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September 3, 2015

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-138-14 (the PBR Plan)

Annual Review for 2016 Rates

In accordance with the PBR Plan and Commission Order G-138-15 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2016 Rates Application materials.

Should further information be required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FEI's PBR Proceeding

FortisBC Energy Inc.

Multi-Year Performance Based Ratemaking Plan

for 2014 through 2019

Annual Review

for 2016 Rates

Volume 1 - Application

September 3, 2015

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1. APPROVALS SOUGHT, OVERVIEW OF APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Energy Inc. (FEI or the Company) files this Application in compliance with British Columbia Utilities Commission (the Commission) Order G-138-14, which approved a Performance Based Ratemaking Plan (PBR Plan) for FEI for the years 2014 to 2019. In accordance with the PBR Plan, an annual review process is required to set rates for each year under the PBR Plan. With the filing of this Application, FEI seeks to commence the second annual review of the PBR Plan and set FEI's delivery rates for 2016.

The PBR Plan approved by the Decision attached to Order G-138-14 (PBR Decision) increases FEI's incentives to seek out savings while maintaining service quality.[1] Pursuant to the earnings sharing approved by the Commission, any savings in formula-driven O&M and capital expenditures achieved by the Company are shared equally with customers, as discussed in Section 10 of the Application.

Under the PBR Plan, FEI projects savings in 2015 due to a continuation of its ongoing productivity focus, including a broad-based Company-wide effort to seek alternate solutions to the filling of vacancies and a number of initiatives that result in O&M and capital savings. Overall, FEI proposes to distribute $5.068 million[2] in earnings sharing to customers in 2016. FEI has achieved these savings while maintaining a high level of service quality and meeting the Service Quality Indicators (SQIs) approved in the PBR Decision.

The proposed delivery rates for 2016 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 2.22 percent increase over 2015 delivery rates, or an increase of approximately $13 to the annual bill for an average Mainland residential customer.[3] After consideration of the delivery rate riders which are primarily related to amalgamation, the bill impact change is an increase of approximately 5.44 percent for a Mainland residential customer, a decrease of approximately 3.16 percent for a Vancouver Island residential customer, and a decrease of approximately 8.22 percent for a Whistler residential customer. The delivery rate increase of 2.22 percent before delivery rate riders is in line with 2016 inflation which is forecast at approximately 2 percent.[4]

In the subsections below, FEI sets out the approvals it is seeking, provides an overview of the requirements for the annual review process, and provides an evaluation of the PBR Plan for 2015. This is followed by a summary of FEI's proposed revenue requirement and rate changes

1 PBR Decision, p. 138.
2 This amount includes both the 2015 earnings sharing estimated and adjustments related to 2014 actuals.
3 Based on a Mainland Residential customer using approximately 90 GJs per year.
4 Conference Board of Canada - Provincial Outlook 2015 - Long-Term Economic Forecast. (CPI Updated March 2, 2015).

for 2016 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FEI requests Commission approval for the following pursuant to sections 59 to 61 of the Utilities Commission Act:

1. Interim delivery rates for all non-bypass customers effective January 1, 2016, resulting in an increase of 2.22 per cent compared to 2015 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at existing levels. Rates will remain interim pending the outcome of FEI's current cost of capital proceeding;
2. The creation of rate base deferral accounts for the following regulatory proceedings as described in Section 7.5:
    - 2015 System Extension Application;
    - BERC Rate Methodology Application; and
    - 2017 Long-term Resource Plan Application;
3. Rate Stabilization Deferral Account (RSDA) riders for 2016 in the amounts set out in Table 10-5 in Section 10;
4. Phase-In Rate riders for 2016 in the amounts set out in Table 10-7 for Mainland customers and Table 10-9 for Vancouver Island and Whistler customers in Section 10;
5. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2016 in the amounts set out in Table 10-10 in Section 10;
6. Depreciation rates in the amounts set out in Table 12-2 in Section 12;
7. The 2016 revenue requirement impact of the difference between the updated depreciation rates and the existing depreciation rates for Fort Nelson to be captured in the existing Fort Nelson Revenue Surplus/Deficit deferral account.
8. Net salvage rates in the amounts set out in Table 12-3 in Section 12; and
9. The transfer of the December 31, 2015 remaining balance of the FEW Rider B Refund Deferral to the existing Residual Rate Riders deferral account as described in Section 12.4.1.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On pages 185 and 186 of the PBR Decision, the Commission set out its expectations for the Annual Review component of the PBR Plan, with one further directive (number 8 in the table below) provided on page 17 of Order G-120-15 in the Capital Exclusion Criteria compliance filing. For reference, the table below sets out each requirement and FEI's response or where it is addressed in the Application:

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns.	Section 1.4
2	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 2(a) to 2(g) below
2(a)	Customer growth, volumes and revenues;	Section 3
2(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
2(c)	Expenses (determined by the PBR formula plus flow-through items);	Section 6
2(d)	Capital expenditures (as determined by the PBR formula plus flow-through items);	Section 7
2(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;	Sections 7 and 12
2(f)	Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and	Section 10
2(g)	Any proposals for funding of incremental resources in support of customer service and load growth initiatives.	FEI does not have any proposals at this time
3	Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives.	FEI has not identified any efficiency investments with a payback beyond the end of the PBR period
4	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers.	FEI has not identified any exogenous factors
5	Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service.	Section 13
6	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.	FEI does not have any recommendations for new SQIs or the discontinuation of SQIs at this time
7	Assess and make recommendations to the Commission on the scope for future Annual Reviews.	FEI does not have any recommendations at this time
8	Where the dead band is exceeded for any year, FEI and FBC are directed in the next Annual Review filing to include recommendations as to any adjustment to base capital other than those driven by the 1-X mechanism.	Dead band was not exceeded for 2014 and is not forecast to be exceeded for 2015.

1.4 *EVALUATION OF THE PBR PLAN*

FEI has continued its productivity focus in 2015 and initiated additional projects to enhance the customer experience and improve productivity. As a result of this focus and these initiatives, FEI was able to realize savings in O&M expenditures, while FEI's capital expenditures continue to be above the capital formula amount. Overall, the savings achieved result in $5.068 million of earnings sharing that will be returned to customers in 2015, serving to reduce overall delivery rates for FEI's customers. FEI's performance with respect to SQIs, as reported in Section 13 of the Application, demonstrates that FEI achieved these savings while maintaining a high level of service quality.

1.4.1 Overview of O&M Savings

In 2015, FEI is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $10.21 million lower than the formula amount. In addition, the actual O&M savings for 2014 was higher than the projected and approved amount by $0.632 million.

The 2015 projected O&M savings have been achieved with the Company's continued broad-based focus on productivity. Major initiatives involving processes that may span across departments are described in Section 1.4.3 below and comprise a significant portion of the productivity savings, accounting for approximately $4 million of the projected O&M savings. Much of the remainder of the projected O&M savings of approximately $6 million is being achieved through the Company's ongoing productivity focus. Resources are being redeployed and roles and responsibilities are being broadened. Departments and employees are asked to review the way they operate to streamline processes and make it more efficient for our customers to do business with us. Expenditures and filling of vacancies are being reviewed. While some of the savings are one-time in nature (e.g. delay in filling vacancies) as the result of the continuing productivity focus throughout the Company, many of these efficiencies and savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

1.4.2 Staffing Levels

As a result of the Company's focus on productivity and the resulting impact on the Company's labour requirements, FEI may see further reductions in the number of employees. As shown in Table 1-2 below, staffing levels have been declining in recent years with FEI expecting to continue to see this trend in the remainder of 2015.

Table 1-2: Employees at Year-End[5]

	Headcount	FTEs
2013 Actual	1,764	1,679
2014 Actual	1,704	1,650
2015 Projected	1,686	1,598

As shown in Table 1-2 above, from 2013 Actual to 2015 Projected, total FTEs for the Company decreased by approximately 81, with the decreases estimated to contribute to O&M savings of approximately $7 million[6]. The largest FTE declines are expected in the Customer Service and Operations areas as discussed below.

Customer Service reductions from 2013 to 2015 are estimated at approximately 65 FTEs contributing to O&M savings of approximately $4.7 million. Reductions include M&E reductions due to management reorganization and COPE reductions related to experienced lower call volumes and lower high-bill complaints in 2015 as the result of warmer weather. Included in the estimated total of $4.7 million in Customer Service savings are reductions in COPE FTEs related to Project Blue Pencil in 2015, contributing an estimated O&M savings of $1 million.

Operations reductions from 2013 to 2015 are estimated at approximately 14 FTEs contributing to estimated O&M savings of $1.7 million. Reductions include those due to ongoing productivity initiatives. Included in the estimated total of $1.7 million in Operations savings are reductions related to the Regionalization initiative started in 2014, contributing an estimated annual O&M labour savings of $0.850 million.

1.4.3 Major Initiatives Undertaken

In FEI's Annual Review for 2015 Rates, FEI provided information regarding two major initiatives that were undertaken in 2014 - the Regionalization Initiative and Project Blue Pencil. Directive 28 attached to Order G-86-15 regarding FEI's Annual Review for 2015 Rates stated:

> *"The Panel directs FEI to continue to provide in each annual review application the information that was provided in response to BCUC IRs 1.2.9 (Regionalization Initiative) and 1.3.3 (Project Blue Pencil) and to update these tables for actual results as this data becomes available. The same analysis is to be performed on new initiatives that are implemented during the PBR term."*

5 Figures provided are total FTEs and include FTEs that charge time to O&M, capital, deferral accounts, and Core Market Administration Expense. The FTEs are the average FTEs for the 12 month calendar year, consistent with other reporting provided to the Commission.

6 2013 Actual FTEs is used as the reference point for the start of the PBR Plan as a 2014 Base average FTEs is not available. The O&M savings are calculated by comparing the 2013 actual average FTEs to the 2015 projected average FTEs.

FEI provides a summary below of the major initiatives undertaken or ongoing in 2015. A table for each initiative that has been implemented (initiatives 1 through 3 below) showing the requested information is provided in Appendix C3.

1. ***The Regionalization Initiative*** is aimed at both enhancing the customer experience and achieving a more efficient process in the field. Throughout 2014, Operations moved certain aspects of its centralized operational activities into regional locations. In particular, the Field Dispatch and Planning and Design groups are now located within their regional locations. The transition to a regional operations model has also resulted in eight emergency centres around the province instead of one large central emergency centre. These changes have enabled optimal decision making, and have been found to be more cost-effective and to serve customers better. 2015 marked the first full year operating under a regional business model. 2015 O&M savings projected for the Operations department compared to 2013 actuals are approximately $1 million.

2. ***Project Blue Pencil*** is an initiative focused on reviewing and streamlining several high-volume, customer-facing processes from the perspective of the customer. In 2014, analysis of several customer touch points showed opportunities to improve not only the customer experience but also to increase operational efficiencies at the same time. Specifically, initiatives are currently underway in the areas of new service connections, meter exchange, collections and high bill inquiry, each on a timeline to increase productivity for existing resources in both the Operations and Customer Service groups. Improvements in these areas will simplify the process of connecting new customers to the system and performing meter exchanges, and will strengthen the Company's focus on customer service. The 2015 O&M savings from Project Blue Pencil projected for the Customer Service department compared to 2013 actuals are approximately $1 million.

3. ***Review of Technical and Infrastructure Support Provider*** is an initiative to review the existing agreement with the Company's technical and infrastructure service provider responsible for providing Information Systems (IS) Customer and Infrastructure Services to FEI. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. In 2015, FEI replaced its existing technical and infrastructure support provider through an RFP process with a new service provider, Compugen. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. For each new efficiency identified, on a one-time basis (i.e. first full year savings), the vendor shares in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies. Additionally, the new contract provides dedicated support resources rather than a distributed support service resulting in quicker response times and better understanding of the Company's requirements. The 2015 O&M savings projected for the Information Systems department compared to 2013 actuals are approximately $1.8 million.

4. ***The Training and Development Initiative*** is a company-wide effort currently under development to introduce a defined process that enables the Company to plan and track required training activities, ensuring skills requirements for employee training are addressed efficiently and effectively. Presently, there is limited evaluation of the skills requirements for employee training, which may lead to a gap between the training conducted and the skill set or competency that the training was intended to address. Implementation of a new process is expected by late 2015. No O&M savings are anticipated for 2015.

Other initiatives the Company is currently investigating include streamlining of the new service application process and workflow management optimization for field resources. The Company is investigating ways to shorten the cycle time for new services, including possibly using technology to capture the required customer information at the new construction site without requiring customers to call in their request for a new service. With regards to workflow management optimization for field resources, there is an opportunity to optimize workflow leading to better utilization of field resources. Details of these two initiatives will be provided in upcoming annual reviews as they reach implementation stage.

1.4.4 Capital Expenditures Overview

FEI is not projecting any savings in capital relative to the formula in 2015.

Projected 2015 capital expenditures excluding items forecast outside of the PBR formula are $6.816 million higher than the formula amount. Growth capital is projected to be above the formula by $9.733 million as the formula for growth capital, which utilizes one-half of prior year service line additions, does not adequately fund the increase in capital required to support customer additions. In addition to growth capital, FEI was challenged in 2015 in sustainment capital in the Vancouver Island region, where FEI was unable to reduce sustainment capital spending to match the significant $6.3 million reduction to the Base Capital amount for Vancouver Island determined by the Commission in June 2015.[7]

FEI has sought to mitigate the impact of spending in growth and sustainment capital above the formula amount by making significant reductions to its IT capital plans in 2015, and through shifting projects otherwise planned for 2015 into 2016. However, the challenges FEI is facing in meeting its growth and sustainment capital formula spending amounts are expected to continue through the remainder of the term of the PBR Plan.

[7] Order G-106-15 in FEI's Application for Approval to Include FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. into the 2014-2019 Multi-Year Performance Based Ratemaking Plan.

1.4.5 Summary

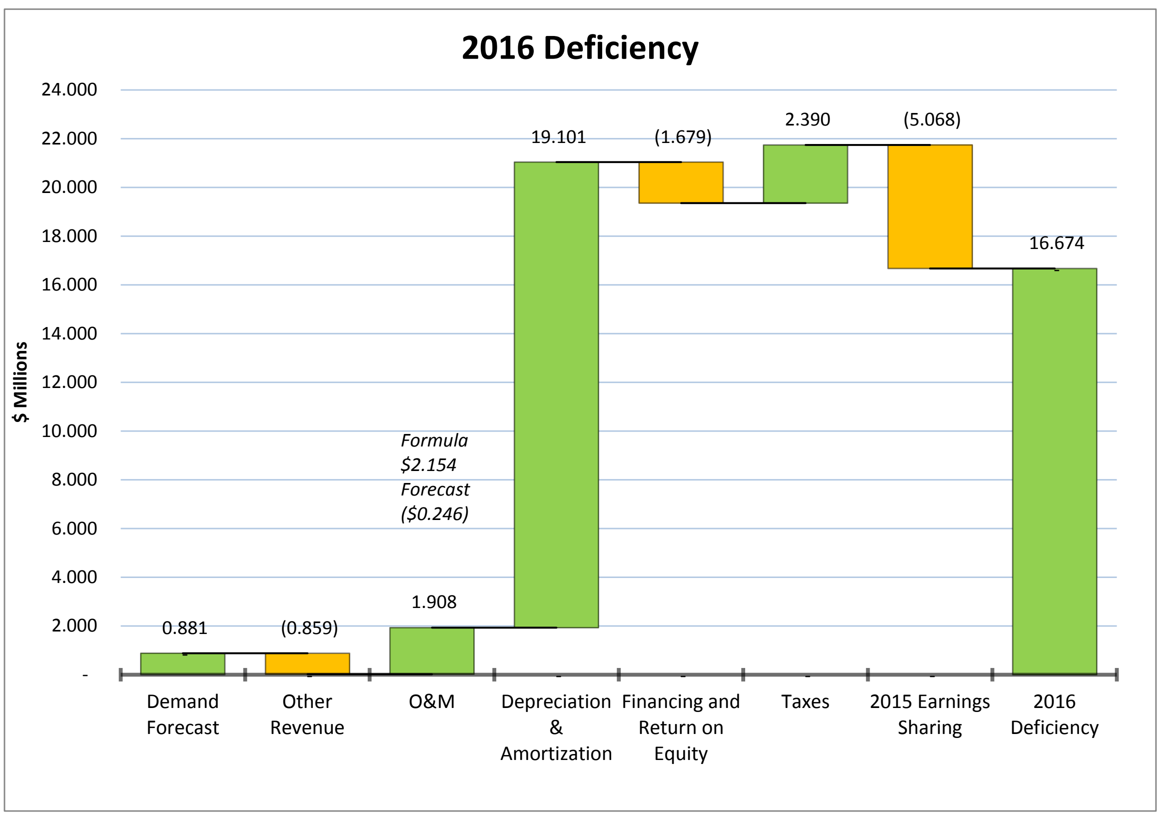
In summary, 2014 and 2015 provide a preliminary basis on which to evaluate the PBR Plan, and have shown the potential for strong earnings sharing on O&M, with increases in delivery rates that are in line with inflation. The first two years of PBR have also shown the challenges of the Growth Capital formula, and the challenges in meeting the reduced sustainment capital spending for the Vancouver Island region.

1.5 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2015*

The Company is requesting a delivery rate increase of 2.2 percent for 2016 compared to 2015 delivery rates. The rate increase results from a revenue deficiency of $16.674 million. The revenue deficiency is due to revenue at existing rates being lower than the forecast cost of service. The forecast cost of service is impacted by both items calculated under the PBR Plan formula (controllable O&M and capital expenditures), and items that are forecast on a cost of service basis.

The following chart summarizes the items that contribute to the 2016 revenue deficiency.

Figure 1-1: 2016 Delivery Revenue Deficiency ($ millions)[8]



[8] Due to its relative size, the impact of increasing formula capital of approximately $0.289 million has not been isolated and is embedded within all capital-related revenue requirement categories.

Each of the categories is discussed briefly below.

1.5.1 Demand Forecast (Section 3)

In 2016, demand is forecast to increase slightly, by 0.852 PJs from 2015 approved, primarily due to customer growth in the Industrial sector where there is an addition of three customers, and increasing Liquefied Natural Gas (LNG) volumes. Based on the existing rates for each rate schedule, FEI's 2016 revenue forecast is $1,248.727 million and 2016 gross margin forecast is $768.529 million.

1.5.2 Other Revenue (Section 5)

Other revenue is forecast to decrease in 2016 by approximately $0.859 million, almost all due to Natural Gas for Transportation (NGT) related recoveries.

1.5.3 Operations and Maintenance (O&M) Expense (Section 6)

FEI establishes the bulk of its O&M costs by formula during the PBR term. For 2016, the formula incorporates an inflation factor (I Factor) of 1.569 percent, a productivity improvement factor (X Factor) of 1.1 percent and a customer growth factor of 0.567 percent for a total increase in formula O&M of 1.039 percent. O&M forecast outside of the formula is increasing at a rate of 0.387 percent, primarily due to higher O&M supporting incremental revenues from Rate Schedule 46 (Liquefied Natural Gas Sales, Dispensing and Transportation Service) offset by decreases in pension and OPEB and insurance expenses. Overall the increase in Gross O&M Expense from 2015 to 2016 is 0.955 percent. The increase in O&M expense net of capitalized overhead is $1.908 million.

1.5.4 Depreciation and Amortization (Section 7 and Section 12)

Depreciation expense has remained relatively constant with increases from higher plant in service being offset by lower depreciation rates as recommended by an updated depreciation study. However, there has been a significant increase in amortization expense of $19.175 million (excluding the amortization of the earnings sharing), which is the single largest driver of the revenue deficiency. The increase in amortization expense is primarily due to an increase of $11.9 million resulting from updated net salvage and contribution in aid of construction (CIAC) amortization rates from the depreciation study. Also contributing to the increase is the reduced amortization of the Flow-Through Variance Account, and a higher balance in the Energy Efficiency and Conservation deferral and the Lower Mainland Intermediate Pressure System Upgrade deferral accounts.

1.5.5 Financing and Return on Equity (Section 8)

FEI has two long-term debt issues forecast for 2016 with a coupon rate of 4.5 percent which replace existing debt with a coupon rate of 10.3 percent and finance growth in rate base. FEI is forecasting a short-term debt rate for 2016 of 1.25 percent, a decrease from the 1.4 percent rate embedded in the 2015 forecast. Overall, interest expense is forecast to decrease from 2015 by $2.689 million.

Increases in rate base increase the equity return by $1.010 million. In calculating 2016 delivery rates, FEI has utilized its 2015 approved capital structure and return on equity of 38.5 percent at 8.75 percent, respectively. FEI will update its 2016 delivery rate calculations once a decision is reached on its 2016 capital structure and return on equity.

1.5.6 Taxes (Section 9)

Property taxes are forecast to increase 3.3 percent or $2.028 million from 2015. Increases are driven by construction activities, market value increases and changes in tax policies of local taxing authorities.

There has been no change in the income tax rate of 26 percent from 2015. Taxes are forecast to increase in 2016 by $0.362 million, excluding the reduction in taxes related to earnings sharing of $1.318 million, primarily due to an increase in the amortization of deferral accounts and partially offset by an increase in capital cost allowance deductions in 2016.

1.5.7 Earnings Sharing (Section 10)

As discussed in Section 1.3 above, earnings sharing has been forecast at $5.068 million. This amount will be returned to customers through amortization in 2016.

1.6 *SERVICE QUALITY INDICATORS*

FEI's June 2015 year-to-date SQI results indicate that the Company's overall performance is better than the benchmark and representative of a high level of service quality. For those SQIs with benchmarks, seven are performing better than the approved benchmarks with the remaining two performing better than the threshold and within the performance range. For the four SQIs that are informational only, performance remains at a consistent level with prior years. Details of the SQIs are included in Section 13.

2. FORMULA DRIVERS

2.1 *INTRODUCTION AND OVERVIEW*

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2016 O&M and Capital formula amounts according to the PBR formula.

In the PBR Decision and Commission Order G-162-14, the Commission approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting, and the following growth factors:

- For growth capital, the growth factor is 50% of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as [1 + ((SLAt-1/SLAt-2)/SLAt-2) x 50%)].
- For all other cases, the growth factor is 50% of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as [1 + ((ACt-1/ACt-2)/ ACt-2) x 50%)].

Further guidance on how to calculate the Inflation and Growth factors was provided in Commission Order G-164-14, which states:

> 1. *FortisBC Energy Inc. is approved to use inflation data from July through June for the 2014 rate change calculations and the future annual reviews.*
> 2. *FortisBC Energy Inc. is approved to use CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC.*
> 3. *FortisBC Energy Inc. is approved to adjust 2014 inflation for the transition from Harmonized Sales Tax to Provincial Sales Tax as of April 1, 2013 for an increase of 0.1750 percent.*

The Inflation Factor and Growth Factor calculations utilize these inputs, but as applied to 2016. FEI has used July 2013 through June 2015 inflation data for the 2016 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

Regarding item 3 above, 2015 was the second and final year of the adjustment to CPI for the impact of the transition from Harmonized Sales Tax (HST) to Provincial Sales Tax (PST), and no adjustment is required for 2016 or future years.

As discussed below, the 2016 inflation factor based on prior year's BC-CPI and BC-AWE is 1.569 percent, and the SLA and AC Growth Factors are 16.249 percent and 0.567 percent, respectively.

2.2 *INFLATION FACTOR CALCULATION SUMMARY*

In the PBR Decision, the Commission approved an inflation factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and a 55 percent labour weighting. Consistent with Commission Order G-164-14 regarding FEI's PBR Compliance Filing, FEI used inflation data from July through June and the CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC. The supporting Statistics Canada CANSIM Tables 326-0020 and 281-0063 are provided in Appendix A1.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing CPI-BC of 0.980 percent and AWE-BC of 2.050 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (0.980 percent x 45 percent) + (2.050 percent x 55 percent) = 1.569 percent. This calculation is shown in Table 2-1 below.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020	*CANSIM 281-0063*	12 Mth Average		Year over year % change			
	2002 = 100							
Date	BC CPI index	BC AWE $	CPI index	AWE $	CPI %	AWE %	I Factor %	PBR Year
Jul-2013	117.9	869.85						
Aug-2013	118.0	872.95						
Sep-2013	118.1	872.39						
Oct-2013	117.7	875.32						
Nov-2013	117.4	890.51						
Dec-2013	117.0	888.27						
Jan-2014	117.1	886.83						
Feb-2014	118.0	889.12						
Mar-2014	118.6	894.20						
Apr-2014	119.0	895.19						
May-2014	119.7	894.44						
Jun-2014	119.8	888.88	118.192	884.829				
Jul-2014	119.6	893.39						
Aug-2014	119.6	900.50						
Sep-2014	119.5	897.76						
Oct-2014	119.0	905.02						
Nov-2014	118.8	902.65						
Dec-2014	118.1	895.30						
Jan-2015	118.0	911.15						
Feb-2015	118.9	909.08						
Mar-2015	119.8	904.92						
Apr-2015	119.6	902.83						
May-2015	120.6	904.23						
Jun-2015	120.7	908.74	119.350	902.964	0.980%	2.050%	1.569%	2016

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the Commission approved the use of the following growth terms for FEI:

- For growth capital, the growth factor is 50% of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as [1 + ((SLAt-1/SLAt-2)/SLAt-2) x 50%)].
- For all other cases, the growth factor is 50% of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as [1 + ((ACt-1/ACt-2)/ ACt-2) x 50%)].

The calculations for the Average Customer and Service Line Additions growth factors are provided in Tables 2-2 and 2-3 below. The AC and SLA growth shown below reflect an amalgamated company, incorporating data for Vancouver Island and Whistler service areas for the periods prior to January 2015.

Table 2-2: Average Customer (AC) Growth Factor Calculation

	FEI	FEVI	FEW	Total Average Customers	12 Month Avg Customers	AC Factor @ 50%	PBR Year
Jul-13	838,723	101,756	2,627	943,106			
Aug-13	838,832	101,780	2,630	943,242			
Sep-13	839,614	102,062	2,653	944,329			
Oct-13	842,318	102,564	2,665	947,547			
Nov-13	845,190	103,102	2,682	950,974			
Dec-13	847,189	103,439	2,695	953,323			
Jan-14	849,547	104,014	2,706	956,267			
Feb-14	850,802	104,441	2,716	957,959			
Mar-14	851,725	104,672	2,714	959,111			
Apr-14	851,644	104,810	2,713	959,167			
May-14	851,169	104,847	2,705	958,721			
Jun-14	850,515	104,882	2,718	958,115	952,655		
Jul-14	850,036	104,889	2,721	957,646			
Aug-14	849,603	105,047	2,726	957,376			
Sep-14	849,829	105,323	2,738	957,890			
Oct-14	851,467	105,719	2,755	959,941			
Nov-14	854,127	106,227	2,762	963,116			
Dec-14	855,614	106,629	2,768	965,011			
Jan-15	966,744			966,744			
Feb-15	967,096			967,096			
Mar-15	967,144			967,144			
Apr-15	967,038			967,038			
May-15	966,516			966,516			
Jun-15	965,884			965,884	963,450	0.567%	2016

Table 2-3: Service Line Additions (SLA) Growth Factor Calculation

	FEI	FEVI	FEW	Total Service Line Additions	12 Month Sum	SLA Factor @ 50%	PBR Year
Jul-13	420	135		555			
Aug-13	534	132	8	674			
Sep-13	473	150	4	627			
Oct-13	775	235	3	1,013			
Nov-13	833	184	13	1,030			
Dec-13	618	181	4	803			
Jan-14	920	260	2	1,182			
Feb-14	532	211		743			
Mar-14	499	175		674			
Apr-14	474	172		646			
May-14	384	125	2	511			
Jun-14	502	130		632	9,090		
Jul-14	668	184	10	862			
Aug-14	706	203	3	912			
Sep-14	972	321	6	1,299			
Oct-14	855	261	7	1,123			
Nov-14	1,363	296	6	1,665			
Dec-14	597	250	3	850			
Jan-15	717	316	2	1,035			
Feb-15	604	256	-	860			
Mar-15	572	214	3	789			
Apr-15	684	222	1	907			
May-15	604	204	9	817			
Jun-15	682	237	6	925	12,044	16.249%	2016

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

Using the I-Factor and Growth Factors as calculated above, and the approved X-Factor of 1.1 percent, a summary of the factors used in the PBR formula for 2016 is provided in Table 2-4.

Table 2-4: Summary of Formula Drivers

	2016
Cost Drivers	
Service Line Additions Factor @ 50%	16.249%
Customer Growth Factor @ 50%	0.567%
Escalators	
CPI	0.980%
AWE	2.050%
Non Labour	45%
Labour	55%
CPI/AWE Inflation	1.569%
Productivity Factor	-1.100%
Net Inflation Factor	0.469%

In summary, the formula factor for O&M and for sustainment and other capital for 2016 is 101.039 percent, calculated as (1+0.567 percent) X (1+0.469 percent).

The formula factor for growth capital for 2016 is 16.794 percent, calculated as growth in service line additions of 16.249 percent, with the cost per service line addition growing at a rate of 0.469 percent.

3. DEMAND FORECAST AND REVENUE AT EXISTING RATES

3.1 INTRODUCTION AND OVERVIEW

This section describes FEI's forecast of gas sales and transportation volumes based on the forecast total energy demand from residential, commercial and industrial customers in 2016, as well as the revenue and margin at 2015 delivery rates and applicable 2015 common commodity and storage and transport rates[9]. As described in detail below, FEI's forecast of demand for natural gas is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand for 2016. FEI is forecasting an increase in consumption in 2016, with the total normalized demand projected to be approximately 208 PJs in 2016, up approximately 3.5 PJs from the new 2015 projected consumption, 2.2 PJs from higher industrial volumes and 1.3 PJs from increased LNG volumes. Based on the 2015 rates for each customer class, FEI's 2016 revenue forecast is $1,232.053 million and FEI's 2016 gross margin forecast is $751.856 million. FEI has provided extensive supplementary information on its demand forecast in Appendix A of the Application.

The remainder of this section is organized as follows:

- Section 3.2 – Outline of Responses to Directives
- Section 3.3 – Overview of Forecast Methods
- Section 3.4 – Use per Customer Forecast
- Section 3.5 – Net Customer Addition Forecast
- Section 3.6 – Total Demand Forecast
- Section 3.7 – Revenue and Margin Forecast
- Section 3.8 – Summary

3.2 OUTLINE OF RESPONSES TO DIRECTIVES

This section provides an outline of FEI's responses to previous Commission directives with respect to the demand forecast.

In Directive 12 of the Commission's Decision on FEI's Annual Review for 2015 Delivery Rates at page 14, the Commission set out a number of directives related to the demand forecast, as follows:

[9] Orders G-86-15 and G-106-15 for delivery rates, G-175-14 for storage and transport rates and the commodity rate effective January 1, 2015 and G-39-15 for the commodity rate effective April 1, 2015. The delivery rates do not include delivery rate riders which are set separately from the delivery rate.

The Panel accepts FEI's proposal to include in its next Annual Review application a fulsome description of its demand forecast methodology. The Panel also directs FEI to include information that in this proceeding was obtained through staff and intervener information requests as well as the analyses of alternative forecasting methodologies directed in this Decision. This information is to include:

- Historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals;
- The results along with an explanation of various aspects of the Industrial Survey used by FEI to forecast industrial demand;
- As directed in Sections 2.1.2 and 2.1.3 of this Decision, a fulsome description of alternatives to existing forecast methodologies with recommendations to improve residential and commercial UPC forecasts and commercial net customer additions forecasts; and
- As directed in Section 2.1.5 of this Decision, a proposal for including some or all of the spot purchases in FEI's future demand forecasts.

Furthermore, the Panel directs FEI to include the most recent ten years of historical actual data where possible.

The responses to these directives that are included in the Application are as follows:

- Historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals, including variance analysis and the results of the Industrial Survey, are provided in Appendix A2.
- A detailed description of FEI's demand forecast methodology, including an explanation of the Industrial Survey, is provided in Appendix A3.
- FEI's proposal for including spot purchases in future demand forecasts is provided in Appendix B, Section 4.

Pursuant to the extension approved by Commission Letter L-30-15, FEI will provide alternatives to existing forecast methodologies with recommendations to improve residential and commercial UPC forecasts and commercial net customer additions forecasts in its Annual Review for 2017 delivery rates. FEI intends to establish the alternatives and recommendations through a review process to be conducted by a third party consultant. The review process has not been finalized at this time, but is expected to include the following:

- Establish forecast variance benchmarks.
- Solicit suggestions from stakeholders for alternative methodologies or changes to current methodologies.
- Test all methods and compare results to the benchmarks.

- Recommend changes where required.

As noted above, FEI will report on the results of the review process in its Annual Review for 2017 delivery rates.

Finally, Directive 90 of the PBR Decision directed FEI to develop a mechanism to adjust the Rate Schedule 22 demand forecast methodology to better reflect the impact of falling gas prices. FEI has responded to this directive in Appendix A4.

3.3 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting process followed by FEI in previous years, the demand forecast relies on three components:

- Net customer additions forecast;[10]
- Average use per customer (UPC) forecast; and
- Industrial Forecast.

The demand forecast for residential and commercial customers is based upon forecasts for net customer additions and UPC rates, consistent with the past methodology. Specifically, the average UPC is estimated for customers served under Rate Schedules 1, 2, and 3/23 and is then multiplied by the corresponding forecast of the number of customers in these rate schedules to derive energy consumption.

The forecast of industrial energy demand is based upon customer-specific forecasts obtained through a survey as discussed in Section 3.6.3.

The forecast NGT Demand is for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) volumes. The methodology used to complete the NGT demand forecast is discussed in Appendix B.

The following sections set out the results of the demand forecast. In the figures provided in the demand forecast sections, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For the 2016 Annual Review the latest calendar year for which full actual data exists is the 2014 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 a range of 2 or more years depending on the filing.

[10] The net customer additions are the year-over-year change in the total number of customers.

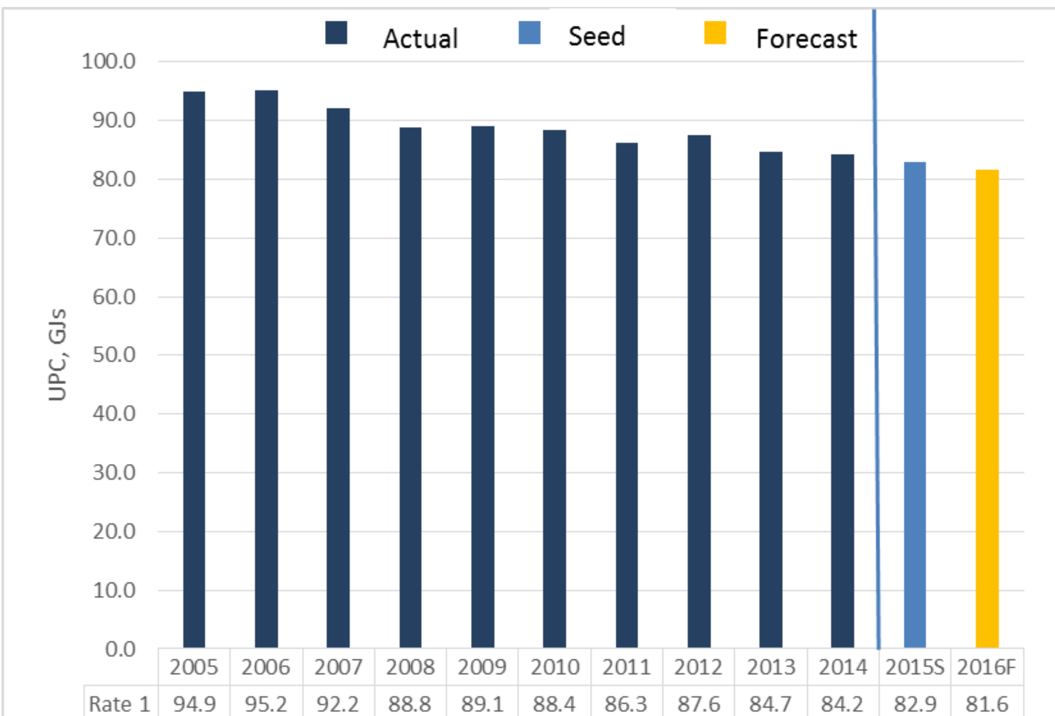
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2015 and the Seed Year forecast is based on the latest actual years, including 2014. As such, the 2015 Seed Year forecast in this Application will differ from the 2015 Forecast presented in the Annual Review for 2015 Delivery Rates, for which 2014 actual data was not available.

