128,413	0.00066	0.99934	99.36
7.5	183,754,531	161,677	0.00088	0.99912	99.29
8.5	171,081,653	209,994	0.00123	0.99877	99.20
9.5	165,171,178	623,526	0.00378	0.99622	99.08
10.5	154,005,363	164,354	0.00107	0.99893	98.71
11.5	145,436,532	141,212	0.00097	0.99903	98.60
12.5	134,109,455	295,835	0.00221	0.99779	98.50
13.5	122,799,558	142,549	0.00116	0.99884	98.28
14.5	110,154,321	160,138	0.00145	0.99855	98.17
15.5	100,008,256	97,215	0.00097	0.99903	98.03
16.5	88,238,501	221,124	0.00251	0.99749	97.93
17.5	79,929,750	275,668	0.00345	0.99655	97.68
18.5	74,163,690	84,737	0.00114	0.99886	97.34
19.5	68,182,357	349,748	0.00513	0.99487	97.23
20.5	64,824,707	385,940	0.00595	0.99405	96.73
21.5	60,055,009	63,676	0.00106	0.99894	96.15
22.5	56,909,236	116,496	0.00205	0.99795	96.05
23.5	54,025,958	420,973	0.00779	0.99221	95.85
24.5	51,041,416	72,499	0.00142	0.99858	95.10
25.5	47,275,689	37,460	0.00079	0.99921	94.96
26.5	44,802,791	392,956	0.00877	0.99123	94.88

FortisBC

Account 36400 - Poles, Towers and Fixtures - Distribution Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

27.5	40,860,197	710,148	0.01738	0.98262	94.05
28.5	36,765,286	49,660	0.00135	0.99865	92.42
29.5	34,044,718	286,233	0.00841	0.99159	92.30
30.5	31,723,332	137,423	0.00433	0.99567	91.52
31.5	29,407,783	343,951	0.01170	0.98830	91.12
32.5	27,011,242	120,077	0.00445	0.99555	90.05
33.5	25,133,320	34,655	0.00138	0.99862	89.65
34.5	23,629,510	39,358	0.00167	0.99833	89.53
35.5	22,399,626	165,439	0.00739	0.99261	89.38
36.5	20,869,765	33,626	0.00161	0.99839	88.72
37.5	15,033,894	67,768	0.00451	0.99549	88.58
38.5	13,703,391	34,802	0.00254	0.99746	88.18
39.5	12,388,719	34,415	0.00278	0.99722	87.96
40.5	10,757,783	23,629	0.00220	0.99780	87.72
41.5	8,975,562	29,779	0.00332	0.99668	87.53
42.5	8,945,782	46,900	0.00524	0.99476	87.24
43.5	7,906,509	24,903	0.00315	0.99685	86.78
44.5	6,752,579	27,294	0.00404	0.99596	86.51
45.5	5,953,968	233,487	0.03922	0.96078	86.16
46.5	4,924,861	45,004	0.00914	0.99086	82.78
47.5	4,240,231	25,606	0.00604	0.99396	82.02
48.5	3,788,790	18,278	0.00482	0.99518	81.52
49.5	3,489,357	18,979	0.00544	0.99456	81.13
50.5	3,234,470	24,665	0.00763	0.99237	80.69
51.5	3,025,562	12,696	0.00420	0.99580	80.07
52.5	2,849,232	11,456	0.00402	0.99598	79.73
53.5	2,657,331	505,742	0.19032	0.80968	79.41
54.5	1,975,756	603,355	0.30538	0.69462	64.30
55.5	1,190,101	443,092	0.37231	0.62769	44.66
56.5	689,210	413,714	0.60027	0.39973	28.03
57.5	275,495	263,940	0.95806	0.04194	11.20

FortisBC

Account 36400 - Poles, Towers and Fixtures - Distribution Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

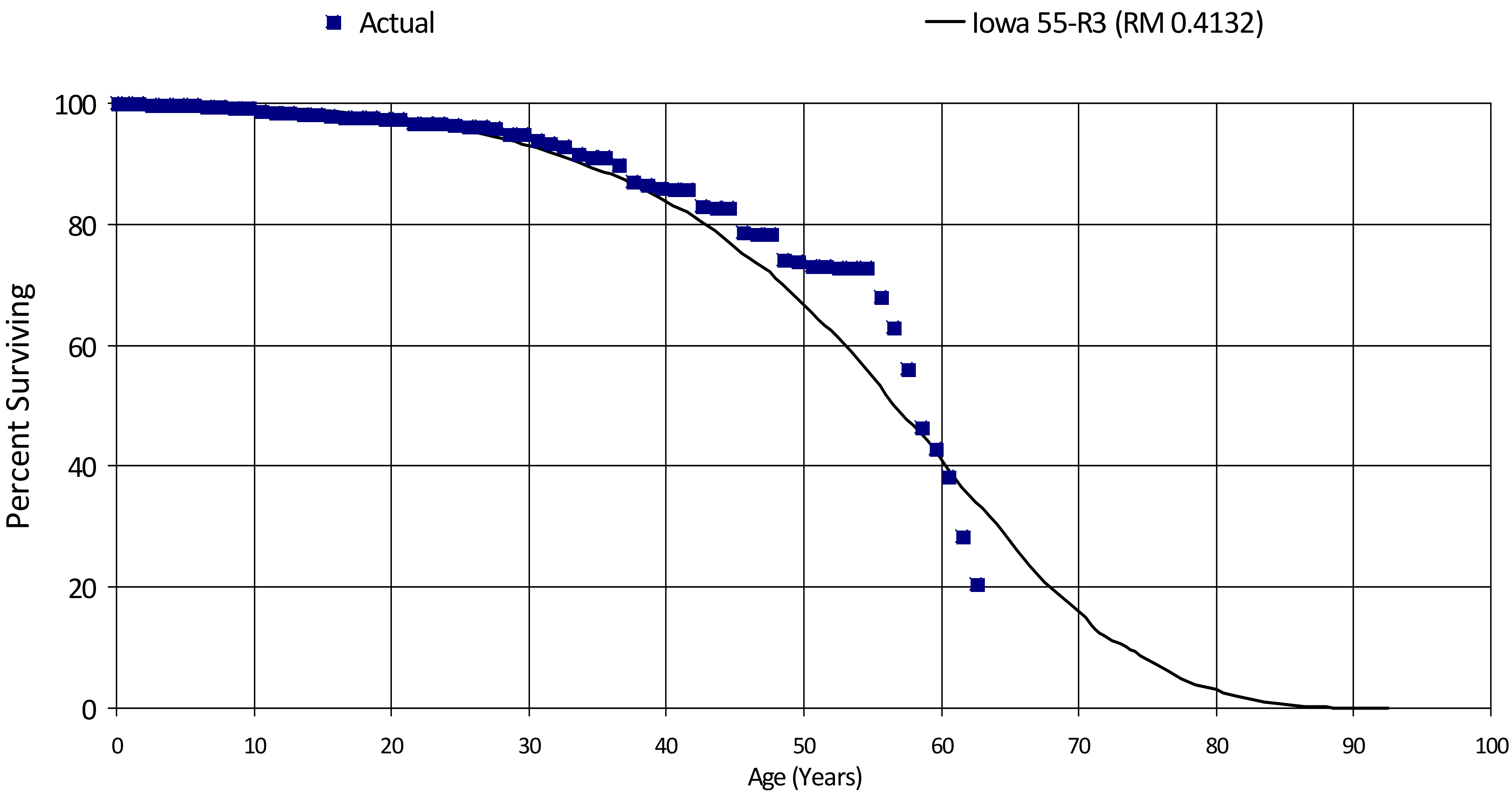
58.5	11,555	0	0.00000	1.00000	0.47
59.5	11,555	11,555	0.99998	0.00002	0.47
60.5	0	0	0.00000	0.00000	0.00
	Totals:	10,905,848			

FortisBC

Account 36500 - Conductors and Devices - Distribution Plant

Placement Band - 1950 - 2022 Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 36500 - Conductors and Devices - Distribution Plant

Placement Band - 1950 - 2022   Experience Band - 1975 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	438,938,279	140,913	0.00032	0.99968	100.00
0.5	418,828,594	326,053	0.00078	0.99922	99.97
1.5	398,241,507	121,928	0.00031	0.99969	99.89
2.5	379,173,297	87,805	0.00023	0.99977	99.86
3.5	363,159,320	211,298	0.00058	0.99942	99.84
4.5	345,806,513	338,006	0.00098	0.99902	99.78
5.5	328,607,126	587,247	0.00179	0.99821	99.68
6.5	313,333,637	172,474	0.00055	0.99945	99.50
7.5	297,667,367	361,130	0.00121	0.99879	99.45
8.5	277,989,855	196,958	0.00071	0.99929	99.33
9.5	268,825,263	1,710,041	0.00636	0.99364	99.26
10.5	252,457,825	166,007	0.00066	0.99934	98.63
11.5	238,101,682	414,388	0.00174	0.99826	98.56
12.5	220,691,052	233,400	0.00106	0.99894	98.39
13.5	203,693,042	212,011	0.00104	0.99896	98.29
14.5	183,892,956	507,106	0.00276	0.99724	98.19
15.5	166,258,724	254,422	0.00153	0.99847	97.92
16.5	147,490,867	179,242	0.00122	0.99878	97.77
17.5	135,688,026	56,009	0.00041	0.99959	97.65
18.5	127,615,039	137,587	0.00108	0.99892	97.61
19.5	118,592,059	136,201	0.00115	0.99885	97.50
20.5	113,693,638	692,596	0.00609	0.99391	97.39
21.5	105,138,067	96,799	0.00092	0.99908	96.80
22.5	99,520,286	120,840	0.00121	0.99879	96.71
23.5	94,521,905	108,516	0.00115	0.99885	96.59
24.5	90,018,817	237,275	0.00264	0.99736	96.48
25.5	83,120,292	56,707	0.00068	0.99932	96.23
26.5	78,655,696	152,929	0.00194	0.99806	96.16

FortisBC

Account 36500 - Conductors and Devices - Distribution Plant

Placement Band - 1950 - 2022   Experience Band - 1975 - 2022

27.5	72,195,514	791,328	0.01096	0.98904	95.97
28.5	65,641,780	46,980	0.00072	0.99928	94.92
29.5	60,860,964	645,162	0.01060	0.98940	94.85
30.5	56,600,146	230,719	0.00408	0.99592	93.84
31.5	52,450,434	262,668	0.00501	0.99499	93.46
32.5	48,366,543	708,147	0.01464	0.98536	92.99
33.5	44,511,880	242,692	0.00545	0.99455	91.63
34.5	41,568,295	25,279	0.00061	0.99939	91.13
35.5	39,367,601	489,280	0.01243	0.98757	91.07
36.5	36,392,372	1,143,062	0.03141	0.96859	89.94
37.5	29,101,407	192,990	0.00663	0.99337	87.11
38.5	26,595,024	160,201	0.00602	0.99398	86.53
39.5	24,093,493	71,157	0.00295	0.99705	86.01
40.5	21,134,512	24,630	0.00117	0.99883	85.76
41.5	17,896,014	583,525	0.03261	0.96739	85.66
42.5	17,312,488	23,834	0.00138	0.99862	82.87
43.5	15,472,868	12,130	0.00078	0.99922	82.76
44.5	13,371,705	650,291	0.04863	0.95137	82.70
45.5	11,236,352	36,036	0.00321	0.99679	78.68
46.5	9,680,983	10,276	0.00106	0.99894	78.43
47.5	8,460,613	454,536	0.05372	0.94628	78.35
48.5	7,186,735	21,208	0.00295	0.99705	74.14
49.5	6,644,349	76,703	0.01154	0.98846	73.92
50.5	6,099,485	8,667	0.00142	0.99858	73.07
51.5	5,726,675	5,746	0.00100	0.99900	72.97
52.5	5,399,191	5,421	0.00100	0.99900	72.90
53.5	5,036,065	7,519	0.00149	0.99851	72.83
54.5	4,677,955	301,327	0.06441	0.93559	72.72
55.5	4,037,822	301,288	0.07462	0.92538	68.04
56.5	3,435,687	369,196	0.10746	0.89254	62.96
57.5	2,673,721	464,454	0.17371	0.82629	56.19

58.5	1,980,767	149,833	0.07564	0.92436	46.43
59.5	1,540,938	162,850	0.10568	0.89432	42.92
60.5	1,141,504	297,766	0.26085	0.73915	38.38
61.5	673,098	186,808	0.27753	0.72247	28.37
62.5	0	0	0.00000	0.00000	20.50
	Totals:	17,179,597			

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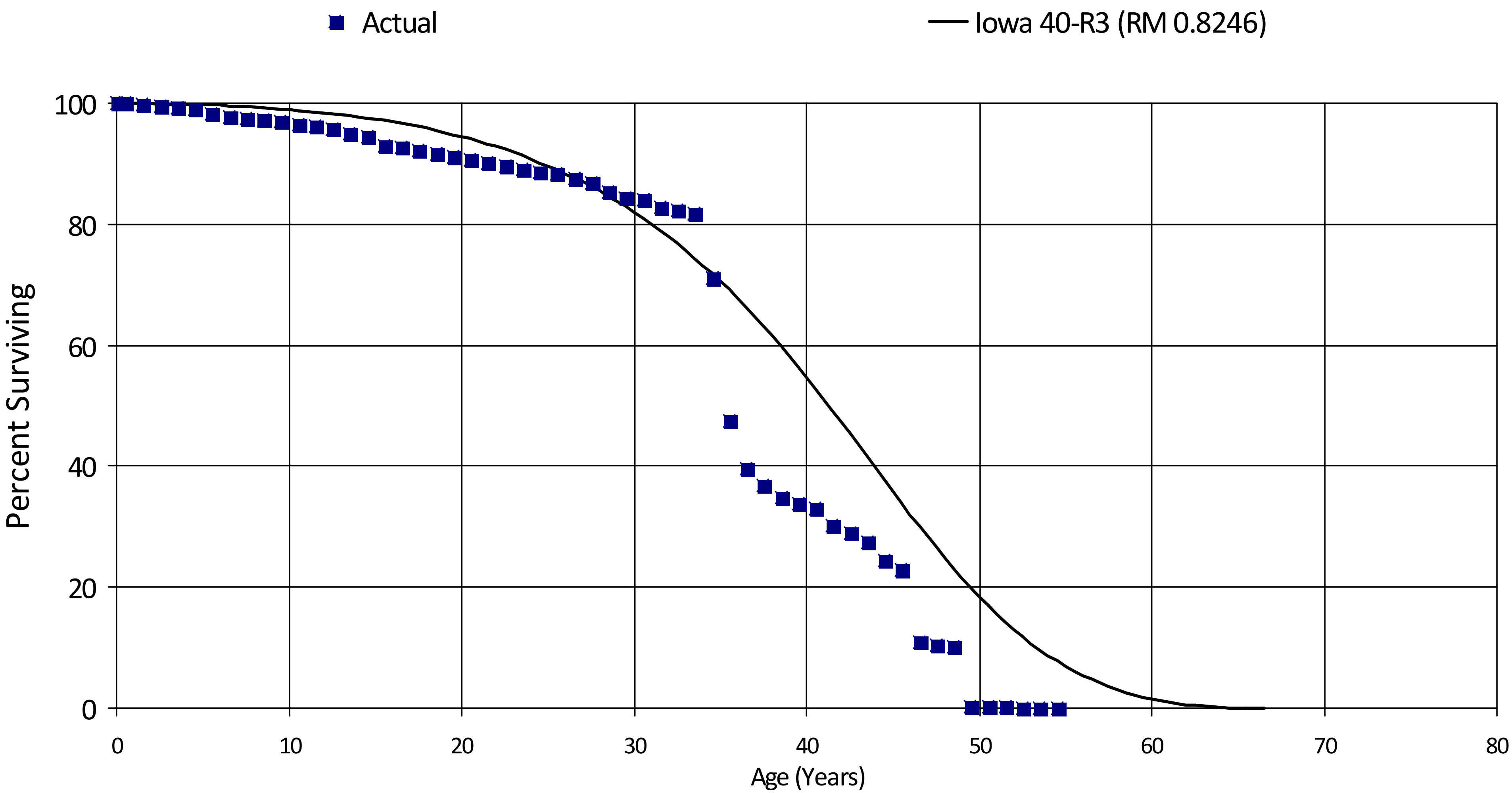
Account 36800 - Line Transformers - Distribution Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

Actual and Smooth Survivor Curves



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Account 36800 - Line Transformers - Distribution Plant

Placement Band - 1940 - 2022   Experience Band - 1975 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	232,535,934	257,987	0.00111	0.99889	100.00
0.5	219,305,064	573,517	0.00262	0.99738	99.89
1.5	205,131,750	544,074	0.00265	0.99735	99.63
2.5	191,641,826	401,151	0.00209	0.99791	99.37
3.5	180,122,221	475,476	0.00264	0.99736	99.16
4.5	168,564,611	1,189,130	0.00705	0.99295	98.90
5.5	157,339,061	667,626	0.00424	0.99576	98.20
6.5	148,604,146	434,109	0.00292	0.99708	97.78
7.5	139,803,017	431,128	0.00308	0.99692	97.49
8.5	129,643,853	380,735	0.00294	0.99706	97.19
9.5	124,809,096	575,180	0.00461	0.99539	96.90
10.5	117,655,901	414,254	0.00352	0.99648	96.45
11.5	109,989,982	471,665	0.00429	0.99571	96.11
12.5	100,880,498	807,157	0.00800	0.99200	95.70
13.5	91,371,547	470,664	0.00515	0.99485	94.93
14.5	80,809,598	1,221,470	0.01512	0.98488	94.44
15.5	68,601,312	352,108	0.00513	0.99487	93.01
16.5	56,870,302	204,035	0.00359	0.99641	92.53
17.5	50,965,618	251,712	0.00494	0.99506	92.20
18.5	46,306,279	326,896	0.00706	0.99294	91.74
19.5	41,529,285	210,629	0.00507	0.99493	91.09
20.5	37,962,330	200,352	0.00528	0.99472	90.63
21.5	35,119,338	230,019	0.00655	0.99345	90.15
22.5	33,136,119	155,891	0.00470	0.99530	89.56
23.5	31,578,982	190,897	0.00605	0.99395	89.14
24.5	29,966,815	109,241	0.00365	0.99635	88.60
25.5	27,641,926	186,003	0.00673	0.99327	88.28
26.5	26,053,550	282,774	0.01085	0.98915	87.69

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Account 36800 - Line Transformers - Distribution Plant

Placement Band - 1940 - 2022 Experience Band - 1975 - 2022

27.5	23,694,407	369,940	0.01561	0.98439	86.74
28.5	21,899,353	267,027	0.01219	0.98781	85.39
29.5	20,145,834	101,494	0.00504	0.99496	84.35
30.5	18,891,654	252,070	0.01334	0.98666	83.92
31.5	17,385,977	104,416	0.00601	0.99399	82.80
32.5	16,175,145	93,563	0.00578	0.99422	82.30
33.5	15,118,992	1,979,333	0.13092	0.86908	81.82
34.5	12,864,614	4,288,618	0.33337	0.66663	71.11
35.5	8,549,226	1,396,040	0.16329	0.83671	47.40
36.5	7,134,628	519,782	0.07285	0.92715	39.66
37.5	4,537,413	244,480	0.05388	0.94612	36.77
38.5	4,289,814	131,526	0.03066	0.96934	34.79
39.5	4,156,563	98,636	0.02373	0.97627	33.72
40.5	4,057,926	333,162	0.08210	0.91790	32.92
41.5	3,724,764	173,726	0.04664	0.95336	30.22
42.5	3,551,038	177,296	0.04993	0.95007	28.81
43.5	3,373,742	381,155	0.11298	0.88702	27.37
44.5	2,992,587	168,069	0.05616	0.94384	24.28
45.5	2,824,517	1,494,823	0.52923	0.47077	22.92
46.5	1,329,694	53,834	0.04049	0.95951	10.79
47.5	1,275,860	15,121	0.01185	0.98815	10.35
48.5	1,260,739	1,224,850	0.97153	0.02847	10.23
49.5	35,889	0	0.00000	1.00000	0.29
50.5	35,889	0	0.00000	1.00000	0.29
51.5	35,889	24,891	0.69355	0.30645	0.29
52.5	10,998	0	0.00000	1.00000	0.09
53.5	10,998	10,998	0.99996	0.00004	0.09
54.5	0	0	0.00000	0.00000	0.00
	Totals:	25,920,730			

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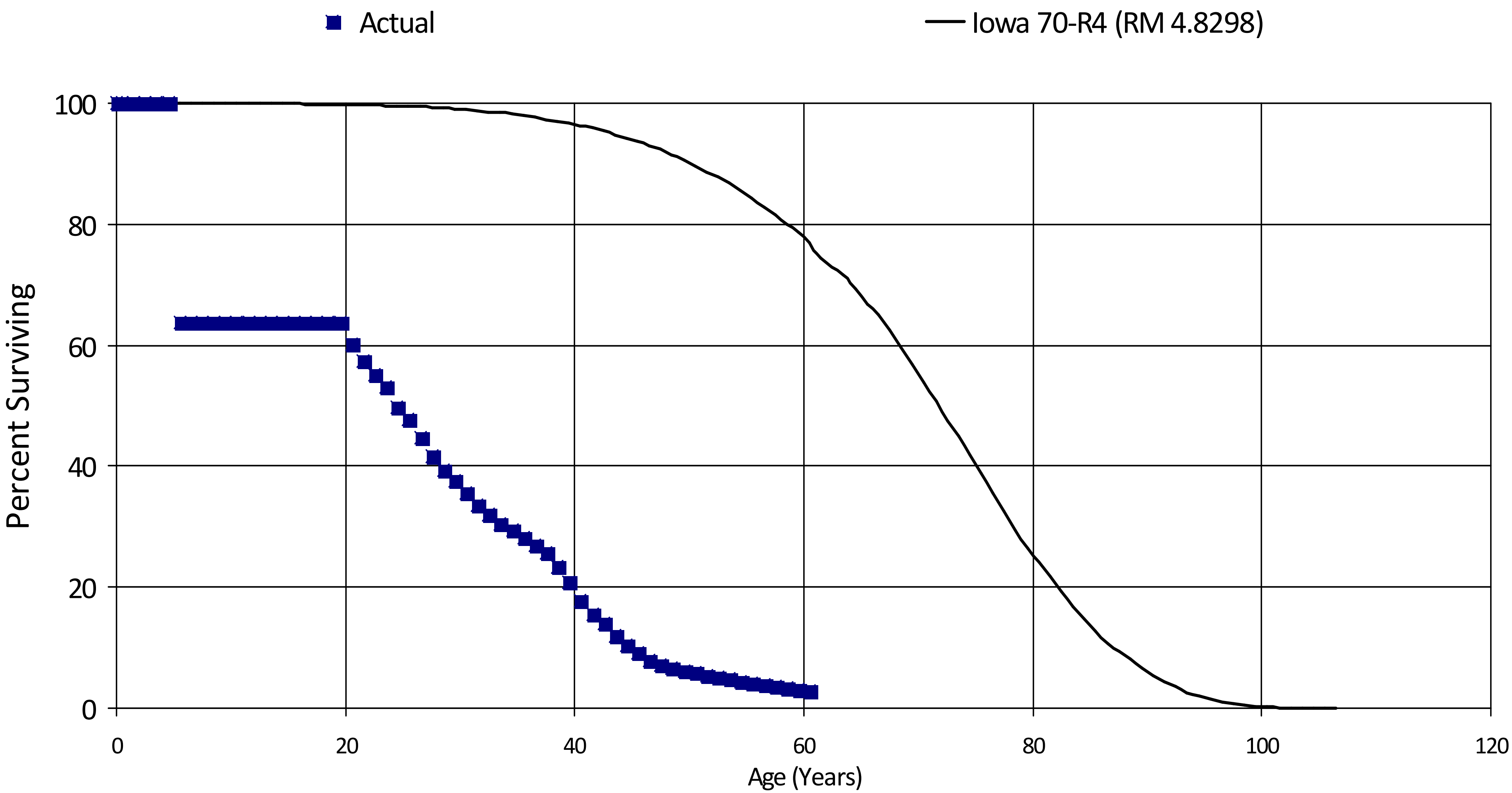
Account 36900 - Services - Distribution Plant

Placement Band - 1960 - 2012   Experience Band - 1980 - 2022

Actual and Smooth Survivor Curves



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Account 36900 - Services - Distribution Plant

Placement Band - 1960 - 2012   Experience Band - 1980 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,041,450	0	0.00000	1.00000	100.00
0.5	15,041,450	0	0.00000	1.00000	100.00
1.5	15,041,450	0	0.00000	1.00000	100.00
2.5	15,041,450	94	0.00001	0.99999	100.00
3.5	15,041,356	28	0.00000	1.00000	100.00
4.5	15,041,328	5,454,914	0.36266	0.63734	100.00
5.5	9,586,413	312	0.00003	0.99997	63.73
6.5	9,586,101	0	0.00000	1.00000	63.73
7.5	9,586,101	0	0.00000	1.00000	63.73
8.5	9,586,101	1,996	0.00021	0.99979	63.73
9.5	9,584,105	0	0.00000	1.00000	63.72
10.5	9,295,350	0	0.00000	1.00000	63.72
11.5	8,916,591	2	0.00000	1.00000	63.72
12.5	8,909,942	0	0.00000	1.00000	63.72
13.5	8,704,760	238	0.00003	0.99997	63.72
14.5	8,523,154	0	0.00000	1.00000	63.72
15.5	8,382,193	3,877	0.00046	0.99954	63.72
16.5	8,195,621	29	0.00000	1.00000	63.69
17.5	7,987,224	0	0.00000	1.00000	63.69
18.5	7,882,890	0	0.00000	1.00000	63.69
19.5	7,825,081	444,624	0.05682	0.94318	63.69
20.5	7,362,555	322,882	0.04385	0.95615	60.07
21.5	6,973,856	291,616	0.04182	0.95818	57.44
22.5	6,662,585	250,208	0.03755	0.96245	55.04
23.5	6,398,339	387,392	0.06055	0.93945	52.97
24.5	5,944,681	255,700	0.04301	0.95699	49.76
25.5	5,682,203	364,326	0.06412	0.93588	47.62
26.5	5,305,702	359,892	0.06783	0.93217	44.57

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Account 36900 - Services - Distribution Plant

Placement Band - 1960 - 2012 Experience Band - 1980 - 2022

27.5	4,911,514	268,646	0.05470	0.94530	41.55
28.5	4,619,164	206,489	0.04470	0.95530	39.28
29.5	4,411,577	223,088	0.05057	0.94943	37.52
30.5	4,157,139	260,391	0.06264	0.93736	35.62
31.5	3,877,787	176,001	0.04539	0.95461	33.39
32.5	3,666,901	154,824	0.04222	0.95778	31.87
33.5	3,453,707	125,322	0.03629	0.96371	30.52
34.5	3,298,470	145,073	0.04398	0.95602	29.41
35.5	3,139,476	145,330	0.04629	0.95371	28.12
36.5	2,984,496	135,470	0.04539	0.95461	26.82
37.5	1,633,746	136,796	0.08373	0.91627	25.60
38.5	1,495,328	170,115	0.11376	0.88624	23.46
39.5	1,324,316	190,225	0.14364	0.85636	20.79
40.5	1,134,091	142,997	0.12609	0.87391	17.80
41.5	991,094	109,095	0.11008	0.88992	15.56
42.5	881,999	123,394	0.13990	0.86010	13.85
43.5	758,605	88,766	0.11701	0.88299	11.91
44.5	669,839	90,300	0.13481	0.86519	10.52
45.5	579,539	73,541	0.12690	0.87310	9.10
46.5	505,998	49,342	0.09751	0.90249	7.95
47.5	456,656	40,519	0.08873	0.91127	7.17
48.5	416,137	28,803	0.06922	0.93078	6.53
49.5	387,334	21,944	0.05665	0.94335	6.08
50.5	365,390	20,405	0.05584	0.94416	5.74
51.5	344,986	21,520	0.06238	0.93762	5.42
52.5	323,466	21,129	0.06532	0.93468	5.08
53.5	302,337	19,959	0.06602	0.93398	4.75
54.5	282,378	17,767	0.06292	0.93708	4.44
55.5	264,611	23,196	0.08766	0.91234	4.16
56.5	241,414	14,142	0.05858	0.94142	3.80
57.5	227,272	17,366	0.07641	0.92359	3.58

58.5	209,906	14,373	0.06847	0.93153	3.31
59.5	195,533	10,696	0.05470	0.94530	3.08
60.5	184,837	184,837	1.00000		2.91
	Totals:	11,609,991			

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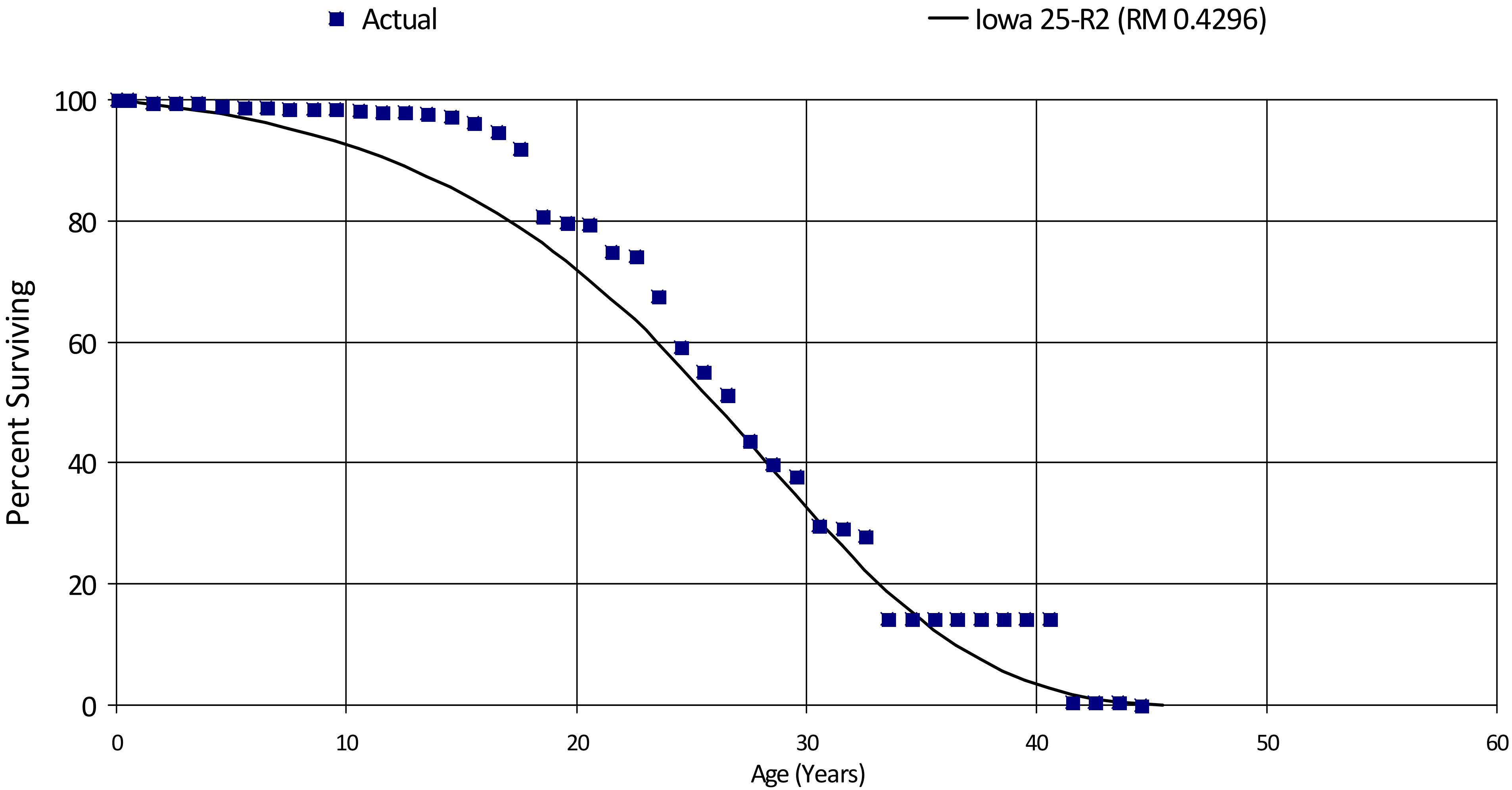
Account 37300 - Street Lighting and Signal Systems - Distribution Plant

Placement Band - 1950 - 2022   Experience Band - 1976 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 37300 - Street Lighting and Signal Systems - Distribution Plant

Placement Band - 1950 - 2022   Experience Band - 1976 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,166,414	2,138	0.00013	0.99987	100.00
0.5	16,123,390	70,665	0.00438	0.99562	99.99
1.5	15,894,100	13,264	0.00083	0.99917	99.55
2.5	15,399,410	9,972	0.00065	0.99935	99.47
3.5	14,750,446	45,464	0.00308	0.99692	99.41
4.5	14,092,555	39,805	0.00282	0.99718	99.10
5.5	13,781,751	16,785	0.00122	0.99878	98.82
6.5	13,567,980	18,468	0.00136	0.99864	98.70
7.5	13,436,435	13,978	0.00104	0.99896	98.57
8.5	13,334,349	14,752	0.00111	0.99889	98.47
9.5	13,309,261	29,996	0.00225	0.99775	98.36
10.5	13,260,065	20,137	0.00152	0.99848	98.14
11.5	12,548,555	11,435	0.00091	0.99909	97.99
12.5	11,280,925	35,055	0.00311	0.99689	97.90
13.5	9,905,768	35,120	0.00355	0.99645	97.60
14.5	8,139,008	82,174	0.01010	0.98990	97.25
15.5	6,389,916	108,820	0.01703	0.98297	96.27
16.5	4,727,517	132,652	0.02806	0.97194	94.63
17.5	3,527,431	428,125	0.12137	0.87863	91.97
18.5	2,284,580	31,725	0.01389	0.98611	80.81
19.5	1,310,567	4,308	0.00329	0.99671	79.69
20.5	1,306,259	76,953	0.05891	0.94109	79.43
21.5	1,148,555	10,685	0.00930	0.99070	74.75
22.5	1,086,678	94,819	0.08726	0.91274	74.05
23.5	973,518	122,252	0.12558	0.87442	67.59
24.5	822,373	54,925	0.06679	0.93321	59.10
25.5	767,448	54,308	0.07076	0.92924	55.15
26.5	713,140	106,590	0.14947	0.85053	51.25

FortisBC

Account 37300 - Street Lighting and Signal Systems - Distribution Plant

Placement Band - 1950 - 2022 Experience Band - 1976 - 2022

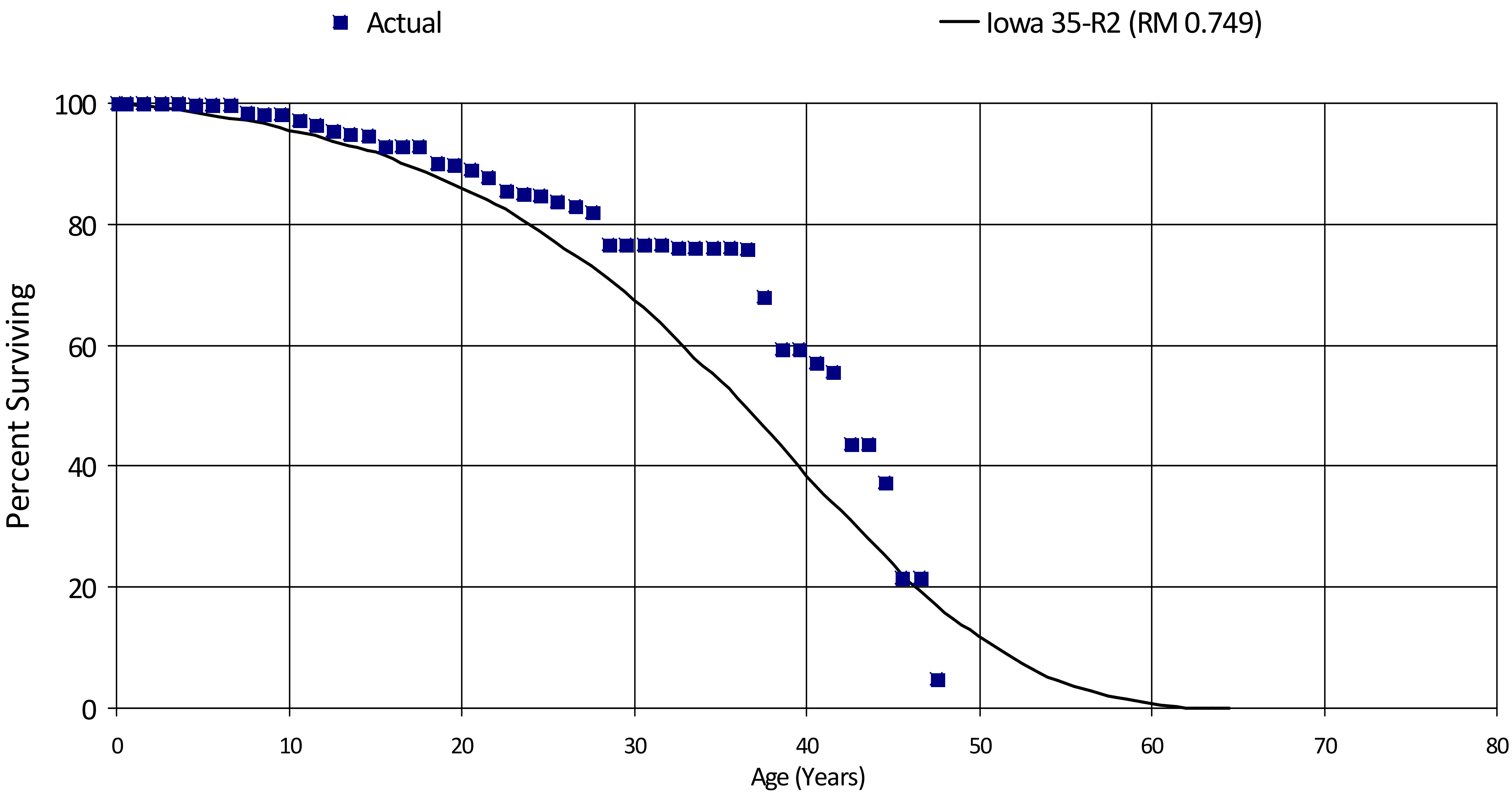
27.5	606,550	51,791	0.08539	0.91461	43.59
28.5	554,760	26,803	0.04831	0.95169	39.87
29.5	527,957	113,384	0.21476	0.78524	37.94
30.5	414,573	7,116	0.01716	0.98284	29.79
31.5	407,457	20,309	0.04984	0.95016	29.28
32.5	387,147	189,764	0.49016	0.50984	27.82
33.5	197,383	0	0.00000	1.00000	14.18
34.5	197,383	0	0.00000	1.00000	14.18
35.5	197,383	0	0.00000	1.00000	14.18
36.5	197,383	0	0.00000	1.00000	14.18
37.5	51,610	0	0.00000	1.00000	14.18
38.5	51,610	21	0.00041	0.99959	14.18
39.5	51,589	0	0.00000	1.00000	14.17
40.5	51,589	49,629	0.96200	0.03800	14.17
41.5	1,960	12	0.00612	0.99388	0.54
42.5	1,947	0	0.00000	1.00000	0.54
43.5	1,947	1,947	0.99977	0.00023	0.54
44.5	0	0	0.00000	0.00000	0.00
	Totals:	2,146,146			

FortisBC

Account 39010 - Structures - Masonry - General Plant

Placement Band - 1940 - 2022   Experience Band - 1977 - 2022

Actual and Smooth Survivor Curves



Account 39010 - Structures - Masonry - General Plant

Placement Band - 1940 - 2022   Experience Band - 1977 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	54,399,519	6,648	0.00012	0.99988	100.00
0.5	51,998,475	0	0.00000	1.00000	99.99
1.5	49,385,148	2,953	0.00006	0.99994	99.99
2.5	47,245,321	47,464	0.00100	0.99900	99.98
3.5	46,075,272	10,393	0.00023	0.99977	99.88
4.5	44,236,508	2,579	0.00006	0.99994	99.86
5.5	27,777,015	23,761	0.00086	0.99914	99.85
6.5	25,958,507	341,270	0.01315	0.98685	99.76
7.5	25,291,509	55,537	0.00220	0.99780	98.45
8.5	24,572,905	21,959	0.00089	0.99911	98.23
9.5	8,635,249	72,658	0.00841	0.99159	98.14
10.5	8,510,470	76,669	0.00901	0.99099	97.31
11.5	8,099,135	84,963	0.01049	0.98951	96.43
12.5	7,775,816	35,488	0.00456	0.99544	95.42
13.5	7,335,098	14,636	0.00200	0.99800	94.98
14.5	7,224,144	137,936	0.01909	0.98091	94.79
15.5	6,629,132	0	0.00000	1.00000	92.98
16.5	6,516,536	4,089	0.00063	0.99937	92.98
17.5	6,461,903	194,672	0.03013	0.96987	92.92
18.5	6,163,858	13,567	0.00220	0.99780	90.12
19.5	5,929,485	59,208	0.00999	0.99001	89.92
20.5	5,764,948	71,340	0.01237	0.98763	89.02
21.5	5,384,637	148,757	0.02763	0.97237	87.92
22.5	5,220,764	23,235	0.00445	0.99555	85.49
23.5	5,025,069	23,881	0.00475	0.99525	85.11
24.5	4,933,712	56,733	0.01150	0.98850	84.71
25.5	4,789,944	48,534	0.01013	0.98987	83.74
26.5	4,712,557	56,444	0.01198	0.98802	82.89

FortisBC

Account 39010 - Structures - Masonry - General Plant

Placement Band - 1940 - 2022 Experience Band - 1977 - 2022

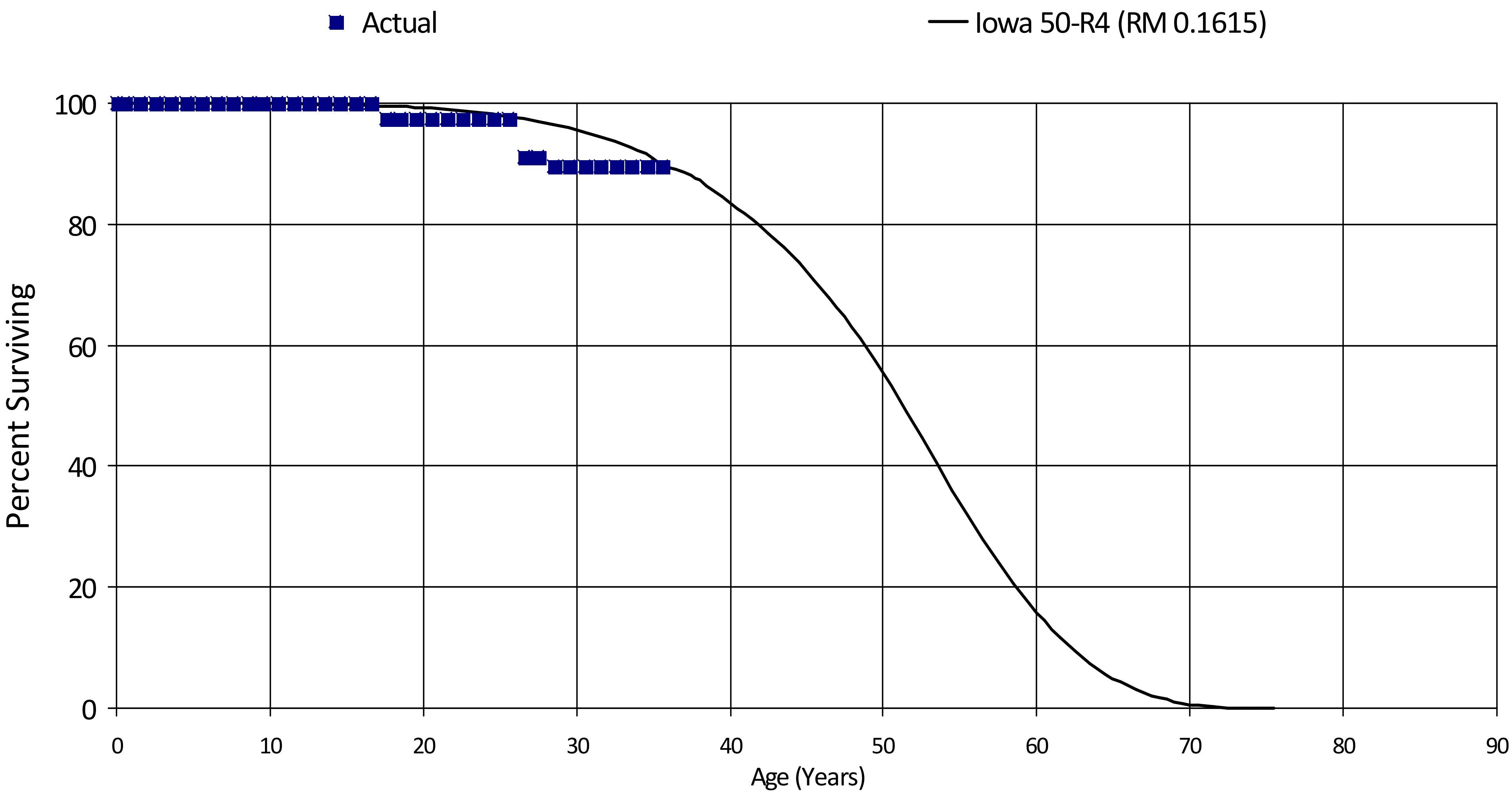
27.5	4,611,691	290,602	0.06301	0.93699	81.90
28.5	3,998,926	5,719	0.00143	0.99857	76.74
29.5	3,974,988	2,566	0.00065	0.99935	76.63
30.5	3,939,440	2,327	0.00059	0.99941	76.58
31.5	3,703,001	15,896	0.00429	0.99571	76.53
32.5	3,686,987	0	0.00000	1.00000	76.20
33.5	3,291,262	880	0.00027	0.99973	76.20
34.5	2,720,885	1,099	0.00040	0.99960	76.18
35.5	2,683,906	6,283	0.00234	0.99766	76.15
36.5	2,676,057	283,809	0.10605	0.89395	75.97
37.5	1,144,717	143,890	0.12570	0.87430	67.91
38.5	976,861	1,575	0.00161	0.99839	59.37
39.5	916,879	31,525	0.03438	0.96562	59.27
40.5	867,577	24,579	0.02833	0.97167	57.23
41.5	842,351	182,490	0.21664	0.78336	55.61
42.5	658,281	0	0.00000	1.00000	43.56
43.5	153,096	22,088	0.14428	0.85572	43.56
44.5	131,008	55,471	0.42342	0.57658	37.28
45.5	68,107	0	0.00000	1.00000	21.49
46.5	68,107	52,676	0.77343	0.22657	21.49
47.5	0	0	0.00000	0.00000	4.87
	Totals:	2,758,849			

FortisBC

Account 39020 - Operations Buildings - General Plant

Placement Band - 1986 - 2022   Experience Band - 2019 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 39020 - Operations Buildings - General Plant

Placement Band - 1986 - 2022 Experience Band - 2019 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	18,289,527	0	0.00000	1.00000	100.00
0.5	17,554,942	0	0.00000	1.00000	100.00
1.5	16,982,839	0	0.00000	1.00000	100.00
2.5	15,662,165	0	0.00000	1.00000	100.00
3.5	14,671,031	0	0.00000	1.00000	100.00
4.5	14,502,893	0	0.00000	1.00000	100.00
5.5	14,136,076	10,000	0.00071	0.99929	100.00
6.5	14,049,100	0	0.00000	1.00000	99.93
7.5	13,717,473	0	0.00000	1.00000	99.93
8.5	13,303,514	0	0.00000	1.00000	99.93
9.5	12,637,835	0	0.00000	1.00000	99.93
10.5	11,329,550	0	0.00000	1.00000	99.93
11.5	10,713,714	0	0.00000	1.00000	99.93
12.5	10,452,687	0	0.00000	1.00000	99.93
13.5	9,717,727	3,000	0.00031	0.99969	99.93
14.5	9,331,360	0	0.00000	1.00000	99.90
15.5	8,791,332	0	0.00000	1.00000	99.90
16.5	8,205,833	195,205	0.02379	0.97621	99.90
17.5	7,832,317	0	0.00000	1.00000	97.52
18.5	7,832,317	0	0.00000	1.00000	97.52
19.5	3,108,091	0	0.00000	1.00000	97.52
20.5	369,421	0	0.00000	1.00000	97.52
21.5	369,421	0	0.00000	1.00000	97.52
22.5	369,421	0	0.00000	1.00000	97.52
23.5	369,421	0	0.00000	1.00000	97.52
24.5	369,421	0	0.00000	1.00000	97.52
25.5	369,421	24,650	0.06673	0.93327	97.52
26.5	344,771	0	0.00000	1.00000	91.01

FortisBC

Account 39020 - Operations Buildings - General Plant

Placement Band - 1986 - 2022 Experience Band - 2019 - 2022

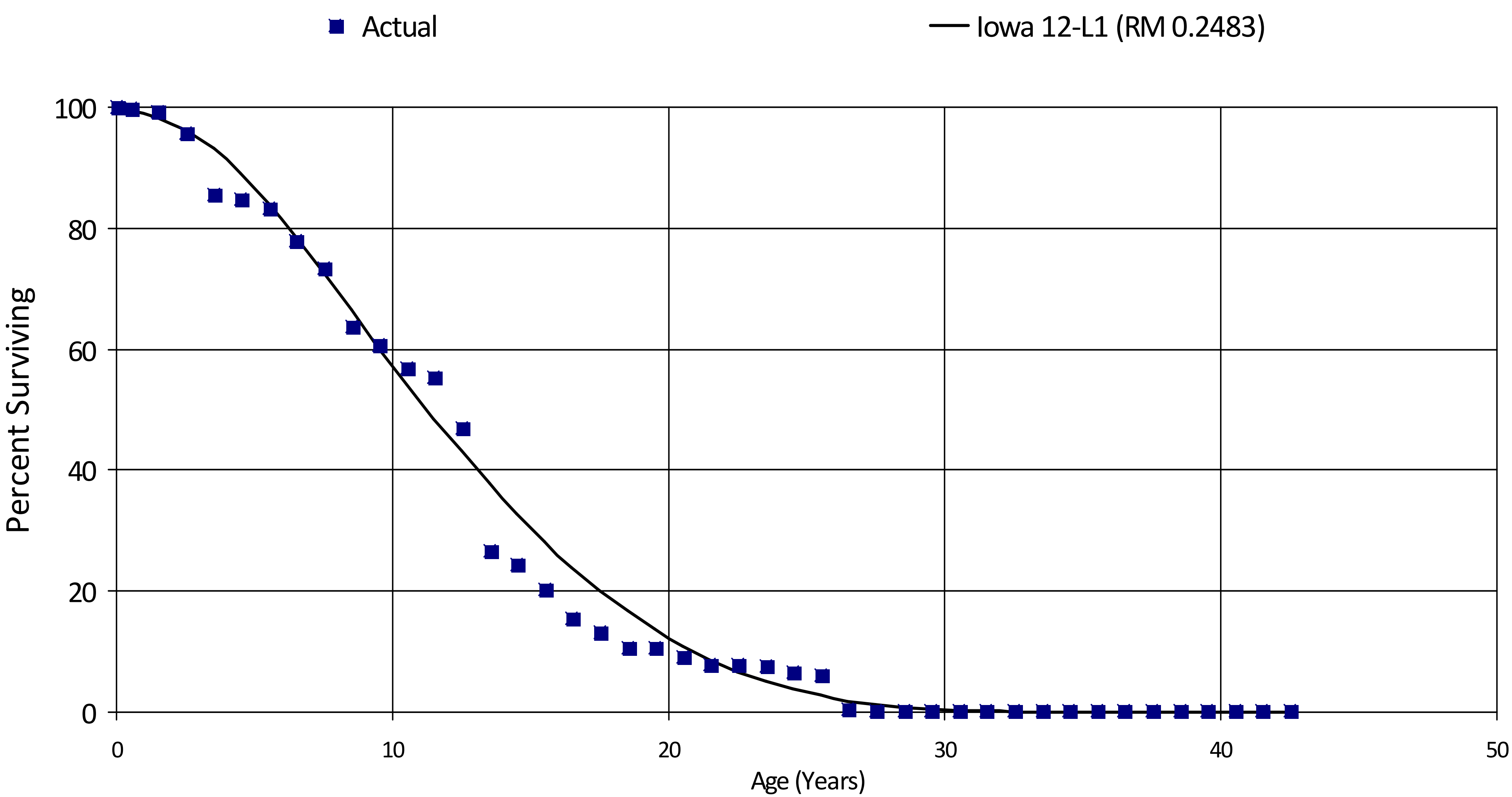
27.5	344,771	5,000	0.01450	0.98550	91.01
28.5	339,771	0	0.00000	1.00000	89.69
29.5	53,408	0	0.00000	1.00000	89.69
30.5	53,408	0	0.00000	1.00000	89.69
31.5	53,408	0	0.00000	1.00000	89.69
32.5	53,408	0	0.00000	1.00000	89.69
33.5	53,408	0	0.00000	1.00000	89.69
34.5	53,100	0	0.00000	1.00000	89.69
35.5	44,990	0	0.00000	1.00000	89.69
	Totals:	237,855			

FortisBC

Account 39210 - Light Duty Vehicles - General Plant

Placement Band - 1966 - 2022 Experience Band - 2006 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 39210 - Light Duty Vehicles - General Plant

Placement Band - 1966 - 2022 Experience Band - 2006 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,346,512	73,371	0.00314	0.99686	100.00
0.5	23,168,316	90,773	0.00392	0.99608	99.69
1.5	22,565,548	836,070	0.03705	0.96295	99.30
2.5	20,806,908	2,210,790	0.10625	0.89375	95.62
3.5	18,201,739	124,964	0.00687	0.99313	85.46
4.5	16,960,731	332,551	0.01961	0.98039	84.87
5.5	16,406,348	1,057,373	0.06445	0.93555	83.21
6.5	15,338,043	894,080	0.05829	0.94171	77.85
7.5	14,410,110	1,877,189	0.13027	0.86973	73.31
8.5	12,235,181	596,613	0.04876	0.95124	63.76
9.5	11,156,408	679,634	0.06092	0.93908	60.65
10.5	10,306,122	312,686	0.03034	0.96966	56.96
11.5	9,752,148	1,450,717	0.14876	0.85124	55.23
12.5	8,298,709	3,603,970	0.43428	0.56572	47.01
13.5	4,643,124	399,520	0.08605	0.91395	26.59
14.5	4,165,918	691,237	0.16593	0.83407	24.30
15.5	3,422,378	823,540	0.24063	0.75937	20.27
16.5	2,558,271	369,100	0.14428	0.85572	15.39
17.5	2,152,143	392,090	0.18219	0.81781	13.17
18.5	1,760,053	0	0.00000	1.00000	10.77
19.5	1,760,053	249,645	0.14184	0.85816	10.77
20.5	1,502,483	206,682	0.13756	0.86244	9.24
21.5	1,295,801	0	0.00000	1.00000	7.97
22.5	1,295,801	39,922	0.03081	0.96919	7.97
23.5	1,255,879	185,109	0.14739	0.85261	7.72
24.5	1,070,770	91,431	0.08539	0.91461	6.58
25.5	979,339	882,850	0.90148	0.09852	6.02
26.5	96,489	35,514	0.36806	0.63194	0.59

FortisBC

Account 39210 - Light Duty Vehicles - General Plant

Placement Band - 1966 - 2022 Experience Band - 2006 - 2022

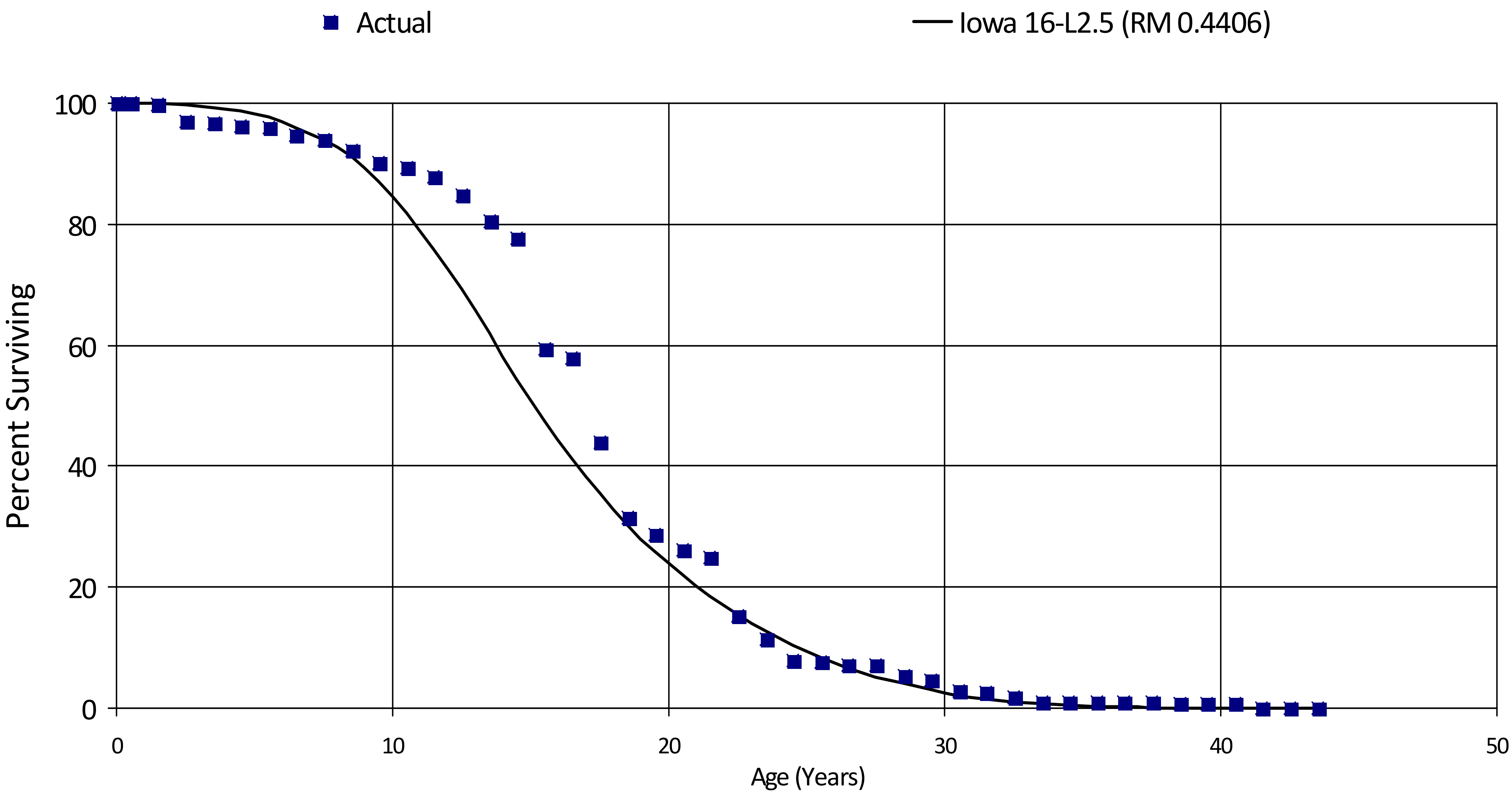
27.5	60,975	0	0.00000	1.00000	0.37
28.5	60,975	0	0.00000	1.00000	0.37
29.5	60,975	0	0.00000	1.00000	0.37
30.5	60,975	0	0.00000	1.00000	0.37
31.5	60,975	11,287	0.18511	0.81489	0.37
32.5	49,688	0	0.00000	1.00000	0.30
33.5	49,688	3,891	0.07831	0.92169	0.30
34.5	45,797	0	0.00000	1.00000	0.28
35.5	45,797	0	0.00000	1.00000	0.28
36.5	45,797	0	0.00000	1.00000	0.28
37.5	45,797	0	0.00000	1.00000	0.28
38.5	45,797	17,435	0.38070	0.61930	0.28
39.5	28,362	0	0.00000	1.00000	0.17
40.5	28,362	0	0.00000	1.00000	0.17
41.5	28,362	0	0.00000	1.00000	0.17
42.5	28,362	28,362	1.00000		0.17
	Totals:	18,568,396			