3.4 *RESIDENTIAL AND COMMERCIAL USE PER CUSTOMER FORECAST*

Individual UPC projections for each residential and commercial rate schedule are developed for each rate schedule by considering the recent (three-year) historical weather-normalized UPC. The analysis of historical normalized residential use rates indicates a continued downward trend, while normalized commercial use rates are continuing to increase.

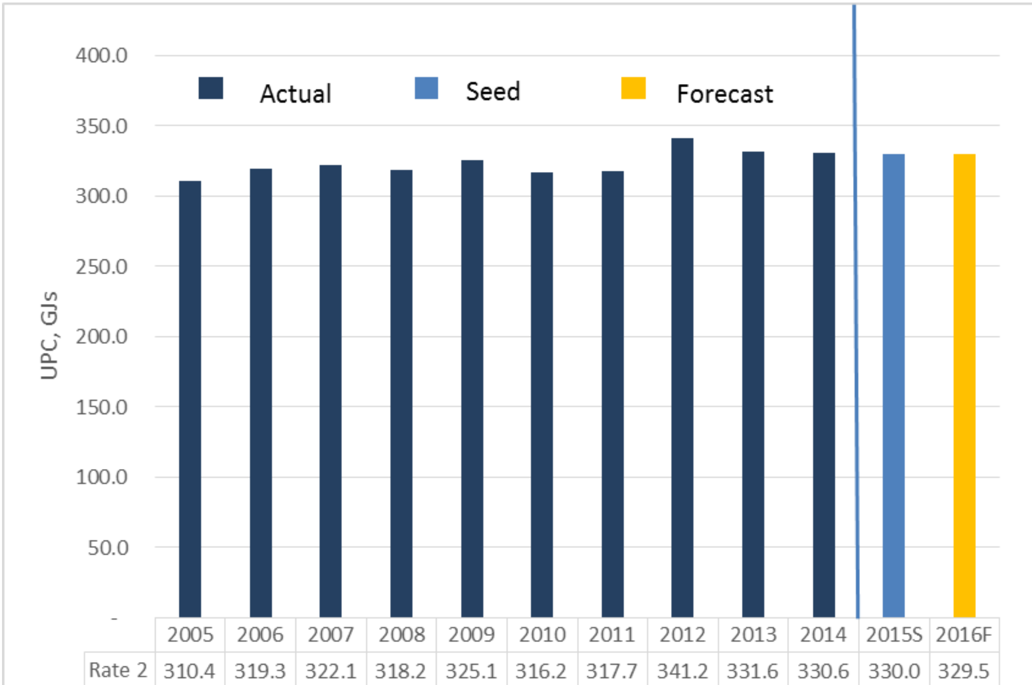
As shown in Figure 3-1, the Residential (Rate Schedule 1) UPC is forecast to decline by approximately 1.3 GJ (1.6 percent) in 2016.

Figure 3-1: Rate Schedule 1 UPC Declining Consistent with Prior Years



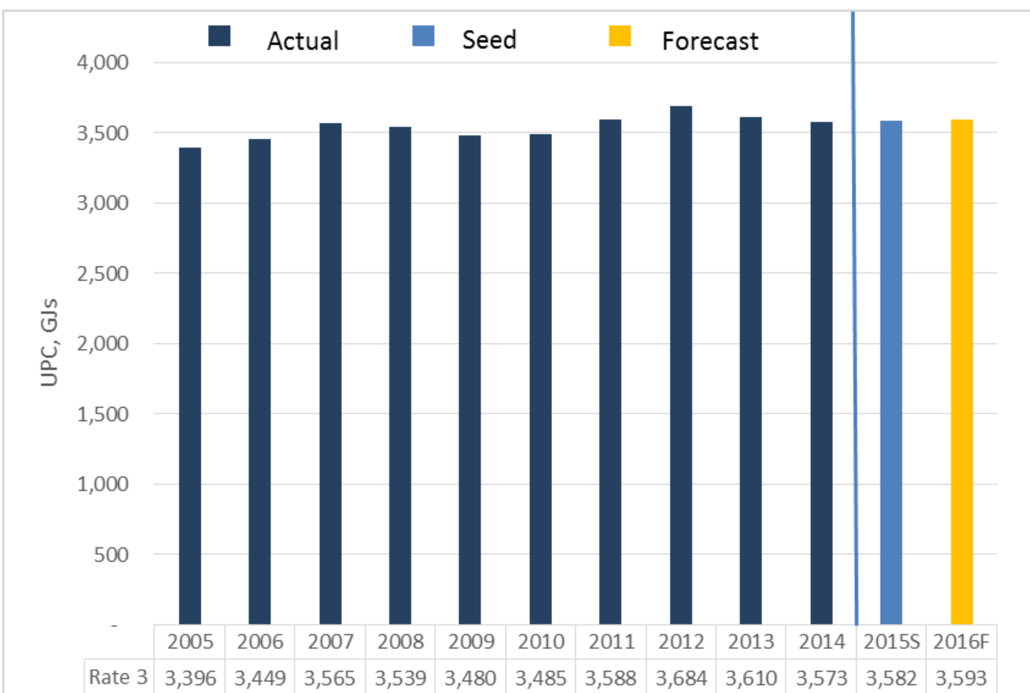
As shown in Figure 3-2, the Small Commercial (Rate Schedule 2) UPC is forecast to decrease slightly, by 0.5 GJ (0.2 percent), during 2016.

Figure 3-2: Rate Schedule 2 UPC Consistent with Prior Years



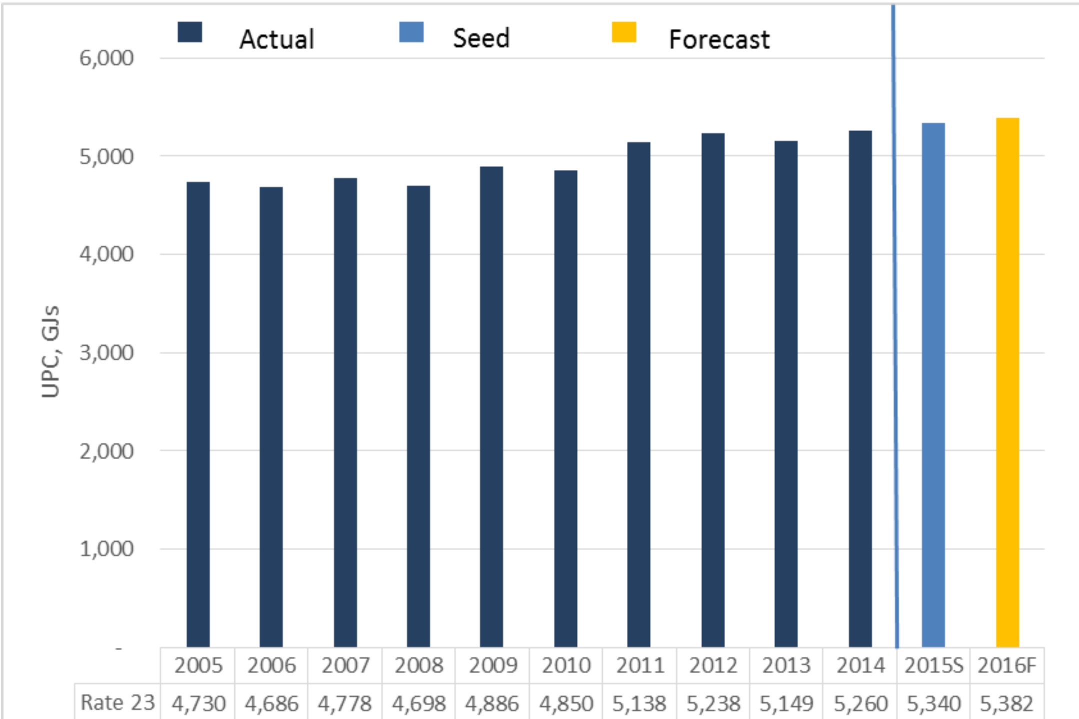
As shown in Figure 3-3, the upward trend in Large Commercial (Rate Schedule 3) UPC has been consistent and this trend is forecast to continue. The Rate Schedule 3 UPC is forecast to increase by 11 GJ (0.3 percent) in 2016.

Figure 3-3: Rate Schedule 3 UPC Trend Consistent with Prior Years



As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to continue the recent upward trend and grow by 42 GJs (0.8 percent) in 2016.

Figure 3-4: Rate Schedule 23 UPC Recent Upward Trend

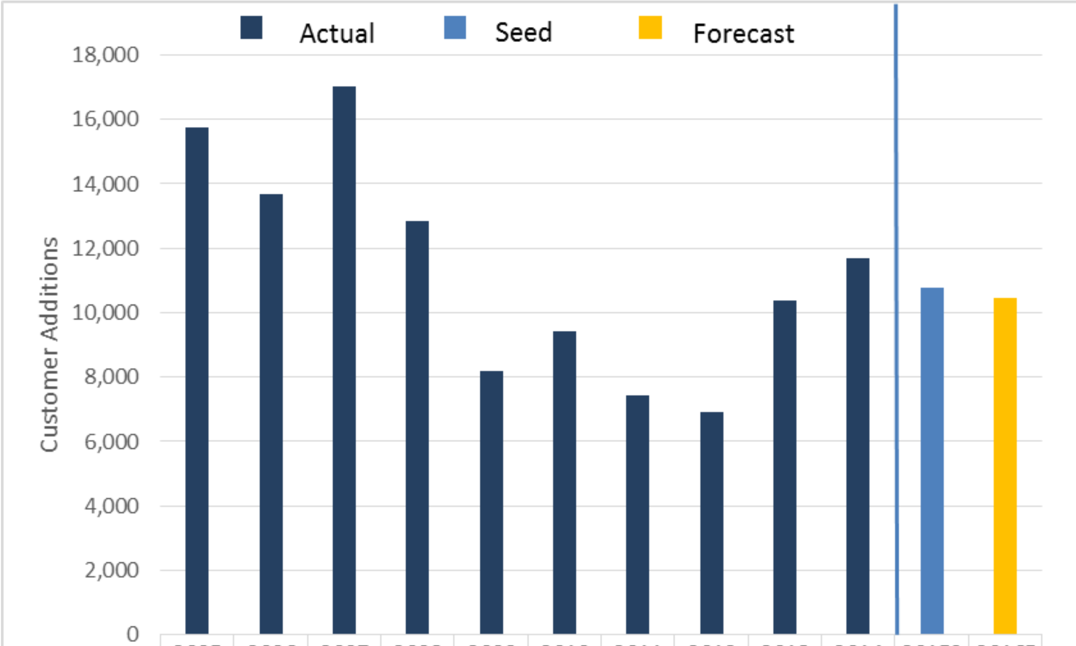


3.5 RESIDENTIAL AND COMMERCIAL NET CUSTOMER ADDITIONS FORECAST

The forecast of net customer additions is the next component of determining the total energy demand for residential and commercial customers.

As shown in Figure 3-5, the rate of growth seen in FEI's customer base (residential, commercial and industrial) reached a high in 2007 of roughly 17,000 net customer additions then declined to below 10,000 annual net customer additions for the period from 2009 through 2012. Net customer additions in 2013 and 2014 were stronger, above 10,000 per year. The Company is forecasting customer additions at approximately 10,759 in 2015 and 10,466 in 2016.

Figure 3-5: Total Net Customer Additions Consistent with Recent Years

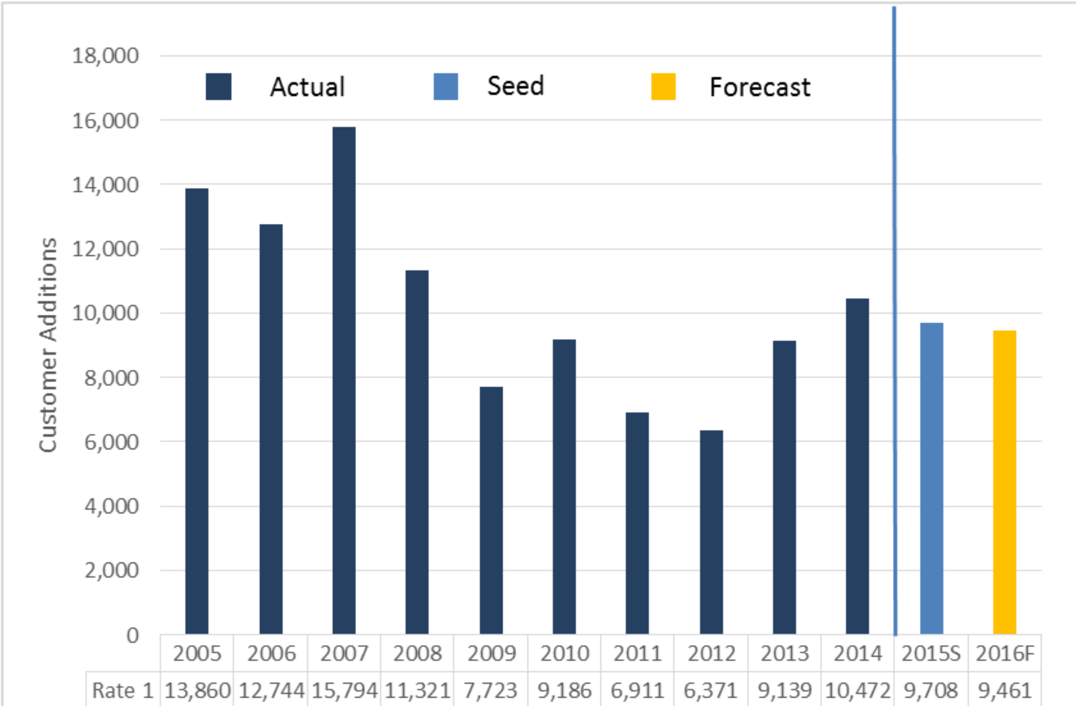


	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015S	2016F
Total	15,739	13,667	17,018	12,825	8,179	9,409	7,433	6,932	10,391	11,673	10,759	10,466

The Conference Board of Canada (CBOC) housing starts forecast found in Appendix A1 provides a proxy for residential net customer additions, while the commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2012 to 2014).

Figure 3-6 provides a breakdown of the residential net customer additions for 2016.

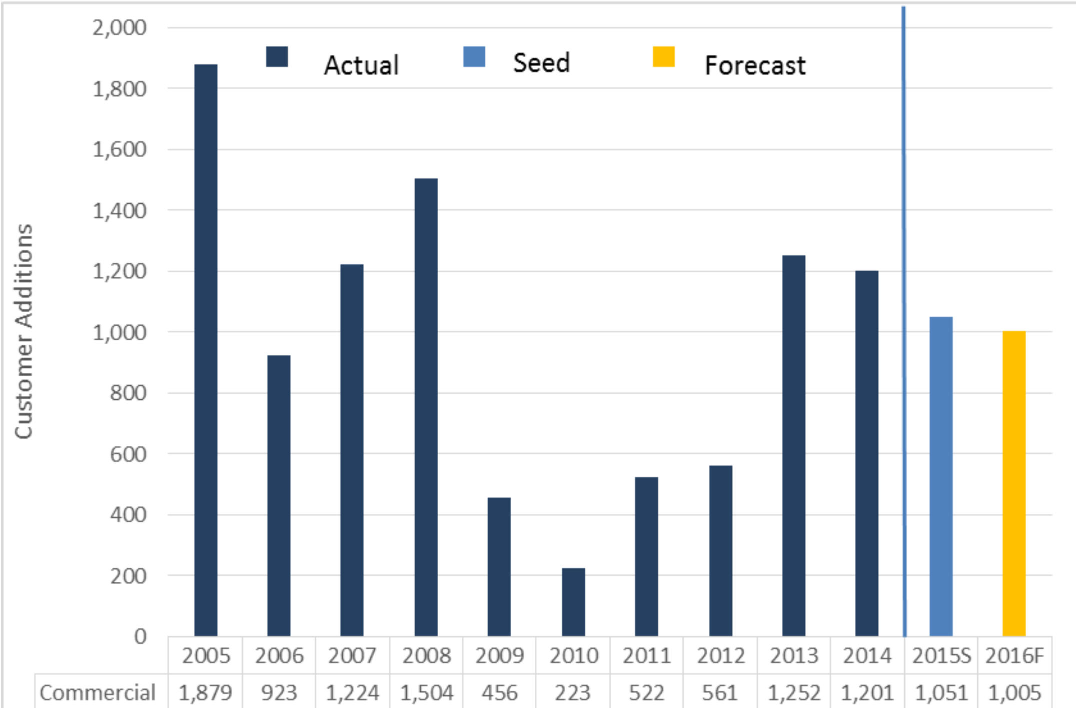
Figure 3-6: Residential Net Customer Additions



As shown in the preceding figure, residential net customer additions rebounded in 2013 and 2014. The 2015 and 2016 forecast of 9,708 and 9,461, respectively, is consistent with the past two years of actual experience.

Figure 3-7 provides a breakdown of the commercial net customer additions for 2016.

Figure 3-7: Commercial Net Customers Additions

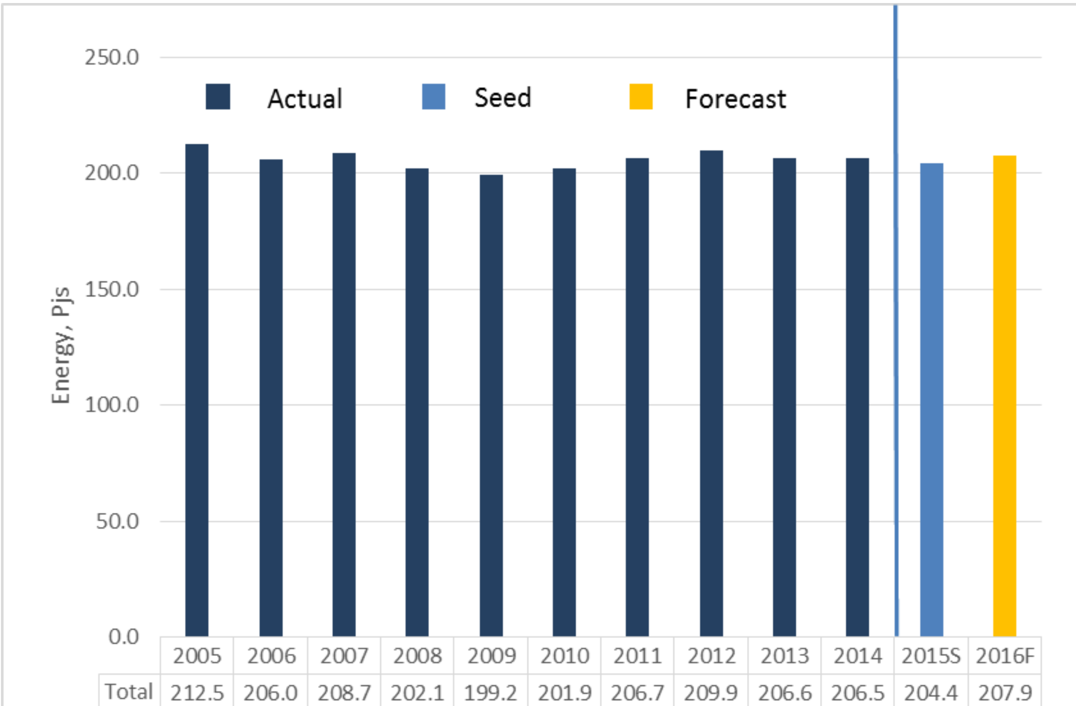


As shown above, the Company is forecasting just over 1,000 commercial net customer additions for 2016 based on three years of history (2012 to 2014).

3.6 *DEMAND FORECAST*

FEI's total energy demand consists of the residential and commercial normalized demand and the industrial and NGT demand. As seen below in Figure 3-8, the total energy demand is projected to be approximately 208 PJs in 2016, up approximately 3.5 PJs from 2015.

Figure 3-8: Total Energy Demand in PJs[11]



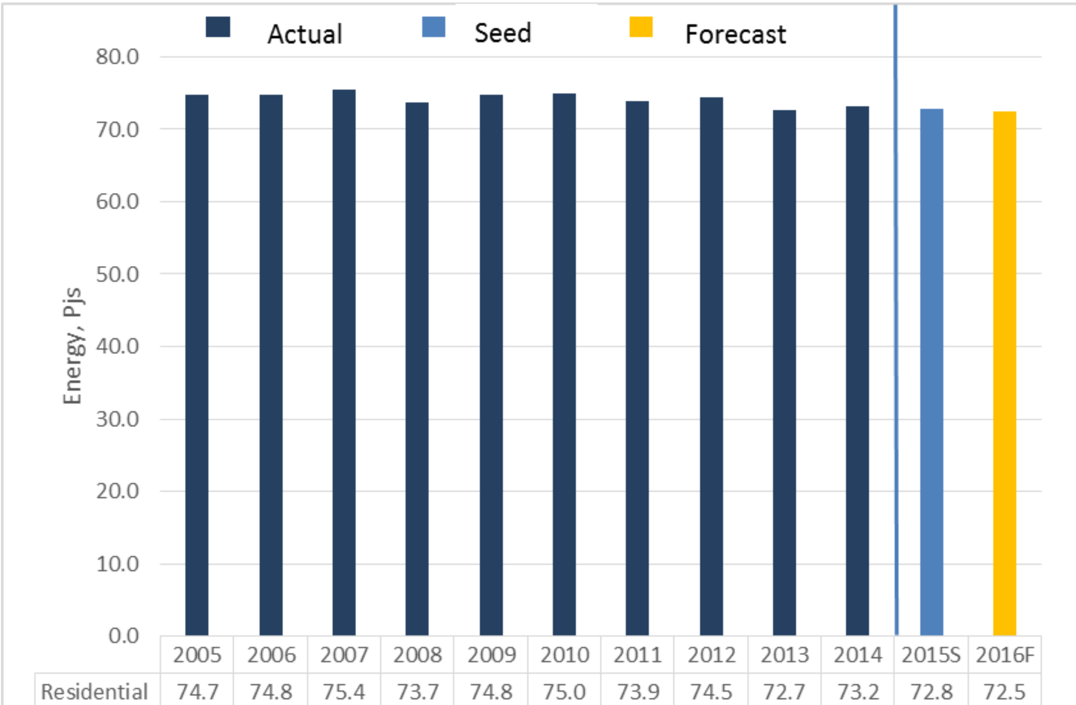
The residential and commercial, industrial and NGT demand forecasts are provided separately in the following subsections.

3.6.1 Residential Demand

As shown below in Figure 3-9, the impact of the forecast 2016 residential net customer additions does not offset the forecast decline in average residential UPC, which results in an overall forecast decline in residential normalized energy demand.

[11] Excludes Burrard Thermal. 2016 forecasted total volumes in Section 11, Schedule 18, Line 6 = 208,238 TJs / 1,000 – 2016 forecasted Burrard Thermal volumes of 322.9 TJs / 1000 = 207.9 PJs per Figure 3-8.

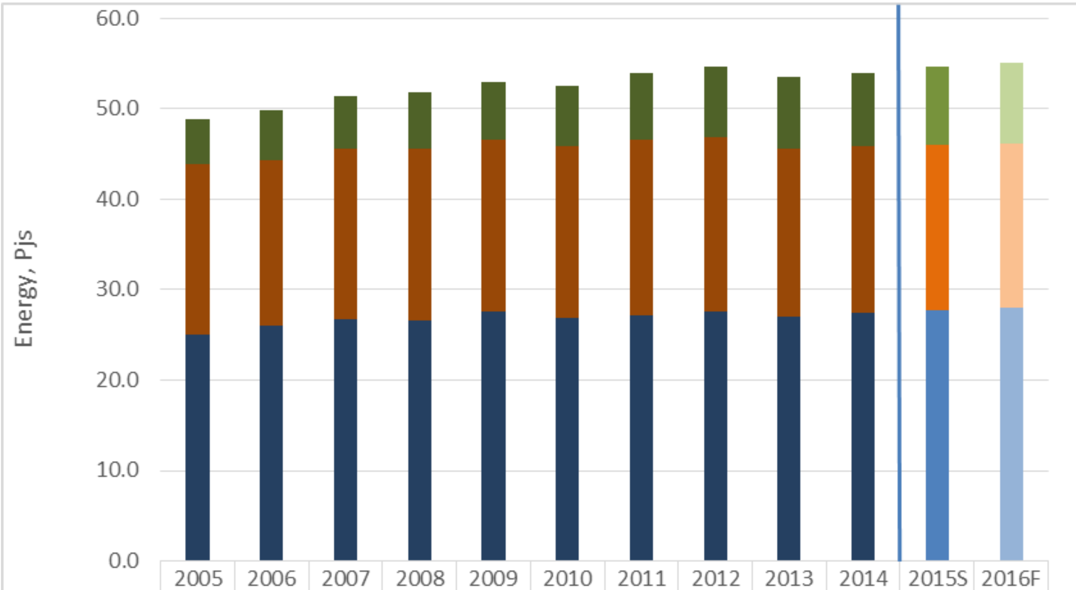
Figure 3-9: Normalized Residential Demand



3.6.2 Commercial Demand

As seen in Figure 3-10 below, demand in Rate Schedules 2 and 23 are forecast to grow slightly in 2016, partially offset by a slight decline in Rate Schedule 3 demand.

Figure 3-10: Commercial Demand



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015S	2016F
Rate 23	5.0	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.7	9.0
Rate 3	18.9	18.3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	18.2	18.1
Rate 2	25.0	26.0	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	27.7	28.0

3.6.3 Industrial Demand

The demand for the majority of industrial customers is forecast using the Industrial Survey. Consistent with past practice, the forecast demand for Burrard Thermal, Vancouver Island Joint Venture, and BC Hydro Island Cogeneration Project is set at the contract demand for each customer and these customers are not surveyed.

For the 2016 Forecast, customers completed the survey in May-June 2015. As shown in Table 3-1 below, the response rate achieved in 2015 was 44 percent of industrial customers, representing approximately 86 percent of industrial volumes. Of the remaining industrial customers, 41% received the survey and three reminder letters but did not reply. This group represents 12% of the industrial demand. Surveys could not be delivered to 15% of the industrial customers due to issues such as incorrect email addresses. This group represents just 2% of the total industrial load.

Table 3-1: Industrial Survey response

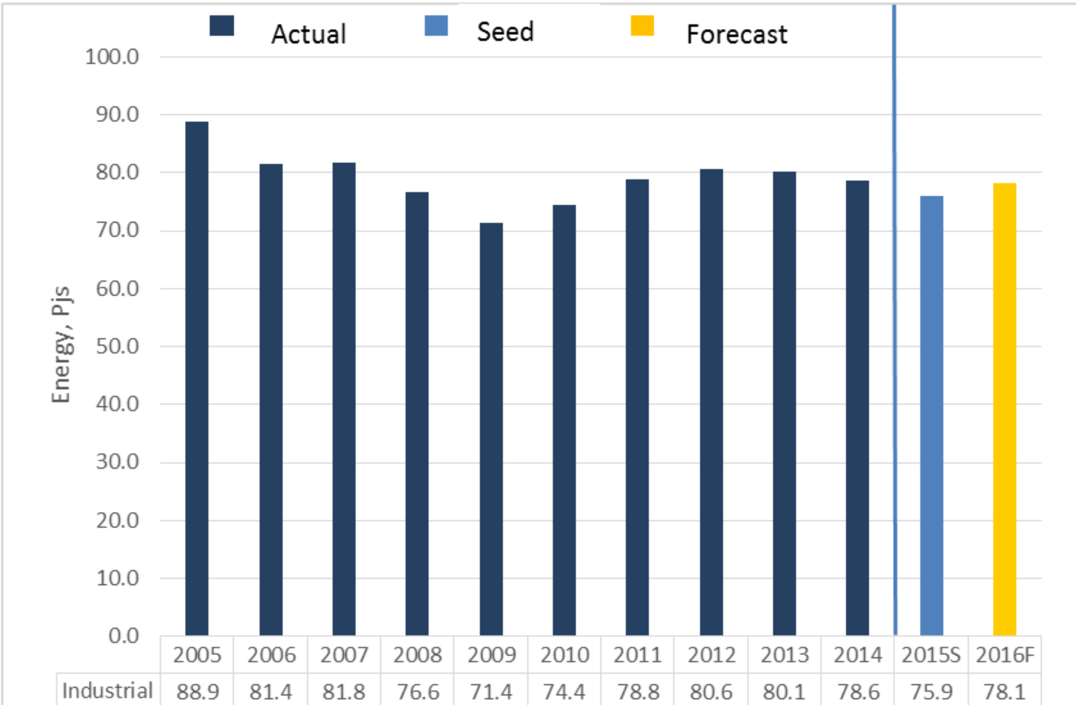
2015 Industrial Survey	Description	Customers	Demand
Survey completed	The survey was delivered and completed.	44%	86%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	41%	12%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	15%	2%
Total		100%	100%

The forecast of demand for all customers that either chose not to reply to the survey or could not be contacted (representing 14% of the total industrial demand) was set to 2014 actual consumption.

FEI's Industrial Marketing group identified three new industrial customers that will be consuming gas before the end of 2016. These three customers' estimated demand for 2016 is included in the 2016 Forecast. These three customers will receive Industrial Surveys in the spring of 2016 for the 2017 Forecast. Consistent with historical practice, no additional growth in customer additions was assumed for 2016 in the industrial rate schedules beyond those new customers specifically identified by FEI.

As seen in Figure 3-11 below, the demand from the industrial rate schedules is forecast to increase to 78.1 PJs/yr (an increase of 2.2 PJs from 2015, 0.65 PJs of which is from the three new customers).

Figure 3-11: Industrial Demand[12]



The Industrial demand in the figure above includes demand under Rate Schedule 22. The 2016 forecast Rate Schedule 22 demand is 36.3 PJs, up approximately 1.6 PJs from 2015 projected demand of 34.7 PJs. In the PBR Decision, on page 194, the Commission directed FEI to develop a mechanism to adjust the Rate Schedule 22 demand forecast methodology to better reflect the impact of falling gas prices, for review at the Annual Review for 2016 delivery rates. In compliance with this directive, FEI has included a detailed discussion of Rate Schedule 22 demand and included it as Appendix A4 to this Application.

3.6.4 Natural Gas for Transportation and LNG Demand

This section summarizes the CNG and LNG demand forecasts related to demand derived from GGRR incentives awarded, FEI's General Terms and Conditions 12B and non-NGT related Rate Schedule 16/46 LNG[13] demand. The details of incentives and fuelling stations driving the NGT portion of this demand can be found in Appendix B.

The following table shows the 2011 to 2014 Actual, 2015 Projected and 2016 Forecast annual demand for CNG and LNG for Rates Schedules 16/46 (LNG) and Rate Schedule 25 (CNG). FEI notes that there was no NGT demand in 2010.

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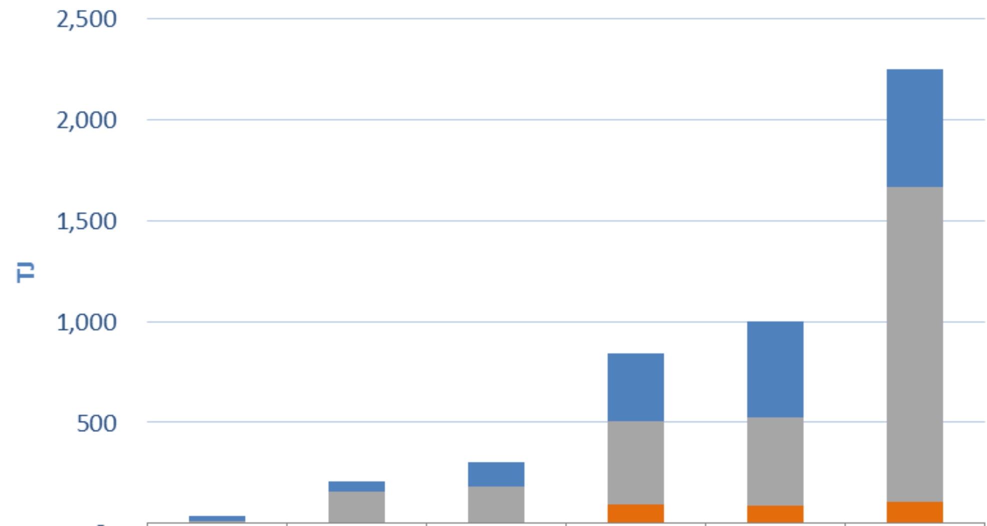
[12] Excludes Burrard Thermal and NGT.

[13] Rate 16 expired on December 31, 2014. Volumes projected for 2015 and forecast for 2016 are for Rate 46.

Figure 3-12: Actual (A) Projected (P) and Forecast (F) Demand for CNG & LNG[14]



	2011A	2012A	2013A	2014A	2015P	2016F
Rate 25 - NGT	26	52	120	336	480	586
Rate16/46 - NGT	8	154	183	411	435	1,560
Rate 16/46 - Other	-	-	-	96	87	107

The forecast increase in demand in Rate Schedule 25 – CNG is primarily attributable to new incremental load due to an additional 45 buses for Coast Mountain Bus Company and a fuelling station built for the City of Vancouver (City) municipality at which the City will begin fuelling approximately 33 heavy duty and 15 light vehicles in late 2015.

The forecast increase in demand in Rate Schedule 46 – LNG is primarily attributable to new incremental load related to LNG for marine customers such as Puget Sound Energy, BC Ferries and Seaspan. Of the 1,560 TJ's of growth in NGT demand, 1,028 TJ's is related to new incremental load from these customers.

The Rate Schedules 16/46 - Other demand in 2014 to 2016 includes LNG used for non-NGT activities primarily related the use of LNG for power generation in northern Canada. These customers are currently taking LNG on a spot basis (i.e. with no contract demand). In 2015, FEI expects to deliver approximately 87 TJs to these customers and for 2016 the customers have indicated increases in LNG demand to approximately 107 TJ's.

[14] Forecast includes all NGT related and other LNG demand inclusive of contract and excess demand flowing through stations as well as 3rd party station CNG/LNG volume.

3.7 REVENUE AND MARGIN FORECAST

The forecast of revenues and margins has been developed by considering the total energy forecast applied at 2015 delivery rates and applicable 2015 commodity and storage and transport rates.