FortisBC

Account 39220 - Heavy Duty Vehicles - General Plant

Placement Band - 1972 - 2022   Experience Band - 1990 - 2022

Actual and Smooth Survivor Curves



FortisBC

Account 39220 - Heavy Duty Vehicles - General Plant

Placement Band - 1972 - 2022   Experience Band - 1990 - 2022

RETIREMENT RATE ANALYSIS

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	51,819,550	0	0.00000	1.00000	100.00
0.5	48,316,644	134,594	0.00279	0.99721	100.00
1.5	46,925,611	1,297,252	0.02764	0.97236	99.72
2.5	43,397,134	76,333	0.00176	0.99824	96.96
3.5	41,401,815	291,507	0.00704	0.99296	96.79
4.5	39,285,307	113,570	0.00289	0.99711	96.11
5.5	36,885,779	489,675	0.01328	0.98672	95.83
6.5	34,004,525	243,138	0.00715	0.99285	94.56
7.5	31,823,910	551,728	0.01734	0.98266	93.88
8.5	30,360,495	711,420	0.02343	0.97657	92.25
9.5	27,648,207	268,051	0.00970	0.99030	90.09
10.5	26,735,236	410,332	0.01535	0.98465	89.22
11.5	24,905,816	848,929	0.03409	0.96591	87.85
12.5	23,533,458	1,212,868	0.05154	0.94846	84.86
13.5	20,921,141	736,627	0.03521	0.96479	80.49
14.5	19,411,147	4,557,005	0.23476	0.76524	77.66
15.5	11,937,830	324,952	0.02722	0.97278	59.43
16.5	9,972,052	2,382,488	0.23892	0.76108	57.81
17.5	7,119,203	2,009,716	0.28230	0.71770	44.00
18.5	5,078,453	479,301	0.09438	0.90562	31.58
19.5	4,568,387	397,650	0.08704	0.91296	28.60
20.5	4,144,318	195,861	0.04726	0.95274	26.11
21.5	3,948,457	1,547,761	0.39199	0.60801	24.88
22.5	2,400,696	575,777	0.23984	0.76016	15.13
23.5	1,824,919	579,467	0.31753	0.68247	11.50
24.5	1,245,452	30,840	0.02476	0.97524	7.85
25.5	1,214,612	97,507	0.08028	0.91972	7.66
26.5	1,086,946	0	0.00000	1.00000	7.05

FortisBC

Account 39220 - Heavy Duty Vehicles - General Plant

Placement Band - 1972 - 2022 Experience Band - 1990 - 2022

27.5	1,072,087	273,824	0.25541	0.74459	7.05
28.5	798,263	102,374	0.12825	0.87175	5.25
29.5	662,362	253,003	0.38197	0.61803	4.58
30.5	409,359	31,802	0.07769	0.92231	2.83
31.5	369,407	125,946	0.34094	0.65906	2.61
32.5	243,461	99,775	0.40982	0.59018	1.72
33.5	134,866	0	0.00000	1.00000	1.02
34.5	134,866	0	0.00000	1.00000	1.02
35.5	134,866	0	0.00000	1.00000	1.02
36.5	134,866	0	0.00000	1.00000	1.02
37.5	134,866	43,735	0.32428	0.67572	1.02
38.5	91,131	0	0.00000	1.00000	0.69
39.5	91,131	0	0.00000	1.00000	0.69
40.5	90,375	78,670	0.87048	0.12952	0.69
41.5	11,705	0	0.00000	1.00000	0.09
42.5	11,705	0	0.00000	1.00000	0.09
43.5	0	0	0.00000	0.00000	0.09
	Totals:	21,573,478			

SECTION 7

7 NET SALVAGE CALCULATIONS

FortisBC Inc.
ACCOUNT 33100 - GENERATION PLANT STRUCTURES AND IMPROVEMENTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	4,071	0	0	0	0	0	0					0	0
1996	13,454		0	0	0	0	0					0	0
1997			0	0	0	0	0	0	0			0	0
1998	2		0	0	0	0	0	0	0			0	0
1999	17		0	0	0	0	0	0	0	0	0	0	0
2000	14,613	10	0	0	0	(10)	(0)	(3)	(0)	(2)	(0)	(2)	(0)
2001	8		0	0	0	0	0	(3)	(0)	(2)	(0)	(1)	(0)
2002			0	0	0	0	0	(3)	(0)	(2)	(0)	(1)	(0)
2003	59,794		0	0	0	0	0	0	0	(2)	(0)	(1)	(0)
2004	15,748	409	3	0	0	(409)	(3)	(136)	(1)	(84)	(0)	(42)	(0)
2005		455	0	0	0	(455)	0	(288)	(1)	(173)	(1)	(80)	(1)
2006		45	0	0	0	(45)	0	(303)	(6)	(182)	(1)	(77)	(1)
2007		73	0	0	0	(73)	0	(191)	0	(197)	(1)	(76)	(1)
2008		372	0	0	0	(372)	0	(164)	0	(271)	(9)	(98)	(1)
2009		34,323	0	0	0	(34,323)	0	(11,589)	0	(7,054)	0	(2,379)	(33)
2010	1,634	11,001	673	0	0	(11,001)	(673)	(15,232)	(2,797)	(9,163)	(2,804)	(2,918)	(43)
2011		38,355	0	0	0	(38,355)	0	(27,893)	(5,122)	(16,825)	(5,149)	(5,003)	(78)
2012	77,308	74,904	97	0	0	(74,904)	(97)	(41,420)	(157)	(31,791)	(201)	(8,886)	(86)
2013			0	0	0	0	0	(37,753)	(147)	(31,717)	(201)	(8,418)	(86)
2014	16,615	349,560	2,104	0	0	(349,560)	(2,104)	(141,488)	(452)	(94,764)	(496)	(25,475)	(251)
2015	13,016	189,502	1,456	0	0	(189,502)	(1,456)	(179,687)	(1,819)	(130,464)	(610)	(33,286)	(323)
2016	1,489	215,519	14,471	0	0	(215,519)	(14,471)	(251,527)	(2,425)	(165,897)	(765)	(41,570)	(420)
2017	249,915	435,309	174	0	0	(435,309)	(174)	(280,110)	(318)	(237,978)	(423)	(58,689)	(289)
2018	14,642	53,758	367	0	0	(53,758)	(367)	(234,862)	(265)	(248,730)	(421)	(58,483)	(291)
2019		836	0	0	0	(836)	0	(163,301)	(185)	(178,985)	(321)	(56,177)	(291)
2020	10,620	3,649	34	0	0	(3,649)	(34)	(19,414)	(231)	(141,814)	(256)	(54,157)	(286)
2021			0	0	0	0	0	(1,495)	(42)	(98,710)	(179)	(52,151)	(286)
2022	1,672	48,856											
TOTAL	**494,619**	**1,456,939**	**295**	**0**	**0**	**(1,408,083)**	**(285)**						

FortisBC Inc.
ACCOUNT 33200 - GENERATION PLANT RESERVOIRS, DAMS AND WATERWAYS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	85	0	0	0	0	0	0	0	0	0	0	0	0
2000	4,736	0	0	0	0	0	0	0	0	0	0	0	0
2001	2,887	0	0	0	0	0	0	0	0	0	0	0	0
2002		0	0	0	0	0	0	0	0	0	0	0	0
2003	50	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
2004	70,485	685	1	0	0	(685)	(1)	(228)	(1)	(137)	(1)	(68)	(1)
2005		655	0	0	0	(655)	0	(446)	(2)	(268)	(2)	(122)	(2)
2006		806	0	0	0	(806)	0	(715)	(3)	(429)	(3)	(179)	(3)
2007	400,326	1,474	0	0	0	(1,474)	(0)	(979)	(1)	(724)	(1)	(278)	(1)
2008	19,323	47	0	0	0	(47)	(0)	(776)	(1)	(733)	(1)	(262)	(1)
2009	55,471	213,012	384	0	0	(213,012)	(384)	(71,511)	(45)	(43,199)	(45)	(14,445)	(39)
2010	271,167	35,678	13	0	0	(35,678)	(13)	(82,913)	(72)	(50,204)	(34)	(15,772)	(31)
2011		48,265	0	0	0	(48,265)	0	(98,985)	(91)	(59,695)	(40)	(17,684)	(36)
2012	5,645	85,181	1,509	0	0	(85,181)	(1,509)	(56,375)	(61)	(76,437)	(109)	(21,434)	(46)
2013		11,455	0	0	0	(11,455)	0	(48,300)	(2,567)	(78,718)	(118)	(20,908)	(48)
2014	21,610	22,140	102	0	0	(22,140)	(102)	(39,592)	(436)	(40,544)	(68)	(20,970)	(49)
2015	764	42,048	5,505	0	0	(42,048)	(5,505)	(25,214)	(338)	(41,818)	(746)	(21,974)	(54)
2016	35,604	7,306	21	0	0	(7,306)	(21)	(23,831)	(123)	(33,626)	(264)	(21,307)	(53)
2017	12,826	212,445	1,656	0	0	(212,445)	(1,656)	(94,646)	(401)	(76,115)	(498)	(29,617)	(76)
2018	27,053	1,069,845	3,955	0	0	(1,069,845)	(3,955)	(443,881)	(1,746)	(273,048)	(1,395)	(72,960)	(189)
2019	437,064	2,552,679	584	0	0	(2,552,679)	(584)	(1,280,758)	(750)	(781,293)	(730)	(172,149)	(315)
2020	280,880	4,451,143	1,585	0	0	(4,451,143)	(1,585)	(2,762,038)	(1,093)	(1,667,093)	(1,050)	(336,726)	(532)
2021	303,615	4,364,800	1,438	368	0	(4,364,432)	(1,437)	(4,146,033)	(1,186)	(2,531,570)	(1,154)	(485,900)	(673)
2022	111,921	1,131,951	1,011	0	0	(1,131,951)	(1,011)	(4,166,735)	(1,103)	(2,756,499)	(1,175)	(508,973)	(691)
TOTAL	**2,061,511**	**14,251,616**	**691**	**368**	**53**	**(14,251,248)**	**(691)**						

FortisBC Inc.
ACCOUNT 33300 - GENERATION PLANT WATERHEELS, TURBINES AND GENERATORS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995		149	0	0	0	(149)	0					(149)	0
1996		0	0	0	0	0	0					(74)	0
1997	12,549	0	0	0	0	0	0	(50)	(1)			(50)	(1)
1998		0	0	0	0	0	0	0	0			(37)	(1)
1999		433	0	0	0	(433)	0	(144)	(3)	(116)	(5)	(116)	(5)
2000	16,508	563	3	0	0	(563)	(3)	(332)	(6)	(199)	(3)	(191)	(4)
2001	350	17	5	0	0	(17)	(5)	(338)	(6)	(203)	(3)	(166)	(4)
2002		0	0	0	0	0	0	(193)	(3)	(203)	(6)	(145)	(4)
2003	7,529	5	0	0	0	(5)	(0)	(7)	(0)	(204)	(4)	(130)	(3)
2004	1,044	4,290	411	0	0	(4,290)	(411)	(1,432)	(50)	(975)	(19)	(546)	(14)
2005		3,442	0	0	0	(3,442)	0	(2,579)	(90)	(1,551)	(87)	(809)	(23)
2006	349	138	39	0	0	(138)	(39)	(2,623)	(565)	(1,575)	(88)	(753)	(24)
2007		3,509	0	0	0	(3,509)	0	(2,363)	(2,030)	(2,277)	(128)	(965)	(33)
2008	13,082	4,722	36	0	0	(4,722)	(36)	(2,790)	(62)	(3,220)	(111)	(1,233)	(34)
2009	292,325	491,636	168	0	0	(491,636)	(168)	(166,623)	(164)	(100,689)	(165)	(33,927)	(148)
2010		572,346	0	0	0	(572,346)	0	(356,235)	(350)	(214,470)	(351)	(67,578)	(315)
2011		458,607	0	0	0	(458,607)	0	(507,530)	(521)	(306,164)	(501)	(90,580)	(448)
2012	169,203	48,160	28	0	0	(48,160)	(28)	(359,704)	(638)	(315,094)	(332)	(88,223)	(310)
2013	8,624	3,593	42	0	0	(3,593)	(42)	(170,120)	(287)	(314,869)	(335)	(83,769)	(305)
2014	3,485	0	0	0	0	(0)	(0)	(17,251)	(29)	(216,541)	(597)	(79,581)	(303)
2015		0	0	0	0	0	0	(1,198)	(30)	(102,072)	(281)	(75,791)	(303)
2016		127,000	0	0	0	(127,000)	0	(42,333)	(3,644)	(35,751)	(99)	(78,119)	(327)
2017	143,044	187,807	131	96,902	68	(90,905)	(64)	(72,635)	(152)	(44,300)	(143)	(78,675)	(271)
2018	23,370	183,299	784	259,373	1,110	76,074	326	(47,277)	(85)	(28,366)	(83)	(72,227)	(251)
2019	135,059	185,773	138	5,708	4	(180,065)	(133)	(64,966)	(65)	(64,379)	(107)	(76,540)	(232)
2020	109,711	103,154	94	237	0	(102,917)	(94)	(68,970)	(77)	(84,963)	(103)	(77,555)	(215)
2021	8,565	8,054	94	0	0	(8,054)	(94)	(97,012)	(115)	(61,174)	(73)	(74,981)	(214)
2022	2,889	3,863	134	0	0	(3,863)	(134)	(38,278)	(95)	(43,765)	(78)	(72,441)	(214)
TOTAL	**947,686**	**2,390,562**	**252**	**362,220**	**143,594**	**(2,028,342)**	**(214)**						

FortisBC Inc.
ACCOUNT 33400 - GENERATION PLANT ACCESSORY ELECTRICAL EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	5,466	0	0	0	0	0	0					0	0
1996	1	0	0	0	0	0	0					0	0
1997	16,757	0	0	0	0	0	0	0	0			0	0
1998		0	0	0	0	0	0	0	0			0	0
1999	2	440	18,714	0	0	(440)	(18,714)	(147)	(3)	(88)	(2)	(88)	(2)
2000		653	0	0	0	(653)	0	(364)	(46,515)	(219)	(7)	(182)	(5)
2001		0	0	0	0	0	0	(364)	(46,515)	(219)	(7)	(156)	(5)
2002		473	0	0	0	(473)	0	(375)	0	(313)	(66,624)	(196)	(7)
2003	363,864	2	0	0	0	(2)	(0)	(158)	(0)	(314)	(0)	(174)	(0)
2004	68,452	690	1	0	0	(690)	(1)	(388)	(0)	(364)	(0)	(226)	(0)
2005		2,527	0	0	0	(2,527)	0	(1,073)	(1)	(738)	(1)	(435)	(1)
2006		247	0	0	0	(247)	0	(1,155)	(5)	(788)	(1)	(419)	(1)
2007	36,910	1,073	3	0	0	(1,073)	(3)	(1,283)	(10)	(908)	(1)	(470)	(1)
2008	12,203	1,160	10	0	0	(1,160)	(10)	(827)	(5)	(1,140)	(5)	(519)	(1)
2009	180,652	209,855	116	0	0	(209,855)	(116)	(70,696)	(92)	(42,972)	(94)	(14,475)	(32)
2010	332,337	236,934	71	0	0	(236,934)	(71)	(149,316)	(85)	(89,854)	(80)	(28,378)	(45)
2011	881,293	236,004	27	0	0	(236,004)	(27)	(227,597)	(49)	(137,005)	(47)	(40,592)	(36)
2012	518,489	175,354	34	0	0	(175,354)	(34)	(216,097)	(37)	(171,861)	(45)	(48,078)	(36)
2013	805,425	36,883	5	0	0	(36,883)	(5)	(149,413)	(20)	(179,006)	(33)	(47,489)	(28)
2014	51,089	67,019	131	0	0	(67,019)	(131)	(93,085)	(20)	(150,439)	(29)	(48,466)	(30)
2015	625,646	70,394	11	0	0	(70,394)	(11)	(58,099)	(12)	(117,131)	(20)	(49,510)	(27)
2016	2,232	31,478	1,411	27,289	1,223	(4,189)	(188)	(47,201)	(21)	(70,768)	(18)	(47,450)	(27)
2017	38,305	19,243	50	0	0	(19,243)	(50)	(31,275)	(14)	(39,546)	(13)	(46,223)	(27)
2018	41,341	25,134	61		0	(25,134)	(61)	(16,189)	(59)	(37,196)	(25)	(45,345)	(27)
2019	135,282	39,168	29	1,027	1	(38,141)	(28)	(27,506)	(38)	(31,420)	(19)	(45,057)	(27)
2020	110,810	157,670	142		0	(157,670)	(142)	(73,648)	(77)	(48,875)	(75)	(49,388)	(30)
2021	31,827	307,542	966	1,867	6	(305,675)	(960)	(167,162)	(180)	(109,173)	(153)	(58,880)	(37)
2022	96,240	2,993	3	1,142	1	(1,851)	(2)	(155,065)	(195)	(105,694)	(127)	(56,843)	(37)
TOTAL	**4,354,623**	**1,622,936**	**37**	**31,325**	**84,050**	**(1,591,611)**	**(37)**						

FortisBC Inc.
ACCOUNT 33500 - GENERATION PLANT OTHER POWER PLANT EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995		0	0	0	0	0	0					0	0
1996	31,927	0	0	0	0	0	0					0	0
1997		0	0	0	0	0	0	0	0			0	0
1998	6,582	0	0	0	0	0	0	0	0			0	0
1999	3,488	0	0	0	0	0	0	0	0	0	0	0	0
2000	3,176	598	19	0	0	(598)	(19)	(199)	(5)	(120)	(1)	(100)	(1)
2001	882	84	10	0	0	(84)	(10)	(227)	(9)	(136)	(5)	(97)	(1)
2002		0	0	0	0	0	0	(227)	(17)	(136)	(5)	(85)	(1)
2003	6,585	0	0	0	0	0	0	(28)	(1)	(136)	(5)	(76)	(1)
2004	24,694	0	0	0	0	0	0	0	0	(136)	(2)	(68)	(1)
2005		0	0	0	0	0	0	0	0	(17)	(0)	(62)	(1)
2006	15,701	0	0	0	0	0	0	0	0	0	0	(57)	(1)
2007	1,025,791	227	0	0	0	(227)	(0)	(76)	(0)	(45)	(0)	(70)	(0)
2008	33,422	137	0	0	0	(137)	(0)	(121)	(0)	(73)	(0)	(75)	(0)
2009		0	0	0	0	0	0	(121)	(0)	(73)	(0)	(70)	(0)
2010	76,624	13,556	18	0	0	(13,556)	(18)	(4,564)	(12)	(2,784)	(1)	(913)	(1)
2011		0	0	0	0	0	0	(4,519)	(18)	(2,784)	(1)	(859)	(1)
2012	146,880	61,811	42	0	0	(61,811)	(42)	(25,122)	(34)	(15,101)	(29)	(4,245)	(6)
2013		1,830	0	0	0	(1,830)	0	(21,214)	(43)	(15,439)	(35)	(4,118)	(6)
2014	316,700	18,186	6	0	0	(18,186)	(6)	(27,275)	(18)	(19,076)	(18)	(4,821)	(6)
2015	24,933	13,058	52	0	0	(13,058)	(52)	(11,024)	(10)	(18,977)	(19)	(5,214)	(6)
2016	9,153	6,916	76	0	0	(6,916)	(76)	(12,720)	(11)	(20,360)	(20)	(5,291)	(7)
2017	130,169	10,938	8	0	0	(10,938)	(8)	(10,304)	(19)	(10,186)	(11)	(5,537)	(7)
2018	151,819	5,885	4		0	(5,885)	(4)	(7,913)	(8)	(10,997)	(9)	(5,551)	(7)
2019	8,153	5,500	67		0	(5,500)	(67)	(7,441)	(8)	(8,460)	(13)	(5,549)	(7)
2020	6,745	5,900	87		0	(5,900)	(87)	(5,762)	(10)	(7,028)	(11)	(5,563)	(7)
2021			0		0	0	0	(3,800)	(77)	(5,645)	(10)	(5,356)	(7)
2022			0		0	0	0	(1,967)	(87)	(3,457)	(10)	(5,165)	(7)
TOTAL	**2,023,423**	**144,625**	**7**	**0**	**0**	**(144,625)**	**(7)**						

FortisBC Inc.
ACCOUNT 35300 - TRANSMISSION PLANT SUBSTATION EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	2,381	0	0	0	0	0	0					0	0
1996	31,527	0	0	0	0	0	0					0	0
1997	6,244	0	0	0	0	0	0	0	0			0	0
1998	5,225	1,886	36	0	0	(1,886)	(36)	(629)	(4)			(472)	(4)
1999	8,388	68	1	0	0	(68)	(1)	(651)	(10)	(391)	(4)	(391)	(4)
2000	2,073	382	18	0	0	(382)	(18)	(779)	(15)	(467)	(4)	(389)	(4)
2001	18,139	173	1	0	0	(173)	(1)	(208)	(2)	(502)	(6)	(358)	(3)
2002		0	0	0	0	0	0	(185)	(3)	(502)	(7)	(314)	(3)
2003	418,396	0	0	0	0	0	0	(58)	(0)	(125)	(0)	(279)	(1)
2004	11,494	901	8	0	0	(901)	(8)	(300)	(0)	(291)	(0)	(341)	(1)
2005	23,390	795	3	0	0	(795)	(3)	(565)	(0)	(374)	(0)	(382)	(1)
2006	268,498	2,350	1	0	0	(2,350)	(1)	(1,349)	(1)	(809)	(1)	(546)	(1)
2007		3,370	0	0	0	(3,370)	0	(2,172)	(2)	(1,483)	(1)	(763)	(1)
2008		5,005	0	0	0	(5,005)	0	(3,575)	(4)	(2,484)	(4)	(1,066)	(2)
2009	21,559	242,754	1,126	0	0	(242,754)	(1,126)	(83,710)	(1,165)	(50,855)	(81)	(17,179)	(32)
2010	312,038	535,418	172	0	0	(535,418)	(172)	(261,059)	(235)	(157,779)	(131)	(49,569)	(70)
2011	1,353,741	317,257	23	0	0	(317,257)	(23)	(365,143)	(65)	(220,761)	(65)	(65,315)	(45)
2012	74,473	210,447	283	0	0	(210,447)	(283)	(354,374)	(61)	(262,176)	(74)	(73,378)	(52)
2013	36,703	192,463	524	0	0	(192,463)	(524)	(240,055)	(49)	(299,668)	(83)	(79,646)	(58)
2014	388,636	450,636	116	0	0	(450,636)	(116)	(284,515)	(171)	(341,244)	(79)	(98,195)	(66)
2015		85,660	0	1,348	0	(84,312)	0	(242,470)	(171)	(251,023)	(68)	(97,534)	(69)
2016	108,305	4,447	4	0	0	(4,447)	(4)	(179,798)	(109)	(188,461)	(155)	(93,303)	(66)
2017	156,090	24,253	16	0	0	(24,253)	(16)	(37,670)	(43)	(151,222)	(110)	(90,301)	(64)
2018	415,590	146,974	35		0	(146,974)	(35)	(58,558)	(26)	(142,124)	(66)	(92,662)	(61)
2019	341,598	220,203	64		0	(220,203)	(64)	(130,477)	(43)	(96,038)	(47)	(97,764)	(61)
2020	397,115	69,185	17		0	(69,185)	(17)	(145,454)	(38)	(93,012)	(33)	(96,665)	(57)
2021	342,795	374,369	109		0	(374,369)	(109)	(221,252)	(61)	(166,997)	(51)	(106,950)	(61)
2022	57,817	413,212	715		0	(413,212)	(715)	(285,589)	(107)	(244,789)	(79)	(117,888)	(69)
TOTAL	**4,802,215**	**3,302,207**	**69**	**1,348**	**1,961**	**(3,300,859)**	**(69)**						

FortisBC Inc.
ACCOUNT 35500 - TRANSMISSION PLANT POLES, TOWERS AND FIXTURES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	97,467	974	1	0	0	(974)	(1)					(974)	(1)
1996	77,451	2,079	3	0	0	(2,079)	(3)					(1,526)	(2)
1997	9,984	(883)	(9)	0	0	883	9	(723)	(1)			(723)	(1)
1998	69,303	0	0	0	0	0	0	(399)	(1)			(543)	(1)
1999	7,174	3,462	48	0	0	(3,462)	(48)	(860)	(3)	(1,126)	(2)	(1,126)	(2)
2000	52,493	1,251	2	0	0	(1,251)	(2)	(1,571)	(4)	(1,182)	(3)	(1,147)	(2)
2001	3,947	25	1	0	0	(25)	(1)	(1,579)	(7)	(771)	(3)	(987)	(2)
2002	50,686	454	1	0	0	(454)	(1)	(577)	(2)	(1,038)	(3)	(920)	(2)
2003	337,600	20	0	0	0	(20)	(0)	(166)	(0)	(1,042)	(1)	(820)	(1)
2004	1,382,416	15,852	1	0	0	(15,852)	(1)	(5,442)	(1)	(3,520)	(1)	(2,323)	(1)
2005	210,401	(3,428)	(2)	0	0	3,428	2	(4,148)	(1)	(2,585)	(1)	(1,801)	(1)
2006	333,310	3,571	1	0	0	(3,571)	(1)	(5,332)	(1)	(3,294)	(1)	(1,948)	(1)
2007	45,720	2,282	5	0	0	(2,282)	(5)	(808)	(0)	(3,659)	(1)	(1,974)	(1)
2008		2,508	0	0	0	(2,508)	0	(2,787)	(2)	(4,157)	(1)	(2,012)	(1)
2009	24,687	330,850	1,340	0	0	(330,850)	(1,340)	(111,880)	(477)	(67,156)	(55)	(23,934)	(13)
2010	3,751,805	1,293,489	34	0	0	(1,293,489)	(34)	(542,282)	(43)	(326,540)	(39)	(103,282)	(26)
2011	79,952	939,959	1,176	0	0	(939,959)	(1,176)	(854,766)	(66)	(513,818)	(66)	(152,498)	(40)
2012	91,681	280,618	306	0	0	(280,618)	(306)	(838,022)	(64)	(569,485)	(72)	(159,616)	(43)
2013	6,992	71,710	1,026	0	0	(71,710)	(1,026)	(430,762)	(723)	(583,325)	(74)	(154,989)	(44)
2014	201,964	1,679,731	832	142,550	71	(1,537,180)	(761)	(629,836)	(629)	(824,591)	(100)	(224,099)	(66)
2015	387,408	936,134	242	18,222	5	(917,913)	(237)	(842,268)	(424)	(749,476)	(488)	(257,137)	(75)
2016	329,766	418,377	127	0	0	(418,377)	(127)	(957,823)	(313)	(645,159)	(317)	(264,466)	(77)
2017		325,945	0	0	0	(325,945)	0	(554,078)	(232)	(654,225)	(353)	(267,139)	(81)
2018	59,524	643,496	1,081	17,760	30	(625,736)	(1,051)	(456,686)	(352)	(765,030)	(391)	(282,081)	(89)
2019	185,312	339,110	183		0	(339,110)	(183)	(430,264)	(527)	(525,416)	(273)	(284,362)	(91)
2020	51,032	672,819	1,318		0	(672,819)	(1,318)	(545,889)	(554)	(476,397)	(381)	(299,303)	(99)
2021	1,084,495	1,723,131	159	620,250	57	(1,102,881)	(102)	(704,937)	(160)	(613,298)	(222)	(329,065)	(99)
2022	56,009	601,707	1,074		0	(601,707)	(1,074)	(792,469)	(200)	(668,451)	(233)	(338,802)	(106)
TOTAL	**8,988,577**	**10,285,243**	**114**	**798,782**	**698,079**	**(9,486,461)**	**(106)**						

FortisBC Inc.
ACCOUNT 35600 - TRANSMISSION PLANT CONDUCTORS AND DEVICES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	622,639	125	0	0	0	(125)	(0)					(125)	(0)
1996	39,650	3,731	9	0	0	(3,731)	(9)					(1,928)	(1)
1997	35,784	(122)	(0)	0	0	122	0	(1,245)	(1)			(1,245)	(1)
1998	61,698	0	0	0	0	0	0	(1,203)	(3)			(933)	(0)
1999	137,642	3,619	3	0	0	(3,619)	(3)	(1,166)	(1)	(1,471)	(1)	(1,471)	(1)
2000	38,354	1,250	3	0	0	(1,250)	(3)	(1,623)	(2)	(1,696)	(3)	(1,434)	(1)
2001	19,852	69	0	0	0	(69)	(0)	(1,646)	(3)	(963)	(2)	(1,239)	(1)
2002		0	0	0	0	0	0	(440)	(2)	(988)	(2)	(1,084)	(1)
2003	494,206	9	0	0	0	(9)	(0)	(26)	(0)	(989)	(1)	(965)	(1)
2004	443,409	4,055	1	0	0	(4,055)	(1)	(1,355)	(0)	(1,077)	(1)	(1,274)	(1)
2005	18,745	4,976	27	0	0	(4,976)	(27)	(3,013)	(1)	(1,822)	(1)	(1,610)	(1)
2006	513,813	3,571	1	0	0	(3,571)	(1)	(4,201)	(1)	(2,522)	(1)	(1,774)	(1)
2007	158,315	2,069	1	0	0	(2,069)	(1)	(3,538)	(2)	(2,936)	(1)	(1,796)	(1)
2008		2,508	0	0	0	(2,508)	0	(2,716)	(1)	(3,436)	(2)	(1,847)	(1)
2009		419,432	0	0	0	(419,432)	0	(141,336)	(268)	(86,511)	(63)	(29,686)	(17)
2010	3,251,631	1,290,786	40	0	0	(1,290,786)	(40)	(570,909)	(53)	(343,673)	(44)	(108,505)	(30)
2011	139,123	924,568	665	0	0	(924,568)	(665)	(878,262)	(78)	(527,872)	(74)	(156,508)	(45)
2012	91,336	1,251,596	1,370	0	0	(1,251,596)	(1,370)	(1,155,650)	(100)	(777,778)	(112)	(217,347)	(64)
2013	10,564	36,924	350	0	0	(36,924)	(350)	(737,696)	(918)	(784,661)	(112)	(207,851)	(65)
2014	230,488	1,399,905	607	16,034	7	(1,383,871)	(600)	(890,797)	(804)	(977,549)	(131)	(266,652)	(85)
2015	414,623	396,656	96	0	0	(396,656)	(96)	(605,817)	(277)	(798,723)	(451)	(272,842)	(85)
2016	347,009	395,876	114	0	0	(395,876)	(114)	(725,468)	(219)	(692,985)	(317)	(278,435)	(87)
2017		333,945	0	0	0	(333,945)	0	(375,492)	(148)	(509,454)	(254)	(280,848)	(91)
2018	72,524	643,496	887	17,760	24	(625,736)	(863)	(451,852)	(323)	(627,217)	(295)	(295,219)	(99)
2019	187,179	339,110	181		0	(339,110)	(181)	(432,930)	(500)	(418,265)	(205)	(296,974)	(101)
2020	66,851	672,819	1,006		0	(672,819)	(1,006)	(545,888)	(501)	(473,497)	(351)	(311,430)	(109)
2021	364,129	1,723,132	473	620,250	170	(1,102,882)	(303)	(704,937)	(342)	(614,898)	(445)	(340,743)	(117)
2022	81,794	601,708	736										
TOTAL	**7,841,358**	**10,455,811**	**133**	**654,044**	**490,502**	**(9,200,059)**	**(117)**						

ACCOUNT 36200 - DISTRIBUTION PLANT SUBSTATION EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	171,545	3,074	2	0	0	(3,074)	(2)					(3,074)	(2)
1996	191,598	3,403	2	0	0	(3,403)	(2)					(3,239)	(2)
1997	265,679	0	0	0	0	0	0	(2,159)	(1)			(2,159)	(1)
1998	37,002	0	0	0	0	0	0	(1,134)	(1)			(1,619)	(1)
1999	19,743	0	0	0	0	0	0	0	0	(1,296)	(1)	(1,296)	(1)
2000	32,805	115	0	0	0	(115)	(0)	(38)	(0)	(704)	(1)	(1,099)	(1)
2001	14,781	307	2	0	0	(307)	(2)	(141)	(1)	(84)	(0)	(986)	(1)
2002	12,296	83	1	0	0	(83)	(1)	(169)	(1)	(101)	(0)	(873)	(1)
2003	154,134	4	0	0	0	(4)	(0)	(132)	(0)	(102)	(0)	(776)	(1)
2004	123,082	1,877	2	0	0	(1,877)	(2)	(655)	(1)	(477)	(1)	(886)	(1)
2005	10,838	328	3	0	0	(328)	(3)	(737)	(1)	(520)	(1)	(836)	(1)
2006	298,331	768	0	0	0	(768)	(0)	(991)	(1)	(612)	(1)	(830)	(1)
2007	127,901	2,769	2	0	0	(2,769)	(2)	(1,288)	(1)	(1,149)	(1)	(979)	(1)
2008	667,727	1,302	0	0	0	(1,302)	(0)	(1,613)	(0)	(1,409)	(1)	(1,002)	(1)
2009	1,203,524	77,851	6	0	0	(77,851)	(6)	(27,307)	(4)	(16,604)	(4)	(6,126)	(3)
2010	450,479	976,059	217	0	0	(976,059)	(217)	(351,738)	(45)	(211,750)	(39)	(66,746)	(28)
2011	1,611,032	288,635	18	0	0	(288,635)	(18)	(447,515)	(41)	(269,323)	(33)	(79,799)	(25)
2012	105,331	160,924	153	0	0	(160,924)	(153)	(475,206)	(66)	(300,954)	(37)	(84,306)	(28)
2013	444,823	131,391	30	0	0	(131,391)	(30)	(193,650)	(27)	(326,972)	(43)	(86,784)	(28)
2014	987,706	1,132,395	115	2,358	0	(1,130,037)	(114)	(474,117)	(92)	(537,409)	(75)	(138,946)	(40)
2015	363,676	231,112	64	6,472	2	(224,640)	(62)	(495,356)	(83)	(387,125)	(55)	(143,027)	(41)
2016	207,263	111,327	54	5,908	3	(105,419)	(51)	(486,698)	(94)	(350,482)	(83)	(141,318)	(41)
2017	161,801	101,958	63	0	0	(101,958)	(63)	(144,005)	(59)	(338,689)	(78)	(139,606)	(42)
2018	420,563	287,226	68		0	(287,226)	(68)	(164,868)	(63)	(369,856)	(86)	(145,757)	(43)
2019	419,947	61,717	15		0	(61,717)	(15)	(150,300)	(45)	(156,192)	(50)	(142,396)	(42)
2020	452,022	132,998	29		0	(132,998)	(29)	(160,647)	(37)	(137,864)	(41)	(142,034)	(41)
2021	2,274,518	371,586	16	5,440	0	(366,146)	(16)	(186,954)	(18)	(190,009)	(25)	(150,335)	(36)
2022	2,201,603	205,584	9		0	(205,584)	(9)	(234,909)	(14)	(210,734)	(18)	(152,308)	(32)
TOTAL	**13,431,750**	**4,284,795**	**32**	**20,178**	**63,254**	**(4,264,617)**	**(32)**						

FortisBC Inc.
ACCOUNT 36400 - DISTRIBUTION PLANT POLES, TOWERS AND FIXTURES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	42,017	4,178	10	0	0	(4,178)	(10)					(4,178)	(10)
1996	909,516	83	0	0	0	(83)	(0)					(2,131)	(0)
1997	47,874	865	2	0	0	(865)	(2)	(1,709)	(1)			(1,709)	(1)
1998	154,526	1,154	1	0	0	(1,154)	(1)	(701)	(0)			(1,570)	(1)
1999	57,321	2,893	5	0	0	(2,893)	(5)	(1,637)	(2)	(1,835)	(1)	(1,835)	(1)
2000	125,481	3,773	3	0	0	(3,773)	(3)	(2,607)	(2)	(1,754)	(1)	(2,158)	(1)
2001	38,728	3,368	9	0	0	(3,368)	(9)	(3,345)	(5)	(2,411)	(3)	(2,331)	(1)
2002	10,183	5,836	57	0	0	(5,836)	(57)	(4,326)	(7)	(3,405)	(4)	(2,769)	(2)
2003	1,527,483	2	0	0	0	(2)	(0)	(3,068)	(1)	(3,174)	(1)	(2,461)	(1)
2004	313,979	4,070	1	0	0	(4,070)	(1)	(3,302)	(1)	(3,410)	(1)	(2,622)	(1)
2005	18,409	12	0	0	0	(12)	(0)	(1,361)	(0)	(2,657)	(1)	(2,385)	(1)
2006	383,685	4	0	0	0	(4)	(0)	(1,362)	(1)	(1,985)	(0)	(2,186)	(1)
2007	126,130	(70)	(0)	0	0	70	0	18	0	(804)	(0)	(2,013)	(1)
2008	993,640	(56)	(0)	0	0	56	0	40	0	(792)	(0)	(1,865)	(1)
2009	246,130	899,583	365	0	0	(899,583)	(365)	(299,819)	(66)	(179,895)	(51)	(61,713)	(19)
2010	393,795	826,460	210	0	0	(826,460)	(210)	(575,329)	(106)	(345,184)	(81)	(109,510)	(33)
2011	181,714	563,990	310	0	0	(563,990)	(310)	(763,344)	(279)	(457,981)	(118)	(136,244)	(42)
2012	462,339	427,020	92	0	0	(427,020)	(92)	(605,823)	(175)	(543,399)	(119)	(152,398)	(45)
2013	273,713	342,056	125	0	0	(342,056)	(125)	(444,355)	(145)	(611,822)	(196)	(162,380)	(49)
2014	727,613	900,638	124	853	0	(899,785)	(124)	(556,287)	(114)	(611,862)	(150)	(199,250)	(57)
2015	374,796	1,286,206	343	69,511	19	(1,216,695)	(325)	(819,512)	(179)	(689,909)	(171)	(247,700)	(70)
2016	289,315	781,922	270	4,647	2	(777,275)	(269)	(964,585)	(208)	(732,566)	(172)	(271,772)	(78)
2017	517,824	940,902	182	10,434	2	(930,468)	(180)	(974,813)	(247)	(833,256)	(191)	(300,411)	(84)
2018	1,009,071	1,048,130	104		0	(1,048,130)	(104)	(918,624)	(152)	(974,471)	(167)	(331,566)	(86)
2019	164,134	915,778	558		0	(915,778)	(558)	(964,792)	(171)	(977,669)	(208)	(354,934)	(95)
2020	198,669	1,158,664	583		0	(1,158,664)	(583)	(1,040,857)	(228)	(966,063)	(222)	(385,847)	(105)
2021	196,816	1,336,085	679	3,981	2	(1,332,104)	(677)	(1,135,515)	(609)	(1,077,029)	(258)	(420,893)	(116)
2022	147,178	1,151,979	783		0	(1,151,979)	(783)	(1,214,249)	(671)	(1,121,331)	(327)	(447,004)	(126)
TOTAL	**9,932,081**	**12,605,525**	**127**	**89,426**	**70,460**	**(12,516,099)**	**(126)**						

FortisBC Inc.
ACCOUNT 36500 - DISTRIBUTION PLANT CONDUCTORS AND DEVICES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	81,031	1,670	2	0	0	(1,670)	(2)					(1,670)	(2)
1996	62,998	(3,213)	(5)	0	0	3,213	5					771	1
1997	104,498	5,100	5	0	0	(5,100)	(5)	(1,186)	(1)			(1,186)	(1)
1998	87,355	1,261	1	0	0	(1,261)	(1)	(1,050)	(1)			(1,205)	(1)
1999	61,791	2,090	3	0	0	(2,090)	(3)	(2,817)	(3)	(1,382)	(2)	(1,382)	(2)
2000	302,013	3,744	1	0	0	(3,744)	(1)	(2,365)	(2)	(1,797)	(1)	(1,775)	(2)
2001	12,584	3,034	24	0	0	(3,034)	(24)	(2,956)	(2)	(3,046)	(3)	(1,955)	(2)
2002	24,285	(368)	(2)	0	0	368	2	(2,136)	(2)	(1,952)	(2)	(1,665)	(2)
2003	1,268,315	1	0	0	0	(1)	(0)	(889)	(0)	(1,700)	(1)	(1,480)	(1)
2004	531,178	5,802	1	0	0	(5,802)	(1)	(1,812)	(0)	(2,443)	(1)	(1,912)	(1)
2005	608,984	(296)	(0)	0	0	296	0	(1,836)	(0)	(1,635)	(0)	(1,711)	(1)
2006	264,656	(1,269)	(0)	0	0	1,269	0	(1,412)	(0)	(774)	(0)	(1,463)	(1)
2007	94,595	(274)	(0)	0	0	274	0	613	0	(793)	(0)	(1,329)	(0)
2008	1,273,470	0	0	0	0	0	0	514	0	(793)	(0)	(1,234)	(0)
2009	1,026,720	1,393,766	136	0	0	(1,393,766)	(136)	(464,497)	(58)	(278,385)	(43)	(94,070)	(24)
2010	819,182	1,318,948	161	0	0	(1,318,948)	(161)	(904,238)	(87)	(542,234)	(78)	(170,625)	(41)
2011	386,010	903,468	234	0	0	(903,468)	(234)	(1,205,394)	(162)	(723,182)	(100)	(213,733)	(52)
2012	506,631	688,743	136	0	0	(688,743)	(136)	(970,386)	(170)	(860,985)	(107)	(240,123)	(58)
2013	826,339	398,316	48	0	0	(398,316)	(48)	(663,509)	(116)	(940,648)	(132)	(248,449)	(57)
2014	913,935	1,428,938	156	1,375	0	(1,427,563)	(156)	(838,207)	(112)	(947,407)	(137)	(307,404)	(66)
2015	697,034	1,962,414	282	0	0	(1,962,414)	(282)	(1,262,764)	(155)	(1,076,101)	(162)	(386,214)	(81)
2016	627,531	1,253,671	200	0	0	(1,253,671)	(200)	(1,547,883)	(207)	(1,146,141)	(160)	(425,644)	(88)
2017	757,201	1,500,757	198	0	0	(1,500,757)	(198)	(1,572,280)	(227)	(1,308,544)	(171)	(472,388)	(96)
2018	878,884	1,708,317	194	17,784	2	(1,690,533)	(192)	(1,481,654)	(196)	(1,566,987)	(202)	(523,144)	(103)
2019	285,897	1,480,752	518	3,688	1	(1,477,064)	(517)	(1,556,118)	(243)	(1,576,888)	(243)	(561,301)	(112)
2020	359,402	1,870,970	521	2,154	1	(1,868,815)	(520)	(1,678,804)	(330)	(1,558,168)	(268)	(611,590)	(124)
2021	621,057	2,148,559	346		0	(2,148,559)	(346)	(1,831,479)	(434)	(1,737,146)	(299)	(668,515)	(134)
2022	549,624	1,858,034	338		0	(1,858,034)	(338)	(1,958,469)	(384)	(1,808,601)	(336)	(710,998)	(142)
TOTAL	**14,033,199**	**19,932,933**	**142**	**25,002**	**17,602**	**(19,907,932)**	**(142)**						

FortisBC Inc.
ACCOUNT 36800 - DISTRIBUTION PLANT - LINE TRANSFORMERS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	63,290	492	1	0	0	(492)	(1)					(492)	(1)
1996	370,363	(85)	(0)	0	0	85	0					(203)	(0)
1997	123,944	0	0	0	0	0	0	(136)	(0)			(136)	(0)
1998	53,505	0	0	0	0	0	0	28	0			(102)	(0)
1999	14,197	2,340	16	0	0	(2,340)	(16)	(780)	(1)	(549)	(0)	(549)	(0)
2000	19,665	308	2	0	0	(308)	(2)	(883)	(3)	(513)	(0)	(509)	(0)
2001	782,848	2,407	0	0	0	(2,407)	(0)	(1,685)	(1)	(1,011)	(1)	(780)	(0)
2002	1,320	2,017	153	0	0	(2,017)	(153)	(1,577)	(1)	(1,414)	(1)	(935)	(1)
2003	442,043	3	0	0	0	(3)	(0)	(1,476)	(0)	(1,415)	(1)	(831)	(0)
2004	88,448	7,569	9	0	0	(7,569)	(9)	(3,196)	(2)	(2,461)	(1)	(1,505)	(1)
2005	64,694	277	0	0	0	(277)	(0)	(2,616)	(1)	(2,454)	(1)	(1,393)	(1)
2006	1,180,314	1,308	0	0	0	(1,308)	(0)	(3,051)	(1)	(2,234)	(1)	(1,386)	(1)
2007	21,417	3,020	14	0	0	(3,020)	(14)	(1,535)	(0)	(2,435)	(1)	(1,512)	(1)
2008	1,670,566	2,048	0	0	0	(2,048)	(0)	(2,125)	(0)	(2,844)	(0)	(1,550)	(0)
2009	1,781,554	737,628	41	0	0	(737,628)	(41)	(247,565)	(21)	(148,856)	(16)	(50,622)	(11)
2010	1,322,898	712,410	54	0	0	(712,410)	(54)	(484,028)	(30)	(291,283)	(24)	(91,984)	(18)
2011	694,406	538,093	77	0	0	(538,093)	(77)	(662,710)	(52)	(398,640)	(36)	(118,225)	(23)
2012	830,813	478,654	58	0	0	(478,654)	(58)	(576,385)	(61)	(493,766)	(39)	(138,249)	(26)
2013	482,526	279,130	58	0	0	(279,130)	(58)	(431,959)	(65)	(549,183)	(54)	(145,664)	(28)
2014	1,672,584	807,074	48	523	0	(806,551)	(48)	(521,445)	(52)	(562,968)	(56)	(178,708)	(31)
2015	1,249,686	752,504	60	0	0	(752,504)	(60)	(612,729)	(54)	(570,986)	(58)	(206,032)	(33)
2016	1,149,584	476,393	41	0	0	(476,393)	(41)	(678,483)	(50)	(558,646)	(52)	(218,321)	(34)
2017	1,410,276	570,285	40	0	0	(570,285)	(40)	(599,727)	(47)	(576,973)	(48)	(233,624)	(35)
2018	2,163,998	642,400	30		0	(642,400)	(30)	(563,026)	(36)	(649,627)	(42)	(250,656)	(34)
2019	878,645	561,280	64		0	(561,280)	(64)	(591,322)	(40)	(600,572)	(44)	(263,081)	(35)
2020	1,147,804	710,146	62		0	(710,146)	(62)	(637,942)	(46)	(592,101)	(44)	(280,276)	(37)
2021	2,386,509	816,448	34		0	(816,448)	(34)	(695,958)	(47)	(660,112)	(41)	(300,134)	(37)
2022	1,602,043	706,049	44		0	(706,049)	(44)	(744,214)	(43)	(687,264)	(42)	(314,631)	(37)
TOTAL	**23,669,938**	**8,810,194**	**37**	**523**	**1,404**	**(8,809,672)**	**(37)**						

FortisBC Inc.
ACCOUNT 37300 - DISTRIBUTION PLANT - STREET LIGHTING AND SIGNAL SYSTEMS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	26,524	157	1	0	0	(157)	(1)					(157)	(1)
1996	1,132	0	0	0	0	0	0					(79)	(1)
1997	67,599	0	0	0	0	0	0	(52)	(0)			(52)	(0)
1998	2,480	0	0	0	0	0	0	0	0			(39)	(0)
1999	2,155	27	1	0	0	(27)	(1)	(9)	(0)	(37)	(0)	(37)	(0)
2000	5,528	113	2	0	0	(113)	(2)	(47)	(1)	(28)	(0)	(50)	(0)
2001	12,763	0	0	0	0	0	0	(47)	(1)	(28)	(0)	(43)	(0)
2002		0	0	0	0	(0)	0	(38)	(1)	(28)	(1)	(37)	(0)
2003	105,102	0	0	0	0	(0)	(0)	(0)	(0)	(28)	(0)	(33)	(0)
2004	94,015	660	1	0	0	(660)	(1)	(220)	(0)	(155)	(0)	(96)	(0)
2005		2	0	0	0	(2)	0	(221)	(0)	(132)	(0)	(87)	(0)
2006	15,352	(0)	(0)	0	0	0	0	(220)	(1)	(132)	(0)	(80)	(0)
2007		(1)	0	0	0	1	0	(0)	(0)	(132)	(0)	(74)	(0)
2008		1	0	0	0	(1)	0	0	0	(132)	(1)	(69)	(0)
2009	52,621	124,577	237	0	0	(124,577)	(237)	(41,525)	(237)	(24,916)	(183)	(8,369)	(33)
2010	36,949	118,203	320	0	0	(118,203)	(320)	(80,927)	(271)	(48,556)	(231)	(15,234)	(58)
2011	11,413	80,753	708	0	0	(80,753)	(708)	(107,844)	(320)	(64,707)	(320)	(19,088)	(75)
2012	28,176	0	0	0	0	0	0	(66,319)	(260)	(64,707)	(250)	(18,027)	(70)
2013	129,040	0	0	0	0	0	0	(26,918)	(48)	(64,707)	(125)	(17,079)	(55)
2014	580,009	0	0	0	0	0	0	0	0	(39,791)	(25)	(16,225)	(28)
2015	44,885	0	0	0	0	0	0	0	0	(16,151)	(10)	(15,452)	(27)
2016	34,643	0	0	0	0	0	0	0	0	0	0	(14,750)	(26)
2017	62,942	0	0	0	0	0	0	0	0	0	0	(14,108)	(25)
2018	211,807	0	0	0	0	0	0	0	0	0	0	(13,521)	(21)
2019	156,588	0	0	0	0	0	0	0	0	0	0	(12,980)	(19)
2020	75,759	0	0	0	0	0	0	0	0	0	0	(12,480)	(18)
2021	24,879	0	0	0	0	0	0	0	0	0	0	(12,018)	(18)
2022	23,795	0	0	0	0	0	0	0	0	0	0	(11,589)	(18)
TOTAL	**1,806,154**	**324,492**	**18**	**0**	**0**	**(324,492)**	**(18)**						

FortisBC Inc.
ACCOUNT 39010 - GENERAL PLANT - STRUCTURE - MASONRY
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	(2,710)	0	0	0	0	0	0					0	0
1996		0	0	0	0	0	0					0	0
1997	13,180	0	0	0	0	0	0	0	0			0	0
1998	4,313	0	0	0	0	0	0	0	0			0	0
1999		0	0	0	0	0	0	0	0	0	0	0	0
2000	24,079	0	0	0	0	0	0	0	0	0	0	0	0
2001		0	0	0	0	0	0	0	0	0	0	0	0
2002		(127)	0	0	0	127	0	42	1	25	0	16	0
2003	160,413	6	0	0	0	(6)	(0)	40	0	24	0	13	0
2004	18,554	204	1	0	0	(204)	(1)	(27)	(0)	(16)	(0)	(8)	(0)
2005	62,471	4	0	0	0	(4)	(0)	(71)	(0)	(17)	(0)	(8)	(0)
2006		0	0	0	0	0	0	(69)	(0)	(17)	(0)	(7)	(0)
2007	78,131	489	1	0	0	(489)	(1)	(164)	(0)	(141)	(0)	(44)	(0)
2008		2,547	0	0	0	(2,547)	0	(1,012)	(4)	(649)	(2)	(223)	(1)
2009		723	0	0	0	(723)	0	(1,253)	(5)	(753)	(3)	(256)	(1)
2010		525	0	0	0	(525)	0	(1,265)	0	(857)	(5)	(273)	(1)
2011		0	0	0	0	0	0	(416)	0	(857)	(5)	(257)	(1)
2012		0	0	0	0	0	0	(175)	0	(759)	0	(243)	(1)
2013		0	0	0	0	0	0	0	0	(250)	0	(230)	(1)
2014		0	0	0	0	0	0	0	0	(105)	0	(219)	(1)
2015		0	0	0	0	0	0	0	0	0	0	(208)	(1)
2016		0	0	0	0	0	0	0	0	0	0	(199)	(1)
2017	1,634,099	14,135	1	0	0	(14,135)	(1)	(4,712)	(1)	(2,827)	(1)	(805)	(1)
2018		1,177,425	0	0	0	(1,177,425)	0	(397,187)	(73)	(238,312)	(73)	(49,830)	(60)
2019	19,674	(21,972)	(112)	0	0	21,972	112	(389,863)	(71)	(233,918)	(71)	(46,958)	(58)
2020	358,360	73,000	20	2,500	1	(70,500)	(20)	(408,651)	(324)	(248,018)	(62)	(47,864)	(52)
2021			0	0	0	0	0	(16,176)	(13)	(248,018)	(62)	(46,091)	(52)
2022			0	0	0	0	0	(23,500)	(20)	(245,191)	(324)	(44,445)	(52)
TOTAL	**2,370,565**	**1,246,958**	**53**	**2,500**	**4,753**	**(1,244,458)**	**(52)**						

FortisBC Inc.
ACCOUNT 39020 - GENERAL PLANT - OPERATIONS BUILDINGS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995			0	0	0	0	0					0	0
1996			0	0	0	0	0					0	0
1997			0	0	0	0	0	0	0			0	0
1998			0	0	0	0	0	0	0			0	0
1999			0	0	0	0	0	0	0	0	0	0	0
2000			0	0	0	0	0	0	0	0	0	0	0
2001			0	0	0	0	0	0	0	0	0	0	0
2002			0	0	0	0	0	0	0	0	0	0	0
2003			0	0	0	0	0	0	0	0	0	0	0
2004			0	0	0	0	0	0	0	0	0	0	0
2005			0	0	0	0	0	0	0	0	0	0	0
2006			0	0	0	0	0	0	0	0	0	0	0
2007			0	0	0	0	0	0	0	0	0	0	0
2008			0	0	0	0	0	0	0	0	0	0	0
2009			0	0	0	0	0	0	0	0	0	0	0
2010			0	0	0	0	0	0	0	0	0	0	0
2011			0	0	0	0	0	0	0	0	0	0	0
2012			0	0	0	0	0	0	0	0	0	0	0
2013			0	0	0	0	0	0	0	0	0	0	0
2014			0	0	0	0	0	0	0	0	0	0	0
2015			0	0	0	0	0	0	0	0	0	0	0
2016			0	0	0	0	0	0	0	0	0	0	0
2017			0	0	0	0	0	0	0	0	0	0	0
2018			0	0	0	0	0	0	0	0	0	0	0
2019	109,855		0	0	0	0	0	0	0	0	0	0	0
2020	110,000		0	0	0	0	0	0	0	0	0	0	0
2021	18,000		0	0	0	0	0	0	0	0	0	0	0
2022			0	0	0	0	0	0	0	0	0	0	0
TOTAL	**237,855**	**0**	**0**	**0**	**0**	**0**	**0**						

FortisBC Inc.
ACCOUNT 39210 - GENERAL PLANT - LIGHT DUTY VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995		0	0	0	0	0	0					0	0
1996		0	0	0	0	0	0					0	0
1997		0	0	0	0	0	0	0	0			0	0
1998		0	0	0	0	0	0	0	0			0	0
1999		0	0	0	0	0	0	0	0	0	0	0	0
2000		0	0	0	0	0	0	0	0	0	0	0	0
2001		0	0	0	0	0	0	0	0	0	0	0	0
2002		0	0	0	0	0	0	0	0	0	0	0	0
2003		0	0	0	0	0	0	0	0	0	0	0	0
2004		0	0	0	0	0	0	0	0	0	0	0	0
2005		0	0	0	0	0	0	0	0	0	0	0	0
2006	2,125,040	0	0	0	0	0	0	0	0	0	0	0	0
2007	4,135,040	0	0	0	0	0	0	0	0	0	0	0	0
2008	5,590,539	0	0	0	0	0	0	0	0	0	0	0	0
2009	180,976	0	0	0	0	0	0	0	0	0	0	0	0
2010	243,789	0	0	0	0	0	0	0	0	0	0	0	0
2011	185,109	0	0	0	0	0	0	0	0	0	0	0	0
2012	537,957	0	0	0	0	0	0	0	0	0	0	0	0
2013	311,316	0	0	0	0	0	0	0	0	0	0	0	0
2014	1,200,552	0	0	0	0	0	0	0	0	0	0	0	0
2015	793,922	0	0	0	0	0	0	0	0	0	0	0	0
2016	119,502	6,759	6	200,570	168	193,811	162	64,604	9	38,762	7	8,810	1
2017	49,643	4,778	10	156,794	316	152,016	306	115,276	36	69,165	14	15,036	2
2018	494,253	8,785	2	124,602	25	115,817	23	153,881	70	92,329	17	19,235	3
2019	1,348,645	5,189	0	112,208	8	107,019	8	124,950	20	113,732	20	22,746	3
2020	261,687	1,676	1	47,683	18	46,007	18	89,614	13	122,934	27	23,641	3
2021	517,342	5,120	1	187,044	36	181,924	35	111,650	16	120,556	23	29,503	4
2022	473,086	(72,508)	(15)	132,345	28	204,853	43	144,261	35	131,124	21	35,766	5
TOTAL	**18,568,397**	**(40,200)**	**(0)**	**961,246**	**(443,995,727)**	**1,001,446**	**5**						

FortisBC Inc.
ACCOUNT 39220 - GENERAL PLANT - HEAVY DUTY VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995		0	0	0	0	0	0					0	0
1996		0	0	0	0	0	0					0	0
1997		0	0	0	0	0	0	0	0			0	0
1998		0	0	0	0	0	0	0	0			0	0
1999		0	0	0	0	0	0	0	0	0	0	0	0
2000		0	0	0	0	0	0	0	0	0	0	0	0
2001		0	0	0	0	0	0	0	0	0	0	0	0
2002		0	0	0	0	0	0	0	0	0	0	0	0
2003		0	0	0	0	0	0	0	0	0	0	0	0
2004		0	0	0	0	0	0	0	0	0	0	0	0
2005		0	0	0	0	0	0	0	0	0	0	0	0
2006	1,392,590	0	0	0	0	0	0	0	0	0	0	0	0
2007	2,691,810	0	0	0	0	0	0	0	0	0	0	0	0
2008	10,214,837	0	0	0	0	0	0	0	0	0	0	0	0
2009	373,953	0	0	0	0	0	0	0	0	0	0	0	0
2010	486,403	9,685	2	102,761	21	93,076	19	31,025	1	18,615	1	5,817	1
2011	3,902	3,392	87	6,207	159	2,815	72	31,964	11	19,178	1	5,641	1
2012	242,323	5,682	2	86,477	36	80,795	33	58,895	24	35,337	2	9,816	1
2013	20,992	3,613	17	67,005	319	63,392	302	49,000	55	48,015	21	12,636	2
2014	871,252	13,659	2	0	0	(13,659)	(2)	43,509	12	45,284	14	11,321	1
2015	911,343	0	0	329,182	36	329,182	36	126,305	21	92,505	23	26,457	3
2016	756,231	0	0	0	0	0	0	105,174	12	91,942	16	25,255	3
2017	729,719	0	0	0	0	0	0	109,727	14	75,783	12	24,157	3
2018	527,308		0			0	0	0	0	63,105	8	23,150	3
2019	527,382		0			0	0	0	0	65,836	10	22,224	3
2020	235,287		0			0	0	0	0	0	0	21,369	3
2021	838,114		0			0	0	0	0	0	0	20,578	3
2022	749,290		0			0	0	0	0	0	0	19,843	3
TOTAL	**21,572,735**	**36,031**	**0**	**591,631**	**#########**	**555,600**	**3**						

FortisBC Inc.
ACCOUNT 39700 - GENERAL PLANT - COMMUNICATION STRUCTURES & EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995			0		0	0	0					0	0
1996			0		0	0	0					0	0
1997			0		0	0	0	0	0			0	0
1998			0		0	0	0	0	0			0	0
1999			0		0	0	0	0	0	0	0	0	0
2000			0		0	0	0	0	0	0	0	0	0
2001			0		0	0	0	0	0	0	0	0	0
2002			0		0	0	0	0	0	0	0	0	0
2003			0		0	0	0	0	0	0	0	0	0
2004			0		0	0	0	0	0	0	0	0	0
2005			0		0	0	0	0	0	0	0	0	0
2006			0		0	0	0	0	0	0	0	0	0
2007			0		0	0	0	0	0	0	0	0	0
2008			0		0	0	0	0	0	0	0	0	0
2009			0		0	0	0	0	0	0	0	0	0
2010			0		0	0	0	0	0	0	0	0	0
2011			0		0	0	0	0	0	0	0	0	0
2012			0		0	0	0	0	0	0	0	0	0
2013			0		0	0	0	0	0	0	0	0	0
2014			0		0	0	0	0	0	0	0	0	0
2015			0		0	0	0	0	0	0	0	0	0
2016			0		0	0	0	0	0	0	0	0	0
2017			0		0	0	0	0	0	0	0	0	0
2018	515,496	12,116	2			(12,116)	(2)	(4,039)	(2)	(2,423)	(2)	(505)	(2)
2019	561,750	31,000	6			(31,000)	(6)	(14,372)	(4)	(8,623)	(4)	(1,725)	(4)
2020	7,100,511	0	0			0	0	(14,372)	(1)	(8,623)	(1)	(1,658)	(1)
2021	1,707,514	10,695	1			(10,695)	(1)	(13,899)	(0)	(10,762)	(1)	(1,993)	(1)
2022	943,166	16,503	2			(16,503)	(2)	(9,066)	(0)	(14,063)	(1)	(2,511)	(1)
TOTAL	**10,828,436**	**70,315**	**1**	**0**	**0**	**(70,315)**	**(1)**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATIONS

FortisBC

Account #: 33010 - Land Rights - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1980	83,965.00	45,483	77,204	0.9195	6,761	34.37	197	42.0
1983	14,974.00	7,578	12,864	0.8591	2,110	37.04	57	39.0
2005	20,957.55	4,730	8,030	0.3831	12,928	58.07	223	17.0
2007	726,878.34	144,874	245,914	0.3383	480,964	60.05	8,009	15.0
2008	114,583.26	21,322	36,192	0.3159	78,391	61.04	1,284	14.0
TOTAL	961,358.15	223,988	380,204		581,154		9,770	

COMPOSITE ANNUAL ACCRUAL RATE 1.02%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.40

COMPOSITE AVERAGE AGE (YEARS) 17.66

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 57.53

FortisBC

Account #: 33100 - Structures and Improvements - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S1.5
ASL: 60
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	141,406.67	85,764	100,069	0.6433	55,478	26.92	2,061	40.0
1984	3,658.00	2,138	2,495	0.6201	1,529	28.11	54	38.0
1985	28,887.75	16,560	19,323	0.6081	12,454	28.73	433	37.0
1986	56,563.00	31,774	37,074	0.5959	25,145	29.36	856	36.0
1987	15,641.14	8,602	10,037	0.5834	7,168	30.00	239	35.0
1988	20,857.00	11,221	13,092	0.5707	9,850	30.66	321	34.0
1989	29,039.00	15,268	17,815	0.5577	14,128	31.32	451	33.0
1990	92,385.21	47,422	55,331	0.5445	46,292	32.00	1,447	32.0
1991	811,084.00	406,030	473,756	0.5310	418,437	32.69	12,798	31.0
1992	267,598.00	130,500	152,268	0.5173	142,090	33.40	4,254	30.0
1993	1,160,244.00	550,509	642,334	0.5033	633,935	34.12	18,580	29.0
1994	1,403,771.00	647,210	755,164	0.4890	788,984	34.85	22,638	28.0
1995	2,185,168.00	977,630	1,140,698	0.4746	1,262,987	35.60	35,480	27.0
1996	156,174.00	67,696	78,988	0.4598	92,803	36.36	2,553	26.0
1997	94,696.00	39,707	46,330	0.4448	57,835	37.13	1,558	25.0
1998	455,428.07	184,415	215,176	0.4295	285,795	37.91	7,538	24.0
1999	70,304.00	27,438	32,015	0.4140	45,320	38.71	1,171	23.0
2000	464,971.00	174,551	203,666	0.3982	307,802	39.52	7,788	22.0
2001	1,021,391.00	368,010	429,395	0.3822	694,136	40.35	17,204	21.0
2002	367,013.55	126,601	147,718	0.3659	255,997	41.18	6,216	20.0
2003	467,173.86	153,878	179,544	0.3494	334,347	42.03	7,954	19.0
2004	209,949.46	65,840	76,822	0.3326	154,123	42.89	3,593	18.0
2005	401,350.75	119,432	139,353	0.3156	302,132	43.77	6,903	17.0
2006	217,430.19	61,175	71,378	0.2984	167,795	44.65	3,758	16.0
2007	621,007.69	164,526	191,969	0.2810	491,140	45.55	10,783	15.0
2008	771,956.58	191,674	223,645	0.2634	625,508	46.46	13,464	14.0
2009	295,448.33	68,390	79,797	0.2455	245,196	47.37	5,176	13.0
2010	595,952.42	127,822	149,143	0.2275	506,405	48.30	10,484	12.0

FortisBC

Account #: 33100 - Structures and Improvements - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S1.5
ASL: 60
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	156,210.73	30,821	35,961	0.2093	135,870	49.24	2,759	11.0
2012	923,741.19	166,237	193,966	0.1909	822,150	50.18	16,383	10.0
2013	176,153.41	28,620	33,394	0.1723	160,375	51.14	3,136	9.0
2014	901,620.00	130,579	152,359	0.1536	839,423	52.10	16,112	8.0
2015	1,335,846.95	169,725	198,036	0.1348	1,271,396	53.07	23,957	7.0
2016	1,131,567.70	123,527	144,132	0.1158	1,100,593	54.05	20,364	6.0
2017	1,136,820.82	103,628	120,914	0.0967	1,129,589	55.03	20,528	5.0
2018	1,074,549.21	78,502	91,597	0.0775	1,090,408	56.02	19,466	4.0
2019	112,496.10	6,173	7,203	0.0582	116,543	57.01	2,044	3.0
2020	602,738.22	22,075	25,757	0.0388	637,255	58.00	10,987	2.0
2021	943,918.77	17,299	20,184	0.0194	1,018,127	59.00	17,256	1.0
2022	86,837.29	0	0	0.0000	95,521	60.00	1,592	0.0
TOTAL	21,009,050.06	5,748,970	6,707,897		16,402,058		360,339	

COMPOSITE ANNUAL ACCRUAL RATE	1.72%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	16.17
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	45.07

FortisBC

Account #: 33200 - Reservoirs, Dams and Waterways - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S2
ASL: 75
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	8,399,663.38	5,354,816	-555,489	-0.0509	11,475,052	38.22	300,229	40.0
1987	87,783.00	50,122	-5,200	-0.0456	119,317	42.06	2,837	35.0
1989	65,068.00	35,327	-3,665	-0.0433	88,253	43.68	2,021	33.0
1991	15,350.00	7,890	-819	-0.0410	20,774	45.34	458	31.0
1993	599,823.40	290,526	-30,138	-0.0386	809,909	47.06	17,211	29.0
1994	507,161.00	237,977	-24,687	-0.0374	683,996	47.93	14,271	28.0
1996	18,978.00	8,321	-863	-0.0350	25,535	49.70	514	26.0
1997	31,458.00	13,301	-1,380	-0.0337	42,275	50.61	835	25.0
1998	1,083,532.41	441,001	-45,748	-0.0325	1,454,340	51.52	28,229	24.0
2003	847,766.00	276,155	-28,647	-0.0260	1,130,743	56.21	20,117	19.0
2004	1,104,371.66	341,386	-35,414	-0.0247	1,471,097	57.17	25,734	18.0
2005	238,606.50	69,764	-7,237	-0.0233	317,426	58.13	5,460	17.0
2006	2,897,371.90	798,382	-82,821	-0.0220	3,849,405	59.10	65,131	16.0
2007	2,188,732.51	566,104	-58,726	-0.0206	2,904,078	60.08	48,338	15.0
2008	3,486,392.04	842,479	-87,396	-0.0193	4,619,705	61.06	75,660	14.0
2009	1,548,559.95	347,789	-36,078	-0.0179	2,049,206	62.04	33,029	13.0
2010	2,209,837.24	458,483	-47,561	-0.0166	2,920,350	63.03	46,332	12.0
2011	705,347.99	134,229	-13,924	-0.0152	930,877	64.02	14,540	11.0
2012	2,080,696.83	360,152	-37,361	-0.0138	2,742,267	65.01	42,180	10.0
2013	232,034.36	36,162	-3,751	-0.0124	305,396	66.01	4,627	9.0
2014	2,164,343.07	299,926	-31,113	-0.0111	2,844,759	67.01	42,456	8.0
2015	990,072.67	120,079	-12,457	-0.0097	1,299,551	68.00	19,110	7.0
2016	678,133.28	70,509	-7,314	-0.0083	888,888	69.00	12,882	6.0
2017	650,247.93	56,348	-5,845	-0.0069	851,168	70.00	12,159	5.0
2018	1,067,754.39	74,027	-7,679	-0.0055	1,395,760	71.00	19,659	4.0
2019	15,280,398.77	794,565	-82,425	-0.0041	19,946,944	72.00	277,041	3.0
2020	24,987,075.70	866,214	-89,858	-0.0028	32,573,056	73.00	446,206	2.0
2021	25,790,442.65	447,034	-46,374	-0.0014	33,573,949	74.00	453,702	1.0

FortisBC

Account #: 33200 - Reservoirs, Dams and Waterways - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: S2
ASL: 75
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2022	16,324,845.99	0	0	0.0000	21,222,300	75.00	282,964	0.0
TOTAL	116,281,848.62	13,399,067	-1,389,971		152,556,374		2,313,932	

COMPOSITE ANNUAL ACCRUAL RATE	1.99%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	-0.01
COMPOSITE AVERAGE AGE (YEARS)	6.91
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	68.35

FortisBC

Account #: 33300 - Water Wheels, Turbines and Generators - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 70
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	7,237.91	6,614	6,524	0.6933	2,886	20.79	139	62.0
1963	661,927.48	583,782	575,780	0.6691	284,726	22.51	12,648	59.0
1964	834,199.00	726,508	716,550	0.6607	367,908	23.11	15,923	58.0
1965	266.36	229	226	0.6522	120	23.71	5	57.0
1969	296.00	241	237	0.6167	147	26.23	6	53.0
1971	320.00	252	249	0.5981	167	27.55	6	51.0
1977	5,452.00	3,877	3,824	0.5396	3,263	31.70	103	45.0
1982	5,943,711.67	3,821,182	3,768,807	0.4878	3,958,018	35.38	111,863	40.0
1983	26.00	16	16	0.4772	18	36.14	0	39.0
1984	76,397.00	46,956	46,312	0.4663	53,004	36.90	1,436	38.0
1985	24,262.00	14,565	14,365	0.4555	17,175	37.68	456	37.0
1986	141,673.00	83,001	81,863	0.4445	102,312	38.45	2,661	36.0
1987	23,239.00	13,277	13,095	0.4334	17,116	39.24	436	35.0
1988	20,333.00	11,317	11,162	0.4223	15,271	40.03	381	34.0
1989	124,840.00	67,638	66,711	0.4111	95,581	40.83	2,341	33.0
1990	70,198.00	36,985	36,478	0.3997	54,779	41.63	1,316	32.0
1991	264,678.00	135,470	133,613	0.3883	210,468	42.44	4,959	31.0
1992	76,763.00	38,127	37,604	0.3768	62,188	43.26	1,438	30.0
1993	74,999.00	36,105	35,610	0.3652	61,888	44.08	1,404	29.0
1994	202,347.00	94,303	93,010	0.3536	170,041	44.91	3,787	28.0
1995	240,866.11	108,523	107,035	0.3418	206,090	45.74	4,506	27.0
1996	609,784.00	265,238	261,602	0.3300	531,117	46.58	11,403	26.0
1997	242,471.00	101,663	100,269	0.3181	214,943	47.42	4,532	25.0
1998	563,945.00	227,544	224,425	0.3061	508,703	48.27	10,538	24.0
1999	175,583.00	68,056	67,123	0.2941	161,135	49.13	3,280	23.0
2000	8,983,992.00	3,338,522	3,292,762	0.2819	8,386,427	49.99	167,761	22.0
2001	1,677,510.00	596,412	588,237	0.2697	1,592,526	50.86	31,315	21.0
2002	167,941.99	56,992	56,210	0.2575	162,114	51.73	3,134	20.0

FortisBC

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 70
Net Salvage: -30%
Truncation Year:

Account #: 33300 - Water Wheels, Turbines and Generators - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2022

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	111,541.33	36,038	35,544	0.2451	109,459	52.60	2,081	19.0
2004	13,810,092.50	4,236,092	4,178,029	0.2327	13,775,091	53.48	257,559	18.0
2005	226,645.86	65,796	64,894	0.2202	229,746	54.37	4,226	17.0
2006	10,137,657.60	2,775,529	2,737,486	0.2077	10,441,469	55.26	188,959	16.0
2007	6,979,034.20	1,794,866	1,770,265	0.1951	7,302,480	56.15	130,049	15.0
2009	8,256,043.52	1,847,245	1,821,926	0.1698	8,910,931	57.95	153,763	13.0
2010	12,327,471.75	2,550,775	2,515,813	0.1570	13,509,901	58.86	229,533	12.0
2011	20,664,520.99	3,926,566	3,872,746	0.1442	22,991,131	59.77	384,670	11.0
2012	1,344,753.93	232,702	229,512	0.1313	1,518,668	60.68	25,027	10.0
2013	226,553.72	35,344	34,860	0.1184	259,660	61.60	4,215	9.0
2014	1,117,010.02	155,157	153,030	0.1054	1,299,083	62.52	20,778	8.0
2015	366,480.82	44,617	44,005	0.0924	432,420	63.44	6,816	7.0
2016	240,162.83	25,100	24,756	0.0793	287,456	64.37	4,466	6.0
2017	266,285.85	23,229	22,910	0.0662	323,261	65.30	4,950	5.0
2018	10,699,115.74	747,765	737,515	0.0530	13,171,335	66.24	198,853	4.0
2019	6,795,158.14	356,721	351,832	0.0398	8,481,874	67.17	126,269	3.0
2020	5,615,125.03	196,819	194,122	0.0266	7,105,541	68.11	104,321	2.0
2021	1,112,652.26	19,531	19,263	0.0133	1,427,185	69.05	20,667	1.0
2022	759,438.70	0	0	0.0000	987,270	70.00	14,104	0.0
TOTAL	122,271,003.31	29,553,288	29,148,212		129,804,092		2,279,083	

COMPOSITE ANNUAL ACCRUAL RATE	1.86%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	14.33
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	56.99

FortisBC

Account #: 33400 - Accessory Electrical Equipment - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 42
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	2,318,383.40	2,622,556	2,597,044	0.8962	300,935	3.99	75,391	62.0
1963	36,009.00	40,008	39,619	0.8802	5,392	4.67	1,155	59.0
1964	4,376.00	4,832	4,785	0.8747	685	4.90	140	58.0
1966	934.00	1,018	1,008	0.8634	159	5.38	30	56.0
1968	3,150.00	3,386	3,353	0.8515	585	5.88	99	54.0
1969	4,532.00	4,836	4,789	0.8453	876	6.15	143	53.0
1971	166,041.00	174,396	172,699	0.8321	34,852	6.71	5,195	51.0
1973	3,044.00	3,142	3,111	0.8176	694	7.32	95	49.0
1974	6,163.00	6,300	6,238	0.8098	1,465	7.65	191	48.0
1975	242.00	245	242	0.8016	60	8.00	7	47.0
1976	10,090.00	10,099	10,001	0.7929	2,612	8.37	312	46.0
1977	4,199.00	4,154	4,114	0.7838	1,135	8.76	130	45.0
1978	12,510.00	12,226	12,107	0.7742	3,531	9.16	385	44.0
1979	2,324.00	2,242	2,220	0.7641	685	9.59	71	43.0
1984	41,292.00	36,820	36,461	0.7064	15,154	12.04	1,259	38.0
1986	96,990.47	83,256	82,446	0.6800	38,792	13.16	2,948	36.0
1988	3,190.00	2,625	2,600	0.6519	1,388	14.35	97	34.0
1989	54,978.00	44,224	43,794	0.6373	24,928	14.97	1,665	33.0
1990	34,251.00	26,901	26,639	0.6222	16,174	15.61	1,036	32.0
1991	134,455.00	102,986	101,984	0.6068	66,084	16.26	4,063	31.0
1992	47,926.00	35,755	35,407	0.5910	24,500	16.93	1,447	30.0
1993	75,949.00	55,118	54,582	0.5749	40,355	17.62	2,291	29.0
1994	233.00	164	163	0.5585	129	18.31	7	28.0
1996	200,512.00	132,800	131,508	0.5247	119,132	19.75	6,033	26.0
1998	297,286.05	183,767	181,979	0.4897	189,629	21.23	8,932	24.0
1999	36,767.00	21,896	21,683	0.4718	24,276	21.99	1,104	23.0
2000	1,201,184.76	687,780	681,089	0.4536	820,392	22.76	36,043	22.0
2001	3,330,091.79	1,829,266	1,811,471	0.4352	2,351,144	23.54	99,866	21.0

FortisBC

Account #: 33400 - Accessory Electrical Equipment - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 42
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	286,368.26	150,544	149,079	0.4165	208,881	24.34	8,583	20.0
2003	196,323.46	98,512	97,554	0.3975	147,851	25.14	5,881	19.0
2004	5,259,126.66	2,511,562	2,487,130	0.3783	4,086,778	25.95	157,463	18.0
2005	104,954.72	47,548	47,086	0.3589	84,108	26.78	3,141	17.0
2006	2,100,809.02	899,636	890,884	0.3393	1,735,127	27.61	62,841	16.0
2007	2,772,544.74	1,117,724	1,106,851	0.3194	2,358,830	28.45	82,898	15.0
2008	527,543.72	199,296	197,357	0.2993	462,072	29.31	15,767	14.0
2009	4,883,068.59	1,719,658	1,702,929	0.2790	4,400,906	30.17	145,884	13.0
2010	5,819,300.59	1,898,790	1,880,319	0.2585	5,393,807	31.04	173,789	12.0
2011	6,648,755.68	1,995,851	1,976,436	0.2378	6,334,508	31.91	198,488	11.0
2012	3,473,708.77	951,254	942,000	0.2169	3,400,136	32.80	103,666	10.0
2013	541,805.27	133,978	132,675	0.1959	544,582	33.69	16,164	9.0
2014	890,608.10	196,393	194,482	0.1747	918,778	34.59	26,561	8.0
2015	550,876.65	106,617	105,580	0.1533	583,016	35.50	16,424	7.0
2016	116,767.94	19,428	19,239	0.1318	126,721	36.41	3,480	6.0
2017	422,538.43	58,753	58,181	0.1102	469,992	37.33	12,591	5.0
2018	3,847,006.07	429,080	424,906	0.0884	4,383,852	38.25	114,603	4.0
2019	1,755,743.61	147,257	145,824	0.0664	2,048,855	39.18	52,291	3.0
2020	2,042,655.65	114,498	113,384	0.0444	2,439,936	40.12	60,821	2.0
2021	553,662.87	15,555	15,404	0.0223	676,675	41.06	16,482	1.0
2022	802,053.01	0	0	0.0000	1,002,566	42.00	23,871	0.0

FortisBC

Account #: 33400 - Accessory Electrical Equipment - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 42
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	51,723,325.28	18,944,727	18,760,437		45,893,719		1,551,824	

COMPOSITE ANNUAL ACCRUAL RATE	3.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.36
COMPOSITE AVERAGE AGE (YEARS)	14.61
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.69

FortisBC

Account #: 33500 - Other Power Plant Equipment - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 45
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	296,699.41	301,503	311,534	1.0000	0	1.45	0	62.0
1966	3,794.00	3,724	3,857	0.9681	127	2.93	43	56.0
1974	920.00	851	881	0.9124	85	5.35	16	48.0
1975	1,560.00	1,429	1,480	0.9036	158	5.73	28	47.0
1976	13,034.00	11,817	12,236	0.8941	1,450	6.15	236	46.0
1977	21,030.00	18,847	19,515	0.8838	2,566	6.59	389	45.0
1978	20,835.00	18,437	19,091	0.8727	2,786	7.08	394	44.0
1979	5.00	4	5	0.8610	1	7.59	0	43.0
1982	309,056.20	257,020	266,135	0.8201	58,374	9.36	6,237	40.0
1984	61,166.00	48,993	50,731	0.7899	13,493	10.67	1,264	38.0
1985	83,345.00	65,431	67,751	0.7742	19,761	11.35	1,740	37.0
1986	296,355.09	227,834	235,914	0.7581	75,259	12.05	6,244	36.0
1987	150,893.78	113,492	117,517	0.7417	40,922	12.77	3,206	35.0
1988	148,774.00	109,364	113,243	0.7249	42,970	13.50	3,184	34.0
1989	149,348.00	107,186	110,988	0.7078	45,828	14.24	3,218	33.0
1990	383,592.00	268,476	277,998	0.6902	124,773	15.00	8,316	32.0
1991	167,474.00	114,168	118,217	0.6723	57,631	15.78	3,651	31.0
1992	40,941.00	27,148	28,111	0.6539	14,877	16.58	897	30.0
1993	190,147.39	122,482	126,826	0.6352	72,829	17.39	4,187	29.0
1994	234,783.00	146,693	151,896	0.6162	94,626	18.22	5,193	28.0
1995	258,143.00	156,203	161,744	0.5967	109,307	19.07	5,733	27.0
1996	378,152.00	221,235	229,081	0.5769	167,978	19.93	8,430	26.0
1997	570,774.00	322,289	333,720	0.5568	265,593	20.80	12,769	25.0
1998	2,167,667.66	1,179,116	1,220,936	0.5364	1,055,115	21.69	48,651	24.0
2002	495,110.01	226,973	235,023	0.4521	284,842	25.35	11,235	20.0
2003	18,238,607.57	7,960,607	8,242,950	0.4304	10,907,588	26.29	414,830	19.0
2004	10,403,339.19	4,310,328	4,463,205	0.4086	6,460,301	27.24	237,133	18.0
2005	922,110.20	361,462	374,283	0.3866	593,933	28.20	21,061	17.0

FortisBC

Account #: 33500 - Other Power Plant Equipment - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 45
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2006	777,610.65	287,341	297,533	0.3644	518,959	29.16	17,795	16.0
2007	684,155.32	237,340	245,758	0.3421	472,605	30.13	15,684	15.0
2008	373,290.15	121,015	125,307	0.3197	266,648	31.11	8,572	14.0
2009	2,308,438.00	695,657	720,330	0.2972	1,703,530	32.08	53,095	13.0
2010	755,928.57	210,477	217,942	0.2746	575,783	33.07	17,413	12.0
2011	259,214.50	66,214	68,563	0.2519	203,613	34.05	5,979	11.0
2012	1,503,860.41	349,475	361,870	0.2292	1,217,183	35.04	34,736	10.0
2013	126,103.57	26,390	27,326	0.2064	105,082	36.03	2,916	9.0
2014	1,231,984.12	229,296	237,429	0.1835	1,056,155	37.02	28,527	8.0
2015	335,460.38	54,655	56,594	0.1607	295,640	38.02	7,776	7.0
2016	27,619.85	3,859	3,995	0.1378	25,005	39.01	641	6.0
2017	462,024.16	53,806	55,714	0.1148	429,411	40.01	10,733	5.0
2018	439,174.88	40,927	42,378	0.0919	418,755	41.01	10,212	4.0
2019	349,638.39	24,442	25,309	0.0689	341,811	42.00	8,138	3.0
2020	347,432.34	16,194	16,769	0.0460	348,035	43.00	8,093	2.0
2021	4,708.22	110	114	0.0230	4,830	44.00	110	1.0
2022	34.10	0	0	0.0000	36	45.00	1	0.0
TOTAL	45,994,334.11	19,120,312	19,797,799		28,496,252		1,038,706	

COMPOSITE ANNUAL ACCRUAL RATE 2.26%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.43

COMPOSITE AVERAGE AGE (YEARS) 18.31

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 27.18

FortisBC

Account #: 33600 - Roads, Railroads and Bridges - Generation Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	589,100.00	305,189	277,711	0.4714	311,389	36.15	8,615	40.0
1984	24,405.00	12,057	10,971	0.4496	13,434	37.95	354	38.0
1988	12,362.00	5,500	5,005	0.4049	7,357	41.63	177	34.0
1989	33,467.00	14,473	13,169	0.3935	20,298	42.57	477	33.0
1990	124,442.00	52,251	47,547	0.3821	76,895	43.51	1,767	32.0
1991	10,933.00	4,453	4,052	0.3706	6,881	44.45	155	31.0
1992	100,650.00	39,716	36,140	0.3591	64,510	45.41	1,421	30.0
1999	147,710.00	44,964	40,915	0.2770	106,795	52.17	2,047	23.0
2003	2,238.48	564	513	0.2294	1,725	56.10	31	19.0
2004	918.03	219	200	0.2174	718	57.08	13	18.0
2006	6,819.52	1,449	1,319	0.1934	5,501	59.06	93	16.0
2008	234,389.25	43,616	39,689	0.1693	194,701	61.04	3,190	14.0
TOTAL	1,287,434.28	524,450	477,231		810,203		18,340	

COMPOSITE ANNUAL ACCRUAL RATE	1.42%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.37
COMPOSITE AVERAGE AGE (YEARS)	31.23
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	44.45

FortisBC

Account #: 35020 - Surface and Mineral - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	71,278.06	55,433	61,445	0.8621	9,833	16.67	590	65.0
1958	34,551.79	26,565	29,447	0.8523	5,105	17.34	294	64.0
1959	2,763.34	2,100	2,328	0.8423	436	18.01	24	63.0
1960	582.44	437	485	0.8322	98	18.69	5	62.0
1961	2,850.33	2,114	2,343	0.8220	507	19.38	26	61.0
1962	20,156.50	14,759	16,360	0.8116	3,797	20.08	189	60.0
1963	31,260.31	22,593	25,043	0.8011	6,217	20.80	299	59.0
1964	16,993.61	12,119	13,433	0.7905	3,561	21.52	165	58.0
1965	19,273.35	13,557	15,027	0.7797	4,246	22.24	191	57.0
1966	3,950.77	2,740	3,037	0.7688	914	22.98	40	56.0
1967	2,359.50	1,613	1,788	0.7577	572	23.73	24	55.0
1968	595.99	401	445	0.7465	151	24.49	6	54.0
1969	1,196.56	794	880	0.7351	317	25.26	13	53.0
1970	869.76	568	629	0.7235	240	26.04	9	52.0
1971	1,642.63	1,055	1,169	0.7119	473	26.83	18	51.0
1972	479.26	303	336	0.7001	144	27.63	5	50.0
1973	832.69	517	573	0.6881	260	28.44	9	49.0
1974	4,497.72	2,743	3,040	0.6760	1,457	29.26	50	48.0
1975	8,196.07	4,908	5,440	0.6637	2,756	30.09	92	47.0
1976	85,868.53	50,456	55,928	0.6513	29,940	30.93	968	46.0
1977	10,063.09	5,799	6,428	0.6388	3,635	31.78	114	45.0
1978	10,831.78	6,119	6,782	0.6261	4,050	32.63	124	44.0
1979	26,493.79	14,660	16,250	0.6133	10,244	33.50	306	43.0
1980	51,385.22	27,835	30,854	0.6004	20,531	34.37	597	42.0
1981	19,722.84	10,452	11,585	0.5874	8,138	35.26	231	41.0
1982	41,635.32	21,570	23,909	0.5742	17,726	36.15	490	40.0
1983	50,103.21	25,357	28,108	0.5610	21,995	37.04	594	39.0
1984	137,982.87	68,168	75,562	0.5476	62,421	37.95	1,645	38.0

FortisBC

Account #: 35020 - Surface and Mineral - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	104,391.94	50,305	55,761	0.5341	48,631	38.86	1,251	37.0
1986	130,939.68	61,496	68,166	0.5206	62,774	39.78	1,578	36.0
1987	80,226.62	36,689	40,669	0.5069	39,558	40.70	972	35.0
1988	96,448.17	42,911	47,565	0.4932	48,883	41.63	1,174	34.0
1989	49,216.47	21,283	23,592	0.4793	25,625	42.57	602	33.0
1990	58,928.31	24,743	27,427	0.4654	31,501	43.51	724	32.0
1991	65,498.62	26,676	29,569	0.4514	35,930	44.45	808	31.0
1992	50,101.05	19,770	21,914	0.4374	28,187	45.41	621	30.0
1993	61,506.44	23,486	26,034	0.4233	35,473	46.36	765	29.0
1994	309,831.48	114,346	126,748	0.4091	183,083	47.32	3,869	28.0
1995	50,913.71	18,136	20,104	0.3949	30,810	48.28	638	27.0
1996	316,525.13	108,671	120,458	0.3806	196,067	49.25	3,981	26.0
1997	74,245.06	24,530	27,190	0.3662	47,055	50.22	937	25.0
1998	212,930.29	67,588	74,919	0.3518	138,011	51.19	2,696	24.0
1999	78,129.38	23,783	26,363	0.3374	51,767	52.17	992	23.0
2000	225,136.61	65,596	72,710	0.3230	152,426	53.15	2,868	22.0
2001	120,078.37	33,416	37,040	0.3085	83,038	54.13	1,534	21.0
2003	289,525.31	72,974	80,889	0.2794	208,637	56.10	3,719	19.0
2004	169,460.57	40,483	44,874	0.2648	124,587	57.08	2,183	18.0
2005	1,089,610.87	245,942	272,618	0.2502	816,993	58.07	14,069	17.0
2006	71,615.33	15,220	16,871	0.2356	54,745	59.06	927	16.0
2007	1,483,559.61	295,689	327,760	0.2209	1,155,800	60.05	19,247	15.0
2008	1,114,560.16	207,400	229,895	0.2063	884,665	61.04	14,492	14.0
2009	450,433.59	77,854	86,298	0.1916	364,136	62.04	5,870	13.0
2010	437,550.01	69,828	77,402	0.1769	360,148	63.03	5,714	12.0
2011	86,283.89	12,625	13,995	0.1622	72,289	64.03	1,129	11.0
2012	44,631.51	5,938	6,582	0.1475	38,049	65.02	585	10.0
2013	12,577.56	1,506	1,670	0.1328	10,908	66.02	165	9.0

FortisBC

Account #: 35020 - Surface and Mineral - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	53,530.73	5,700	6,318	0.1180	47,213	67.01	705	8.0
2015	42,496.52	3,960	4,390	0.1033	38,107	68.01	560	7.0
2016	34,749.10	2,776	3,077	0.0885	31,672	69.01	459	6.0
2017	48,986.21	3,261	3,615	0.0738	45,371	70.01	648	5.0
2018	44,071.29	2,348	2,602	0.0590	41,469	71.00	584	4.0
2019	16,816.64	672	745	0.0443	16,072	72.00	223	3.0
2020	72,073.47	1,920	2,128	0.0295	69,945	73.00	958	2.0
2021	111,178.25	1,481	1,641	0.0148	109,537	74.00	1,480	1.0
2022	32,130.74	0	0	0.0000	32,131	75.00	428	0.0
TOTAL	8,449,306.02	2,226,733	2,468,250		5,981,056		107,273	

COMPOSITE ANNUAL ACCRUAL RATE 1.27%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.29

COMPOSITE AVERAGE AGE (YEARS) 20.10

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 55.23

FortisBC

Account #: 35300 - Substation Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 52
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	56,830.00	68,037	73,879	1.0000	0	4.11	0	62.0
1961	142.00	169	185	1.0000	0	4.39	0	61.0
1964	12.00	14	15	0.9827	0	5.30	0	58.0
1965	6,772.00	7,850	8,590	0.9757	214	5.63	38	57.0
1966	383,092.29	440,739	482,270	0.9684	15,750	5.98	2,633	56.0
1967	25,270.00	28,839	31,556	0.9606	1,295	6.35	204	55.0
1968	47.00	53	58	0.9522	3	6.75	0	54.0
1969	458,346.17	513,732	562,142	0.9434	33,708	7.17	4,704	53.0
1970	9,963.00	11,055	12,097	0.9340	855	7.62	112	52.0
1971	16,270.00	17,858	19,541	0.9239	1,610	8.10	199	51.0
1972	383,550.00	416,073	455,280	0.9131	43,335	8.61	5,034	50.0
1973	4,006.00	4,291	4,696	0.9017	512	9.15	56	49.0
1974	1,472.00	1,556	1,702	0.8896	211	9.73	22	48.0
1975	84,593.00	88,128	96,433	0.8769	13,538	10.33	1,311	47.0
1976	12,018.00	12,332	13,494	0.8637	2,130	10.96	194	46.0
1977	1,346,375.25	1,359,674	1,487,799	0.8500	262,489	11.60	22,619	45.0
1978	1,358,311.09	1,349,100	1,476,227	0.8360	289,577	12.27	23,598	44.0
1979	1,579,780.00	1,542,183	1,687,505	0.8217	366,209	12.95	28,274	43.0
1980	168,265.00	161,343	176,546	0.8071	42,198	13.65	3,092	42.0
1981	15,936.00	14,999	16,412	0.7922	4,305	14.35	300	41.0
1982	2,719,436.00	2,510,523	2,747,093	0.7771	788,174	15.07	52,291	40.0
1983	76,549.00	69,262	75,789	0.7616	23,725	15.81	1,501	39.0
1984	684,890.31	606,864	664,050	0.7458	226,307	16.56	13,668	38.0
1985	3,610,718.91	3,130,407	3,425,389	0.7297	1,268,545	17.32	73,238	37.0
1986	487,289.00	412,984	451,900	0.7134	181,576	18.10	10,032	36.0
1987	2,513,283.45	2,080,217	2,276,239	0.6967	991,029	18.89	52,456	35.0
1988	35,160.00	28,392	31,067	0.6797	14,641	19.70	743	34.0
1989	234,355.00	184,432	201,811	0.6624	102,850	20.52	5,012	33.0

FortisBC

Account #: 35300 - Substation Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 52
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1990	198,898.00	152,376	166,735	0.6448	91,832	21.36	4,300	32.0
1991	740,444.00	551,556	603,530	0.6270	359,048	22.20	16,170	31.0
1992	568,108.00	410,955	449,680	0.6089	288,861	23.07	12,524	30.0
1993	1,435,439.47	1,007,025	1,101,918	0.5905	764,153	23.94	31,922	29.0
1994	658,881.65	447,659	489,843	0.5719	366,703	24.82	14,773	28.0
1995	1,416,953.00	930,973	1,018,700	0.5530	823,339	25.72	32,013	27.0
1996	3,706,520.00	2,351,291	2,572,856	0.5340	2,245,620	26.63	84,341	26.0
1997	457,406.00	279,684	306,039	0.5147	288,588	27.54	10,478	25.0
1998	809,687.00	476,357	521,245	0.4952	531,348	28.47	18,665	24.0
1999	350,200.00	197,855	216,499	0.4756	238,761	29.40	8,121	23.0
2000	597,805.28	323,676	354,176	0.4557	422,971	30.34	13,940	22.0
2001	1,435,971.84	743,439	813,495	0.4358	1,053,269	31.29	33,660	21.0
2002	43,751.97	21,607	23,643	0.4157	33,235	32.25	1,031	20.0
2003	32,637,225.81	15,333,877	16,778,810	0.3955	25,649,584	33.21	772,418	19.0
2004	9,730,205.02	4,336,503	4,745,138	0.3751	7,904,129	34.17	231,297	18.0
2005	50,036,642.81	21,085,605	23,072,531	0.3547	41,975,105	35.14	1,194,379	17.0
2006	18,927,523.18	7,514,744	8,222,869	0.3342	16,382,911	36.12	453,583	16.0
2007	9,563,061.29	3,562,802	3,898,529	0.3136	8,533,450	37.10	230,027	15.0
2008	2,220,920.31	772,899	845,731	0.2929	2,041,466	38.08	53,610	14.0
2009	2,849,461.85	921,480	1,008,312	0.2722	2,695,988	39.06	69,014	13.0
2010	10,145,633.44	3,030,529	3,316,100	0.2514	9,873,223	40.05	246,511	12.0
2011	41,062,019.64	11,249,574	12,309,637	0.2306	41,070,988	41.04	1,000,721	11.0
2012	6,303,160.17	1,570,638	1,718,642	0.2097	6,475,467	42.03	154,058	10.0
2013	1,666,020.09	373,790	409,013	0.1888	1,756,813	43.03	40,832	9.0
2014	9,796,553.07	1,954,479	2,138,653	0.1679	10,596,866	44.02	240,730	8.0
2015	1,733,514.52	302,715	331,240	0.1470	1,922,329	45.01	42,704	7.0
2016	1,673,424.18	250,545	274,155	0.1260	1,901,297	46.01	41,322	6.0
2017	3,453,191.06	430,945	471,554	0.1050	4,017,595	47.01	85,466	5.0

FortisBC

Account #: 35300 - Substation Equipment - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 52
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2018	7,273,124.30	726,269	794,707	0.0841	8,660,355	48.01	180,402	4.0
2019	2,690,891.65	201,559	220,552	0.0630	3,277,607	49.00	66,885	3.0
2020	2,126,961.92	106,223	116,233	0.0420	2,648,818	50.00	52,974	2.0
2021	8,264,689.35	206,370	225,816	0.0210	10,518,280	51.00	206,236	1.0
2022	23,340,135.00	0	0	0.0000	30,342,176	52.00	583,500	0.0
TOTAL	274,187,157.34	96,887,108	106,016,347		250,426,957		6,529,938	

COMPOSITE ANNUAL ACCRUAL RATE	2.38%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	14.45
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	37.87

FortisBC

Account #: 35500 - Poles, Towers and Fixtures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -40%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	219,250.78	258,194	257,648	0.8394	49,303	7.94	6,208	65.0
1958	168,996.12	197,469	197,051	0.8329	39,543	8.27	4,782	64.0
1959	90,431.20	104,822	104,600	0.8262	22,003	8.60	2,558	63.0
1960	9,833.95	11,305	11,281	0.8194	2,487	8.94	278	62.0
1961	2,985.80	3,403	3,396	0.8124	784	9.29	84	61.0
1962	176,321.75	199,189	198,768	0.8052	48,083	9.65	4,981	60.0
1963	272,982.95	305,565	304,919	0.7978	77,258	10.02	7,708	59.0
1964	115,082.83	127,597	127,327	0.7903	33,789	10.40	3,248	58.0
1965	25,094.17	27,549	27,491	0.7825	7,641	10.79	708	57.0
1966	33,086.52	35,952	35,876	0.7745	10,445	11.19	933	56.0
1967	19,091.25	20,525	20,482	0.7663	6,246	11.60	538	55.0
1968	2,958.59	3,146	3,139	0.7579	1,003	12.03	83	54.0
1969	1,071.19	1,126	1,124	0.7492	376	12.46	30	53.0
1970	601.60	625	624	0.7403	219	12.91	17	52.0
1971	2,317.50	2,377	2,372	0.7312	872	13.36	65	51.0
1972	3,819.70	3,868	3,860	0.7218	1,488	13.83	108	50.0
1973	1,047.59	1,047	1,045	0.7122	422	14.32	29	49.0
1974	30,071.68	29,631	29,569	0.7023	12,532	14.81	846	48.0
1975	92,277.62	89,621	89,431	0.6923	39,758	15.31	2,596	47.0
1976	971,859.43	929,799	927,833	0.6819	432,770	15.83	27,336	46.0
1977	53,720.34	50,600	50,493	0.6714	24,716	16.36	1,511	45.0
1978	86,619.23	80,275	80,105	0.6606	41,161	16.90	2,435	44.0
1979	51,347.49	46,792	46,693	0.6495	25,193	17.45	1,443	43.0
1980	438,751.51	392,897	392,067	0.6383	222,186	18.02	12,331	42.0
1981	166,776.50	146,659	146,348	0.6268	87,139	18.59	4,686	41.0
1982	423,491.13	365,446	364,673	0.6151	228,214	19.18	11,898	40.0
1983	570,543.21	482,788	481,767	0.6031	316,993	19.78	16,027	39.0
1984	1,396,709.34	1,158,061	1,155,612	0.5910	799,781	20.39	39,228	38.0

FortisBC

Account #: 35500 - Poles, Towers and Fixtures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -40%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	987,147.37	801,343	799,649	0.5786	582,357	21.01	27,721	37.0
1986	1,404,861.44	1,115,629	1,113,270	0.5660	853,536	21.64	39,445	36.0
1987	495,272.29	384,416	383,603	0.5532	309,778	22.28	13,904	35.0
1988	784,777.60	594,808	593,551	0.5402	505,138	22.93	22,029	34.0
1989	330,215.38	244,165	243,649	0.5270	218,653	23.59	9,268	33.0
1990	494,249.24	356,162	355,409	0.5136	336,540	24.26	13,870	32.0
1991	472,759.70	331,660	330,959	0.5000	330,905	24.94	13,265	31.0
1992	402,942.89	274,888	274,307	0.4863	289,814	25.64	11,305	30.0
1993	462,889.95	306,710	306,061	0.4723	341,984	26.34	12,986	29.0
1994	3,418,367.89	2,197,116	2,192,470	0.4581	2,593,245	27.05	95,886	28.0
1995	566,373.73	352,639	351,893	0.4438	441,030	27.76	15,885	27.0
1996	3,629,040.57	2,185,646	2,181,024	0.4293	2,899,632	28.49	101,775	26.0
1997	837,746.19	487,285	486,255	0.4146	686,590	29.23	23,492	25.0
1998	2,392,273.60	1,341,636	1,338,799	0.3997	2,010,384	29.97	67,078	24.0
1999	845,500.99	456,355	455,390	0.3847	728,312	30.72	23,705	23.0
2000	2,576,329.36	1,335,671	1,332,847	0.3695	2,274,015	31.48	72,227	22.0
2001	1,367,064.87	679,307	677,871	0.3542	1,236,020	32.25	38,322	21.0
2002	434,792.97	206,596	206,159	0.3387	402,552	33.03	12,187	20.0
2003	8,463,226.89	3,835,456	3,827,345	0.3230	8,021,173	33.81	237,210	19.0
2004	6,981,127.86	3,008,941	3,002,578	0.3072	6,771,001	34.61	195,655	18.0
2005	5,677,730.83	2,320,048	2,315,141	0.2913	5,633,682	35.41	159,115	17.0
2006	2,760,083.55	1,065,474	1,063,221	0.2752	2,800,896	36.21	77,345	16.0
2007	7,287,093.39	2,646,940	2,641,342	0.2589	7,560,589	37.03	204,190	15.0
2008	3,070,855.07	1,044,850	1,042,641	0.2425	3,256,556	37.85	86,042	14.0
2009	4,498,334.78	1,426,267	1,423,251	0.2260	4,874,418	38.68	126,031	13.0
2010	20,375,227.14	5,984,110	5,971,456	0.2093	22,553,862	39.51	570,827	12.0
2011	2,845,486.69	768,681	767,056	0.1925	3,216,626	40.35	79,714	11.0
2012	2,234,254.45	550,532	549,368	0.1756	2,578,588	41.20	62,587	10.0

FortisBC

Account #: 35500 - Poles, Towers and Fixtures - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 50
Net Salvage: -40%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	579,886.16	129,021	128,748	0.1586	683,093	42.05	16,243	9.0
2014	8,846,707.51	1,755,261	1,751,550	0.1414	10,633,841	42.91	247,794	8.0
2015	3,204,973.82	558,162	556,982	0.1241	3,929,981	43.78	89,766	7.0
2016	3,449,165.92	516,467	515,375	0.1067	4,313,457	44.65	96,601	6.0
2017	2,114,414.52	264,636	264,076	0.0892	2,696,104	45.53	59,216	5.0
2018	2,860,713.77	287,280	286,673	0.0716	3,718,327	46.41	80,113	4.0
2019	2,190,577.18	165,464	165,114	0.0538	2,901,694	47.30	61,344	3.0
2020	3,707,962.29	187,246	186,850	0.0360	5,004,298	48.20	103,831	2.0
2021	6,052,924.24	153,245	152,921	0.0180	8,321,173	49.10	169,488	1.0
2022	5,334,259.33	0	0	0.0000	7,467,963	50.00	149,359	0.0
TOTAL	129,864,752.39	45,396,441	45,300,443		136,510,210		3,639,516	

COMPOSITE ANNUAL ACCRUAL RATE 2.80%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.35

COMPOSITE AVERAGE AGE (YEARS) 14.93

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 37.52

FortisBC

Account #: 35600 - Conductors and Devices - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 51
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	281,178.49	316,122	285,287	0.7516	94,304	8.53	11,059	65.0
1958	179,371.02	200,068	180,553	0.7456	61,598	8.86	6,950	64.0
1959	96,685.51	106,962	96,529	0.7395	33,997	9.21	3,692	63.0
1960	10,752.20	11,795	10,644	0.7333	3,871	9.56	405	62.0
1961	7,130.63	7,754	6,997	0.7269	2,629	9.92	265	61.0
1962	175,143.41	188,728	170,320	0.7203	66,124	10.29	6,425	60.0
1963	276,711.54	295,385	266,572	0.7136	106,988	10.67	10,024	59.0
1964	119,989.58	126,844	114,472	0.7067	47,514	11.06	4,294	58.0
1965	26,131.96	27,347	24,679	0.6996	10,599	11.47	924	57.0
1966	35,000.72	36,246	32,710	0.6923	14,541	11.88	1,224	56.0
1967	22,491.67	23,039	20,792	0.6848	9,572	12.30	778	55.0
1968	3,045.31	3,084	2,784	0.6771	1,328	12.74	104	54.0
1969	1,102.59	1,104	996	0.6692	492	13.18	37	53.0
1970	619.24	612	553	0.6611	283	13.64	21	52.0
1971	2,385.44	2,329	2,102	0.6528	1,118	14.11	79	51.0
1972	3,931.67	3,789	3,419	0.6442	1,888	14.59	129	50.0
1973	1,078.30	1,025	925	0.6355	531	15.09	35	49.0
1974	30,953.22	29,013	26,183	0.6266	15,604	15.59	1,001	48.0
1975	95,643.47	88,340	79,723	0.6174	49,396	16.11	3,067	47.0
1976	1,006,391.69	915,473	826,176	0.6081	532,453	16.64	32,008	46.0
1977	49,992.86	44,762	40,396	0.5985	27,094	17.17	1,578	45.0
1978	54,826.53	48,290	43,580	0.5888	30,436	17.73	1,717	44.0
1979	119,633.28	103,590	93,485	0.5788	68,020	18.29	3,719	43.0
1980	556,044.63	473,031	426,891	0.5687	323,770	18.86	17,165	42.0
1981	171,665.47	143,379	129,394	0.5583	102,354	19.45	5,263	41.0
1982	435,905.59	357,205	322,362	0.5478	266,110	20.04	13,277	40.0
1983	595,647.07	478,541	431,863	0.5371	372,260	20.65	18,028	39.0
1984	1,438,281.89	1,132,010	1,021,592	0.5261	920,089	21.27	43,264	38.0

FortisBC

Account #: 35600 - Conductors and Devices - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 51
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	1,104,056.99	850,610	767,640	0.5150	722,837	21.89	33,015	37.0
1986	1,443,598.62	1,087,824	981,715	0.5037	967,143	22.53	42,922	36.0
1987	552,485.18	406,846	367,161	0.4923	378,694	23.18	16,337	35.0
1988	806,421.49	579,792	523,238	0.4806	565,431	23.84	23,719	34.0
1989	339,895.51	238,365	215,114	0.4688	243,745	24.51	9,946	33.0
1990	508,737.92	347,647	313,737	0.4568	373,059	25.18	14,813	32.0
1991	486,618.42	323,682	292,110	0.4447	364,825	25.87	14,101	31.0
1992	414,755.01	268,237	242,073	0.4323	317,847	26.57	11,964	30.0
1993	476,459.36	299,247	270,058	0.4199	373,162	27.27	13,682	29.0
1994	3,664,537.69	2,232,279	2,014,538	0.4072	2,932,588	27.99	104,782	28.0
1995	582,976.71	343,967	310,415	0.3944	476,603	28.71	16,600	27.0
1996	3,773,458.85	2,153,329	1,943,289	0.3815	3,150,880	29.44	107,020	26.0
1997	862,304.34	475,182	428,831	0.3684	735,280	30.18	24,361	25.0
1998	2,463,135.06	1,308,537	1,180,899	0.3551	2,144,333	30.93	69,327	24.0
1999	904,695.72	462,501	417,387	0.3417	803,952	31.69	25,372	23.0
2000	2,643,304.16	1,297,824	1,171,232	0.3282	2,397,229	32.45	73,871	22.0
2001	1,384,679.17	651,550	587,996	0.3146	1,281,321	33.22	38,566	21.0
2002	452,321.19	203,497	183,648	0.3007	426,986	34.00	12,557	20.0
2003	8,468,839.19	3,633,559	3,279,134	0.2868	8,153,799	34.79	234,362	19.0
2004	7,223,738.19	2,947,355	2,659,864	0.2727	7,092,183	35.59	199,295	18.0
2005	4,214,035.08	1,629,893	1,470,910	0.2586	4,218,037	36.39	115,917	17.0
2006	2,553,606.24	932,978	841,974	0.2442	2,605,395	37.20	70,042	16.0
2007	5,568,549.12	1,914,202	1,727,487	0.2298	5,790,054	38.01	152,315	15.0
2008	3,067,051.68	987,489	891,167	0.2152	3,249,352	38.84	83,667	14.0
2009	4,734,616.55	1,420,405	1,281,855	0.2005	5,109,877	39.67	128,821	13.0
2010	20,375,342.07	5,661,652	5,109,403	0.1858	22,397,309	40.50	552,982	12.0
2011	2,798,083.59	715,082	645,331	0.1708	3,132,081	41.35	75,754	11.0
2012	2,235,444.73	521,056	470,231	0.1558	2,547,619	42.19	60,378	10.0

FortisBC

Account #: 35600 - Conductors and Devices - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life

Survivor Curve: R2

ASL: 51

Net Salvage: -35%

Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	979,476.92	206,133	186,027	0.1407	1,136,267	43.05	26,394	9.0
2014	7,610,667.41	1,428,195	1,288,886	0.1254	8,985,515	43.91	204,631	8.0
2015	3,411,785.89	561,941	507,128	0.1101	4,098,782	44.78	91,536	7.0
2016	3,480,349.90	492,827	444,756	0.0947	4,253,717	45.65	93,180	6.0
2017	2,114,706.99	250,278	225,865	0.0791	2,628,989	46.53	56,502	5.0
2018	2,860,690.04	271,636	245,140	0.0635	3,616,792	47.41	76,283	4.0
2019	2,190,572.80	156,444	141,184	0.0477	2,816,089	48.30	58,302	3.0
2020	3,707,954.11	177,027	159,759	0.0319	4,845,979	49.20	98,503	2.0
2021	6,052,918.83	144,871	130,740	0.0160	8,040,701	50.10	160,506	1.0
2022	5,334,249.09	0	0	0.0000	7,201,236	51.00	141,200	0.0
TOTAL	127,644,854.79	42,749,809	38,579,901		133,740,653		3,520,057	

COMPOSITE ANNUAL ACCRUAL RATE 2.76%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.30

COMPOSITE AVERAGE AGE (YEARS) 15.14

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 38.35

FortisBC

Account #: 35900 - Roads and Trails - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	4,051.98	3,656	4,052	1.0000	0	4.88	0	65.0
1958	1,964.19	1,762	1,953	0.9942	11	5.15	2	64.0
1959	540.81	482	534	0.9881	6	5.42	1	63.0
1960	74.44	66	73	0.9820	1	5.70	0	62.0
1961	162.04	143	158	0.9756	4	5.99	1	61.0
1962	1,145.84	1,002	1,110	0.9690	36	6.29	6	60.0
1963	1,777.07	1,543	1,710	0.9621	67	6.60	10	59.0
1964	966.04	832	922	0.9549	44	6.92	6	58.0
1965	1,095.64	937	1,038	0.9474	58	7.26	8	57.0
1966	227.59	193	214	0.9396	14	7.61	2	56.0
1967	134.14	113	125	0.9314	9	7.98	1	55.0
1968	33.89	28	31	0.9230	3	8.36	0	54.0
1969	68.02	56	62	0.9140	6	8.77	1	53.0
1970	49.43	40	45	0.9045	5	9.19	1	52.0
1971	93.39	75	84	0.8947	10	9.63	1	51.0
1972	27.25	22	24	0.8848	3	10.09	0	50.0
1973	47.34	37	41	0.8739	6	10.57	1	49.0
1974	255.71	199	221	0.8629	35	11.07	3	48.0
1975	465.91	358	397	0.8515	69	11.58	6	47.0
1976	4,881.41	3,698	4,098	0.8396	783	12.12	65	46.0
1977	572.07	427	473	0.8273	99	12.68	8	45.0
1978	615.76	453	502	0.8146	114	13.25	9	44.0
1979	1,506.11	1,089	1,207	0.8015	299	13.84	22	43.0
1980	2,921.12	2,077	2,302	0.7881	619	14.45	43	42.0
1981	1,121.19	783	868	0.7742	253	15.07	17	41.0
1982	2,366.86	1,623	1,799	0.7601	568	15.71	36	40.0
1983	2,993.83	2,014	2,232	0.7455	762	16.37	47	39.0
1984	7,843.97	5,171	5,731	0.7307	2,113	17.04	124	38.0

FortisBC

Account #: 35900 - Roads and Trails - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	5,934.42	3,831	4,246	0.7155	1,688	17.72	95	37.0
1986	7,443.59	4,701	5,210	0.7000	2,233	18.42	121	36.0
1987	4,585.54	2,831	3,137	0.6842	1,448	19.13	76	35.0
1988	5,482.85	3,306	3,663	0.6681	1,819	19.86	92	34.0
1989	2,797.83	1,646	1,824	0.6518	974	20.59	47	33.0
1990	3,349.93	1,920	2,128	0.6352	1,222	21.34	57	32.0
1991	3,723.43	2,077	2,302	0.6183	1,421	22.10	64	31.0
1992	2,249.64	1,220	1,353	0.6012	897	22.88	39	30.0
1993	3,496.50	1,842	2,041	0.5839	1,455	23.66	62	29.0
1994	17,613.14	8,999	9,974	0.5663	7,639	24.45	312	28.0
1995	2,894.32	1,432	1,587	0.5484	1,307	25.26	52	27.0
1996	18,011.74	8,620	9,553	0.5304	8,459	26.07	324	26.0
1997	4,220.63	1,950	2,161	0.5121	2,059	26.90	77	25.0
1998	12,086.53	5,383	5,966	0.4936	6,121	27.73	221	24.0
1999	4,505.92	1,931	2,140	0.4749	2,366	28.58	83	23.0
2000	12,734.01	5,239	5,806	0.4560	6,928	29.43	235	22.0
2001	6,467.55	2,549	2,825	0.4368	3,642	30.29	120	21.0
2003	203,814.63	73,193	81,117	0.3980	122,697	32.04	3,829	19.0
2004	400,777.56	136,801	151,611	0.3783	249,166	32.93	7,566	18.0
2005	57,486.72	18,591	20,604	0.3584	36,883	33.83	1,090	17.0
2009	304,250.00	76,105	84,344	0.2772	219,906	37.49	5,865	13.0

FortisBC

Account #: 35900 - Roads and Trails - Transmission Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	1,121,929.52	393,049	435,601		686,328		20,848	

COMPOSITE ANNUAL ACCRUAL RATE	1.86%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	18.82
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	32.48

FortisBC

Account #: 36020 - Surface and Mineral - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	8,862.06	6,653	8,019	0.9049	843	18.69	45	62.0
1961	512.83	380	458	0.8937	55	19.38	3	61.0
1962	689.10	505	608	0.8825	81	20.08	4	60.0
1963	832.63	602	725	0.8710	107	20.80	5	59.0
1964	678.06	484	583	0.8595	95	21.52	4	58.0
1965	1,698.13	1,194	1,440	0.8478	259	22.24	12	57.0
1966	942.31	654	788	0.8359	155	22.98	7	56.0
1967	956.96	654	788	0.8238	169	23.73	7	55.0
1968	1,013.01	682	822	0.8116	191	24.49	8	54.0
1969	1,031.77	684	825	0.7992	207	25.26	8	53.0
1970	978.30	639	770	0.7867	209	26.04	8	52.0
1971	1,052.12	676	814	0.7740	238	26.83	9	51.0
1972	1,380.94	872	1,051	0.7612	330	27.63	12	50.0
1973	1,472.18	914	1,101	0.7481	371	28.44	13	49.0
1974	2,365.72	1,443	1,739	0.7350	627	29.26	21	48.0
1975	656,480.53	393,081	473,749	0.7216	182,732	30.09	6,072	47.0
1976	4,329.44	2,544	3,066	0.7082	1,263	30.93	41	46.0
1977	4,255.93	2,453	2,956	0.6946	1,300	31.78	41	45.0
1978	5,916.12	3,342	4,028	0.6808	1,888	32.63	58	44.0
1979	5,230.62	2,894	3,488	0.6669	1,742	33.50	52	43.0
1980	6,856.02	3,714	4,476	0.6529	2,380	34.37	69	42.0
1981	9,120.39	4,833	5,825	0.6387	3,295	35.26	93	41.0
1982	8,156.20	4,225	5,093	0.6244	3,064	36.15	85	40.0
1983	6,558.69	3,319	4,001	0.6100	2,558	37.04	69	39.0
1984	6,495.14	3,209	3,867	0.5954	2,628	37.95	69	38.0
1985	6,967.88	3,358	4,047	0.5808	2,921	38.86	75	37.0
1986	6,955.58	3,267	3,937	0.5660	3,019	39.78	76	36.0
1987	6,008.60	2,748	3,312	0.5512	2,697	40.70	66	35.0

FortisBC

Account #: 36020 - Surface and Mineral - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	7,422.32	3,302	3,980	0.5362	3,442	41.63	83	34.0
1989	8,438.39	3,649	4,398	0.5212	4,040	42.57	95	33.0
1990	10,168.89	4,270	5,146	0.5061	5,023	43.51	115	32.0
1991	10,696.00	4,356	5,250	0.4908	5,446	44.45	123	31.0
1992	9,900.16	3,907	4,708	0.4756	5,192	45.41	114	30.0
1993	12,880.28	4,918	5,928	0.4602	6,953	46.36	150	29.0
1994	17,255.09	6,368	7,675	0.4448	9,580	47.32	202	28.0
1995	17,467.66	6,222	7,499	0.4293	9,968	48.28	206	27.0
1996	12,259.58	4,209	5,073	0.4138	7,187	49.25	146	26.0
1997	18,573.59	6,137	7,396	0.3982	11,178	50.22	223	25.0
1998	11,996.28	3,808	4,589	0.3826	7,407	51.19	145	24.0
1999	13,981.55	4,256	5,129	0.3669	8,852	52.17	170	23.0
2000	15,480.63	4,510	5,436	0.3512	10,045	53.15	189	22.0
2001	15,930.29	4,433	5,343	0.3354	10,587	54.13	196	21.0
2003	1,042,250.77	262,695	316,604	0.3038	725,646	56.10	12,936	19.0
2004	811,493.91	193,860	233,644	0.2879	577,850	57.08	10,123	18.0
2005	363,509.94	82,050	98,888	0.2720	264,622	58.07	4,557	17.0
2006	995,363.15	211,536	254,946	0.2561	740,417	59.06	12,536	16.0
2007	1,702,630.22	339,352	408,993	0.2402	1,293,637	60.05	21,542	15.0
2008	508,195.45	94,566	113,973	0.2243	394,223	61.04	6,458	14.0
2009	2,113,133.73	365,237	440,190	0.2083	1,672,944	62.04	26,967	13.0
2010	1,486,282.22	237,195	285,871	0.1923	1,200,411	63.03	19,045	12.0
2011	53,244.96	7,791	9,390	0.1764	43,855	64.03	685	11.0
2012	194,831.63	25,923	31,242	0.1604	163,589	65.02	2,516	10.0
2013	110,696.29	13,258	15,979	0.1443	94,717	66.02	1,435	9.0
2014	133,416.05	14,206	17,122	0.1283	116,294	67.01	1,735	8.0
2015	536,512.92	49,995	60,255	0.1123	476,258	68.01	7,003	7.0
2016	77,664.86	6,204	7,477	0.0963	70,187	69.01	1,017	6.0

FortisBC

Account #: 36020 - Surface and Mineral - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	250,224.09	16,659	20,078	0.0802	230,146	70.01	3,287	5.0
2018	225,739.23	12,025	14,492	0.0642	211,247	71.00	2,975	4.0
2019	84,029.47	3,357	4,046	0.0482	79,983	72.00	1,111	3.0
2020	113,190.87	3,015	3,634	0.0321	109,557	73.00	1,501	2.0
2021	351,166.97	4,676	5,636	0.0160	345,531	74.00	4,669	1.0
2022	463,179.66	0	0	0.0000	463,180	75.00	6,176	0.0
TOTAL	12,557,004.36	2,457,968	2,962,387		9,594,617		157,463	