3.7.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEI has developed a reasonable forecast of revenues by multiplying the energy forecast by the common rates for each customer class.

Table 3-2 below summarizes the approved, projected and forecast revenue for 2015 and 2016.

Table 3-2: Forecast Sales Revenue at Approved Rates

Revenue ($ millions)	Approved 2015	Projected 2015	Forecast 2016
Residential[1]	814.408	761.637	722.183
Commercial[2]	454.626	412.188	390.764
Industrial[3]	124.188	109.558	119.106
Total	**1,393.222**	**1,283.383**	**1,232.053**

Notes:
[1] Rate Schedule 1
[2] Rate Schedules 2, 3, 23
[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Burrard Thermal, Joint Venture, BC Hydro/Island Cogeneration Project

3.7.2 Margin

Margins are calculated by subtracting the cost of gas (discussed in Section 4) from the total revenues set out in Table 3-2 above.

Table 3-3 below summarizes the approved, projected and forecast margin for 2015 and 2016, by customer segment, at 2015 delivery rates.

Table 3-3: Forecast Gross Margin at approved Rates

Margin ($ millions)	Approved 2015	Projected 2015	Forecast 2016
Residential[1]	435.303	434.655	434.537
Commercial[2]	212.508	210.061	211.665
Industrial[3]	104.925	98.027	105.654
Total	**752.736**	**742.743**	**751.856**

Notes:
[1] Rate Schedule 1
[2] Rate Schedules 2, 3, 23
[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Burrard Thermal, Joint Venture, BC Hydro/Island Cogeneration Project

Variances between the delivery margin forecast in this section and actual delivery margin are captured in either the Revenue Stabilization Adjustment Mechanism (RSAM) if they relate to use rate variances for residential and commercial customers, or the Flow-through deferral account, for all other variances.

3.8 *SUMMARY*

FEI's forecast of demand for natural gas is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand for 2016. Based on this methodology, FEI is forecasting an increase in consumption in 2016, with the total normalized demand projected to be approximately 208 PJs in 2016, up approximately 3.5 PJs from the new 2015 projected consumption. Based on the common rates for each customer class, FEI's 2016 revenue forecast is $1,232.053 million and 2016 gross margin forecast is $751.856 million.

4. COST OF GAS

The cost of gas includes the cost of the gas commodity and the cost of midstream resources (storage and transportation). The Company is not requesting approval of forecast gas costs with this Application. Instead, any rate changes related to the flow-through of gas costs are dealt with in separate applications to the Commission. Any variations between forecast and actual gas costs will continue to be returned to or recovered from customers through the existing deferral account mechanisms.

While the Company is not requesting approval of forecast gas costs with this Application, the forecast cost of gas is required in the determination of a number of revenue requirement line items that form part of the forecasts included in this Application. The total cost of gas for the purposes of this Application has been determined by multiplying forecast sales volumes using the demand forecast described in Section 3 by the existing (as of July 1, 2015) unit gas cost recovery charges for each rate schedule.

The natural gas commodity cost recovery rate for the Mainland, Vancouver Island, and Whistler service areas became effective April 1, 2015 pursuant to Commission Order G-39-15, dated March 16, 2015. The natural gas storage and transport rates and riders, also known as the midstream cost recovery rates and Midstream Cost Reconciliation Account (MCRA) rate riders, for the Mainland, Vancouver Island, and Whistler service areas became effective January 1, 2015 pursuant to Commission Order G-175-14, dated November 14, 2014.

The propane cost recovery rates for the Revelstoke service area became effective July 1, 2015 pursuant to Commission Order G-99-15, dated June 12, 2015.

The table below sets out the forecast cost of gas at existing rates, by rate schedule group.

Table 4-1: Forecast Cost of Gas at Existing Rates[15]

Cost of Gas ($ millions)	Approved 2015	Projected 2015	Forecast 2016
Residential[1]	379.106	326.982	287.645
Commercial[2]	242.118	202.127	179.099
Industrial[3]	19.262	11.531	13.454
Total	**640.486**	**540.640**	**480.198**

Notes:

1. Includes Rate Schedules 1 volumes
2. Includes Rate Schedules 2, 3, 23 volumes
3. Includes Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27 volumes

[15] Biomethane commodity costs are excluded from the table given they are allocated directly to the Biomethane Variance Account.

The natural gas storage and transport, or midstream, component of the cost of gas includes the costs for the contracted third party pipeline and storage resources, spot and peaking gas purchases, and also includes costs for unaccounted for gas (UAF).

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Sources of UAF comprise, but are not limited to, system leakage, lost gas (gas lost as a result of utility and third party activities, including gas theft), and measurement inaccuracies. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered from core customers[16] via the gas cost rates, whereas the cost of UAF related to the Transportation Service rate classes is included in the determination of the delivery rates to facilitate recovery of UAF costs from Transportation Service customers, as they do not pay midstream charges.

[16] Core customers are those for whom FEI is obligated to ensure the purchase, transportation, and uninterrupted delivery of natural gas to their premises.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

As shown in the table below, FEI is forecasting other revenues to increase from the amounts approved for 2015.

Table 5-1: 2015 and 2016 Other Revenue Components

Other Operating Revenue, ($ millions)			
	Approved 2015	Projected 2015	Forecast 2016
Late Payment Charge	2.542	2.714	2.314
Connection Charge	3.033	3.032	3.060
Other Recoveries	0.291	0.290	0.290
NGT Related Recoveries	2.356	2.205	3.174
Biomethane Other Revenue	(0.070)	(0.215)	0.250
SCP Third Party Revenue	15.035	15.035	14.957
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**41.226**	**41.101**	**42.085**

In the following sections, FEI summarizes the methodology for forecasting the line items included in the table above, and also addresses the largest components of other revenue, the SCP third party revenue and the LNG Capacity Assignment.

5.2 OTHER REVENUE COMPONENTS

5.2.1 Late Payment Charge

The forecast Late Payment Charge revenue is calculated as a percentage of total forecast revenue for Rate Schedule 1, 2 and 3 customers[17]. Specifically, FEI uses the three-year average of the actual ratio of Late Payment Charges to Rate Schedule 1, 2, and 3 revenues (Late Payment Charge Factor or LPC Factor) to calculate the 2016 forecast.

The following table summarizes the calculation of the Late Payment Charge Factor:

[17] Includes Rate Schedules 1, 1B, 1U, 2, 2B, 2U, 3, 3B, 3U.

Table 5-2: Late Payment Charge Revenue Factor Calculation (revenues in $ millions)

		Actual 2012	Actual 2013	Actual 2014	3 Yr Average
FEI	Late Payment Charge	2.402	2.297	2.842	
FEVI	Late Payment Charge	0.447	0.288	0.317	
FEW	Late Payment Charge	0.014	0.015	0.014	
		2.863	2.600	3.173	
FEI	Rates 1, 2, 3 Revenue	1,187	1,137	1,190	
FEVI	Rates 1, 2, 3 Revenue	170	168	153	
FEW	Rates 1, 2, 3 Revenue	11	11	12	
		1,369	1,316	1,354	
Total	LPC Factor	0.2092%	0.1976%	0.2343%	0.2137%

The Late Payment Charge factor of 0.2137 percent is multiplied by the forecast revenue of $1,082,926 million to arrive at the forecast Late Payment Charge Revenue of $2.314 million for 2016.

5.2.2 Connection Charge

Consistent with the methodology used in previous years, the Connection Charge revenue is calculated based on three factors: a $25 connection fee, the historical move ratio of 12.5 percent[18] and the projected or forecast number of average customers.

In 2016, the number of average customers is forecast to increase; therefore the forecast for Connection Charge revenue is also forecast to increase.

The following formula summarizes how FEI has calculated the 2016 forecast amounts in Connection Charge revenue:

Connection Charge of $25 * (Average Customers of 979,082) * Move Ratio of 12.5% = Connection Charge Revenue of $3.060 million.

5.2.3 Other Recoveries

Other recoveries consist of NSF returned cheque charges as well as other miscellaneous income items. Consistent with past practice, the 2016 forecast of these items has been

[18] The historical move ratio reflects the percentage of customers that move from one location to another each year.

determined based on the 2015 projected amounts of $0.088 million and $0.202 million, respectively.[19]

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing charge that is applied to FEI fuelling station customers, tanker rentals from LNG customers and CNG and LNG fuelling stations (CNG & LNG Service Revenues) as shown in Table 5-3 below.

Table 5-3: 2015 and 2016 NGT Related Recoveries[20]

NGT Related Recoveries, ($ millions)			
	Approved 2015	**Projected 2015**	**Forecast 2016**
NGT Overhead and Marketing Recovery	0.227	0.222	0.263
NGT Tanker Rental Revenue	0.215	0.168	0.486
CNG & LNG Service Revenues	1.914	1.816	2.426
Total NGT Related Recoveries	**2.356**	**2.205**	**3.174**

As discussed in Appendix B, Section 5, overhead and marketing revenue has been determined based on the forecast of FEI-owned fuelling stations, tanker rental revenue has been forecast based on the 2015 projected delivery frequency, and the CNG and LNG service revenues have been forecast based on existing and forecast fuelling stations and volumes attributable to CNG and LNG customers for 2016. Please refer to Appendix B, Section 5 for a more detailed discussion of each item.

5.2.5 Biomethane Other Revenue

The other revenue increase of $0.250 million in 2016 shown in Table 5-1 above is the transfer to the delivery margin from the Biomethane Variance Account (BVA) for the cost of service of the Biomethane capital assets.

In accordance with Commission Order G-210-13, which approved the Biomethane Program on a permanent basis, the following delivery margin related costs must be included in the BVA[21]:

- Upgrading plant cost of service;
- Interconnection cost of service for projects introduced after Order G-210-13; and

[19] 2015 projected amounts are based on six months of 2015 actual information that was available at time of preparing the forecast.

[20] Included in CNG & LNG Service Revenues 2016 forecast line is $0.025 million of revenue associated with compression revenue from the Surrey Ops pump. Appendix B does not include the $0.025 million forecast in revenue associated with the Surrey Ops pump.

[21] Please note that the cost of procuring Biomethane supply does not need to be transferred because it is accounted for directly in the BVA.

- Program overhead costs.[22]

The $0.145 million variance between the 2015 Approved and 2015 Projected other revenue is due to timing differences in the in-service date for the Kelowna Upgrader. The 2015 Approved included the removal from the delivery margin of the favourable tax impacts of depreciation and capital cost allowance associated with the anticipated 2014 in-service date; however, the project in-service date was delayed until 2015.

For 2016, there is a credit to the delivery margin and a charge to the BVA due to the earned return on the capital related to the existing upgrading plant and the $0.850 million[23] interconnection for the new City of Surrey landfill project. The earned return associated with these projects is more than the tax component of the cost of service, both of which are embedded in the calculation of FEI's delivery margin. FEI has credited Other Revenue to remove the impacts of the earned return and taxes from FEI's delivery margin, with an offsetting charge to the BVA.

With respect to other Biomethane capital expenditures, FEI notes that there is a forecast capital expenditure of $0.505 million[24] for interconnections related to projects approved before or as a part of Order G-210-13 that remain in the delivery margin, as clarified in Commission letter L-10-14, dated February 18, 2014 regarding Order G-210-13. FEI also notes that the transfer of the Biomethane upgrader O&M and program overhead costs to the BVA is accounted for in FEI's 2015 Approved and 2016 Forecast O&M (Section 11, Schedule 21, Line 29, Column 4).

5.3 *SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE*

The SCP Third Party Revenue for 2015 and 2016 includes the items shown in the table below.

[22] Program costs as defined in Order G-210-13 to include education, marketing, direct administration, cost of enrollment and the cost of IT upgrades.

[23] In Section 11, Schedule 4, Line 21, Column 4, the 2016 capital expenditure amount of $1.355M includes $0.850 million for City of Surrey, the cost of service of which is transferred to the BVA and also $0.505 million for LuLu Island and Dicklands Farms projects, the costs of service of which are recovered through the delivery margin as per Order G-210-13.

[24] Ibid.

Table 5-4: 2015 and 2016 SCP Revenue Components

Southern Crossing Pipeline Revenue, *($ thousands)*						
	Approved 2015		Projected 2015 (A)		Forecast 2016 (B)	
Northwest Natural Gas Co. (NWN)	$	5,470	$	5,470	$	6,362
MCRA		3,600		3,600		3,600
Net Mitigation (Spectra T-South Enhanced Service)		5,965		5,965		4,995
Total SCP Revenue	**$**	**15,035**	**$**	**15,035**	**$**	**14,957**

Notes: (A) Projected 2015 amounts equal Approved 2015 amounts - any variances from Approved amounts are captured in the SCP Mitigation Revenues Variance Account.
(B) Revenue calculations for NWN & Spectra daily demand charges reflect 2016 leap year.

The components of the SCP Third Party Revenues shown in Table 5-4 are discussed separately below. Any variance from the forecast SCP Third Party Revenues will continue to be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a two-year period.

5.3.1 Northwest Natural Gas Co.

The Company has a firm service contract with Northwest Natural Gas Co. (NWN), approved in Order G-98-05, for 46.5 MMcfd of SCP capacity over the period November 2004 through October 2020. Consistent with the PBR Application, the NWN revenues are recorded net of the costs for the Spectra Energy Kingsvale South Transportation and the Pacific Gas & Electric (PG&E) termination fees as shown in Table 5-5 below.

Table 5-5: Calculation of 2016 Northwest Natural Gas Co. Revenue

Forecast 2016 (A) NWN Revenue, *($ thousands)*		
NWN Revenue	$	9,019
Transportation Tolls (B)		(2,512)
PG&E Termination Fee		(145)
Net NWN Revenue	**$**	**6,362**

Notes: (A) Revenues for NWN daily demand charges reflect 2016 leap year.
(B) Forecast cost of Spectra Kingsvale South capacity.

5.3.2 MCRA

The revenue of $3.6 million per year is related to the inclusion of SCP capacity in the MCRA portfolio. Consistent with Order G-44-12 for 2012 and 2013, in Order G-138-14, the

Commission approved the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the PBR Period.

This treatment is appropriate as the SCP capacity is an essential part of FEI's midstream portfolio, meeting the objectives of safe, reliable and cost-effective resources, and continues to provide optimal benefits to customers.

5.3.3 Net Mitigation Revenue (Spectra T-South Enhanced Service)

As part of the SCP Revenue, the Company has included revenue associated with the T-South Enhanced Service in the amount of $4.995 million.

The T-South Enhanced Service is an initiative between Spectra Energy and the Company that adds value to Spectra Energy's T-South service by providing shippers the option to access the Kingsgate market through the Company's Interior Transmission System (ITS) and SCP. As a result of this initiative with Spectra Energy, the Company's customers benefit from increased liquidity in the BC marketplace, decreased T-South tolls, and incremental SCP mitigation revenue.

The T-South Enhanced Service agreement between Spectra Energy and FEI is in effect until October 31, 2016, and provides a maximum capacity of 91 MMcfd, as approved in Order G-104-13. The Company continues to investigate its options for contracting the capacity beyond 2016.

The forecast revenue of $4.995 million is based on the 91 MMcfd of capacity being fully contracted through the current term. Under the agreement with Spectra Energy, the volume of contracted capacity could be less, which would in turn reduce the total amount paid by Spectra Energy. Spectra Energy uses the capacity to offer T-South Enhanced Service to its shippers. The actual volume Spectra Energy contracts with FEI matches the volume Spectra Energy contracts with shippers under its T-South Enhanced Service.

5.4 *LNG CAPACITY ASSIGNMENT*

The $18.039 million in LNG capacity assignment other revenue shown in Table 5-1 above represents a transfer of costs from the delivery margin to gas costs reflecting to the allocation of a portion the Mt. Hayes LNG facility to gas costs.[25]

The LNG capacity assignment to the gas supply portfolios commenced in 2011 as a result of the Mt. Hayes LNG Facility becoming operational. The 2015 transfer reflects the level of LNG service provided to the gas supply portfolio and is consistent with the level of service provided pre-amalgamation. Generally, this transfer reflects the use of the Mt. Hayes LNG facility for storage services (which is recovered through gas storage and transportation rates) and capacity requirements (which is recovered through delivery rates).

[25] The amount is the summation of $12.026 million as set out in the Mount Hayes Storage and Delivery Agreement approved by the Commission in Order G-161-11 and $6.013 million as approved in Order G-140-09.

The Mt. Hayes LNG facility includes rate base capital costs and operating costs which are embedded in the delivery margin. The $18.039 million capacity assignment is based on market valuation of avoided storage costs and transport costs on NWN pipe. To properly allocate the capacity assignment value of $18.039 million to the midstream requires an equal offset to the delivery margin which is accomplished by crediting Other Revenue.

The allocation between delivery margin and gas costs will be reviewed in the Rate Design Application to be filed by December 31, 2016.

5.5 *SUMMARY*

FEI has forecast the other revenue components for 2016 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in other revenue are recorded in either the SCP Mitigation Revenues Variance Account (for variances in the items discussed in Section 5.3), the CNG/LNG Recoveries deferral (for variances in the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4) or the Flow-through variance deferral, for all other variances.

6. O&M EXPENSE

6.1 *INTRODUCTION AND OVERVIEW*

Under the PBR Plan, FEI's O&M Expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2016, the formula-O&M is $238.068 million, representing a 1.039 percent increase from 2015, entirely due to the formula drivers. O&M expenses forecast outside the formula are $34.990 million, representing a 0.387 percent increase from the amount approved for 2015. Overall the increase in Gross O&M Expense from 2015 to 2016 is 0.955 percent. This rate of increase is less than forecast inflation and below recent historical increases, 3.9 percent for 2011, 5.7 percent for 2012, 4 percent for 2013, and 1.1 percent in 2014.

The components of 2016 O&M expense are shown in Table 6-1 below.

Table 6-1: 2016 O&M Expense

Line No.	Description	$ millions
1	Formula O&M	238.068
2	Forecast O&M	34.990
3	Total Gross O&M	273.058
4	Capitalized Overhead (12%)	(32.767)
5	Biomethane O&M transferred to BVA	(0.959)
6		
7	Net O&M	239.332

In the subsections below, FEI provides further details on its formula and forecast O&M expenses for 2016.

6.2 *FORMULA O&M EXPENSE*

The formula-driven portion of Base O&M starts from a base of the 2015 Approved formula O&M for FEI, escalated by the prior year's inflation less a productivity improvement factor of 1.1 percent, and one-half of the prior year's growth in average customers. As calculated in Section 2, the 2016 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.469 percent and one-half of the prior year's customer growth is 0.567 percent.

For 2016, the annual operating and maintenance expense under the formula is calculated as:

2015 Approved formula O&M x [1 + (I Factor – X Factor)] x [1 + (0.5 x customer growth)]

Table 6-2 below shows the calculation of the 2016 Formula O&M.

Table 6-2: Calculation of 2016 Formula O&M

Line No.	Description	Amount ($ millions)	Source
1	FEI 2015 Formula O&M	235.620	FEI 2015 Rates Compliance Filing Schedule 10 Line 35 Column 8
2			
3	Net Inflation Factor	0.469%	Section 2 Table 2-4
4	Customer Growth Factor	0.567%	Section 2 Table 2-2
5			
6	FEI Amalgamated 2016 Formula O&M	238.068	Line 1 x (1 + Line 3) x (1 + Line 4)

6.2.1 Allocation of O&M to the Fort Nelson Service Area

On June 10, 2015, the Commission issued Order G-97-15 and accompanying decision in FEI's 2015 and 2016 Revenue requirements and Rates Application for the Fort Nelson Service Area (the Fort Nelson Decision).

On page 20 of the Fort Nelson Decision, the Commission Panel discussed FEI's proposal to allocate $24 thousand in communication and line heater fuel costs to Fort Nelson that had not been allocated prior to 2013:

> *"Of concern to the Panel is the movement of communication and line heater fuel costs which were previously centralized in FEI to FEFN. In our view this is very similar to the situation involving intangible plant capital additions which have been denied in Section 4.1.4 of this Decision. These communications and line heater fuel costs already form part of FEI's Base O&M and are being escalated annually in accordance with the PBR Decision. As explained in Section 4.1.4 of this Decision, if the Panel were to accept the transfer of these costs to FEFN as proposed, it would amount to "double dipping." Therefore, the Panel considers moving the communication and line heater fuel costs to FEFN to be inappropriate at this time and denies the inclusion of these costs as part of FEFN's forecast 2015 and 2016 O&M expenses...FEI is directed to identify any other cases where FEI Base Capital or O&M amounts have been allocated to FEFN since approval of the PBR Plan. FEI is further directed to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how the communication and line heater fuel costs can be most appropriately and equitably handled going forward given the current PBR Plan."*

FEI acknowledges that its proposal to allocate the communication and line heater fuel costs to Fort Nelson should be coordinated with a reduction to FEI's O&M Base.

Given that Fort Nelson rates have already been set for 2015 and 2016, the earliest year that the transfer of costs can be coordinated is in 2017. FEI therefore proposes that in its next Annual Review filing it will adjust its base O&M starting in 2017 for the amounts to be allocated to Fort Nelson. FEI proposes that this would consist of the actual 2013 communication and line heater fuel costs of $29 thousand, escalated by the PBR formula. These O&M costs will then be forecast as part of Fort Nelson's revenue requirements starting in 2017 in the ordinary course and as appropriate.

In section 7.2.1.1 below, FEI addresses the capital expenditures that were proposed to be allocated to Fort Nelson as discussed in the Fort Nelson Decision.

FEI confirms that there are no other cases where FEI Base Capital or O&M amounts have been allocated or proposed to be allocated to FEFN since approval of the PBR Plan.

6.3 *O&M EXPENSE FORECAST OUTSIDE THE FORMULA*

After calculating the Formula O&M, the Formula O&M is then adjusted to add in pension and OPEB expense, insurance, and O&M supporting Biomethane, NGT and Rate Schedule 46. These amounts are shown in Table 6-3 below along with a comparison to 2015.

Table 6-3: 2016 Forecast O&M ($ millions)

		2015		2016
Line No.	Description	Approved	Projected	Forecast
1	Pension/OPEB (O&M Portion)	25.699	25.699	24.218
2	Insurance	6.649	6.185	6.275
3	Bio-Methane O&M	0.646	0.659	1.022
4	NGT O&M	0.926	0.836	1.185
5	RS 46 O&M	0.935	0.680	2.290
6				
7	FEI Amalgamated 2016 Forecast O&M	34.855	34.060	34.990

Each of these items that are forecast outside of the formula is discussed below. Variances in Pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account. Variances in insurance, net Biomethane O&M, and NGT and Rate Schedule 46 O&M are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expenses for 2016 are based upon the most recent actuarial estimates using assumptions at December 31, 2014 provided by the Company's actuary, Towers Watson. Pension and OPEB expense is broken out into categories as shown in Table 6-4.

Table 6-4: 2015-2016 Pension and OPEB Expense ($ millions)

Line No.	Description	2015 Approved	2016 Forecast
1	O&M	25.699	24.218
2	Forecast Capital - Growth	1.098	1.035
3	Forecast Capital - Other	3.226	3.040
4	Retirement Costs	1.313	1.237
5	CMAE	0.400	0.377
6			
7	Total Pension & OPEB Expense	31.737	29.907

The table above shows the allocations of pension and OPEB expense to O&M, Capital (Growth and Other), Retirement Costs, and Core Market Administration Expense (CMAE).

Overall, Pension and OPEB expense for 2016 is forecast to be $1.830 million lower than what was approved for 2015, of which $1.481 million resides in O&M. This decrease is primarily due to favourable investment returns partially offset by a decrease in the assumed discount rate.

The 2015 variance between approved and actual pension and OPEB expense and any 2016 variance between these amounts is captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period as approved by the Commission in Order G-138-14.

6.3.2 Insurance

The insurance expense relates to insurance premium expense allocated to FEI by Fortis Inc.

The 2016 insurance expense is forecast at $6.275 million, a decrease of $0.374 million or 5.6 percent from what was approved for 2015. The 2016 Forecast is calculated by taking the known annual insurance premium of $6.116 million which is applicable to the first six months of 2016 and escalating that amount by five percent for the remaining six months[26]. The five percent escalation is based on a combination of historical increases in premiums, increases in the value of assets year over year and the expectations of Fortis Inc.'s insurance broker on future premiums.

6.3.3 Biomethane O&M

The only Biomethane O&M that is recovered through delivery rates is related to Biomethane interconnections which pre-dated or were approved in Order G-210-13, the costs of which were

[26] $6.120 million/2 = $3.060 million x 1.05 = $3.215 million rounded up. $3.060 million + $3.215 million = $6.275 million.

approved to be recovered from all customers. As discussed below, the 2016 forecast of Biomethane O&M to be recovered in delivery rates is $0.063 million.[27]

The 2016 forecast of total Biomethane O&M is $1.022 million. This total forecast is based on the forecast operating costs of FEI-owned upgraders (Salmon Arm and Kelowna), interconnect stations and Biomethane program costs. Of this forecast cost, $0.959 million relates to upgrader O&M and program overhead which is transferred to the BVA for recovery through the Biomethane Energy Recovery Charge (BERC). The remainder of $0.063 million is the O&M associated with interconnection stations which pre-dated or were approved in Order G-210-13[28], and is recovered through delivery rates.

The $0.063 million biomethane O&M recovered in delivery rates is $0.011 million higher than the 2015 approved amount due to two additional interconnection being in service. The 2015 Approved reflects the O&M related to the four interconnections in service in 2015. In 2016, the two additional interconnections (Lulu Island and Dicklands) are forecast to be placed into service as discussed in Section 7.2.2.

6.3.4 NGT O&M

NGT O&M is forecast to increase by $0.259 million from what was approved for 2015. The total NGT O&M of $1.185 million is composed of $0.987 million of NGT station O&M and $0.198 million of LNG tanker and related O&M (Appendix B Sections 5.1.3 and 6.1.2, and Table B-15). These O&M costs are offset by NGT revenue as discussed in Appendix B Section 4.1.2. Please refer to Appendix B NGT for a discussion of these amounts.

6.3.5 Incremental O&M to Support Rate Schedule 46 Revenues

The O&M costs to support Rate Schedule 46 include all incremental costs associated with the liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers to transport LNG at the Tilbury and Mt. Hayes LNG facilities. These costs are incremental to the regular O&M costs for operating the Tilbury and Mt. Hayes LNG facilities as peaking storage facilities. Specific costs include additional labour, materials, contractors, power and fuel.

The incremental O&M costs to support Rate Schedule 46 are forecast to increase by $1.355 million compared to what was approved for 2015 and are related to meeting the growth in demand for LNG. As shown in Table 6-5 below, the primary drivers of the increase are labour and power costs. Labour costs are forecast to increase due to additional staff required to support the increased number of truck loadings at the facility and power costs are forecast to increase based on the increase in daily liquefaction.

A table breaking out the various components of the Rate Schedule 46 O&M is included below.

[27] Also referred to as net Biomethane O&M.
[28] These projects were Fraser Valley Biogas, Salmon Arm Landfill, Kelowna Landfill, Seabreeze Farms, Lulu Island WWTP, and Dicklands Farm.

Table 6-5: Rate Schedule 46 O&M ($ millions)

Line No.	Description	2015 Approved	2015 Projected	2016 Forecast
1	Tilbury Plant:			
2	Labour	0.290	0.210	0.390
3	Materials	0.044	0.030	0.060
4	Contractor	0.066	0.040	0.090
5	Power	0.460	0.340	0.620
6	Fuel Gas	0.040	0.025	0.050
7	Sub-total	0.900	0.645	1.210
8	Mt Hayes Plant:			
9	Labour	0.014	0.014	0.350
10	Materials	0.005	0.005	0.050
11	Contractor	0.007	0.007	0.080
12	Power	0.007	0.007	0.550
13	Fuel Gas	0.002	0.002	0.050
14	Sub-total	0.035	0.035	1.080
15	FEI Amalgamated 2015 Forecast O&M	0.935	0.680	2.290

The decrease in expenses between the 2015 Approved and 2015 Projected is the result of a decrease in the projected volumes related to Rate Schedule 46 spot customers as a result of lower actual volumes taken in the first six months of 2015 than was forecast in the previous year. The decrease in volumes taken by spot customers can be the result of a number of factors, such as the customer incurring delays in the completion of planned projects or the customer choosing an alternative source of supply.

The $2.290 million forecast for the year 2016 assumes an average supply of 2,552 GJ per day from the Tilbury LNG facility and an average supply of 2,015 GJ per day from the Mt. Hayes LNG facility to meet the forecast LNG demand as described in Section 3.6.4, which has more than tripled from the 2015 projection.

6.4 *NET O&M EXPENSE*

Net O&M expense is Gross O&M less capitalized overhead and Biomethane O&M transferred to the BVA. As approved by the Commission in Order G-138-14, the capitalized overhead rate is set at 12 percent for FEI. After capitalized overhead and the transfer of $0.959 million of Biomethane O&M to the BVA, the net O&M expense is $239.332 million.

6.5 SUMMARY

Overall the increase in Gross O&M Expense from Approved 2015 to 2016 is 0.955 percent. The formula-driven O&M is increasing at a rate of 1.039 percent with very little change in the O&M forecast outside of the formula. The capitalized overhead rate remains unchanged from 2015.

7. RATE BASE

7.1 *INTRODUCTION AND OVERVIEW*

The 2016 Rate Base for FEI is forecast to be $3.691 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, cash working capital, other working capital, deferred income tax, and LILO benefit.

The 2016 Rate Base of FEI includes the full-year impacts of the 2015 closing projected plant balances as well as the mid-year impact of the following amounts:

- Capital additions resulting from regular capital expenditures of $200.205 million
- The $7.370 million plant addition of the Huntingdon Station CPCN29
- Plant depreciation and Contribution in Aid of Construction (CIAC) amortization of $156.457 million

In addition, various changes in deferred charges, working capital and other items decrease rate base by a net amount of $23.844 million.

Details of the 2016 forecasted plant balances can be found in Section 11, Schedules 5 through 9.

7.2 *2015 REGULAR CAPITAL EXPENDITURES*

Under the PBR Plan, FEI's regular capital expenditures are primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis. In 2016, the formula-capital is $145.315 million[30], representing a 4.258 percent increase from 2015, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $12.304 million, representing a 15.955 percent increase from 2015, primarily due to higher expenditures on NGT assets partially offset by lower expenditures on Biomethane assets. Overall, the increase in regular capital expenditures from 2015 to 2016 is 4.918 percent. The components of 2016 regular capital expenditures are shown in Table 7-1 below.

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[29] Given the in-service date for CPCN's is January 1st of the year following when the project actually went into service, the rate base calculation which assumes a mid-year addition for capital expenditures has been adjusted to recognize a full year impact of this project using the "Adjustment for Timing of Capital Additions" line in Section 11, Schedule 2.

[30] From Table 7-1 $145.315 million = $33.262 million + 118.568 million - $6.515 million.

Table 7-1: 2016 Regular Capital Expenditures

Line No.	Description	$ millions
1	Formula Growth Capex	33.262
2	Formula Other Capex (before CIAC)	118.568
3	Forecast Capex	12.304
4	Total Gross Regular Capex	164.134
5	Less: Formula CIAC	(6.515)
6		
7	Net Regular Capex	157.619

In the subsections below, FEI provides further details on its formula and forecast capital expenditures for 2016.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2015 approved formula capital expenditures for FEI, escalated by the prior year's inflation less a productivity improvement factor of 1.1 percent, and one-half of the prior year's growth in average customers or service line additions. As calculated in Section 2, the 2016 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.469 percent, one-half of the prior year's average customer growth is 0.567 percent and one-half of the prior year's service line additions growth is 16.249 percent. In accordance with Order G-138-14, regular capital expenditure amounts will not be rebased to actual amounts during the term[31].

Unlike the O&M formula, the capital expenditure formula has two growth components in addition to formula inflation, resulting in separate calculations of Growth Capital and Other Capital. For 2016, the annual capital expenditures under the formula are calculated as:

> 2016 Growth Capital = 2015 Growth capital x [(1 + (I Factor – X Factor)] x [1 + SLA customer growth][32]

> 2016 Other Capital = 2015 Other Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth][33]

[31] The exception is the operation of the capital dead band. In relation to the capital dead band, page 178 of the PBR Decision states "The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula." This was further clarified in Appendix A to Order G-120-15 on Page 17: "Where the dead band is exceeded for any year, FEI and FBC are directed in the next Annual Review filing to include recommendations as to any adjustment to base capital other than those driven by the 1-X mechanism."

[32] SLA customer growth factor as calculated in Section 2, Table 2-2. Formula may also be represented as 2016 Growth Capital = 2015 Growth capital per SLA x [(1 + (I Factor – X Factor)] x 2016 SLA.

Tables 7-2 and 7-3 below show the calculation of the resulting 2016 formula capital expenditures.

Table 7-2: Calculation of 2016 Formula Growth Capital

Line No.	Description	Amount ($ millions)	Source
1	2015 Formula Growth Capex Base	28.479	FEI 2015 Rates Compliance Filing Schedule 18 Line 26 Column 6
2			
3	Net Inflation Factor	0.469%	Section 2 Table 2-4
4	Customer Growth Factor	16.249%	Section 2 Table 2-3
5			
6	2016 Formula Growth Capex	33.262	Line 1 x (1 + Line 3) x (1 + Line 4)

Table 7-3: Calculation of 2016 Formula Other Capital

Line No.	Description	Amount ($ millions)	Source
1	2015 Formula Other Capex Base	110.901	FEI 2015 Rates Compliance Filing Schedule 31 Line 26 Column 6
2			
3	Net Inflation Factor	0.469%	Section 2 Table 2-4
4	Customer Growth Factor	0.567%	Section 2 Table 2-2
5			
6	2016 Formula Other Capex	112.053	Line 1 x (1 + Line 3) x (1 + Line 4)

The formula Other Capital amount of $112.053 million is net of CIAC. The amount of CIAC is $6.515 million, which is required to be separated for purposes of the financial schedules and rate calculations. Therefore, the gross formula Other Capital amount is $118.568 million as shown in Table 7-1 above.

7.2.1.1 Allocation of Capital Expenditures to the Fort Nelson Service Area

On June 10, 2015, the Commission issued Order G-97-15 and accompanying decision in FEI's 2015 and 2016 Revenue requirements and Rates Application for the Fort Nelson Service Area (the Fort Nelson Decision).

On page 17 of the Fort Nelson Decision, the Commission Panel discussed FEI's proposal to allocate $62 thousand in Intangible Plant addition to Fort Nelson that had not been allocated prior to 2013:

> *"The Panel is not persuaded that the allocated amounts being charged to FEFN for Intangible Plant additions are appropriate. Moving these costs from FEI to FEFN is based on the premise that a review of fixed asset records indicates that these costs have been inappropriately charged to FEI in the past and moving them to FEFN reflects the correct allocation of costs between FEI and FEFN. The Panel may have been inclined to accept this reasoning were FEI operating under a two-year cost of service*

[33] This formula is also applied to contributions in aid of construction.