COMPOSITE ANNUAL ACCRUAL RATE	1.25%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	14.85
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	60.32

FortisBC

Account #: 36200 - Substation Equipment - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1962	2,829.19	3,216	3,137	0.8530	541	6.29	86	60.0
1963	116.00	131	128	0.8469	23	6.60	3	59.0
1965	1,763.00	1,959	1,912	0.8341	380	7.26	52	57.0
1966	32,117.45	35,399	34,536	0.8272	7,216	7.61	948	56.0
1967	1,124.00	1,228	1,198	0.8200	263	7.98	33	55.0
1968	2,773.14	3,002	2,929	0.8124	676	8.36	81	54.0
1969	13,689.39	14,676	14,318	0.8045	3,478	8.77	397	53.0
1970	20,619.68	21,879	21,345	0.7963	5,460	9.19	594	52.0
1971	42,827.00	44,951	43,855	0.7877	11,820	9.63	1,227	51.0
1972	3,791.00	3,934	3,838	0.7787	1,091	10.09	108	50.0
1973	4,706.13	4,825	4,707	0.7694	1,411	10.57	133	49.0
1974	128,525.00	130,098	126,926	0.7597	40,156	11.07	3,628	48.0
1975	208,579.54	208,327	203,248	0.7496	67,905	11.58	5,861	47.0
1976	314,750.42	309,984	302,427	0.7391	106,749	12.12	8,807	46.0
1977	485,873.57	471,511	460,016	0.7283	171,619	12.68	13,540	45.0
1978	683,293.65	652,924	637,006	0.7171	251,276	13.25	18,967	44.0
1979	52,343.00	49,213	48,013	0.7056	20,032	13.84	1,448	43.0
1980	2,159,267.53	1,996,058	1,947,396	0.6938	859,652	14.45	59,510	42.0
1981	624,949.14	567,572	553,735	0.6816	258,699	15.07	17,167	41.0
1982	2,848,824.37	2,539,860	2,477,940	0.6691	1,225,532	15.71	78,011	40.0
1983	2,375,376.09	2,077,270	2,026,628	0.6563	1,061,361	16.37	64,854	39.0
1984	516,335.22	442,535	431,746	0.6432	239,490	17.04	14,058	38.0
1985	1,141,063.47	957,652	934,305	0.6298	549,077	17.72	30,985	37.0
1986	2,226,494.73	1,828,170	1,783,601	0.6162	1,110,842	18.42	60,309	36.0
1987	1,730,070.91	1,388,533	1,354,682	0.6023	894,410	19.13	46,751	35.0
1988	792,032.00	620,750	605,616	0.5882	424,025	19.86	21,355	34.0
1989	1,645,529.76	1,258,134	1,227,462	0.5738	911,727	20.59	44,273	33.0
1990	2,414,612.03	1,799,124	1,755,263	0.5592	1,383,733	21.34	64,835	32.0

FortisBC

Account #: 36200 - Substation Equipment - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1991	3,468,821.00	2,515,996	2,454,658	0.5443	2,054,809	22.10	92,964	31.0
1992	560,228.80	395,097	385,465	0.5293	342,833	22.88	14,987	30.0
1993	1,582,668.89	1,083,938	1,057,512	0.5140	999,957	23.66	42,266	29.0
1994	3,032,141.89	2,014,062	1,964,961	0.4985	1,976,824	24.45	80,844	28.0
1995	4,239,321.65	2,727,247	2,660,759	0.4828	2,850,359	25.26	112,855	27.0
1996	3,812,540.61	2,371,928	2,314,102	0.4669	2,642,201	26.07	101,344	26.0
1997	2,160,976.00	1,298,084	1,266,437	0.4508	1,542,831	26.90	57,362	25.0
1998	1,967,495.32	1,139,164	1,111,392	0.4345	1,446,352	27.73	52,156	24.0
1999	3,006,115.17	1,674,528	1,633,704	0.4180	2,274,246	28.58	79,588	23.0
2000	1,236,140.00	661,142	645,024	0.4014	961,958	29.43	32,687	22.0
2001	2,241,870.96	1,148,756	1,120,750	0.3846	1,793,682	30.29	59,213	21.0
2002	788,217.81	386,024	376,613	0.3675	648,070	31.16	20,796	20.0
2003	3,497,995.16	1,633,041	1,593,228	0.3504	2,954,165	32.04	92,190	19.0
2004	811,827.27	360,240	351,458	0.3330	703,918	32.93	21,374	18.0
2005	7,005,704.11	2,945,324	2,873,520	0.3155	6,233,896	33.83	184,271	17.0
2006	16,561,100.64	6,572,987	6,412,743	0.2979	15,116,688	34.73	435,202	16.0
2007	21,337,190.06	7,962,465	7,768,347	0.2801	19,970,000	35.65	560,212	15.0
2008	34,114,170.35	11,914,936	11,624,460	0.2621	32,723,962	36.57	894,912	14.0
2009	31,187,154.39	10,141,499	9,894,258	0.2440	30,649,043	37.49	817,460	13.0
2010	20,006,929.59	6,020,653	5,873,874	0.2258	20,135,134	38.43	524,000	12.0
2011	17,889,359.91	4,946,673	4,826,078	0.2075	18,430,090	39.36	468,187	11.0
2012	3,924,003.31	988,655	964,552	0.1891	4,136,652	40.31	102,622	10.0
2013	2,368,496.25	538,229	525,107	0.1705	2,553,938	41.26	61,899	9.0
2014	13,718,248.32	2,776,669	2,708,976	0.1519	15,124,747	42.22	358,278	8.0
2015	8,834,290.18	1,567,608	1,529,391	0.1332	9,955,186	43.18	230,577	7.0
2016	3,403,716.55	518,626	505,983	0.1144	3,918,849	44.14	88,783	6.0
2017	3,157,679.95	401,626	391,835	0.0955	3,713,149	45.11	82,317	5.0
2018	9,282,166.98	945,975	922,913	0.0765	11,143,904	46.08	241,837	4.0

FortisBC

Account #: 36200 - Substation Equipment - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2019	4,178,712.95	319,871	312,072	0.0574	5,120,254	47.06	108,812	3.0
2020	11,334,968.35	579,239	565,118	0.0384	14,170,341	48.03	295,003	2.0
2021	12,222,157.88	312,685	305,062	0.0192	15,583,744	49.02	317,932	1.0
2022	17,554,809.07	0	0	0.0000	22,821,252	50.00	456,425	0.0
TOTAL	290,961,495.78	96,295,879	93,948,266		284,301,678		7,647,376	

COMPOSITE ANNUAL ACCRUAL RATE 2.63%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.32

COMPOSITE AVERAGE AGE (YEARS) 13.62

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 37.27

FortisBC

Account #: 36400 - Poles, Towers and Fixtures - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -40%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1966	57,799.50	68,606	62,815	0.7763	18,105	7.61	2,380	56.0
1967	182,300.21	214,501	196,394	0.7695	58,827	7.98	7,374	55.0
1968	175,833.11	204,990	187,686	0.7624	58,481	8.36	6,992	54.0
1969	180,443.98	208,324	190,739	0.7550	61,883	8.77	7,058	53.0
1970	163,633.87	186,982	171,198	0.7473	57,889	9.19	6,299	52.0
1971	184,242.76	208,257	190,677	0.7392	67,263	9.63	6,984	51.0
1972	235,908.08	263,618	241,365	0.7308	88,906	10.09	8,811	50.0
1973	281,154.82	310,409	284,205	0.7220	109,411	10.57	10,351	49.0
1974	425,834.91	464,203	425,017	0.7129	171,152	11.07	15,464	48.0
1975	639,626.44	687,995	629,918	0.7034	265,559	11.58	22,923	47.0
1976	795,620.29	843,846	772,613	0.6936	341,255	12.12	28,154	46.0
1977	771,316.46	806,095	738,048	0.6835	341,795	12.68	26,965	45.0
1978	1,129,026.93	1,161,834	1,063,758	0.6730	516,880	13.25	39,016	44.0
1979	992,373.25	1,004,809	919,988	0.6622	469,335	13.84	33,916	43.0
1981	1,758,592.65	1,719,992	1,574,799	0.6396	887,231	15.07	58,875	41.0
1982	1,596,521.23	1,532,863	1,403,467	0.6279	831,663	15.71	52,939	40.0
1983	1,279,869.71	1,205,344	1,103,595	0.6159	688,223	16.37	42,054	39.0
1984	1,262,734.06	1,165,500	1,067,114	0.6036	700,714	17.04	41,132	38.0
1985	5,802,244.62	5,244,193	4,801,504	0.5911	3,321,638	17.72	187,444	37.0
1986	1,364,422.38	1,206,503	1,104,656	0.5783	805,535	18.42	43,733	36.0
1987	1,190,526.50	1,029,002	942,138	0.5653	724,599	19.13	37,875	35.0
1988	1,469,155.22	1,240,013	1,135,337	0.5520	921,480	19.86	46,408	34.0
1989	1,757,844.73	1,447,393	1,325,211	0.5385	1,135,772	20.59	55,153	33.0
1990	2,052,589.82	1,647,026	1,507,993	0.5248	1,365,633	21.34	63,987	32.0
1991	2,178,126.62	1,701,359	1,557,739	0.5108	1,491,639	22.10	67,485	31.0
1992	2,035,152.93	1,545,681	1,415,202	0.4967	1,434,012	22.88	62,688	30.0
1993	2,670,908.16	1,969,962	1,803,668	0.4824	1,935,604	23.66	81,814	29.0
1994	3,384,762.92	2,421,231	2,216,843	0.4678	2,521,825	24.45	103,132	28.0

FortisBC

Account #: 36400 - Poles, Towers and Fixtures - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -40%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1995	3,549,638.29	2,459,217	2,251,623	0.4531	2,717,871	25.26	107,609	27.0
1996	2,435,437.14	1,631,731	1,493,988	0.4382	1,915,624	26.07	73,475	26.0
1997	3,693,228.77	2,389,151	2,187,471	0.4231	2,983,049	26.90	110,909	25.0
1998	2,563,568.39	1,598,461	1,463,527	0.4078	2,125,468	27.73	76,646	24.0
1999	2,766,782.31	1,659,764	1,519,655	0.3923	2,353,840	28.58	82,373	23.0
2000	3,082,096.78	1,775,245	1,625,388	0.3767	2,689,548	29.43	91,391	22.0
2001	4,383,757.66	2,419,070	2,214,864	0.3609	3,922,396	30.29	129,486	21.0
2002	3,007,902.84	1,586,414	1,452,497	0.3449	2,758,567	31.16	88,518	20.0
2003	5,896,595.18	2,964,584	2,714,329	0.3288	5,540,904	32.04	172,914	19.0
2004	5,490,392.17	2,623,713	2,402,232	0.3125	5,284,317	32.93	160,456	18.0
2005	8,087,627.63	3,661,737	3,352,632	0.2961	7,970,047	33.83	235,591	17.0
2006	11,672,539.81	4,989,116	4,567,960	0.2795	11,773,596	34.73	338,956	16.0
2007	9,985,927.32	4,013,132	3,674,363	0.2628	10,305,935	35.65	289,109	15.0
2008	12,502,687.51	4,702,675	4,305,699	0.2460	13,198,064	36.57	360,931	14.0
2009	11,014,062.40	3,857,080	3,531,484	0.2290	11,888,203	37.49	317,078	13.0
2010	11,185,865.14	3,625,078	3,319,067	0.2119	12,341,144	38.43	321,168	12.0
2011	8,404,476.95	2,502,729	2,291,461	0.1947	9,474,807	39.36	240,692	11.0
2012	10,542,289.05	2,860,454	2,618,989	0.1774	12,140,216	40.31	301,174	10.0
2013	5,700,480.29	1,395,052	1,277,289	0.1600	6,703,384	41.26	162,468	9.0
2014	12,511,201.52	2,727,151	2,496,939	0.1426	15,018,744	42.22	355,767	8.0
2015	9,880,355.92	1,888,092	1,728,709	0.1250	12,103,789	43.18	280,342	7.0
2016	9,008,890.32	1,478,282	1,353,493	0.1073	11,258,954	44.14	255,076	6.0
2017	10,699,997.80	1,465,623	1,341,902	0.0896	13,638,095	45.11	302,343	5.0
2018	10,750,966.87	1,179,947	1,080,342	0.0718	13,971,012	46.08	303,189	4.0
2019	10,221,743.83	842,639	771,508	0.0539	13,538,934	47.06	287,720	3.0
2020	11,600,955.72	638,434	584,541	0.0360	15,656,797	48.03	325,949	2.0
2021	12,970,751.53	357,362	327,195	0.0180	17,831,857	49.02	363,796	1.0
2022	12,702,480.31	0	0	0.0000	17,783,472	50.00	355,669	0.0

FortisBC

Account #: 36400 - Poles, Towers and Fixtures - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -40%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	262,331,265.61	95,002,462	86,982,832		280,280,940		7,658,201	

COMPOSITE ANNUAL ACCRUAL RATE	2.92%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.33
COMPOSITE AVERAGE AGE (YEARS)	14.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	37.07

FortisBC

Account #: 36500 - Conductors and Devices - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	486,290.74	558,301	554,401	0.8445	102,091	8.23	12,410	62.0
1961	170,640.28	194,391	193,033	0.8379	37,331	8.59	4,347	61.0
1962	236,583.72	267,320	265,453	0.8311	53,935	8.97	6,015	60.0
1963	289,995.62	324,871	322,601	0.8240	68,893	9.36	7,361	59.0
1964	228,499.62	253,680	251,908	0.8166	56,566	9.77	5,790	58.0
1965	392,770.35	431,942	428,924	0.8089	101,316	10.20	9,937	57.0
1966	300,846.42	327,576	325,287	0.8009	80,855	10.64	7,599	56.0
1967	338,806.33	365,078	362,528	0.7926	94,860	11.10	8,546	55.0
1968	350,590.63	373,659	371,049	0.7840	102,249	11.58	8,831	54.0
1969	357,705.17	376,889	374,256	0.7750	108,646	12.07	8,998	53.0
1970	321,738.89	334,943	332,603	0.7658	101,744	12.59	8,083	52.0
1971	364,143.55	374,352	371,737	0.7562	119,857	13.12	9,137	51.0
1972	468,160.28	475,004	471,686	0.7463	160,330	13.66	11,734	50.0
1973	521,178.82	521,588	517,945	0.7361	185,647	14.23	13,049	49.0
1974	819,341.30	808,316	802,670	0.7257	303,441	14.81	20,492	48.0
1975	1,210,093.77	1,176,112	1,167,896	0.7149	465,731	15.40	30,236	47.0
1976	1,519,332.28	1,453,874	1,443,718	0.7039	607,381	16.01	37,927	46.0
1977	1,485,062.15	1,398,262	1,388,495	0.6926	616,339	16.64	37,039	45.0
1978	2,089,032.85	1,934,096	1,920,585	0.6810	899,609	17.28	52,058	44.0
1979	1,815,786.39	1,651,907	1,640,367	0.6692	810,944	17.94	45,213	43.0
1981	3,213,868.19	2,817,284	2,797,604	0.6448	1,541,118	19.29	79,906	41.0
1982	2,887,823.72	2,482,270	2,464,930	0.6323	1,433,632	19.98	71,751	40.0
1983	2,341,329.29	1,971,936	1,958,161	0.6195	1,202,633	20.69	58,135	39.0
1984	2,313,393.24	1,907,614	1,894,288	0.6065	1,228,793	21.41	57,406	38.0
1985	6,147,902.68	4,959,347	4,924,703	0.5934	3,374,966	22.14	152,468	37.0
1986	2,485,948.62	1,960,125	1,946,432	0.5800	1,409,598	22.88	61,617	36.0
1987	2,175,415.33	1,675,133	1,663,431	0.5664	1,273,379	23.63	53,892	35.0
1988	2,700,892.97	2,029,239	2,015,064	0.5526	1,631,142	24.39	66,876	34.0

FortisBC

Account #: 36500 - Conductors and Devices - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1989	3,146,516.15	2,304,398	2,288,301	0.5387	1,959,496	25.16	77,872	33.0
1990	3,821,223.33	2,725,089	2,706,053	0.5246	2,452,598	25.95	94,527	32.0
1991	3,918,992.98	2,718,567	2,699,576	0.5103	2,591,065	26.74	96,904	31.0
1992	3,615,655.30	2,436,960	2,419,937	0.4958	2,461,198	27.54	89,366	30.0
1993	4,733,836.34	3,096,340	3,074,711	0.4811	3,315,969	28.35	116,957	29.0
1994	5,762,406.26	3,653,065	3,627,546	0.4663	4,151,702	29.17	142,316	28.0
1995	6,307,252.72	3,870,010	3,842,975	0.4513	4,671,816	30.00	155,715	27.0
1996	4,407,889.67	2,613,840	2,595,581	0.4362	3,355,070	30.84	108,786	26.0
1997	6,661,250.62	3,811,513	3,784,888	0.4209	5,207,800	31.69	164,344	25.0
1998	4,394,571.36	2,422,231	2,405,310	0.4054	3,527,361	32.54	108,387	24.0
1999	4,877,541.65	2,585,004	2,566,946	0.3898	4,017,735	33.41	120,262	23.0
2000	5,520,981.43	2,807,851	2,788,237	0.3741	4,665,088	34.28	136,087	22.0
2001	7,862,974.83	3,829,037	3,802,289	0.3582	6,812,727	35.16	193,761	21.0
2002	4,762,220.13	2,215,278	2,199,803	0.3422	4,229,194	36.05	117,320	20.0
2003	8,885,393.21	3,938,052	3,910,543	0.3260	8,084,738	36.94	218,841	19.0
2004	8,016,977.61	3,375,618	3,352,038	0.3097	7,470,882	37.85	197,403	18.0
2005	11,623,599.19	4,634,841	4,602,464	0.2933	11,089,395	38.75	286,142	17.0
2006	18,513,434.22	6,965,900	6,917,239	0.2768	18,075,897	39.67	455,647	16.0
2007	17,127,127.20	6,056,490	6,014,182	0.2601	17,107,440	40.59	421,435	15.0
2008	19,588,074.31	6,480,321	6,435,053	0.2433	20,008,848	41.52	481,888	14.0
2009	16,764,610.69	5,161,807	5,125,748	0.2265	17,506,476	42.46	412,344	13.0
2010	16,996,241.16	4,841,101	4,807,284	0.2095	18,137,642	43.40	417,960	12.0
2011	14,190,136.59	3,712,718	3,686,783	0.1925	15,469,901	44.34	348,888	11.0
2012	14,657,396.22	3,493,150	3,468,748	0.1753	16,318,737	45.29	360,311	10.0
2013	8,967,634.18	1,927,025	1,913,563	0.1581	10,192,743	46.25	220,406	9.0
2014	19,316,382.28	3,696,144	3,670,325	0.1407	22,406,791	47.20	474,676	8.0
2015	15,493,795.73	2,598,460	2,580,308	0.1234	18,336,316	48.17	380,679	7.0
2016	14,686,240.86	2,114,520	2,099,749	0.1059	17,726,676	49.13	360,781	6.0

FortisBC

Account #: 36500 - Conductors and Devices - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 55
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	16,861,382.02	2,026,086	2,011,933	0.0884	20,750,933	50.10	414,153	5.0
2018	17,141,508.59	1,650,073	1,638,546	0.0708	21,502,490	51.08	420,972	4.0
2019	15,926,171.39	1,151,304	1,143,262	0.0532	20,357,070	52.05	391,070	3.0
2020	18,946,282.22	914,199	907,813	0.0355	24,669,668	53.03	465,166	2.0
2021	20,261,034.53	489,373	485,954	0.0178	26,866,442	54.02	497,380	1.0
2022	19,968,772.39	0	0	0.0000	26,957,843	55.00	490,142	0.0
TOTAL	421,758,680.56	139,721,476	138,745,441		430,628,778		10,385,741	

COMPOSITE ANNUAL ACCRUAL RATE 2.46%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.33

COMPOSITE AVERAGE AGE (YEARS) 14.55

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 41.50

FortisBC

Account #: 36800 - Line Transformers - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1983	1,725.40	1,763	1,367	0.6096	876	8.56	102	39.0
1984	3,118.85	3,136	2,432	0.5997	1,623	9.06	179	38.0
1985	2,077,434.13	2,053,139	1,591,893	0.5894	1,108,771	9.59	115,610	37.0
1986	18,557.15	18,008	13,962	0.5788	10,162	10.14	1,002	36.0
1987	26,770.42	25,477	19,754	0.5676	15,048	10.72	1,404	35.0
1988	275,044.06	256,429	198,821	0.5561	158,736	11.31	14,031	34.0
1989	962,590.53	878,101	680,832	0.5441	570,536	11.93	47,818	33.0
1990	1,106,415.41	986,381	764,786	0.5317	673,554	12.57	53,589	32.0
1991	1,253,606.88	1,090,799	845,747	0.5190	783,942	13.23	59,269	31.0
1992	1,152,686.08	977,687	758,046	0.5059	740,446	13.90	53,261	30.0
1993	1,486,492.99	1,227,292	951,576	0.4924	980,865	14.60	67,201	29.0
1994	1,425,113.51	1,143,744	886,797	0.4787	965,850	15.31	63,104	28.0
1995	2,076,369.86	1,617,378	1,254,027	0.4646	1,445,254	16.03	90,145	27.0
1996	1,402,372.54	1,058,590	820,774	0.4502	1,002,311	16.77	59,755	26.0
1997	2,215,648.10	1,617,997	1,254,508	0.4355	1,625,835	17.53	92,743	25.0
1998	1,421,270.47	1,002,317	777,143	0.4206	1,070,509	18.30	58,495	24.0
1999	1,401,246.05	952,452	738,480	0.4054	1,083,140	19.09	56,752	23.0
2000	1,753,200.32	1,146,243	888,735	0.3899	1,390,425	19.88	69,930	22.0
2001	2,642,639.67	1,658,086	1,285,590	0.3742	2,149,841	20.69	103,886	21.0
2002	3,356,325.89	2,016,088	1,563,166	0.3583	2,800,058	21.52	130,130	20.0
2003	4,450,098.39	2,552,164	1,978,810	0.3421	3,806,318	22.35	170,277	19.0
2004	4,407,626.87	2,406,407	1,865,798	0.3256	3,864,117	23.20	166,549	18.0
2005	5,700,648.98	2,953,067	2,289,649	0.3090	5,121,195	24.06	212,844	17.0
2006	11,378,902.46	5,572,661	4,320,741	0.2921	10,471,833	24.93	420,029	16.0
2007	10,986,815.27	5,065,782	3,927,734	0.2750	10,355,126	25.81	401,160	15.0
2008	10,091,285.44	4,360,442	3,380,851	0.2577	9,737,820	26.70	364,649	14.0
2009	8,701,794.17	3,504,914	2,717,521	0.2402	8,594,811	27.61	311,330	13.0
2010	8,637,818.92	3,223,369	2,499,226	0.2226	8,729,939	28.52	306,122	12.0

FortisBC

Account #: 36800 - Line Transformers - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	7,251,665.12	2,489,144	1,929,948	0.2047	7,497,216	29.44	254,675	11.0
2012	6,578,014.46	2,059,398	1,596,746	0.1867	6,954,673	30.37	229,021	10.0
2013	4,454,022.03	1,258,815	976,017	0.1686	4,814,211	31.30	153,790	9.0
2014	9,728,035.78	2,450,964	1,900,345	0.1503	10,746,101	32.25	333,236	8.0
2015	8,367,020.56	1,849,453	1,433,966	0.1318	9,443,161	33.20	284,443	7.0
2016	8,067,289.41	1,532,298	1,188,062	0.1133	9,299,415	34.16	272,265	6.0
2017	10,036,419.69	1,592,222	1,234,523	0.0946	11,812,823	35.12	336,369	5.0
2018	11,082,134.28	1,409,528	1,092,872	0.0759	13,313,903	36.09	368,944	4.0
2019	11,118,454.50	1,062,655	823,925	0.0570	13,630,066	37.06	367,792	3.0
2020	12,945,850.58	826,380	640,731	0.0381	16,188,875	38.04	425,621	2.0
2021	13,599,796.29	434,738	337,072	0.0191	17,342,663	39.02	444,497	1.0
2022	12,972,883.87	0	0	0.0000	16,864,749	40.00	421,618	0.0
TOTAL	206,615,205.38	66,335,508	51,432,973		217,166,794		7,383,637	

COMPOSITE ANNUAL ACCRUAL RATE	3.57%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	10.60
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	30.12

FortisBC

Account #: 36900 - Services - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 70
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1983	897.21	484	267	0.2980	630	32.26	20	39.0
1984	1,621.80	854	472	0.2911	1,150	33.14	35	38.0
1985	1,215,280.03	624,412	345,158	0.2840	870,122	34.03	25,566	37.0
1986	9,649.72	4,834	2,672	0.2769	6,978	34.93	200	36.0
1987	13,920.62	6,793	3,755	0.2697	10,166	35.84	284	35.0
1988	29,915.05	14,207	7,853	0.2625	22,062	36.76	600	34.0
1989	58,370.07	26,951	14,898	0.2552	43,472	37.68	1,154	33.0
1990	34,884.74	15,645	8,648	0.2479	26,237	38.61	680	32.0
1991	18,961.67	8,251	4,561	0.2405	14,401	39.54	364	31.0
1992	31,349.90	13,220	7,308	0.2331	24,042	40.48	594	30.0
1993	1,097.39	448	248	0.2256	850	41.43	21	29.0
1994	23,703.99	9,353	5,170	0.2181	18,534	42.38	437	28.0
1995	34,296.53	13,065	7,222	0.2106	27,075	43.33	625	27.0
1996	12,175.69	4,471	2,472	0.2030	9,704	44.29	219	26.0
1997	6,778.47	2,396	1,324	0.1954	5,454	45.26	121	25.0
1998	66,265.78	22,506	12,441	0.1877	53,825	46.23	1,164	24.0
1999	14,038.36	4,573	2,528	0.1801	11,510	47.20	244	23.0
2000	19,655.05	6,129	3,388	0.1724	16,267	48.17	338	22.0
2001	65,817.48	19,606	10,838	0.1647	54,980	49.15	1,119	21.0
2002	17,902.39	5,082	2,809	0.1569	15,093	50.13	301	20.0
2003	57,808.58	15,600	8,623	0.1492	49,185	51.11	962	19.0
2004	104,333.96	26,689	14,753	0.1414	89,581	52.09	1,720	18.0
2005	208,367.82	50,365	27,840	0.1336	180,527	53.08	3,401	17.0
2006	182,695.99	41,582	22,985	0.1258	159,711	54.07	2,954	16.0
2007	140,960.30	30,090	16,633	0.1180	124,327	55.06	2,258	15.0
2008	181,367.53	36,148	19,982	0.1102	161,386	56.05	2,879	14.0
2009	205,182.31	37,987	20,998	0.1023	184,184	57.04	3,229	13.0
2010	6,647.25	1,136	628	0.0945	6,019	58.03	104	12.0

FortisBC

Account #: 36900 - Services - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 70
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	378,758.20	59,369	32,818	0.0866	345,940	59.03	5,861	11.0
2012	288,754.86	41,157	22,751	0.0788	266,004	60.02	4,432	10.0
TOTAL	3,431,458.74	1,143,404	632,042		2,799,417		61,886	

COMPOSITE ANNUAL ACCRUAL RATE	1.80%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.18
COMPOSITE AVERAGE AGE (YEARS)	23.77
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	46.68

FortisBC

Account #: 37010 - AMI Meters - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 18
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	7,740,011.70	3,440,005	2,133,021	0.2756	5,606,991	10.00	560,699	8.0
2015	22,513,889.55	8,755,401	5,428,903	0.2411	17,084,986	11.00	1,553,181	7.0
2016	3,650,638.70	1,216,880	754,542	0.2067	2,896,096	12.00	241,341	6.0
2017	1,460,459.64	405,683	251,549	0.1722	1,208,910	13.00	92,993	5.0
2018	1,266,631.61	281,474	174,532	0.1378	1,092,100	14.00	78,007	4.0
2019	1,824,395.96	304,066	188,540	0.1033	1,635,856	15.00	109,057	3.0
2020	1,289,225.86	143,247	88,822	0.0689	1,200,403	16.00	75,025	2.0
2021	496,841.98	27,602	17,115	0.0344	479,727	17.00	28,219	1.0
2022	1,692,920.18	0	0	0.0000	1,692,920	18.00	94,051	0.0
TOTAL	41,935,015.18	14,574,359	9,037,025		32,897,990		2,832,573	

COMPOSITE ANNUAL ACCRUAL RATE	6.75%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.22
COMPOSITE AVERAGE AGE (YEARS)	6.26
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.74

FortisBC

Account #: 37300 - Street Lighting and Signal Systems - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 25
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	145,773.01	150,023	153,922	0.9182	13,717	2.63	5,221	37.0
1998	28,893.11	23,380	23,988	0.7219	9,239	7.41	1,247	24.0
1999	18,341.09	14,411	14,785	0.7010	6,307	7.92	796	23.0
2000	51,191.69	38,963	39,975	0.6790	18,895	8.45	2,235	22.0
2001	80,751.15	59,388	60,931	0.6561	31,932	9.01	3,543	21.0
2003	942,287.30	641,666	658,343	0.6075	425,287	10.20	41,710	19.0
2004	814,725.80	531,378	545,188	0.5819	391,746	10.82	36,201	18.0
2005	1,067,434.90	664,480	681,750	0.5554	545,800	11.47	47,596	17.0
2006	1,553,579.05	919,493	943,391	0.5280	843,225	12.13	69,495	16.0
2007	1,666,917.51	933,992	958,267	0.4999	958,688	12.82	74,785	15.0
2008	1,731,640.84	914,138	937,897	0.4710	1,053,490	13.52	77,899	14.0
2009	1,340,102.17	662,900	680,129	0.4413	860,988	14.25	60,435	13.0
2010	1,256,194.50	578,636	593,675	0.4110	850,949	14.99	56,781	12.0
2011	691,373.55	294,399	302,051	0.3799	493,029	15.74	31,317	11.0
2012	19,199.86	7,493	7,688	0.3482	14,392	16.52	871	10.0
2013	10,335.90	3,659	3,754	0.3158	8,132	17.30	470	9.0
2014	88,109.24	27,936	28,663	0.2829	72,663	18.11	4,013	8.0
2015	113,076.04	31,601	32,422	0.2493	97,616	18.92	5,158	7.0
2016	196,985.67	47,518	48,753	0.2152	177,780	19.76	8,999	6.0
2017	270,999.27	54,846	56,271	0.1806	255,378	20.60	12,397	5.0
2018	612,425.69	99,801	102,395	0.1454	601,895	21.46	28,051	4.0
2019	638,992.96	78,585	80,627	0.1097	654,215	22.33	29,302	3.0
2020	481,426.01	39,706	40,738	0.0736	512,902	23.21	22,101	2.0
2021	158,625.23	6,578	6,749	0.0370	175,670	24.10	7,290	1.0
2022	40,885.72	0	0	0.0000	47,019	25.00	1,881	0.0

FortisBC

Account #: 37300 - Street Lighting and Signal Systems - Distribution Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 25
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	14,020,267.26	6,824,969	7,002,353		9,120,954		629,794	

COMPOSITE ANNUAL ACCRUAL RATE	4.49%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.50
COMPOSITE AVERAGE AGE (YEARS)	13.13
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.42

FortisBC

Account #: 39010 - Structures - Masonry - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 35
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1975	15,431.00	13,845	16,203	1.0000	0	5.09	0	47.0
1977	7,431.00	6,526	7,803	1.0000	0	5.73	0	45.0
1979	505,185.00	433,366	523,488	0.9869	6,956	6.41	1,086	43.0
1980	1,580.00	1,338	1,617	0.9746	42	6.76	6	42.0
1981	647.00	541	653	0.9618	26	7.13	4	41.0
1982	17,777.00	14,656	17,704	0.9485	962	7.52	128	40.0
1983	58,407.00	47,450	57,317	0.9346	4,010	7.92	506	39.0
1984	23,966.00	19,170	23,157	0.9202	2,007	8.34	241	38.0
1985	1,247,531.11	981,682	1,185,831	0.9053	124,077	8.77	14,148	37.0
1986	1,566.00	1,211	1,463	0.8898	181	9.22	20	36.0
1987	35,879.75	27,247	32,914	0.8736	4,760	9.69	491	35.0
1988	569,496.92	424,211	512,429	0.8569	85,543	10.17	8,411	34.0
1989	395,725.00	288,822	348,885	0.8397	66,626	10.67	6,243	33.0
1990	118.00	84	102	0.8218	22	11.19	2	32.0
1991	234,112.00	163,474	197,469	0.8033	48,348	11.72	4,124	31.0
1992	32,982.00	22,485	27,160	0.7843	7,471	12.28	609	30.0
1993	18,219.00	12,110	14,628	0.7647	4,502	12.84	350	29.0
1994	322,163.00	208,489	251,847	0.7445	86,425	13.43	6,436	28.0
1995	44,422.00	27,948	33,760	0.7238	12,884	14.03	918	27.0
1996	28,853.00	17,619	21,283	0.7025	9,012	14.64	615	26.0
1997	87,035.00	51,500	62,210	0.6807	29,177	15.28	1,910	25.0
1998	67,476.00	38,619	46,650	0.6584	24,200	15.92	1,520	24.0
1999	172,461.00	95,288	115,104	0.6356	65,980	16.58	3,979	23.0
2000	15,116.00	8,046	9,719	0.6124	6,153	17.26	357	22.0
2001	308,971.00	158,077	190,950	0.5886	133,469	17.95	7,437	21.0
2002	105,328.54	51,670	62,415	0.5644	48,180	18.65	2,584	20.0
2003	220,805.72	103,581	125,122	0.5397	106,724	19.36	5,512	19.0
2004	103,373.33	46,236	55,851	0.5146	52,691	20.09	2,623	18.0

FortisBC

Account #: 39010 - Structures - Masonry - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R2
ASL: 35
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2005	50,544.20	21,485	25,953	0.4890	27,119	20.83	1,302	17.0
2006	112,595.65	45,321	54,746	0.4631	63,479	21.58	2,941	16.0
2007	457,076.16	173,508	209,590	0.4367	270,340	22.35	12,098	15.0
2008	96,318.19	34,323	41,461	0.4100	59,673	23.12	2,581	14.0
2009	405,228.74	134,846	162,889	0.3828	262,602	23.91	10,984	13.0
2010	238,355.84	73,618	88,927	0.3553	161,346	24.70	6,531	12.0
2011	334,666.06	95,258	115,067	0.3275	236,332	25.51	9,264	11.0
2012	52,120.29	13,557	16,376	0.2992	38,350	26.33	1,457	10.0
2013	15,915,696.99	3,744,791	4,523,551	0.2707	12,187,931	27.16	448,795	9.0
2014	663,066.75	139,365	168,347	0.2418	527,874	27.99	18,857	8.0
2015	325,727.49	60,193	72,711	0.2126	269,303	28.84	9,338	7.0
2016	1,794,747.00	285,605	344,999	0.1831	1,539,485	29.70	51,842	6.0
2017	16,456,914.16	2,192,249	2,648,145	0.1533	14,631,615	30.56	478,789	5.0
2018	1,828,370.93	195,703	236,401	0.1231	1,683,388	31.43	53,556	4.0
2019	1,122,585.47	90,502	109,322	0.0927	1,069,393	32.31	33,095	3.0
2020	2,136,874.00	115,320	139,301	0.0621	2,104,417	33.20	63,384	2.0
2021	2,613,327.43	70,791	85,512	0.0312	2,658,481	34.10	77,968	1.0
2022	2,394,395.31	0	0	0.0000	2,514,115	35.00	71,831	0.0
TOTAL	51,640,669.03	10,751,726	12,987,032		41,235,671		1,424,873	

COMPOSITE ANNUAL ACCRUAL RATE 2.76%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.25

COMPOSITE AVERAGE AGE (YEARS) 8.40

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 28.06

FortisBC

Account #: 39020 - Operations Buildings - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1986	44,990.00	31,812	45,677	0.9669	1,563	16.33	96	36.0
1987	8,110.00	5,603	8,045	0.9447	471	17.10	28	35.0
1988	308.00	208	298	0.9221	25	17.89	1	34.0
1993	286,363.00	168,117	241,388	0.8028	59,293	22.04	2,690	29.0
2002	2,738,669.94	1,134,694	1,629,233	0.5666	1,246,370	30.27	41,175	20.0
2003	4,724,226.43	1,862,473	2,674,204	0.5391	2,286,234	31.23	73,214	19.0
2005	178,311.07	63,070	90,559	0.4837	96,668	33.16	2,915	17.0
2006	585,498.10	195,140	280,189	0.4558	334,584	34.13	9,803	16.0
2007	540,028.60	168,911	242,529	0.4277	324,501	35.11	9,244	15.0
2008	383,366.66	112,019	160,841	0.3996	241,694	36.09	6,698	14.0
2009	734,960.51	199,576	286,558	0.3713	485,150	37.07	13,088	13.0
2010	261,026.71	65,475	94,012	0.3430	180,066	38.06	4,732	12.0
2011	615,836.39	141,690	203,444	0.3146	443,184	39.04	11,351	11.0
2012	1,308,284.26	273,792	393,121	0.2862	980,578	40.03	24,493	10.0
2013	665,679.56	125,439	180,110	0.2577	518,854	41.03	12,647	9.0
2014	413,958.50	69,366	99,599	0.2291	335,058	42.02	7,974	8.0
2015	331,627.53	48,641	69,841	0.2006	278,368	43.02	6,471	7.0
2016	76,975.55	9,680	13,899	0.1720	66,925	44.01	1,521	6.0
2017	366,817.46	38,452	55,211	0.1433	329,948	45.01	7,331	5.0
2018	168,137.51	14,103	20,250	0.1147	156,295	46.01	3,397	4.0
2019	991,134.33	62,362	89,542	0.0860	951,149	47.00	20,236	3.0
2020	1,320,673.82	55,405	79,552	0.0574	1,307,156	48.00	27,231	2.0
2021	572,103.21	12,001	17,231	0.0287	583,478	49.00	11,907	1.0
2022	734,584.86	0	0	0.0000	771,314	50.00	15,426	0.0

FortisBC

Account #: 39020 - Operations Buildings - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: R4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	18,051,672.00	4,858,030	6,975,330		11,978,926		313,669	

COMPOSITE ANNUAL ACCRUAL RATE	1.74%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.39
COMPOSITE AVERAGE AGE (YEARS)	12.96
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	37.18

FortisBC

Account #: 39110 - Computer Hardware - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2019	3,015,558.48	2,261,669	2,080,413	0.6899	935,146	1.00	935,146	3.0
2020	4,152,584.17	2,076,292	1,909,893	0.4599	2,242,692	2.00	1,121,346	2.0
2021	3,124,864.73	781,216	718,607	0.2300	2,406,257	3.00	802,086	1.0
2022	2,799,318.75	0	0	0.0000	2,799,319	4.00	699,830	0.0
TOTAL	13,092,326.13	5,119,177	4,708,913		8,383,413		3,558,408	

COMPOSITE ANNUAL ACCRUAL RATE 27.18%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.36

COMPOSITE AVERAGE AGE (YEARS) 1.56

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 2.44

FortisBC

Account #: 39160 - AMI Computer Software - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	6,166,997.22	4,933,598	4,936,422	0.8005	1,230,575	2.00	615,287	8.0
2015	2,723,309.26	1,906,316	1,907,408	0.7004	815,901	3.00	271,967	7.0
2016	380,945.27	228,567	228,698	0.6003	152,247	4.00	38,062	6.0
2017	310,437.94	155,219	155,308	0.5003	155,130	5.00	31,026	5.0
TOTAL	9,581,689.69	7,223,700	7,227,836		2,353,854		956,342	

COMPOSITE ANNUAL ACCRUAL RATE	9.98%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.75
COMPOSITE AVERAGE AGE (YEARS)	7.54
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.46

FortisBC

Account #: 39210 - Light Duty Vehicles - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L1
ASL: 12
Net Salvage: 10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2002	7,924.52	5,068	6,030	0.8455	1,102	3.47	317	20.0
2005	37,028.11	21,643	25,754	0.7728	7,572	4.21	1,800	17.0
2006	40,567.04	22,912	27,264	0.7467	9,247	4.47	2,069	16.0
2007	52,302.50	28,468	33,876	0.7197	13,196	4.74	2,782	15.0
2008	77,685.72	40,631	48,350	0.6915	21,568	5.03	4,291	14.0
2009	51,615.44	25,852	30,763	0.6622	15,691	5.32	2,948	13.0
2010	2,721.77	1,300	1,547	0.6317	902	5.63	160	12.0
2011	241,288.25	109,464	130,257	0.5998	86,902	5.95	14,603	11.0
2012	170,652.10	73,124	87,014	0.5665	66,573	6.29	10,589	10.0
2013	482,160.42	193,918	230,754	0.5318	203,191	6.64	30,612	9.0
2014	297,740.02	111,549	132,739	0.4954	135,227	7.00	19,305	8.0
2015	33,852.58	11,707	13,930	0.4572	16,537	7.39	2,238	7.0
2016	10,932.24	3,441	4,095	0.4162	5,744	7.80	736	6.0
2017	221,831.83	61,943	73,710	0.3692	125,939	8.28	15,216	5.0
2018	1,116,043.78	264,959	315,289	0.3139	689,150	8.83	78,006	4.0
2019	394,379.15	74,285	88,396	0.2490	266,546	9.49	28,091	3.0
2020	922,570.09	121,668	144,779	0.1744	685,534	10.24	66,936	2.0
2021	511,994.64	35,135	41,809	0.0907	418,986	11.09	37,798	1.0
2022	104,824.46	0	0	0.0000	94,342	12.00	7,861	0.0
TOTAL	4,778,114.66	1,207,067	1,436,356		2,863,947		326,358	

COMPOSITE ANNUAL ACCRUAL RATE 6.83%

THEORETICAL ACCUMULATED DEPRECIATION FACTOR 0.30

COMPOSITE AVERAGE AGE (YEARS) 5.13

DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS) 8.63

FortisBC

Account #: 39220 - Heavy Duty Vehicles - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L2.5
ASL: 16
Net Salvage: 10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1979	11,705.00	10,535	9,691	0.9199	844	1.00	844	43.0
1982	756.00	646	594	0.8736	86	1.00	86	40.0
1989	8,820.00	6,839	6,291	0.7925	1,647	2.22	743	33.0
1991	8,150.00	6,197	5,700	0.7771	1,635	2.48	658	31.0
1993	33,527.00	24,907	22,911	0.7593	7,263	2.79	2,600	29.0
1995	14,859.00	10,739	9,879	0.7387	3,494	3.15	1,109	27.0
1996	30,159.00	21,462	19,743	0.7274	7,400	3.35	2,210	26.0
2002	26,419.42	16,766	15,423	0.6486	8,355	4.72	1,771	20.0
2003	30,765.02	19,135	17,602	0.6357	10,087	4.94	2,041	19.0
2004	31,034.06	18,936	17,419	0.6236	10,512	5.15	2,040	18.0
2005	470,360.81	281,862	259,277	0.6125	164,048	5.35	30,682	17.0
2006	1,640,825.93	966,146	888,730	0.6018	588,013	5.53	106,290	16.0
2007	2,916,312.21	1,685,924	1,550,832	0.5909	1,073,849	5.72	187,649	15.0
2008	773,367.24	437,655	402,587	0.5784	293,444	5.94	49,406	14.0
2009	1,399,448.12	771,062	709,278	0.5631	550,226	6.20	88,676	13.0
2010	523,429.84	278,545	256,226	0.5439	214,861	6.54	32,856	12.0
2011	1,419,088.06	721,710	663,880	0.5198	613,299	6.96	88,134	11.0
2012	644,920.25	309,460	284,663	0.4904	295,765	7.47	39,597	10.0
2013	2,000,867.91	892,393	820,887	0.4559	979,894	8.07	121,408	9.0
2014	911,687.11	371,459	341,694	0.4164	478,824	8.76	54,681	8.0
2015	1,937,477.54	706,590	649,972	0.3727	1,093,758	9.52	114,933	7.0
2016	2,391,578.55	761,642	700,612	0.3255	1,451,808	10.34	140,430	6.0
2017	2,285,958.17	616,229	566,851	0.2755	1,490,511	11.21	132,991	5.0
2018	1,825,000.47	399,079	367,101	0.2235	1,275,399	12.11	105,296	4.0
2019	1,918,986.80	318,426	292,911	0.1696	1,434,177	13.05	109,898	3.0
2020	2,231,224.61	249,016	229,063	0.1141	1,779,039	14.02	126,930	2.0
2021	1,256,438.91	70,504	64,854	0.0574	1,065,941	15.00	71,051	1.0
2022	3,502,906.69	0	0	0.0000	3,152,616	16.00	197,036	0.0

FortisBC

Account #: 39220 - Heavy Duty Vehicles - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: L2.5
ASL: 16
Net Salvage: 10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	30,246,073.72	9,973,865	9,174,671		18,046,795		1,812,046	

COMPOSITE ANNUAL ACCRUAL RATE	5.99%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	7.40
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	10.14

FortisBC

Account #: 39710 - Fiber - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2007	4,585,814.97	4,585,815	4,517,926	0.9852	67,889	1.00	67,889	15.0
2008	198,018.17	184,817	182,081	0.9195	15,937	1.00	15,937	14.0
2009	246,703.46	213,810	210,644	0.8538	36,059	2.00	18,030	13.0
2011	55,183.95	40,468	39,869	0.7225	15,315	4.00	3,829	11.0
2012	1,053,253.29	702,169	691,774	0.6568	361,480	5.00	72,296	10.0
2013	79,492.11	47,695	46,989	0.5911	32,503	6.00	5,417	9.0
2014	1,777,243.51	947,863	933,831	0.5254	843,413	7.00	120,488	8.0
2015	1,501.09	701	690	0.4598	811	8.00	101	7.0
2016	2,254.46	902	888	0.3941	1,366	9.00	152	6.0
2017	30,455.90	10,152	10,002	0.3284	20,454	10.00	2,045	5.0
2019	2,285,736.48	457,147	450,380	0.1970	1,835,357	12.00	152,946	3.0
TOTAL	10,315,657.39	7,191,539	7,085,073		3,230,584		459,130	

COMPOSITE ANNUAL ACCRUAL RATE	4.45%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.69
COMPOSITE AVERAGE AGE (YEARS)	10.46
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.99

FortisBC

Account #: 39720 - AMI Communications Structure and Equipment - General Plant

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF December 31, 2022

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	2,274,693.23	1,213,170	1,213,776	0.5336	1,060,917	7.00	151,560	8.0
2015	1,632,846.04	761,995	762,376	0.4669	870,470	8.00	108,809	7.0
2016	952,988.89	381,196	381,386	0.4002	571,603	9.00	63,511	6.0
2017	109,203.68	36,401	36,419	0.3335	72,784	10.00	7,278	5.0
TOTAL	4,969,731.84	2,392,761	2,393,958		2,575,774		331,158	

COMPOSITE ANNUAL ACCRUAL RATE	6.66%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.48
COMPOSITE AVERAGE AGE (YEARS)	7.22
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	7.78

SECTION 9

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service" [4]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age" [5]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1, shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age." [6] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[7]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

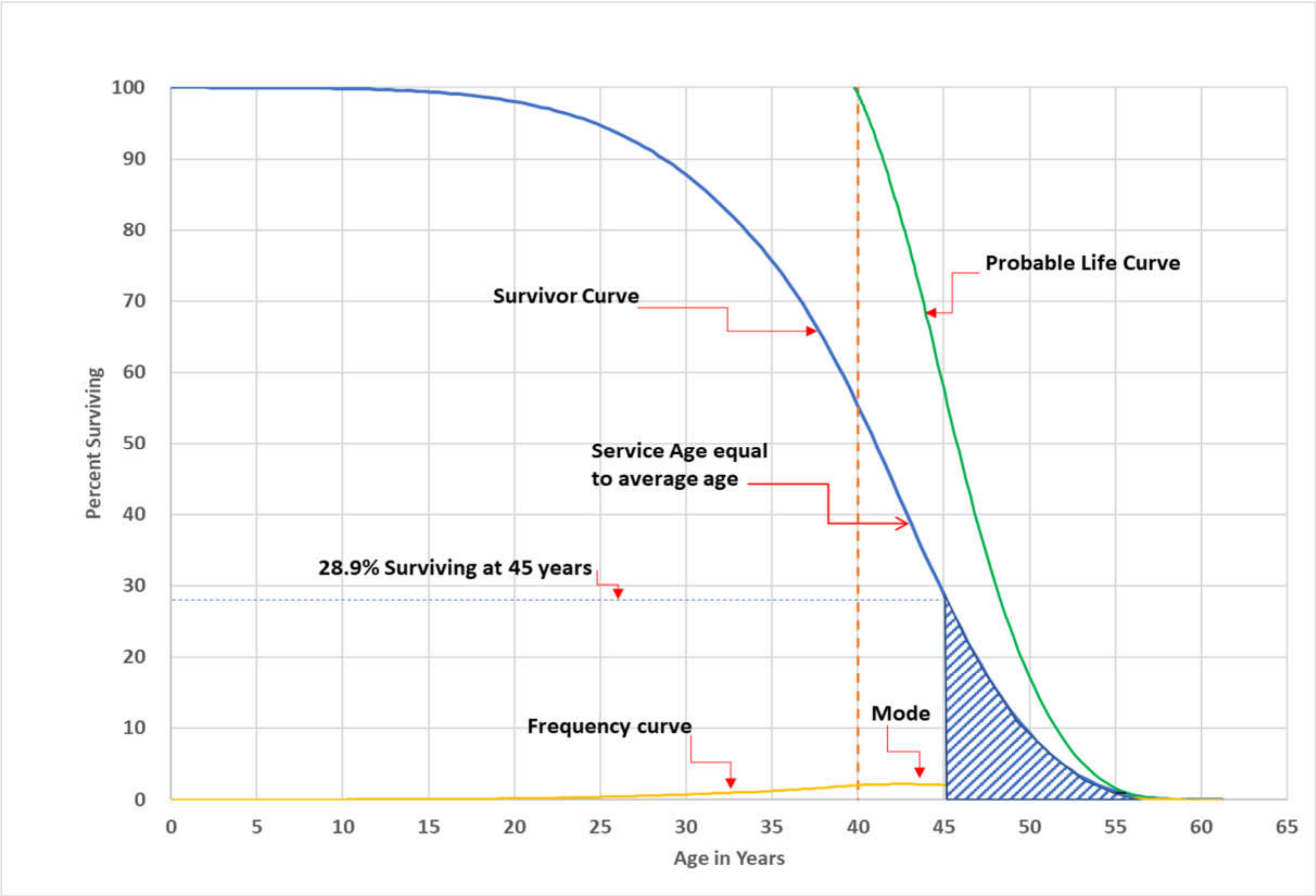
[4] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21

[5] *Ibid*, 23.

[6] *Ibid*, 29.

[7] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment"[8]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[9]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[10] presenting his development of the fourth family consisting of the four O-type survivor curves.

[8] *Ibid*, 21

[9] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[10] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

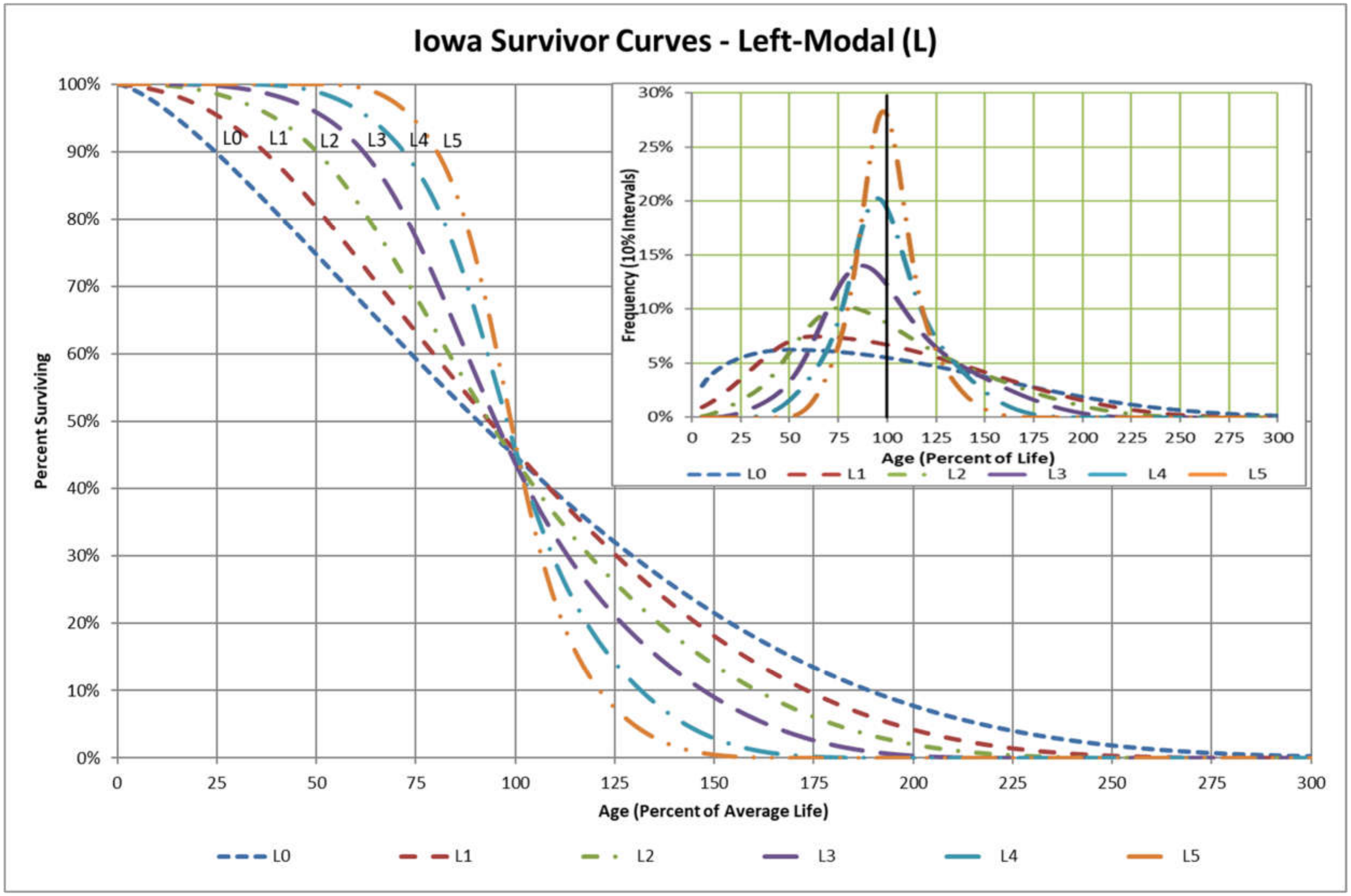


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

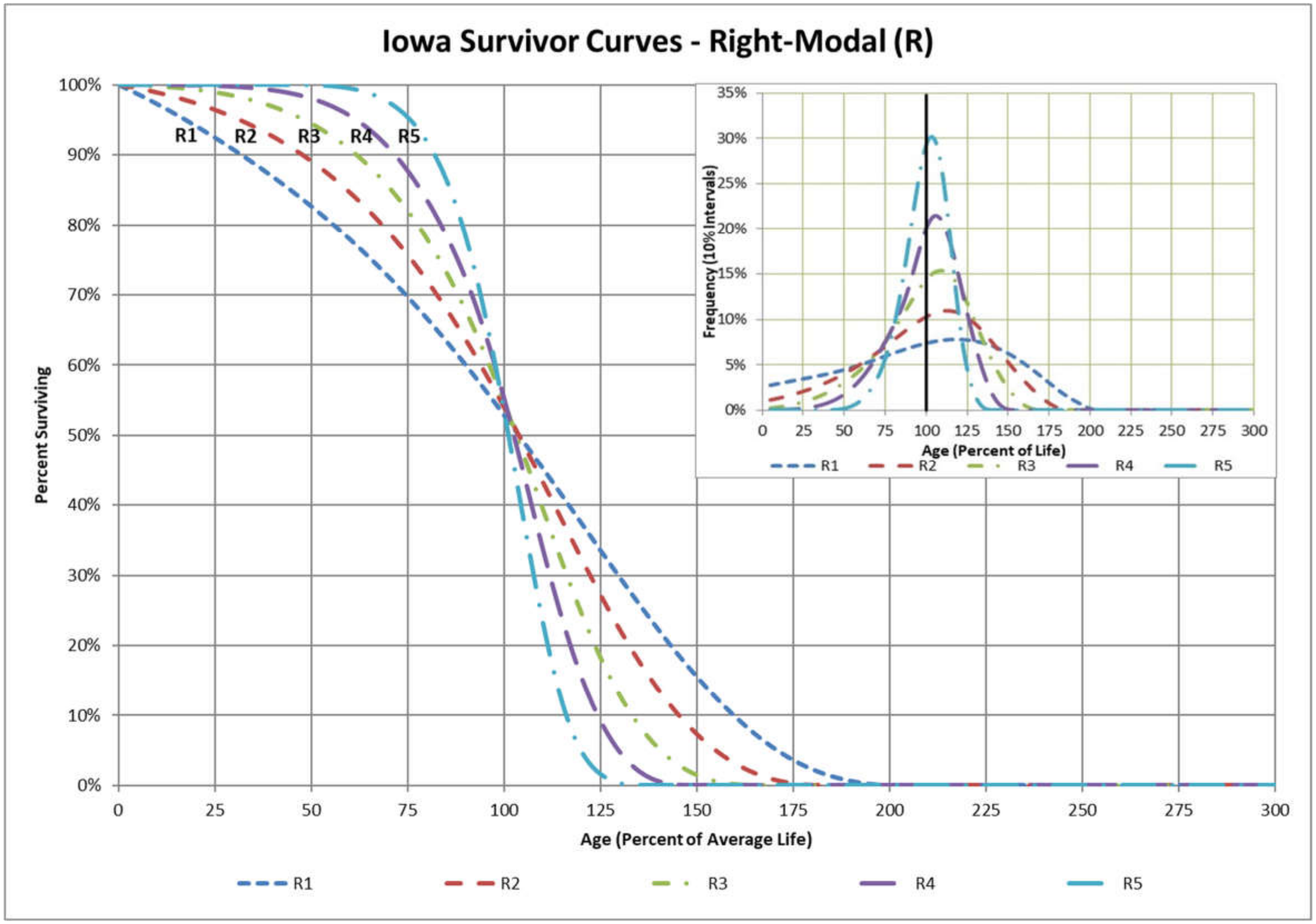


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

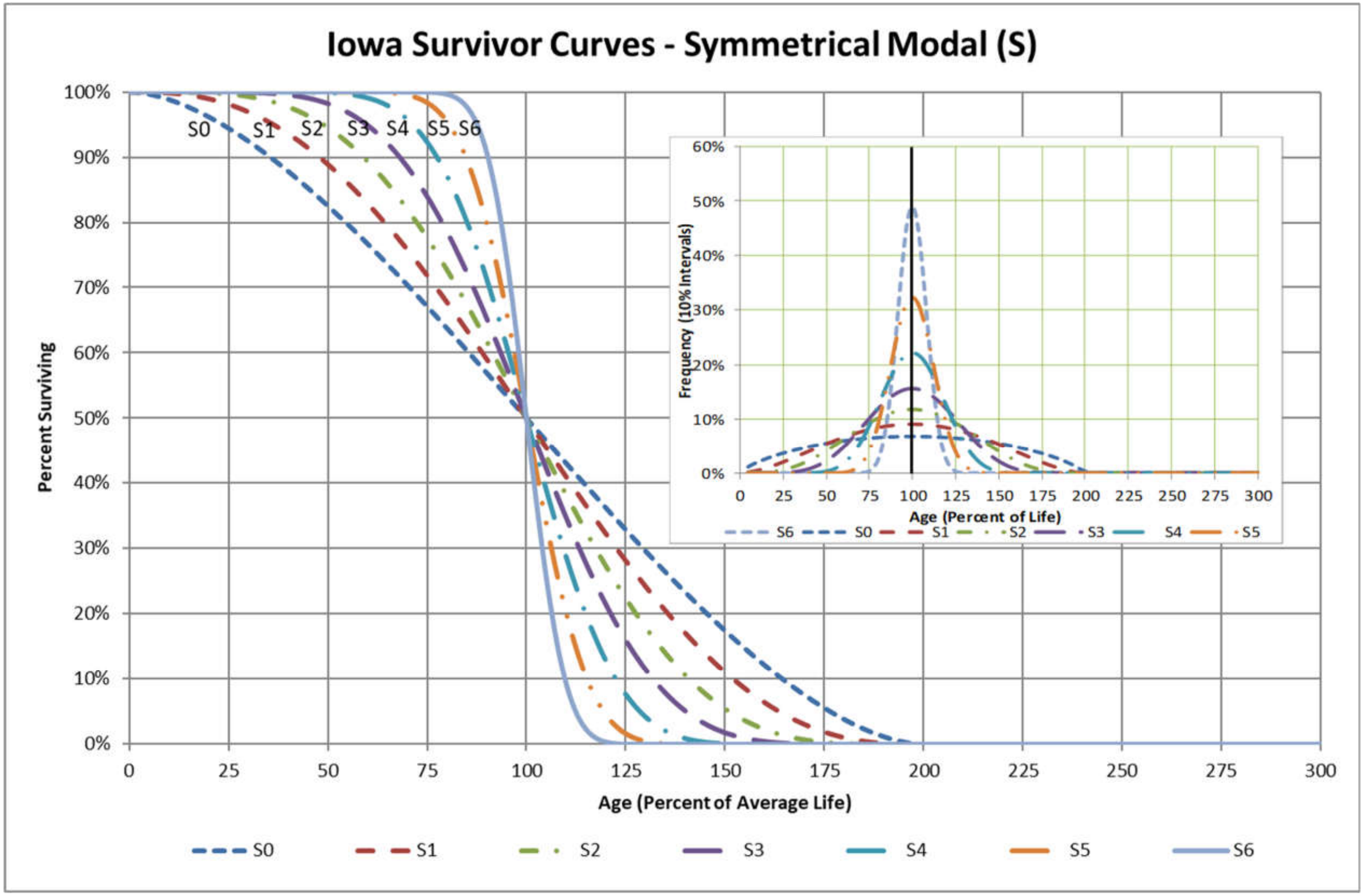
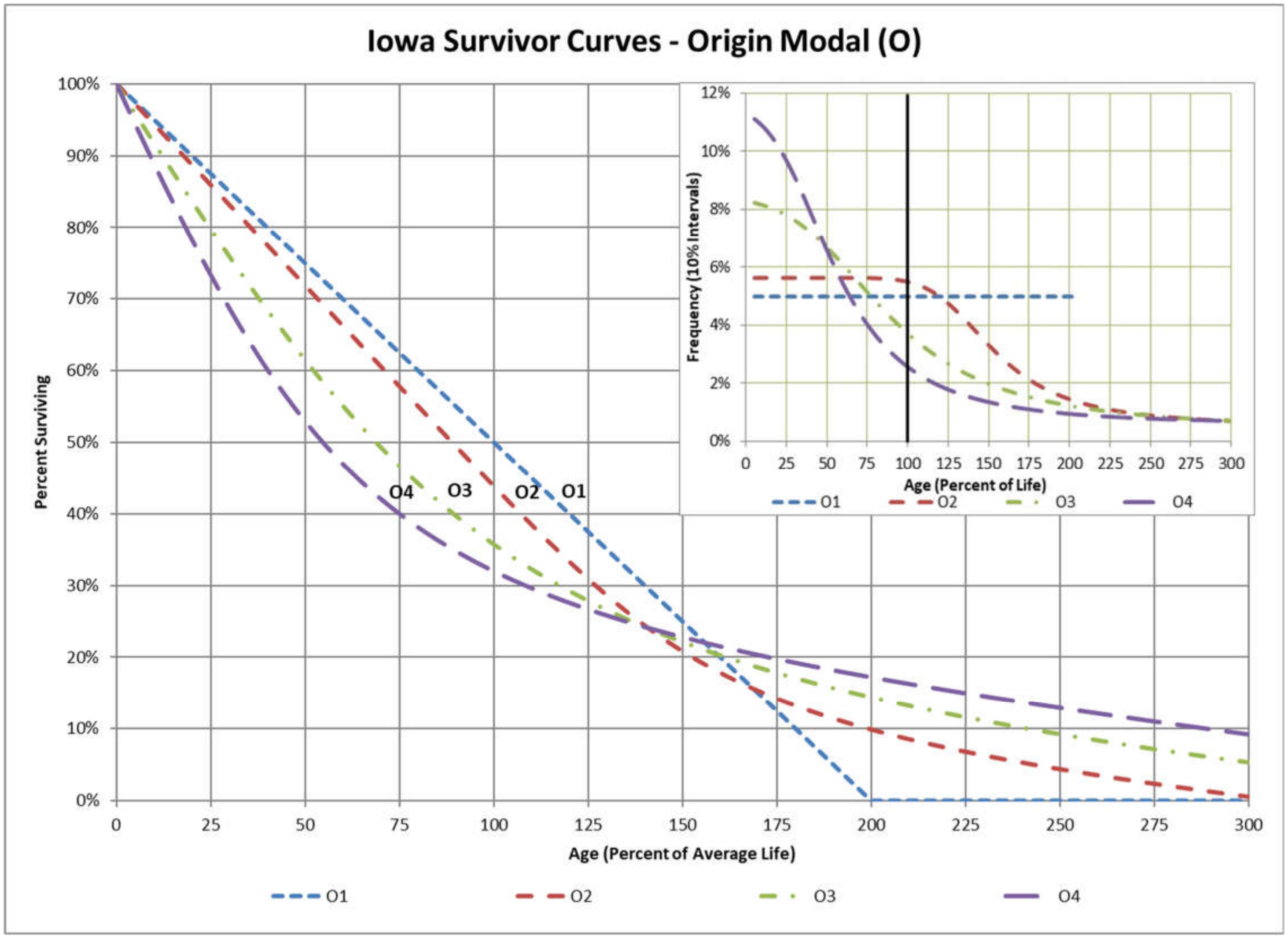


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements, [11] Engineering Valuation and Depreciation [12] and Depreciation Systems.[13]

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[11] Anson, Winfrey & Hempstead, *supra* note 3

[12] Anson, Winfrey & Hempstead, *supra* note 3

[13] Wolf & Fitch, supra note 1

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] *Transfer Affecting Exposures at Beginning of Year*
[b] *Transfer Affecting Exposures at End of Year*
[c] *Sale with Continued Use*
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2008 through 2017 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2017, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
420	460	510	580	660	750	850	960	1080	1220	0
1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	\$3,789,000		
Retirements from age 4½ to 5½	=	\$143,000		
Retirement Ratio	=	\$143,000 ÷ \$3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4 ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017				**Placement Band 2003-2017**	
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

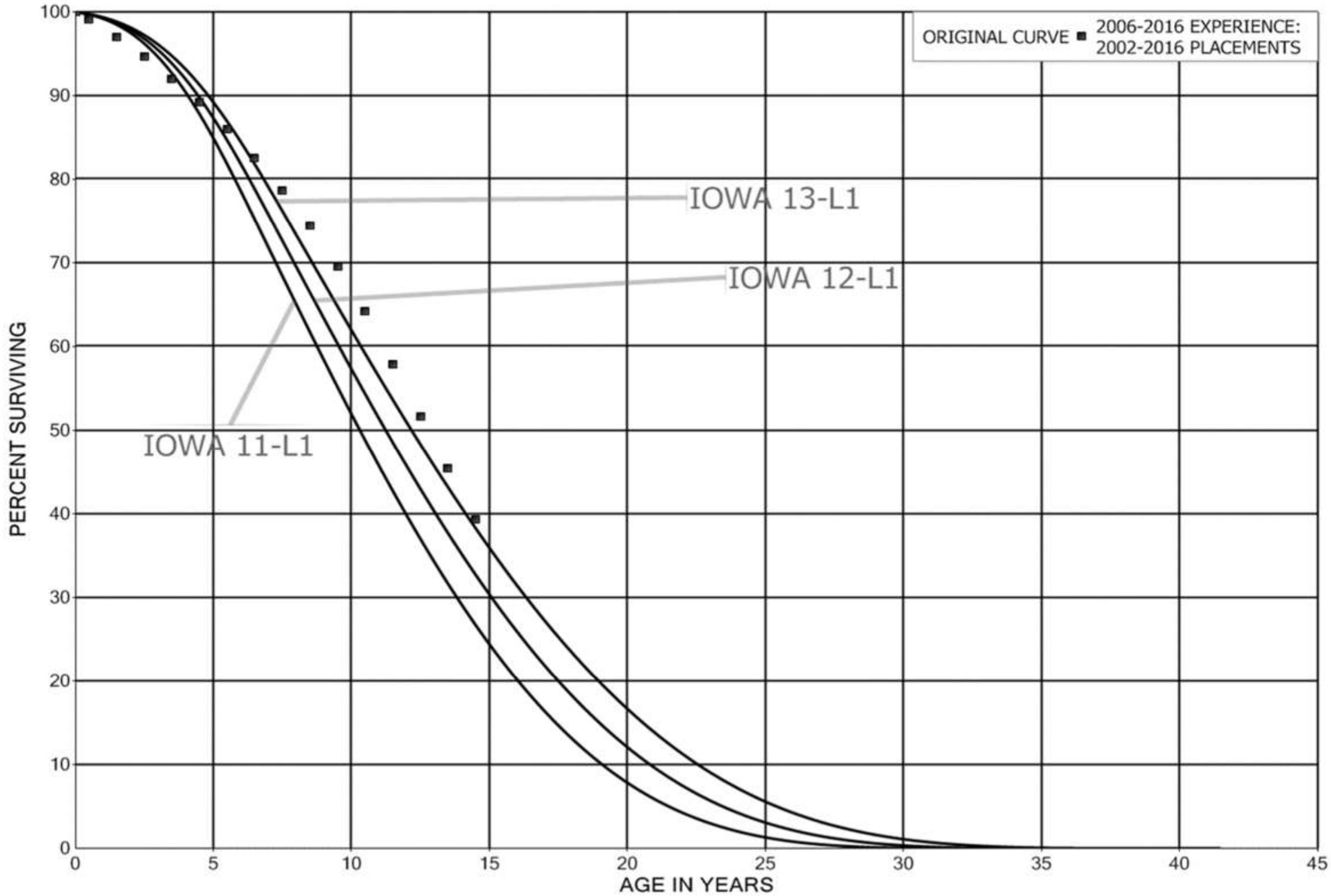


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

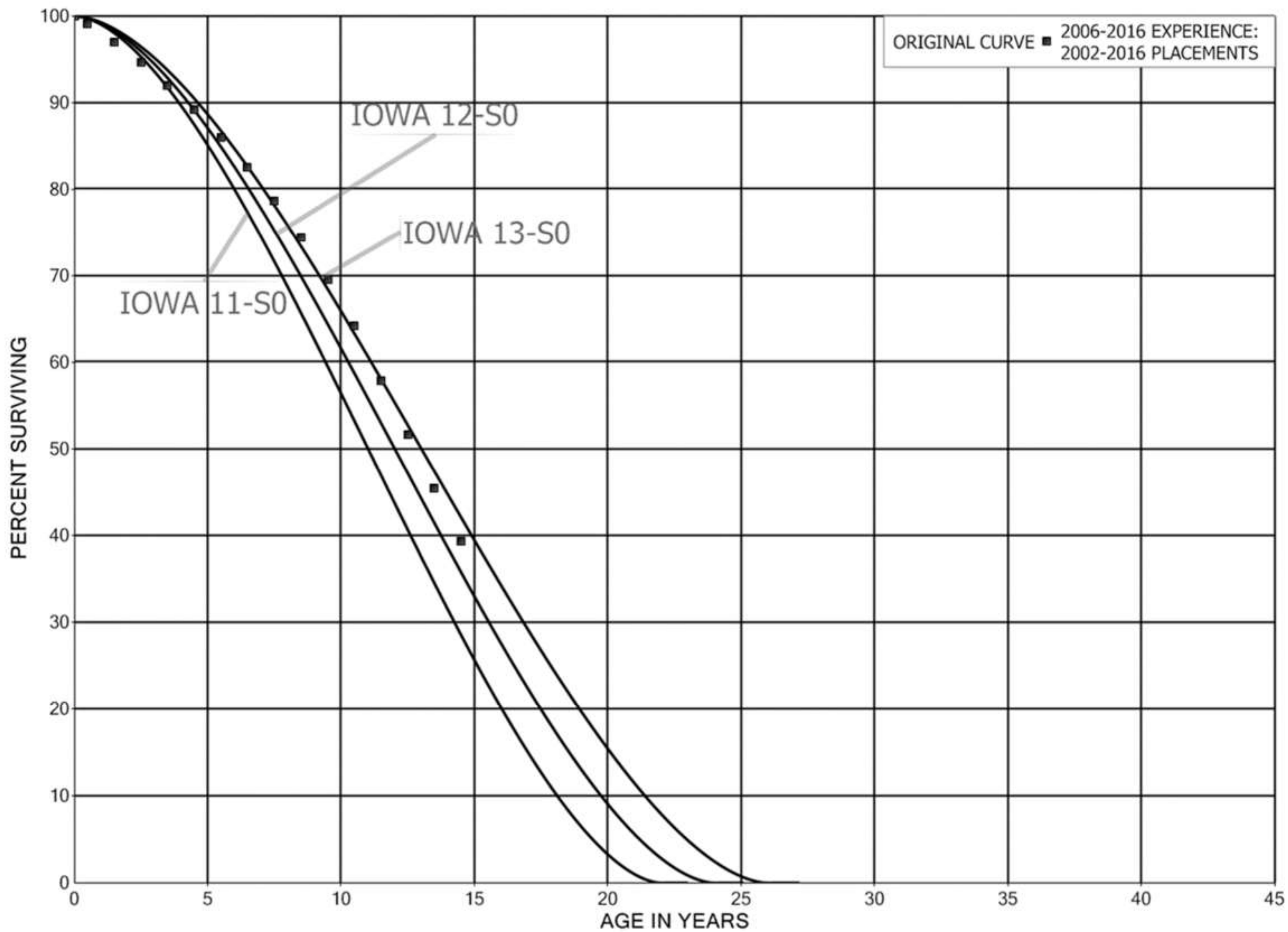


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

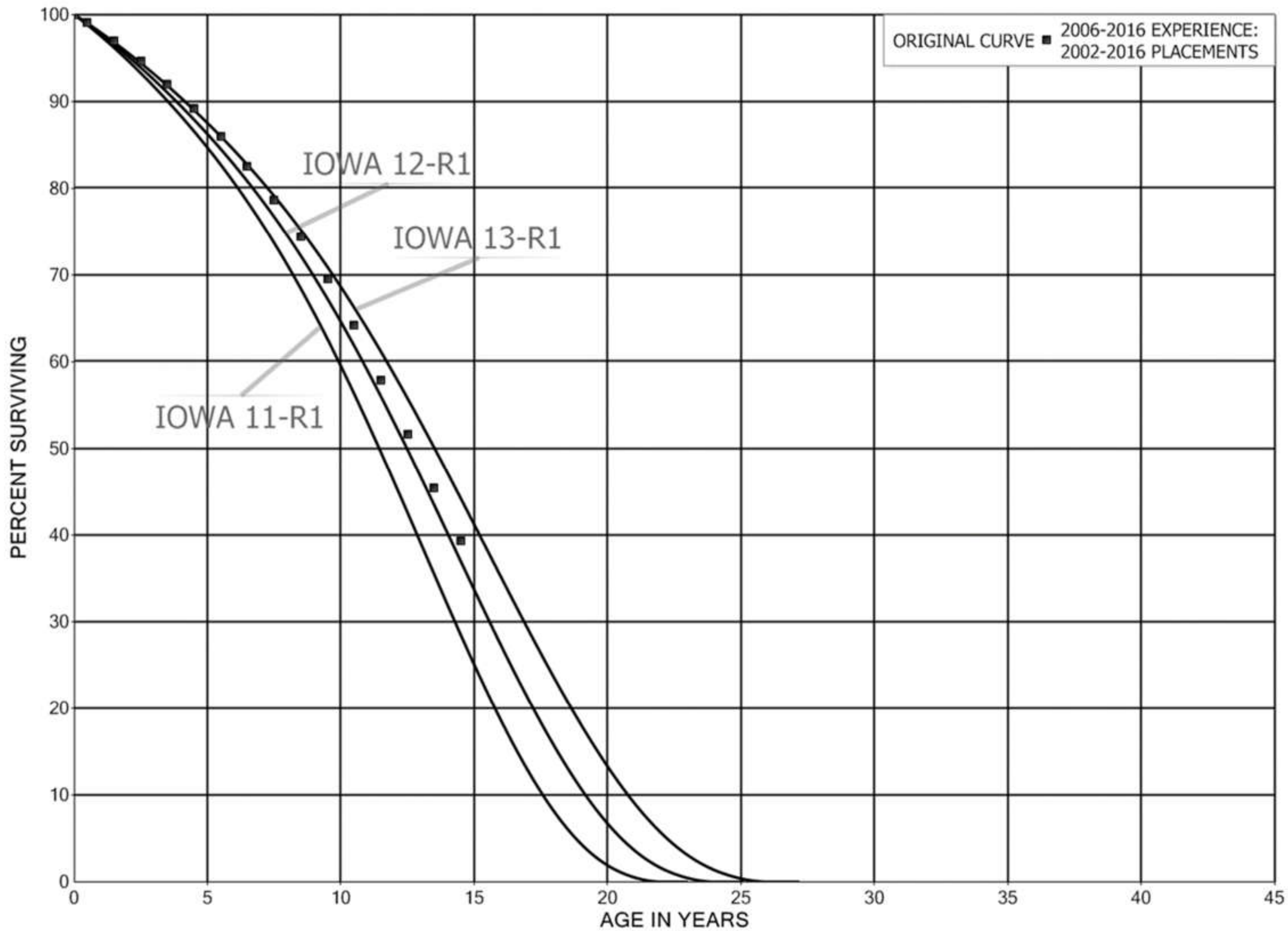
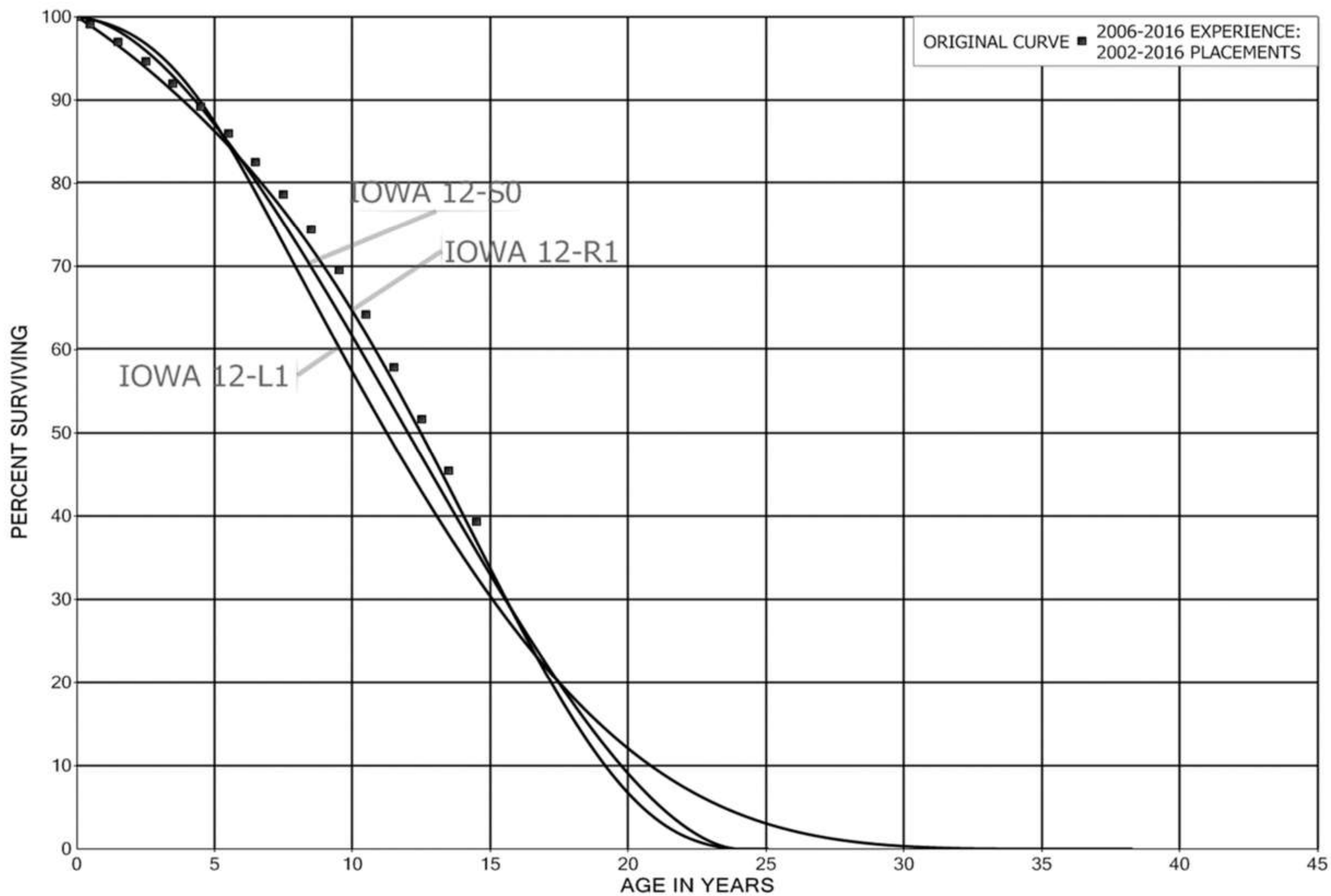


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated is usually determined using the "Traditional Approach" for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

Appendix D3-1

FEI LEAD-LAG STUDY

Appendix D3-1

FortisBC Energy Inc.

Cash Working Capital Lead-Lag Study

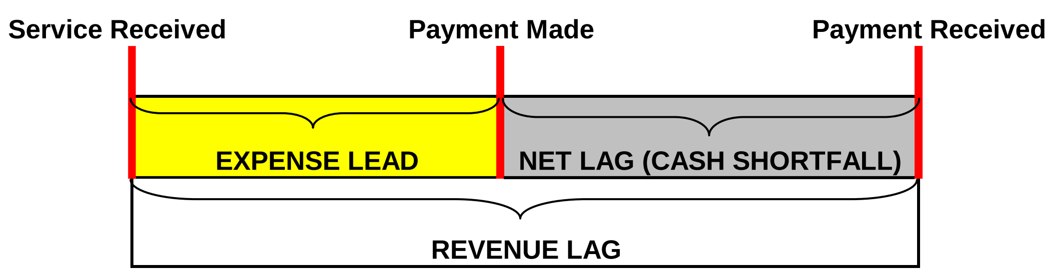
Table of Contents

Index of Tables and Figures

1. INTRODUCTION

The objective of the Lead-Lag study is to provide a measure of cash working capital needs for FortisBC Energy Inc. (FEI) in order to support its future working capital submissions before the British Columbia Utilities Commission (BCUC). Cash working capital is defined as the average amount of capital provided by investors in the company, over and above investments in plant and intangibles, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days. The study recognizes that there are timing differences between when FEI provides a service and when they receive payment (**revenue lag**) as well as the time between when they receive a service and subsequently make payment (**expense lead**). The difference between the total revenue lag and total expense lead is the **net lag**. A net lag number greater than zero indicates a cash working capital shortfall position; this occurs when the payment of an expense precedes the collection of its related revenue stream. In some cases, however, revenue may be received prior to payment for the related expense (a net lead or negative net lag), which indicates a cash working capital surplus position, and a reduction to rate base. Figure 1 illustrates the components of the lead/lag as discussed above.

Figure 1: Lead Lag Schematic Diagram



2. SUMMARY OF KEY FINDINGS

The lead lag days determined in this study will be used for the computation of the cash working capital requirements in FEI's 2025 and future rate applications until another lead-lag study is performed.

Lag days for total revenue and lead days for total expenditures are calculated using 2022 actual data, the most recent year of actual data available to prepare this study. For illustrative purposes within this Appendix, and as shown in the table below, the results of the lead-lag study were compared using the impact to 2024 Forecast revenue requirements of the proposed 2023 Lead-Lag Study results versus the currently approved 2018 Lead-Lag Study results. The updated study has no impact to total cash working capital requirements.

Table 1 summarizes the cash working capital requirements and lead lag days for each significant receipt and expenditure component.

Table 1: FEI Example of Change in Cash Working Capital Requirements

Line	Particulars	2024 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days	2024 Forecast (000's $)	Approved Lead Lag Days	Dollar Days
1	**Sales Revenue**						
2	Residential Tariff Revenue	1,092,727	38.5	42,068,285	1,092,727	40.3	44,036,898
3	Commercial Tariff Revenue	586,461	37.6	22,061,744	586,461	37.8	22,168,226
4	Industrial Tariff Revenue	193,678	45.3	8,774,971	193,678	47.7	9,238,441
5	Bypass and Special Rates	41,569	40.0	1,663,382	41,569	37.6	1,562,994
6							
7	**Total Sales Revenue**	1,914,435	39.0	74,568,383	1,914,435	40.2	77,006,559
8							
9	**Other Revenues**						
10	Late Payment Charges	3,607	52.9	190,660	3,607	53.8	194,057
11	Application Charges	1,797	38.1	68,391	1,797	39.0	70,083
12	Other Utility Income	37,075	38.1	1,411,017	37,075	39.0	1,445,925
13							
14	**Total Other Revenues**	42,479	39.3	1,670,068	42,479	40.3	1,710,065
15							
16	**TOTAL REVENUES**	1,956,914	**39.0**	76,238,451	1,956,914	**40.2**	78,716,624
17							
18	Energy Purchases	744,149	40.1	29,875,690	744,149	40.0	29,765,960
19	Operating & Maintenance	305,157	29.9	9,129,398	305,157	31.8	9,703,993
20	Property Taxes	83,359	0.6	47,922	83,359	1.3	108,367
21	Operating Fees	12,248	343.9	4,211,485	12,248	352.9	4,322,319
22	Carbon Tax	615,283	28.9	17,755,764	615,283	30.7	18,889,188
23	GST	47,796	33.3	1,593,709	47,796	39.7	1,897,501
24	PST	48,479	40.9	1,983,666	48,479	45.8	2,220,338
25	Income Tax	87,400	15.2	1,328,480	87,400	15.2	1,328,480
26							
27	**TOTAL EXPENDITURES**	1,943,870	**33.9**	65,926,113	1,943,870	**35.1**	68,236,146
28							
29	**NET LEAD-LAG DAYS (Line 16 - Line 27)**		**5.1**			**5.1**	
30							
31	**CASH WORKING CAPITAL (Line 27/365 x Line 29)**		**$ 27,161**			**$ 27,161**	
32							

3. METHODOLOGY AND APPROACH

The methodology used to determine the lead lag days for individual revenue and expenditure items is generally similar for regulated utilities. In addition, the methodology of calculating the lead lag days in this study is consistent with that used in the last study approved by the BCUC in 2020 (Order G-165-20).

The actual data for this lead/lag study is the 2022 calendar year data. This lead/lag analysis takes into account both the working capital requirements associated with lag times and the offsetting working capital requirements associated with lead times. Two primary categories of leads and lags were considered: (1) lag times related to revenues and the respective collection of those amounts owed to FEI (revenue lags); and (2) lead/lag times related to the payment for goods and services received by FEI (expense leads (lags)).

These two major categories, revenue lags and expense leads (lags), were further broken down into their individual components to obtain the corresponding individual lead/lag times. The results were then rolled up through a weighted average into total lag days for revenues and total lead days for expenses. Total lag days for revenues were then deducted from total lead days for expenses to arrive at the net lag days, which were then applied to total expenditures to arrive at the cash working capital requirements.

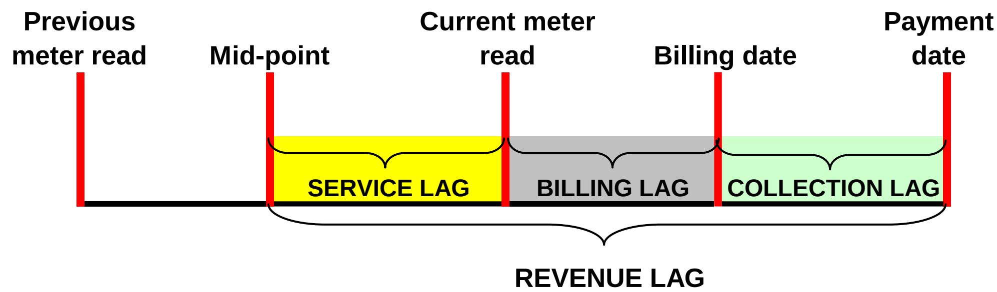
3.1 *CALCULATION OF REVENUE LAG*

The lag days pertaining to revenue receipts are determined by measuring the elapsed time between the date the service is deemed to be rendered and the date FEI receives the related payments from the customer. The revenue lag is the sum of the service lag, the billing lag and the collection lag.

- The service lag is the number of days from the deemed receipt date of service (generally the mid-point of the cycle) to the meter reading date.
- The billing lag is the number of days between the meter reading date and the billing date.
- The collection lag is the number of days from the billing date to the date the payment is received from the customer.

Figure 2 below illustrates these components of the revenue lag.

Figure 2: Revenue Lag Schematic Diagram



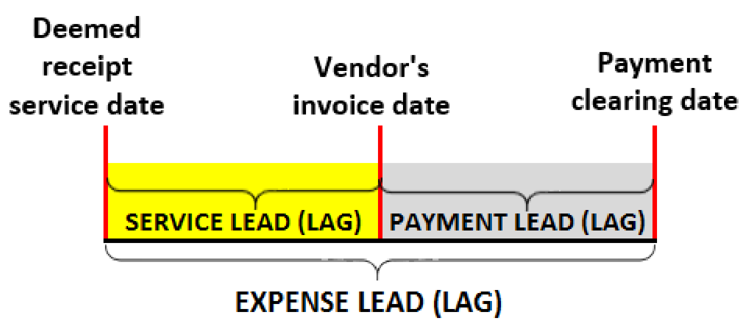
3.2 *CALCULATION OF EXPENSE LEAD (LAG)*

The lead days are determined by measuring the elapsed time from the deemed receipt service date (generally the mid-point) to the date payment is made by the Company. The expense lead (lag) is the sum of the service lead (lag) and the payment lead (lag).

- The service lead (lag) is the number of days from the deemed receipt service date to the vendor's invoice date.
- The payment lead (lag) is the number of days between the vendor's invoice date to the date the funds clear the Company's bank account.

Figure 3 below illustrates these components of the expense lead (lag).

Figure 3: Expense Lead (Lag) Schematic Diagram



3.3 *CALCULATION OF CASH WORKING CAPITAL REQUIREMENTS*

Once the revenue lags and expense leads (lags) are determined, the calculation of the cash working capital requirement involves the following steps:

- For the individual revenue and expense components, multiply the applicable lead/lag days by the respective forecast revenue and expenditure amount to derive the *dollar days*.

- Divide the total revenue and expenditure dollar days by the total forecast revenues and expenditures to derive *total weighted average revenue lag days and expenditure lead days*.
- Deduct the total weighted average expenditure lead days from the total weighted average revenue lag days to determine the *net weighted average lag days*.

Multiply total budgeted expenditures by the net weighted average lag days and divide this product by 365 days to determine the ***cash working capital requirement of the Company.***

4. REVENUE LAGS

FEI recognizes two revenue streams: A) Sales Revenue and B) Other Revenue.

4.1 *SALES REVENUE*

The sales revenue lag days for residential, commercial, and industrial customers are derived from the assessment of three timeframes:

- **Service Lag:** the time from the deemed average receipt date of service to the average meter reading date;
- **Billing Lag:** the time from the average meter reading date to the average date the customer is billed; and
- **Collection Lag:** the time from the average billing date to the average date the customer pays the bill.

4.1.1 Service Lag

The service receipt date is assumed to be the mid-point of the billing period given that customers are expected to receive service evenly throughout the service period. The average days between the deemed service receipt date and meter reading date is 30.4 days, calculated based on 12 billing periods in a 365-day year. When a service is continuous, such as gas sales, the mid-point of the service period is considered the service lag, which would be 15.2 (30.4/2) using the above approach. This is consistent with the approach used in previous studies.

4.1.2 Billing Lag

FEI bills customers (except large industrial customers) on the same day as the gas meter reading date. A separate analysis was necessary for large industrial customers as the average meter reading date differs from the average billing date for this group. FEI analyzed all of its large industrial customers (approximately 11,000 individual customer payment transactions) to determine a weighted average billing lag for these customers.

4.1.3 Collection Lag

For the purposes of the lead/lag study, FEI analyzed every customer payment transaction (approximately 11 million invoice records) to derive the average collection lag days. FEI bills customers for gas consumption every month. The majority of payments are due 22 days following the invoiced date. All customers do not necessarily pay on the due date.

4.1.4 Summary of Revenue Lag

The following table shows the calculation of the revenue lags by rate class:

Table 2: Calculation of Sales Revenue Lags

Customer Class	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Residential	15.2	0.0	23.3	38.5
Commercial	15.2	0.0	22.4	37.6
Industrial	15.2	11.2	18.9	45.3
Bypass and Special Rates	15.2	0.0	24.8	40.0

4.2 *OTHER REVENUE*

Other revenue receipts consist of the following major items:

1. Late Payment Charges;
2. Application Charges; and
3. Other Utility Income.

For FEI, Late Payment Charges are added to the bill that follows after the bill where the late payment occurred, and then that bill is assumed to be collected by the invoice due date. Application Charges and Other Utility Income are primarily a product of residential and small commercial customers. Hence, the weighted average lag days associated with residential and small commercial revenues were applied to Application Charges and Other Utility Income.

Table 3: Calculation of Other Revenue Lags

Other Revenue	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Late Payment Charges	0.0	30.0	22.9	52.9
Application Charges	15.2	0.0	22.9	38.1
Other Utility Income	15.2	0.0	22.9	38.1

5. EXPENSE LEADS (LAGS)

Expense leads and lags correspond to the lead or lag times associated with the payment for goods and services provided to FEI by its vendors/suppliers.

FEI calculated the expense lead by analyzing each of its expenses for 2022 to determine the average number of lead days between when a service is received and when payment is made. FEI also analyzed Accounts Payable transaction detail for all of 2022 and used known payment dates and cycles for various recurring expenditures.

For each expense item, FEI derived lead times and then dollar-weighted the lead times to produce total weighted average expenditure lead days.

Similar to past Lead Lag studies, eight major groupings of expenses were considered:

1. Energy Purchases;
2. Operations and Maintenance (O&M);
3. Property Taxes;
4. Operating Fees;
5. Carbon Tax;
6. GST;
7. PST; and
8. Income Tax.

FEI discusses each of these groupings and the associated expense lead or lag times below.

5.1 *ENERGY PURCHASES*

FEI purchases its gas requirements from numerous vendors. Given that energy purchases comprise the majority of expenditures, each vendor was analyzed in detail. For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date (15.2 days). Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

Table 4: Calculation of Energy Purchase Leads

Expenditure	Service Lead	Payment Lag	Total Lead Days
	a	b	c=a+b
Energy Purchase	15.2	24.9	40.1

5.2 *OPERATIONS AND MAINTENANCE (O&M)*

To determine the lead days for O&M expenses, these expenses were grouped according to general ledger account.

The primary groupings are comprised of six broad categories: (1) payroll and benefits; (2) contractors; (3) materials; (4) computer costs; (5) insurance; and (6) other O&M. The expense lead times related with each category of O&M are discussed in the following section.

Table 5: Calculation of O&M Leads (Lags)

	2022 Actual Expenses	Weighting Factor	Service Lead (Lag)	Payment Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
	a	b	c	d	e=c+d	f=bxe
O&M						
Payroll & Benefits	$ 162,048,959	59.9%	28.1	10.6	38.6	23.1
Contractors	54,115,215	20.0%	15.2	29.2	44.4	8.9
Materials	11,589,772	4.3%	15.2	35.7	50.9	2.2
Computer Costs	17,239,851	6.4%	42.1	(32.3)	9.8	0.6
Insurance	11,485,088	4.2%	182.5	(344.9)	(162.4)	(6.9)
Other O&M	14,214,453	5.3%	15.2	23.4	38.6	2.0
Total O&M Expenses	$ 270,693,338	100.0%				29.9

5.2.1 Payroll and Benefits

Payroll and Benefits is comprised of a number of expense-related items:

Payroll

There are four different categories of payroll:

- Management & Exempt Employees (M&E);
- Movement of United Professionals (MoveUP);
- International Brotherhood of Electrical Workers (IBEW); and
- M&E, MoveUP Part time and Temporary.

Depending on the category, each of these has different payment terms and different lead/lag days.

The M&E and MoveUP payroll categories are both based on a biweekly pay period. For this group, actual payment occurs 1 day prior to the end of the biweekly pay period. The total average of 6 lead days is determined by adding the elapsed days from the midpoint to the end of the pay period (service lead of 7 days) and the elapsed days from the end of the pay period to the payment date (payment lag of 1 day).

For the IBEW category, actual payment occurs 7 days subsequent to the end of the biweekly pay period. Thus the service lead is 7 days similar to M&E and MoveUP while the payment lead is 7 days for a total average of 14 lead days.

For the M&E and MoveUP Part Time and Temporary category, actual payment occurs 6 days subsequent to the end of the biweekly pay period producing a total average of 13 lead days.

Benefits

FEI calculates lead days individually for each benefit type based on known service periods and specifically recurring payment due dates:

- Disability Insurance;
- Extended Health;
- Dental Plans;
- Group Life Insurance;
- Employer Health Tax;
- Workers Compensation;
- Employer portion of Canadian Pension Plan;
- Employer portion of Employment Insurance;
- Pension;
- Employee Savings Plan;
- Employee Incentive Plans; and
- Other Post Employment Benefits (OPEB).

5.2.2 Contractors, Materials and Computer Costs

FEI analyzed samples of the largest suppliers in each category. For goods and services received, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.2.3 Insurance

For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.2.4 Other O&M

The remaining costs not falling into the categories above were analyzed and a dollar weighting of the payment leads were captured. Once again, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.3 *PROPERTY TAX*

FEI makes property tax payments to approximately 199 municipalities within British Columbia. These payments are generally made once a year, with the majority of payments occurring within one or two days of July 2nd. FEI used a mid-year approach to determine deemed receipt of service, while also analyzing actual payment records to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.4 *OPERATING FEES*

Operating fees are collected from customers located within municipal boundaries in the Inland, Columbia and Vancouver Island service areas. Fees are collected from customers through the billing system on a monthly basis. These fees are typically remitted to the municipalities in either March or November of the following year.[1] FEI used a mid-year approach to determine the deemed receipt date of service, while also analyzing actual payment records to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.5 *CARBON TAX*

Carbon Tax is a tax implemented by the BC Provincial Government on all fossil fuels consumed. Amounts paid are related to both funds collected from customers as well as self-assessed carbon tax amounts. Amounts collected from customers are remitted by the 15th of the month following month of service while self-assessed amounts are remitted at the end of the month following month of service. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

5.6 *GST*

FEI recovers Canadian Goods and Services tax (GST) paid to suppliers on the purchase of goods and services and remits GST collected on revenues from customers. FEI used a mid-

[1] FEI notes that there has been a shift in when payments are remitted to municipalities, such that more payments are now being remitted in March instead of November, which results in a decrease in lead days.

month approach to determine receipt date of service, while also analyzing actual remittance records to determine the payment lead.

5.7 *PST*

FEI remits Provincial Sales Tax (PST) collected on revenues from commercial and industrial customers. The Innovative Clean Energy (ICE) Levy, collected from all customers, is related to purchases of electricity, natural gas, fuel oil and propane. FEI used a mid-month approach to determine receipt date of service, while also analyzing actual remittance records to determine the payment lead.

5.8 *INCOME TAX*

An analysis of actual income tax remittances in any given year includes both regulated and non-regulated aspects. For the purposes of this lead lag study, FEI only considered the regulated aspects of taxes paid. Accordingly, an examination of actual remittance records is not considered applicable. The methodology for determining the amount and timing of regulated taxes paid is therefore on a theoretical basis and is in accordance with one of the three accepted methods in the Income Tax Act for calculating monthly instalment payments. One of the accepted methods is to pay to CRA 1/12 of the estimated tax payable for the current tax year at the end of each month of the taxation year. On this basis, FEI used a mid-month approach to determine the receipt date of service and used an end of month date as the payment date.

Appendix D3-2

FBC LEAD-LAG STUDY

Appendix D3-2

FortisBC Inc.

Cash Working Capital Lead-Lag Study

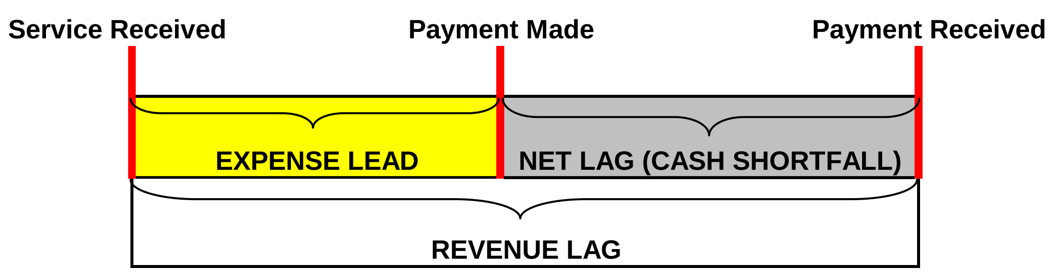
Table of Contents

Index of Tables and Figures

1. INTRODUCTION

The objective of the Lead-Lag study is to provide a measure of cash working capital needs for FortisBC Inc. (FBC) in order to support its future working capital submissions before the British Columbia Utilities Commission (BCUC). Cash working capital is defined as the average amount of capital provided by investors in the company, over and above investments in plant and intangibles, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days. The study recognizes that there are timing differences between when FBC provides a service and when they receive payment (**revenue lag**) as well as the time between when they receive a service and subsequently make payment (**expense lead**). The difference between the total revenue lag and total expense lead is the **net lag**. A net lag number greater than zero indicates a cash working capital shortfall position; this occurs when the payment of an expense precedes the collection of its related revenue stream. In some cases, however, revenue may be received prior to payment for the related expense (a net lead or negative net lag), which indicates a cash working capital surplus position, and a reduction to rate base. Figure 1 illustrates the components of the lead/lag as discussed above.

Figure 1: Lead Lag Schematic Diagram



2. SUMMARY OF KEY FINDINGS

The lead lag days determined in this study will be used for the computation of the cash working capital requirements in FBC's 2025 and future rate applications until another lead-lag study is performed.

Lag days for total revenue and lead days for total expenditures are calculated using 2022 actual data, which is the most recent year of actual data available to prepare this study. For illustrative purposes within this Appendix and as shown in the table below, the results of the lead-lag study were compared using the impact to 2024 Forecast revenue requirements of the proposed 2023 Lead-Lag Study results versus the currently approved 2018 Lead-Lag Study results. The change in weighted net lead-lag days was then used to derive the approximate forecasted change in cash working capital included in rate base.

Table 1 summarizes the cash working capital requirements and lead lag days for each significant receipt and expenditure component.

Table 1: FBC Example of Change in Cash Working Capital Requirements

Line	Particulars	2024 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days	2024 Forecast (000's $)	Approved Lead Lag Days	Dollar Days
1	**Sales Revenue**						
2	Residential Tariff Revenue	219,891	54.2	11,909,656	219,891	56.0	12,313,896
3	Commercial Tariff Revenue	118,276	44.0	5,198,789	118,276	45.1	5,334,248
4	Wholesale Tariff Revenue	59,319	36.7	2,178,116	59,319	37.5	2,224,463
5	Industrial Tariff Revenue	53,156	35.7	1,899,426	53,156	38.0	2,019,928
6	Lighting Tariff Revenue	2,371	44.0	104,258	2,371	34.6	82,037
7	Irrigation Tarrif Revenue	4,234	39.8	168,368	4,234	47.0	198,998
8							
9	**Total Sales Revenue**	457,247	46.9	21,458,612	457,247	48.5	22,173,569
10							
11	**Other Revenues**						
12	Apparatus and Facilities Rental	6,199	90.3	559,851	6,199	90.0	557,910
13	Contract Revenue	2,260	60.0	135,478	2,260	62.2	140,563
14	Transmission Access Revenue	1,723	60.2	103,725	1,723	65.2	112,340
15	Late Payment Charges	962	53.7	51,602	962	54.0	51,922
16	Connection Charge	561	38.4	21,543	561	30.5	17,104
17	Other Utility Income	388	55.3	21,451	388	63.4	24,606
18							
19	**Total Other Revenues**	12,092	73.9	893,650	12,092	74.8	904,444
20							
21	**TOTAL REVENUES**	469,339	**47.6**	22,352,262	469,339	**49.2**	23,078,013
22							
23	Power Purchases	173,694	45.8	7,957,100	173,694	51.5	8,945,261
24	Wheeling	7,324	39.7	290,820	7,324	46.9	343,514
25	Water Fees	12,513	1.9	24,094	12,513	1.4	17,518
26	Operating and Maintenance	63,174	23.9	1,509,851	63,174	28.6	1,806,768
27	Property Tax	18,573	4.1	76,543	18,573	4.9	91,008
28	GST	703	39.4	27,718	703	45.4	31,916
29	Income Tax	12,484	15.2	189,757	12,484	15.2	189,757
31							
32	**TOTAL EXPENDITURES**	288,466	**34.9**	10,075,883	288,466	**39.6**	11,425,742
33							
34	**NET LEAD-LAG DAYS (Line 21 - Line 32)**		**12.7**			**9.6**	
35							
36	**CASH WORKING CAPITAL (Line 32/365 x Line 34)**		**$ 10,037**			**$ 7,587**	
37							

3. METHODOLOGY AND APPROACH

The methodology used to determine the lead lag days for individual revenue and expenditure items is generally similar for all regulated utilities. In addition, the methodology of calculating the lead lag days in this study is consistent with that used in the last study approved by the BCUC in 2020 (Order G-166-20).

The actual data for this lead/lag study is the 2022 calendar year data. This lead/lag analysis takes into account both the working capital requirements associated with lag times as well as the offsetting working capital requirements associated with lead times. Two primary categories of leads and lags were considered: (1) lag times related to revenues and the respective collection of those amounts owed to FBC (revenue lags); and (2) lead/lag times related to the payment for goods and services received by FBC (expense leads (lags)).

These two major categories, revenue lags and expense leads (lags), were further broken down into their individual components to obtain the corresponding individual lead/lag times. The results were then rolled up through a weighted average into total lag days for revenues and total lead days for expenses. Total lag days for revenues were then deducted from total lead days for expenses to arrive at net lag days, which were then applied to total expenditures to arrive at cash working capital requirements.

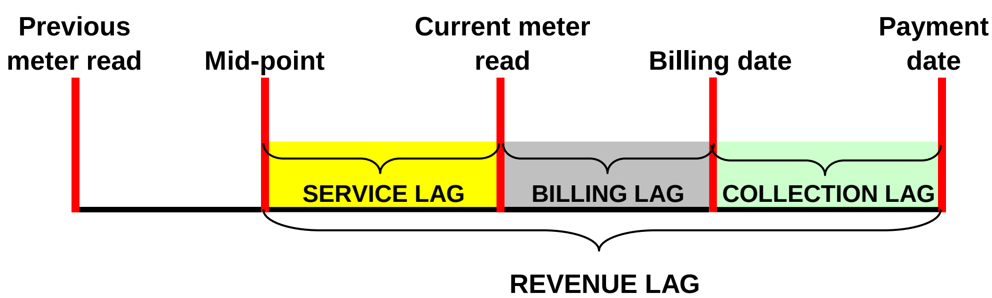
3.1 *CALCULATION OF REVENUE LAG*

The lag days pertaining to revenue receipts are determined by measuring the elapsed time between the date the service is deemed to be rendered and the date FBC receives the related payments from the customer. The revenue lag is the sum of the service lag, the billing lag and the collection lag.

- The service lag is the number of days from the deemed receipt date of service (generally the mid-point of the cycle) to the meter reading date.
- The billing lag is the number of days between the meter reading date and the billing date.
- The collection lag is the number of days from the billing date to the date the payment is received from the customer.

Figure 2 below illustrates these components of the revenue lag.

Figure 2: Revenue Lag Schematic Diagram



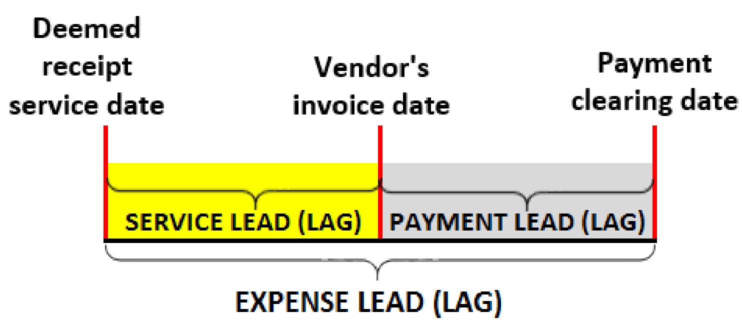
3.2 *CALCULATION OF EXPENSE LEAD (LAG)*

The lead days are determined by measuring the elapsed time from the deemed receipt service date (generally the mid-point) to the date payment is made by the Company. The expense lead (lag) is the sum of the service lead (lag) and the payment lead (lag).

- The service lead (lag) is the number of days from the deemed receipt service date to the vendor's invoice date.
- The payment lead (lag) is the number of days between the vendor's invoice date to the date the funds clear the Company's bank account.

Figure 3 below illustrates these components of the expense lead (lag).

Figure 3: Expense Lead (Lag) Schematic Diagram



3.3 *CALCULATION OF CASH WORKING CAPITAL REQUIREMENTS*

Once the revenue lags and expense leads (lags) are determined, the calculation of the cash working capital requirement involves the following steps:

- For the individual revenue and expense components, multiply the applicable lead/lag days by the respective forecast revenue and expenditure amount to derive the *dollar days*.

- Divide the total revenue and expenditure dollar days by the total forecast revenues and expenditures to derive *total weighted average revenue lag days and expenditure lead days*.
- Deduct the total weighted average expenditure lead days from the total weighted average revenue lag days to determine the *net weighted average lag days.*

Multiply total budgeted expenditures by the net weighted average lag days and divide this product by 365 days to determine the ***cash working capital requirement of the Company.***

4. REVENUE LAGS

FBC recognizes two revenue streams: A) Sales Revenue and B) Other Revenue.

4.1 *SALES REVENUE*

The sales revenue lag days for residential, commercial and other customers are derived from the assessment of three timeframes:

1. **Service Lag:** the time from the deemed average receipt date of service to the average meter reading date;
2. **Billing Lag:** the time from the average meter reading date to the average date the customer is billed, and
3. **Collection Lag:** the time from the average billing date to the average date the customer pays the bill.

4.1.1 Service Lag

The service receipt date is assumed to be the mid-point of the billing period given that customers are expected to receive service evenly throughout the service period. Depending on the billing frequency, the service lag is determined as follows:

- For monthly billings, average days between the deemed service receipt date and meter reading date is 30.4 days, calculated based on 12 billing periods in a 365-day year. When a service is continuous, such as electricity sales, the mid-point of the service period is considered the service lag, which would be 15.2 (30.4/2) using the above approach.
- For bi-monthly billings, average days between the deemed service receipt date and meter reading date is 60.8 days, calculated based on six billing periods in a 365-day year. When a service is continuous, such as electricity sales, the mid-point of the service period is considered the service lag, which would be 30.4 (60.8/2) using the above approach.

4.1.2 Billing Lag

FBC bills customers two days after the meter reading date. This lag time is built into the average billing lag days calculation for each customer rate category in the residential, commercial and other customer classes.

4.1.3 Collection Lag

For the purposes of the lead/lag study, FBC analyzed every customer payment transaction (approximately 1 million invoice records) to derive the average collection lag days.

FBC bills customers every month or every two months. Payments are due 17 days and 22 days following the invoiced date for monthly and bi-monthly billings, respectively. All customers do not necessarily pay on the due date.

4.1.4 Summary of Revenue Lag

The following table shows the calculation of the revenue lags by rate class:

Table 2: Calculation of Sales Revenue Lags

Customer Class	Service Period to Meter Read		Proportion Billed		Service Lag	Meter Read to Billing	Billing to Collection		Proportion Billed		Collection Lag	Total Lag Days
	Monthly	Bimonthly	Monthly	Bimonthly		Billing Lag	Monthly	Bimonthly	Monthly	Bimonthly		
	a	b	c	d	e=a*c+b*d	f	g	h	i=c	j=d	k=g*i+h*j	r=e+f+n
Residential	15.2	30.4	29.5%	70.5%	25.9	2.0	22.6	27.8	29.5%	70.5%	26.2	54.2
Commercial	15.2	30.4	74.3%	25.7%	19.1	2.0	21.3	27.3	74.3%	25.7%	22.8	43.9
Wholesale	15.2	30.4	100.0%	0.0%	15.2	2.0	19.5	0.0	100.0%	0.0%	19.5	36.7
Industrial	15.2	30.4	100.0%	0.0%	15.2	2.0	18.5	0.0	100.0%	0.0%	18.5	35.7
Lighting	15.2	30.4	88.6%	11.4%	16.9	2.0	24.6	28.5	88.6%	11.4%	25.0	44.0
Irrigation	15.2	30.4	99.0%	1.0%	15.3	2.0	22.3	36.1	99.0%	1.0%	22.4	39.8

4.2 *OTHER REVENUE*

Other revenue receipts consist of the following major items:

1. Apparatus and Facilities Rental;
2. Contract Revenue;
3. Transmission Access Revenue;
4. Late Payment Charges;
5. Connection Charges; and
6. Other Utility Income.

FBC calculated the lag days for other revenue receipts separately for each major item using the various individual source data.

Table 3: Calculation of Other Revenue Lags

Other Revenue	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Apparatus and Facilities Rental	180.6	(120.0)	29.7	90.3
Contract Revenue	15.2	14.8	30.0	60.0
Transmission Access Revenue	15.2	15.0	30.0	60.2
Late Payment Charges	0.0	30.0	23.7	53.7
Connection Charge	14.3	1.9	22.2	38.4
Other Utility Income	24.6	5.9	24.8	55.3

5. EXPENSE LEADS (LAGS)

Expense leads and lags correspond to the lead or lag times associated with the payment for goods and services provided to FBC by its vendors/suppliers.

FBC calculated the expense lead by analyzing each of FBC's expenses for 2022 to determine the average number of lead days between when a service is received and when payment is made. FBC also analyzed Accounts Payable transaction detail for all of 2022 and used known payment dates and cycles for various recurring expenditures.

For each expense item, FBC derived lead times and then dollar-weighted the lead times to produce total weighted average expenditure lead days.

Seven major groupings of expenses were considered:

- Power Purchases;
- Water Fees ;
- Wheeling;
- Operations and Maintenance (O&M);
- Property Taxes;
- GST; and
- Income Tax.

FBC discusses each of these groupings and the associated expense lead or lag times are discussed below.

5.1 *POWER PURCHASES, WATER FEES AND WHEELING*

FBC purchases its power, water and wheeling requirements from various vendors, each of which was analyzed in detail. For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

Table 4: Calculation of Power Purchases Leads (Lags)

Expenditure	2022 Actual Expenses	Weighting Factor	Service Lead	Payment Lead	Expense Lead	Expense Lead
	a	b	c	d	e=c+d	f=bxe
Power Purchase	137,965	81%	15.2	29.4	44.6	36.2
Power Purchase - Return on Capital	32,139	19%	182.5	(131.4)	51.1	9.7
	170,104	100%				45.8

Table 5: Calculation of Water Fees and Wheeling Purchase Leads (Lags)

Expenditure	Service Lead	Payment Lead	Total Lead Days
Water Fees	182.5	(180.6)	1.9
Wheeling	15.2	24.5	39.7

5.2 OPERATIONS AND MAINTENANCE (O&M)

To determine the lead days for O&M expenses, these expenses were grouped according to general ledger account.

The primary groupings are comprised of seven broad categories: (1) payroll and benefits; (2) contractors; (3) rental of T&D facilities; (4) office leases; (5) computer costs; (6) insurance; and (7) other O&M. The expense lead times related with each category of O&M are discussed in the following section.

Table 6: Calculation of O&M Leads (Lags)

Line No.		2022 Actual Expenses	Weighting Factor	Service Lead (Lag)	Payment Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
		a	b	c	d	e=c+d	f=bxe
1	O&M						
2	Payroll & Benefits	35,795	66%	16.2	7.4	23.6	15.7
3	Contractors	10,990	20%	13.0	30.4	43.3	8.8
4	Rental of T&D Facilities	3,578	7%	182.5	(132.6)	49.9	3.3
5	Office Leases	240	0%	15.2	(30.3)	(15.1)	(0.1)
6	Computer Costs	1,890	4%	66.5	(68.1)	(1.6)	(0.1)
7	Insurance	1,356	3%	181.7	(333.6)	(151.9)	(3.8)
8	Other O&M	137	0%	15.2	26.1	41.3	0.1
9	Total O&M Expenses	53,986	100%				23.9

5.2.1 Payroll and Benefits

Payroll

There are four different categories of salaries and wages:

- Management & Exempt Employees (M&E);
- Movement of United Professionals (MoveUP);
- International Brotherhood of Electrical Workers (IBEW); and
- M&E, MoveUP Part time and Temporary.

Depending on the category, each of these has different payment terms and different lead/lag days.

The M&E and MoveUP payroll categories are both based on a biweekly pay period. For this group, actual payment occurs 1 day prior to the end of the biweekly pay period. The total average of 6 lead days is determined by adding the elapsed days from the midpoint to the end of the pay period (service lead of 7 days) and the elapsed days from the end of the pay period to the payment date (payment lag of 1 day).

For the IBEW category, actual payment occurs 7 days subsequent to the end of the biweekly pay period. Thus the service lead is 7 days similar to M&E and MoveUP while the payment lead is 7 days for a total average of 14 lead days.

For the M&E and MoveUP Part Time and Temporary category, actual payment occurs 6 days subsequent to the end of the biweekly pay period producing a total average of 13 lead days.

Benefits

FBC calculates lead days individually for each benefit type based upon known service periods and specifically recurring payment due dates:

- Disability Insurance;
- Extended Health;
- Dental Plans;
- Group Life Insurance;
- Employer Health Tax;
- Workers Compensation;
- Employer portion of Canadian Pension Plan;
- Employer portion of Employment Insurance;
- Pension;
- Employee Savings Plan;
- Employee Incentive Plans; and
- Other Post Employment Benefits (OPEB).

5.2.2 Contractors and Computer Costs

FBC analyzed samples of the largest suppliers in both categories. For goods and services received, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.2.3 Rental of T&D Facilities, Office Leases and Insurance

For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.2.4 Other O&M

The remaining costs not falling into the categories above were analyzed and a dollar weighting of the payment leads were captured. Once again, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.3 *PROPERTY TAX*

FBC makes property tax payments to approximately 43 municipalities within British Columbia. These payments are generally made once a year, with the majority of payments occurring within one or two days of July 2nd. FBC used a mid- year approach to determine deemed receipt of service, while also analyzing actual payment records to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.4 *GST*

FBC recovers Canadian Goods and Services tax (GST) paid to suppliers on the purchase of goods and services and remits GST collected on revenues from customers. FBC used a mid-month approach to determine receipt date of service, while also analyzing actual remittance records to determine the payment lead.

5.5 *INCOME TAX*

An analysis of actual income tax remittances in any given year includes both regulated and non-regulated aspects. For the purposes of this lead lag study, FBC only considered the regulated aspects of taxes paid. Accordingly, an examination of actual remittance records is not considered applicable. The methodology for determining the amount and timing of regulated taxes paid is therefore on a theoretical basis and is in accordance with one of the three accepted methods in the *Income Tax* Act for calculating monthly instalment payments. One of the accepted methods is to pay CRA 1/12 of the estimated tax payable for the current tax year at the end of each month of the taxation year. On this basis, FBC used a mid-month approach to determine the receipt date of service and used an end of month date as the payment date.

Appendix D4-1

KPMG FORTISBC CORPORATE SERVICES COST ALLOCATION REPORT

FortisBC Energy Inc., FortisBC Inc., and FortisBC Holdings Inc.