> *regime. However, this is not the case. FEI is operating under a six-year PBR Plan which, among other things, has established a level of base capital under which FEI is to operate. This base capital amount includes the 2013 Intangible Plant additions of $64 thousand and these costs will remain in FEI's Base Capital, escalating based on the PBR formula, for the entire six-year PBR term. Therefore, allowing FEI to allocate these costs to FEFN would be effectively facilitating "double dipping." First, by allocating the Intangible Plant expenditures to FEFN, FEI is recovering these costs from the FEFN customer base; and second, since the reallocated costs still remain in the FEI Base Capital amount (i.e. the Base Capital has not been adjusted downwards for the PBR period), the FEI ratepayers are also paying for this same amount in every year of the PBR regime. FEI's shareholders thus benefit through the Earnings Sharing Mechanism despite the fact that no actual "savings" have occurred... FEI is further ordered to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how these costs can be most appropriately and equitably handled going forward given the current PBR Plan in place."*

FEI acknowledges that its proposal to allocate the Intangible Plant additions to Fort Nelson should have been coordinated with a reduction to FEI's Base Capital.

Given that Fort Nelson rates have already been set for 2015 and 2016, the earliest year that the allocation of the capital additions can be coordinated is in 2017. FEI therefore proposes that in its next Annual Review filing it will adjust its Base Capital starting in 2017 for the amounts to be allocated to Fort Nelson. FEI proposes that this would consist of the actual 2013 Intangible Plant additions of $64 thousand, escalated by the PBR formula. These capital additions will then be forecast as part of Fort Nelson's revenue requirements starting in 2017 in the ordinary course and as appropriate.

7.2.2 Regular Capital Expenditures Forecast Outside the Formula

To calculate total regular capital expenditures, the formula capital expenditures are adjusted to add in pension and OPEB expense, Biomethane and NGT capital expenditures which are forecast outside the formula. These amounts are shown in Table 7-4 below along with a comparison to 2015.

Table 7-4: 2016 Forecast Regular Capital Expenditures ($ millions)

Line No.	Description	2015 Approved	2015 Projected	2016 Forecast
1	Pension/OPEB (Capital Portion)	4.324	4.324	4.075
2	Bio-Methane Upgraders	-	0.786	-
3	Bio-Methane Interconnect	2.897	1.560	1.355
4	NGT Assets	3.390	5.541	6.874
5				
6	Forecast Regular Capex	10.611	12.212	12.304

Each of the items forecast outside of the formula is described further below.

- The forecast Pension and OPEB capital expenditures of $4.075 million represent the forecast capital portion of the total Pension and OPEB costs for 2016. Pension and OPEB costs are described in Section 6.3.1.
- The forecast Biomethane Interconnect capital expenditures of $0.505 million in 2016 are for two Biomethane Supply projects that were approved by the Commission in Order G-210-13: the Lulu Island Wastewater Treatment Plant Project ($0.302 million) and Dicklands Farms Project ($0.203 million). Both projects are forecast to be included in rate base in 2016. The cost of service of these interconnections remains in the delivery margin as clarified in Commission letter L-10-14, dated February 18, 2014 regarding Order No. G-210-13. In addition to these two projects, the forecast capital expenditure of $0.850 million for the City of Surrey Landfill is forecast to be included in rate base in 2016. The cost of service of the City of Surrey Landfill is recovered through the Biomethane Variance Account.
- The forecast NGT Assets capital expenditures of $6.874 million are the forecasts for NGT Fuelling Stations and Tankers (Appendix B, Section 7, Table B-15 amounts of $2.100 million and $4.774 million).

7.2.2.1 CPCN and Special Project Capital Expenditures

Also forecast outside of the formula are any capital expenditures related to approved CPCNs and other projects which are proceeding as a result of an Order in Council. In 2016, FEI is forecasting capital expenditures related to a number of such projects: the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) CPCN, the Tilbury Expansion Project, and the three Coastal Transmission Projects. Although all of these projects have capital expenditures occurring in 2016, none are included in rate base or affect delivery rates in 2016. Each project is discussed below.

The LMIPSU CPCN application was filed with the Commission in December 2014 and the regulatory review process has been completed, with a decision expected before the end of

2015. The LMIPSU is an integrity project to address an increasing number of gas leaks on the Coquitlam IP line and seismic upgrades required to the Fraser Gate IP line, with an expected in-service date at the end of 2018. The estimated capital cost for the LMIPSU CPCN in as-spent dollars, excluding AFUDC and including abandonment/demolition costs, is $241.413 million. In 2015 and 2016, FEI has forecast expenditures of $5.642 million and $28.879 million[34] respectively of this total. This is in addition to $1.647 million of expenditures in 2013 and 2014.

The cost recovery of expenditures associated with the Tilbury Expansion Project are authorized by Direction No. 5 to the BCUC as amended (Orders in Council Nos. 557 and 749). The 2015 and 2016 forecast spending for this project is $177.850 million and $80.565 million[35] respectively. This is in addition to the 2013 and 2014 actual capital spending of $136.253 million. Under the Order in Council, FEI can spend up to $400 million plus construction carrying costs and feasibility and development costs. The project is expected to be completed in 2016 and included in rate base effective January 1, 2017.

The Coastal Transmission Projects for which there will be capital expenditures in 2016 are the Cape Horn to Coquitlam, Nichol to Port Mann and Nicol to Roebuck projects. Cost recovery in rates for these projects is authorized by Direction No. 5 to the BCUC as amended (Orders in Council Nos. 557 and 749). FEI anticipates spending $18.224 million[36] on these projects in 2016 and a total of $162.744 million on all three projects, with an expected in-service date of November 2017.

As part of the Biomethane program, FEI is forecasting capital expenditures of approximately $15 million for a new project with the City of Vancouver Landfill. Of the $15 million, $6.8 million[37] is forecast to be spent in 2016 and the remaining dollars in 2017. This project involves adding an upgrader and interconnection which would enter rate base at the end of 2017.

7.3 *2016 PLANT ADDITIONS*

The 2016 Plant Additions are comprised of FEI's 2016 regular capital expenditures from Section 7.2 above plus the Huntingdon Station CPCN, the change in work in progress which adjusts for capital expenditures for projects such as those listed in Section 7.2 that are in progress at year end, allowance for funds used during construction (AFUDC), and overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Schedule 5 in Section 11.

[34] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 11.
[35] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 14.
[36] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 13.
[37] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 15.

Table 7-5: Reconciliation of Capital Expenditures to Plant Additions

Line No.	Description	$ millions	Source
1	Formula Growth Capex	33.262	Table 7-2
2	Formula Other Capex	112.053	Table 7-3
3	Forecast Capex	12.304	Table 7-4
4	Total Gross Regular Capex	157.619	
5	Formula CIAC	6.515	Table 7-1
6	Total Regular Capex	164.134	
7			
8	Change in Work in Progress	1.386	Section 11, Schedule 5, Line 27
9	Hungtingdon Station Bypass	7.370	
10	AFUDC	1.918	Section 11, Schedule 5, Line 25
11	Capitalized Overhead	32.767	Table 6-1
12	2016 Plant Additions	**207.575**	

The Huntingdon Station CPCN was approved by Order C-6-14 and FEI has forecast spending of $0.300 million[38] in 2016, in addition to the 2014 and 2015 cumulative projected capital expenditures of $7.070 million, including AFUDC, for this project for a total of $7.370 million which compares to a total capital cost of $7.977 million as forecast in the CPCN. This project will be in-service in 2015 and as such, is included in rate base effective January 1, 2016.

7.4 *ACCUMULATED DEPRECIATION*

The rate base of FEI includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation expense, and decreased through retirements.

The depreciation rates used for 2016 are the rates that have been proposed in Section 12.3.2 and set out in Table 12-2. Depreciation is calculated starting January 1 of the year after the assets are placed in service, which is the treatment approved in Commission Order G-138-14.

Based on calculating depreciation expense at these proposed depreciation rates on the opening plant-in-service balance net of CIAC, the 2016 depreciation expense is calculated as $154.735 million[39].

7.5 *DEFERRED CHARGES*

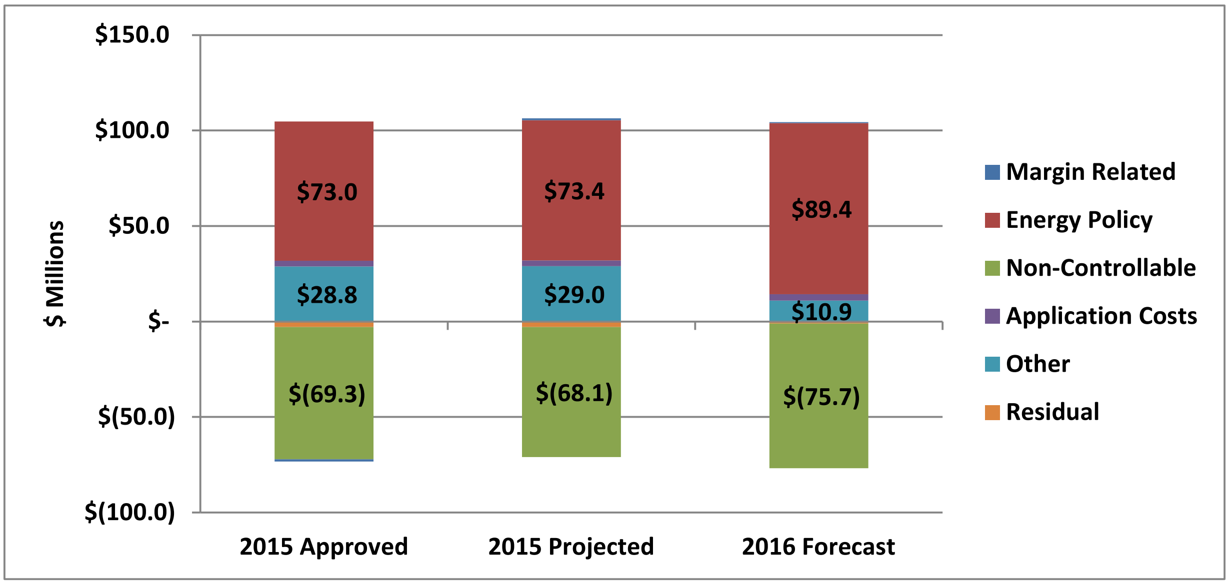
The forecast mid-year balance of unamortized deferred charges in rate base for FEI is $27.577 million in 2016 and this balance is driven largely by the balances in several deferral accounts

[38] As shown in the financial schedules in Section 11, Schedule 5, Line 12.

[39] $163.888 million depreciation expense as calculated in Section 11 Schedule 22, Line 5 less $9.153 amortization of CIAC as calculated in Section 11, Schedule 22, Line 10.

including the Energy Efficiency and Conservation, Gains and Losses on Asset Disposition, Revenue Stabilization Adjustment Mechanism, NGT Incentives, 2011 Customer Service O&M and COS deferral and Whistler Pipeline Conversion deferrals, while partially offset by the net variance between the Pension and OPEB Funding accounts, the Negative Salvage Provision/Cost account, Midstream Cost Reconciliation Account and Customer Service Variance Account. Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

Figure 7-1: FEI Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances using the approved amortization periods, the 2016 amortization expense is calculated as $50.605 million[40]. The section below includes a discussion on any new rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.5.1 New Accounts

FEI is proposing to create three new deferral accounts to address the costs of applications related to the 2015 System Extension review, the BERC Rate Methodology and the Long Term Resource Plan (LTRP).

7.5.1.1 2015 System Extension Application

On June 30, 2015, FEI filed with the Commission the 2015 System Extension Application which contained an evaluation of the Main Extension (MX) Test to ensure that the test remains appropriate for both existing and new customers. As part of the filing and review of this

[40] Total of Section 11, Schedule 11.1, Line 38, Column 6 and Schedule 12, Line 17, Column 6.

Application, FEI expects to incur approximately $325 thousand in costs related to consulting costs, legal fees, intervener and participant funding costs, Commission costs and miscellaneous facilities, stationery and supplies. Therefore, FEI requests approval to capture the costs of the 2015 System Extension Application in this rate base deferral account and to amortize these costs over a two-year period beginning in 2016. Although FEI expects the system extension policies to be in place for longer than two years, there is a minimal rate impact difference between a two-year amortization period and an amortization period longer than two years. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates the following year.

7.5.1.2 BERC Rate Methodology Application

FEI filed an Application in August of 2015 relating to a proposed change to the rate methodology used from calculating the Biomethane Energy Recovery Charge (BERC) rate (the BERC Rate Methodology Application). As part of the filing and review of the BERC Rate Methodology Application, FEI expects to incur approximately $75 thousand in costs related to legal fees, intervener and participant funding costs, Commission costs and miscellaneous facilities, stationery and supplies, but notes the actual amount will be dependent on the process and number of participants. Therefore, FEI requests approval to capture the costs of the the BERC Rate Methodology Application in a rate base deferral account and to amortize the costs over a one-year period in 2016. Given the relatively small amount anticipated for this account, a longer amortization period has minimal impact on the rate impact to customers. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates the following year.

7.5.1.3 2017 Long-Term Resource Plan Application

FEI is seeking a deferral account to capture the costs of external resources required for the 2017 Long Term Resource Plan (LTRP) that are incremental to the costs in FEI's Base O&M for the LTRP. Generally, these incremental costs are required to comply with the Commission directives from the 2010 and 2014 LTRP Decisions to conduct work incremental to that required for prior LTRPs. Costs to meet the incremental requirements directed by the 2010 LTRP Decision were approved in rates for 2012 and 2013 and the related activities were completed for the 2014 LTRP. However, in the PBR Decision (Order G-138-14), the Commission did not allow any of these costs to be included in FEI's Base O&M. Further, in the 2014 LTRP Decision the Commission directed FEI to conduct additional activities and analyses for the 2017 LTRP that were not required for the 2014 LTRP. The additional activities required by the 2014 LTRP Decision were not contemplated at the time the Base O&M was set for the PBR period.

In its Decision on the Annual Review of 2015 Rates for FEI, the Commission agreed that the requirement to complete these incremental LTRP activities would "precipitate additional costs within the PBR period that were not anticipated in the PBR decision,"[41] but indicated that it

[41] Order G-86-15, Decision on the Annual Review of 2015 Delivery Rates for FortisBC Energy Inc., page 26.

required a more detailed review of the expected expenditures prior to approving the deferral account[42]. The Commission set out a list of requirements in order to facilitate this review as set out below:

> *The Panel directs FEI to provide the following specific information in its upcoming annual review application:*
>
> - The total forecast spending for 2016 on preparation of the LTRP;
> - A description of each key activity that FEI intends to undertake in developing the LTRP, and the reasons why these activities are deemed as "incremental" to Base O&M. For each key activity identified, provide the following:
> - Budget amounts for 2016 and project totals, with comparisons to the 2014 LTRP amounts;
> - Breakdowns of internal versus external resource budgets, including the estimated percentage of 2016 spending related to external consultants versus internal staff, with descriptions of the role(s) undertaken by each group, again with comparisons to 2014 experience;
> - The number of hours forecast to be spent by external consultants on the LTRP in 2016 compared to the number of hours forecast to be spent by internal staff; and
> - Whether FEI plans to hire additional permanent employees to perform LTRP-related work, including an estimated number of new employees to be hired for 2016.

FEI has responded to this direction in Appendix C2.

The Commission also indicated at page 27 of its Decision that "it was of the view that costs eligible for deferral account treatment are largely restricted to the use of external resources (i.e. as opposed to those aspects of the filing developed by internal staff)". Consistent with this view, FEI is only proposing to capture in the deferral account the costs of external resources required to carry out the incremental activities for the 2017 LTRP.

The total expenditures for external resources required to carry out the incremental activities for the 2017 LTRP that FEI expects to capture in the requested deferral account are $1.050 million, of which $0.505 million will be incurred in 2016[43]. Details with respect to the nature of the incremental activities, and the role and cost of the external resources required to complete them, are provided in Appendix C2.

[42] Ibid.
[43] As shown in the financial schedules in Section 11, Schedule 11.1, Line 10, Column 4

The estimated timing of the expenditures for the 2017 LTRP as described in Appendix C2 assumes that the Commission approves the deferral account in late 2015. As such, all of the estimated expenditures for incremental activities are expected to occur in 2016 and 2017.

Only those costs that are actually spent will be captured in the deferral account and the amounts for each item will vary based on formal proposals from third-party consultants to assist with this work and the actual final amounts billed by the consultants.

7.6 *WORKING CAPITAL*

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Companies to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Commission Order G-44-12 and updated through Commission Order G-138-14.

Other working capital includes gas in storage, transmission line pack gas, and inventory of materials and supplies, less small amounts for construction advances and refundable contributions.

The main component of other working capital is gas in storage and transmission line pack, which are forecast on a 13-month average basis using the approved costs embedded in the 2015 Q2 gas cost report and historical volumes. Materials and supplies, construction advances and refundable contributions are forecast based on 2015 levels.

7.7 *SUMMARY*

FEI's rate base includes the impact of both formula-driven capital expenditures and those capital expenditures that are forecast outside of the formula and CPCNs, adjusted for work-in-progress, AFUDC and overheads capitalized. In addition, FEI has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11, and discussed new accounts in this section of the Application. Finally, the rate base includes other working capital, composed of gas in storage and other smaller components that have been forecast consistently with prior years.

8. FINANCING AND RETURN ON EQUITY

8.1 INTRODUCTION AND OVERVIEW

FEI has prepared this Application using the 2015 benchmark capital structure of 61.5 percent debt and 38.5 percent equity and Return on Equity (ROE) of 8.75 percent as approved by Order G-75-13. FEI will file its evidence on its capital structure and ROE for 2016 no later than November 30, 2015 as directed by the Commission. When a decision is reached on that application, FEI will update its rate calculations once the final approved amounts have been determined. The 2016 forecast for financing costs, including the interest expense on issued long and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FEI's AFUDC Rate for 2016 (which is equal to its after-tax weighted average cost of capital) is 5.98 percent. Variances in the interest expense recovered in rates will be recorded in the Flow-through deferral account for return to or recovery from customers in the following year.

8.2 CAPITAL STRUCTURE AND RETURN ON EQUITY

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the Commission from time to time. Pursuant to Order G-75-13, the Commission has approved a benchmark capital structure of 61.5 percent debt and 38.5 percent equity with an allowed ROE of 8.75 percent, effective January 1, 2013 until December 31, 2015, with an Automatic Adjustment Mechanism (AAM) in place.

The AAM was not triggered for 2014 or 2015, such that the ROE remained as approved in Order G-75-13. FEI has therefore prepared this Application using an ROE of 8.75 percent and a common equity percentage of 38.5 percent. As part of Order G-75-13, the Commission directed FEI to file a cost of capital application no later than November 2015, for determination of cost of capital for periods beyond December 31, 2015. The outcome of this proceeding will be reflected in rates once determined and effective January 1, 2016.

8.3 FINANCING COSTS

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long-term debt and short-term (unfunded) debt.

8.3.1 Long-Term Debt

FEI is a public issuer of long-term debt. During April 2015, FEI issued long-term debt of $150 million at a rate of 3.375 percent for a term of 30 years. The proceeds of the issue were used to repay existing short-term indebtedness and to refinance a $75 million Purchase Money Mortgage (PMM) maturing on September 30, 2015. In 2016, FEI plans to issue long-term debt of $350 million, $200 million of which will be to refinance a $200 million PMM[44] with a coupon rate of 10.3 percent maturing on September 30, 2016. The remaining $150 million will be used to finance growing rate base. The debt issuances are reflected in the financial schedules in January 2016 in the amount of $150 million and September 2016 in the amount of $200 million, both at a rate of 4.5 percent. The exact timing, amount and rate of the issuances will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through Variance account.

8.3.2 Short-Term Debt

FEI obtains short term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the commercial paper by maintaining a $700 million committed credit facility that currently matures in August 2018. The credit facility provides FEI with required liquidity should there be constraints issuing debt to fund FEI's capital program and working capital requirements.

8.3.3 Forecast of Interest Rates

FEI uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FEI are maintained. FEI currently expects to issue long term debt in 2016 for the repayment of maturing debt as well as other capital requirements. The estimated issue rate for 2016 is approximately 4.5 percent based on a 30 year GOC rate of 2.83 percent and an indicative spread of 1.64 percent.

FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FEI under its commercial paper program. CDOR is used because FEI's short-term borrowings under its credit facility are priced off of CDOR and so CDOR is tracked relative to FEI's commercial paper borrowings. CDOR is not forecast by economists either; therefore, FEI must first obtain the 3-Month T-Bill rate forecast then convert it to a CDOR forecast. FEI does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. To then derive the short-term borrowing rate forecast, FEI further adjusts the CDOR forecast with the 3-year historical spread between CDOR and rates of issuances under its commercial paper program.

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[44] Only $157 million of which is financing FEI's rate base in 2016 as the remainder finances the non-rate base Lower Mainland Acquisition Premium.

The 3-month T-Bill rate is projected to increase from 0.54 percent in 2015 to approximately 0.70 percent in 2016. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast[45]

	2015	2016
3-month T-BILLS[1]	0.54%	0.70%
Spread to CDOR	0.31%	0.31%
CDOR	0.85%	1.01%
Spread to CP	-0.22%	-0.22%
CP Dealer Comission	0.10%	0.10%
Standby Fee on undrawn Credit[2]	0.25%	0.30%
FEI Short-term Rate (Rounded)	**1.00%**	**1.25%**

Note 1 - 3 month T-Bill rate for 2015 based on a composite of actual historical rates as at June 30, 2015 and forecasted rates for the remainder of the year.

Note 2 - Amounts undrawn on the credit facility are subject to a Standby Fee, which is estimated to be 16 bps in 2015 and beyond. The Standby Fee as shown reflects the amount payable had it been converted to a rate applied to the Commercial Paper borrowings and has been shown as such to develop an all-in Short-Term Rate.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FEI's existing and forecast borrowing costs on long-term debt and short-term debt.

The calculation for short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the effective interest method. For each long-term debt issue, the effective rate (forecast effective rate if it is a new issue) is multiplied by the average balance of that long-term debt for the year. The 2016 long-term debt schedule for FEI can be found in Section 11, Schedule 27.

FEI's Flow-through Variance account captures the variances in interest expense for return to or recovery from customers in the following year.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

Based on the above information, FEI's AFUDC Rate for 2016 (which is equal to its after-tax weighted average cost of capital) is 5.98 percent. The calculation of the rate is shown in the following table.

FEI applies AFUDC to projects that are greater than 3 months in duration and greater than $100 thousand. Based on these criteria, the calculation of AFUDC for 2016 is as follows.

[45] The 2015 short term rate is projected and compares to the 2015 approved short term rate for FEI which was 1.40%.

Table 8-2: Calculation of AFUDC Rate for 2016

	Weight	Pre Tax Rate	After Tax Rate
Short Term Debt	3.38%	1.25%	0.93%
Long Term Debt	58.12%	6.01%	4.45%
Common Equity	38.50%	11.82%	8.75%
Weighted Average	100.00%	8.09%	5.98%

8.4 SUMMARY

FEI's capital structure and ROE have been forecast for 2016 at the same percentages as approved for 2015 and will be updated once a decision is reached on the 2016 capital structure and ROE. FEI's financing costs on rate base are primarily determined by embedded rates on long-term debt, with one maturity forecast to be refinanced at a lower rate in 2016, and short-term debt rates remaining stable.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FEI's forecasts of property taxes and income tax which have been forecast on a consistent basis with prior years. In 2016 property taxes are forecast to increase 3.3 percent from 2015 Approved, while Income tax is forecast to decrease by $0.956 million or 2.0 percent compared to 2015 Approved. Any variances from the forecast of property taxes and income tax included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.2 PROPERTY TAXES

Property taxes for 2016 of $63.043 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from gas consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Tax Forecasts ($ millions)

Asset Type	Approved 2015	Projected 2015	Forecast 2016
Distribution Assets	$ 23.113	$ 22.759	$ 23.667
Transmission Assets	17.289	17.265	17.616
Gas Storage Assets	3.422	3.756	4.422
Manufactured Gas Assets	0.028	0.030	0.029
General Assets	3.403	3.432	3.493
In-Lieu	13.465	13.132	13.522
OGC Fees	0.295	0.289	0.294
Total Property Taxes	$ 61.015	$ 60.663	$ 63.043
Forecast Change from 2015 Approved			3.3%
Forecast Change from 2015 Projected			3.9%

As shown in the table above, in 2016 property taxes are forecast to increase by 3.3 percent from 2015 Approved and increase 3.9 percent compared to 2015 Projected. In general, the increase from 2015 Projected is due to construction activities, market value increases and changes in tax policies of local taxing authorities. The most significant forecast drivers of the changes are as follows:

1. ***Changes in_Tax Rates***. Tax Rates are based on FEI's average annual change in the tax rate applicable to FEI since 2010. On average:

    a. Municipal rates are expected to increase by 1.71 percent in the Lower Mainland, 0.35 percent in the Interior, and decrease 0.27 percent on Vancouver Island;

   b. School rates are expected to decrease by 1.21 percent;

   c. Other rates are expected to decrease by 0.29 percent in the Lower Mainland, increase 2.09 percent in the Interior and 2.47 percent on Vancouver Island.

2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 3.67 percent in the Lower Mainland, 7.86 percent in the Interior and decrease by 3.91 percent on Vancouver Island based on actual revenues to be reported. As grants in-lieu of taxes are based on a fixed percentage of revenues, the overall increase in revenues reported to municipalities increases the grants in-lieu of taxes due.

3. ***Changes in Assessed Values***. Forecast changes in the assessed values of FEI's property are based on the increases that BC Assessment was proposing at the time the forecast was developed. These include:

   a. A 4.25 percent increase in assessed values of distribution lines and services;

   b. A 2 percent increase in assessed values of transmission lines;

   c. A 1.3 percent increase in assessed values for LNG assets; and

   d. Land value changes which are expected to range from a 1.69 percent decrease in the assessed value for right of ways to a 2 percent increase in the market value for properties owned in fee simple.

Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.3 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with Commission approved past practice, at the corporate tax rate of 26 percent for 2016, which is unchanged from 2015. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and will be updated each year as part of the annual rate setting process.

Income tax for 2016 is forecast to decrease by $0.956 million or 2.0 percent compared to 2015 Approved. This decrease is primarily due to an increase in capital cost allowance deductions in 2016.

Any variances from the forecast of income taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.4 *LIQUEFIED NATURAL GAS (LNG) INCOME TAX*

On October 21, 2014, the provincial government of BC introduced an LNG income tax on net income from LNG facilities in BC. The new LNG income tax will apply to income from liquefaction activities at, or in respect of, LNG facilities in BC, for taxation years beginning on or after January 1, 2017.

The new LNG income tax is a two-tier tax that applies a minimum 1.5 percent tax on LNG facilities' profits before recovery of capital investment costs and a 3.5 percent tax on LNG facilities' profits once payback is achieved (which increases to 5 per cent in 2037 and thereafter). The new tax will apply to income earned at the existing Tilbury Facility, the Tilbury Expansion scheduled to go into service in 2016 and the Mt. Hayes LNG Facility on Vancouver Island.

Along with the LNG income tax legislation, the provincial government has also provided an LNG income tax credit against the current 11% BC corporate income tax. This BC corporate income tax credit is effectively equal to the lesser of (i) 3 percent of the cost of gas owned and liquefied by the taxpayer at the LNG facility and (ii) the BC corporate income tax payable by the taxpayer from all sources (not just LNG income), but cannot be greater than the amount that would reduce the effective BC corporate income tax rate to 8 percent.

It is expected that the new LNG income tax, net of any related corporate income tax credits, will be included in FEI's 2017 income tax expense calculations in the next Annual Review.

9.5 *SUMMARY*

FEI has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes in property tax rates and assessments.

10. EARNINGS SHARING AND RATE RIDERS

10.1 EARNINGS SHARING

The PBR Decision (at page 124) stated that the inclusion of symmetric earnings sharing is beneficial to both FEI and its customers and approved an earnings sharing mechanism where gains and losses are shared equally between FEI and customers. As described below, FEI proposes to distribute $4.846 million in earnings sharing to customers as a reduction in 2016 revenue requirements. This amount is then adjusted for the earned return variance for 2014 capital expenditures of $0.094 million, and the difference between the 2014 projected and actual earnings sharing of $0.316 million, for a total earnings sharing distribution in 2016 of $5.068 million.

As set out in FEI's letter dated November 7, 2014 in response to Order G-162-14 and as approved by Order G-86-15 for FEI's Annual Review for 2015 Delivery Rates, the earnings sharing is calculated each year as one-half of the pre-tax earnings impact of the variances in the formula-driven gross O&M and cumulative capital expenditures, as follows:

> Formula-driven O&M less actual base O&M[46] x 50% +
>
> ((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[47]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

As discussed in Section 1.4, FEI is projecting 2015 formula-driven O&M savings at $10.21 million, and 2015 capital expenditures in excess of the formula by $6.816 million[48].

In addition, as set out in Order G-15-15 in relation to formula capital expenditures, *"FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. This positive or negative variance in earned return resulting from the Growth Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism."* FEI has calculated the resulting adjustment for 2014 as shown in Table 10-1 below based on its actual customer additions, and has included the amount in the earnings sharing calculation as shown in line 41 of Table 10-2 below.

[46] Excluding items that are reforecast outside of the formula.
[47] Ibid.
[48] $11.394 million cumulative capital expenditure variance.

Table 10-1: Calculation of Earnings Sharing Adjustment for Actual Customer Growth

Line No.	Particulars		$ millions	Reference
1	Average Customers 2014		851,341	
2	Average Customers 2013		841,175	
3	Growth in Average Customers		10,166	Line 1 - Line 2
4	Average Customer Growth		1.209%	Line 3 / Line 2
5			50%	G-138-14
6	Average Customer Growth to be recast in Formula		0.604%	Line 4 x Line 5
7	Net Inflation Factor		0.360%	G-138-14
8	2013 Sustainment/Other Capital Base	$	99.243	G-138-14
9	2014 Reforecast Formulaic Sustainment/Other Capital	$	100.202	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2014 Year Formulaic Sustainment/Other Capital		99.859	G-138-14
11	Sustainment/Other Capital Increase from actual growth	$	0.343	Line 9 - Line 10
12				
13				
14	Service Line Additions 2014		8,472	
15	Service Line Additions 2013		7,133	
16	Growth in Average Customers		1,339	Line 14 - Line 15
17	Average Customer Growth		18.77%	Line 16 / Line 15
18			50%	G-138-14
19	Average Customer Growth used in Formula		9.39%	Line 18 x Line 17
20	Service Line Additions 2013 Base		7,989	G-138-14
21	2014 ReForecast Service Line Additions		8,739	Line 20 x (1 + Line 19)
22	Service Line Addition Cost per Customer ($)		2,749	G-138-14
23	2014 Reforecast Formulaic Growth Capital	$	24.023	Line 21 x Line 22 / 1000000
24	2014 Formulaic Growth Capital		21.809	G-138-14
25	Growth Capital Increase from actual growth	$	2.214	Line 23 - Line 24
26				
27				
28	Increase in Capital Requirements from Actual Growth	$	2.557	Line 11 + Line 25
29	Mid Year	$	1.279	Line 28 / 2
30				
31	Equity Cost Component		3.37%	G-138-14
32	Debt Cost Component		3.97%	G-138-14
33	Earned Return on incremental Capital Requirerments	$	0.094	Line 29 x (Line 31 + Line 32)

Finally, FEI has calculated its final 2014 earnings sharing adjustment based on the results included in its 2014 Annual Report to the Commission. The final amount of earnings sharing for 2014 was $3.657 million, which was $0.316 million higher than the $3.341 million projected for 2014.

The earnings sharing calculation including all the components discussed is projected at $5.068 million, calculated as set out in Table 10-2 below.

Table 10-2: Calculation of Earnings Sharing to be Returned in 2016 ($000s)

Line No.	Particulars	$ millions	Reference
1	Approved Formula O&M	235.620	G-138-14
2			
3	Actual/Projected Gross O&M	258.852	
4	Less: O&M Tracked outside of Formula		
5	Pension/OPEB (O&M portion)	25.699	
6	Insurance	6.185	
7	Net Bio-Methane	0.042	
8	NGT O&M	0.836	
9	RS 16/46 O&M	0.680	
10	Total	33.442	Sum of Lines 5 through 9
11			
12	Actual/Projected Base O&M	225.410	Line 3 - Line 10
13			
14	O&M Subject to Sharing	(10.210)	Line 12 - Line 1
15			
16			
17	Cumulative Formula CapEx	261.048	G-138-14
18			
19	Cumulative Total Regular CapEx	301.809	
20	Less: CapEx tracked outside of Fformula		
21	Cumulative Pension and OPEB	6.392	
22	Cumulative NGT	11.357	
23	Cumulative Bio-Methane	6.002	
24	Cumulative Gateway CIAC Receivable	0.389	
25	Cumulative AFUDC	5.227	
26		29.367	Sum of Lines 21 through 25
27			
28	Actual/Projected Cumulative Base CapEx	272.442	Line 19 - Line 26
29			
30	Actual/Projected Cumulative Base CapEx Variance	11.394	Line 28 - Line 17
31	Equity Component of Rate Base	38.50%	G-75-13
32	Approved Return on Equity	8.75%	G-75-13
33	After Tax CapEx Subject to Sharing	0.384	Product of Lines 30, 31 & 32
34	Tax Rate	26%	G-138-14
35			
36	Before Tax CapEx Subject to Sharing	0.519	Line 33 / (1 - Line 34)
37			
38	Total before tax Sharing Amount	(9.691)	Line 14 + Line 36
39	Sharing percentage	50%	G-138-14
40	Earnings Sharing before adjustments	(4.846)	Line 38 x Line 39
41	Actual Customer Growth Adjustment	0.094	Tables 10-1, Line 33
42	2015 Earnings Sharing	**(4.752)**	
43			
44	2014 Pre-Tax Earnings Sharing True-Up	(0.316)	
45	2016 Pre-tax Amortization	(5.068)	
46	2016 After-tax Amortization	(3.750)	Schedule 12, Line 9, Column 6

FEI proposes to distribute $5.068 million to customers in 2016 as a reduction in 2016 revenue requirements through amortization of the projected 2016 opening after-tax balance of $3.750 million in the Earnings Sharing deferral account.

As part of the Annual Review for 2017 delivery rates, the earnings sharing for 2015 will be subject to a true-up. This true-up will account for the actual O&M and capital expenditure amounts for 2015, as well as impacts, if any, associated with non-performance of Service Quality Metrics, based on final 2015 results.

10.2 RATE RIDERS

There are three delivery rate riders that are set each year through the annual review process. These are the RSDA Rate Riders, the Phase-In Rate Riders, and the RSAM Rate Riders. Each of these is discussed separately below.

10.2.1 RSDA Rate Riders

The RSDA Rate Riders distribute the ending 2014 Vancouver Island RSDA balance to Mainland customers. In Order G-78-14, the Commission approved the 2015 RSDA Rate Riders based on the projected 2014 RSDA balance (including the projected Gas Cost Variance Account or GCVA balance) and the 2015 preliminary forecast demand for the Mainland service area. As stated by FEI at the time of filing for approval of the RSDA Rate Riders: “The differences that arise between the forecast RSDA balance and the final 2014 RSDA and GCVA balances, as well as the differences that result from the actual volumes varying from the forecast set out in this filing, will be included in the calculation of the 2016 RSDA Rate Riders and, in this way, will be returned to or collected from customers.”[49]

FEI provides below a summary of the currently projected 2015 ending balance in the RSDA. This includes a comparison of the actual 2014 ending balance to the projected 2014 ending balance, and a comparison of the currently projected 2015 demand for the Mainland service area to the demand that was used to determine the 2015 rate rider.

The 2014 RSDA balance was originally forecast to be $93.472 million before tax. The actual balance was $99.227 million. A comparison of each of the components is included in Table 10-3 below.

Table 10-3: 2014 RSDA Balance ($000s)

RSDA Reconciliation for Rider	2014 Forecast	2014 Actual
Closing RSDA Balance, before Tax	(100,708)	(105,426)
Less: GCVA balance	5,455	4,418
Less: FEI 2014 Deficiency	1,781	1,781
Closing RSDA Balance, before Tax for RSDA Rider	(93,472)	(99,227)

FEI calculated the 2015 rate riders based on the preliminary forecast demand for the Mainland service area of 162,546.3 TJs. The current forecast for 2015 demand for the Mainland service

[49] Application for 2015 Common Delivery Rates and Delivery Rate Riders, dated October 31, 2014, p. 9.

area is 158,847.2 TJs. Based on this updated forecast, FEI projects the 2015 ending balance in the RSDA to be $61.442 million. Table 10-4 below shows the projected and forecast continuity of the RSDA and its disposition through 2015 and 2016.

Table 10-4: 2015 and 2016 RSDA Balances ($000s)

RSDA Continuity	2015	2016	Notes/ Reference
Opening Balance	$ (99,227)	$ (61,442)	
Projected Disposition through Rider (before interest is added)	38,902	43,009	1, 2
Net	$ (60,325)	$ (18,433)	
Interest	(1,117)	(499)	3
Closing Balance	$ (61,442)	$ (18,932)	
Total Amount to be disbursed through Rider		$ 43,509	4

Table Notes:

1. $38,902 is based on 2015 Approved Riders by Rate Schedule multiplied by the latest 2015 Projected Volume by Rate Schedule
2. $43,009 = 42% / (42% + 18%) x $61,442
3. Interest Rate for 2015 and 2016 equals 1.40% and 1.25% respectively
4. $43,509 = $43,009 + $499

Based on the current projected 2015 ending balance of the RSDA, the 2016 forecast demand for the Mainland service area, and returning 42% of the 2014 ending balance to customers in 2016 as approved by Order G-131-14, the 2016 RSDA Rate Riders by rate schedule are shown in Table 10-5 below.

Table 10-5: 2016 RSDA Riders

	2016 RSDA ($000s)	2016 RSDA Interest ($000s)	Total ($000s)	2016 Volume	2016 RSDA Rider ($/GJ)
Rate 1/1B/1U/1X	$ (25,939)	$ (301)	$ (26,240)	67,695	$ (0.388)
Rate 2/2B/2U/2X	(6,740)	(78)	(6,818)	24,854	$ (0.274)
Rate 3/3B/3U/23/3X	(5,535)	(64)	(5,600)	24,403	$ (0.229)
Rate 4 (off-peak)	(22)	(0)	(22)	130	$ (0.167)
Rate 4 (extension)	-	-	-		$ (0.167)
Rate 5/5B/25	(2,288)	(27)	(2,315)	14,622	$ (0.158)
Rate 6/26	(17)	(0)	(17)	44	$ (0.398)
Rate 6A	-	-	-		$ (0.398)
Rate 6P	-	-	-		$ (0.398)
Rate 7/27	(628)	(7)	(635)	6,529	$ (0.097)
Rate 22	(968)	(11)	(979)	11,441	$ (0.086)
Rate 22A: Firm MTQ	(667)	(8)	(674)	9,030	$ (0.075)
Rate 22A: Interruptible MTQ	-	-	-		$ (0.075)
Rate 22B: Elkview Coal - Firm MTQ	(163)	(2)	(165)	1,744	$ (0.095)
Rate 22B: Elkview Coal - Interruptible MTQ - Apr. 1 to Nov. 1	-	-	-		$ (0.095)
Rate 22B: Elkview Coal - Interruptible MTQ - Nov. 1 to Apr.1	-	-	-		$ (0.095)
Rate 22B: Columbia except Elkview - Firm MTQ	(43)	(0)	(44)	779	$ (0.056)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Apr. 1 to Nc	-	-	-		$ (0.056)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Nov. 1 to Ap	-	-	-		$ (0.056)
Total of Rate 22	(1,841)	(21)	(1,862)	22,994.5	
Grand Total	**$ (43,009)**	**$ (499)**	**$ (43,509)**	**161,270.4**	

As approved by the Commission, the 2016 RSDA Rate Riders are applicable to Mainland customers only.

10.2.2 Phase-In Rate Riders

The Phase-in Rate Riders are designed to phase-in the rate decrease to Vancouver Island and Whistler customers, and the offsetting rate increase for Mainland customers, due to amalgamation of the utilities, allowing all customers to have the same underlying delivery rate. The amount of the riders will decrease over the three years 2015 through 2017 and be eliminated by 2018. In Order G-178-14, the Commission approved the 2015 Phase-in Rate Riders.

The Phase-in Rate Riders collected from Vancouver Island and Whistler customers are calculated to offset the rate reduction due to the implementation of common rates by 40% for Rate Schedule 1 and Rate Schedule 2 customers, 25% for Rate Schedule 3 customers, 30% for Rate Schedule 5 and 25 FEVI customers and 25% for Rate Schedule 5 and 25 FEW customers.[50] The Phase-in Rate Rider for Mainland customers is then designed to distribute to Mainland customers the amount forecast to be collected from Vancouver Island and Whistler customers. Two adjustments must be made to the Phase-in Rate Riders, as explained below.

First, the 2015 projected volume variance (or imbalance) in the Phase-in Rider Balancing Account must be accounted for when setting the 2016 Mainland Phase-in Riders. The variance

[50] These are the percentages for 2016 approved through Commission Order G-131-14.

in this account is the difference between the projected amount collected from Vancouver Island and Whistler customers less the projected disbursement to Mainland customers. The difference, or imbalance, is then added to the Mainland disbursement rider (and not the Vancouver Island and Whistler collection rider) because the intention is to phase-in Vancouver Island and Whistler customers with the resulting amount collected being distributed to Mainland customers.

The amount of the rate rider for 2016 collected from Vancouver Island and Whistler customers, including the 2015 imbalance in the Phase-in Rider Balancing Account, is shown in Table 10-6 below.

Table 10-6: 2016 Rate Rider Collected from Vancouver Island and Whistler Customers Excluding Amalgamation Costs

			2016		
	Difference ($/GJ)	Phase-In %	($/GJ)	(TJ)	thousand)
FEVI RS1/1B	$ 4.12	40%	$ 1.648	4,559.1	$ 7,513
FEW RS1/1B	$ 7.86	40%	$ 3.146	212.4	$ 668
FEVI RS2/2B	$ 4.69	40%	$ 1.876	3,023.3	$ 5,672
FEW RS2/2B	$ 8.67	40%	$ 3.468	135.1	$ 469
FEVI RS3/3B/23	$ 3.48	25%	$ 0.869	2,402.2	$ 2,088
FEW RS3/3B/23	$ 9.23	25%	$ 2.307	284.7	$ 657
FEVI RS4 (off-peak)*			$ 0.869	-	$ -
FEVI RS4 (extension)*			$ 0.869	-	$ -
FEW RS4 (off-peak)*			$ 2.307	-	$ -
FEW RS4 (extension)*			$ 2.307	-	$ -
FEVI RS5/5B/25	$ 5.03	30%	$ 1.510	1,062.5	$ 1,604
FEW RS5/5B/25	$ 9.23	25%	$ 2.307	34.7	$ 80
FEVI RS6/26*			$ 0.869	-	$ -
FEW RS6/26*			$ 2.307	-	$ -
FEVI RS7/27	$ 3.48	25%	$ 0.869	162.9	$ 142
FEW RS7/27*			$ 2.307		$ -
FEVI R22*			$ 0.869	-	$ -
FEW R22*			$ 2.307	-	$ -
Total				11,876.9	$ 18,892

Phase-In Rider Imbalance	2015	
Opening Phase-In Rider Balancing Account	$ -	
Projected collections from Vancouver Island & Whistler	28,240	
Projected disbursements to Mainland	(29,674)	
Projected imbalance as adjustment to Mainland disbursement		$ (1,434)
2016 Disbursement to Mainland Customers		$ 17,458

**There are no 2016 forecasted volumes for these rate classes, therefore rate riders from FEVI and FEW Rate Schedule 3 have been assigned.*

These 2016 collections and 2015 volume variance result in the following Phase-in Rate Riders for Mainland customers in 2016.

Table 10-7: Phase-in Rate Rider Calculation for Mainland Customers

	Allocation		2016	
	%	% thousands	Volume (TJ)	Rider ($/GJ)
Rate 1/1B/1U/1X	60.3%	$ (10,529)	67,694.7	$ (0.156)
Rate 2/2B/2U/2X	15.7%	$ (2,736)	24,853.9	$ (0.110)
Rate 3/3B/3U/23/3X	12.9%	$ (2,247)	24,403.2	$ (0.092)
Rate 4 (off-peak)	0.1%	$ (9)	130.0	$ (0.067)
Rate 4 (extension)	0.0%			$ (0.067)
Rate 5/5B/25	5.3%	$ (929)	14,621.8	$ (0.064)
Rate 6/26	0.0%	$ (7)	43.7	$ (0.160)
Rate 6A	0.0%			$ (0.160)
Rate 6P	0.0%			$ (0.160)
Rate 7/27	1.5%	$ (255)	6,528.6	$ (0.039)
Rate 22	2.3%	$ (393)	11,441.2	$ (0.034)
Rate 22A: Firm MTQ	1.6%	$ (271)	9,029.8	$ (0.030)
Rate 22A: Interruptible MTQ	0.0%			$ (0.030)
Rate 22B: Elkview Coal - Firm MTQ	0.4%	$ (66)	1,744.4	$ (0.038)
Rate 22B: Elkview Coal - Interruptible MTQ - Apr. 1 to Nov. 1	0.0%			$ (0.038)
Rate 22B: Elkview Coal - Interruptible MTQ - Nov. 1 to Apr.1	0.0%			$ (0.038)
Rate 22B: Columbia except Elkview - Firm MTQ	0.1%	$ (17)	779.1	$ (0.022)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Apr. 1 to Nov. 1	0.0%			$ (0.022)
Rate 22B: Columbia except Elkview - Interruptible MTQ - Nov. 1 to Apr.1	0.0%			$ (0.022)
Total of Rate 22	4.3%	$ (747)	22,994.5	
Grand Total	100.0%	$ (17,458)	161,270.4	

Second, the Phase-In Rate Rider must be adjusted to recover the costs of amalgamation and the balance in the Amalgamation Regulatory account, which is approved for recovery over three years. The Amalgamation Regulatory Account includes approximately $1.9 million of amalgamation costs plus interest, with a projected 2015 after-tax closing balance in this account of $0.961 million. The difference between the actual and 2015 Projected or 2016 Forecast volumes, will be returned to or recovered from customers in the calculation of the 2017 rider amount.

Table 10-8 below adds 2016 additions (interest) to the 2016 opening balance (pre-tax) and divides the sum by two years (remaining phase-in years). This result is then divided by 2016 forecast volume to calculate the 2016 Amalgamation Cost Component of the Vancouver Island and Whistler Phase-In Riders.

1 **Table 10-8: Amalgamation Cost Component of Phase-In Rider ($000s)**

2016 Opening Balance Amalgamation Regulatory Account after-tax	$ 961.3
Tax Rate	26%
2016 Opening Balance Amalgamation Regulatory Account pre-tax	$ 1,299.0
2016 Projected Interest Costs	12.0
Total	$ 1,311.0
Amount to be recovered in 2016 ($1,311.0 / 2)	655.5
2016 Forecast Volume for Vancouver Island and Whistler (TJ)	11,876.9
2016 Amalgamation Cost Component of Phase-In Rider ($/GJ)	$ 0.055

2

3

4 Finally, to determine the 2016 Phase-in rider for Vancouver Island and Whistler customers, the 5 amounts from Table 10-6 above need to be increased by the revised Amalgamation Cost 6 Component calculated in Table 10-8. The table below shows the Phase-in Riders including this 7 amount.

8 **Table 10-9: Phase-in Rate Rider Calculation for Vancouver Island and Whistler Customers**
9 **including Amalgamation Costs**

	Phase In Rate Rider ($/GJ)	Amalgamation Cost Component of Phase-In Rider ($/GJ)	Total Rider ($/GJ)	Volume (TJ)	Total ($ thousand)
FEVI RS1/1B	$ 1.648	$ 0.055	$ 1.703	4,559.1	$ 7,765
FEW RS1/1B	$ 3.146	$ 0.055	$ 3.201	212.4	$ 680
FEVI RS2/2B	$ 1.876	$ 0.055	$ 1.931	3,023.3	$ 5,839
FEW RS2/2B	$ 3.468	$ 0.055	$ 3.523	135.1	$ 476
FEVI RS3/3B/23	$ 0.869	$ 0.055	$ 0.924	2,402.2	$ 2,220
FEW RS3/3B/23	$ 2.307	$ 0.055	$ 2.362	284.7	$ 672
FEVI RS4 (off-peak)*	$ 0.869	$ 0.055	$ 0.924		
FEVI RS4 (extension)*	$ 0.869	$ 0.055	$ 0.924		
FEW RS4 (off-peak)*	$ 2.307	$ 0.055	$ 2.362		
FEW RS4 (extension)*	$ 2.307	$ 0.055	$ 2.362		
FEVI RS5/5B/25	$ 1.510	$ 0.055	$ 1.565	1,062.5	$ 1,663
FEW RS5/5B/25	$ 2.307	$ 0.055	$ 2.362	34.7	$ 82
FEVI RS6/26*	$ 0.869	$ 0.055	$ 0.924		
FEW RS6/26*	$ 2.307	$ 0.055	$ 2.362		
FEVI RS7/27	$ 0.869	$ 0.055	$ 0.924	162.9	$ 151
FEW RS7/27*	$ 2.307	$ 0.055	$ 2.362		
FEVI R22*	$ 0.869	$ 0.055	$ 0.924		
FEW R22*	$ 2.307	$ 0.055	$ 2.362		
Total				11,876.9	$ 19,548

**There are no 2016 forecasted volumes for these rate classes, therefore rate riders from FEVI and FEW Rate Schedule 3 have been assigned.*

10

10.2.3 RSAM Rate Riders

The RSAM Rate Riders collect one-half of the previous year's projected RSAM balance from Rate Schedule 1, 2, 3, and 23 customers. The projected balance in the RSAM account at the end of 2015 is a debit of $36.2 million. The calculation of the 2016 RSAM riders is shown in Table 10-10.

Table 10-10: 2016 RSAM Riders

2015 RSAM + Interest Closing Balance ($000)	36,191
Amortization Period (years)	2
2016 Amortization post-tax ($000)	18,096
Tax Rate	26%
2016 Amortization pre-tax ($000)	24,453

RSAM (Rider 5) Calculation			
Rate Class	**RSAM Amortization ($000)**	**2016 Volume (TJ)**	**Rider ($/GJ)**
Rate 1/1B/1U/1X		72,466.3	0.192
Rate 2/2B/2U/2X		28,012.3	0.192
Rate 3/3B/3U/3X		18,121.1	0.192
Rate 23		8,969.0	0.192
	24,453	127,568.7	0.192

The differences that result from the actual 2015 ending RSAM balance varying from the projection, and the actual 2016 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2017 RSAM Rate Riders and, in this way, refunded to or collected from customers.

10.3 *SUMMARY*

FEI has calculated the amount of earnings sharing to be returned to customers in 2016 in compliance with the approved mechanism, including an estimate for 2015, a true-up for 2014, and an adjustment for the impact of actual customer additions on growth capital. In addition, FEI has updated all of the 2016 delivery rate riders for 2015 projected ending balances and 2016 forecast volumes.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Non Reg Plant Continuity Schedule	8
Contributions In Aid Of Construction Continuity Schedule	9
Negative Salvage Continuity Schedule	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Deferred Income Tax Liability / Asset	15
Revenue Requirement	
Utility Income And Earned Return	16
Cost Of Energy	17
Volume And Revenue	18
Margin And Revenue At Existing And Revised Rates	19
Other Revenue	20
Operating And Maintenance Expense	21
Depreciation And Amortization Expense	22
Property And Sundry Taxes	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2016
($000,000s)

Line No.	Particulars	2016 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ 0.881		
3	Change in Other Revenue	(0.859)	$ 0.022	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	2.218		
7	Capitalized Overhead Change	(0.310)	1.908	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation Rate Change (Depr Study)	(6.921)		
11	Depreciation from Net Additions	6.847	(0.074)	
12				
13	**AMORTIZATION EXPENSE**			
14	CIAC Rate Change (Depr Study)	1.832		
15	CIAC from Net Additions	(0.389)		
16	Negative Salvage Rate Change (Depr Study)	10.060		
17	Deferrals	3.922	15.425	
18				
19	**FINANCING AND RETURN ON EQUITY**			
20	Financing Rate Changes	(9.627)		
21	Financing Ratio Changes	5.799		
22	Rate Base Growth	2.149	(1.679)	
23				
24	**TAX EXPENSE**			
25	Property and Other Taxes	2.028		
26	Other Income Taxes Changes	(0.956)	1.072	
27				
28				
29	Revenue Deficiency (Surplus)		$ 16.674	Schedule 16, Line 12, Column 4
30				
31	Margin @ Existing Rates		751.856	Schedule 16, Line 16, Column 3
32	Rate Change		2.22%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 5,356,070	$ 5,517,458	$ 161,388	Schedule 6.2, Line 39, Column 3
2	Opening Balance Adjustment	-	-	-	
3	Net Additions	160,638	154,672	(5,966)	Schedule 6.2, Line 39, Column 4+5+6
4	Plant in Service, Ending	5,516,708	5,672,130	155,422	
5					
6	Accumulated Depreciation Beginning	$ (1,565,971)	$ (1,691,556)	$ (125,585)	Schedule 7.2, Line 39, Column 5
7	Opening Balance Adjustment	-	-	-	
8	Net Additions	(125,576)	(112,707)	12,869	Schedule 7.2, Line 39, Column 6+7
9	Accumulated Depreciation Ending	(1,691,547)	(1,804,263)	(112,716)	
10					
11	CIAC, Beginning	$ (445,070)	$ (425,250)	$ 19,820	Schedule 9, Line 8, Column 2
12	Opening Balance Adjustment	14,550	-	(14,550)	
13	Net Additions	5,269	1,022	(4,247)	Schedule 9, Line 8, Column 4+5
14	CIAC, Ending	(425,251)	(424,228)	1,023	
15					
16	Accumulated Amortization Beginning - CIAC	$ 131,682	$ 139,013	$ 7,331	Schedule 9, Line 17, Column 2
17	Opening Balance Adjustment	(1,548)	-	1,548	
18	Net Additions	8,879	6,616	(2,263)	Schedule 9, Line 17, Column 4+5
19	Accumulated Amortization Ending - CIAC	139,013	145,629	6,616	
20					
21	Net Plant in Service, Mid-Year	$ 3,514,318	$ 3,564,467	$ 50,149	
22					
23	Adjustment for timing of Capital additions	$ -	$ 3,685	$ 3,685	
24	Capital Work in Progress, No AFUDC	36,377	35,156	(1,221)	
25	Unamortized Deferred Charges	31,570	27,577	(3,993)	Schedule 11.1, Line 38, Column 10
26	Working Capital	79,936	61,140	(18,796)	Schedule 13, Line 18, Column 3
27	Deferred Income Taxes Regulatory Asset	395,930	388,446	(7,484)	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(395,930)	(388,446)	7,484	Schedule 15, Line 6, Column 3
29	LILO Benefit	(817)	(651)	166	
30					
31	Mid-Year Utility Rate Base	$ 3,661,384	$ 3,691,374	$ 29,990	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Reference	2014	2015	2016	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Formula Cost Drivers**					
2	CPI		0.473%	0.879%	0.980%	
3	AWE		2.277%	1.646%	2.050%	
4	Labour Split					
5	Non Labour		45.000%	45.000%	45.000%	
6	Labour		55.000%	55.000%	55.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	1.460%	1.301%	1.569%	
8	Productivity Factor		-1.100%	-1.100%	-1.100%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.360%	0.201%	0.469%	
10						
11	Average Customer Growth		0.260%	0.614%	0.567%	
12	Inflation Factor for Base Capital	(1 + Line 9) x (1 + Line 11)	100.621%	100.816%	101.039%	
13						
14	Customer Growth Factor		-0.688%	-5.615%	16.249%	
15	Inflation Factor for Growth Capital	(1 + Line 9) x (1 + Line 14)	99.669%	94.575%	116.794%	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 4

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**2013**					
2	Base	$ 21,881	$ 99,243			
3	**2014**					
4	Net Inflation Factor	99.669%	100.621%			Schedule 3, Line 12 & 15, Column 3
5	FEI Formula Capex	21,809	99,859			
6	Reclassify Pension & OPEB from Formula	(331)	(1,516)			
7	FEI Net Formula Capex	21,478	98,343			
8	FEVI Capex	8,378	11,518			Note 1
9	FEW Capex	258	142			
10	Total	30,114	110,003			
11	**2015**					
12	Net Inflation Factor	94.575%	100.816%			Schedule 3, Line 12 & 15, Column 4
13	Formula Capex	28,479	110,901			
14	**2016**					
15	Net Inflation Factor	116.794%	101.039%			Schedule 3, Line 12 & 15, Column 5
16	Formula Capex	$ 33,262	$ 112,053		$ 145,315	
17						
18	**Capital Tracked Outside of Formula**					
19	Pension & OPEB (Capital Portion)			$ 4,075		
20	Biomethane Upgraders			-		
21	Biomethane Interconnect			1,355		
22	NGT Assets			6,874		
23	Total			$ 12,304	12,304	
24						
25	**Total Capital Expenditures Net of CIAC**				$ 157,619	
26						
27	Contributions in Aid of Construction				6,515	
28	**Total Capital Expenditures before CIAC**				$ 164,134	
29						
30	Notes					
31	1. FEVI growth capex of $8,802 thousand less $424 thousand of pension and OPEBs; FEVI other capex of $13,908 thousand less $2,390 thousand of pension and OPEBs.					

CAPITAL EXPENDITURES TO PLANT RECONCILIATION Schedule 5
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2016 Formula	Cross Reference
	(1)	(2)	(3)
1	**CAPEX**		
2			
3	Growth Capital Expenditures	$ 33,262	Schedule 4, Line 16, Column 2
4	Sustainment Capital Expenditures	112,053	Schedule 4, Line 16, Column 3
5	Forecast Capital Expenditures	12,304	Schedule 4, Line 23, Column 4
6	CIAC	6,515	Schedule 4, Line 27, Column 5
7	Total Regular Capital Expenditures	$ 164,134	
8			
9	**Special Projects and CPCN's**		
10			
11	LMIPSU	$ 28,879	
12	Huntingdon Station	300	
13	CTS	18,224	
14	Tilbury Expansion	80,565	
15	City of Vancouver Biomethane Plant	6,800	
16	Total Regular Capital Expenditures	$ 134,768	
17			
18	**Total Capital Expenditures**	$ 298,902	
19			
20			
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**		
22			
23	Regular Capital Expenditures	$ 164,134	
24	Add - Capitalized Overheads	32,767	Schedule 21, Line 30, Column 4
25	Add - AFUDC	1,918	
26	Gross Capital Expenditures	198,819	
27	Change in Work in Progress	1,386	
28	**Total Additions to Plant**	$ 200,205	
29			
30	Special Projects and CPCN's	$ 134,768	
31	Add - AFUDC	26,674	
32	Gross Capital Expenditures	161,442	
33	Change in Work in Progress	(154,072)	
34	**Total Additions to Plant**	$ 7,370	
35			
36	**Grand Total Additions to Plant**	$ 207,575	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	Particulars	12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**INTANGIBLE PLANT**						
2	117-00	Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	
3	175-00	Unamortized Conversion Expense	109	-	-	-	109	
4	175-00	Unamortized Conversion Expense - Squamish	777	-	-	-	777	
5	178-00	Organization Expense	728	-	-	-	728	
6	179-01	Other Deferred Charges	-	-	-	-	-	
7	401-00	Franchise and Consents	297	-	-	-	297	
8	402-00	Utility Plant Acquisition Adjustment	62	-	-	-	62	
9	402-00	Other Intangible Plant	1,907	-	-	-	1,907	
10	431-00	Mfg'd Gas Land Rights	-	-	-	-	-	
11	461-00	Transmission Land Rights	53,068	-	487	-	53,555	
12	461-02	Transmission Land Rights - Mt. Hayes	610	-	-	-	610	
13	461-10	Transmission Land Rights - Byron Creek	16	-	-	-	16	
14	461-13	IP Land Rights Whistler	87	-	-	-	87	
15	471-00	Distribution Land Rights	3,079	-	-	-	3,079	
16	471-10	Distribution Land Rights - Byron Creek	1	-	-	-	1	
17	402-01	Application Software - 12.5%	108,270	-	7,174	(10,931)	104,513	
18	402-02	Application Software - 20%	27,628	-	6,260	(5,632)	28,256	
19			$ 196,639	$ -	$ 13,921	$ (16,563)	$ 193,997	
20								
21		**MANUFACTURED GAS / LOCAL STORAGE**						
22	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ 31	
23	431-00	Manufact'd Gas - Land Rights	-	-	-	-	-	
24	432-00	Manufact'd Gas - Struct. & Improvements	998	-	-	-	998	
25	433-00	Manufact'd Gas - Equipment	1,093	-	338	-	1,431	
26	434-00	Manufact'd Gas - Gas Holders	2,940	-	-	-	2,940	
27	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	367	
28	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	-	-	-	875	
29	443-00	Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	
30	440/44	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	15,164	
31	442-00	Structures & Improvements (Tilbury)	4,959	-	-	-	4,959	
32	443-00	Gas Holders - Storage (Tilbury)	16,499	-	-	-	16,499	
33	446-00	Compressor Equipment (Tilbury)	-	-	-	-	-	
34	447-00	Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	
35	448-00	Purification Equipment (Tilbury)	-	-	-	-	-	
36	449-00	Local Storage Equipment (Tilbury)	29,762	-	2,514	-	32,276	
37	440/44	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	1,083	
38	442-00	Structures & Improvements (Mount Hayes)	17,310	-	-	-	17,310	
39	443-00	Gas Holders - Storage (Mount Hayes)	60,112	-	-	-	60,112	
40	446-00	Compressor Equipment (Mount Hayes)	-	-	-	-	-	
41	447-00	Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	
42	448-00	Purification Equipment (Mount Hayes)	-	-	-	-	-	
43	448-10	Piping (Mount Hayes)	11,488	-	-	-	11,488	
44	448-20	Pre-treatment (Mount Hayes)	28,714	-	-	-	28,714	
45	448-30	Liquefaction Equipment (Mount Hayes)	28,714	-	-	-	28,714	
46	448-40	Send out Equipment (Mount Hayes)	22,960	-	-	-	22,960	
47	448-50	Sub-station and Electric (Mount Hayes)	21,644	-	-	-	21,644	
48	448-60	Control Room (Mount Hayes)	5,900	-	-	-	5,900	
49	449-00	Local Storage Equipment (Mount Hayes)	6,335	-	-	-	6,335	
50			$ 276,948	$ -	$ 2,852	$ -	$ 279,800	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	Particulars	12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**TRANSMISSION PLANT**						
2	460-00	Land in Fee Simple	$ 10,627	$ 240	$ -	$ -	$ 10,867	
3	461-00	Transmission Land Rights	1	-	-	-	1	
4	462-00	Compressor Structures	29,484	-	-	-	29,484	
5	463-00	Measuring Structures	14,015	-	-	-	14,015	
6	464-00	Other Structures & Improvements	6,485	14	-	-	6,499	
7	465-00	Mains	1,168,419	4,775	14,988	(1,619)	1,186,563	
8	465-00	Mains - INSPECTION	16,043	-	2,568	-	18,611	
9	465-11	IP Transmission Pipeline - Whistler	42,288	-	-	-	42,288	
10	465-30	Mains - Mt Hayes	6,299	-	-	-	6,299	
11	465-10	Mains - Byron Creek	974	-	-	-	974	
12	466-00	Compressor Equipment	178,840	-	2,864	(742)	180,962	
13	466-00	Compressor Equipment - OVERHAUL	3,856	-	-	-	3,856	
14	467-00	Measuring and Regulating Equipment - Mt. Hayes	5,342	-	-	-	5,342	
15	467-00	Measuring & Regulating Equipment	49,540	2,239	-	-	51,779	
16	467-10	Telemetering	13,045	102	362	(21)	13,488	
17	467-31	IP Intermediate Pressure Whistler	313	-	-	-	313	
18	467-20	Measuring & Regulating Equipment - Byron Creek	39	-	-	-	39	
19	468-00	Communication Structures & Equipment	4,245	-	-	-	4,245	
20			$ 1,549,855	$ 7,370	$ 20,782	$ (2,382)	$ 1,575,625	
21								
22		**DISTRIBUTION PLANT**						
23	470-00	Land in Fee Simple	$ 4,207	$ -	$ -	$ -	$ 4,207	
24	471-00	Distribution Land Rights	-	-	-	-	-	
25	472-00	Structures & Improvements	21,577	-	-	-	21,577	
26	472-10	Structures & Improvements - Byron Creek	107	-	-	-	107	
27	473-00	Services	1,064,669	-	45,240	(3,058)	1,106,851	
28	474-00	House Regulators & Meter Installations	197,454	-	-	(494)	196,960	
29	477-00	Meters/Regulators Installations	99,324	-	27,091	-	126,415	
30	475-00	Mains	1,337,768	-	29,934	(1,688)	1,366,014	
31	476-00	Compressor Equipment	1,110	-	-	-	1,110	
32	477-00	Measuring & Regulating Equipment	121,607	-	9,382	(1,084)	129,905	
33	477-00	Telemetering	10,504	-	1,028	-	11,532	
34	477-10	Measuring & Regulating Equipment - Byron Creek	163	-	-	-	163	
35	478-10	Meters	237,085	-	13,866	(7,556)	243,395	
36	478-20	Instruments	11,944	-	-	-	11,944	
37	479-00	Other Distribution Equipment	-	-	-	-	-	
38			$ 3,107,519	$ -	$ 126,541	$ (13,880)	$ 3,220,180	
39								
40		**BIO GAS**						
41	472-00	Bio Gas Struct. & Improvements	$ 553	$ -	$ -	$ -	$ 553	
42	475-10	Bio Gas Mains – Municipal Land	1,336	-	-	-	1,336	
43	475-20	Bio Gas Mains – Private Land	465	-	357	-	822	
44	418-10	Bio Gas Purification Overhaul	178	-	-	-	178	
45	418-20	Bio Gas Purification Upgrader	7,646	-	-	-	7,646	
46	477-10	Bio Gas Reg & Meter Equipment	1,619	-	-	-	1,619	
47	478-30	Bio Gas Meters	635	-	542	-	1,177	
48	474-10	Bio Gas Reg & Meter Installations	1,046	-	714	-	1,760	
49			$ 13,478	$ -	$ 1,613	$ -	$ 15,091	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 6.2