Corporate Services Cost Allocation Review

KPMG LLP

March 2024

This report contains 28 pages

KPMG FortisBC Corporate Services Allocation Report.docx

FortisBC Energy Inc., FortisBC Inc., and FortisBC Holdings Inc.
Corporate Services Cost Allocation Review
March 2024

Table of Contents

Executive Summary

KPMG LLP ("KPMG") was retained by FortisBC Energy Inc. ("FEI") and by FortisBC Inc. ("FBC"), collectively referred to as FortisBC, to perform an independent review of:

(i) The corporate services cost allocation methodology of Fortis Inc (FI), whereby FI allocates corporate services costs to FEI and FBC via Fortis Holdings Inc. ("FHI"); and,[1]

(ii) FHI's corporate services cost allocation methodology, whereby FHI allocates additional corporate services costs incurred by FHI to FEI and FBC.

The basis of the review is to assist FEI and FBC in preparation of their next Rate Making Frameworks beginning in 2025, which are to be submitted to the British Columbia Utilities Commission ("BCUC"). KPMG completed a prior review of FI and FHI's corporate services cost allocation models, and this review was submitted by each of FEI and FBC as part of their 2020 – 2024 Multi-Year Rate Plan Applications. Our prior report was titled *Corporate Services Cost Allocation Model (March 8, 2019).*

KPMG was engaged to assess:

(i) Whether the corporate services department costs (or "cost pools") in FI and FHI met Management tests for costs eligible for sharing and which were therefore deemed relevant and appropriate for allocation; and,

(ii) Whether the cost allocators ("allocators") used for each of the corporate services cost pools met Management's assessment criteria for cost allocators and were therefore deemed to be reasonable as the basis for allocation.

KPMG's assessment did not include a benchmarking of corporate services costs to those at peer utilities. Additionally, the assessment did not evaluate the cost differential if FEI and FBC were to operate as stand-alone entities as opposed to receiving centralized corporate services from FI and FHI.

Since our prior report, FI's and FHI's corporate services cost allocation models have largely remained the same with two notable exceptions:

1) FI has removed the position of EVP - Western Utility Operations, the costs of which were fully allocated to FEI and FBC (via FHI) and FortisAlberta Inc.

2) FHI completed the sale of the Aitken Creek Natural Gas Storage Facility ("ACGS") (held by FortisBC Midstream Inc. ("FMI")) on November 1, 2023. This sale resulted in a change to the proportions of costs allocated to FEI and FBC using the Massachusetts formula; however, the underlying calculation approach remains the same.

KPMG's evaluation finds that:

[1] FI is the ultimate parent of FEI and FBC. FHI is an intermediate holding company.

- FI's corporate services cost allocation methodology is a reasonable mechanism for allocating FI corporate services costs to FHI.

- FHI's corporate services cost allocation methodology is a reasonable mechanism for allocating eligible FHI corporate services costs to FEI and FBC.

In addition to appropriately allocating costs, the mechanisms exclude costs that are not eligible for recovery from consumers prior to their allocation to FEI and FBC. Accordingly, the mechanisms provide an appropriate basis for setting utility rates.

1 Introduction

1.1 Background and Scope

FortisBC Energy Inc. (“FEI”) and by FortisBC Inc. (“FBC”), collectively referred to as “FortisBC”, retained KPMG LLP (“KPMG”) to conduct an evaluation of Fortis Inc.’s (“FI”) and Fortis Holdings Inc.’s (“FHI”) 2023 corporate services cost allocation models in preparation for FortisBC’s next Ratemaking Framework beginning in 2025.

Specifically, KPMG was engaged to:

- Review FI’s allocation methodology (**Section 4**) and whether the cost pools for corporate services departments and the allocators used for these pools met the assessment criteria set by FortisBC’s Management for these pools and allocators (**Section 2**); and,
- Review FHI’s allocation methodology (**Section 5**) and whether the cost pools for corporate services departments and the allocators used for these pools met the assessment criteria set by FortisBC’s Management for these pools and allocators (**Section 2**).

KPMG also assessed whether the allocation model and the treatment following the divestiture of Aitken Creek Natural Gas Storage Facility (“ACGS”) remains appropriate.

1.2 Limitations

1.2.1 Fortis Inc. and Fortis Holdings Inc. Management Responsibility

FI’s and FHI's corporate services costs allocation model are the responsibility of their respective management, which also maintains responsibility for the accuracy and completeness of the data and information associated with the corporate services cost allocation methodologies and associated costs.

1.2.2 KPMG Engagement

KPMG’s engagement is to comment on the reasonableness of the corporate services cost allocation methodologies used to allocate corporate services costs from FI to FHI and from FHI to FEI and FBC.

This engagement does not constitute an audit of the corporate service cost allocation methodologies or associated costs and is therefore not subject to assurance or other standards issued by the Canadian Auditing and Assurance Standards Board. Consequently, no opinions or conclusions intended to convey assurance have been expressed. The results summarized in this report are based on the information provided to us during the course of our work, which includes financial information and information obtained through discussions with FHI, FEI, and FBC management and employees. This Report relies on data and information from the sources noted and makes no representations with respect to their accuracy or completeness. We have no obligation to update our report or to revise the information contained herein to reflect corrections or changes to information or representations provided to us or other events and transactions occurring subsequent to completion of our fieldwork.

FI and FHI prepared the proposed corporate services cost allocations using 2023 budgeted O&M costs. Our findings and conclusions are therefore limited to the allocation approaches for 2023 costs. We did not assess the reasonableness of associated amounts. Additionally, our findings and conclusions are limited to the allocations of FI corporate service costs to FEI and FBC via FHI, and the allocations of FHI corporate service costs to FEI and FBC.

The information contained herein is for the internal use of FEI, FBC, and FHI management. It is understood that this report may be distributed by FEI, FBC, and FHI externally to the BCUC as part of the regulatory process. KPMG disclaims any responsibility or liability for losses, damages, or costs incurred by anyone as a result of any external circulation, publication, reproduction, or use of the information contained herein.

2 Approach

This section summarizes KPMG's approach to completing the review of FI's and FHI's corporate services allocation methodology.

2.1 Work Plan

Our work plan was developed in collaboration with management to meet the objectives of this review.

Table 1: Work Plan Summary

Step	Description
1	**Review study context**. In this step, KPMG met with management to understand FortisBC's organizational structure and the business context for this review, including any changes in operations since the last review undertaken by FortisBC, the response to prior corporate service cost allocation studies filed by FortisBC, and FortisBC's plans for future general rate filings.
2	**Review and document regulatory guidance**. In this step, KPMG researched and documented the guidance provided by regulatory authorities on the topic of corporate service cost allocation. The objective of this step was to ensure that the approach and corporate service cost allocation methodologies adopted by FI and FHI are consistent with regulatory precedent.
3	**Initial review of cost pools and allocation methodology.** In this step, KPMG reviewed: ▪ FHI's cost center cost information (2023 Budget) and cost pools for allocation to FEI and FBC ▪ FHI's calculation of the Massachusetts Formula ▪ FI management fee allocation and allocation methodology The initial review was focused on establishing an understanding of current cost pool build up and identifying any key changes that could impact the approach or application of the approach.
4	**Participate in interviews with company officials**. In this step, KPMG participated in interviews held by FortisBC with representatives from the relevant FHI corporate functions. The purpose of the interviews in this step was to gain an understanding of: ▪ The scope of activities completed within each FHI corporate function for the benefit of FHI subsidiaries and affiliates, and the appropriateness of allocating these costs to FEI and FBC in alignment with the principles outline in **Section 2.2**. ▪ Any anticipated changes to the scope of activities through the next Ratemaking Framework period ▪ Impact of the divestiture of FMI (ACGS) on scope and/or level of activity completed within FHI corporate services functions ▪ Estimated level of effort by FHI subsidiary and affiliate (pre and post FMI (ACGS) divestiture) ▪ Factors that drive level of effort and the appropriateness of the Massachusetts Formula Interview questions are provided in **Appendix A.** Interviewees were also provided with summary cost centre budget data to assist in answering questions.
5	**Assessment of cost pools and allocation methodology.** In this step, KPMG assessed the cost pools and allocation methodology with additional context gathered from the interviews in Step 4. The assessment was aligned with evaluation criteria outlined in **Section 2.3**.
6	**Prepare report**. In this step, KPMG summarized the results of the evaluation.

2.2 Cost Allocation Principles

FI and FHI apply the following basic assessment criteria when evaluating which shared goods or service expenditures should be included in cost pools to be allocated from FI to FHI and from FHI to FEI and FBC.

The goods or services must have both of the following basic attributes to be included in a corporate services cost allocation pool:

- The services performed at the corporate parents (FI and FHI) provide a direct or indirect benefit to the subsidiaries (FHI, FEI, and FBC) and hence to their respective customer bases; and,
- If the services were no longer provided by FI or FHI, then the affected subsidiaries (FHI, FEI, and FBC) would be negatively impacted and would have to find other sources for the services or perform such services on their own. By implication, the services would still be required by the recipient entities (FHI, FEI, or FBC) if they were standalone operations.

These principles are consistent with the principles applied in FortisBC's prior cost allocation study that was prepared to support the 2020-2024 Multi-Year Rate Plan.

2.3 Evaluation Criteria

FortisBC has traditionally used a set of criteria for the evaluation of methodologies for corporate services cost allocation and of associated cost drivers. These criteria continue to be used by FortisBC management for the Ratemaking Framework beginning in 2025 and KPMG accepts these criteria as reasonable. The criteria were used both by:

1) FortisBC management in applying the methodology and its supporting calculations, and
2) KPMG in evaluating the methodology and its results.

Evaluation criteria are summarized in the table below.

Table 2: Evaluation Criteria

No.	Evaluation Criteria	Description
1.	Cost Causality	The identified driver, being it work effort or investment, has a direct correlation to the cost of the services or goods and also has a direct effect on the level of service.
2.	Objective Results	The use of the allocation driver results in an objective allocation amount that is free from undue bias.
3.	Cost Effectiveness	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense to implement and administer.
4.	Stability Over Time	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.

No.	Evaluation Criteria	Description
5.	Transparent and Supportable Methodology	The driver used and the source or basis on how it is determined is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model and other supporting documentation.
6.	Regulatory Precedence	The cost allocation methodology has been tested and approved through previous regulatory reviews and/or is defendable from a regulatory perspective.
7.	Distinguishable from Directly Allocated Costs	The costs must be distinguished from those that are directly charged to the entity.
8.	Accuracy of Underlying Data	Any data used in the methodology should be accurate and reliable. The data should provide an appropriate measure of the underlying volume of activity or output.
9.	Flexibility/Adaptability	The methodology should be able to accommodate future changes in regulations, accounting, and organization structure with reasonable ease.

3 Background

3.1 Organizational Structure

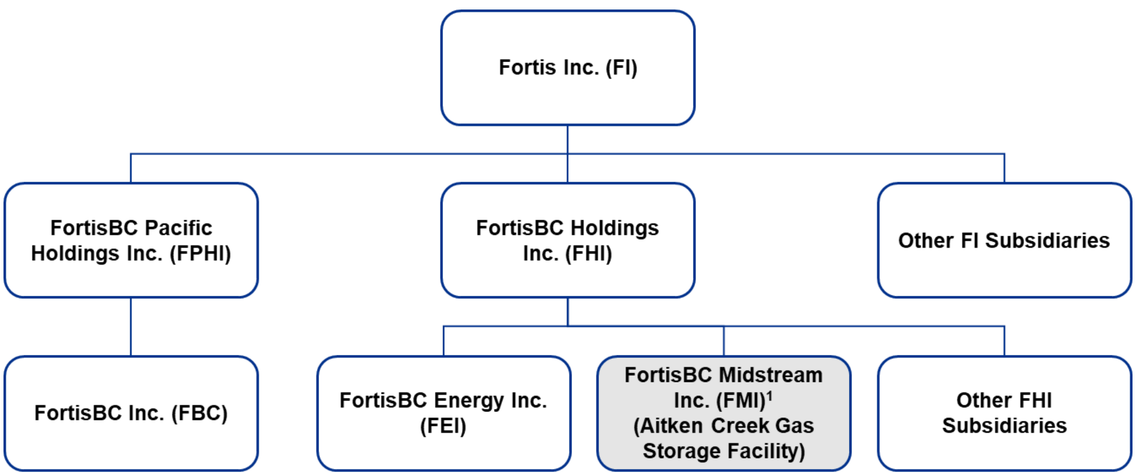
FI provides strategic direction, leadership, risk management, oversight, and equity to its various subsidiaries, which include FEI and FBC. FHI, a direct subsidiary of FI, in turn provides administrative, accounting, and other reporting services to its subsidiaries and other affiliated companies in the FI group of companies.

Figure 1 provides a simplified overview of FI's corporate structure, highlighting the relationship between FI, FBC, and FEI. As shown in Figure 1, FI's ownership interest in FEI and FBC is not held directly but rather through the intermediate holding companies FHI and FPHI, respectively.[2]

FHI allocates its corporate services costs to FEI, FBC, and (formerly) FMI using the Massachusetts formula (further described in **Section 5.5**). FHI directly charges corporate services costs to its other subsidiaries.[3] These direct charges are excluded from the cost pool that is allocated to FEI, FBC, and (formerly) FMI.

In November 2023, FI completed the sale of its interest in Aitken Creek Gas Storage Facility, an asset held by FortisBC Midstream Inc. ("FMI"). As a result, FMI, the holding company, has been dissolved and will no longer receive allocated costs from FHI.

Figure 1: Fortis Inc. Simplified Corporate Structure.



[1]Aitken Creek Gas Storage Facility was sold on November 1, 2023. As a result, FMI, the holding company, has been dissolved and will no longer receive allocated costs from FHI.

[2] Although FI's equity interest in FBC is held through FPHI, allocations of FI corporate services costs to FBC flow through FHI, an indirect affiliate of FBC.

[3] These other subsidiaries are much smaller than FEI and FBC and use of direct charges is a fairer and more representative approach to cost recovery than inclusion of these entities in the Massachusetts formula. Services provided to these other entities may vary considerably from year to year depending on specific initiatives or developments.

FEI provides natural gas transmission and distribution services to its customers, and it procures natural gas on behalf of many of these customers. FBC provides electricity transmission and distribution services to its customers; it also manages electricity generation plants and buys electricity from other suppliers to supply its customers. Pursuant to the Utilities Commission Act (British Columbia), the BCUC regulates such matters as rates, construction, and financing for both FEI and FBC.

It is common in the utility industry to have a parent company that provides certain services to its regulated subsidiaries and other affiliates. This can help in the sharing of specific expertise and associated overhead costs across various operating entities and can thus support economies of scale. In this case, FI and FHI have different and complementary responsibilities to FEI and FBC.

FHI, FEI, and FBC are all managed under the same executive leadership team and governed under the same Board of Directors. As a result of this integration, FHI provides support services to FBC in addition to the services that it provides to FEI. As a result, FBC pays fees to FHI in recognition of the services provided. In this case, FBC is not a direct subsidiary of FHI but rather a subsidiary of a related entity (FPHI) that has the same ultimate parent as FHI (that parent being FI). The allocation of FHI corporate services costs between FEI and FBC is done using a Massachusetts formula (methodology outlined in **Section 5**).

3.2 Comparators

KPMG completed a review of the corporate services cost allocation approaches of select comparator utilities. As confirmed by this review, the use of multi-factor (or composite) allocators continues to be a common approach to allocating corporate services costs. While there is variation on the specific allocation factors used, they generally align with the Massachusetts formula, incorporating factors related to revenue, assets, and labour.

Table 3 summarizes allocation methodologies for our utility sample group.

Table 3: Comparator Corporate Shared Service Allocation Methodologies

Comparator	Regulator	Corporate Services Cost Allocation Approach
Creative Energy Vancouver Platforms (“Creative Energy”)[4]	BCUC	The BCUC approved Creative Energy’s use of a Massachusetts formula to allocate Sales, General, & Administration (SG&A) costs between Creative Energy’s core steam services and its other regulated Vancouver projects.
Corix Infrastructure Inc. (“Corix”)[5]	BCUC	The BCUC approved Corix’s cost allocation approach, which allocated indirect corporate costs (i.e., those corporate costs not directly assigned) to subsidiaries using the Massachusetts formula.

[4] BCUC Decision and Order G-205-18, October 25, 2018, p. 33 - 37
[5] BCUC Decision and Order G-349-20, 2020, p. 6 -18

Comparator	Regulator	Corporate Services Cost Allocation Approach
ATCO Pipelines ("AP")[6]	AUC	ATCO Ltd. allocates corporate shared services costs to ATCO Pipelines and other subsidiaries. ATCO uses several different allocators such as proportion of headcount, vehicles, AP invoice, and contract spend. ATCO also uses a 'General Common Allocator' (GCA), which is the average of net revenue, total assets, and total labour. Variations of the GCA are applied depending on the scope of the cost allocation (i.e., all subsidiaries, utilities only, etc.).
ENMAX Power Corporation ("EPC")[7]	AUC	ENMAX Corporation allocates corporate shared service costs to EPC and other subsidiaries. Costs are assigned using a combination of different allocators, which include activity/estimated work effort, headcount, device/user count, square footage, and a 'universal allocator'. The universal allocator is a multi-factor allocator that is the average of gross margin, total assets, and headcount.
EPCOR Distribution & Transmission Inc. ("EDTI")[8]	AUC	EDTI's parent, EPCOR Utilities Inc. ("EUI"), allocates corporate shared service costs to EDTI and 'business units' (i.e., subsidiaries). Costs are allocated either through: ▪ Direct charges, where costs can be reasonably isolated and assigned to a particular business unit. ▪ Allocated, where costs cannot be directly isolated and assigned to a particular business unit. Where costs are allocated, EUI utilizes either: ▪ Functional Cost Allocators – These allocators are used where costs can be logically allocated using an identified cost driver. Examples include headcount, PP&E, net income, and direct information services costs. ▪ Composite Allocator – Where a logical functional cost allocator cannot be identified, EUI uses a composite allocator which is the average of a business unit's proportion of revenues, assets, and headcount.
APEX Utilities Inc. ("AUI")[9]	AUC	AUI's parent, TriSummit Utilities Inc. ("TSU"), allocated corporate shared service costs to AUI and its subsidiaries using a 'Modified Massachusetts Formula' (MMF) comprised of: ▪ Total Assets ▪ Payroll ▪ Normalized EBITDA TSU initially proposed the use of 'Property' (defined as PP&E including construction work-in-progress, plus Materials and Supplies Inventories and Gas Inventories). The AUC directed Apex to utilize Total Assets.

[6] ATCO Pipelines 2024-2026 General Rate Application, October 10, 2023, Section 4.2.4.
[7] ENMAX Power Corporation 2023-2025 Transmission General Tariff Application, October 3, 2022, p. 119 – 121 and MFR Schedule 27
[8] EDTI 2023-2025 TFO Tariff Application, Appendix K, November 17, 2022
[9] AUC Decision 26616-D01-2022, ATCO Gas Apex Utilities Inc. 2023 Cost-of-Service Review, September 1, 2022, p. 46 – 49

4 Allocation Model for FI to FHI

4.1 Cost Allocation Model Overview

Costs for corporate services are calculated at the cost center level and combined into a cost pool for allocation. This cost pool is then allocated to FI's subsidiaries using a proportional allocator based on assets and controllable costs.

Figure 2 summarizes the steps in the cost allocation process. After excluding certain costs as noted in Section 4.3, FI allocates its remaining operating costs to its various subsidiaries. Costs are allocated using a two-factor allocator that considers each subsidiary's share of assets and controllable costs, as more fully outlined in Section 4.4. The allocation to FHI takes into account the assets and controllable costs of both FBC and FHI's direct subsidiaries (which include FEI). Effectively, FBC is considered as part of FHI in the calculation of FHI's share of FI costs. FHI then allocates the eligible portion of charges from FI to FBC and to its own subsidiaries through its own separate corporate services cost allocation methodology (outlined in **Section 5**). Thus, FI charges flow to FBC through FHI.

Figure 2: Summary of FI Cost Allocation Steps

4.2 FI Operating Costs

FI provides strategic direction, leadership, risk management, and oversight to its subsidiary companies. These services enable subsidiaries to take advantage of the benefits that arise through economies of scale from shared corporate services and from access to capital markets through FI, which meets regulatory requirements as an issuer of equity in Canada.

The table below outlines the primary activities provided by FI. (Note that this table does not provide an exhaustive list of FI services.)

Table 4: Summary of Activities by FI Function

Function	Activities
Executive	Provides strategic direction, leadership, and management for Fortis Inc., manage the organizational structure, financial planning, maintaining controls and internal systems, employee relations, external communication, board relations, regulatory compliance, provision of legal services, maintain internal and external audit activities, and corporate financing and budgeting.
Treasury and Taxation	Performs Fortis Inc. treasury services and provides oversight to subsidiary companies for debt and equity financings, maintaining the capital structure, corporate cash management and forecasting, management of hedging activities,

	preparation of corporate tax returns, tax planning, coordinating corporate tax audits, rating agency process, and corporate credit facilities.
Investor Relations	Manages analyst, investor and shareholder communications, coordinate Fortis Inc. annual general meeting, preparation of quarterly investor relations reports, manage public and media relations, maintain Fortis Inc. website, manage dividend reinvestment and share purchase plans, and oversight over the Annual Report preparation process.
Financial Reporting	Prepares monthly, quarterly and annual consolidated and non-consolidated Fortis Inc. financial statements, coordination with external auditors, analysis of financial information, preparation of the Annual Information Form for Fortis Inc., Annual Report for Fortis Inc., quarterly and annual Management Discussion and Analysis for Fortis Inc. and other continuous disclosure documents for Fortis Inc., coordinate consistent accounting policy treatment across the Fortis group, oversight and review of compliance with U.S. GAAP, preparation of the company-wide quarterly forecast consolidated earnings for Fortis Inc. and earnings per share and maintaining internal controls over financial reporting for Fortis Inc.
Internal Audit	Performs Fortis Inc. internal audit activities, provides oversight over the internal audit function at the Fortis subsidiary companies, administers and monitors reports of allegations of suspected improper conduct or wrongdoing, development of a company-wide Enterprise Risk Management program approach.

4.3 Specified Exclusions

Some of FI's corporate services costs are not eligible for inclusion in customer rates and are therefore not passed on to the regulated utilities in the form of a management fee. The costs excluded from the calculation of the FI Management fee include:

- Debt financing costs (i.e., interest on debt and dividends associated with preferred equity).
- All identifiable business development costs related to potential and completed acquisitions, including a portion of internal labour costs, and all incremental external expense including but not limited to legal, consulting fees, financial advisory, and travel.
- Costs associated with retired FI employees or FI employees transferred to an operating subsidiary such as pension-related costs, Performance Share and Restricted Share Unit expenses and any insurance premiums.
- Specific communication and investor relations department costs relating to branding and marketing.
- All costs associated with conferences and seminars attended by FI employees, meals and entertainment of FI employees and Board of directors, FI employee relocation costs and corporate donations.

To calculate the portion of FI labour costs associated with shareholder-related (i.e., business development) activities to be excluded from the recoverable regulated operating costs, FI management estimates the approximate time spent by the senior executives on shareholder related activity. FI's estimates of the portion of salary and benefits to be excluded from the general cost pool are provided in **Table 5**.

Table 5: FI Role-Based Business Development Exclusions

Role	Percentage Excluded
President and CEO	50%
EVP & CFO	50%
EVP, Operations & Innovation	25%
EVP, Sustainability and CLO	37%
SVP, Capital Markets & Business Development	50%
VP, Investor Relations	0%
VP, General Counsel	25%
VP, Finance	25%
VP, Controller	25%
VP, Chief Information Officer	0%
VP, Communications	75%
VP, Innovation and Technologies	25%

In a previous study commissioned by FortisBC for their 2020 – 2024 Multi-Year Rate Plan, there was a separate allocation related to the EVP, Western Utility Operations role, which was allocated only to FHI and FortisAlberta. The EVP, Western Utility Operations role is no longer present at FI.

4.4 Allocation of FI Costs to FHI

The general operating costs incurred by FI, less excluded costs or identifiable costs directly allocated to specific operating subsidiaries, are included in a general cost pool and allocated on a pro rata basis to FI's operating subsidiaries. Specifically, FI uses two cost allocation factors weighted as follows:

- Total assets, excluding Goodwill (75% weighting)
- Controllable costs (25% weighting)

The use of multiple factors for general cost allocation is a balanced methodology. The methodology is consistent with the approach used by many utilities, and based on our research is favoured by many regulators. Using multiple factors also recognizes that there is no one perfect allocator, and mitigates the inherent risk associated with using one measure for calculating general cost allocations.

In the FI methodology, the weighting for assets recognizes that assets provide the basis upon which regulated utilities earn a return, with total assets (excluding goodwill) closely correlating with the debt and equity investment that is required in operating subsidiaries. The weighting for controllable operating expenses is a measure of each subsidiary's scale of operating activities, which are in turn a major driver of requirements for management oversight and attention. Combined, the asset and operating cost measures are a strong proxy for activity levels at the subsidiaries that drive, and benefit from, corporate services at the parent company level. Using both assets and controllable operating activities also helps account for the diversity of operating subsidiaries, which include transmission and distribution, transmission-only utilities, vertically integrated utilities, and natural gas utilities, among others.

FHI's portion of FI recoverable cost is calculated based on the weighted average of the FortisBC gas and electric asset allocation (excluding goodwill), and controllable cost allocation as represented in the table below:

Table 6: FI Corporate Service Cost Allocation Percent to FHI

Allocation Factor	Weighting	Allocation % to FHI
Asset Allocation (Excluding Goodwill)	75%	21.3%
Controllable Cost Allocation	25%	23.3%
Total Allocation		21.8%

Potential Alternative Approaches

FI has determined that the use or addition of other cost allocation factors, such as total revenue or personnel/payroll, are not appropriate given:

- the diversity of its businesses,
- the Fortis business operating model, and
- the role of FI in providing equity.

For example, using revenue as a cost allocator may distort the allocation of recoverable costs as certain utilities in the Fortis group of companies, such as FortisAlberta and ITC Holdings, only charge customers for distribution or transmission services. A revenue-based allocation method would result in a disproportionately low allocation of costs to these two utilities relative to their equity investment requirements.

Conversely, for certain other utilities in the Fortis group of companies, revenues include the recovery of the costs of purchasing power, natural gas, or fuel. These are flow-through costs that can be volatile and will fluctuate with external market conditions. These flow-through costs are not a major driver of corporate services support and should not be a factor in allocation percentages.

For similar reasons, personnel metrics such as labour or payroll are not an appropriate allocation factor for FI corporate services costs. Certain subsidiaries, such as ITC Holdings, outsource a significant component of their operating functions. Measures of labour or payroll would result in an under-allocation of costs to these subsidiaries, to the detriment of entities such as FEI and FBC, which have much larger employee complements relative to their operating costs and asset base.

4.5 FHI Proportion of FI Recoverable Costs

The general operating costs incurred by Fortis, less excluded costs and less identifiable costs directly allocated to specific operating subsidiaries, are included in a general cost pool and allocated to FHI based on the overall allocation percentage of 21.8%.

Table 7: Breakdown of FI Management Fee Allocated to FHI

FI Recoverable Cost Categories	21.8% Allocation of 2023 Actuals to FHI
Salaries	6,080
Directors' fees and costs	1,090
Trustees and DRIP administration	151
Consulting	703
Legal	189
Audit	262
Listing and filing	160
Annual meeting and report	282
Business Development/special projects*	-
Other fees	189
Occupancy	404
Insurance	411
Office related	318
Investor Relations	111
Communications	117
Miscellaneous	8
Travel	194
Telephone	31
Total 2023 Amount Allocated to FHI ($CAD)	10,700
Variance from 2023 Forecast	150
Total 2023 FHI Recoverable Amount ($CAD)	10,550
* Business Development/special projects remain in FI and are not allocated to FHI.	

5 Allocation Model for FHI to FEI and FBC

5.1 FHI Cost Allocation Model

During the 2020-2024 Multi-Year Rate Plan term, FHI allocated shared services to FEI, FBC, and FMI (ACGS) through a Massachusetts formula and it allocated shared service costs to other FHI subsidiaries through direct charging. For the next Ratemaking Framework beginning in 2025, FHI will continue to apply the same methodology; however, FHI will no longer be allocating costs to FMI (ACGS) due to the divestiture of that entity that occurred on November 1, 2023. Accordingly, the calculation of the Massachusetts formula will be based on revenue, payroll, and tangible capital assets plus inventories for FBC and FEI only. **Section 6** assesses the impact of the FMI (ACGS) divestiture.

FHI establishes cost pools at the department level, removing any direct charges to other subsidiaries (i.e., those subsidiaries that are not FEI, FBC, or FMI(ACGS)) and any specified exclusions (**Section 5.3**). These cost pools are then allocated to FEI, FBC, and FMI (ACGS) using a Massachusetts formula (**Section 5.5**). **Figure 3** summarizes the steps taken by FHI to calculate the portion of its recoverable operating costs to allocate to FEI, FBC, and FMI (ACGS).

Figure 3: Summary of FHI Cost Allocation Steps

FHI Operating Costs (including FI Management Fee) **(Section 5.2)**	-	Specified Exclusions **(Section 5.3)**	=	FHI Recoverable Operating Costs **(Section 5.4)**	X	FEI, FBC, and FMI Proportion Based on Mass. Formula **(Section 5.5)**	=	FEI, FBC, and FMI Proportion Based on Mass. Formula **(Section 5.6)**

5.2 FHI Operating Expenses

FHI provides management services to its subsidiaries and FBC to take advantage of the benefits that arise through economies of scale by providing specific services centrally.

FHI's activities are focused on providing fiduciary services to FEI and FBC. The business services included in the cost allocation model (listed in the table below) are commonly found in gas and electric utilities.

In addition to the services listed in the table above, FHI allocates the recoverable portion of the FI management fee to FEI and FBC.

Table 8: Description of Activities by FHI Corporate Function

Function	Activities Include
Governance & Board of Directors	Ensure all continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, manage the relationship and corporate activities of the FortisBC Inc. and FortisBC Energy Inc. Board of Directors, and develop and maintain governance procedures and policies. The Board of Directors is a joint Board that is shared with FortisBC Inc.

Function	Activities Include
External Financial Reporting	Preparation of monthly, quarterly and annual consolidated and non-consolidated financial statements, coordination with external auditors, analysis of financial information, assisting in the preparation of the Annual Information Form, quarterly and annual Management Discussion and Analysis and other continuous disclosure documents, assessing new and existing accounting policy treatments, preparing quarterly forecasts of consolidated earnings and maintaining internal controls over financial reporting.
Internal Audit	Developing, planning, and conducting audits/reviews, conducting annual risk assessment processes, monitoring and evaluating the effectiveness and efficiency of internal controls.
Legal	Provides all legal services and counsel to various departments on issues including regulatory, environmental, business development, employment, securities, financing, and intellectual property, and manages legal matters that have been outsourced to outside legal counsel.
Insurance & Risk Management	Ensuring compliance with the TSX requirements on risk management, arranging for coverage based on assessed potential risk, and providing an appropriate and prudent insurance program.
Taxation	Provides a full range of services in income and commodity taxes including financial reporting for taxes (year-end and quarterly tax provisions for current and future income taxes), tax compliance (filing of tax returns, coordination of tax audits), regulatory tax accounting (tax calculations for rate cases and annual reports), tax planning including guidance and support for significant transactions, and tax dispute management and resolution.
Treasury & Financial Planning	Execute short and long term financings, cash management and forecasting, arrange operating credit facilities, and negotiate bank-service fees for all FEI entities; responsible for treasury related controls and compliance, compliance reporting, hedging of interest rate and foreign exchange risks, managing the rating agencies, maintaining bank and debt investor relationships, investor and shareholder communication, preparing regulatory submissions in support of ROE, capital structure and financing related matters, providing credit and counter-party credit risk management, and preparing quarterly financial forecasts.
Facilities & Support	Providing building space, shared services, computer software, computer hardware, office supplies and stationery, admin, computer outsourcing.

5.3 FHI Specified Exclusions

Some of the costs that FHI incurs are not recoverable from customers under BCUC regulatory rules or practices. Accordingly, these costs have been excluded from the calculation of the FHI management fee. Cost exclusions are as follows:

- **All identifiable business development costs**: Management has estimated the internal labour costs and related benefits to be excluded based on an estimate of the proportion of time spent by each employee on business development activities.
- **Costs incurred for non-regulated entities**: Estimates of the time spent supporting non-regulated entities has been made for each corporate service cost centre, with labour and associated costs excluded for certain employees in the following divisions: External Financial Reporting, Risk Management & Insurance, Legal, Taxation, and Treasury & Financial Planning. The excluded amounts vary from 15% to 100% of the employee's cost of labour and associated benefits.

  Management has determined the estimated internal labour costs and related benefits to be excluded based on an estimate of the time spent by each employee on non-regulated entities. Management estimates consulting fees related to activities on non-regulated entities based on historical cost levels.
- **Pension bonus amounts for defined benefit supplemental pension plans**: Based on previous determinations by the BCUC, pension bonus amounts for defined benefit supplemental pension plans are not eligible for inclusion in customer rates and are not passed on to the FEI and FBC. Management has excluded these costs when calculating the fully loaded costs for employees of FHI.
- **Services directly charged to other related entities**: Support services provided by FHI, and directly charged to other regulated and non-regulated entities are excluded in the corporate services cost pools. These exclusions have reduced the costs relating to Legal, Taxation, and Accounting.

5.3.1 FI Management Fee Ineligible Expenses

FHI is allocated a portion of the corporate services cost pools of FI (**Section 4**). Of the total FI management fee being charged to FHI, certain amounts are operating costs that are not recoverable from the regulated utilities. As previously determined by the BCUC, these non-recoverable costs are ineligible for inclusion in customer rates and are not passed on to the utilities.

Ineligible components of the FI management fee include Defined Benefit Supplemental Employee Retirement Plan and stock compensation costs that were not already excluded by FI. The specified exclusions of FI management fees and corporate services costs to be allocated are presented in Table below.

Table 9: FI Corporate Service Cost Exclusions

Fortis Inc. Management Fee	
Fortis Inc. Corporate Costs Allocated to FHI	$10,550,000
(Less) Stock Compensation Costs Not Already Excluded by FI	$2,992,000
Eligible FI Corporate Costs for Allocation	$7,558,000

5.4 FHI Allocation of Eligible Corporate Services Costs

Gross FHI operating costs less the specified exclusions, as outlined in **Section 5.3**, results in the FHI costs that are eligible for allocation to FEI, FBC, and FMI (ACGS). The table below summarizes the eligible costs; the amounts shown are based on the 2023 FHI budget.

Table 10: Summary of FHI Operating Costs, Exclusions, and Cost Pools

FHI Corporate Services Cost Pools Eligible for Allocation	FHI Operating Costs	Specified Exclusions	Eligible Costs (Cost Pools)
Governance & Board of Directors	$2,052,945	$67,361	$1,985,585
External Financial Reporting	917,818	258,686	659,132
Internal Audit	1,707,758	153,698	1,554,060
Legal	3,281,011	1,165,247	2,115,764
Insurance & Risk Management	381,816	9,545	372,271
Taxation	1,340,076	279,486	1,060,590
Treasury & Financial Planning	1,717,916	571,652	1,146,264
Facilities & Support	1,429,529	187,343	1,242,186
Fortis Inc. Management Fee	10,550,000	2,992,000	7,558,000
Other Excluded Costs	7,440,020	7,440,020	-
Total	$30,818,888	$13,125,038	$17,693,852

5.5 Massachusetts Formula

For all eligible costs, FHI uses the Massachusetts formula to determine the percentage of operating costs to be allocated from FHI to FEI, FBC, and FMI (ACGS). The Massachusetts formula is a widely used and accepted cost allocator in the North American utility industry. For each entity, the allocator is the average of that entity's share (in percentage terms) of each of:

- Revenues[10];
- Payroll; and
- Two-year Average NBV of Tangible Capital Assets plus Inventories.

[10] FHI uses Gross Margin (revenue less acquisition cost of energy) in place of revenue in its application of the Massachusetts formula.

FHI uses Gross Margin rather than Revenue in its application of the Massachusetts formula for the following reasons:

- FEI and FBC do not charge a markup on commodity costs (gas or electricity), which are treated as a pass-through in the rate-setting process; therefore, gross margin is used as the measure since it captures that portion of revenues that covers FEI's and FBC's regulated cost base; and
- Relative to Gross Margin, Revenues are more affected by fluctuations in underlying commodity prices and volumes; therefore, Gross Margin is a more stable measure of relative entity scale and of underlying cost trends.

The Table below provides the cost allocation proportions as determined by the Massachusetts formula for 2023. As shown, these allocations assumed that FMI (ACGS) was part of the corporate structure.

Table 11: 2023 FHI Massachusetts Formula Calculation (FEI, FBC, and FMI (ACGS))

Component	FEI	FBC	FMI (ACGS)
Gross Margin	$1,028,362,980	$322,356,643	$74,164,617
	72.2%	22.6%	5.2%
Payroll	$181,817,748	$54,115,246	$4,361,938
	75.7%	22.5%	1.8%
Average of NBV of PP&E + Inventories	$5,845,742,233	$1,614,297,507	$490,035,176
	73.5%	20.3%	6.2%
Massachusetts Formula Allocation	**73.8%**	**21.8%**	**4.4%**

5.6 Portion of FHI Recoverable Operating Costs

Eligible FHI costs are allocated on a monthly basis to FEI, FBC, and FMI (ACGS) using the allocation percentages determined through use of the Massachusetts Formula.

The sale of FMI (ACGS) occurred on November 1, 2023. To avoid unanticipated changes in FEI and FBC's financial position, the cost allocations to FMI (ACGS) for the months of November and December were retained in FHI (i.e., these two months were not reallocated to FEI or FBC).

The table below provides illustrative allocations based on FHI's 2023 budget. As noted above, ACGS received allocations in 2023 as it was not divested until late in the financial year (see **Section 6** for results excluding ACGS).

Table 12: Summary of FHI Cost Allocated to FEI, FBC, and FMI (ACGS)

FHI Corporate Services Cost Pools Eligible for Allocation	Eligible Costs	FEI (73.8%)	FBC (21.8%)	FMI (ACGS) (4.4%) Jan – Oct (Allocated)	FMI (ACGS) (4.4%) *Nov-Dec (Retained in FHI)*
Governance & Board of Directors	$1,985,585	$1,465,141	$433,183	$72,717	*$14,543*
External Financial Reporting	659,132	486,366	143,799	24,139	*4,828*
Internal Audit	1,554,060	1,146,724	339,040	56,914	*11,383*
Legal	2,115,764	1,561,199	461,583	77,485	*15,497*
Insurance & Risk Management	372,271	274,695	81,216	13,634	*2,727*
Taxation	1,060,590	782,598	231,382	38,841	*7,768*
Treasury & Financial Planning	1,146,264	845,816	250,073	41,979	*8,396*
Facilities & Support	1,242,186	916,596	271,000	45,492	*9,098*
Fortis Inc. Management Fee	7,558,000	5,576,966	1,648,882	276,793	*55,359*
Other Excluded Costs	-	-	-	-	-
Total	**$17,693,850**	**$13,056,101**	**$3,860,158**	**$647,993**	*$129,599*

6 ACGS Divestiture

Through its wholly owned subsidiary FMI, FHI was the owner of ACGS until ACGS's sale on November 1, 2023. As a non-regulated entity, ACGS provided natural gas storage and optimization services to its customers. Prior to ACGS's divestiture, FHI provided support services to FMI (ACGS) similar to those provided to FEI and FBC. Consequently, FHI allocated corporate shared service costs to FMI (ACGS) through the Massachusetts formula.

The divestiture of ACGS influences both:

- The proportion of costs allocated by FI to FHI (**Section 4.4**), and
- The proportion of FHI corporate services costs allocated to FEI and FBC (**Section 5.5**)

If there were no change to the value of assets and controllable costs for all FI subsidiaries, the sale of ACGS would result in FHI receiving a smaller corporate shared service allocation from FI. In practice, however, there may be other changes to FI and its subsidiaries' operations, including through other acquisitions and divestitures.

The proportion of costs allocated by FI to FHI was recalculated by FI for 2023 excluding ACGS's assets and controllable operating costs. This resulted in the FHI's share of the management fee falling from 21.8% to 20.9%.

The impact of the divestiture of ACGS on the allocations from FHI to FEI and FBC is more direct. Thus, the share of FHI's corporate services costs that are allocated to FEI and FBC will increase as a result of the removal of FMI (ACGS) from the cost allocation formula.

Table 13 provides revised corporate service cost allocation proportions for FEI and FBC using the Massachusetts formula, to reflect the removal of FMI (ACGS).

Table 13: 2023 FHI Massachusetts Formula Calculation (excluding ACGS)

Component	FEI	FBC
Gross Margin	$1,028,362,980	$322,356,643
	76.1%	23.9%
Payroll	$181,817,748	$54,115,246
	77.1%	22.9%
Two Year Average of NBV of PP&E + inventories	$5,845,742,233	$1,614,297,507
	78.4%	21.6%
Massachusetts Formula Allocation	**77.2%**	**22.8%**
Observed Increase in % Allocation with Removal of FMI (ACGS)[11]	**+3.4%**	**+1.0%**

[11] Observed increase is calculated based on the difference is shares relative to those shown in Table 11.

Table 14 provides the revised allocations of costs using the proportions from **Table 13**. To facilitate a comparison with numbers shown earlier, allocations are calculated using 2023 budget amounts but with one adjustment: the FI Management fee to be allocated is adjusted downward to account for the expected reduction in FHI's share of this fee with the divestiture of ACGS. Total eligible costs to be allocated decrease, but FEI and FBC nevertheless see an increase in allocations because they must absorb ACGS's share of FHI costs.

Table 14: Summary of FHI Costs Allocated to FEI and FBC (excluding ACGS)

FHI Corporate Services Cost Pools Eligible for Allocation	Eligible Costs	FEI (77.2%)	FBC (22.8%)
Governance & Board of Directors	$1,985,585	$1,532,597	$452,988
External Financial Reporting	$659,132	$508,759	150,373
Internal Audit	1,554,060	1,199,519	354,541
Legal	2,115,764	1,633,077	482,687
Insurance & Risk Management	372,271	287,342	84,929
Taxation	1,060,590	818,629	241,961
Treasury & Financial Planning	1,146,264	884,757	261,507
Facilities & Support	1,242,186	958,796	283,390
FI Management Fee	7,245,972	5,592,888	1,653,084
Other Excluded Costs	-	-	-
Total	**$17,381,824**	**$13,416,363**	**$3,965,461**
Net Increase in Allocation with Removal of FMI (ACGS)		**+$360,261**	**+$105,303**

Table 15 shows the changes in allocations by service element with the removal of FMI (ACGS) from the allocation pool. Based on the 2023 budget, the ACGS divestiture is expected to result in the reallocation of approximately $466,000 in costs to FBC and FEI.[12] Across these departments, none of the FHI costs that are reallocated by department would be greater than or equal to the average cost of an FTE within FHI (approximately $190,000). Further, based on interviews with FHI cost centre owners, the support provided to FMI (ACGS) did not take the form of dedicated staff; support was instead provided through part-time effort spread across several FTEs. Therefore, the divestiture of FMI (ACGS) is not expected to result in any changes in staffing levels that would result in a reduction of cost. Accordingly, it is not unreasonable for FEI and FBC to see some increase in cost allocations given the narrower base of operations at FHI and a reduction in its ability to spread costs across different operating units. The expected change in the allocation of FI Management fees is minor: reductions in FI allocations to FHI largely offset the increased share of these fees now borne by FEI and FBC. This is reasonable and as expected.

[12] Calculated as 360,000 plus 106,000 (with rounding).

Table 15: Net Changes in FHI Costs Allocated Across FEI, FBC, and ACGS

FHI Corporate Services Cost Pools Eligible for Allocation	FEI (77.2%)	FBC (22.8%)	FMI (ACGS) (0%)
Governance & Board of Directors	$67,455	$19,805	($87,261)
External Financial Reporting	22,393	6,574	(28,967)
Internal Audit	52,795	15,501	(68,296)
Legal	71,878	21,104	(92,982)
Insurance & Risk Management	12,647	3,713	(16,360)
Taxation	36,031	10,579	(46,610)
Treasury & Financial Planning	38,941	11,434	(50,375)
Facilities & Support	42,200	12,390	(54,590)
FI Management Fee	15,922	4,203	(332,152)
Other Excluded Costs	-	-	-
Difference in Allocation with FMI (ACGS)	**+$360,261**	**+$105,303**	**($777,592)**

While the FMI (ACGS) divestiture results in changes to the allocation proportions, FI's and FHI's corporate shared service cost allocation methodologies remained the same. The use of a consistent approach aligns with the following evaluation criteria from **Section 2.3:**

- **Objective Results** – By using consistent corporate services cost allocation methodologies FI and FHI are not introducing any undue bias.
- **Transparent and Supportable Methodology** – The allocators use in the cost allocation methodologies are visible and transparent, and the impact of the divestiture can be readily observed.
- **Flexibility/Adaptability** – The cost allocation methodologies could easily accommodate the impact of the divestiture.

7 Conclusion

KPMG evaluated FI's and FHI's capital overhead cost allocation methodologies in alignment with the evaluation criteria introduced in **Section 2.3.** Overall, both allocation methodologies appear to be a reasonable mechanism to allocate corporate services costs.

No.	Evaluation Criteria	Description
1.	Cost Causality	FI's allocation methodology of O&M has been designed to account for the variability of operations in its operating subsidiaries and uses allocators (75% assets excluding goodwill and 25% controllable O&M) that continue to be reasonable proxies of cost causality. When considering the general nature of the shared services allocated from FHI to FEI and FBC, the Massachusetts formula continues to be a reasonable proxy of cost causality.
2.	Objective Results	The allocation formulas are based on objective, financial inputs, and are therefore not subject to subjective bias or manipulation.
3.	Cost Effectiveness	The multi-factor allocation mechanisms used by FI and FHI are easy to apply. Changes in organizational structure and in the mix of operating activities are readily addressed through application of the allocation factors. In contrast, it would be difficult, by definition, to allocate general corporate services costs to individual entities through detailed cost analysis. Most corporate support is of a general nature and not concerned with any individual entity.
4.	Stability Over Time	FI's and FHI's multi-factor allocation mechanisms are based on overarching financial measures, allowing the allocators to be updated on a regular basis or as changes occur. The multi-factor allocation mechanisms are scalable as the factors are relative proportions.
5.	Transparent and Supportable Methodology	Both FI's and FHI's corporate services cost allocation methodologies are based on financial measures that are visible and transparent.
6.	Regulatory Precedence	Neither FI's nor FHI's allocation methodology has materially changed since the 2018 study and were previously approved by the BCUC in FortisBC's 2020 – 2024 Multi-Year Rate Plan. Further, the use of multi-factor allocation mechanisms, and specifically the Massachusetts Formula, is a common practice across regulated utilities.
7.	Distinguishable from Directly Allocated Costs	FHI directly charges its other subsidiaries and affiliates (i.e., those other than FBC and FEI) for corporate services rendered. Services that are rendered in support of FHI directly are estimated and retained within FHI and excluded from the cost allocation pool.
8.	Accuracy of Underlying Data	Based on the data made available to KPMG, the calculation of the Massachusetts formula used by FHI appears accurate. Data for the calculation of the FI multi-factor allocator was not made available for review.
9.	Flexibility/Adaptability	FI's and FHI's corporate services cost allocation methodologies use multi-factor allocators, which provide flexibility in adapting to changes in organizational structure (such as the divestiture of FMI (ACGS)). The methodologies should be reviewed in the event of material changes to regulations (i.e., changes to eligibility of costs) and/or accounting practices (i.e., changes impacting the calculation of the factors used in the multi-factor allocations).

A Interview Questionnaire

Data collection sheets included the following questions:

1) Please describe the scope of activities for each FHI cost centre that you are responsible for.
   a) Do these activities differ for any of the subsidiaries (i.e., FBC, FEI, FAES, FMI/ACGS, other subsidiaries)?
2) How many employees are within your department and how many are directly employed by FHI?
3) Do you expect the scope and/or volume of activities to change during the 2025 Customer Rate Application?
4) How will the divestiture of Aitken Creek Gas Storage (ACGS) impact the scope and/or volume of activities within your Cost Centres?
5) Can you provide a percentage estimate of your functional area's time spent supporting the subsidiaries (pre-ACGS divestiture)?
   a) FEI
   b) FBC
   c) FAES
   d) FHI Corporate
   e) FMI/ACGS
   f) Other
6) Can you provide a percentage estimate of your functional area's time spent supporting the subsidiaries (post-ACGS divestiture)?
   a) FEI
   b) FBC
   c) FAES
   d) FHI Corporate
   e) Other
7) What basis / supporting measures were used to estimate the above percentages (i.e., time estimates, headcount, transaction volume, asset value, volume of facility space, etc.)?
8) Which of the following factors, if changed, would result in an incremental change in the level of effort and/or cost for FEI or FBC?
   a) Total Assets
   b) Gross Margin
   c) Revenue
   d) Sales/Customer Demand
   e) Controllable O&M
   f) Annual CapEx
   g) Rate Base
   h) Number of Employees
   i) Number of Customers
   j) Company Annual Reporting Requirements
   k) Other (Please Specify)

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Appendix D5-1

KPMG FEI OVERHEAD CAPITALIZATION REVIEW

FortisBC Energy Inc.

Overhead Capitalization Methodology Review

KPMG LLP

March 2024

This report contains 36 pages

KPMG FEI Overhead Capitalization Review Report.docx

FortisBC Energy Inc.
Overhead Capitalization Methodology Review
March 2024

Contents

Executive Summary

KPMG LLP ("KPMG") was retained by FortisBC Energy Inc. ("FEI") to review the overhead capitalization methodology and the resulting updated overhead capitalization rate to be used in the next Ratemaking Framework beginning in 2025.

FEI defines Gross Operations and Maintenance ("O&M") costs as all costs net of any costs directly charged to capital projects. However, not all costs related to capital activity are directly charged to capital projects and therefore remain in O&M. These remaining capital-related costs are charged to capital projects through the overhead capitalization mechanism. As implied by the definitions above, the value of O&M included in the denominator when calculating the rate excludes any capital-related costs that have been directly charged to capital projects or assets.

We understand that FEI transitioned to U.S. Generally Accepted Accounting Principles ("U.S. GAAP") for regulatory accounting and reporting purposes on January 1, 2012. The British Columbia Utilities Commission ("BCUC") approved this transition in Order G-117-11. FEI subsequently applied for extensions to continue using U.S. GAAP, which was approved by the BCUC in Order G-83-14 (July 3, 2014) and G-352-22 (December 5, 2022). In accordance with these regulatory approvals, FEI's overhead capitalization methodology and resulting overhead capitalization rate leverage guidance from U.S. GAAP. This guidance includes the application of regulatory accounting in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification 980 ("ASC 980") Regulated Operations.

There is no universally accepted definition or standard that prescribes the types of indirect costs (i.e., those related to capital projects that have not been directly charged to those capital projects) that should be considered for capitalization for the purposes of regulatory and financial reporting. While U.S. GAAP provides some guidance on the costs of a capital asset, there is considerable judgment required by decision-makers to determine "costs that are incurred to bring it to the condition and location necessary for its intended use."[1] Notwithstanding the importance of judgment and thus the potential for variation in methodologies, the guidance reviewed highlights a common general principle:

> That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity.

The analysis and findings in this report used FEI's 2023 O&M Budget figures to derive the overhead capitalization rate by applying FEI's overhead capitalization methodology. FEI's overhead capitalization methodology uses the results of surveys and interviews with management staff and cost centre owners to understand the nature of capital related costs that are not directly allocated to capital. These surveys provide a basis to assess the eligibility of costs for capitalization. FEI then uses a variety of overhead capitalization estimation methods to allocate capital related costs from the various cost centres. These estimation methods are selected based on the nature of the capital activities and the cost drivers associated with these activities. The application of FEI's overhead capitalization

[1] FASB (Financial Accounting Standards Board). (n.d.). ASC 360-10-30-1

methodology using the 2023 O&M Budget results in an overhead capitalization rate of **14.5%**.

KPMG's evaluation finds that FEI's capital overhead cost allocation methodology is a reasonable mechanism to establish the overhead capitalization rate.

1 Introduction

1.1 Background and Scope

KPMG LLP ("KPMG") was retained by FortisBC Energy Inc. ("FEI") to review the overhead capitalization methodology and the resulting updated overhead capitalization rate to be used in the next Ratemaking Framework beginning in 2025. The results of this review are summarized in this report.

FEI's overhead capitalization methodology and the resulting overhead capitalization rate are based on U.S. Generally Accepted Accounting Principles ("U.S. GAAP"). These principles include the application of regulatory accounting in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification 980 ("ASC 980") Regulated Operations.

In the preparation of its financial accounts, FEI allocates costs directly to capital projects that form the base value of the associated asset. These direct charges will typically include, among other things, construction labour and the materials and installed equipment that make up a new asset. FEI then defines Gross Operations and Maintenance ("O&M") costs as those costs that remain after deduction of these direct charges to capital assets. A portion of these remaining costs are then also flowed through to capital through the overhead capitalization process. These are costs that are related to capital activity but that cannot be directly identified with specific projects. The overhead capitalization rate is the proportion of O&M costs transferred to capital through this overhead capitalization process.

As implied by the definitions above, the value of O&M included in the denominator when calculating the overhead capitalization rate excludes any capital-related costs that have been directly charged to specific projects.

1.2 Limitations

1.2.1 Management Responsibility

FEI's capitalization methodology is the responsibility of management, who also maintain responsibility for the accuracy and completeness of the data and information associated with the capital cost allocation methodology and associated costs.

1.2.2 KPMG Engagement

KPMG's engagement is to comment on the reasonableness of the capital overhead cost allocation methodology, in the context of FEI's reporting under U.S. GAAP, inclusive of ASC 980, and to undertake the steps outlined in **Section 2** of this report.

This evaluation does not constitute an audit of the capital overhead cost allocation methodology, associated costs[2], or the resulting overhead capitalization rate, and is therefore not subject to assurance or other standards issued by the Canadian Auditing and

[2] FortisBC Inc. ("FBC") and FEI also cross-charge shared service costs between entities using a shared service cross-charging approach approved by the BCUC in the 2020-2024 Multi-Year Rate Plan Application. KPMG does not express an opinion on this cross-charging approach.

Assurance Standards Board. Consequently, no opinions or conclusions intended to convey assurance have been expressed. KPMG assessed the proposed capital cost allocation methodology in the context of the approved 2023 budget. KPMG has not audited or otherwise independently verified the accuracy or fair presentation of the approved 2023 budget and costs that form the basis of the percentages capitalized. However, we did take steps to assess the accuracy of the underlying data and these steps are outlined in **Section 2**.

The information contained herein is for the internal use of FEI management. It is understood that this report may be distributed by FEI externally to the BCUC as part of the regulatory process. KPMG disclaims any responsibility or liability for losses, damages, or costs incurred by anyone as a result of any external circulation, publication, reproduction, or use of the information contained herein.

2 Approach

This section summarizes KPMG's approach to completing the review of FEI's overhead capitalization methodology.

2.1 Work Plan

Our work plan was developed in collaboration with management in order to meet the objectives of this review. Our work plan incorporated the following steps:

Table 1: Work Plan Steps

Step	Description
1	**Review study context**. In this step, KPMG met with management to understand FEI's overall organizational structure and the business context for this review, including any changes in operations since the last review (2018), the response to prior overhead capitalization studies filed by FEI with the BCUC, and FEI's plans for future general rate filings.
2	**Review and document regulatory and accounting policy guidance**. In this step, KPMG researched and documented the guidance provided by various accounting and regulatory authorities on the topic of overhead capitalization. The objective of this step was to ensure that the approach and methodology adopted in FEI's overhead capitalization update is consistent with U.S. GAAP and applicable regulatory precedents from other filed and approved overhead capitalization studies.
3	**Review methodology**. In this step, KPMG worked with management to design the process for updating the overhead capitalization rate through this study. This included: ▪ Agreement on the sources of data to be used in the estimate and on appropriate cost allocation approaches. ▪ Preparation of a survey and associated data collection template for individual departments. ▪ Development of an interview schedule.
4	**Participate in interviews with company officials**. In this step, KPMG participated in interviews held by FEI with representatives from the operating areas. The purpose of the interviews in this step was to gain an understanding of and document: ▪ FEI's approach to the acquisition, construction, and installation of capital assets. ▪ The specific supporting activities within FEI that relate to the implementation of capital projects. ▪ The nature of costs that are currently directly charged to projects, causal factors relating to support efforts, and the suitability of potential cost drivers.
5	**Provide support to FEI in the calculation updates.** In this step, KPMG personnel were available as a resource to FEI personnel as they developed supporting calculations. This included providing advice on potential cost allocation mechanisms, including supporting cost drivers, for specific overhead support functions.

Step	Description
6	**Assessed the reasonableness of FEI's estimate of capitalized overhead costs.** In this step, KPMG assessed the reasonableness of the methodology that FEI implemented with respect to the capitalization of overhead costs from each cost centre. In our assessment, we took into account the following: ▪ The relationship between activities in a cost centre and capital projects. This was done to ensure that there is a clear causal link between the activities and capital projects. ▪ The reasonability of drivers or metrics used to apportion costs between capital and operating activities. This was done to ensure that drivers are unbiased and accurately reflect cost causality in the cost centre or department. ▪ Consistency with external accounting guidance.
7	**Data Validation of Capital Overhead Capitalization Model.** In this step, KPMG conducted the following procedures with respect to calculations supporting the quantum of estimated costs: ▪ Reviewed the overhead capitalization model for formula accuracy. ▪ Validated costs used in the capital overhead cost allocation methodology against the 2023 approved O&M budget; and ▪ Validated cost drivers against supporting system records or other corroborative evidence.
8	**Assessed the reasonableness of the resulting overhead capitalization rate.** In this step, KPMG assessed the reasonability of the proposed overhead capitalization rate, taking into account the results of all prior work steps as well as consistency with results of prior overhead capitalization studies of FEI and reasonableness considering the current and planned levels of capital activity.
9	**Document findings.** In this step, KPMG prepared this summary report to document the findings of our review and key outputs from this overhead capitalization update.

2.2 Evaluation Criteria

FEI's prior overhead capitalization studies used a set of criteria for the evaluation of the overhead capitalization methodology and associated cost drivers. These criteria have been adopted internally by management at FEI for this update and KPMG accepts these criteria as reasonable. The criteria were used both by:

1) FEI management in making decisions while setting up the methodology and its supporting calculations, and
2) KPMG in evaluating the methodology and its results.

Evaluation criteria are summarized in the table below.

Table 2: Overhead Capitalization Evaluation Criteria

No.	Evaluation Criteria	Description
1.	Cost Causality	The identified driver, being it work effort or investment, has a direct correlation to the cost of the services or goods associated with a capital project and also has a direct effect on the level of service for that capital project.

No.	Evaluation Criteria	Description
2.	Objective Results	The use of the allocation driver results in an objective allocation amount that is free from undue bias.
3.	Cost Effectiveness	The allocation driver is calculated and maintained from readily available information, resulting in minimal time and expense to implement the allocation approach.
4.	Stability Over Time	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.
5.	Transparent and Supportable Methodology	The driver used, and the source or basis for how it is determined, is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model or other supporting documentation.
6.	Regulatory Precedence	The cost allocation methodology has been tested and approved through previous regulatory reviews.
7.	Distinguishable from Directly Allocated Capital Costs	The overhead costs must be distinguished from those that are directly charged to capital.
8.	Accuracy of Underlying Data	Any data used in the methodology is accurate and can be relied upon. The data provides an appropriate measure of the underlying volume of activity or output.
9.	Flexibility/Adaptability	The methodology can accommodate future changes in regulatory, accounting, and organizational changes with reasonable ease.

3 Financial Accounting Framework

3.1 Background

The BCUC approved the BC utilities of Fortis Inc.[3] use of U.S. GAAP for regulatory accounting and reporting purposes in Order G-117-11 on July 7, 2011, with an effective date of January 1, 2012. The FortisBC Utilities[4] subsequently filed an application to extend the use of U.S. GAAP in 2014 which was approved by the BCUC in Order G-83-14 with the condition that, *"[a]pproval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes, whichever is earlier.*"

As part of FEI's 2023 annual rate review proceeding, FortisBC sought a variance to Order G-83-14 seeking to ensure that FortisBC had continued approval to use U.S. GAAP for regulatory accounting purposes. The BCUC approved the extension request in Order G-352-22, which states, *"Approval is granted until such time as FEI no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes."*

For the purposes of this Overhead Capitalization Methodology Review, U.S. GAAP was the primary accounting standard used to assess FEI's overhead capitalization methodology. If FEI transitions to a different accounting standard for regulatory and accounting purposes, then the Overhead Capitalization Methodology would need to be re-evaluated.