Line No.	Account (1)	Particulars (2)	12/31/15 (3)	CPCN's (4)	Additions (5)	Retirements (6)	12/31/16 (7)	Cross Reference (8)
1		**Natural Gas for Transportation**						
2	476-10	NG Transportation CNG Dispensing Equipment	$ 7,581	$ -	$ 2,006	$ -	$ 9,587	
3	476-20	NG Transportation LNG Dispensing Equipment	6,075	-	-	-	6,075	
4	476-30	NG Transportation CNG Foundations	931	-	100	-	1,031	
5	476-40	NG Transportation LNG Foundations	897	-	-	-	897	
6	476-50	NG Transportation LNG Pumps	63	-	-	-	63	
7	476-60	NG Transportation CNG Dehydrator	253	-	-	-	253	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	
9			$ 15,800	$ -	$ 2,106	$ -	$ 17,906	
10								
11		**GENERAL PLANT & EQUIPMENT**						
12	480-00	Land in Fee Simple	$ 30,082	$ -	$ 385	$ -	$ 30,467	
13	481-00	Land Rights	-	-	-	-	-	
14	482-00	Frame Buildings	16,822	-	-	-	16,822	
15	482-00	Masonry Buildings	118,744	-	6,079	(125)	124,698	
16	482-00	Leasehold Improvement	4,650	-	198	(69)	4,779	
17	483-30	GP Office Equipment	4,686	-	578	(524)	4,740	
18	483-40	GP Furniture	21,543	-	1,951	(1,450)	22,044	
19	483-10	GP Computer Hardware	48,270	-	9,693	(10,421)	47,542	
20	483-20	GP Computer Software	4,519	-	-	(732)	3,787	
21	483-21	GP Computer Software	-	-	-	-	-	
22	483-22	GP Computer Software	-	-	-	-	-	
23	484-00	Vehicles	11,958	-	2,684	-	14,642	
24	484-00	Vehicles - Leased	27,602	-	-	(1,479)	26,123	
25	485-10	Heavy Work Equipment	858	-	-	-	858	
26	485-20	Heavy Mobile Equipment	2,747	-	6,160	-	8,907	
27	486-00	Small Tools & Equipment	50,673	-	3,427	(3,405)	50,695	
28	487-00	Equipment on Customer's Premises	24	-	-	-	24	
29	487-00	VRA Compressor Installation Costs	-	-	-	-	-	
30	488-00	Telephone	5,747	-	-	(1,849)	3,898	
31	488-00	Radio	8,294	-	1,235	(24)	9,505	
32	489-00	Other General Equipment	-	-	-	-	-	
33			$ 357,219	$ -	$ 32,390	$ (20,078)	$ 369,531	
34								
35		**UNCLASSIFIED PLANT**						
36	499-00	Plant Suspense	-	-	-	-	-	
37			$ -	$ -	$ -	$ -	$ -	
38								
39		**Total Plant in Service**	$ 5,517,458	$ 7,370	$ 200,205	$ (52,903)	$ 5,672,130	
40								
41		Cross Reference		Schedule 5, Line 34, Column 2	Schedule 5, Line 28, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**INTANGIBLE PLANT**									
2	117-00	Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
3	175-00	Unamortized Conversion Expense	109	1.00%	58	1	-	-	-	59	
4	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	657	78	-	-	-	735	
5	178-00	Organization Expense	728	1.00%	414	7	-	-	-	421	
6	179-01	Other Deferred Charges	-	0.00%	-	-	-	-	-	-	
7	401-00	Franchise and Consents	297	5.39%	194	11	-	-	-	205	
8	402-00	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	62	
9	402-00	Other Intangible Plant	1,907	2.01%	992	38	-	-	-	1,030	
10	431-00	Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-	-	
11	461-00	Transmission Land Rights	53,068	0.00%	1,766	-	-	-	-	1,766	
12	461-02	Transmission Land Rights - Mt. Hayes	610	0.00%	-	-	-	-	-	-	
13	461-10	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	19	
14	461-13	IP Land Rights Whistler	87	0.00%	10	-	-	-	-	10	
15	471-00	Distribution Land Rights	3,079	0.00%	238	-	-	-	-	238	
16	471-10	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	1	
17	402-01	Application Software - 12.5%	108,270	12.50%	52,235	13,534	(10,931)	-	-	54,838	
18	402-02	Application Software - 20%	27,628	20.00%	12,365	5,526	(5,632)	-	-	12,259	
19			$ 196,639		$ 69,011	$ 19,195	$ (16,563)	$ -	$ -	$ 71,643	
20											
21		**MANUFACTURED GAS / LOCAL STORAGE**									
22	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
23	431-00	Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-	-	
24	432-00	Manufact'd Gas - Struct. & Improvements	998	2.82%	254	28	-	-	-	282	
25	433-00	Manufact'd Gas - Equipment	1,093	4.66%	198	51	-	-	-	249	
26	434-00	Manufact'd Gas - Gas Holders	2,940	2.45%	443	72	-	-	-	515	
27	436-00	Manufact'd Gas - Compressor Equipment	367	3.68%	94	13	-	-	-	107	
28	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	2.34%	768	20	-	-	-	788	
29	443-00	Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-	-	
30	440/44	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	1	
31	442-00	Structures & Improvements (Tilbury)	4,959	3.03%	3,320	150	-	-	-	3,470	
32	443-00	Gas Holders - Storage (Tilbury)	16,499	1.88%	11,676	310	-	-	-	11,986	
33	446-00	Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-	-	
34	447-00	Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-	-	
35	448-00	Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-	-	
36	449-00	Local Storage Equipment (Tilbury)	29,762	3.83%	14,181	1,140	-	-	-	15,321	
37	440/44	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	
38	442-00	Structures & Improvements (Mount Hayes)	17,310	3.88%	3,167	672	-	-	-	3,839	
39	443-00	Gas Holders - Storage (Mount Hayes)	60,112	1.65%	4,599	992	-	-	-	5,591	
40	446-00	Compressor Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-	-	
41	447-00	Measuring & Regulating Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-	-	
42	448-00	Purification Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-	-	
43	448-10	Piping (Mount Hayes)	11,488	2.48%	1,316	285	-	-	-	1,601	
44	448-20	Pre-treatment (Mount Hayes)	28,714	3.88%	5,263	1,114	-	-	-	6,377	
45	448-30	Liquefaction Equipment (Mount Hayes)	28,714	2.46%	3,289	706	-	-	-	3,995	
46	448-40	Send out Equipment (Mount Hayes)	22,960	2.44%	2,630	560	-	-	-	3,190	
47	448-50	Sub-station and Electric (Mount Hayes)	21,644	2.44%	2,479	528	-	-	-	3,007	
48	448-60	Control Room (Mount Hayes)	5,900	6.30%	1,803	372	-	-	-	2,175	
49	449-00	Local Storage Equipment (Mount Hayes)	6,335	2.86%	6	181	-	-	-	187	
50			$ 276,948		$ 55,487	$ 7,194	$ -	$ -	$ -	$ 62,681	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**TRANSMISSION PLANT**									
2	460-00	Land in Fee Simple	$ 10,867	0.00%	$ 503	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	1	0.00%	-	-	-	-	-	-	
4	462-00	Compressor Structures	29,484	3.51%	14,532	1,035	-	-	-	15,567	
5	463-00	Measuring Structures	14,015	2.29%	6,299	321	-	-	-	6,620	
6	464-00	Other Structures & Improvements	6,499	3.66%	2,462	238	-	-	-	2,700	
7	465-00	Mains	1,173,194	1.47%	361,730	17,246	(1,619)	-	-	377,357	
8	465-00	Mains - INSPECTION	16,043	15.20%	6,577	2,439	-	-	-	9,016	
9	465-11	IP Transmission Pipeline - Whistler	42,288	1.53%	3,883	647	-	-	-	4,530	
10	465-30	Mains - Mt Hayes	6,299	1.55%	501	98	-	-	-	599	
11	465-10	Mains - Byron Creek	974	5.03%	1,133	49	-	-	-	1,182	
12	466-00	Compressor Equipment	178,840	2.89%	78,287	5,168	(742)	-	-	82,713	
13	466-00	Compressor Equipment - OVERHAUL	3,856	10.19%	1,886	393	-	-	-	2,279	
14	467-00	Measuring and Regulating Equipment - Mt. Hayes	5,342	2.58%	978	138	-	-	-	1,116	
15	467-00	Measuring & Regulating Equipment	51,779	2.41%	21,374	1,248	-	-	-	22,622	
16	467-10	Telemetering	13,147	9.75%	6,523	1,282	(21)	-	-	7,784	
17	467-31	IP Intermediate Pressure Whistler	313	2.55%	76	8	-	-	-	84	
18	467-20	Measuring & Regulating Equipment - Byron Creek	39	2.41%	10	1	-	-	-	11	
19	468-00	Communication Structures & Equipment	4,245	0.56%	4,325	24	-	-	-	4,349	
20			$ 1,557,225		$ 511,079	$ 30,335	$ (2,382)	$ -	$ -	$ 539,032	
21											
22		**DISTRIBUTION PLANT**									
23	470-00	Land in Fee Simple	$ 4,207	0.00%	$ (9)	$ -	$ -	$ -	$ -	$ (9)	
24	471-00	Distribution Land Rights	-	0.00%	-	-	-	-	-	-	
25	472-00	Structures & Improvements	21,577	2.41%	7,974	520	-	-	-	8,494	
26	472-10	Structures & Improvements - Byron Creek	107	4.67%	48	5	-	-	-	53	
27	473-00	Services	1,064,669	2.45%	246,171	26,084	(3,058)	-	-	269,197	
28	474-00	House Regulators & Meter Installations	197,454	5.99%	66,166	11,826	(494)	-	-	77,498	
29	477-00	Meters/Regulators Installations	99,324	4.55%	6,951	4,519	-	-	-	11,470	
30	475-00	Mains	1,337,768	1.54%	436,085	20,602	(1,688)	-	-	454,999	
31	476-00	Compressor Equipment	1,110	0.00%	1,265	-	-	-	-	1,265	
32	477-00	Measuring & Regulating Equipment	121,607	3.05%	43,083	3,709	(1,084)	-	-	45,708	
33	477-00	Telemetering	10,504	2.82%	6,104	296	-	-	-	6,400	
34	477-10	Measuring & Regulating Equipment - Byron Creek	163	0.00%	216	-	-	-	-	216	
35	478-10	Meters	237,085	7.09%	113,718	16,809	(7,556)	-	-	122,971	
36	478-20	Instruments	11,944	2.99%	2,427	357	-	-	-	2,784	
37	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	
38			$ 3,107,519		$ 930,199	$ 84,727	$ (13,880)	$ -	$ -	$ 1,001,046	
39											
40		**BIO GAS**									
41	472-00	Bio Gas Struct. & Improvements	$ 553	2.72%	$ 31	$ 15	$ -	$ -	$ -	$ 46	
42	475-10	Bio Gas Mains – Municipal Land	1,336	1.55%	23	21	-	-	-	44	
43	475-20	Bio Gas Mains – Private Land	465	1.55%	3	7	-	-	-	10	
44	418-10	Bio Gas Purification Overhaul	178	5.00%	-	9	-	-	-	9	
45	418-20	Bio Gas Purification Upgrader	7,646	4.89%	434	374	-	-	-	808	
46	477-10	Bio Gas Reg & Meter Equipment	1,619	3.24%	134	52	-	-	-	186	
47	478-30	Bio Gas Meters	635	5.02%	4	32	-	-	-	36	
48	474-10	Bio Gas Reg & Meter Installations	1,046	5.24%	6	55	-	-	-	61	
49			$ 13,478		$ 635	$ 565	$ -	$ -	$ -	$ 1,200	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.2
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**Natural Gas for Transportation**									
2	476-10	NG Transportation CNG Dispensing Equipment	$ 7,581	5.00%	$ 933	$ 379	$ -	$ -	$ -	$ 1,312	
3	476-20	NG Transportation LNG Dispensing Equipment	6,075	5.00%	414	304	-	-	-	718	
4	476-30	NG Transportation CNG Foundations	931	5.00%	119	47	-	-	-	166	
5	476-40	NG Transportation LNG Foundations	897	5.00%	98	45	-	-	-	143	
6	476-50	NG Transportation LNG Pumps	63	10.00%	18	6	-	-	-	24	
7	476-60	NG Transportation CNG Dehydrator	253	5.00%	36	13	-	-	-	49	
8	476-70	NG Transportation LNG Dehydrator	-	0.00%	-	-	-	-	-	-	
9			$ 15,800		$ 1,618	$ 794	$ -	$ -	$ -	$ 2,412	
10											
11		**GENERAL PLANT & EQUIPMENT**									
12	480-00	Land in Fee Simple	$ 30,082	0.00%	$ 17	$ -	$ -	$ -	$ -	$ 17	
13	481-00	Land Rights	-	0.00%	-	-	-	-	-	-	
14	482-00	Frame Buildings	16,822	6.04%	6,853	1,016	-	-	-	7,869	
15	482-00	Masonry Buildings	118,744	1.95%	23,153	2,316	(125)	-	-	25,344	
16	482-00	Leasehold Improvement	4,650	9.49%	1,676	441	(69)	-	-	2,048	
17	483-30	GP Office Equipment	4,686	6.67%	3,897	313	(524)	-	-	3,686	
18	483-40	GP Furniture	21,543	5.00%	8,484	1,077	(1,450)	-	-	8,111	
19	483-10	GP Computer Hardware	48,270	20.00%	21,683	9,654	(10,421)	-	-	20,916	
20	483-20	GP Computer Software	4,519	12.50%	2,401	565	(732)	-	-	2,234	
21	483-21	GP Computer Software	-	0.00%	-	-	-	-	-	-	
22	483-22	GP Computer Software	-	0.00%	-	-	-	-	-	-	
23	484-00	Vehicles	11,958	10.55%	4,802	1,262	-	-	-	6,064	
24	484-00	Vehicles - Leased	27,602	9.44%	19,923	2,358	(1,479)	-	-	20,802	
25	485-10	Heavy Work Equipment	858	6.38%	453	55	-	-	-	508	
26	485-20	Heavy Mobile Equipment	2,747	9.85%	2,014	271	-	-	-	2,285	
27	486-00	Small Tools & Equipment	50,673	5.00%	22,433	2,534	(3,405)	-	-	21,562	
28	487-00	Equipment on Customer's Premises	24	6.67%	17	2	-	-	-	19	
29	487-00	VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	
30	488-00	Telephone	5,747	6.67%	3,759	383	(1,849)	-	-	2,293	
31	488-00	Radio	8,294	6.67%	1,962	553	(24)	-	-	2,491	
32	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	
33			$ 357,219		$ 123,527	$ 22,800	$ (20,078)	$ -	$ -	$ 126,249	
34											
35		**UNCLASSIFIED PLANT**									
36	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	
37			$ -		$ -	$ -	$ -	$ -	$ -	$ -	
38											
39		**Total**	$ 5,524,828		$ 1,691,556	$ 165,610	$ (52,903)	$ -	$ -	$ 1,804,263	
40		Less: Depreciation & Amortization transferred to biomethane BVA				(383)					
41		Less: Vehicle Depreciation Allocated To Capital Projects				(1,339)					
42						$ 163,888					
43											
44		Cross Reference	Schedule 6.2, Line 39, Column 3+4								

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars			12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Non-Regulated Plant**								
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	176,594	
4	Mobile Refueling Station			744	-	-	-	744	
5								-	
6	**Total**			$ 178,392	$ -	$ -	$ -	$ 178,392	
7									
8									
9									

10 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
11 **FOR THE YEAR ENDING DECEMBER 31, 2016**
12 **($000s)**
13
14

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Expense	Depreciation Retirements	Cost of Removal	12/31/16	Cross Reference
17	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
18									
19	**Non-Regulated Plant Depreciation**								
20	NRB Depreciation @ 0%	$ 1,054	0.00%	$ 291	$ -	$ -	$ -	$ 291	
21	NRB Depreciation @ 2.4%	176,594	2.40%	112,984	4,238	-	-	117,222	
22	Mobile Refueling Station	744	5.00%	81	37	-	-	118	
23								-	
24	**Total**	$ 178,392		$ 113,356	$ 4,275	$ -	$ -	$ 117,631	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	12/31/15	Adjustment	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2	Distribution Contributions	$ 268,788	$ -	$ 6,056	$ -	$ 274,844	
3	Transmission Contributions	145,125	-	459	-	145,584	
4	Others	722	-	-	-	722	
5	Software Tax Savings - Infrastructure/Custom	5,069	-	-	(2,537)	2,532	
6	Government Loans Contribution	5,000	-	-	(5,000)	-	
7	Biomethane	546	-	-	-	546	
8	**Total**	$ 425,250	$ -	$ 6,515	$ (7,537)	$ 424,228	
9							
10	**Amortization**						
11	Distribution Contributions	$ (88,605)	$ -	$ (6,236)	$ -	$ (94,841)	
12	Transmission Contributions	(45,594)	-	(2,148)	-	(47,742)	
13	Others	(499)	-	(108)	-	(607)	
14	Software Tax Savings - Infrastructure/Custom	(4,221)	-	(634)	2,537	(2,318)	
15	Government Loans Contribution	-	-	-	-	-	
16	Biomethane	(94)	-	(27)	-	(121)	
17	**Total**	$ (139,013)	$ -	$ (9,153)	$ 2,537	$ (145,629)	
18							
19	**Net CIAC**	$ 286,237	$ -	$ (2,638)	$ (5,000)	$ 278,599	

NEGATIVE SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 10

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/15	Negative Salv Provision	Removal Costs/ Proceeds on Disp.	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**MANUFACTURED GAS / LOCAL STORAGE**							
2	442-00	Structures & Improvements (Tilbury)	$ 4,959	0.36%	$ 72	$ 18	$ -	$ 90	
3	443-00	Gas Holders - Storage (Tilbury)	16,499	0.45%	264	74	-	338	
4	449-00	Local Storage Equipment (Tilbury)	29,762	0.39%	379	116	-	495	
5	442-00	Structures & Improvements (Mount Hayes)	17,310	0.45%	-	78	-	78	
6	443-00	Gas Holders - Storage (Mount Hayes)	60,112	0.35%	-	210	-	210	
7	448-10	Piping (Mount Hayes)	11,488	0.27%	-	31	-	31	
8	448-20	Pre-treatment (Mount Hayes)	28,714	0.46%	-	132	-	132	
9	448-30	Liquefaction Equipment (Mount Hayes)	28,714	0.54%	-	155	-	155	
10	448-40	Send out Equipment (Mount Hayes)	22,960	0.27%	-	62	-	62	
11	448-50	Sub-station and Electric (Mount Hayes)	21,644	0.54%	-	117	-	117	
12	449-00	Local Storage Equipment (Mount Hayes)	6,335	0.28%	-	18	-	18	
13			$ 248,497		$ 715	$ 1,011	$ -	$ 1,726	
14									
15		**TRANSMISSION PLANT**							
16	462-00	Compressor Structures	$ 29,484	-0.02%	$ 413	$ (6)	$ -	$ 407	
17	463-00	Measuring Structures	14,015	0.57%	129	80	-	209	
18	464-00	Other Structures & Improvements	6,499	0.22%	21	14	-	35	
19	465-00	Mains	1,173,194	0.37%	8,138	4,341	-	12,479	
20	465-11	IP Transmission Pipeline - Whistler	42,288	0.34%	-	144	-	144	
21	465-30	Mains - Mt Hayes	6,299	0.32%	-	20	-	20	
22	466-00	Compressor Equipment	178,840	-0.12%	2,414	(215)	-	2,199	
23	467-00	Measuring and Regulating Equipment - Mt. Hayes	5,342	0.21%	185	11	-	196	
24	467-00	Measuring & Regulating Equipment	51,779	0.22%	119	114	-	233	
25	467-31	IP Intermediate Pressure Whistler	313	0.22%	-	1	-	1	
26	468-00	Communication Structures & Equipment	4,245	-0.38%	357	(16)	-	341	
27			$ 1,512,298		$ 11,776	$ 4,488	$ -	$ 16,264	
28									
29		**DISTRIBUTION PLANT**							
30	472-00	Structures & Improvements	$ 21,577	0.32%	$ 152	$ 69	$ -	$ 221	
31	473-00	Services	1,064,669	1.61%	6,982	16,454	(9,548)	13,888	
32	474-00	House Regulators & Meter Installations	197,454	1.77%	(2,886)	3,210	(3,565)	(3,241)	
33	477-00	Meters/Regulators Installations	99,324	0.00%	997	-	-	997	
34	475-00	Mains	1,337,768	0.43%	15,502	5,582	(549)	20,535	
35	476-00	Compressor Equipment	1,110	0.00%	584	-	-	584	
36	477-00	Measuring & Regulating Equipment	121,607	0.46%	1,880	559	-	2,439	
37	477-00	Telemetering	10,504	0.42%	(12)	44	-	32	
38	478-10	Meters	237,085	-0.26%	3,330	(590)	-	2,740	
39			$ 3,091,098		$ 26,529	$ 26,445	$ (13,661)	$ 39,312	
40									
41		**BIO GAS**							
42	472-00	Bio Gas Struct. & Improvements	$ 553	0.29%	$ -	$ 2	$ -	$ 2	
43	475-10	Bio Gas Mains – Municipal Land	1,336	0.39%	6	5	-	11	
44	475-20	Bio Gas Mains – Private Land	465	0.39%	1	2	-	3	
45	418-20	Bio Gas Purification Upgrader	7,646	0.26%	-	20	-	20	
46	478-30	Bio Gas Meters	635	-0.21%	-	(1)	-	(1)	
47	474-10	Bio Gas Reg & Meter Installations	1,046	1.35%	-	14	-	14	
48			$ 11,681		$ 7	$ 42	$ -	$ 49	
49									
50		**GENERAL PLANT & EQUIPMENT**							
51	482-00	Frame Buildings	$ 16,822	0.00%	$ (12)	$ -	$ -	$ (12)	
52	482-00	Masonry Buildings	118,744	0.25%	(1)	297	-	296	
53	484-00	Vehicles	11,958	-1.00%	-	(120)	-	(120)	
54	485-10	Heavy Work Equipment	858	-0.68%	-	(6)	-	(6)	
55	485-20	Heavy Mobile Equipment	2,747	-2.89%	-	(79)	-	(79)	
56			$ 151,129		$ (13)	$ 92	$ -	$ 79	
57									
58		**Total**	$ 5,014,703		$ 39,014	$ 32,078	$ (13,661)	$ 57,430	
59									
60		Cross Reference	Schedule 6 - 6.2, Column 3+4						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	12/31/15	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/16	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (12,370)	$ -	$ 16,716	$ (4,346)	$ -	$ -	$ -	$ (0)	$ (6,185)	
3	Midstream Cost Reconciliation Account (MCRA)	(9,989)	-	(23,937)	6,224	-	7,493	(1,948)	(22,157)	(16,073)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	35,953	-	-	-	-	(24,293)	6,316	17,976	26,965	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,000)	-	1,372	(357)	149	(161)	42	(2,955)	(3,477)	
6	Revelstoke Propane Cost Deferral Account	(198)	-	268	(70)	-	-	-	0	(99)	
7	SCP Mitigation Revenues Variance Account	(834)	-	-	-	544	-	-	(290)	(562)	
8		$ 8,563	$ -	$ (5,581)	$ 1,451	$ 692	$ (16,961)	$ 4,410	$ (7,426)	$ 569	
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	$ 61,769	$ 9,633	$ 15,000	$ (3,900)	$ (8,365)	$ -	$ -	$ 74,138	$ 72,770	
11	NGV Conversion Grants	56	-	45	(12)	(16)	-	-	73	65	
12	Emissions Regulations	3	-	-	-	-	-	-	3	3	
13	NGT Incentives	15,664	-	5,498	(1,429)	(1,845)	-	-	17,888	16,776	
14	CNG and LNG Recoveries	(332)	-	-	-	332	-	-	-	(166)	
15		$ 77,160	$ 9,633	$ 20,543	$ (5,341)	$ (9,893)	$ -	$ -	$ 92,102	$ 89,447	
16	Non-Controllable Items Deferral Accounts										
17	Pension & OPEB Variance	$ 6,861	$ -	$ -	$ -	$ (6,771)	$ -	$ -	$ 90	$ 3,476	
18	BCUC Levies Variance	423	-	-	-	(423)	-	-	(0)	211	
19	Customer Service Variance Account	(10,371)	-	-	-	3,456	-	-	(6,915)	(8,643)	
20	Pension & OPEB Funding	(214,316)	-	(10,565)	-	-	-	-	(224,881)	(219,598)	
21	US GAAP Pension & OPEB Funded Status	148,811	-	-	-	-	-	-	148,811	148,811	
22		$ (68,592)	$ -	$ (10,565)	$ -	$ (3,737)	$ -	$ -	$ (82,894)	$ (75,743)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	12/31/15	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/16	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2019 PBR Requirements	$ 990	$ -	$ -	$ -	$ (247)	$ -	$ -	$ 743	$ 866	
3	2014 Long Term Resource Plan Application	50	-	-	-	(50)	-	-	(0)	25	
4	AES Inquiry Cost	254	-	-	-	(132)	-	-	123	189	
5	Generic Cost of Capital Application	11	-	-	-	(11)	-	-	(0)	5	
6	2016 Cost of Capital Application	231	-	300	(78)	-	-	-	453	342	
7	Amalgamation and Rate Design Application Costs	522	-	-	-	(490)	-	-	32	277	
8	2015-2019 Annual Review Costs	222	-	200	(52)	(222)	-	-	148	185	
9	2017 Rate Design Application	111	-	500	(130)	-	-	-	481	296	
10	2017 Long Term Resource Plan Application	-	-	505	(131)	-	-	-	374	187	
11	LMIPSU Application Costs	-	1,047	-	-	(349)	-	-	698	873	
12	2015 System Extension Application	241	-	-	-	(120)	-	-	120	180	
13	BERC Rate Methodology Application	56	-	-	-	(56)	-	-	-	28	
14		$ 2,687	$ 1,047	$ 1,505	$ (391)	$ (1,676)	$ -	$ -	$ 3,172	$ 3,453	
15	Other Deferral Accounts										
16	Whistler Pipeline Conversion	$ 10,151	$ -	$ -	$ -	$ (745)	$ -	$ -	$ 9,406	$ 9,779	
17	2010-2011 Customer Service O&M and COS	14,560	-	-	-	(3,251)	-	-	11,309	12,934	
18	Gas Asset Records Project	1,237	-	1,770	(460)	(516)	-	-	2,031	1,634	
19	BC OneCall Project	840	-	-	-	(358)	-	-	482	661	
20	Gains and Losses on Asset Disposition	32,402	-	-	-	(3,986)	-	-	28,416	30,409	
21	Negative Salvage Provision/Cost	(38,589)	-	13,661	-	(32,078)	-	-	(57,005)	(47,797)	
22	TESDA Overhead Allocation Variance	296	-	-	-	(296)	-	-	-	148	
23	PCEC Start Up Costs	920	-	-	-	(88)	-	-	832	876	
24	Huntingdon CPCN Pre-Feasibility Costs	-	360	-	-	(120)	-	-	240	300	
25	LMIPSU Development Costs	-	2,382	-	-	(794)	-	-	1,588	1,985	
26		$ 21,818	$ 2,742	$ 15,431	$ (460)	$ (42,232)	$ -	$ -	$ (2,701)	$ 10,929	
27	Residual Deferred Accounts										
28	BFI Costs and Recoveries	$ (193)	$ -	$ -	$ -	$ -	$ -	$ -	$ (193)	$ (193)	
29	Fuelling Stations Variance Account	53	-	-	-	(53)	-	-	-	26	
30	US GAAP Transitional Costs	(70)	-	-	-	70	-	-	-	(35)	
31	Residual Delivery Rate Riders	-	8	-	-	(8)	-	-	-	4	
32	Property Tax Deferral	(1,456)	-	-	-	1,448	-	-	(8)	(732)	
33	Interest Variance	(338)	-	-	-	338	-	-	-	(169)	
34	Interest Variance - Funding benefits via Customer Deposit	40	-	-	-	(40)	-	-	0	20	
35	FEW 2014 Revenue Surplus/Deficiency	-	-	-	-	-	-	-	-	-	
36		$ (1,965)	$ 8	$ -	$ -	$ 1,756	$ -	$ -	$ (201)	$ (1,079)	
37											
38	**Total**	$ 39,671	$ 13,431	$ 21,333	$ (4,742)	$ (55,090)	$ (16,961)	$ 4,410	$ 2,052	$ 27,577	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	12/31/15	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/16	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Non-Rate Base										
2	Biomethane Variance Account	$ 1,096	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,096	$ 1,096	
3	KORP Feasibility Costs	479	-	-	-	-	-	-	479	479	
4	EEC-Incentives	9,633	(9,633)	-	-	-	-	-	-	-	
5	US GAAP Uncertain Tax Positions	466	-	-	-	-	-	-	466	466	
6	Mark to Market - Hedging Transactions	11,165	-	-	-	-	-	-	11,165	11,165	
7	Huntingdon CPCN Pre-Feasibility Costs	360	(360)	-	-	-	-	-	-	-	
8	Amalgamation Regulatory Account	961	-	12	-	-	(656)	170	488	725	
9	2014-2019 Earning Sharing Account	(3,750)	-	-	-	3,750	-	-	0	(1,875)	
10	Flow-Through Account	(713)	-	(21)	-	734	-	-	-	(357)	
11	Phase-In-Rider Balancing Account	1,061	-	-	-	-	(1,434)	373	-	531	
12	LMIPSU Application Costs	1,047	(1,047)	-	-	-	-	-	-	-	
13	LMIPSU Development Costs	2,382	(2,382)	-	-	-	-	-	0	0	
14	PEC Pipeline Development Costs and Commitment Fees	8,479	-	-	-	-	-	-	8,479	8,479	
15	Rate Stabilization Deferral Account (RSDA)	(45,467)	-	(499)	130	-	43,009	(11,182)	(14,009)	(29,738)	
16	FEW Rider B Refund Deferral	8	(8)	-	-	-	-	-	-	-	
17	**Total Non Rate Base Deferral Accounts**	$ (12,792)	$ (13,431)	$ (508)	$ 130	$ 4,485	$ 40,919	$ (10,639)	$ 8,164	$ (9,029)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 11,837	$ 13,355	$ 1,518	Schedule 14, Line 29, Column 5
3					
4	Less: Funds Available				
5	Average Customer Deposits	-	-	-	
6	Reserve for bad debts	(7,927)	(5,597)	2,330	
7	Employee Withholdings	(5,292)	(5,537)	(245)	
8					
9	**Other Working Capital Items**				
10	Construction Advances	(13)	(13)	-	
11	Transmission Line Pack Gas	2,251	2,332	81	
12	Gas In Storage	77,811	55,331	(22,480)	
13	Inventory - Materials and Supplied	1,567	1,567	0	
14	Refundable Contributions	(298)	(298)	-	
15					
16	Total	$ 79,936	$ 61,140	$ (18,796)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2016 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential & Commercial Tariff Revenue	$ 1,097,326	38.4	$ 42,089,089		
4	Industrial Tariff Revenue	87,066	45.1	3,928,908		
5	Other Tariff Revenue	79,292	43.4	3,438,174		
6						
7	**Other Revenue**					
8	Late Payment Charges	2,314	38.3	88,638		
9	Connection Charges	3,060	38.4	117,382		
10	Other Utility Income	21,754	37.4	814,297		
11						
12	Total	$ 1,290,812		$ 50,476,488	39.1	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 480,198	(40.2)	$ (19,303,960)		
16	Operating and Maintenance	239,332	(25.5)	(6,102,966)		
17	Property Taxes	63,043	(2.0)	(126,086)		
18	Franchise Fees	8,256	(420.3)	(3,469,996)		
19	Carbon Tax	182,903	(29.1)	(5,322,483)		
20	GST	10,830	(38.8)	(420,208)		
21	PST	4,549	(37.1)	(168,759)		
22	Income Tax	48,046	(15.2)	(730,299)		
23						
24	Total	$ 1,037,157		$ (35,644,757)	(34.4)	
25						
26	Net Lag (Lead) Days				4.7	
27	Total Expenses				$ 1,037,157	
28						
29	Cash Working Capital				$ 13,355	

Schedule 15

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (293,874)	$ (285,802)	$ 8,072	
2	Tax Gross Up	(103,253)	(100,417)	2,836	
3	DIT Liability/Asset - End of Year	$ (397,127)	$ (386,219)	$ 10,908	
4	DIT Liability/Asset - Opening Balance	(394,733)	(390,672)	4,061	
5					
6	DIT Liability/Asset - Mid Year	$ (395,930)	$ (388,446)	$ 7,484	

UTILITY INCOME AND EARNED RETURN Schedule 16
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast at Existing Rates	2016 Forecast Revised Revenue	2016 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	124,737	122,770		122,770	(1,967)	
3	Transportation Volume (TJ)	82,649	85,468		85,468	2,819	
4		207,386	208,238	-	208,238	852	Schedule 18, Line 6, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,267,517	$ 1,109,988	$ -	$ 1,109,988	$ (157,529)	
8	Deficiency (Surplus)	4,488	-	14,563	14,563	10,075	
9	RSAM Revenue		-	-	-	-	
10	Transportation	120,575	122,065	-	122,065	1,490	
11	Deficiency (Surplus)	642	-	2,111	2,111	1,469	
12	Total	1,393,222	1,232,053	16,674	1,248,727	(145,964)	Schedule 19, Line 15, Column 8
13							
14	**COST OF ENERGY**	640,486	480,198	-	480,198	(160,288)	Schedule 17, Line 8, Column 3
15							
16	**MARGIN**	752,736	751,856	16,674	768,529	15,793	
17							
18	**EXPENSES**						
19	O&M Expense (net)	237,424	239,332	-	239,332	1,908	Schedule 21, Line 31, Column 4
20	Depreciation & Amortization	189,989	205,340	-	205,340	15,351	Schedule 22, Line 13, Column 3
21	Property Taxes	61,015	63,043	-	63,043	2,028	Schedule 23, Line 4, Column 3
22	Other Revenue	(41,226)	(42,085)	-	(42,085)	(859)	Schedule 20, Line 12, Column 3
23	Utility Income Before Income Taxes	305,534	286,226	16,674	302,899	(2,635)	
24							
25	Income Taxes	49,002	43,711	4,335	48,046	(956)	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 256,532	$ 242,515	$ 12,339	$ 254,853	$ (1,679)	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 3,661,384	$ 3,691,314		$ 3,691,374	$ 29,990	Schedule 2, Line 31, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	7.01%	6.57%		6.90%	-0.10%	Schedule 26, Line 5, Column 6

COST OF ENERGY Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential	$ 379,106	$ 287,645	$ (91,461)	
3	Commercial	242,118	179,099	(63,019)	
4	Industrial	19,135	13,310	(5,825)	
5	Bypass and Special Rates	127	144	17	
6	Total	$ 640,486	$ 480,198	$ (160,288)	
7					
8	Total	$ 640,486	$ 480,198	$ (160,288)	

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential	73,068	72,466	(602)	
3	Commercial	55,573	55,102	(471)	
4	Industrial	47,394	49,316	1,922	
5	Bypass and Special Rates	31,352	31,355	3	
6	Total	207,386	208,238	852	
7					
8	**REVENUE AT EXISTING RATES**				
9	Residential	$ 814,408	$ 722,183	$ (92,225)	
10	Commercial	454,626	390,764	(63,862)	
11	Industrial	94,386	89,560	(4,826)	
12	Bypass and Special Rates	29,802	29,546	(256)	
13	Total	$ 1,393,222	$ 1,232,053	$ (161,169)	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved Margin	2016 Forecast Margin at Existing Rates	2016 Forecast Effective Increase	2016 Forecast Margin at Revised Rates	2016 Forecast Revenue at Existing Rates	2016 Forecast Effective Increase	2016 Forecast Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential	$ 435,303	$ 434,537	$ 10,153	$ 444,690	$ 722,183	$ 10,153	$ 732,336	$ 886,652	$ 72,466	
3	Commercial	212,508	211,665	4,936	216,601	390,764	4,936	395,700	91,446	55,102	
4	Industrial	75,250	76,253	1,585	77,838	89,560	1,585	91,145	968	49,316	
5	Total Non-Bypass	$ 723,062	$ 722,455	$ 16,674	$ 739,128	$ 1,202,507	$ 16,674	$ 1,219,181	$ 979,066	$ 176,884	
6											
7											
8	**BYPASS**										
9	Residential	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
10	Commercial				-		-	-			
11	Industrial	29,674	29,401	-	29,401	29,546	-	29,546	16	31,355	
12	Total Bypass	$ 29,674	$ 29,401	$ -	$ 29,401	$ 29,546	$ -	$ 29,546	$ 16	$ 31,355	
13											
14											
15	Total	$ 752,736	$ 751,856	$ 16,674	$ 768,529	$ 1,232,053	$ 16,674	$ 1,248,727	$ 979,082	$ 208,238	
16											
17	**Effective Increase**			2.22%				1.35%			

OTHER REVENUE Schedule 20
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,542	$ 2,314	$ (228)	
2	Connection Charge	3,033	$ 3,060	27	
3	NSF Returned Cheque Charges	89	$ 88	(1)	
4	Other Recoveries	202	$ 202	-	
5	SCP Third Party Revenue	15,035	$ 14,957	(78)	
6	NGT Tanker Rental Revenue	215	$ 486	271	
7	NGT Overhead and Marketing Recovery	227	$ 263	36	
8	Biomethane Other Revenue	(70)	$ 250	320	
9	LNG Mitigation Revenue from FEI	18,039	$ 18,039	-	
10	CNG & LNG Service Revenues	1,914	$ 2,426	512	
11					
12	Total	$ 41,226	$ 42,085	$ 859	

OPERATING AND MAINTENANCE EXPENSE Schedule 21
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base O&M	$ 228,020			
3	Less: O&M tracked outside of Formula	(30,721)			
4	O&M Subject to Formula	197,299			
5	**2014**				
6	Net Inflation Factor	100.621%			Schedule 3, Line 12, Column 3
7	FEI Formula O&M	198,524			
8	Add: FEVI/FEW Base O&M	38,498			
9	Less: FEVI Pension & OPEB's	(2,016)			
10	Less: FEVI Insurance	(1,250)			
11	Less: FEVI NGT Station O&M	(44)			
12	Total	233,712			
13	**2015**				
14	Net Inflation Factor	100.816%			Schedule 3, Line 12, Column 4
15	Formula O&M	235,619			
16	**2016**				
17	Net Inflation Factor	101.039%			Schedule 3, Line 12, Column 5
18	Formula O&M	$ 238,068		$ 238,068	
19					
20	**O&M Tracked Outside of Formula**				
21	Pension & OPEB (O&M Portion)		$ 24,218		
22	Insurance		6,275		
23	Biomethane O&M		1,022		
24	NGT Stations O&M		1,185		
25	LNG Production O&M		2,290		
26	Total		$ 34,990	34,990	
27					
28	**Total Gross O&M**			$ 273,058	
29	O&M Transferred to Biomethane BVA			(959)	
30	Capitalized Overhead			(32,767)	
31	**Net O&M Expense**			$ 239,332	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 165,608	$ 165,610	$ 2	Schedule 7.2, Line 39, Column 6
3	Depreciation transferred to BVA	(171)	(383)	(212)	Schedule 7.2, Line 40, Column 6
4	Vehicle Depreciation allocated to Capital Projects	(1,475)	(1,339)	136	Schedule 7.2, Line 41, Column 6
5		163,962	163,888	(74)	
6					
7	**Amortization**				
8	Rate Base deferrals	$ 39,522	$ 55,090	$ 15,568	Schedule 11.1, Line 38, Column 6
9	Non-Rate Base deferrals	(2,899)	(4,485)	(1,586)	Schedule 12, Line 17, Column 6
10	CIAC	(10,596)	(9,153)	1,443	Schedule 9, Line 17, Column 4
11		26,027	41,452	15,425	
12					
13	Total	$ 189,989	$ 205,340	$ 15,351	

PROPERTY AND SUNDRY TAXES Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 47,550	$ 49,521	$ 1,971	
2	1% In-Lieu of Municipal Taxes	13,465	13,522	57	
3					
4	Total	$ 61,015	$ 63,043	$ 2,028	

INCOME TAXES Schedule 24
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 256,532	$ 254,853	$ (1,679)	Schedule 16, Line 5, Column 7
2	Deduct: Interest on Debt	(133,189)	(130,500)	2,689	Schedule 16, Line 1+2, Column 7
3	Adjustments to Taxable Income	16,123	12,392	(3,731)	Schedule 24, Line 37
4	Accounting Income After Tax	$ 139,466	$ 136,745	$ (2,721)	
5					
6	1 - Current Income Tax Rate	74.00%	74.00%	0.00%	
7	Taxable Income	$ 188,468	$ 184,791	$ (3,677)	
8					
9	Current Income Tax Rate	26.00%	26.00%	0.00%	
10	Income Tax - Current	$ 49,002	$ 48,046	$ (956)	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 49,002	$ 48,046	$ (956)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 992	$ 1,000	$ 8	
19	Depreciation	163,962	163,888	(74)	Schedule 22, Line 5, Column 3
20	Amortization of Deferred Charges	36,623	50,605	13,982	Schedule 22, Line 8+9, Column 3
21	Amortization of Debt Issue Expenses	925	879	(46)	
22	Vehicles: Interest & Capitalized Depreciation	1,726	1,548	(178)	
23	Pension Expense	21,394	18,969	(2,425)	
24	OPEB Expense	10,343	10,938	595	
25	Biomethane Other Revenue	70	(250)	(320)	Schedule 20, Line 8, Column 3
26					
27	Deductions:				
28	Capital Cost Allowance	(156,972)	(174,615)	(17,643)	Schedule 25, Line 24, Column 6
29	CIAC Amortization	(10,596)	(9,153)	1,443	Schedule 22, Line 10, Column 3
30	Cumulative Eligible Capital Allowance	(1,815)	(1,736)	79	
31	Debt Issue Costs	(578)	(1,233)	(655)	
32	Vehicle Lease Payment	(2,747)	(2,567)	180	
33	Pension Contributions	(17,285)	(15,903)	1,382	
34	OPEB Contributions	(3,199)	(3,487)	(288)	
35	Overheads Capitalized Expensed for Tax Purposes	(10,819)	(10,922)	(103)	
36	Removal Costs	(14,009)	(13,661)	348	Schedule 11.1, Line 21, Column 4
37	Major Inspection Costs	(1,892)	(1,908)	(16)	
38	Total	$ 16,123	$ 12,392	$ (3,731)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Class	CCA Rate	12/31/2015 UCC Balance	Adjustments	2016 Additions	2016 CCA	12/31/2016 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 1,177,102	$ -	$ 2,451	$ (47,133)	$ 1,132,420
2	1(b)	6%	58,965	-	6,236	(3,725)	61,476
3	2	6%	118,369	-	-	(7,102)	111,267
4	3	5%	2,182	-	-	(109)	2,073
5	6	10%	113	-	-	(11)	102
6	7	15%	16,451	-	2,184	(2,631)	16,004
7	8	20%	27,126	-	7,161	(6,141)	28,146
8	10	30%	6,130	-	2,683	(2,242)	6,571
9	12	100%	6,476	-	13,065	(13,010)	6,531
10	13	manual	3,456	-	196	(415)	3,237
11	14	manual	178	-	-	(25)	153
12	17	8%	1,586	-	-	(127)	1,459
13	38	30%	1,359	-	6,160	(1,332)	6,187
14	39	25%	-	-	-	-	-
15	42	12%				-	-
16	43.2	50%	6,914	-	-	(3,457)	3,457
17	45	45%	38	-	-	(17)	21
18	46	30%				-	-
19	47	8%	125,277	-	420,069	(26,825)	518,521
20	49	8%	127,858	-	5,438	(10,446)	122,850
21	50	55%	12,346	-	9,438	(9,385)	12,399
22	51	6%	622,577	-	104,252	(40,482)	686,347
23							
24	Total		$ 2,314,503	$ -	$ 579,333	$ (174,615)	$ 2,719,221

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 26

Line No.	Particulars	2015 Approved Earned Return	2016 Amount	2016 Ratio	2016 Average Embedded Cost	2016 Cost Component	2016 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 129,861	$ 2,145,291	58.12%	6.01%	3.49%	$ 128,939	$ (922)	Schedule 27
2	Short Term Debt	3,328	124,904	3.38%	1.25%	0.04%	1,561	(1,767)	
3	Common Equity	123,343	1,421,179	38.50%	8.75%	3.37%	124,353	1,010	
4									
5	Total	$ 256,532	$ 3,691,374	100.00%		6.90%	$ 254,853	$ (1,679)	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

EMBEDDED COST OF LONG TERM DEBT Schedule 27
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Series B Purchase Money Mortgage	November 30, 1991	September 30, 2016	$ 164,672	$ 124,491	10.461%	$ 13,023	
2	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	147,710	150,000	7.073%	10,610	
3	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
4	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
5	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
6	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
7	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
8	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
9	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
10	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,500	150,000	3.429%	5,144	
11	2016 Medium Term Debt Issue - Series 27	January 1, 2016	January 1, 2046	148,500	150,000	4.562%	6,843	
12	2016 Medium Term Debt Issue - Series 28 (Series B Renewal)	September 30, 2016	September 30, 2046	165,327	42,409	4.562%	1,935	
13								
14	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
15	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
16								
17	LILO Obligations - Kelowna				19,106	6.511%	1,244	
18	LILO Obligations - Nelson				3,108	8.237%	256	
19	LILO Obligations - Vernon				9,180	9.564%	878	
20	LILO Obligations - Prince George				24,000	8.442%	2,026	
21	LILO Obligations - Creston				2,294	7.541%	173	
22								
23	Vehicle Lease Obligation				6,499	3.216%	209	
24								
25	Sub-Total				$ 2,151,087		$ 129,293	
26	Less: Fort Nelson Division Portion of Long Term Debt				(5,796)		(354)	
27	Total				$ 2,145,291		$ 128,939	
28								
29	Average Embedded Cost					6.01%		
30								
31	* Interest Rate is Effective interest rate as it includes amortization of debt issue costs							

12. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

12.1 *INTRODUCTION AND OVERVIEW*

In this section, FEI discusses "Exogenous Factors" under its PBR Plan (none of which are identified for 2016), emerging accounting guidance, the results of its 2014 Depreciation Study, and the status of its non-rate base deferral accounts. FEI proposes new depreciation and net salvage rates based on the results of the 2014 Depreciation Study. With respect to its non-rate base deferral accounts, FEI proposes to transfer the December 31, 2015 balance in the FEW Rider B Refund deferral account to the existing rate base Residual Delivery Rate Riders deferral account. FEI also reports on the Flow-through deferral account in this section.

12.2 *EXOGENOUS (Z) FACTORS*

FEI is permitted to adjust the cost of service for "Exogenous Factors" under its PBR Plan. The following criteria have been established for evaluating whether the impact of an event qualifies for exogenous factor treatment:

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 Commission-defined materiality threshold.

The materiality threshold (item 5) for FEI has been established at $1.140 million, as approved by Commission Order G-164-14.

For 2016, FEI has not identified any items that merit exogenous factor treatment.

12.3 *ACCOUNTING MATTERS*

In the following two sections, FEI provides information on emerging accounting guidance and on depreciation rates.

12.3.1 Emerging US GAAP Accounting Guidance

In the PBR Decision, the Commission directed FEI to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." FEI discusses two US GAAP accounting standards below, neither of which impacts the accounting policies or rate forecasts for 2016.

12.3.1.1 Revenue Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers*. This standard completes a joint effort by FASB and the International Accounting Standards Board (IASB) to improve financial reporting by creating common revenue recognition guidance for US GAAP and International Financial Reporting Standards (IFRS) that clarifies the principles for recognizing revenue and that can be applied consistently across various transactions, industries and capital markets. This standard was originally effective for annual and interim periods beginning on or after December 15, 2016 and is to be applied on a full retrospective or modified retrospective basis. In August 2015, FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date*. ASU 2015-14 defers by one year the effective date of the new revenue recognition standard to annual and interim periods beginning on or after December 15, 2017. FASB also decided to allow early adoption of the new guidance as of the original effective date.

The new guidance is not expected to significantly change current practice for rate-regulated operations that use published tariff rates to recognize revenue upon delivery of natural gas to a customer meter. FEI is revisiting its revenue contracts associated with take-or-pay arrangements and any bundled arrangements. FEI is also revisiting the accounting treatment of contributions in aid of construction under the new guidance. Any long-term sale arrangements will need to be aggregated and documented to determine whether the terms result in changes to how revenue is recognized under the new guidance. There are various situations that could arise which could change the timing of when revenue is recognized, resulting in revenue being deferred on the balance sheet. FEI is continuing to assess whether there is any exposure under any of its revenue arrangements and will provide an update in the 2016 annual review for 2017 delivery rates.

12.3.1.2 Leases

In May 2013, FASB issued a proposed ASU, *Leases (Topic 842*) which was a revision of the 2010 proposed ASU, *Leases (Topic 840*). A final standard is expected during Q4 2015. Currently, FASB has not set an effective date for the standard. The existing accounting models for leases require lessees to classify their leases as either capital or operating. However, those models have been criticized for failing to meet the needs of users of financial statements because they do not provide a faithful representation of leasing transactions. In particular, they omit relevant information about rights and obligations that meet the definitions of assets and liabilities in the IASB and FASB's conceptual framework. The models also led to a lack of comparability and undue complexity because of the sharp bright-line distinction between capital leases and operating leases. As a result, many users of financial statements adjust the amounts presented in the statement of financial position to reflect the assets and liabilities arising from operating leases.

FASB is pursuing a dual model approach whereby leases would either be recognized as finance leases using the effective interest method resulting in higher expenses in the earlier part of the lease term or a second option of using the straight-line method which distributes expense in a more even manner over the term of the lease.

These proposed changes could result in operating leases being recognized as assets and liabilities on the balance sheet. FEI has building operating leases which could potentially be recorded as assets and liabilities on the balance sheet and the income statement classification would change from operations and maintenance expense to interest and depreciation expense. Once a final standard is issued during Q4 2015 FEI will assess the impact of the standard and provide an update in the 2016 annual review for 2017 delivery rates.

12.3.2 Depreciation Study and Rates

FEI last received approval to update its depreciation rates effective January 1, 2012 in Order G-44-12 and the attached decision (the 2012-2013 RRA Decision). The approved depreciation rates were based on a depreciation study related to gas plant-in-service as at December 31, 2009. At the time, FEI committed to filing an updated depreciation study within 3 to 5 years. In preparation for this annual review, FEI contracted Gannet Fleming Valuation and Rate Consultants Inc. (Gannett Fleming) to perform a review of FEI's depreciation rates. The current depreciation study which is included in Appendix D-1 has been prepared based on gas plant-in-service as of December 31, 2014, which is five years since the completion of the last study.

As in the prior study, Gannett Fleming has estimated the depreciation rates using various statistical methods, operational interviews with FEI staff and informed judgement based on their experience in the natural gas industry. 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 then accounting for the accumulated depreciation already booked in that class. The depreciation study includes recommendations for both depreciation rates and net salvage rates.

Regarding future depreciation studies, the 2012-2013 RRA Decision stated, with regard to forecasts of asset losses:

> *"When the Utilities obtain future depreciation studies, the study expert should incorporate this loss-forecast schedule into the study and should explain how the amounts have been taken into account in the asset class depreciation rates."*[51]

FEI has included a letter from Gannett Fleming as Appendix D-2 in response to this directive.

[51] 2012-2013 RRA Decision Directive 36

Overall, the current depreciation study's results are consistent with the previous study's results. Implementation of the recommended rates for depreciation, net salvage and amortization of CIAC results in a net increase in depreciation and amortization expense of approximately $5.0 million per year, a 2.7 percent increase compared to the depreciation expense using current approved rates. The increase to the delivery margin is 0.665 percent.

Table 12-1: Impact of Implementing Depreciation Study Recommendations ($ millions)

		Existing		Recommended		Change
Depreciation	$	172.5	$	165.6	$	(6.9)
Net Salvage	$	22.0	$	32.1	$	10.1
CIAC	$	(11.0)	$	(9.2)	$	1.8
Total	$	183.6	$	188.5	$	5.0

Further discussion of the recommended changes by Gannett Fleming to the depreciation, net salvage and amortization of CIAC follows.

12.3.2.1 Depreciation Rates

Implementation of the recommended depreciation rates that were developed using the Average Service Life (ASL) depreciation methodology result in a change to the average composite depreciation rate for FEI from 3.19 percent to 3.06 percent. Total depreciation expense for FEI decreases approximately $6.9 million due to the changes in the depreciation rates. This excludes the effects on depreciation expense of additions and retirements to PP&E as well changes to the net salvage rates. The recommended depreciation rates are set out in Table 12-2 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 12-2: Impact of Implementing Recommended Depreciation Rates[52]

Line #	Class		Description	Existing 2015 Rate	Recommended 2016 Rate	Depreciation Based on 2015 Rate	Depreciation Based on 2016 Rate	Increase + / Decrease -
1	175-00	17500	Unamortized Conversion Expense - Squamish*	10.04%	10.0%	78,011	77,700	(311)
2	175-10	17510	Unamortized Conversion Expense *	0.92%	1.0%	1,003	1,090	87
3	178-00	17800	Organization expense	0.96%	1.0%	6,990	7,281	291
4	401-01	40101	Franchises and Consents	2.02%	5.39%	4,000	10,673	6,673
5	402-01	40201	Computer S/W-Applic 8 Year	12.50%	12.50%	13,533,668	13,533,668	-
6	402-02	40202	Computer S/W-Applic 5 Year	20.00%	20.00%	5,525,512	5,525,512	-
7	402-03	40203	Intangible Plant	2.05%	2.01%	39,085	38,322	(763)
8	402-11	40211	Plant Acquisitions and Adjustments	0.00%	0.00%	-	-	-
9	432-00	43200	Mfg. Gas Structures	3.40%	2.82%	33,916	28,130	(5,786)
10	433-00	43300	Mfg. Gas Equipment	6.54%	4.66%	71,501	50,947	(20,554)
11	434-00	43400	Mfg. Gas Holders	2.35%	2.45%	69,088	72,027	2,940
12	436-00	43600	Mfg. Gas Compressor Equipement	5.19%	3.68%	19,026	13,490	(5,535)
13	437-00	43700	Mfg. Gas Meas/Reg Equipment	15.89%	2.34%	139,092	20,483	(118,609)
14	442-00	44200	LNG Gas Structures	3.57%	3.03%	177,053	150,272	(26,781)
15	443-00	44300	LNG Gas Equipment	1.93%	1.88%	318,423	310,174	(8,249)
16	449-00	44900	LNG Gas Other Equipment	4.24%	3.83%	1,261,924	1,139,898	(122,026)
17	442-01	44201	LNG Gas - Structures Mt Hayes	4.00%	3.88%	692,391	671,620	(20,772)
18	443-05	44305	LNG Gas Equipment Mt Hayes	1.67%	1.65%	1,003,875	991,852	(12,022)
19	448-10	44810	LNG Gas - Piping Mt Hayes	2.50%	2.48%	287,210	284,913	(2,298)
20	448-20	44820	LNG Gas - Pre-Treatment Mt Hayes	4.00%	3.88%	1,148,541	1,114,085	(34,456)
21	448-30	44830	LNG Gas - Liquefaction Equipment Mt Hayes	2.50%	2.46%	717,838	706,353	(11,485)
22	448-40	44840	LNG Gas - Send Out Equipment Mt Hayes	2.50%	2.44%	574,006	560,230	(13,776)
23	448-50	44850	LNG Gas - Sub-Station and Electrical Mt Hayes	2.50%	2.44%	541,099	528,112	(12,986)
24	448-60	44860	LNG Gas - Control Room Mt Hayes	6.68%	6.30%	394,124	371,703	(22,420)
25	449-01	44901	LNG Gas - Other Equipment Mt Hayes	3.03%	2.86%	191,956	181,186	(10,770)
26	465-00	46530	LNG - Mains Mt Hayes	1.54%	1.55%	96,999	97,629	630
27	467-00	46700	LNG - Measuring and Regulating Equipment Mt H	3.71%	2.58%	198,180	137,818	(60,362)
28	462-00	46200	TP Compressor Structures	3.66%	3.51%	1,079,101	1,034,876	(44,225)
29	463-00	46300	TP Meas/Reg Structures	3.37%	2.29%	472,293	320,935	(151,358)
30	464-00	46400	TP Other Structures	2.84%	3.66%	184,559	237,847	53,288
31	465-00	46500	TP Transmission Pipeline	1.47%	1.47%	17,245,962	17,245,962	-
32	465-00	46520	TP Mains - Inspection *	14.72%	15.20%	2,361,555	2,438,563	77,007
33	465-10	46510	TP Mains - Byron Creek *	5.03%	5.03%	48,997	48,997	-
34	466-00	46600	TP Compressor Equipment	2.88%	2.89%	5,150,607	5,168,491	17,884
35	466-00	46610	TP Compressor Equipment - Overhauls *	20.17%	10.19%	777,826	392,962	(384,864)
36	467-10	46710	TP Meas/Reg Equipment	4.28%	2.41%	2,216,134	1,247,870	(968,264)
37	467-20	46720	TP Telemetry Equipment	0.84%	9.75%	110,428	1,281,753	1,171,325
38	467-30	46730	TP Meas/Reg Equipment - Byron Creek *	0.00%	2.41%	-	933	933
39	468-00	46800	TP Communications Equipment	11.35%	0.56%	481,791	23,771	(458,020)
40	465-11	46511	IP Transmission Pipeline (Whistler Pipeline)	1.43%	1.53%	604,712	647,000	42,288
41	467-31	46731	IP Meas/Reg Equipment (Whistler Pipeline)	4.15%	2.55%	13,004	7,990	(5,013)
42	472-00	47200	DS Structures	3.30%	2.41%	712,051	520,013	(192,038)
43	472-10	47210	DS Structures - Byron Creek *	4.67%	4.67%	5,008	5,008	-
44	473-00	47300	DS Services	2.37%	2.45%	25,061,842	26,084,401	1,022,559
45	474-00	47400	DS Meters/Regulators Installations	7.36%	5.99%	13,666,453	11,827,510	(1,838,943)
46	474-02	47402	DS Meters/Regulators Installations New	4.55%	4.55%	4,519,234	4,519,234	-
47	475-00	47500	DS Mains	1.55%	1.54%	20,902,156	20,601,611	(300,545)
48	476-00	47600	DS NGV Fuel Equipment	26.58%	0.00%	295,071	-	(295,071)
49	477-00	47720	DS Telemetering	0.26%	2.82%	27,310	296,214	268,903
50	477-10	47710	DS Meas/Reg Additions	4.71%	3.05%	5,727,714	3,709,029	(2,018,685)
51	477-30	47730	DS Meas/Reg Equipment-Byron Creek	0.00%	0.00%	-	-	-
52	478-10	47810	DS Meters	7.82%	7.09%	17,953,483	16,809,326	(1,144,157)
53	478-20	47820	DS Instruments	3.15%	2.99%	376,249	357,137	(19,111)
54	472-00	47220	Biogas - Structures and Improvements	3.78%	2.72%	20,914	15,049	(5,865)
55	475-10	47510	Biogas - Mains on Municipal Land	1.25%	1.55%	16,701	20,709	4,008
56	475-20	47520	Biogas - Mains on Private Land	2.44%	1.55%	11,338	7,202	(4,136)
57	418-10	41810	Biogas - Purication Overhaul	13.33%	5.00%	23,678	8,881	(14,796)
58	418-20	41820	Biogas - Purification Upgrader	6.67%	4.89%	509,964	373,871	(136,092)
59	477-40	47740	Biogas - Reg and Meter Equipment	4.72%	3.24%	76,394	52,440	(23,954)
60	474-10	47410	Biogas - Reg and Meter Installations	5.21%	5.24%	54,516	54,830	314
61	478-30	47830	Biogas - Meters	10.00%	5.02%	63,507	31,881	(31,627)
62	483-25	48325	RNG Comp S/W	5.00%	5.00%	-	-	-
63	476-10	47610	NGV - Transport CNG Dispensing Equipment	4.99%	5.00%	378,311	379,070	758
64	476-20	47620	NGV - Transport LNG Dispensing Equipment	5.01%	5.00%	304,377	303,770	(608)
65	476-30	47630	NGV - Transport CNG Foundations	4.95%	5.00%	46,108	46,574	466
66	476-40	47640	NGV - Transport LNG Foundations	5.05%	5.00%	45,299	44,850	(449)
67	476-50	47650	NGV - Transport LNG Pumps	9.52%	10.00%	5,998	6,300	302
68	476-50	47660	NGV - CNG Dehydrator	5.15%	5.00%	13,035	12,655	(380)
69	476-70	47670	NGV - LNG Dehydrator	5.00%	5.00%	-	-	-
70	482-10	48210	GP (Frame) Structures	5.33%	6.04%	896,636	1,016,076	119,439
71	482-20	48220	GP (Masonry) Structures	2.23%	1.95%	2,647,989	2,315,506	(332,483)
72	482-30	48230	GP (Leased) Structures *	9.29%	9.49%	431,975	441,275	9,300
73	483-10	48310	GP Computer Hardware	20.00%	20.00%	9,653,872	9,653,872	-
74	483-20	48320	GP Computer Systems Software	12.50%	12.50%	564,941	564,941	-
75	483-30	48330	GP Office Equipment	6.67%	6.67%	312,551	312,551	-
76	483-40	48340	GP Furniture	5.00%	5.00%	1,077,154	1,077,154	-
77	484-00	48400	GP Vehicles	16.04%	10.55%	1,918,317	1,261,736	(656,581)
78	484-10	48410	Vehicles-Leased*	9.44%	9.44%	2,358,191	2,358,191	-
79	485-10	48510	GP Heavy Work Equipment	6.47%	6.38%	55,521	54,749	(772)
80	485-20	48520	GP Heavy Mobile Equipment	16.44%	9.85%	451,562	270,553	(181,009)
81	486-00	48600	GP Small Tools/Equipment	5.00%	5.00%	2,533,644	2,533,644	-
82	487-20	48720	GP NGV Cylinders	8.33%	6.67%	2,013	1,612	(401)
83	488-10	48810	GP Telephone Equipment	6.67%	6.67%	383,329	383,329	-
84	488-20	48820	GP Radio Equipment	6.68%	6.67%	554,042	553,212	(829)
85			Total Annual Depreciation			172,529,925	165,609,084	(6,920,841)
86								
87			Annual Composite Rate			3.19%	3.06%	
88								

Note: Numbers above are in actual dollars with depreciation calculated using the January 1, 2016 gross asset values.

52 In addition to the impact on FEI, Fort Nelson's composite depreciation rate decreases from 3.1% to 2.8% from these depreciation rate changes, resulting in a decrease of approximately $43,000 in annual depreciation expense.

The asset categories that account for the majority of the forecast change in depreciation expense are Services (473-00), Meters and Regulators Installations (474-00), Measurement and Regulating Additions (477-10), Meters (478-10) and Telemetry Equipment (467-02). Refer to pages II-4 to II-10 of the Gannett Fleming study included in Appendix D-1 for further discussion.

For Services (473-00), Gannett Fleming recommends a 45 year life, a decrease from the 50 year service life recommended in the previous study. A recent review of retirements, additions and other plant transactions for the period 1957 to 2014 suggests that an average service life of 45 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended shorter service life and the true-up for the depreciation rate over the remaining life of the assets result in an increase of approximately 0.08 percent in the depreciation rate for Services.

For Meters and Regulators Installations (474-00), Gannett Fleming recommends a 20 year life, a decrease from the 22 year service life recommended in the previous study. The recommended Iowa 20-S0 curve provides a reasonable interpretation of the original survivor curve and retirement activities and is consistent with FEI's management expectations. The shortening of the meters/regulators installations asset life by two years is offset by the true-up of for the depreciation rate over the remaining life of the assets resulting in a decrease of approximately 1.37 percent in the depreciation rate for this asset category.

For Measurement and Regulating Additions (477-10), Gannett Fleming recommends a 30 year life, an increase from the 26 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 30 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life of the measurement/regulating addition assets by four years and the true-up for the depreciation rate over the remaining life of the assets result in a decrease of approximately 1.66 percent in the depreciation rate for this asset category.

For Meters (478-10), Gannett Fleming recommends an 18 year life, a decrease from the 20 years meter life recommended in the previous study. Implementation of more stringent metering testing guidelines introduced by Measurement Canada in 2010 will result in residential meters being retired before they reach 20 years of age. Interviews with FEI Measurement staff and indications from metering experts across Canada confirm that residential meters will no longer be tested when they reach 15 to 20 years of age. The recommended shorter meter life and the true-up for the depreciation rate over the remaining life of the assets results in a decrease of approximately 0.73 percent in the depreciation rate for this asset category.

For Telemetry Equipment (467-02), Gannett Fleming recommends an 8 year life, a decrease from the 15 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 8 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended shorter life of the telemetry equipment assets by seven years and the true-up for the depreciation rate over the remaining life of the assets result in an increase of approximately 8.91 percent in the depreciation rate for this asset category.

The adoption of the depreciation rates as outlined in the current depreciation study 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.

12.3.2.2 Net Salvage

As approved by the Commission, the Company 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, as approved by the Commission.

> *"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."*[53]

The current depreciation study includes updated estimates of net salvage rates which FEI has included in amortization expense. As directed by the Commission in the 2012-2013 RRA Decision, FEI records its negative salvage provision in its deferral schedules rather than within the plant continuity schedules:

> *"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."*[54]

The result is that the net salvage expense is included as a component of deferred charge amortization expense.

The asset classes where net salvage is included are shown in Table 12-3 below, comparing the recommended and existing net salvage rates and the impact on net salvage expense (i.e. depreciation expense). As recommended by the current depreciation study, the composite net salvage rate increases from 0.44% using the current approved rates to 0.64% using the recommended rates. The recommended net salvage rate increase is supported by increases in net salvage activities. This change results in an increase to net salvage expense of approximately $10.1 million.

[53] 2012-2013 RRA Decision Directive 34
[54] 2012-2013 RRA Decision Directive 33

Table 12-3: Impact of Implementing Recommended Net Salvage Rates[55]

Line #	Class	Description	Survivor Curve 2015	Survivor Curve 2016	Existing 2015 Rate	Recommended 2016 Rate	Negative Salvage Based on 2015 Rate	Negative Salvage Based on 2016 Rate	Increase + / Decrease -
1	437-00	Mfg. Gas Meas/Reg Equipment	n/a	n/a	-	0.03%	-	263	263
2	442-00	LNG Gas Structures	-10%	-10%	0.36%	0.36%	17,854	17,854	-
3	443-00	LNG Gas Equipment	-20%	-20%	0.40%	0.45%	65,994	74,244	8,249
4	449-00	LNG Gas Other Equipment	-10%	-10%	0.35%	0.39%	104,168	116,073	11,905
5	442-01	LNG Gas - Structures Mt Hayes	n/a	-10%	-	0.45%	-	77,894	77,894
6	443-05	LNG Gas Equipment Mt Hayes	n/a	-20%	-	0.35%	-	210,393	210,393
7	448-10	LNG Gas - Piping Mt Hayes	n/a	-10%	-	0.27%	-	31,019	31,019
8	448-20	LNG Gas - Pre-Treatment Mt Hayes	n/a	-10%	-	0.46%	-	132,082	132,082
9	448-30	LNG Gas - Liquefaction Equipment Mt Hayes	n/a	-20%	-	0.54%	-	155,053	155,053
10	448-40	LNG Gas - Send Out Equipment Mt Hayes	n/a	-10%	-	0.27%	-	61,993	61,993
11	448-50	LNG Gas - Sub-Station and Electrical Mt Hayes	n/a	-20%	-	0.54%	-	116,877	116,877
12	449-01	LNG Gas - Other Equipment Mt Hayes	n/a	-10%	-	0.28%	-	17,739	17,739
13	465-00	LNG - Mains Mt Hayes	n/a	-20%	-	0.32%	-	20,156	20,156
14	467-00	LNG - Measuring and Reg Equip Mt Hayes	n/a	-7%	-	0.21%	-	11,218	11,218
15	462-00	TP Compressor Structures	-5%	-3%	0.18%	-0.02%	53,071	(5,897)	(58,967)
16	463-00	TP Meas/Reg Structures	-5%	-15%	0.08%	0.57%	11,212	79,883	68,672
17	464-00	TP Other Structures	-5%	-5%	0.14%	0.22%	9,098	14,297	5,199
18	465-00	TP Transmission Pipeline	-10%	-20%	0.10%	0.37%	1,173,195	4,340,820	3,167,626
19	466-00	TP Compressor Equipment	-10%	-2%	0.28%	-0.12%	500,753	(214,609)	(715,362)
20	467-10	TP Meas/Reg Equipment	-5%	-7%	0.19%	0.22%	98,380	113,913	15,534
21	468-00	TP Communications Equipment	-5%	n/a	2.11%	-0.38%	89,566	(16,130)	(105,697)
22	465-11	IP Transmission Pipeline (Whistler Pipeline)	n/a	-20%	-	0.34%	-	143,778	143,778
23	467-31	IP Meas/Reg Equipment (Whistler Pipeline)	n/a	-7%	-	0.22%	-	689	689
24	472-00	DS Structures	-5%	-10%	0.16%	0.32%	34,524	69,047	34,524
25	473-00	DS Services	-50%	-60%	1.17%	1.61%	11,956,973	17,141,178	5,184,205
26	474-00	DS Meters/Regulators Installations	-10%	-20%	0.75%	1.77%	1,360,381	3,494,940	2,134,559
27	474-02	DS Meters/Regulators Installations New	n/a	n/a	0.60%	-	595,943	-	(595,943)
28	475-00	DS Mains	-20%	-25%	0.32%	0.43%	4,153,793	5,752,398	1,598,605
29	476-00	DS NGV Fuel Equipment	-20%	n/a	11.43%	-	126,887	-	(126,887)
30	477-00	DS Telemetering	n/a	-5%	-	0.42%	-	44,117	44,117
31	477-10	DS Meas/Reg Additions	-5%	-10%	0.45%	0.46%	547,234	559,395	12,161
32	478-10	DS Meters	-5%	n/a	0.49%	-0.26%	1,112,586	(616,421)	(1,729,006)
33	472-00	Biogas - Structures and Improvements	n/a	-10%	0.00%	0.29%	-	1,605	1,605
34	475-10	Biogas - Mains on Municipal Land	n/a	-25%	0.33%	0.39%	4,409	5,211	802
35	475-20	Biogas - Mains on Private Land	n/a	-25%	0.01%	0.39%	46	1,812	1,766
36	418-20	Biogas - Purification Upgrader	n/a	-5%	-	0.26%	-	19,879	19,879
37	474-10	Biogas - Reg and Meter Installations	n/a	-25%	-	1.35%	-	14,126	14,126
38	478-30	Biogas - Meters	n/a	n/a	0.22%	-0.21%	1,397	(1,334)	(2,731)
39	482-20	GP (Masonry) Structures	n/a	-10%	-	0.25%	-	296,860	296,860
40	484-00	GP Vehicles	n/a	4%	-	-1.00%	-	(119,596)	(119,596)
41	485-10	GP Heavy Work Equipment	n/a	5%	-	-0.68%	-	(5,835)	(5,835)
42	485-20	GP Heavy Mobile Equipment	n/a	15%	-	-2.89%	-	(79,380)	(79,380)
43		Total Annual Negative Salvage					22,017,464	32,077,602	10,060,138
44									
45		Annual Composite Rate					0.44%	0.64%	
46									

Note: Numbers above are in actual dollars with depreciation calculated using the January 1, 2016 gross asset values.

The asset categories that account for the majority of the forecast change in net salvage expense are Transmission Pipeline (465-00), Services (473-00), Meters and Regulators Installations (474-00), Distribution Mains (475-00) and Meters (478-10). Refer to pages II-4 to II-10 of the Gannett Fleming study included in Appendix D-1 for further discussion.

55 In addition to the impact on FEI, Fort Nelson's composite negative salvage depreciation rate increases from 0.38% to 0.63% from these depreciation rate changes, resulting in an increase of approximately $35,000 in annual amortization expense

For Transmission Pipeline (465-00), Gannett Fleming recommends a negative 20 percent to represent the net salvage expectations, an increase from the negative 10 percent recommended in the previous study. This account has witnessed a significant amount of net salvage activity since 2002. A recent review of the retirements and discussions with FEI's management indicates that the historical results would be reasonable future expectations for the equipment in this account. The recommended increase by negative 10 percent leads to an increase of approximately 0.27 percent in the net salvage rate.

For Services (473-00), Gannett Fleming recommends a negative 60 percent to represent the net salvage expectations, an increase from the negative 50 percent recommended in the previous study. This account has witnessed a significant amount of net salvage activity since 2002. A recent review of the retirements and discussions with FEI's management indicates that the historical results would be reasonable future expectations for the equipment in this account. The recommended increase by negative 10 percent leads to an increase of approximately 0.44 percent in the net salvage rate.

For Meters/Regulators Installations (474-00), Gannett Fleming recommends a negative 20 percent to represent the net salvage expectations, an increase from the negative 10 percent recommended in the previous study. This account has witnessed a significant amount of net salvage activity since 2002 with higher level of negative net salvage in more recent years compared to the earlier years. The recommended increase by negative 10 percent leads to an increase of approximately 1.02 percent in the net salvage rate.

For Distribution Mains (475-00), Gannett Fleming recommends a negative 25 percent to represent the net salvage expectations, an increase from the negative 20 percent recommended in the previous study. This account has witnessed a significant amount of net salvage activity since 2002. A recent review of the retirements and discussions with FEI's management indicates that the historical results would be reasonable future expectations for the equipment in this account. The recommended increase by negative five percent leads to an increase of approximately 0.11 percent in the net salvage rate.

For Meters (478-10), Gannett Fleming recommends zero percent to represent the net salvage expectations, a decrease from the negative five percent recommended in the previous study. A recent review of the retirements and discussions with FEI's management indicates that this account has very minimal retirement activity which is offset by the salvage proceeds from scrapped meters. The recommended decrease to zero leads to a decrease of approximately negative 0.75 percent in the negative salvage rate.