3.2 Standards and Guidance Used

As noted in **Section 3.1**, FEI utilizes U.S. GAAP for regulatory accounting and reporting purposes. As such, U.S. GAAP is used as the primary guidance by which to determine eligible costs for capitalization. However, as noted in the subsequent **Section 3.3**, there is limited explicit guidance, definition, or discussion of the treatment of the capitalization of overhead costs under U.S. GAAP. Additional accounting guidance has been reviewed and included to support FEI's overhead capitalization approach (**Sections 3.3 - 3.7**).

3.3 U.S. GAAP

There is limited explicit guidance, definition, or discussion of the treatment of the capitalization of overhead under U.S. GAAP. However, sections of the U.S. GAAP Accounting Standards Codification ("ASC") provide general guidance on asset accounting generally and some specific guidance for rate-regulated activities. The main sources of guidance under U.S. GAAP are noted in Table 3**.** A summary of the guidance is presented below:

[3] The BC utilities of Fortis Inc. included FortisBC Inc., Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc. Terasen Gas is the former name of FEI.
[4] FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

- ASC 360 – Property, Plant, and Equipment addresses PP&E acquisition costs broadly, but provides no guidance on the eligibility of specific types of costs.
- ASC 980 – Regulated Operations provides guidance indicating that if a cost is approved by a regulator and is expected to be recovered from customers in future rates, then that cost may be capitalized as part of PP&E under ASC 980. In absence of ASC 980, such costs may be required to be expensed if they do not meet the capitalization criteria of other standards. It is therefore appropriate to consider guidance and precedence from the BCUC, as it is the regulator of FEI.
- ASC 970 – Real Estate provides more specific guidance on the capitalization of project costs. Although this section may not be directly applicable to the nature of assets created by a utility, ASC 970 has frequently been considered by utilities and used as supplementary guidance in determining capitalization of costs, specifically:
  - ASC 970's definition of indirect project costs provides a precedent for the capitalization of indirect costs and provides further clarification that indirect project costs shared across projects should be allocated to those projects to which costs relate.
  - ASC 970 also defines preacquisition costs as those costs incurred prior to obtaining the property and that these costs should be capitalized upon acquisition of the property. However, these costs are still subject to the definition of project costs. Additionally, ASC 970 discusses the concept of probability as a factor in assessing eligibility.

Table 3: U.S. GAAP ASC Information Related to Overhead Capitalization

ASC Section	Relevant Information
ASC 360 – Property, Plant and Equipment	▪ **Paragraph 360-10-30-1**: "…the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use."
ASC 980 Regulated Operations	▪ **Section 980-10-05-7:** Accounting requirements that are not directly related to the economic effects of rate actions may be imposed on regulated businesses by orders of regulatory authorities and occasionally by court decisions or statutes. This does not necessarily mean that those accounting requirements conform with generally accepted accounting principles (GAAP). For example, a regulatory authority may order an entity to capitalize and amortize a cost that would be charged to income currently by an unregulated entity. Unless capitalization of that cost is appropriate under this Topic, GAAP requires the regulated entity to charge the cost to current income. ▪ **Section 980-10-15-7 (b):** An entity's regulatory accounting. Regulators may require regulated entities to maintain their accounts in a form that permits the regulator to obtain the information needed for regulatory purposes. This Topic neither limits a regulator's actions nor endorses them. Regulators' actions are based on many considerations. Accounting addresses the effects of those actions. This Topic merely specifies how the effects of different types of rate actions are reported in general-purpose financial statements. ▪ **Section 980-340-25-1:** Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. ▪ A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

ASC Section	Relevant Information
ASC 970 – Real Estate	▪ **Project Costs:** Costs clearly associated with the acquisition, development, and construction of a real estate project. ▪ **Indirect Project Costs:** Costs incurred after the acquisition of the property, such as construction administration (for example, the costs associated with a field office at a project site and the administrative personnel that staff the office), legal fees, and various office costs, that clearly relate to projects under development or construction. Examples of office costs that may be considered indirect project costs are cost accounting, design, and other departments providing services that are clearly related to real estate projects. ▪ **Section 970-360-25-2:** Project costs, which are costs that are clearly associated with the acquisition, development, and construction of a real estate project, shall be capitalized as a cost of that project. ▪ **Section 970-360-25-3:** Indirect project costs that relate to several projects shall be capitalized and allocated to the projects to which the costs relate. ▪ **Preacquisition Costs:** Costs related to a property that are incurred for the express purpose of, but prior to, obtaining that property. Examples of preacquisition costs may be costs of surveying, zoning or traffic studies, or payments to obtain an option on the property. ▪ **Section 970-340-25-3:** Payments to obtain an option to acquire real property shall be capitalized as incurred. All other costs related to a property that are incurred before the entity acquires the property, or before the entity obtains an option to acquire it, shall be capitalized if all of the following conditions are met and otherwise shall be charged to expense as incurred: a) The costs are directly identifiable with the specific property. b) The costs would be capitalized if the property were already acquired. c) Acquisition of the property or of an option to acquire the property is probable (that is, likely to occur). This condition requires that the prospective purchaser is actively seeking to acquire the property and has the ability to finance or obtain financing for the acquisition and that there is no indication that the property is not available for sale. ▪ **Section 970-340-25-5:** The view that all internal costs of identifying and acquiring commercial properties should be deferred and, in some manner, capitalized as part of the cost of successful property acquisitions is not appropriate. **Section 970-340-25-6:** Internal costs of preacquisition activities incurred in connection with the acquisition of a property that will be classified as nonoperating at the date of acquisition that are directly identifiable with the acquired property and that were incurred subsequent to the time that acquisition of that specific property was considered probable (that is, likely to occur) shall be capitalized as part of the cost of that acquisition.

3.4 Guidance from BCUC

With respect to the capitalization of overhead, BCUC's *Uniform System of Accounts Prescribed for Gas Utilities* ("BCUC USofA") provides a basis of reference for what BCUC may allow to be capitalized under ASC 980 Regulated Operations. The BCUC USofA includes the following guidance:

> *"Cost of overhead charged to construction includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of actual and reasonable costs."*

The BCUC USofA thus specifically identifies some overhead costs that may be charged to capital projects. Further definition of the various items is not provided, which provides for some discretion in their interpretation.

3.5 Guidance from US Federal Energy Regulatory Commission (FERC)

Similar guidance to that available from BCUC is provided by FERC in its Uniform System of Accounts. Though FERC has no jurisdiction within Canada, the guidance of FERC is indicative of general industry practice. The FERC Uniform System of Accounts states:

> *"All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired."*

3.6 International Financial Reporting Standards (IFRS)

Under IFRS, guidance on accounting for capital assets, including the capitalization of overhead, is governed by International Accounting Standard 16, Property, Plant and Equipment (IAS 16).

IAS 16 states that the cost of an item of property, plant and equipment comprises:

a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and
c) the initial estimate of the costs of dismantling and removing the item.

IAS 16 is more prescriptive than guidance under U.S. GAAP in that it provides examples of "directly attributable" costs, including:

a) costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;
b) costs of site preparation;
c) initial delivery and handling costs;
d) installation and assembly costs;
e) costs of testing whether the asset is functioning properly, and
f) professional fees.

IAS 16 also provides examples of costs that are not to be capitalized as part of an item of property, plant and equipment, including:

a) costs of opening a new facility;
b) costs of introducing a new product or service (including costs of advertising and promotional activities);
c) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
d) administration and other general overhead costs.

While FEI is using U.S. GAAP as the primary guidance to inform its overhead capitalization methodology, a transition to IFRS would require further analysis as it may introduce potential changes to the methodology for capitalization to PP&E, after initial application of IFRS. Specifically, IFRS' guidance on eligibility of costs for capitalization tend to be more prescriptive than guidance provided under U.S. GAAP.

The International Accounting Standards Board ("IASB") published its *Regulatory Assets and Regulatory Liabilities* exposure draft in January 2021. The exposure draft proposes a new accounting model under which a company subject to rate regulation, that meets the scope criteria, would recognize regulatory assets and liabilities. This accounting model would align the total income recognized in a period under IFRS Accounting Standards with the total allowed compensation the company is permitted to earn by the rate regulator. If issued, the proposal will replace *IFRS 14 Regulatory Deferral Accounts*. The new IFRS accounting standard is anticipated to be issued in 2025. The potential changes to the standards, if applied, may provide further guidance on the treatment of capitalized overhead.

3.7 Comparators

A review of select comparators was completed focusing on entities that either utilize U.S. GAAP for regulatory accounting and reporting purposes and/or are regulated by the BCUC.

Table 4: Summary of Select Comparator Overhead Capitalization Approaches

Comparator	Regulator	Accounting Standard	Commentary
Hydro One Networks Inc. (Hydro One) Application for Electricity Transmission and Distribution Rates 2023-2027	OEB	U.S. GAAP	As part of Hydro One's 2023-2027 rate application for its electricity transmission and distribution lines of business, Black and Veatch (B&V) completed a Report on Corporate Cost Allocation Review. This review provides insight into Hydro One's overhead capitalization approach, specifically: ▪ Example of overhead costs capitalized include "…IT sustainment, telecommunication service and equipment costs, and operation center and headquarter costs." ▪ Operation, maintenance, and administration ("OM&A") costs are categorized into: (1) Costs that should remain out of the Overhead Capitalization Rate. (2) Costs that should be fully recovered from capital expenditures as they directly and wholly support capital expenditures. (3) Costs that support both OM&A and capital and should therefore be split between OM&A and capital within the Overhead Capitalization Rate calculation. To develop the overhead capitalization rate, costs in category 2 are allocated to capital based on a 50/50 weighting of the Labour Content-Capital Ratio, which is the Total OM&A Labour divided by the Total Labour in Capital Expenditures, and the Total Spending-Capital Ratio, which is the Total Spending in OM&A versus Total Capital Expenditures. The overhead capitalization rate is then calculate based on the sum of the allocated costs from category 2 plus the costs in category 3 divided by Total Capital Expenditures. ▪ There was a noted change in methodology to establish the size of the cost pool of category 2 (i.e., the costs subject to the 50/50 Labour Content-Capital and Total Spending Capital ratio). Previously, four-week time studies were completed for specific shared services related to customer relations, asset management, and operations. As part of the 2020 review, time surveys were completed instead of four-week time studies. These time surveys were based on interviews with cost centre owners to ascertain how employees within the cost centres spent their time across the entire year The time surveys resulted in more costs being directly assigned to capital, resulting in a smaller pool of costs to be allocated via the 50/50 Labour Content-Capital and Total Spending Capital ratio.

Comparator	Regulator	Accounting Standard	Commentary
Pacific Northern Gas Ltd. ("PNG") 2011 Revenue Requirement Application	BCUC	IFRS (previously U.S. GAAP)	As part of the 2011 Revenue Requirement Application, PNG engaged KPMG to complete a review of a revised overhead capitalization methodology. The evaluation was primarily driven by the transition from U.S. GAAP to IFRS. Key insights include: ▪ There was a noted decrease in the overhead capitalization rate which can be largely attributed to the more prescriptive guidance under IFRS, which resulted in a significant drop in the capitalization of "administration and other general overhead costs". ▪ Mechanisms for allocation varied based on the cost category and included: (1) Estimation of cost of staff time and associated benefit costs to capital activities. (2) Estimation of cost of management time and associated benefit costs to capital activities. (3) Estimation of field employee benefit costs as determined by a benefit load analysis. (4) True up allocation of equipment operating expense based on actual costs and equipment usage.
Corix Multi-Utility Services Inc. (Corix) Burnaby Mountain District Energy Utility 2020-2023 Revenue Requirement and Rates Application	BCUC	Not Specified	Corix did not complete an overhead capitalization study for the 2020-2023 rate application for its Burnaby Mountain District Energy Utility. However, the rate application contains some insight into what was considered eligible for capitalization. Specifically, one of the criteria Corix uses to determine eligibility of costs is: *"When it is not administratively feasible to directly charge every single cost of each corporate and regional activity required to execute the capital project… Examples of these corporate and regional activities* ***include, but are not limited to legal, regulatory, finance, human resources, and procurement.****"*

3.8 Overall Findings Regarding Accounting Framework

Based on the accounting and regulatory guidance related to capitalization of indirect costs and a review of select comparators (**Sections 3.3 - 3.7**), the following is observed:

- While applicable accounting and regulatory guidelines provide guidance for the capitalization of indirect costs associated with capital activity, there is considerable judgment required by decision-makers to determine costs that are incurred to bring an asset to the condition and location necessary for its intended use (when applying U.S. GAAP).
- A review of the overhead capitalization methodologies of comparator utilities that use U.S. GAAP for regulatory accounting and reporting purposes or are regulated by the BCUC, suggests considerable variation in approaches to capitalizing indirect costs, using a combination of general allocators and time analysis.

However, our review of past precedent and available guidance, does highlight a common general principle:

> That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity.

The specific approach that has been adopted by FEI is further discussed in **Section 4**. This approach is designed to demonstrate a causal link to capital activity.

4 FEI Capitalization Methodology

4.1 The Nature of Capitalized Overhead

Capitalized overhead costs can be distinguished from:

- **Costs directly assigned to capital** – These are costs that are charged directly to capital projects and that therefore form part of the direct capital cost of the associated assets. Mechanisms used to directly assign costs are outlined in **Section 4.2**.
- **Costs charged to operating expenses –** These costs appear in the income statement in the period concerned.

Functions that have costs allocated to capitalized overhead generally fall into one of the three categories noted below. While the boundaries between these types of activities may be subject to interpretation, the categories do help to provide a conceptual framework to think about capitalized overhead costs:

1) **Non-Project-Specific Capital Support –** This category encompasses processes for planning, evaluating, designing, and implementing capital additions. This includes feasibility analyses, expenditures to obtain approvals, budgeting, in-house design work, and economic assessments, among others. Activities in this category are specifically focused on capital projects but cannot be charged to any specific projects, either:
   a) Because it is impractical or costly to do so, or
   b) Because the function is related to capital projects generally rather than to specific or identified projects.
2) **Administration and Oversight of Activities Directly Related to Capital Projects –** This category encompasses processes for the supervision and administration, cost control, and reporting of those activities and/or costs that are in direct support of capital projects. Activities in support of projects can either be directly charged to those projects or they can be associated with non-project specific capital support (the first category of capitalized overhead costs noted in the bullet above). Activities in this support category thus include the administration and supervision of construction departments and plant accounting. It can also include supervision of engineering personnel that work on capital projects.
3) **Support Functions and Infrastructure –** This category covers the support functions and infrastructure networks that enable the departments that perform the processes outlined above to do their work. Relevant support functions will include, but are not necessarily limited to: Human Resources, Building Operations, and Information Services. Costs associated with space accommodation (e.g., lease charges), personal computers and other support equipment, telecommunications and vehicles will also be eligible for inclusion in this category, to the extent that these infrastructure items support employees who are working on capital-related activities and where associated costs have not been directly charged to capital projects.

4.1.1 FEI Internal Labour Rate

FEI's internal labour rates include salary costs and a mark-up for benefits (i.e., pension, vacation/leave, health/dental, etc.). Accordingly, these labour-related costs with respect to directly charged time should not be captured again through the overhead capitalization process, since this would result in double-counting.

However, only costs related to employee salaries are picked up through the above mark-up. Accordingly, other non-salary related costs related to employee time should be captured within the overhead capitalization process. Thus, an employee that charges directly to capital projects may have non-salary costs allocated to capitalized overhead. This could include the cost of external training courses and/or equipment costs, as examples.

4.1.2 Treatment of Non-Productive Time

If a person engages in activities to support capital, then an appropriate share of that employee's so-called non-productive time should also be allocated to capitalized overhead. Examples of non-productive time could include time associated with training and internal administration.

In other words, when an employee provides some support to capital, then a proportionate share of all the costs associated with that employee should be allocated to capital. We will refer to this as the "total incremental cost" of such support to capital. Costs thus include an appropriate share of expenses related to the non-productive time associated with the individual. Therefore, a cost centre whose sole function is to provide support to capital (such as, for example, a technical or engineering group), should potentially have all its costs allocated to capitalized overhead (with the exception of any costs that are charged directly to specific projects). The administrative and training costs within such a Cost Centre, for example, would then not be left in OM&A as a residual.

4.2 Direct Assignment of Costs to Capital

Where practical, FEI directly assigns capital related costs to specific projects or internal orders. FEI employs several different mechanisms to directly allocate costs to capital:

Table 5: FEI Mechanism for Direct Assignment of Costs to Capital

Mechanism	Description
Timesheets	Select staff complete timesheets to allocate their time to capital projects. The labour rate used includes wages and benefits (i.e., health, dental, vacation/leave, pension, etc.). The labour rate does not include any allocation of non-productive / administration time, nor does it include any overhead costs such as facilities, fleet, or technology.
Work Orders Settlement Rules	Work orders are allocated using either pre-defined settlement rules and/or are manually allocated. Depending on the underlying nature of the work, work orders can either be 100% allocated to O&M, 100% allocated to capital, or allocated based on some percentage split. Labour and material costs are coded to work orders and the total cost is then allocated appropriately. As noted in 'Timesheets' above, the labour rate includes wages and benefits.
Direct Assignment of Non-Labour Costs	Non-labour costs associated to specific capital projects are directly assigned.

4.3 Surveys and Interviews

FEI's overhead capitalization methodology utilizes survey questions supplemented with management and cost centre owner interviews to understand the nature of capital related costs that are not directly allocated to capital projects. These interviews provide a basis to assess eligibility of costs for capitalization. FEI then uses a variety of overhead capitalization estimation methods to allocate capital related costs from the various cost centres. Details on the application of the methodology are outlined in **Section 5**.

4.4 Overhead Capitalization Estimation Methods

In this section we summarize some of the key methods employed by FEI to estimate the percentage of O&M to be allocated to capital. Different methods are applied based on the nature of capital related activity within cost centres and available information to support the methodology.

Table 6: FEI Overhead Capitalization Estimation Methods

Estimation Method	Description
Management & Supervisory Time	For managers who do not directly charge their time to capital projects but oversee staff supporting capital activity, FEI uses the ratio of the staff labour time charged to capital (direct and indirect) relative to total available staff time for the complement of staff that the manager supervises.
Capitalization Rate of Relevant Functions	For functions that provide operational or administrative support to a specific sub-set of staff that directly or indirectly support capital projects, FEI applies a similar approach as Management & Supervisory Time. FEI uses the ratio of the staff labour time charged to capital (direct and indirect) relative to total available staff time for the specific functions receiving the operational or administrative support.
Incremental Costs Related Capital	For cost centres whose activities are solely related to supporting capital projects, FEI allocates 100% of the remaining incremental costs (i.e., administrative time, training, etc.) to capital.
Support Functions General Allocator	For functions that provide general support to staff, which includes staff who directly or indirectly support capital projects, FEI applies a general allocator. The general allocation is the ratio of total labor cost charged to capital (direct and indirect) to total labour cost. The calculation excludes labor costs relating to the support functions in which the general allocator is used.
Management Estimate	FEI relies on management estimates where other allocation mechanisms are not practical. Management estimates are informed by the interview and survey results. The management estimates are based on either: ▪ Role Assessment – An assessment on a role-by-role basis is completed to allocate individual level of effort between capital related work and operations. ▪ General Estimates – Where a role-by-role assessment is impractical due to the nature of the activities, FEI applies more general management level of effort estimates. ▪ Other – In select instances where the nature of the costs within a particular cost centre and/or department are not subject to the same factors of cost causality, more specific assessments were completed.
Overall Overhead Capitalization Rate	For cost centres related to overall organizational oversight and governance, an aggregated overhead capitalization rate is calculated excluding these cost centres and then applied to the cost centres.

5 Application of Methodology and Results

5.1 Implementation Steps

The steps used by FEI to develop the estimated capitalized overhead costs using the 2023 budget are summarized below:

1) The study team, which included both KPMG and FEI personnel, conducted interviews with representatives of those cost centres that support capital projects to understand the nature of support provided by the cost centre, the costs already directly charged to projects, and the quantum of additional costs that may need to flow through the overhead capitalization mechanism.
    a) In advance of the interviews, FEI provided an excel table with cost center data for those cost centres which the interviewee was responsible for. The tables included:
        i) Gross Spend
        ii) Net Cost Centre Outflows/Inflows[5]
        iii) Approved O&M Budget (Gross Spend Less Net Cost Centre Outflows/Inflows)
        iv) Labour Costs of the Approved O&M Budget
        v) Non-Labour Costs of the Approved O&M Budget
    b) Survey questions were provided in advance to structure the discussion and are provided in **Appendix A**.
2) FEI Finance staff prepared estimates of capitalized overhead for each cost centre based on input from the interviews and available information on potential cost drivers (**Section 5.2** and **Section 5.3**).
3) KPMG confirmed the reasonableness of the cost allocation approach for each cost centre, based on the evaluation criteria outlined in **Section 2.2**.
4) FEI Finance staff compiled individual cost centre estimates to develop an overall aggregate estimate of capitalized overhead at FEI (**Section 5.2**).
5) The study team then evaluated the reasonableness of the overall results, considering FEI's past overhead capitalization rate and current and planned capital activity (**Section 5.4**).

[5] Net Cost Centre Outflows/Inflows is the net charges into or out of the cost center either to other cost centres or internal orders.

5.2 Application of FEI Overhead Capitalization Methodology

The following table summarizes department activities/costs related to capital activity as identified in the interview process, an assessment of the appropriateness for capitalization of the costs associated with such activities, and the mechanism for allocation. Definitions of columns are:

- **Department** – The department in which applicable cost centres are grouped.
- **Activities Related to Capital (Direct)** – Description of the activities whose costs are currently directly charged to capital projects (via one of the mechanisms outlined in **Section 4.2**).
- **Activities Related to Capital (Indirect) –** Description of the activities whose costs are indirectly related to capital, and which are therefore to be charged to capital projects through the overhead capitalization mechanism.
- **Assessment of Appropriateness of Indirect Cost for Capitalization** – Commentary of the appropriateness of capitalizing indirect costs through the overhead capitalization mechanism.
- **Estimation Method** – The method that FEI used to determine the appropriate percentage of indirect costs related to capital activities (via one of the methods outlined in **Section 4.4**).

Table 7: Summary of Capital Related Costs by Department

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
Operations	Operational Areas	**Direct:** Labour is charge to capital and O&M based on pre-defined work order settlement rules.	**Direct:** Materials are charge to capital and O&M based on defined work order settlement rules.	**Appropriate:** Management and supervisory time is not charged to work orders or other direct allocation mechanisms; support/administrative staff facilitate the execution of work orders, but time is not charged to work orders or other direct allocation mechanisms.	**Management Cost Centres:** Management & Supervisory Time **Support/Dispatch Cost Centres:** Capitalization Rate of Relevant Functions
		Indirect: Management/supervisory time supporting staff directly working on capital related activities; support/administrative services related to dispatch and work order creation/coding/review.	**Indirect:** Associated travel, training, vehicles, professional development, etc. for management/supervisory and support/administrative staff.		
	Business Performance	**Direct:** Scheduling support for capital activities; operations/business analysis supporting execution of the capital plan (i.e., reporting, dashboards, metrics, etc.).	**Direct:** None	**Appropriate:** Management and employee time is incremental to capital activity.	**Management Cost Centres:** Management & Supervisory Time **Business Performance and Process Support:** Capitalization Rate of Relevant Functions
		Indirect: Executive Vice President Operations & Engineering, Directors, and Regional Managers overseeing Engineering Services, Regional Operations, System Operations, Transmission / Integrity Management, PMO & Logistics, Business Performance; staff time supporting field tools/software	**Indirect:** None		
	NGT Stations O&M	**Direct:** None	**Direct:** None	**Not Appropriate:** All remaining indirect costs are related to operations and maintenance.	N/A
		Indirect: None	**Indirect:** None		
	LNG Operations & Engineering	**Direct:** Staff charge to LNG capital projects using timesheets.	**Direct:** None	**Appropriate:** Management effort to ensure operation and integration requirements are considered in Tilbury Expansion capital projects.	Management Estimate (Role Assessment)
		Indirect: Operations and integration input into Tilbury expansion capital projects for specific roles.	**Indirect:** None		

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
		Labour	Non-Labour		
	PMO & Logistics	**Direct:** Engineer time, labor hours, project management, warehousing costs, and materials delivery	**Direct:** Supporting materials of warehouse and delivery.	**Appropriate:** PMO staff time is incremental to capital activity. Welding shop staff provide support for select capital projects but time is not directly charged.	**Engineering Project Management** Incremental Costs Related Capital (100%) **Logistics & Shops** Management Estimate (Role Assessment)
		Indirect: Non-productive time of PMO staff (i.e., internal meetings, training, administration, etc.); welding shop staff time spent supporting capital activity.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Transmission / Integrity Management	**Direct:** Labour (including management and supervisory support) related to capital activities is direct charged.	**Direct:** None	**Not Appropriate:** All remaining indirect costs are related to operations and maintenance.	N/A
		Indirect: None	**Indirect:** None.		
	Major Projects	**Direct:** Staff time managing and delivering major projects.	**Direct:** Consultant support managing and delivering major projects.	**Appropriate:** Major project staff time is incremental to capital activity.	Incremental Costs Related Capital (100%)
		Indirect: Non-productive time of major project staff (i.e., internal meetings, training, administration, etc.)	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
Engineering	Engineering	**Direct:** Support on specific capital project development, design, drafting, GIS, etc.	**Direct:** Consulting support for technical designs, drafting, technical analysis/reports, etc.	**Appropriate:** Non-productive time for staff focused on project development is incremental. Management and supervisory time is not directly allocated but management and supervisors are overseeing staff completing capital related activities. System planning, drafting, and records management provide overall support, including to capital related activity.	**Capital Project Specific Cost Centres:** Incremental Costs Related Capital (100%) **Management Cost Centres:** Management & Supervisory Time **System Planning, Drafting and Records Management:** Capitalization Rate of Relevant Functions

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
		Indirect: Capital projects specific teams' training and administrative time; identification and planning of maintenance activities (some of which are capital related); system growth planning and model maintenance; technical standards development and management; management/supervisory time supporting staff directly working on capital related activities	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
Customer Service and Information Systems	Billing Operations & Customer Contact Centres	**Direct:** None	**Direct:** None	**Appropriate:** Staff time that supports maintenance of technology systems used by workforce that delivers capital projects.	Management Estimate (Other)
		Indirect: Labor to support two specific capital programs (computer system for planners and meter exchange)	**Indirect:** None		
	Information Systems	**Direct:** IT services and support charging to Internal Order of specific capital project	**Direct:** None	**Appropriate:** IT provides general support to all staff including those executing capital activities.	General Allocator
		Indirect: IT support of application system, management, IT operation	**Indirect:** Licensing of software that is used to support staff executing capital activities.		
Market Developments and External Relations	Business Innovation	**Direct:** None	**Direct:** None	**Not Appropriate:** Primarily research and development with limited linkages to capital activity.	N/A
		Indirect: None	**Indirect:** None		
	External Communications	**Direct:** None	**Direct:** None	**Not Appropriate:** Activities are generally related to corporate communications (i.e., website management, digital communications, internal communications, etc.)	N/A
		Indirect: None	**Indirect:** None		

Department	Function	Activities Related to Capital – Labour	Activities Related to Capital – Non-Labour	Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
	External Relations	**Direct:** Staff time supporting communications support for major capital projects (municipal engagement, indigenous relations, etc.); Government relations to support policy development	**Direct:** External consulting support to support communications activities related to major capital projects.	**Appropriate:** Management time supervising and supporting staff who directly charge to capital projects has not been captured. Staff time related to stakeholder management and approvals for major and sustaining capital not captured in direct charging.	**Management Cost Centres:** Management & Supervisory Time **Non-Management Cost Centres:** Management Estimate (Role Assessment)
		Indirect: Management and oversight of staff supporting major capital projects and sustaining capital projects; select staff providing services to major and sustaining capital projects that do not charge via time sheets (i.e., supporting project approvals, stakeholder management / issues management during projects, etc.)	**Indirect:** Associated travel, training, vehicles, professional development, etc. for staff related to capital.		
	NGT & Regional LNG	**Direct:** Staff charge to LNG capital projects using timesheets.	**Direct:** Contractor costs related to CNG / tanker design.	**Appropriate:** Costs are related to the advancement of designs for CNG stations and tankers, which are capital projects.	Management Estimate (Role Assessment)
		Indirect: Management and oversight of compressed natural gas (CNG) station and tanker design.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Measurement Services	**Direct:** Labour is charged to capital and O&M based on pre-defined work order settlement rules.	**Direct:** Materials are charged to capital and O&M based on defined work order settlement rules.	**Appropriate:** Management and supervisory time is not charged to work orders or other direct allocation mechanisms, but management and supervisors are overseeing staff completing capital related activities.	Management & Supervisory Time
		Indirect: Management and supervisory time supporting staff directly working on capital related activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc. for management/supervisory staff.		
HR, Environment, Health & Safety, and Facilities	Fleet	**Direct:** Labour related to capital aspects of fleet management are charged to capital internal orders.	**Direct:** Fleet charged out to appropriate cost centres.	**Not Appropriate:** All costs related to fleet management are appropriately captured via internal orders; fleet cost is allocated out to relevant cost centres. No remaining costs to be allocated.	N/A
		Indirect: None	**Indirect:** None		
	Facilities	**Direct:** None	**Direct:** None		General Allocator

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
		Labour	Non-Labour		
		Indirect: Staff time for property / facilities management for space used by staff executing capital activities.	**Indirect:** Rent/lease, building maintenance, and utility costs for space used by staff executing capital activities;	**Appropriate:** Facilities provides space for staff executing capital activities.	
	People	**Direct:** Workforce development (indigenous participation and labour contracts) to support major projects; workforce strategy, recruitment and communications for Eagle Mountain-Woodfibre Gas Pipeline (EGP) and Advanced Meter Infrastructure (AMI) projects	**Direct:** None	**Appropriate:** Staff time that supports existing workforce that executes capital activity as well as development of future workforce for future capital activity.	General Allocator
		Indirect: General human resources support for staff completing capital activities (i.e., recruitment, onboarding, payroll, training, communication, wellness, disability/claims, employee experience, etc.); recruitment strategy; succession planning; compensation	**Indirect:** Legal expenses; compensation consulting; job board subscriptions; associated travel, training, vehicles, professional development, etc.		
	Safety & Operational Learning	**Direct:** None	**Direct:** None	**Appropriate:** Safety & Operations Learning staff provides general support to all staff including those executing capital activities.	General Allocator
		Indirect: Safety instruction, technical education, and general advice/support for staff executing capital activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc.; consulting support.		
	Sustainability & Environment	**Direct:** Labour costs related to environmental support for capital projects	**Direct:** Environmental consulting services for projects;	**Appropriate:** Management time supervising and supporting staff who direct charge to capital projects has not been captured directly and therefore is eligible	Management & Supervisory Time

Department	Function	Activities Related to Capital – Labour	Activities Related to Capital – Non-Labour	Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
		Indirect: Management and supervisory time supporting staff directly working on capital related activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc. for management/supervisory staff.	for inclusion in capitalized overhead.	
Finance and Corporate	Corporate & Governance	**Direct:** None	**Direct:** None	**Appropriate:** General corporate oversight includes time for capital plan approval, as well as management and supervisory time overseeing staff who execute capital activities.	Overall Overhead Capitalization Rate
		Indirect: Portion of utility President and CEO providing oversight of capital plan execution; VP, General Counsel and Sustainability providing oversight of legal and sustainability teams whose staff support capital activity.	**Indirect:** Portion of Fortis Holding's Inc. ('FHI') management fee allocation, which includes general corporate oversight, governance, and support which would include capital plan review and approval.		
	Customer Energy & Forecasting	**Direct:** None	**Direct:** None	**Not Appropriate:** No causal link to capital activity noted.	N/A
		Indirect: None	**Indirect:** None		
	Finance	**Direct:** None	**Direct:** None	**Appropriate:** Finance provide overarching support to capital activity via capital accounting and accounts payable teams. Portion of financial reporting and financial/regulatory accounting effort is driven by level of capital activity. Credit rating agency costs enable financing for capital program.	Management Estimate (Other)
		Indirect: Finance and AP processing for capital projects, and labor component for capital reporting, capital forecast.	**Indirect:** Associated travel, training, vehicles, professional development, etc.; Credit rating agency fees to support financing capital program.		
	Internal Audit	**Direct:** None	**Direct:** None	**Appropriate:** Staff time supporting completion of audits related to capital activity.	Management Estimate (Other)
		Indirect: Select audits relate to capital activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
	Corporate Security & Business Continuity	**Direct:** In select instances, staff supporting on major capital projects directly charge their time.	**Direct:** Consulting support for major capital projects is directly charged.	**Appropriate:** Physical / corporate security supporting capital projects is incremental to base operations.	General Allocator
		Indirect: Ongoing support to physical and corporate security for all projects (both major and sustaining).	**Indirect:** Cyber security software and licensing for capital projects		
Regulatory, Legal and Operations Support	Regulatory	**Direct:** None	**Direct:** None	**Appropriate:** Costs are related to regulatory filings and proceeding for specific capital projects. General rate filings include effort related to capital plans and forecasts.	Management Estimate (General)
		Indirect: Certificate of Public Convenance and Necessity ('CPCN') applications; rate applications for capital projects; capital components of multi-year rate applications and annual rate reviews	**Indirect:** Associated travel, training, vehicles, professional development, etc. for staff related to capital.		
	Risk Management	**Direct:** None	**Direct:** None	**Appropriate:** Staff time that supports major project related insurance claims.	Management Time Estimate (Role Assessment)
		Indirect: Dedicated insurance manager to manage claims related to major projects.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Procurement	**Direct:** Dedicated team supporting major capital projects.	**Direct:** None	**Appropriate:** Management and supervisory time is not directly allocated but management and supervisors are overseeing staff completing capital related activities. Staff time on sustaining capital is not directly allocated.	General Allocator
		Indirect: Staff time supporting sustaining capital projects; Management/supervisory time supporting staff directly working on capital related activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
		Direct: None	**Direct:** None		

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
		Labour	Non-Labour		
	Integrated Resource Planning	**Indirect:** Staff time spent to develop resource requirements to meet future demands and constraints, primarily early-stage pre-project effort considering overall capital program.	**Indirect:** Associated travel, training, vehicles, professional development, etc.; consulting support to develop integrate resource plan.	**Appropriate:** Integrated resource planning includes planning for capital activity.	Management Estimate (General)
	Legal	**Direct:** None	**Direct:** None	**Appropriate:** Legal services spent on capital activities is considered to be incremental to base legal workloads.	Management Estimate (General)
		Indirect: Legal services associated to capital projects, contracts, work permits, sustainment work, RNG projects, etc.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
Energy Supply and Resource Development	Energy Solutions	**Direct:** None	**Direct:** None	**Not Appropriate:** No causal link to capital activity noted.	N/A
		Indirect: None	**Indirect:** None		
	Energy Supply	**Direct:** None	**Direct:** None	**Appropriate:** Management and supervisory time is not directly allocated but management and supervisors are overseeing staff completing capital related activities.	Management & Supervisory Time
		Indirect: A portion of vice president and senior management time with oversight of RNG, Energy Solutions, Power Supply, Resource Development, Integrated Resource Planning, Conservation & Energy Management, and the Regional Gas Supply Diversity (RGSD) project.	**Indirect:** Associated travel, training, vehicles, professional development, etc. for vice president and senior management		
		Direct: Low carbon supply group is charged to a deferral account.	**Direct:** None	**Not Appropriate:** All remaining indirect costs are related to	N/A

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FEI Estimation Method
		Labour	Non-Labour		
	Renewable Natural Gas ('RNG')	**Indirect:** None	**Indirect:** None	operations and maintenance related activities.	
	Resource Development	**Direct:** None	**Direct:** None	**Appropriate:** Resource Development staff provide early project support to develop business plans and input into CPCN applications.	Management Estimate (General)
		Indirect: Management, supervisory, and staff time spent on early project development, including activities that lead to major capital projects	**Indirect:** Associated travel, training, vehicles, professional development, etc.; consulting support.		

5.3 Results

FEI's capital overhead cost allocation methodology results in an overhead capitalization rate of approximately **14.5%**.

Table 8: Results of Overhead Capitalization Methodology (2023 O&M Budget)

Department	Gross O&M ($ Millions)	Capital Related ($ Millions)[6]	Capitalization Rate (%)
Operations	135.4	11.7	9%
Engineering	17.5	2.4	13%
Customer Service and Information Systems	73.8	12.7	17%
Market Developments and External Relations	25.3	3.2	13%
HR, Environment, Health & Safety, and Facilities	27.3	10.6	39%
Finance and Corporate	30.0	5.8	19%
Regulatory, Legal and Operation Supports	29.5	2.6	9%
Energy Supply and Resource Development	15.8	1.2	8%
O&M Subtotal	**354.4**		
Less Bio Methane O&M[7]	**(5.2)**		
Total	**349.2**	**50.2**	**14.5%**

[6] Calculated based on the aggregated results of the estimation methods applied for individual cost centres as outlined in **Section 5.2**.
[7] Biomethane O&M costs charged to the Biomethane Variance Deferral Account (BVA) have been removed as FEI will apply the overhead capitalization rate to Net O&M. Biomethane O&M costs do not have any overhead capitalization applied (i.e., 0%).

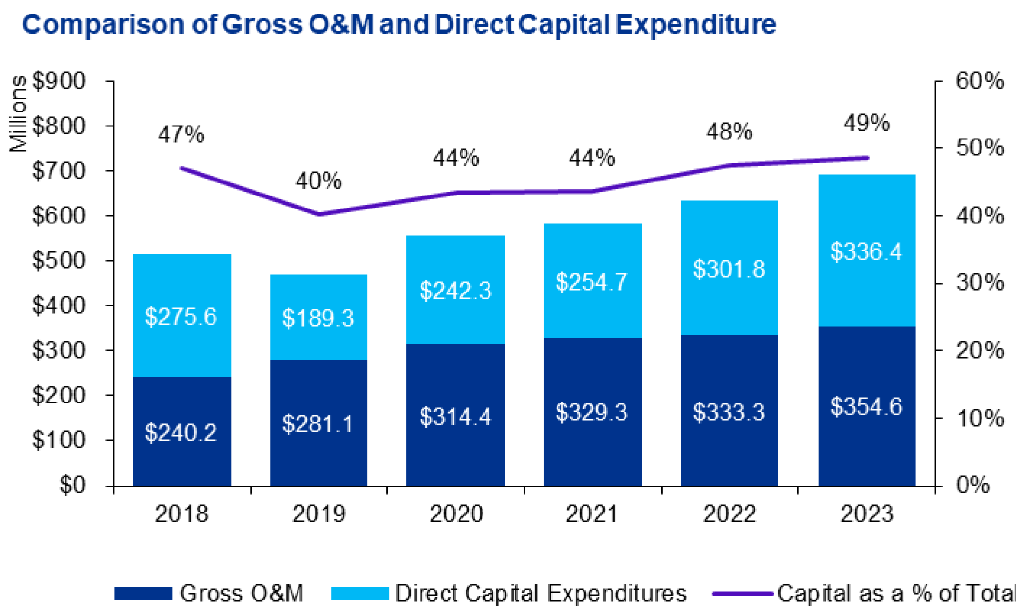
5.4 Comparison of Results with Prior Study

Based on the 2023 budget amounts and using FEI's overhead capitalization methodology, the overhead capitalization rate was determined to be **14.5%**. In comparison, FEI used a rate of 16% for the 2020-24 Multi-Year Rate Plan based on a 2018 study.

In 2018, FEI's budgeted capital expenditures were approximately 47% of the total expenditures whereas in 2023 budgeted capital expenditures were approximately 49% of the total expenditures. The proposed decrease in the overhead capitalization rate as a result of this study can be attributed to:

- **Process improvements.** Process improvements in the Operations and Engineering functional areas mean that direct charging mechanisms now capture more of the management and staff time that is spent on capital activity. This results in less need to account for these costs indirectly through the overhead capitalization rate.
- **Greater stability in the rate of capital spending over time.** At the time of the 2018 study, there had been a significant increase in capital spending relative to prior years and this had resulted in relatively more upfront activity over the prior study period related to the initiation of, and planning for, future capital projects. This upfront planning activity was reflected in a higher overhead capitalization rate. As capital spending has stabilized, there is now less investment in the upfront planning work for future capital projects relative to operating expenditures and to costs being directly charged.

The graph below shows recent movements in the breakdown of FEI budgeted expenditures between direct capital expenditures and Gross O&M.



6 KPMG Evaluation

KPMG evaluated FEI's capital overhead cost allocation methodology in alignment with the evaluation criteria introduced in **Section 2.2.** Overall, FEI's capital overhead cost allocation methodology appears to be a reasonable mechanism to establish the overhead capitalization rate.

No.	Evaluation Criteria	Assessment
1.	Cost Causality	The mechanisms used to estimate the proportions of capital related costs (outlined in **Table 6** and applied as per **Table 7**) demonstrate a reasonable causal link to capital related costs.
2.	Objective Results	The overhead capitalization methodology, where practical and appropriate, prioritizes the use of calculated allocation drivers over management estimates.
3.	Cost Effectiveness	FEI's capital overhead cost allocation methodology is applied largely to functions providing non-project specific capital support, staff providing administrative/oversight support to staff who complete capital activities, or support/infrastructure functions that enable staff who complete capital activities. These are the types of support functions where direct assignment may be impractical and/or costly.
4.	Stability Over Time	The resulting capitalized overhead rate is an aggregation of allocations developed on an individual cost centre level. This provides FEI with the flexibility to adjust individual cost centre allocations as circumstances in those cost centres change. The general methodology can thus remain stable while accommodating shifts in capital project delivery and organizational structure and function.
5.	Transparent and Supportable Methodology	The resulting capitalized overhead rate is an aggregation of allocations developed at the individual cost centre level. The calculations at a cost centre level ensure that allocations are supported with reference to specific supporting activities and personnel.
6.	Regulatory Precedence	The capital overhead cost allocation methodology is aligned with respect to the overall accounting framework and regulatory findings outlined in **Section 3.8**.
7.	Distinguishable from Directly Allocated Capital Costs	The survey questions and interviews that formed the basis of this study included questions intended to distinguish between directly allocated capital costs and those capital costs that need to be captured in the mechanism for capitalized overhead (refer to **Appendix A,** Questions 1 through 5, and **Table 7,** which provides a summary description of capital costs directly allocated). FEI did further assessment of actual data at the cost centre level to confirm and verify the nature of those costs that are directly allocated and to ensure that no overlaps, or conversely no gaps, exists in costs allocated to capital projects.
8.	Accuracy of Underlying Data	The resulting capitalized overhead rate is an aggregation of allocations developed at an individual cost centre basis enabling validation of results at a granular level.
9.	Flexibility/Adaptability	The resulting capitalized overhead rate is an aggregation of allocations developed at an individual cost centre basis which provides flexibility to adjust individual cost centre allocations, enabling the ability to adjust based on changes to regulatory, accounting, and/or organizational changes.

A Interview Questionnaire

Data collection sheets included the following questions:

1) If your cost centers charge any costs directly to capital projects, can you please describe the activities you provide?
2) For costs directly charged to capital projects how are these costs allocated?
3) For direct overhead charged to capital projects how is the direct overhead loading pool determined and allocated? Is there a separate pool for each cost center? (For FBC only)
4) Do you expect the percentage of costs directly charged to capital will change over time? If so, please provide estimates for 2024 and during the 2025-2029 Performance Based Regulation Filing?
5) Can you describe the costs incurred that are not directly charged to capital but are still used to indirectly support capital expenditure programs for the cost centers? Can you provide rationale as to why these costs support capital projects?
6) Would your cost centers operate with fewer staff if the company ceased to undertake all capital projects? If yes, by how much would there be a reduction?
7) Would your cost centers incur less non-labour cost if the company ceased to undertake all capital projects? If yes, by how much would there be a reduction?
8) Would your cost centers operate with more staff if the company doubled the current level of capital expenditure? If yes, by how much would there be an increase?
9) Would your cost centers incur more non-labour cost if the company doubled the current level of capital expenditure? If yes, by how much would there be an increase?
10) What percentage of your cost center do you forecast will be spend to indirectly (i.e., less direct charges to capital) support capital activities for 2024 and during the 2025-2029 Performance Based Regulation rate filing?
11) What is the primary driver you use to estimate the percentage of O&M to indirectly support capital activities (i.e., less direct charges to capital)? Examples could include management estimates, direct staff hours charged between capital / maintenance, customer activity, etc. How is the driver correlated to the percentage of O&M indirectly supporting capital activities. For example:
    a. The percentage tracks closely with percent changes in the driver (i.e., linear relationship).
    b. The percentage only changes when the driver changes by a certain percentage threshold.

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This report has been prepared by KPMG LLP ("KPMG") for FortisBC Energy Inc. and FortisBC Inc. ("Client") pursuant to the terms of our Agreement with the Client dated July 26, 2023, and executed on July 26, 2023. KPMG neither warrants nor represents that the information contained in this report is accurate, complete, sufficient or appropriate for use by any person or entity other than Client or for any purpose other than set out in the Engagement Agreement. This report may not be relied upon by any person or entity other than Client, and KPMG hereby expressly disclaims any and all responsibility or liability to any person or entity other than Client in connection with their use of this report.

This report is based on information and documentation that was made available to KPMG by FortisBC Energy Inc. and FortisBC Inc. at the date of this report. KPMG has not audited nor otherwise attempted to independently verify the information provided unless otherwise indicated. Should additional information be provided to KPMG after the issuance of this report, KPMG reserves the right (but will be under no obligation) to review this information and adjust its comments accordingly.

Pursuant to the terms of our engagement, it is understood and agreed that all decisions in connection with the implementation of advice, opportunities, and/or recommendations as provided by KPMG during the course of this engagement shall be the responsibility of, and made by, FortisBC Energy Inc. and FortisBC Inc. KPMG has not and will not perform management functions or make management decisions for FortisBC Energy Inc. or FortisBC Inc. Comments in this report are not intended, nor should they be interpreted, to be legal advice or opinion.

Appendix D5-2

KPMG FBC OVERHEAD CAPITALIZATION REVIEW

KPMG

FortisBC Inc.

Overhead Capitalization Methodology Review

KPMG LLP

March 2024

This report contains 38 pages

KPMG FBC Overhead Capitalization Review Report.docx

FortisBC Inc.
Overhead Capitalization Methodology Review
March 2024

Contents

Executive Summary

KPMG LLP ("KPMG") was retained by FortisBC Inc. ("FBC") to review the overhead capitalization methodology and the resulting updated overhead capitalization rate to be used in the next Ratemaking Framework beginning in 2025.

FBC defines Gross Operations and Maintenance ("O&M") costs as all costs net of any costs directly charged to capital projects. However, not all costs related to capital activity are directly charged to capital projects and therefore remain in O&M. These remaining capital-related costs are charged to capital projects through the overhead capitalization mechanism. As implied by the definitions above, the value of O&M included in the denominator when calculating the rate excludes any capital-related costs that have been directly charged to capital projects or assets.

We understand that FBC transitioned to U.S. Generally Accepted Accounting Principles ("U.S. GAAP") for regulatory accounting and reporting purposes on January 1, 2012. The British Columbia Utilities Commission ("BCUC") approved this transition in Order G-117-11. FBC subsequently applied for extensions to continue using U.S. GAAP, which was approved by the BCUC in Order G-83-14 (July 3, 2014) and G-382-22 (December 22, 2022). In accordance with these regulatory approvals, FBC's overhead capitalization methodology and resulting overhead capitalization rate leverage guidance from U.S. GAAP. This guidance includes the application of regulatory accounting in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification 980 ("ASC 980") Regulated Operations.

There is no universally accepted definition or standard that prescribes the types of indirect costs (i.e., those related to capital projects that have not been directly charged to those capital projects) that should be considered for capitalization for the purposes of regulatory and financial reporting. While U.S. GAAP provides some guidance on the costs of a capital asset, there is considerable judgment required by decision-makers to determine "costs that are incurred to bring it to the condition and location necessary for its intended use."[1] Notwithstanding the importance of judgment and thus the potential for variation in methodologies, the guidance reviewed highlights a common general principle:

> That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity.

The analysis and findings in this report used FBC's 2023 O&M Budget figures to derive the overhead capitalization rate by applying FBC's overhead capitalization methodology. FBC's overhead capitalization methodology uses the results of surveys and interviews with management staff and cost centre owners to understand the nature of capital related costs that are not directly allocated to capital. These surveys provide a basis to assess the eligibility of costs for capitalization. FBC then uses a variety of overhead capitalization estimation methods to allocate capital related costs from the various cost centres. These estimation methods are selected based on the nature of the capital activities and the cost drivers associated with these activities. The application of FBC's overhead capitalization

[1] FASB (Financial Accounting Standards Board). (n.d.). ASC 360-10-30-1

methodology using the 2023 O&M Budget results in an overhead capitalization rate of **15.5%**.

FBC uses a Direct Overhead Loading mechanism to allocate costs related to Transmission & Distribution ('T&D') projects where costs have not been directly assigned to a specific T&D project. This mechanism is applied to those costs where it would be administratively burdensome to directly charge costs to specific individual T&D projects. Based on the 2023 O&M budget, an estimated total of **$5.5 million** of capital costs are to be allocated using this mechanism. Costs allocated using the Direct Overhead Loading mechanism are evaluated as part of FBC's overhead capitalization methodology and excluded from the O&M costs that the overhead capitalization rate is applied to.

KPMG's evaluation finds that:

- FBC's capital overhead cost allocation methodology is a reasonable mechanism to establish the overhead capitalization rate.
- FBC's Direct Overhead Loading mechanism is a reasonable mechanism to allocate supervisory and administrative costs that are not directly charged to an individual T&D project but are associated with T&D capital projects.

1 Introduction

1.1 Background and Scope

KPMG LLP ("KPMG") was retained by FortisBC Inc. ("FBC") to review the overhead capitalization methodology and the resulting updated overhead capitalization rate to be used in the next Ratemaking Framework beginning in 2025. The results of this review are summarized in this report.

FBC's overhead capitalization methodology and the resulting overhead capitalization rate are based on U.S. Generally Accepted Accounting Principles ("U.S. GAAP"). These principles include the application of regulatory accounting in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification 980 ("ASC 980") Regulated Operations.

In the preparation of its financial accounts, FBC allocates costs directly to capital assets using two mechanisms:

- **Direct Charges** – These are capital costs that are directly charged to specific identified projects and that form the base value of the associated assets. These direct charges will typically include, among other things, construction labour and the materials and installed equipment that make up a new asset.
- **Direct Overhead Loading** – These are capital costs that flow through to Transmission & Distribution ("T&D") projects through a cost pool specific to T&D projects. Costs within the pool are allocated to T&D projects based on project dollar value. This pool is generally used for certain supervisory and administrative costs specifically associated with T&D projects.

FBC then defines Gross Operations and Maintenance ("O&M") costs as those costs that remain after deduction of the above two direct allocations to capital assets noted above. A portion of these remaining costs are then also flowed through to capital through the overhead capitalization process. These are costs that are related to capital activity but that cannot be directly identified with specific projects. The overhead capitalization rate is the proportion of O&M costs transferred to capital through this overhead capitalization process.

As implied by the definitions above, the value of O&M included in the denominator when calculating the overhead capitalization rate excludes any capital-related costs that have been directly charged to specific projects through the two mechanisms noted earlier (direct charges or direct overhead loading).

1.2 Limitations

1.2.1 Management Responsibility

FBC's capitalization methodology is the responsibility of management, who also maintain responsibility for the accuracy and completeness of the data and information associated with the capital cost allocation methodology and associated costs.

1.2.2 KPMG Engagement

KPMG's engagement is to comment on the reasonableness of the capital overhead cost allocation methodology, in the context of FBC's reporting under U.S. GAAP, inclusive of ASC 980, and to undertake the steps outlined in **Section 2** of this report.

This evaluation does not constitute an audit of the capital overhead cost allocation methodology, associated costs[2], or the resulting overhead capitalization rate, and is therefore not subject to assurance or other standards issued by the Canadian Auditing and Assurance Standards Board. Consequently, no opinions or conclusions intended to convey assurance have been expressed. KPMG assessed the proposed capital cost allocation methodology in the context of the approved 2023 budget. KPMG has not audited or otherwise independently verified the accuracy or fair presentation of the approved 2023 budget and costs that form the basis of the percentages capitalized. However, we did take steps to assess the accuracy of the underlying data and these steps are outlined in **Section 2**.

The information contained herein is for the internal use of FBC management. It is understood that this report may be distributed by FBC externally to the BCUC as part of the regulatory process. KPMG disclaims any responsibility or liability for losses, damages, or costs incurred by anyone as a result of any external circulation, publication, reproduction, or use of the information contained herein.

[2] FortisBC Electric Inc. ("FEI") and FBC also cross-charge shared service costs between entities using a shared service cross-charging approach approved by the BCUC in the 2020-2024 Multi-Year Rate Plan Application. KPMG does not express an opinion on this cross-charging approach.

2 Approach

This section summarizes KPMG's approach to completing the review of FBC's overhead capitalization methodology.

2.1 Work Plan

Our work plan was developed in collaboration with management in order to meet the objectives of this review. Our work plan incorporated the following steps:

Table 1: Work Plan Steps

Step	Description
1	**Review study context**. In this step, KPMG met with management to understand FBC's overall organizational structure and the business context for this review, including any changes in operations since the last review (2018), the response to prior overhead capitalization studies filed by FBC with the BCUC, and FBC's plans for future general rate filings.
2	**Review and document regulatory and accounting policy guidance**. In this step, KPMG researched and documented the guidance provided by various accounting and regulatory authorities on the topic of overhead capitalization. The objective of this step was to ensure that the approach and methodology adopted in FBCs overhead capitalization update is consistent with U.S. GAAP and applicable regulatory precedents from other filed and approved overhead capitalization studies.
3	**Review methodology**. In this step, KPMG worked with management to design the process for updating the overhead capitalization rate through this study. This included: ▪ Agreement on the sources of data to be used in the estimate and on appropriate cost allocation approaches. ▪ Preparation of a survey and associated data collection template for individual departments. ▪ Development of an interview schedule.
4	**Participate in interviews with company officials**. In this step, KPMG participated in interviews held by FBC with representatives from the operating areas. The purpose of the interviews in this step was to gain an understanding of and document: ▪ FBC's approach to the acquisition, construction, and installation of capital assets. ▪ The specific supporting activities within FBC that relate to the implementation of capital projects. ▪ The nature of costs that are currently directly charged to projects, causal factors relating to support efforts, and the suitability of potential cost drivers.
5	**Provide support to FBC in the calculation updates.** In this step, KPMG personnel were available as a resource to FBC personnel as they developed supporting calculations. This included providing advice on potential cost allocation mechanisms, including supporting cost drivers, for specific overhead support functions.

Step	Description
6	**Assessed the reasonableness of FBC's estimate of capitalized overhead costs.** In this step, KPMG assessed the reasonableness of the methodology that FBC implemented with respect to the capitalization of overhead costs from each cost centre. In our assessment, we took into account the following: ▪ The relationship between activities in a cost centre and capital projects. This was done to ensure that there is a clear causal link between the activities and capital projects. ▪ The reasonability of drivers or metrics used to apportion costs between capital and operating activities. This was done to ensure that drivers are unbiased and accurately reflect cost causality in the cost centre or department. ▪ Consistency with external accounting guidance.
7	**Data Validation of Capital Overhead Capitalization Model.** In this step, KPMG conducted the following procedures with respect to calculations supporting the quantum of estimated costs: ▪ Reviewed the overhead capitalization model for formula accuracy. ▪ Validated costs used in the capital overhead cost allocation methodology against the 2023 approved O&M budget; and ▪ Validated cost drivers against supporting system records or other corroborative evidence.
8	**Assessed the reasonableness of the resulting overhead capitalization rate.** In this step, KPMG assessed the reasonability of the proposed overhead capitalization rate, taking into account the results of all prior work steps as well as consistency with results of prior overhead capitalization studies of FBC and reasonableness considering the current and planned levels of capital activity.
9	**Document findings.** In this step, KPMG prepared this summary report to document the findings of our review and key outputs from this overhead capitalization update.

2.2 Evaluation Criteria

FBC's prior overhead capitalization studies used a set of criteria for the evaluation of the overhead capitalization methodology and associated cost drivers. These criteria have been adopted internally by management at FBC for this update and KPMG accepts these criteria as reasonable. The criteria were used both by:

1) FBC management in making decisions while setting up the methodology and its supporting calculations, and
2) KPMG in evaluating the methodology and its results.

Evaluation criteria are summarized in the table below.

Table 2: Overhead Capitalization Evaluation Criteria

No.	Evaluation Criteria	Description
1.	Cost Causality	The identified driver, being it work effort or investment, has a direct correlation to the cost of the services or goods associated with a capital project and also has a direct effect on the level of service for that capital project.
2.	Objective Results	The use of the allocation driver results in an objective allocation amount that is free from undue bias.

No.	Evaluation Criteria	Description
3.	Cost Effectiveness	The allocation driver is calculated and maintained from readily available information, resulting in minimal time and expense to implement the allocation approach.
4.	Stability Over Time	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.
5.	Transparent and Supportable Methodology	The driver used, and the source or basis for how it is determined, is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model, or other supporting documentation.
6.	Regulatory Precedence	The cost allocation methodology has been tested and approved through previous regulatory reviews.
7.	Distinguishable from Directly Allocated Capital Costs	The overhead costs must be distinguished from those that are directly charged to capital.
8.	Accuracy of Underlying Data	Any data used in the methodology is accurate and can be relied upon. The data provides an appropriate measure of the underlying volume of activity or output.
9.	Flexibility/Adaptability	The methodology can accommodate future changes in regulatory, accounting, and organizational changes with reasonable ease.

3 Financial Accounting Framework

3.1 Background

The BCUC approved the BC utilities of Fortis Inc.[3] use of U.S. GAAP for regulatory accounting and reporting purposes in Order G-117-11 on July 7, 2011, with an effective date of January 1, 2012. The FortisBC Utilities[4] subsequently filed an application to extend the use of U.S. GAAP in 2014 which was approved by the BCUC in Order G-83-14 with the condition that, *"[a]pproval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes, whichever is earlier.*"

As part of FBC's 2023 annual rate review proceeding, FBC sought a variance to Order G-83-14 seeking to ensure that FBC had continued approval to use U.S. GAAP for regulatory accounting purposes. The BCUC approved the extension request in Order G-382-22, which states, *"Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes."*

For the purposes of this Overhead Capitalization Methodology Review, U.S. GAAP was the primary accounting standard used to assess FBC's overhead capitalization methodology. If FBC transitions to a different accounting standard for regulatory and accounting purposes, then the Overhead Capitalization Methodology would need to be re-evaluated.

3.2 Standards and Guidance Used

As noted in **Section 3.1**, FBC utilizes U.S. GAAP for regulatory accounting and reporting purposes. As such, U.S. GAAP is used as the primary guidance by which to determine eligible costs for capitalization. However, as noted in the subsequent **Section 3.3**, there is limited explicit guidance, definition, or discussion of the treatment of the capitalization of overhead costs under U.S. GAAP. Additional accounting guidance has been reviewed and included to support FBC's overhead capitalization approach (**Sections 3.3 - 3.7**).

3.3 U.S. GAAP

There is limited explicit guidance, definition, or discussion of the treatment of the capitalization of overhead under U.S. GAAP. However, sections of the U.S. GAAP Accounting Standards Codification ("ASC") provide general guidance on asset accounting generally and some specific guidance for rate-regulated activities. The main sources of guidance under U.S. GAAP are noted in Table 3**.** A summary of the guidance is presented below:

[3] The BC utilities of Fortis Inc. included FortisBC Inc. ('FBC'), Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.