12.3.2.3 Amortization of Contributions in Aid of Construction (CIAC)

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 2.32 percent[56] for Distribution CIAC and 1.48 percent[57] Transmission CIAC is based on the average of the recommended depreciation rates for the Distribution Services, Mains and Meters/Reg Installation costs and Transmission Pipeline and IP Transmission Pipeline. With the lower recommended rates for these asset classes, the amortization rates for CIAC will also be lower, resulting in a reduction to amortization of CIAC of approximately $1.8 million year.

12.4 *NON RATE BASE DEFERRAL ACCOUNTS*

In accordance with Directive 128 of Order G-138-14, FEI has included in its financial schedules a continuity of assets that are excluded from rate base, including deferred charges (Section 11, Schedules 8 and 12).

FEI maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a return. In contrast, non-rate base deferral accounts are outside of rate base and, subject to Commission approval, attract a weighted average cost of capital return (which is equal to a rate base return).

In the following sections, FEI provides a discussion of one non-rate base deferral account as required based on a past directive. FEI also provides additional information for one of its recently-approved deferral accounts. Information on FEI's non rate base Earnings Sharing, Phase-in Rider, and Rate Stabilization deferral accounts is included in Section 10.

12.4.1 FEW Rider B Refund Deferral

The Commission approved the creation of the FortisBC Energy (Whistler) Inc. (FEW) Rider B Refund deferral account through Commission Order G-136-09A. In addition, as approved by Commission Order G-198-13, FEW was to refund the difference between interim and permanent rates for the ten-month period from January 1, 2010 and October 31, 2010, with compound interest, to the individual customers that existed during the 2010 refund period. The Commission further directed FEW to effect the refund by making reasonable efforts to contact inactive customers, and to then hold any unreturned funds in an interest bearing account for two years. The Commission directed that any remaining uncollected refunds must be addressed within the next revenue requirement application.

In its Annual Review for 2015 Rates, FEI reported on the balance in the deferral account and stated that it would continue its efforts to locate inactive customers and that if any balance was remaining in the account at the end of 2015, FEI would request disposition at that time.

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[56] For 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, 2014.

[57] For 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, 2014.

As of June 30th, 2015, all customers that consumed gas during the refund period and have active accounts on the system have been issued their refunds through a credit on their bills. Customers with inactive accounts are still being investigated with refunds returned to customers as they are located; however, FEI is experiencing minimal activity in 2015 in regards to these refunds and does not anticipate an increase in activity for the remainder of 2015.

The pre-tax balance of refunds remaining to be returned to customers, including interest, is approximately $0.016 million ($0.012 million after-tax). However, the balance in the deferral account as of June 30th, 2015 is a debit of approximately $0.008 million after-tax. The additional debit to the deferral account of $0.020 million after-tax is primarily related to PST costs that were returned to customers as part of the refund process.

FEI is requesting to transfer the December 31, 2015 balance in this deferral account to the existing rate base Residual Delivery Rate Riders deferral account, which has an approved amortization period of one year, and amortize the balance in 2016.

12.4.2 Flow-Through Deferral Account

As approved through Commission Order G-162-14, the Flow-Through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are included in rates on a forecast basis and which do not have a previously approved deferral account. The specific items included in the Flow-through account were set out in Table 1 which was included in FEI's letter Response to Orders G-162-14 and G-163-14 filed with the Commission November 7, 2014 reproduced below.

Table 12-4: Variances Captured in the Flow-through Deferral Account

	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 purchase variances	N/A	Flow-through deferral
Water fees variances	N/A	Flow-through deferral
Gross O&M:		
Formula driven O&M variances	Earnings sharing	Earnings sharing
BCUC fees variances	BCUC Variances deferral	Flow-through deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances *	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	N/A - no variance	N/A - no variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Depreciation and Amortization:		
Depreciation variances	Flow-through deferral	Flow-through deferral
Amortization of deferrals	N/A - no variance	N/A - no variance
Other Revenues (FEI)/Other Income (FBC):		
SCP Mitigation Revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
All other other revenue/income variances	Flow-through deferral	Flow-through deferral
Wheeling (FBC)/Transportation costs (FEI):		
Transportation and wheeling variances	Flow-through deferral	Flow-through deferral
Income Tax:		
Income tax variances	Flow-through deferral	Flow-through deferral
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas Storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
All other interest variances	Flow-through deferral	Flow-through deferral

* Including items re-forecast outside of the formula such as insurance premiums, AMI, NGT stations, Biomethane, RS46 O&M

In accordance with the method set out in the table, the calculation of the 2015 projected Flow-through amount of $0.713 million credit is shown in Table 12-5 below.

Table 12-5: 2015 Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	FEI APPROVED G-106-15	FEI PROJECTED	Flow-Through Variance
	(1)	(2)	(3)	(4)
1	Delivery Margin			
2	Residential (Rate 1)	$ (435.303)	$ (434.595)	$ 0.708
3	Commercial (Rate 2, 3, 23)	(212.508)	(215.188)	(2.680)
4	Industrial (All Others)	(104.925)	(104.205)	0.720
5	Total Delivery Margin	(752.736)	(753.988)	(1.252)
6				
7	O&M Tracked outside of Formula			
8	Insurance	6.649	6.185	(0.464)
9	Bio-Methane	0.646	0.659	0.013
10	Bio-Methane O&M transferred to BVA	(0.594)	(0.618)	(0.024)
11	NGT O&M	0.926	0.836	(0.090)
12	LNG Production O&M	0.935	0.680	(0.255)
13				
14	Property and Sundry Taxes	61.015	60.663	(0.352)
15				
16	Depreciation and Amortization	189.989	190.269	0.280
17				
18	Other Operating Revenue	(41.226)	(41.094)	0.132
19				
20	Interest Expense	133.189	132.252	(0.937)
21				
22	Income Taxes	49.002	51.236	2.234
23				
24	2015 After-Tax Flow-Through Addition to Deferral Account (excluding AFUDC)			(0.713)

The variances in delivery margin are due to favourable commercial margin as a result of more customers than forecast for Rate Schedules 3 and 23 while unfavourable residential margin is due to lower customers than forecast and unfavourable industrial margin is due to lower customers and volumes than forecast, mainly for Rate Schedules 5 and 25, partially offset by unbudgeted interruptible volumes for the Vancouver Island Joint Venture. Variances in Other Revenue are shown in Section 5, O&M Tracked Outside the Formula are shown in Section 6, and Property Taxes are shown in Section 9. The variance in depreciation and amortization is primarily due to the timing of leased vehicle depreciation. The variance in interest expense is due to lower interest rates. Finally, the variance in income taxes is due to the income tax impacts of each of the aforementioned items, the tax related to the O&M formula variances after-sharing, and the variance between the projected and approved tax timing differences.

As approved by Commission Order G-162-14, the balance in the account will attract a WACC return and be amortized in the following year. Therefore, FEI has included the projected deferral account addition in the non-rate base deferrals section of the financial schedules in Section 11, Schedule 12 along with a forecasted return utilizing the WACC rate in 2016 related to the average outstanding balance in the account. The amortization of the account is included within the amortization of the non-rate base deferred charges in Section 11, Schedule 22. An adjustment to include the difference between the projected and final actual amounts subject to flow-through will be recorded in the deferral account in 2016 and amortized in 2017 rates.

12.5 SUMMARY

FEI does not have any exogenous factors that are affecting delivery rates in 2016 but has provided an updated depreciation study and recommendations for depreciation, net salvage and CIAC amortization rates. In this section, FEI has also requested disposition of one of its non-rate base deferrals, and included information on the amounts recorded in one of its non-rate base deferrals.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

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. Under the PBR Plan, SQIs are used to monitor the utility's performance to ensure that any cost reductions by the utility as a result of implementing productivity initiatives do not result in degradation of the quality of service to customers during the PBR period.

The Commission approved a balanced set of SQIs covering safety, responsiveness to customer needs, and reliability. Nine of the SQIs have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation approved by the Commission in Order G-14-15. Four of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

In the subsections below, FEI reports on its June 2015 year-to-date performance as measured against the SQI benchmarks and thresholds. Consistent with 2014 results, FEI's June 2015 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. For the nine SQIs with benchmarks, seven are performing better than the approved benchmarks with the remaining two performing better than the threshold and within the performance range. For the four SQIs that are informational only, performance remains at a level consistent with prior years.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's June year-to-date performance for 2015 to the Commission-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation and that was approved by the Commission. Actual June year-to-date results for 2015 are also provided for the four informational SQIs.

Table 13-1: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2015 June YTD Results
Safety SQIs				
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	97.5%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	98.4%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	2.95	2.42
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	10
Responsiveness to the Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	81%

Performance Measure	Description	Benchmark	Threshold	2015 June YTD Results
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.62
Meter Reading Accuracy	Number of scheduled meters that were read	95%	92%	98.2%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	93.8%	97.0%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.5
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.1%
Reliability SQIs				
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	2
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0026

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2015. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

This SQI measures the utility's responsiveness to on average 25,500 annual emergency events that include gas odour calls, carbon monoxide calls, house fires and hit lines. It is calculated as:

$$\frac{\text{Number of emergency calls responded to within one hour}}{\text{Total number of emergency calls in the year}}$$

The June 2015 year-to-date performance is 97.5 percent, an improvement from the 2014 year end result of 96.7 percent. The result is within the performance range with the benchmark at 97.7 percent and the threshold at 96.2 percent. 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 improved response time year-to-date in all operating zones is a reflection of a combination of factors including a decrease in the number emergency events year-to-date and changes made to technician shift schedules starting January 2015. The changes to shift schedules were made to provide more emergency response capacity in the late afternoon and early evening.

The Company's 2009 to 2014 emergency response time results are provided below:

Table 13-2: Historical Emergency Response Time

2009	2010	2011	2012	2013	2014
97.7%	97.7%	97.9%	97.4%	97.4%	96.7%

Telephone Service Factor (Emergency)

This indicator 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 June 2015 year-to-date performance is 98.4 percent which is better than the benchmark of 95 percent approved by the Commission. The telephone service factor (TSF) 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. The principal factors influencing the TSF results include the volume of inbound calls received 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 Company's TSF (Emergency) results for 2009 to 2014 are provided below:

Table 13-3: Historical TSF (Emergency) Results

2009	2010	2011	2012	2013	2014
98.3%	99.2%	96.5%	96.5%	95.6%	95.8%

All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an 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). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI and as approved by the Commission, the measurement of performance is based on the three year rolling average of the annual results.

As of June 30, the 2015 annual AIFR is 2.52 as a result of 11 Medical Treatment and 7 Lost Time injuries. The three-year rolling average of the annual results including 2015 June year-to-date results is 2.42 and within the performance range between the benchmark of 2.08 and the threshold of 2.95.

In 2015, safety continues to be a core value for FEI and prevention of injury remains a key focus. FEI continues to focus and reinforce fundamentals of safe work planning, hazard identification and proper body positioning with all employees. In addition, FEI continues to maintain the Certificate of Recognition (COR) through audits performed annually, providing validation of the effectiveness of the Company's safety programs. The COR, administered by the Partners in Injury and Disability Prevention Program of WorkSafeBC, is a voluntary initiative that recognizes and rewards employers who meets the requirements of the Occupational Health and Safety Regulations. An independent qualified auditor is used to assess the Company's Health and Safety programs in consideration of this initiative.

As a part of the Company's focus on continuous improvement, FEI has undertaken a comprehensive review of its Safety Management System including peer reviews with other utilities from the Fortis group of companies who have achieved overall improvement in safety. The results of this review recently completed confirmed that FEI has in place a robust Safety Management system that addresses the hazard and risk requirements of a safe workplace and identifies opportunities for improvement in the Company's safety culture. As a result of the review and to enhance the Company's existing Safety Management system and programs, FEI will be developing the "Target Zero" safety program with the official launch to take place in January 2016. This program will provide a structured format for employees at all levels to provide input into corporate safety enabling the Company to better understand the current state of the safety culture and prioritize and implement initiatives that are relevant to our employees. Increased O&M funding is being reallocated to support this program. Aspects of the program include:

- Targeted and relevant safety communications to increase safety awareness with employees;
- Annual safety performance analysis developed for all departments;
- Safety action plans created by each department on an annual basis that will become the blueprint for each department's continual safety improvement. The results will be reviewed on a quarterly basis;
- Implementation of a new annual employee safety perception survey that will allow the Company to better understand the current state of our safety culture and prioritize and implement initiatives that are relevant to our employees; and
- Development and implementation of a new voluntary employee based safety program. This program will be developed and administered by the employees for employees.

The Company's 2009 to 2014 AFR results are provided below. FEI notes that the 2013 annual AIFR was impacted by ergonomic-related injuries.

Table 13-4: Historical All Injury Frequency Rate Results

All Injury Frequency Rate	2009	2010	2011	2012	2013	2014
Annual Results	2.49	2.66	1.66	1.91	3.02	1.73
Three year rolling average	2.55	2.26	2.27	2.08	2.20	2.22

Public Contact with Pipelines

This metric 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. This indicator is calculated as:

Number of Line Damages per 1,000 BC One Calls received

For the purpose of this service quality indicator, the measurement of performance is based on the three-year rolling average of the annual results. The threshold of 16 is the same as the benchmark and reflects the trend and improvement in recent years.

The three-year rolling average of the June 2015 year-to-date results is 10, below and better than the benchmark of 16 approved by the Commission. 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 One Call program. The current three-year rolling average result reflects 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 One Call program have contributed to the improved performance. The increase in BC One calls is related to increased funding of the BC One Call program which has raised awareness.

In its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates, the Commission directed as follows:

> *"The Panel also agrees that with regard to the SQI Public Contact with Pipelines, the number of line damages and the number of calls to BC One Call would be helpful and directs FEI to also provide this information in future annual reviews."*

The following table provides the June 2015 year-to-date results for the number of BC One Call tickets and the number of line damages and the three-year rolling totals from July 2012 to June 2015 to support the calculation of the three-year rolling average to June 30, 2015.

Table 13-5: June 2015 Year-To-Date Public Contact with Pipeline Results

	June 2015 YTD	July 2012 to June 2015 Three Year Rolling Average
Number of BC One Call tickets	63,057	304,100
Number of Line Damages	475	2,997
Public Contacts with Pipelines metric (Damages per 1,000 BC One calls)	8	10

The Company's 2009 to 2014 results are provided below. The annual result has been trending downward as has the three year rolling average. This is due to the historical upward trend in BC One Calls (increased awareness and increased construction activity) as well as the declining historical trend in line damages.

Table 13-6: Historical Public Contact with Pipelines Results

Public Contacts with Pipeline	2009	2010	2011	2012	2013	2014
Annual Results	20	19	16	13	10	9
Three year rolling average	26	22	18	16	13	11
Calls to BC One Call	72,691	78,734	82,396	86,828	92,002	107,509
Line Damages	1,435	1,457	1,329	1,094	955	954

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

First Contact Resolution

First Call Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FEI. The Company determines the first contact resolution results using a customer survey methodology, tracking the number of customers who responded that their issue was resolved in the first contact with the Company.

The June 2015 year-to-date performance is 81 percent and better than the benchmark of 78 percent approved by the Commission. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs. The FCR rate is also heavily influenced by the composition of the different call drivers as some call types are simpler to resolve in the first call than others. For example, a move call is simpler to resolve in one call than a high bill call. A high bill call may require a site visit to the customer in order to provide the right resolution or it may require more in-depth investigation.

The Company's 2009 to 2014 results are provided below. The improvement in 2012 reflects the repatriation of the contact centre function from a third party provider. Results have remained consistent after 2012.

Table 13-7: Historical First Contact Resolution Levels

2009	2010	2011	2012	2013	2014
72%	77%	75%	78%	81%	80%

Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system 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 is to achieve a score of five or less.

The June 2015 year-to-date performance is 0.62 which is better than the Commission-approved benchmark of less than 5.0. 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, and mail delivery by Canada Post. No significant billing issues have arisen in 2015.

The Company's 2009 to 2014 results are provided below. The 2009 results were affected by a technical upgrade implementation issue which caused billing accuracy errors. The 2012 results were higher as the Company transitioned its billing functions in-house from its previous third party provider.

Table 13-8: Historical Billing Index Results

2009	2010	2011	2012	2013	2014
3.75	2.4	0.24	3.01	1.43	0.89

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:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The June 2015 year-to-date performance is 98.2 percent and is better than the benchmark of 95 percent approved by the Commission. 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.

The Company's 2009 to 2014 results are provided below. As this SQI was not tracked prior to 2013, there are no results available for those years. The Company started tracking gas Meter Reading Accuracy in 2013 when the Gas monthly meter reading function was moved to a new third party meter reading vendor. Performance improved in 2014 after the new vendor stabilized their new meter reading staff and systems in the latter part of 2013.

Table 13-9: Historical Meter Reading Accuracy Results

2009	2010	2011	2012	2013	2014
n/a	n/a	n/a	n/a	92.5%	97.0%

Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) 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 June 2015 year-to-date performance is 71 percent which is better than the benchmark of 70 percent approved by the Commission. Similar to the TSF (Emergency), 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. Principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the calls forecasted based on historical data in order to reach the service level benchmark desired. Other factors that can influence the non-emergency TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries. Additionally, the complexity of the calls can also influence TSF results as more complex calls require more time for the Company's representatives to resolve. Examples of complex calls include high bill queries, meter reading estimate concerns and collections calls.

From 2009 to 2013 as indicated in the following table, the Company's TSF (Non-Emergency) results were consistent with a benchmark of 75 percent. The 2014 result was achieved with the Company targeting 75 percent as the benchmark until the Commission approved the revised target of 70 percent in mid-September 2014. In 2015 and future years, actual results are expected to be lower than that observed in the past, reflective of the revised target of 70 percent approved by the Commission.

Table 13-10: Historical TSF (Non-Emergency) Results

	2009	2010	2011	2012	2013	2014	
	77%	77%	75%	76%	73%	75%	
						Jan-Aug	Sept-Dec
Benchmark	>=75%	>=75%	>=75%	>=75%	>=75%	>=75%	>=70%

Meter Exchange Appointments

The Meter Exchange Appointments SQI measures FEI's performance in meeting appointments for meter exchanges (excluding industrial meters). The calculation for percentage meter exchange appointments met is calculated as:

$$\frac{\text{Number of meter exchange appointments met}}{\text{Number of meter exchange appointments made}}$$

The June 2015 year-to-date performance is 97.0 percent and is better than the benchmark of 95 percent approved by the Commission. Factors influencing results include the recent Blue Pencil process improvements, number of emergencies, weather and traffic conditions. The Blue Pencil process improvements have resulted in the contact center and operations departments working more closely together in order to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The June year-to-date result is a slight improvement from the performance observed in recent years.

The Company's 2009 to 2014 results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

2009	2010	2011	2012	2013	2014
94.7%	94.2%	96.5%	96.5%	97.0%	95.5%

Customer Satisfaction Index

The Customer Satisfaction Index (CSI), an informational indicator as approved by the Commission, measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The Index includes feedback from both residential and mass market commercial customers.

The June 2015 year-to-date average index score is 8.5, equal to the 8.5 score for the same period last year. FEI believes the overall strong result is likely associated with a continued focus on call quality, improvements to the online experience and relatively small bill increases over the last few quarters due to commodity price and delivery margin levels. To date in 2015, FEI has seen continued strong and stable results attained for contact centre service (8.6), field services (9.0), and overall satisfaction (8.4).

The Company's 2009 to 2014 results, in the previous and current formats, are provided below.

Table 13-12: Historical Customer Satisfaction Results

2009	2010	2011	2012	2013	2014
80.1%	80.0%	8.3	8.3	8.3	8.5
80.1%	80.0%	79.3%	78.9%	n/a	n/a

For the years 2009 through 2012, the satisfaction scores were presented as percentages and reflect the results of a different customer satisfaction model. Originally introduced in 2002, the historical metric was calculated using the results of four satisfaction surveys, including a bi-annual residential survey, as well as annual builder-developer, small commercial and large commercial surveys. Each audience was assigned a contributing weight to determine a final index score, which was presented as a percentage. To maintain a level of comparability, the Company ran parallel CSI studies in 2011 and 2012. As shown in the table above, the CSI scores were 79.3% and 8.3 in 2011 and 78.9% and 8.3 in 2012.

Telephone Abandon Rate

The Telephone Abandon Rate, an informational indicator as approved by the Commission, measures the percent of calls abandoned by the customer before speaking to a customer service representative. Abandon rates can be due to waiting times, or due to customers receiving their required information through informational messages in the Company's Interactive Voice Response (IVR) system such that the customer no longer needs to speak to an agent.

The June 2015 year-to-date result is 2.1 percent and consistent with the Company's prior years' results. The Company's 2009 to 2014 results that are available are provided below. Telephone Abandon Rates for 2009 to 2011 were not reported from our third party Customer Service provider. Since repatriation of outsourced Customer Service functions within the Company in 2012, FEI has reported Abandon Rates from 2012 to present.

Table 13-13: Historical Telephone Abandon Rates

2009	2010	2011	2012	2013	2014
n/a	n/a	n/a	2.2%	2.1%	1.8%

13.2.3 Reliability Service Quality Indicators

Transmission Reportable Incidents

The Transmission Reportable Incidents metric, an informational indicator as approved by the Commission, measures the number of reportable incidents to outside agencies for transmission assets as defined by the Oil and Gas Commission (OGC). The metric is intended to be an indicator of the integrity of the transmission system.

The June 2015 year-to-date result is two reported incidents. In the past, the practice has been to report only on the higher pressure transmission events designated as serious. However, the OGC has new reporting criteria effective October 1, 2014, which require the Company to report on more incidents and events. As of October 1, 2014, the Company reports Transmission Reportable Incidents based on the new OGC 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 change in the OGC reporting criteria will likely increase the number of events reported going forward and will limit the comparability of historical performance data for this metric.

As directed by the Commission in its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates:

> *"For subsequent annual reviews, FEI is directed to report the number of Transmission Reportable Incidents in each of the severity levels."*

The following table summarizes the transmission reportable incidents for June 2015 year-to-date by severity level.

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents to June 30 2015
Level 1 (moderate)	2
Level 2 (major)	0
Level 3 (serious)	0

The first Level 1 incident occurred in May 2015 at a residence in Surrey when a third party's excavator pulled and damaged a high pressure gas service impacting 20 customers. An FEI crew subsequently reinstated the service.

The second Level 1 incident occurred in June 2015 at the compressor station in Warfield when an equipment failure (faulty diaphragm in pilot regulator) resulted in a leak at the valve station. The regulator was replaced.

The Company's 2009 to 2014 historical results are provided below. No comparable historical results under the new OGC reporting criteria are available for 2013 and prior years.

Table 13-15: Historical Transmission Reportable Incidents

2009	2010	2011	2012	2013	2014
n/a	n/a	n/a	n/a	n/a	2

Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric, an informational indicator as approved by the Commission, 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.

The June 2015 year-to-date result is 0.0026 which is based on 58 leaks detected year-to-date as compared to 74 in 2014 and 72 in 2013 for the same time period. 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 its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates, the Commission 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.*

Table 13-16 below provides the historical data for the calculation of the June 2015 year-to-date five-year rolling average result of 0.0076 calculated using data from July 2010 to June 2015.

Table 13-16: June 2015 Year-to-Date Five Year Rolling Average

Period	Metric
July – December 2010 (6 months)	0.0042
January – December 2011	0.0087
January – December 2012	0.0089
January – December 2013	0.0075
January – December 2014	0.0059
January – June 2015 (6 months)	0.0026
Five Year Rolling Average	0.0076

The Company's 2009 to 2014 results are provided below. The five year average for each year shown is calculated by including the stated year's results and the four years prior (i.e. 2014 five year average is calculated using 2010 to 2014 annual data).

Table 13-17: Historical Leaks per KM of Distribution System Mains

Leaks per KM of Distribution System Mains	2009	2010	2011	2012	2013	2014
Leaks	122	140	166	169	143	114
Total km	18,760	18,895	18,974	19,040	19,098	19,172
Leaks per km	0.0065	0.0074	0.0087	0.0089	0.0075	0.0059
5 year average	0.0062	0.0064	0.0067	0.0075	0.0078	0.0077

13.3 *ANNUAL GHG EMISSIONS*

In its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates, the Commission directed FEI to provide estimated annual GHG emissions reported to the Ministry of Environment, as follows:

> *"With regard to including the Estimated Annual GHG Emissions (in tCO2e) reported by the Company to the Ministry of Environment, the Panel has no objection, and directs FEI to provide this information in future annual reviews."*

On March 31, 2015 FEI reported to the BC Ministry of Environment its 2014 GHG emissions of 140,507 tCO2e. The 2013 reported value was 127,940 tCO2e.

13.4 *SUMMARY*

In summary, FEI's June 2015 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. For those SQIs with benchmarks, seven are performing better than the approved benchmarks with the remaining two performing better than the threshold and within the performance range. For the four SQIs that are informational only, performance generally remained at a consistent level with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: CANSIM Table 326-0020

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Canada

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Table 326-0020[1, 2, 3, 4, 5, 6, 7, 8, 9, 10]
Consumer Price Index
monthly (2002=100)

Data table | Add/Remove data | Manipulate | Download | Related information | Help

Data table

The data below is a part of CANSIM table 326-0020. Use the Add/Remove data tab to customize your table.

Selected items [Add/Remove data]

Geography[10] = British Columbia

Products and product groups[15]	All-items[16]	Food[17]	Shelter[18]	Household operations, furnishings and equipment	Clothing and footwear	Transportation	Gasoline	Health and personal care	Recreation, education and reading	Alcoholic beverages and tobacco products	All- excl foo ene
2013 July	117.9	126.9	113.2	110.9	98.2	128.0	199.3	111.7	115.1	131.1	111
2013 August	118.0	127.7	113.3	110.3	101.0	127.3	196.2	112.3	115.4	131.1	112
2013 September	118.1	127.0	113.3	110.8	104.2	126.6	191.1	112.6	114.7	131.6	112
2013 October	117.7	125.9	113.2	112.6	103.5	125.7	180.4	111.9	113.3	131.9	112
2013 November	117.4	127.1	113.3	112.7	100.4	124.6	174.2	111.9	112.0	133.2	112
2013 December	117.0	127.5	113.2	111.3	97.9	124.3	172.7	112.5	111.4	131.8	111
2014 January	117.1	127.2	113.5	111.6	98.3	125.2	176.0	112.4	110.7	133.1	111
2014 February	118.0	128.8	113.5	112.5	100.0	126.4	179.0	113.0	111.8	132.8	112
2014 March	118.6	128.8	113.5	112.8	102.4	128.2	191.3	112.8	112.7	134.2	112
2014 April	119.0	128.8	114.8	112.2	102.6	129.0	196.9	113.2	112.4	135.1	112
2014 May	119.7	129.5	114.6	112.5	102.5	130.2	201.3	112.8	115.1	135.6	113
2014 June	119.8	129.6	114.5	112.8	101.1	130.6	204.5	112.9	115.8	135.5	113
2014 July	119.6	130.2	114.5	112.5	101.0	129.0	197.3	112.4	116.2	135.6	113
2014 August	119.6	129.9	114.4	113.4	99.5	128.5	192.7	112.8	117.0	135.6	113
2014 September	119.5	129.7	114.5	113.6	102.9	127.8	190.7	112.8	115.6	136.3	113
2014 October	119.0	129.8	114.1	113.2	103.9	126.9	178.8	112.3	113.7	135.8	113
2014 November	118.8	130.6	114.2	113.5	102.2	126.0	171.6	113.9	112.2	136.3	113
2014 December	118.1	131.1	114.1	113.0	98.4	123.6	155.6	113.1	111.8	135.4	112
2015 January	118.0	132.2	114.0	113.3	99.6	121.8	140.5	113.6	111.2	137.0	112
2015 February	118.9	133.1	114.0	113.9	101.6	123.7	154.9	113.7	113.1	136.8	113
2015 March	119.8	133.5	114.0	114.5	105.6	126.2	168.2	113.0	114.0	136.9	113
2015 April	119.6	132.7	113.7	114.8	106.5	126.1	165.8	113.0	113.3	137.1	113
2015 May	120.6	134.4	114.0	114.7	104.3	128.1	176.6	114.0	116.6	137.2	114
2015 June	120.7	134.7	113.9	114.9	101.0	128.7	180.8	113.9	118.4	137.4	114

Table A1-2: CANSIM Table 281-0063

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Table 281-0063[1, 11, 12, 13, 14]

Survey of Employment, Payrolls and Hours (SEPH), employment and average weekly earnings (including overtime) for all employees by North American Industry Classification System (NAICS), seasonally adjusted

monthly

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Data table

The data below is a part of CANSIM table 281-0063. Use the Add/Remove data tab to customize your table.

Selected items [Add/Remove data]

Geography = British Columbia
Estimate = Average weekly earnings including overtime for all employees (dollars)[2]

North American Industry Classification System (NAICS)[14]	Industrial aggregate excluding unclassified businesses [11-91N][2, 3]	Goods producing industries [11-33N][4]	Forestry, logging and support [11N][5]	Mining, quarrying, and oil and gas extraction [21]	Utilities [22]	Construction [23]	Manufacturing [31-33]	Service producing industries [41-91N][8]	
2013 July	869.85[A]	1,123.00[A]	1,099.49[A]	1,741.22[A]	1,600.74[A]	1,114.93[A]	984.83[A]	820.30[A]	676
2013 August	872.95[A]	1,124.01[A]	1,250.06[A]	1,620.09[A]	1,693.50[A]	1,097.10[A]	1,009.87[A]	823.47[A]	661
2013 September	872.39[A]	1,123.44[A]	1,169.41[A]	1,705.95[A]	1,600.07[A]	1,111.11[A]	995.39[A]	822.75[A]	667
2013 October	875.32[A]	1,123.74[A]	1,139.47[B]	1,795.22[A]	1,628.39[A]	1,109.73[A]	966.10[A]	826.60[A]	659
2013 November	890.51[A]	1,155.45[A]	1,209.29[A]	1,850.24[A]	1,696.51[A]	1,130.49[A]	1,030.41[A]	839.17[A]	679
2013 December	888.27[A]	1,164.43[A]	1,286.89[C]	1,875.48[A]	1,704.96[A]	1,127.22[A]	1,012.32[A]	837.82[A]	702
2014 January	886.83[A]	1,129.29[A]	1,152.38[A]	1,827.78[A]	1,743.03[A]	1,110.35[A]	993.15[A]	839.34[A]	690
2014 February	889.12[A]	1,128.26[A]	1,043.12[A]	1,821.98[A]	1,718.09[A]	1,131.98[A]	992.75[A]	843.86[A]	686
2014 March	894.20[A]	1,139.55[A]	1,090.39[A]	1,903.93[A]	1,739.25[A]	1,122.63[A]	1,008.62[A]	847.14[A]	674
2014 April	895.19[A]	1,140.13[A]	1,117.43[A]	1,903.84[A]	1,707.05[A]	1,124.44[A]	1,000.16[A]	847.64[A]	680
2014 May	894.44[A]	1,149.14[A]	1,176.58[A]	1,895.44[B]	1,694.67[A]	1,137.39[A]	987.65[A]	848.24[A]	684
2014 June	888.88[A]	1,146.87[A]	1,219.14[A]	1,913.41[A]	1,781.11[A]	1,110.87[A]	1,004.60[A]	837.61[A]	690
2014 July	893.39[A]	1,148.98[A]	1,206.48[A]	1,747.10[B]	1,691.20[A]	1,122.02[A]	997.67[A]	843.31[A]	683
2014 August	900.50[A]	1,153.54[A]	1,131.75[A]	1,945.93[B]	1,876.24[A]	1,135.17[A]	1,021.70[A]	851.72[A]	698
2014 September	897.76[A]	1,162.39[A]	1,099.25[A]	1,986.07[A]	1,745.52[A]	1,138.67[A]	1,025.76[A]	845.04[A]	685
2014 October	905.02[A]	1,165.29[A]	1,163.73[A]	2,001.55[A]	1,726.06[A]	1,143.17[A]	1,011.16[A]	854.29[A]	673
2014 November	902.65[A]	1,154.16[A]	1,115.27[A]	1,949.55[A]	1,729.29[A]	1,140.79[A]	1,009.31[A]	854.95[A]	678
2014 December	895.30[A]	1,150.36[A]	1,182.89[A]	1,947.43[B]	1,646.87[A]	1,147.93[A]	986.93[A]	848.71[A]	688
2015 January	911.15[A]	1,164.64[A]	1,204.43[A]	1,919.00[B]	1,690.57[A]	1,174.93[A]	1,016.28[A]	862.03[A]	686
2015 February	909.08[A]	1,150.40[A]	1,197.33[A]	1,913.37[A]	1,700.44[A]	1,125.11[A]	1,043.11[A]	863.41[A]	685
2015 March	904.92[A]	1,151.65[A]	1,230.13[A]	1,989.33[A]	1,668.65[A]	1,125.66[A]	1,035.46[A]	858.81[A]	695
2015 April	902.83[A]	1,155.94[A]	1,212.80[A]	1,807.90[A]	1,630.94[A]	1,135.37[A]	1,044.52[A]	853.71[A]	686
2015 May	904.23[A]	1,146.84[A]	1,185.73[A]	1,761.76[A]	1,572.08[A]	1,127.22[A]	1,060.12[A]	857.74[A]	696
2015 June	908.74[A]	1,154.93[A]	1,211.67[A]	1,801.63[A]	1,809.56[A]	1,140.35[A]	1,033.81[A]	861.69[A]	703

1 **Table A1-3: BC Housing Starts Embedded in Initial Forecast as Filed[1]**

BC	2008	2009	2010	2011	2012	2013	2014	2015	2016
Forecasted Single-Detached Housing Starts (Units)	13,500	11,500	8,000	8,300	11,900	12,368	8,415	8,216	8,175
Forecasted Percentage Change	-5.3%	-2.5%	-9.1%	3.6%	5.3%	3.8%	7.1%	-9.5%	-0.5%
Forecasted Multi-Family Housing Starts (Units)	19,000	20,000	12,700	13,175	17,100	18,123	19,586	20,062	20,112
Forecasted Percentage Change	-10.7%	-16.7%	-9.3%	3.6%	9.6%	5.6%	2.1%	4.6%	0.2%
Forecast Housing Starts Total	**32,500**	**31,500**	**20,700**	**21,475**	**29,000**	**30,491**	**28,001**	**28,278**	**28,287**
Notes		(1)	(2)	(2)					

(1) Evidentiary update Nov 3, 2008 reduced 2009 housing start forecasts to a total of 29,200

2 (2) Customer Additions for 2010 and 2011 were subsequently adjusted as part of the Negotiated Settlement Agreement

[1] The forecasted percentage changes are not calculated based on the previous year forecast in this table; rather, they are calculated based on the previous year projected housing starts identified in each respective filing. For example, the 2014 percentage changes can be found in Table C4-10 of Exhibit B-1 of the 2014-2018 Multi-Year PBR Plan Application, p. 227.

Table A1-4: FEI Customer Counts, Customer Additions, Use per Customer, and Energy

FEI Customer Counts

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015F	2016F
Rate 1	796,724	809,468	825,262	836,583	844,306	853,492	860,403	854,050	863,189	873,661	883,369	892,830
Rate 2	81,214	82,091	83,289	84,619	85,065	85,193	85,704	81,123	82,452	83,625	84,641	85,667
Rate 3	5,482	5,360	5,290	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,086	5,035
Rate 23	1,038	1,206	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,640	1,670
Industrial	1,248	1,324	1,197	1,145	1,113	1,017	951	954	981	977