[4] FortisBC Inc., FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

- ASC 360 – Property, Plant, and Equipment addresses PP&E acquisition costs broadly, but provides no guidance on the eligibility of specific types of costs.
- ASC 980 – Regulated Operations provides guidance indicating that if a cost is approved by a regulator and is expected to be recovered from customers in future rates, then that cost may be capitalized as part of PP&E under ASC 980. In absence of ASC 980, such costs may be required to be expensed if they do not meet the capitalization criteria of other standards. It is therefore appropriate to consider guidance and precedence from the BCUC, as it is the regulator of FBC.
- ASC 970 – Real Estate provides more specific guidance on the capitalization of project costs. Although this section may not be directly applicable to the nature of assets created by a utility, ASC 970 has frequently been considered by utilities and used as supplementary guidance in determining capitalization of costs, specifically:
  - ASC 970's definition of indirect project costs provides a precedent for the capitalization of indirect costs and provides further clarification that indirect project costs shared across projects should be allocated to those projects to which costs relate.
  - ASC 970 also defines preacquisition costs as those costs incurred prior to obtaining the property and that these costs should be capitalized upon acquisition of the property. However, these costs are still subject to the definition of project costs. Additionally, ASC 970 discusses the concept of probability as a factor in assessing eligibility.

Table 3: U.S. GAAP ASC Information Related to Overhead Capitalization

ASC Section	Relevant Information
ASC 360 – Property, Plant and Equipment	▪ **Paragraph 360-10-30-1**: "…the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use."
ASC 980 Regulated Operations	▪ **Section 980-10-05-7:** Accounting requirements that are not directly related to the economic effects of rate actions may be imposed on regulated businesses by orders of regulatory authorities and occasionally by court decisions or statutes. This does not necessarily mean that those accounting requirements conform with generally accepted accounting principles (GAAP). For example, a regulatory authority may order an entity to capitalize and amortize a cost that would be charged to income currently by an unregulated entity. Unless capitalization of that cost is appropriate under this Topic, GAAP requires the regulated entity to charge the cost to current income. ▪ **Section 980-10-15-7 (b):** An entity's regulatory accounting. Regulators may require regulated entities to maintain their accounts in a form that permits the regulator to obtain the information needed for regulatory purposes. This Topic neither limits a regulator's actions nor endorses them. Regulators' actions are based on many considerations. Accounting addresses the effects of those actions. This Topic merely specifies how the effects of different types of rate actions are reported in general-purpose financial statements. ▪ **Section 980-340-25-1:** Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met: a) It is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. b) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost. ▪ A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

ASC Section	Relevant Information
ASC 970 – Real Estate	▪ **Project Costs:** Costs clearly associated with the acquisition, development, and construction of a real estate project. ▪ **Indirect Project Costs:** Costs incurred after the acquisition of the property, such as construction administration (for example, the costs associated with a field office at a project site and the administrative personnel that staff the office), legal fees, and various office costs, that clearly relate to projects under development or construction. Examples of office costs that may be considered indirect project costs are cost accounting, design, and other departments providing services that are clearly related to real estate projects. ▪ **Section 970-360-25-2:** Project costs, which are costs that are clearly associated with the acquisition, development, and construction of a real estate project, shall be capitalized as a cost of that project. ▪ **Section 970-360-25-3:** Indirect project costs that relate to several projects shall be capitalized and allocated to the projects to which the costs relate. ▪ **Preacquisition Costs:** Costs related to a property that are incurred for the express purpose of, but prior to, obtaining that property. Examples of preacquisition costs may be costs of surveying, zoning or traffic studies, or payments to obtain an option on the property. ▪ **Section 970-340-25-3:** Payments to obtain an option to acquire real property shall be capitalized as incurred. All other costs related to a property that are incurred before the entity acquires the property, or before the entity obtains an option to acquire it, shall be capitalized if all of the following conditions are met and otherwise shall be charged to expense as incurred: a) The costs are directly identifiable with the specific property. b) The costs would be capitalized if the property were already acquired. c) Acquisition of the property or of an option to acquire the property is probable (that is, likely to occur). This condition requires that the prospective purchaser is actively seeking to acquire the property and has the ability to finance or obtain financing for the acquisition and that there is no indication that the property is not available for sale. ▪ **Section 970-340-25-5:** The view that all internal costs of identifying and acquiring commercial properties should be deferred and, in some manner, capitalized as part of the cost of successful property acquisitions is not appropriate. **Section 970-340-25-6:** Internal costs of preacquisition activities incurred in connection with the acquisition of a property that will be classified as nonoperating at the date of acquisition that are directly identifiable with the acquired property and that were incurred subsequent to the time that acquisition of that specific property was considered probable (that is, likely to occur) shall be capitalized as part of the cost of that acquisition.

3.4 Guidance from BCUC

With respect to the capitalization of overhead, BCUC's *Uniform System of Accounts Prescribed for Gas Utilities* ("BCUC USofA") provides a basis of reference for what BCUC may allow to be capitalized under ASC 980 Regulated Operations. The BCUC USofA includes the following guidance:

> *"Cost of overhead charged to construction includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of actual and reasonable costs."*

The BCUC USofA thus specifically identifies some overhead costs that may be charged to capital projects. Further definition of the various items is not provided, which provides for some discretion in their interpretation.

3.5 Guidance from US Federal Energy Regulatory Commission (FERC)

Similar guidance to that available from BCUC is provided by FERC in its Uniform System of Accounts. Though FERC has no jurisdiction within Canada, the guidance of FERC is indicative of general industry practice. The FERC Uniform System of Accounts states:

> *"All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired."*

3.6 International Financial Reporting Standards (IFRS)

Under IFRS, guidance on accounting for capital assets, including the capitalization of overhead, is governed by International Accounting Standard 16, Property, Plant and Equipment (IAS 16).

IAS 16 states that the cost of an item of property, plant and equipment comprises:

a) its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
b) any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management; and
c) the initial estimate of the costs of dismantling and removing the item.

IAS 16 is more prescriptive than guidance under U.S. GAAP in that it provides examples of "directly attributable" costs, including:

a) costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;
b) costs of site preparation;
c) initial delivery and handling costs;
d) installation and assembly costs;
e) costs of testing whether the asset is functioning properly, and
f) professional fees.

IAS 16 also provides examples of costs that are not to be capitalized as part of an item of property, plant, and equipment, including:

a) costs of opening a new facility;
b) costs of introducing a new product or service (including costs of advertising and promotional activities);
c) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and
d) administration and other general overhead costs.

While FBC is using U.S. GAAP as the primary guidance to inform its overhead capitalization methodology, a transition to IFRS would require further analysis as it may introduce potential changes to the methodology for capitalization to PP&E, after initial application of IFRS. Specifically, IFRS' guidance on eligibility of costs for capitalization tend to be more prescriptive than guidance provided under U.S. GAAP.

The International Accounting Standards Board ("IASB") published its *Regulatory Assets and Regulatory Liabilities* exposure draft in January 2021. The exposure draft proposes a new accounting model under which a company subject to rate regulation, that meets the scope criteria, would recognize regulatory assets and liabilities. This accounting model would align the total income recognized in a period under IFRS Accounting Standards with the total allowed compensation the company is permitted to earn by the rate regulator. If issued, the proposal will replace *IFRS 14 Regulatory Deferral Accounts*. The new IFRS accounting standard is anticipated to be issued in 2025. The potential changes to the standards, if applied, may provide further guidance on the treatment of capitalized overhead.

3.7 Comparators

A review of select comparators was completed focusing on entities that either utilize U.S. GAAP for regulatory accounting and reporting purposes and/or are regulated by the BCUC.

Table 4: Summary of Select Comparator Overhead Capitalization Approaches

Comparator	Regulator	Accounting Standard	Commentary
Hydro One Networks Inc. (Hydro One) Application for Electricity Transmission and Distribution Rates 2023-2027	OEB	U.S. GAAP	As part of Hydro One's 2023-2027 rate application for its electricity transmission and distribution lines of business, Black and Veatch (B&V) completed a Report on Corporate Cost Allocation Review. This review provides insight into Hydro One's overhead capitalization approach, specifically: ▪ Example of overhead costs capitalized include "…IT sustainment, telecommunication service and equipment costs, and operation center and headquarter costs." ▪ Operation, maintenance, and administration ("OM&A") costs are categorized into: (1) Costs that should remain out of the Overhead Capitalization Rate. (2) Costs that should be fully recovered from capital expenditures as they directly and wholly support capital expenditures. (3) Costs that support both OM&A and capital and should therefore be split between OM&A and capital within the Overhead Capitalization Rate calculation. To develop the overhead capitalization rate, costs in category 2 are allocated to capital based on a 50/50 weighting of the Labour Content-Capital Ratio, which is the Total OM&A Labour divided by the Total Labour in Capital Expenditures, and the Total Spending-Capital Ratio, which is the Total Spending in OM&A versus Total Capital Expenditures. The overhead capitalization rate is then calculate based on the sum of the allocated costs from category 2 plus the costs in category 3 divided by Total Capital Expenditures. ▪ There was a noted change in methodology to establish the size of the cost pool of category 2 (i.e., the costs subject to the 50/50 Labour Content-Capital and Total Spending Capital ratio). Previously, four-week time studies were completed for specific shared services related to customer relations, asset management, and operations. As part of the 2020 review, time surveys were completed instead of four-week time studies. These time surveys were based on interviews with cost centre owners to ascertain how employees within the cost centres spent their time across the entire year. The time surveys resulted in more costs being directly assigned to capital, resulting in a smaller pool of costs to be allocated via the 50/50 Labour Content-Capital and Total Spending Capital ratio.

Comparator	Regulator	Accounting Standard	Commentary
Pacific Northern Gas Ltd. (“PNG”) 2011 Revenue Requirement Application	BCUC	IFRS (previously U.S. GAAP)	As part of the 2011 Revenue Requirement Application, PNG engaged KPMG to complete a review of a revised overhead capitalization methodology. The evaluation was primarily driven by the transition from U.S. GAAP to IFRS. Key insights include: ▪ There was a noted decrease in the overhead capitalization rate which can be largely attributed to the more prescriptive guidance under IFRS, which resulted in a significant drop in the capitalization of “administration and other general overhead costs”. ▪ Mechanisms for allocation varied based on the cost category and included: (1) Estimation of cost of staff time and associated benefit costs to capital activities. (2) Estimation of cost of management time and associated benefit costs to capital activities. (3) Estimation of field employee benefit costs as determined by a benefit load analysis. (4) True up allocation of equipment operating expense based on actual costs and equipment usage.
Corix Multi-Utility Services Inc. (Corix) Burnaby Mountain District Energy Utility 2020-2023 Revenue Requirement and Rates Application	BCUC	Not Specified	Corix did not complete an overhead capitalization study for the 2020-2023 rate application for its Burnaby Mountain District Energy Utility. However, the application contains some insight into what was considered eligible for capitalization. Specifically, one of the criteria Corix uses to determine eligibility of costs is: *“When it is not administratively feasible to directly charge every single cost of each corporate and regional activity required to execute the capital project… Examples of these corporate and regional activities* ***include, but are not limited to legal, regulatory, finance, human resources, and procurement.****”*

3.8 Overall Findings Regarding Accounting Framework

Based on the accounting and regulatory guidance related to capitalization of indirect costs and a review of select comparators (**Sections 3.3 - 3.7**), the following is observed:

- While applicable accounting and regulatory guidelines provide guidance for the capitalization of indirect costs associated with capital activity, there is considerable judgment required by decision-makers to determine costs that are incurred to bring an asset to the condition and location necessary for its intended use (when applying U.S. GAAP).
- A review of the overhead capitalization methodologies of comparator utilities that use U.S. GAAP for regulatory accounting and reporting purposes or are regulated by the BCUC, suggests considerable variation in approaches to capitalizing indirect costs, using a combination of general allocators and time analysis.

However, our review of past precedent and available guidance, does highlight a common general principle:

> That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity.

The specific approach that has been adopted by FBC is further discussed in **Section 4**. This approach is designed to demonstrate a causal link to capital activity.

4 FBC Capitalization Methodology

4.1 The Nature of Capitalized Overhead

Capitalized overhead costs can be distinguished from:

- **Costs directly assigned to capital** – These are costs that are charged directly to capital projects and that therefore form part of the direct capital cost of the associated assets. Mechanisms used to directly assign costs are outlined in **Section 4.2**.
- **Costs charged to operating expenses –** These costs appear in the income statement in the period concerned.

Functions that have costs allocated to capitalized overhead generally fall into one of the three categories noted below. While the boundaries between these types of activities may be subject to interpretation, the categories do help to provide a conceptual framework to think about capitalized overhead costs:

1) **Non-Project-Specific Capital Support –** This category encompasses processes for planning, evaluating, designing, and implementing capital additions. This includes feasibility analyses, expenditures to obtain approvals, budgeting, in-house design work, and economic assessments, among others. Activities in this category are specifically focused on capital projects but cannot be charged to any specific projects, either:
   a) Because it is impractical or costly to do so, or
   b) Because the function is related to capital projects generally rather than to specific or identified projects.
2) **Administration and Oversight of Activities Directly Related to Capital Projects –** This category encompasses processes for the supervision and administration, cost control, and reporting of those activities and/or costs that are in direct support of capital projects. Activities in support of projects can either be directly charged to those projects or they can be associated with non-project specific capital support (the first category of capitalized overhead costs noted in the bullet above). Activities in this support category thus include the administration and supervision of construction departments and plant accounting. It can also include supervision of engineering personnel that work on capital projects.
3) **Support Functions and Infrastructure –** This category covers the support functions and infrastructure networks that enable the departments that perform the processes outlined above to do their work. Relevant support functions will include, but are not necessarily limited to: Human Resources, Building Operations, and Information Services. Costs associated with space accommodation (e.g., lease charges), personal computers and other support equipment, telecommunications and vehicles will also be eligible for inclusion in this category, to the extent that these infrastructure items support employees who are working on capital-related activities and where associated costs have not been directly charged to capital projects.

4.1.1 FBC Internal Labour Rate

FBC's internal labour rates include salary costs and a mark-up for benefits (i.e., pension, vacation/leave, health/dental, etc.). Accordingly, these labour-related costs with respect to directly charged time should not be captured again through the overhead capitalization process, since this would result in double-counting.

However, only costs related to employee salaries are picked up through the above mark-up. Accordingly, other non-salary related costs related to employee time should be captured within the overhead capitalization process. Thus, an employee that charges directly to capital projects may have non-salary costs allocated to capitalized overhead. This could include the cost of external training courses and/or equipment costs, as examples.

4.1.2 Treatment of Non-Productive Time

If a person engages in activities to support capital, then an appropriate share of that employee's so-called non-productive time should also be allocated to capitalized overhead. Examples of non-productive time could include time associated with training and internal administration.

In other words, when an employee provides some support to capital, then a proportionate share of all the costs associated with that employee should be allocated to capital. We will refer to this as the "total incremental cost" of such support to capital. Costs thus include an appropriate share of expenses related to the non-productive time associated with the individual. Therefore, a cost centre whose sole function is to provide support to capital (such as, for example, a technical or engineering group), should potentially have all its costs allocated to capitalized overhead (with the exception of any costs that are charged directly to specific projects). The administrative and training costs within such a Cost Centre, for example, would then not be left in OM&A as a residual.

4.2 Direct Assignment of Costs to Capital

Where practical, FBC directly assigns capital related costs to specific projects or internal orders.

FBC employs several different mechanisms to directly allocate costs to capital:

Table 5: FBC Mechanisms for Direct Assignment of Costs to Capital

Mechanism	Description
Timesheets	Select staff complete timesheets to allocate their time to capital projects. The labour rate used includes wages and benefits (i.e., health, dental, vacation/leave, pension, etc.). The labour rate does not include any allocation of non-productive / administration time, nor does it include any overhead costs such as facilities, fleet, or technology.
Work Orders Settlement Rules	Work orders are allocated using either pre-defined settlement rules and/or are manually allocated. Depending on the underlying nature of the work, work orders can either be 100% allocated to O&M, 100% allocated to capital, or allocated based on some percentage split. Labour and material costs are coded to work orders and the total cost is then allocated appropriately. As noted in 'Timesheets' above, the labour rate includes wages and benefits.
Direct Assignment of Non-Labour Costs	Non-labour costs associated to specific capital projects are directly assigned.

4.2.1 Direct Overhead Loading

In addition to the mechanisms outlined in **Table 5**, FBC also utilizes a “Direct Overhead Loading” mechanism. The Direct Overhead Loading mechanism is intended to recover supervisory and administrative costs that are not directly charged to individual capital projects but that are nevertheless specifically associated with Transmission & Distribution (“T&D”) projects. The purpose of the Direct Overhead Loading mechanism is then to allocate these costs specifically to T&D capital projects rather than having them included in the general overhead capitalization rate which would result in allocation of these costs to Generation and other non-T&D capital projects.

The Direct Overhead Loading mechanism was introduced in the 2004 Revenue Requirements Application. The primary reason for utilizing this approach is the administrative burden associated with attempting to charge certain costs to individual projects.

The Direct Overhead Loading mechanism is used to allocate both labour and non-labour costs:

- **Labour Costs** – Labour costs to be allocated using the Direct Overhead Loading mechanism are reviewed and budgeted for on an annual basis. Employees who allocate time using the Direct Overhead Loading mechanism then code their actual time associated with T&D projects. FBC management review any variances monthly to assess and validate time allocations and, if required, complete any necessary recoding.
- **Non-Labour Costs** – Non-labour costs that are not directly charged to projects are allocated to the Direct Overhead Loading cost pool based on management's estimation of the percentage of these costs that are related to capital.

4.3 Surveys and Interviews

FBC's overhead capitalization methodology utilizes survey questions supplemented with management and cost centre owner interviews to understand the nature of capital related costs that are not directly allocated to capital projects. These interviews provide a basis to assess eligibility of costs for capitalization. FBC then uses a variety of overhead capitalization estimation methods to allocate capital related costs from the various cost centres. Details on the application of the methodology are outlined in **Section 5**.

4.4 Overhead Capitalization Estimation Methods

In this section we summarize some of the key methods employed by FBC to estimate the percentage of O&M to be allocated to capital. Different methods are applied based on the nature of capital related activity within cost centres and available information to support the methodology.

Table 6: FBC Overhead Capitalization Estimation Methods

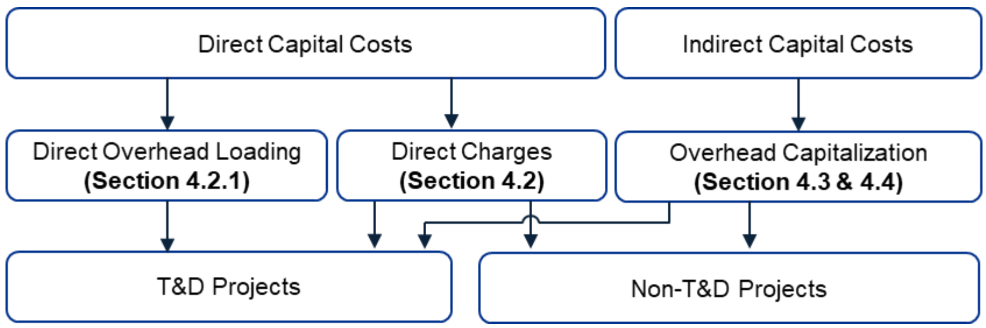
Estimation Method	Description
Management & Supervisory Time	For managers who do not directly charge their time to capital projects but oversee staff supporting capital activity, FBC uses the ratio of the staff labour time charged

Estimation Method	Description
	to capital (direct and indirect) relative to total available staff time for the complement of staff that the manager supervises.
Capitalization Rate of Relevant Functions	For functions that provide operational or administrative support to a specific sub-set of staff that directly or indirectly support capital projects, FBC applies a similar approach as Management & Supervisory Time. FBC uses the ratio of the staff labour time charged to capital (direct and indirect) relative to total available staff time for the specific functions receiving the operational or administrative support.
Incremental Costs Related Capital	For cost centres whose activities are solely related to supporting capital projects, FBC allocates 100% of the remaining incremental costs (i.e., administrative time, training, etc.) to capital.
Support Functions General Allocator	For functions that provide general support to staff, which includes staff who directly or indirectly support capital projects, FBC applies a general allocator. The general allocation is the ratio of total labor cost charged to capital (direct and indirect) to total labour cost. The calculation excludes labor costs relating to the support functions in which the general allocator is used.
Management Estimate	FBC relies on management estimates where other allocation mechanisms are not practical. Management estimates are informed by the interview and survey results. The management estimates are based on either: ▪ Role Assessment – An assessment on a role-by-role basis is completed to allocate individual level of effort between capital related work and operations. ▪ General Estimates – Where a role-by-role assessment is impractical due to the nature of the activities, FBC applies more general management level of effort estimates. ▪ Other – In select instances where the nature of the costs within a particular cost centre and/or department are not subject to the same factors of cost causality, more specific assessments were completed.
Overall Overhead Capitalization Rate	For cost centres related to overall organizational oversight and governance, an aggregated overhead capitalization rate is calculated excluding these cost centres and then applied to the cost centres.

4.5 Summary of FBC's Capitalization Methodology

Figure 1 provides an overall summary of FBC's capitalization methodology.

Figure 1: Overview of FBC Capital Cost Allocation Methodology



5 Application of Methodology and Results

5.1 Implementation Steps

The steps used by FBC to develop the estimated capitalized overhead costs using the 2023 budget are summarized below:

1) The study team, which included both KPMG and FBC personnel, conducted interviews with representatives of those cost centres that support capital projects to understand the nature of support provided by the cost centre, the costs already directly charged to projects, and the quantum of additional costs that may need to flow through the overhead capitalization mechanism.
   a) In advance of the interviews, FBC provided an excel table with cost center data for those cost centres which the interviewee was responsible for. The tables included:
      i) Gross Spend
      ii) Net Cost Centre Outflows/Inflows[5]
      iii) Direct Overhead Loading Pool
      iv) Approved O&M Budget (Gross Spend Less Net Cost Centre Outflows/Inflows and Direct Overhead Loading Pool)
      v) Labour Costs of the Approved O&M Budget
      vi) Non-Labour Costs of the Approved O&M Budget
   b) Survey questions were provided in advance to structure the discussion and are provided in **Appendix A**.
2) FBC Finance staff prepared estimates of capitalized overhead for each cost centre based on input from the interviews and available information on potential cost drivers (**Section 5.2** and **Section 5.3**).
3) KPMG confirmed the reasonableness of the cost allocation approach for each cost centre, based on the evaluation criteria outlined in **Section 2.2**.
4) FBC Finance staff compiled individual cost centre estimates to develop an overall aggregate estimate of capitalized overhead at FBC (**Section 5.2**).
5) The study team then evaluated the reasonableness of the overall results, considering FBC's past overhead capitalization rate and current and planned capital activity (**Section 5.4**).

[5] Net Cost Centre Outflows/Inflows is the net charges into or out of the cost center either to other cost centres or internal orders.

5.2 Application of FBC Overhead Capitalization Methodology

The following table summarizes department activities/costs related to capital activity as identified in the interview process, an assessment of the appropriateness for capitalization of the costs associated with such activities, and the mechanism for allocation. Definitions of columns are:

- **Department** – The department in which applicable cost centres are grouped.
- **Activities Related to Capital (Direct)** – Description of the activities whose costs are currently directly charged to capital (via one of the mechanisms outlined in **Section 4.2**).
- **Activities Related to Capital (Direct Overhead)** – Description of the activities whose costs are charged to capital via the direct overhead loading mechanism (outlined in **Section 4.2.1**).
- **Activities Related to Capital (Indirect) –** Description of the activities whose costs are indirectly related to capital, and which are therefore to be charged to capital through the overhead capitalization mechanism.
- **Assessment of Appropriateness of Indirect Cost for Capitalization** – Commentary of the appropriateness of capitalizing indirect costs through the overhead capitalization mechanism
- **Estimation Method** – The method that FBC used to determine the appropriate percentage of indirect costs related to capital activities (via one of the methods outlined in **Section 4.4**).

Table 7: Summary of Capital Related Costs by Department

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
Operations	Generation	**Direct:** Labour and management/ supervisory time related to capital is directly charged to specific projects if required.	**Direct:** None.	**Appropriate:** While work is primarily related to maintenance activity, some of this activity is considered capital in nature as the work extends the life of the generation turbine units.	Management Estimate (General)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Labour related to upgrading or completing major maintenance activities (i.e., work that extends life of the asset) for generation turbine units is not directly charged to capital.	**Indirect:** None.		
	Generation (Project Management & Project Services)	**Direct:** Staff time related to project management and project administration/ support of sustaining capital.	**Direct:** None.	**Appropriate:** Project management and services staff time is incremental to capital activity.	Incremental Costs Related Capital
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Non-productive time of staff (i.e., internal meetings, training, administration, etc.)	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Transmission Station Projects (Project Management Office)	**Direct:** Staff time related to capital is directly charged to specific projects. Management/supervisory time charged to specific capital projects, where practical.	**Direct:** None	**Not Appropriate:** Costs are already 100% allocated to capital via direct charging and direct overhead loading.	N/A
		Direct (Overhead Loading): Management and supervisory time overseeing staff supporting major capital and sustaining capital related to T&D projects.	**Direct (Overhead Loading):** None		
		Indirect: None	**Indirect:** None.		
	Maintenance & Land	**Direct:** None	**Direct:** None		N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
		Labour	Non-Labour		
		Indirect: None	**Indirect:** None	**Not Appropriate:** Work is primarily related to right-of-way vegetation management.	
	Inventory & Warehousing	**Direct:** Inventory management and staff costs are captured in a material loading rate and are allocate to capital based on material used for capital activity.	**Direct:** Non-labour costs are captured in a material loading rate and are allocated to capital based on material used for capital activity.	**Not Appropriate:** Inventory & warehousing costs are allocated out to respective O&M cost centres and capital projects via a material loading rate.	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: None	**Indirect:** None		
	System Control	**Direct:** Labour (including management and supervisory support) related to capital activities is direct charged.	**Direct:** None	**Not Appropriate:** Work is primarily related to system operations. Where required, time related to capital projects is captured via direct charging mechanisms.	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: None	**Indirect:** None.		
	Network Operations	**Direct:** Staff time related to capital is directly charged to specific projects. Management/supervisory time charged to specific capital projects, where practical.	**Direct:** None.	**Appropriate:** Management and supervisory overseeing staff who provide support to non-T&D projects is not captured in the direct assignment mechanism.	Management & Supervisory Time
		Direct (Overhead Loading): Management and supervisory time overseeing staff supporting major capital and sustaining capital related to T&D projects.	**Direct (Overhead Loading):** None.		
		Indirect: Management and supervisory time overseeing staff supporting major capital and sustaining capital related to non-T&D projects.	**Indirect:** None.		
	Major Projects	**Direct:** Staff time managing and delivering major projects.	**Direct:** None.	**Not Appropriate:** Costs are already 100% allocated to capital via direct charging.	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
		Indirect: None.	**Indirect:** None.		
Engineering	Engineering	**Direct:** Engineering support for major capital projects (i.e., class estimating, IFCs, design, etc.).	**Direct:** Consulting support for technical designs, drafting, technical analysis/reports, etc.	**Appropriate:** The majority of capital related costs are already allocated to capital via direct charging and direct overhead loading. A portion of the labour cost associated with management and maintenance of the security systems that provide general operation are considered eligible as security services would oversee both capital and operational activity.	**Mandatory Reliability** Management Estimate (General)
		Direct (Overhead Loading): Engineering support for capital that is non-project specific (i.e., specifications, standard, etc.). Management and supervisory time overseeing staff completing capital related activities.	**Direct (Overhead Loading):** None.		
		Indirect: Engineering's Mandatory Reliability function manages and maintains security monitoring systems that provide general security service to FBC operations. A part of these operations would be capital activity related.	**Indirect:** None		
Customer Service and Information Systems	Customer Service	**Direct:** None	**Direct:** None	**Not Appropriate:** All work is operational in nature, no capital related activity noted.	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: None.	**Indirect:** None		
	Information Systems	**Direct:** IT services and support charging to Internal Order of specific capital project	**Direct:** None	**Appropriate:** IT provides general support to all staff including those executing capital activities.	General Allocator
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: IT support of application system, management, IT operation	**Indirect:** Licensing of software that is used to support staff executing capital activities.		
Market Developments and External Relations	Business Innovation	**Direct:** None	**Direct:** None	**Not Appropriate:** Primarily research and development with limited linkages to capital activity.	N/A
		Indirect: None	**Indirect:** None		

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
	External Communications	**Direct:** None	**Direct:** None	**Not Appropriate:** Activities are generally related to corporate communications (i.e., website management, digital communications, internal communications, etc.)	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: None	**Indirect:** None		
	External Relations	**Direct:** Staff time supporting communications support for major capital projects (municipal engagement, indigenous relations, etc.); Government relations to support policy development	**Direct:** External consulting support to support communications activities related to major capital projects.	**Appropriate:** External relations are involved in project approvals and required project stakeholder engagement. Staff working on major capital projects direct charge their time, but time related to sustaining / smaller capital projects is not generally captured. Further, management time supervising and supporting staff who directly charge to capital projects is not captured in the direct assignment mechanism.	Management Estimate (Role Assessment)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Management and oversight of staff supporting major capital projects and sustaining capital projects; select staff providing services to major and sustaining capital projects that do not charge via time sheets (i.e., supporting project approvals, stakeholder management / issues management during projects, etc.)	**Indirect:** Associated travel, training, vehicles, professional development, etc. for staff related to capital.		
	EV Charging	**Direct:** None	**Direct:** None	**Not Appropriate:** Flowthrough item excluded from regulated O&M.	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: None	**Indirect:** None		
HR, Environment, Health & Safety, and Facilities	Fleet	**Direct:** Labour related to capital aspects of fleet management are charged to capital internal orders.	**Direct:** Fleet charged out to appropriate cost centres.	**Appropriate:** Fleet is used by staff completing capital activities, the management of the fleet supports this; however, it is not fully captured in direct charging.	General Allocator
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Management and supervisory time (i.e., fleet administration) is not captured through direct charging.	**Indirect:** None		
	Facilities	**Direct:** None	**Direct:** None		General Allocator

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.	**Appropriate:** Facilities provides space for staff executing capital activities.	
		Indirect: Staff time for property / facilities management for space used by staff executing capital activities.	**Indirect:** Rent/lease, building maintenance, and utility costs for space used by staff executing capital activities.		
	People	**Direct:** Workforce development (indigenous participation and labour contracts) to support major projects; workforce strategy, recruitment and communications for EGP and AMI projects	**Direct:** None	**Appropriate:** Staff time that supports existing workforce that executes capital activity as well as development of future workforce for future capital activity. Associated non-labour costs related to compensation consulting and job boards generally support all workforce development, a portion of which would be associated with staff on capital projects. Other non-labour costs related to training, professional development, travel, etc. are incremental to labour costs.	General Allocator
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: General human resources support for staff completing capital activities (i.e., recruitment, onboarding, payroll, training, communication, wellness, disability/claims, employee experience, etc.); recruitment strategy; succession planning; compensation	**Indirect:** Legal expenses; compensation consulting; job board subscriptions; associated travel, training, vehicles, professional development, etc.		
	Safety & Operational Learning	**Direct:** None	**Direct:** None	**Appropriate:** Safety & Operations Learning staff provides general support to all staff including those executing capital activities. Consulting support includes training design and delivery, a portion of which would be delivered to staff who complete capital projects. Other non-labour costs related to training, professional development, travel, etc. are incremental to labour costs.	General Allocator
		Direct (Overhead Loading): Negligible[6]	**Direct (Overhead Loading):** None		
		Indirect: Safety instruction, technical education, and general advice/support for staff executing capital activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc.; consulting support.		

[6] In 2023 a negligible amount (<$1,000) was charged via the direct overhead loading mechanism.

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
		Labour	Non-Labour		
	Sustainability & Environment	**Direct:** Labour costs related to environmental support for capital projects	**Direct:** Environmental consulting services for projects;	**Appropriate:** Management time supervising and supporting staff who direct charge to capital projects has not been captured directly and therefore is eligible for inclusion in capitalized overhead.	Management & Supervisory Time
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Management and supervisory time supporting staff directly working on capital related activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc. for management/supervisory staff.		
Finance and Corporate	Corporate & Governance	**Direct:** None	**Direct:** None	**Appropriate:** General corporate oversight includes time for capital plan approval, as well as management and supervisory time overseeing staff who execute capital activities.	Overall Overhead Capitalization Rate
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Portion of utility President and CEO providing oversight of capital plan execution; VP, General Counsel and Sustainability providing oversight of legal and sustainability teams whose staff support capital activity.	**Indirect:** Portion of Fortis Holding's Inc. ('FHI') management fee allocation, which includes general corporate oversight, governance, and support which would include capital plan review and approval.		
	Executive	**Direct:** None	**Direct:** None	**Appropriate:** Management time supervising and supporting staff who direct charge to capital projects has not been captured directly and therefore is eligible for inclusion in capitalized overhead.	Management & Supervisory Time
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Portion of EVP, Operations & Engineering who provides oversight to departments delivering capital projects.	**Indirect:** Associated travel, training, vehicles, professional development, etc. for EVP.		
	Finance	**Direct:** None	**Direct:** None	**Appropriate:** Finance provide overarching support to capital activity via capital accounting and accounts payable teams. Portion of financial reporting and financial/regulatory accounting	Management Estimate (Other)
		Direct (Overhead Loading): Accounts payable processing for T&D capital projects, and labor component for capital reporting, capital forecast.	**Direct (Overhead Loading):** None		

Department	Function	Activities Related to Capital: Labour	Activities Related to Capital: Non-Labour	Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
		Indirect: AP processing for non-T&D capital projects. Financial support for all capital projects related to capital accounting and financial/regulatory accounting (i.e., project funding, rate modelling for capital projects, support capital planning, etc.).	**Indirect:** Associated travel, training, vehicles, professional development, etc.; Credit rating agency fees to support financing capital program.	effort is driven by level of capital activity. Credit rating agency costs enable financing for capital program.	
	Internal Audit	**Direct:** None	**Direct:** None	**Appropriate:** Staff time supporting completion of audits related to capital activity.	Management Estimate (Other)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Select audits relate to capital activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Corporate Security & Business Continuity	**Direct:** Staff direct charge time related to major capital projects	**Direct:** Consulting support is charged to major capital projects	**Appropriate:** Physical / corporate security supporting capital projects is incremental to base operations.	General Allocator
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Overall management and support physical and corporate security program, which would include support for capital related activities.	**Indirect:** Cyber security software and licensing for capital projects		
Regulatory, Legal and Operations Support	Regulatory	**Direct:** None	**Direct:** None	**Appropriate:** Costs are related to regulatory filings and proceeding for specific capital projects. General rate filings include effort related to capital plans and forecasts.	Management Estimate (General)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Certificate of Public Convenance and Necessity ('CPCN') applications; rate applications for capital projects; capital components of multi-year rate applications and annual rate reviews	**Indirect:** Associated travel, training, vehicles, professional development, etc. for staff related to capital.		
	Risk Management	**Direct:** None	**Direct:** None	**Appropriate:** Staff time that supports major project related insurance claims.	Management Time Estimate (Role Assessment)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		

Department	Function	Activities Related to Capital		Appropriateness of Indirect Cost for Capitalization	FBC Estimation Method
		Labour	Non-Labour		
		Indirect: Dedicated insurance manager to manage claims related to major projects.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Procurement	**Direct:** None	**Direct:** None	**Appropriate:** Management and supervisory time is not directly allocated but management and supervisors are overseeing staff completing capital related activities.	Management & Supervisory Time
		Direct (Overhead Loading): Staff effort supporting the procurement of materials and services (i.e., RFP development, contract development, negotiations, etc.) related to capital projects.	**Direct (Overhead Loading):** None.		
		Indirect: Management/ supervisory time supporting staff directly working on capital related activities.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
	Integrated Resource Planning	**Direct:** None	**Direct:** None	**Appropriate:** Integrated resource planning includes planning for capital activity.	Management Estimate (General)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Staff time spent to develop resource requirements to meet future demands and constraints, primarily early-stage pre-project effort considering overall capital program.	**Indirect:** Associated travel, training, vehicles, professional development, etc.; consulting support to develop integrate resource plan.		
	Legal	**Direct:** None	**Direct:** None	**Appropriate:** Legal team does not charge any of their time but directly provides support across a number of capital projects.	Management Estimate (General)
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: Legal services team associated with major and sustaining capital projects, work includes advising on contracts, work permits, claims, etc.	**Indirect:** Associated travel, training, vehicles, professional development, etc.		
Energy Supply and Resource Development	Power Supply	**Direct:** None	**Direct:** None	**Not Appropriate:** No causal link to capital activity noted.	N/A
		Direct (Overhead Loading): None.	**Direct (Overhead Loading):** None.		
		Indirect: None	**Indirect:** None		

5.3 Results

5.3.1 Direct Overhead Loading

Table 8 shows the contribution of individual functions to the direct overhead loading cost pool, these contributions result in a total cost pool of **$5.5 million**. In comparison, this cost pool was $5 million in the 2018 budget.

FBC's direct overhead loading methodology is consistent with the methodology in the 2018 study.

Table 8: Direct Overhead Loading Summary (2023 O&M Budget)

Department	Function	Total Direct Overhead Loading ($ Millions)
Operations	Network Operations (Kootenay)	0.7
	Network Operations (Okanagan)	1.1
	System Operating	0.8
	Project Management Office	0.6
Engineering	Engineering	0.8
	System Planning	1.0
Corporate Office Support		0.5
	Total	5.5

5.3.2 Overhead Capitalization Rate

FBC's capital overhead cost allocation methodology results in an overhead capitalization rate of approximately **15.5%**.

Table 9: Results of Overhead Capitalization Methodology (2023 O&M Budget)

Department	Total Cost Less Direct Capital Charges ($ Millions)	Direct Overhead Loading ($ Millions)	Gross O&M ($ Millions)	Capital Related ($ Millions)[7]	Capitalization Rate (%)
Operations	26.4	(3.2)	23.6	1.4	6%
Engineering	8.7	(1.8)	6.9	0.4	6%
Customer Service and Information Systems	11.8	-	11.8	3.0	25%
Market Developments and External Relations	2.6	-	2.6	0.2	8%
HR, Environment, Health & Safety, and Facilities	7.2	(0.1)	7.1	3.1	43%
Finance and Corporate	14.8	(0.4)	14.0	3.0	21%
Regulatory, Legal and Operation Supports	5.4	-	5.4	0.4	7%
Energy Supply and Resource Development	1.4	-	1.4	0.0	0%
Total	**78.3**	**(5.5)**	**72.8**	**11.4**	**15.5%**

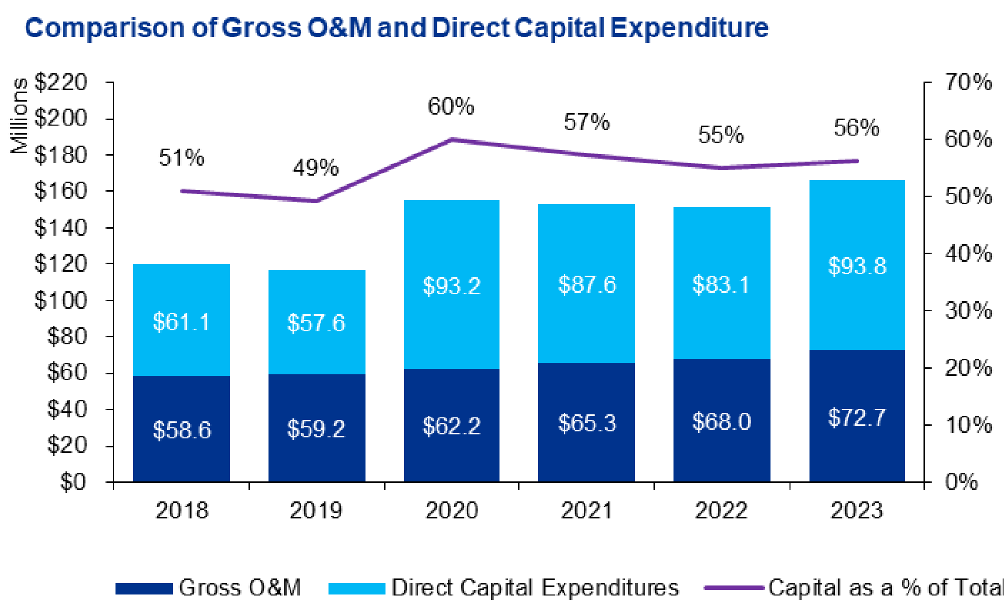
[7] Calculated based on the aggregated results of the estimation methods applied for individual cost centres as outlined in Section 5.2.

5.4 Comparison of Results with Prior Study

Based on the 2023 budget amounts and using FBC's overhead capitalization methodology, the overhead capitalization rate was determined to be **15.5%.** In comparison, FBC used a rate of 15% for the 2020-24 Multi-Year Rate Plan based on a 2018 study.

In 2018, FBC's budgeted capital expenditures were approximately 51% of the total expenditures whereas in 2023 budgeted capital expenditures were approximately 56% of the total expenditures. The slight increase in the overhead capitalization rate aligns with the increase in capital activity.

The graph below shows recent movements in the breakdown of FBC budgeted expenditures between direct capital expenditures and Gross O&M.



6 KPMG Evaluation

KPMG evaluated FBC's capital overhead cost allocation methodology in alignment with the evaluation criteria introduced in **Section 2.2.** Overall, FBC's capital overhead cost allocation methodology appears to be a reasonable mechanism to establish the overhead capitalization rate.

No.	Evaluation Criteria	Assessment
1.	Cost Causality	The mechanisms used to estimate the proportions of capital related costs (outlined in **Table 6** and applied as per **Table 7**) demonstrate a reasonable causal link to capital related costs.
2.	Objective Results	The overhead capitalization methodology, where practical and appropriate, prioritizes the use of calculated allocation drivers over management estimates.
3.	Cost Effectiveness	FBC's capital overhead cost allocation methodology is applied largely to functions providing non-project specific capital support, staff providing administrative/oversight support to staff who complete capital activities, or support/infrastructure functions that enable staff who complete capital activities. These are the types of support functions where direct assignment may be impractical and/or costly.
4.	Stability Over Time	The resulting capitalized overhead rate is an aggregation of allocations developed on an individual cost centre level. This provides FBC with the flexibility to adjust individual cost centre allocations as circumstances in those cost centres change. The general methodology can thus remain stable while accommodating shifts in capital project delivery and organizational structure and function.
5.	Transparent and Supportable Methodology	The resulting capitalized overhead rate is an aggregation of allocations developed at the individual cost centre level. The calculations at a cost centre level ensure that allocations are supported with reference to specific supporting activities and personnel.
6.	Regulatory Precedence	The capital overhead cost allocation methodology is aligned with respect to the overall accounting framework and regulatory findings outlined in **Section 3.8**.
7.	Distinguishable from Directly Allocated Capital Costs	The survey questions and interviews that formed the basis of this study included questions intended to distinguish between directly allocated capital costs and those capital costs that need to be captured in the mechanism for capitalized overhead (refer to **Appendix A,** Questions 1 through 5, and **Table 7,** which provides a summary description of capital costs directly allocated). Costs allocated using the direct overhead loading mechanism are excluded from the O&M costs that the overhead capitalization rate is applied to (refer to **Table 7** for a summary description of capital costs allocated using direct overhead loading and **Table 8** for the resulting allocations). FBC did further assessment of actual data at the cost centre level to confirm and verify the nature of those costs that are directly allocated and to ensure that no overlaps, or conversely no gaps, exists in costs allocated to capital projects.
8.	Accuracy of Underlying Data	The resulting capitalized overhead rate is an aggregation of allocations developed at an individual cost centre basis enabling validation of results at a granular level.
9.	Flexibility/Adaptability	The resulting capitalized overhead rate is an aggregation of allocations developed at an individual cost centre basis which provides flexibility to adjust individual cost centre allocations, enabling the ability to adjust based on changes to regulatory, accounting, and/or organizational changes.

A Interview Questionnaire

Data collection sheets included the following questions:

1) If your cost centers charge any costs directly to capital projects, can you please describe the activities you provide?
2) For costs directly charged to capital projects how are these costs allocated?
3) For direct overhead charged to capital projects how is the direct overhead loading pool determined and allocated? Is there a separate pool for each cost center? (For FBC only)
4) Do you expect the percentage of costs directly charged to capital will change over time? If so, please provide estimates for 2024 and during the 2025-2029 Performance Based Regulation Filing?
5) Can you describe the costs incurred that are not directly charged to capital but are still used to indirectly support capital expenditure programs for the cost centers? Can you provide rationale as to why these costs support capital projects?
6) Would your cost centers operate with fewer staff if the company ceased to undertake all capital projects? If yes, by how much would there be a reduction?
7) Would your cost centers incur less non-labour cost if the company ceased to undertake all capital projects? If yes, by how much would there be a reduction?
8) Would your cost centers operate with more staff if the company doubled the current level of capital expenditure? If yes, by how much would there be an increase?
9) Would your cost centers incur more non-labour cost if the company doubled the current level of capital expenditure? If yes, by how much would there be an increase?
10) What percentage of your cost center do you forecast will be spend to indirectly (i.e., less direct charges to capital) support capital activities for 2024 and during the 2025-2029 Performance Based Regulation rate filing?
11) What is the primary driver you use to estimate the percentage of O&M to indirectly support capital activities (i.e., less direct charges to capital)? Examples could include management estimates, direct staff hours charged between capital / maintenance, customer activity, etc. How is the driver correlated to the percentage of O&M indirectly supporting capital activities. For example:
    a. The percentage tracks closely with percent changes in the driver (i.e., linear relationship).
    b. The percentage only changes when the driver changes by a certain percentage threshold.

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This report has been prepared by KPMG LLP ("KPMG") for FortisBC Energy Inc. and FortisBC Inc. ("Client") pursuant to the terms of our Agreement with the Client dated July 26, 2023, and executed on July 26, 2023. KPMG neither warrants nor represents that the information contained in this report is accurate, complete, sufficient or appropriate for use by any person or entity other than Client or for any purpose other than set out in the Engagement Agreement. This report may not be relied upon by any person or entity other than Client, and KPMG hereby expressly disclaims any and all responsibility or liability to any person or entity other than Client in connection with their use of this report.

This report is based on information and documentation that was made available to KPMG by FortisBC Energy Inc. and FortisBC Inc. at the date of this report. KPMG has not audited nor otherwise attempted to independently verify the information provided unless otherwise indicated. Should additional information be provided to KPMG after the issuance of this report, KPMG reserves the right (but will be under no obligation) to review this information and adjust its comments accordingly.

Pursuant to the terms of our engagement, it is understood and agreed that all decisions in connection with the implementation of advice, opportunities, and/or recommendations as provided by KPMG during the course of this engagement shall be the responsibility of, and made by, FortisBC Energy Inc. and FortisBC Inc. KPMG has not and will not perform management functions or make management decisions for FortisBC Energy Inc. or FortisBC Inc. Comments in this report are not intended, nor should they be interpreted, to be legal advice or opinion.

Appendix E

DRAFT ORDERS

Appendix E1

DRAFT PROCEDURAL ORDER

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Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for the Years 2025 through 2027

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On April 8, 2024, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 of the *Utilities Commission Act* seeking approval of a rate setting framework (Rate Framework) for the years 2025 through 2027 (Application);

B. In the Application, FortisBC seeks approval of the Rate Framework for the upcoming three years, including, amongst other items, an indexed approach to FEI's and FBC's Operations and Maintenance (O&M) expense and FEI's Growth capital, three-year forecasts of FEI's Regular Sustainment and Other capital and FBC's Regular Growth, Sustainment and Other capital, Service Quality Indicators (SQIs) for FEI and FBC, and a refreshed innovation fund for FEI;

C. The Application also seeks approval of deferral accounts, updated depreciation rates and other supporting studies, and other approvals for the term of the Rate Framework; and

D. The BCUC has commenced review of the Application and considers that the following determinations are warranted.

NOW THEREFORE the BCUC orders as follows:

1. A regulatory timetable for the review of the Application is established as set out in Appendix A to this order.

2. FortisBC must provide a copy, electronically where possible, of the Application and this order by no later than Friday, May 24, 2024 to the following parties:

a. All interveners in the FortisBC 2020-2024 Multi-Year Rate Plan proceeding and the Annual Reviews for 2024 Rates proceedings; and

b. All stakeholders that attended the FortisBC 2025+ Rate Setting Framework Workshop, identified in Appendix B2-3 to the Application.

3. FortisBC must publish notice of this Application and order on its website at www.fortisbc.com and appropriate social media platforms, on or before Friday, May 24, 2024 and publish weekly reminder notices on each platform until the conclusion of the intervener registration period on Friday, June 7, 2024.

4. FortisBC is directed to provide confirmation of compliance with Directives 2 and 3 by Wednesday, May 29, 2024. Such confirmation shall include confirmation of the notice published on FortisBC's website, including a list of the social media platforms on which the notice was posted, as well as a list of all parties notified.

5. In accordance with the BCUC's Rules of Practice and Procedure, parties who wish to actively participate in this proceeding must submit the Request to Intervene Form, available on the BCUC's website at https://www.bcuc.com/GetInvolved/GetInvolvedProceeding, by Friday, June 7, 2024, as established in the regulatory timetable. Parties may also submit letters of comment by completing a Letter of Comment Form, available on the BCUC's website.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for the Years 2025 through 2027

REGULATORY TIMETABLE

Action	Date (2024)	
FortisBC publishes notice	Friday, May 24	
FortisBC confirmation of notice	Wednesday, May 29	
Registration of Interveners	Friday, June 7	
BCUC Information Request (IR) No. 1	Tuesday, June 11	
Intervener IR No. 1	Tuesday, June 18	
FortisBC response to IR No. 1	Tuesday, July 23	
Intervener confirmation of intent to file Evidence	Friday, August 9	
BCUC and Intervener IR No. 2	Tuesday, August 20	
BCUC notice of remaining timetable	Tuesday, August 27	
FortisBC response to IR No. 2	Thursday, September 12	
Action	**Without Evidence**	**With Evidence**
Intervener Evidence		Tuesday, October 1
IRs on Intervener Evidence		Wednesday, October 23
Intervener responses to IRs on Evidence		Thursday, November 14
FortisBC Rebuttal Evidence (if required)	Not applicable	Tuesday, December 3
IRs on Rebuttal Evidence (if required)		Thursday, December 19
		Dates (2025)
FortisBC responses to IRs on Rebuttal Evidence (if required)		Tuesday, January 14
Letters of comment deadline	Thursday, September 19	Thursday, January 16
FortisBC Final Argument	Friday, October 4	Tuesday, January 21
Intervener Final Arguments	Friday, October 25	Tuesday, February 11
FortisBC Reply Argument	Monday, November 18	Tuesday, March 4

bcuc
British Columbia Utilities Commission

We want to hear from you

FORTISBC RATE SETTING FRAMEWORK FOR THE YEARS 2025 THROUGH 2027

On April 8, 2024, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC) filed an application for approval of a rate setting framework for the years 2025 through 2027. The Application seeks BCUC approval of FortisBC's proposed framework for how it will set rates over the upcoming three years, including, among other things, the use of an index-based approach to FEI's and FBC's Operations and Maintenance (O&M) expense and FEI's Growth capital, three-year forecasts of FEI's Regular Sustainment and Other capital and FBC's Regular Growth, Sustainment and Other capital, Service Quality Indicators (SQIs) for FEI and FBC, and a refreshed innovation fund for FEI.

HOW TO PARTICIPATE

- **Submit a letter of comment**
- **Request intervener status**

IMPORTANT DATES

1. **Friday, June 7, 2024** – Deadline to register as an intervener with the BCUC

For more information about the Application, please visit the Proceeding Webpage on bcuc.com under "Our Work – Proceedings." To learn more about getting involved, please visit our website (www.bcuc.com/get-involved) or contact us at the information below.

GET MORE INFORMATION

FortisBC Energy Inc. Regulatory Affairs

16705 Fraser Highway
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British Columbia Utilities Commission

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Appendix E2

DRAFT FINAL ORDER - FEI

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for the Years 2025 through 2027

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On April 8, 2024, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 pf the *Utilities Commission Act* seeking approval of a rate setting framework (Rate Framework) for the years 2025 through 2027 (Application);

B. In the Application, FortisBC seeks approval of the Rate Framework for the upcoming three years, including, amongst other items, an indexed approach to FEI's and FBC's Operations and Maintenance (O&M) expense and FEI's Growth capital, three-year forecasts of FEI's Regular Sustainment and Other capital and FBC's Regular Growth, Sustainment and Other capital, Service Quality Indicators (SQIs) for FEI and FBC, and a refreshed innovation fund for FEI;

C. The Application also seeks approval of deferral accounts, updated depreciation rates and other supporting studies, and other approvals for the term of the Rate Framework;

D. By Order G-##-24, the BCUC established a public hearing process and regulatory timetable for the review of the Application; and

E. The BCUC has reviewed the Application, the evidence and submissions by all parties in this proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, and for the reasons provided in the decision issued concurrently with this order, the BCUC orders as follows for FEI:

1. Approval of the rate setting mechanisms set out in Section C1 and in Table C1-1 of the Application for setting delivery rates for the years 2025 through 2027, including:

    a. A three-year term from 2025 to 2027, with the potential to extend the term beyond 2027, subject to review and approval by the BCUC (Section C1.2);

    b. Use of an index-based approach to Base O&M and Growth capital, incorporating:

        i. A 2024 Base O&M per customer, as described in Section C2.4;

        ii. A 2024 Base Unit Cost Growth Capital of $9,300, as described in Section C3.3.1.2.2, Table C3-4;

        iii. An inflation factor as set out in Section C1.3, including a fixed labour weighting of 51 percent and fixed non-labour weighting of 49 percent;

        iv. An X-Factor of 0.38 percent, as set out in Section C1.4.2; and

        v. A growth factor set at 100 percent of the growth in average number of customers for O&M and 100 percent of Gross Customer Additions for Growth capital, with a true-up to actual when available, all as set out in Section C1.5;

    c. Approval of the level of forecast Sustainment and Other capital to be incorporated in rates over the term of the Rate Framework, as set out in Section C3.3;

    d. Flow-through treatment for the items described in Section C4.13.2 and Table C4-7;

    e. Exogenous factor treatment as described in Section C1.6;

    f. The Service Quality Indicators listed in Table C6-2 of Section C6.3 and described in Appendix C6-1;

    g. Continuation of the Earnings Sharing Mechanism, with half of ROE variances to be shared with customers as set out in Section C1.7;

    h. Off ramps as described in Section C1.9; and

    i. The Annual Review process, with changes to the scope of the Annual Reviews, as described in Section C1.10, including approval of FEI's demand forecasting methods for the term of the Rate Framework.

2. Approval to return to customers the balance in the 2020 Clean Growth Innovation Fund (CGIF) and to establish the 2025 CGIF and rate rider for the term of the Rate Framework as follows:

    a. Establish the non-rate base 2025 CGIF, attracting a WACC return, to record the funding collected through the Innovation Fund rate rider and the expenditures. Any residual balance will be returned to customers at the end of the Rate Framework;

b. Continue the Innovation Fund basic charge rate rider of $0.40 per month during the term of the Rate Framework; and

c. Return the ending balance of the 2020 CGIF to customers through amortization of the deferral account over one year in 2025.

3. Approval of the following regarding CMAE during the term of the Rate Framework:

   a. To continue to forecast the CMAE budget by cost component using a new, simplified template, as described in Appendix C4-3;

   b. To submit the CMAE forecast for approval as a separate application at or near the same time as FEI's Third Quarter Gas Cost Report;

   c. To review the prior year's forecast to actual CMAE variances within the CMAE forecast application, using the new, simplified template;

   d. To continue to treat CMAE as part of FEI's Cost of Gas, allocating 25 percent of costs to the Commodity Cost Reconciliation Account (CCRA) and 75 percent to the Midstream Cost Reconciliation Account (MCRA); and

   e. To record the variances between forecast and actual CMAE in the CCRA and MCRA using the same allocation as is used to allocate the forecast CMAE.

4. Approvals of the following based on supporting studies to be used in the determination of rates for FEI effective January 1, 2025:

   a. Depreciation rates in the amounts set out in Table D2-3 in Section D2.2;

   b. Net salvage rates in the amounts set out in Table D2-4 in Section D2.2;

   c. Modification to the approved Lead Lag days as set out in Table D3-1, Section D3.2;

   d. The methodologies of allocating common corporate service costs from Fortis Inc. and FortisBC Holdings Inc. to FEI, as set out in Section D4; and

   e. The capitalized overhead rate of 14.5 percent, as set out in Section D5.4.

5. Approval to continue the use of the non-rate base Flow-through deferral account, attracting a Weighted Average Cost of Capital (WACC) return, as described in Section C4.13.2 and Table C4-7.

6. Approval of Exogenous Factor treatment for the 2021 Flood costs, as described in Section C1.6.1.

7. Approval to maintain the CPCN threshold at $15 million during the term of the Rate Framework.

8. FEI is directed to file with the BCUC, within 30 days of the issuance of this order, a compliance filing for the Panel's approval incorporating the impacts of all adjustments as outlined in the Decision.

9. FEI must comply with all other directives contained in the Decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Appendix E3

DRAFT FINAL ORDER - FBC

bcuc
British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Rate Setting Framework for the Years 2025 through 2027

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On April 8, 2024, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC) filed an application with the British Columbia Utilities Commission (BCUC) pursuant to sections 59 to 61 pf the *Utilities Commission Act* seeking approval of a rate setting framework (Rate Framework) for the years 2025 through 2027 (Application);

B. In the Application, FortisBC seeks approval of the Rate Framework for the upcoming three years, including, amongst other items, an indexed approach to FEI's and FBC's Operations and Maintenance (O&M) expense and FEI's Growth capital, three-year forecasts of FEI's Regular Sustainment and Other capital and FBC's Regular Growth, Sustainment and Other capital, Service Quality Indicators (SQIs) for FEI and FBC, and a refreshed innovation fund for FEI;

C. The Application also seeks approval of deferral accounts, updated depreciation rates and other supporting studies, and other approvals for the term of the Rate Framework;

D. By Order G-##-24, the BCUC established a public hearing process and regulatory timetable for the review of the Application; and

E. The BCUC has reviewed the Application, the evidence and submissions by all parties in this proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, and for the reasons provided in the decision issued concurrently with this order, the BCUC orders as follows for FBC:

1. Approval of the rate setting mechanisms set out in Section C1 and in Table C1-1 of the Application for setting rates for the years 2025 through 2027, including:

    a. A three-year term from 2025 to 2027, with the potential to extend the term beyond 2027, subject to review and approval by the BCUC (Section C1.2);

    b. Use of an index-based approach to Base O&M, incorporating:

        i. A 2024 Base O&M per customer, as described in Section C2.4;

        ii. An inflation factor as set out in Section C1.3, including a fixed labour weighting of 61 percent and fixed non-labour weighting of 39 percent;

        iii. An X-Factor of 0.20 percent, as set out in Section C1.4.3; and

        iv. A growth factor set at 100 percent of the growth in average number of customers, with a true-up to actual when available, all as set out in Section C1.5;

    c. Approval of the level of forecast Growth, Sustainment and Other capital to be incorporated in rates over the term of the Rate Framework, as set out in Section C3.4;

    d. Flow-through treatment for the items described in Section C4.13.2 and Table C4-7;

    e. Exogenous factor treatment as described in Section C1.6;

    f. The Service Quality Indicators listed in Table C6-7 of Section C6.4 and described in Appendix C6-2;

    g. Continuation of the Earnings Sharing Mechanism, with half of ROE variances to be shared with customers as set out in Section C1.7;

    h. Off ramps as described in Section C1.9; and

    i. The Annual Review process, with changes to the scope of the Annual Reviews, as described in Section C1.10, including approval of FBC's load forecasting methods for the term of the Rate Framework.

2. Approvals of the following based on supporting studies to be used in the determination of rates for FBC effective January 1, 2025:

    a. Depreciation rates in the amounts set out in Table D2-7 in Section D2.3;

    b. Net salvage rates in the amounts set out in Table D2-8 in Section D2.3;

    c. Modification to the approved Lead Lag days as set out in Table D3-2, Section D3.3;

    d. The methodologies of allocating common corporate service costs from Fortis Inc. and FortisBC Holdings Inc. to FBC, as set out in Section D4; and

    e. The capitalized overhead rate of 15.5 percent, as set out in Section D5.4.

3. Approval to continue the use of the non-rate base Flow-through deferral account, attracting a Weighted Average Cost of Capital (WACC) return, as described in Section C4.13.2 and Table C4-7.

4. Approval of Exogenous Factor treatment for the 2021 Flood costs, as described in Section C1.6.1.
5. Approval to maintain the CPCN threshold at $20 million during the term of the Rate Framework.
6. FBC is directed to file with the BCUC, within 30 days of the issuance of this order, a compliance filing for the Panel's approval incorporating the impacts of all adjustments as outlined in the Decision.
7. FBC must comply with all other directives contained in the Decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner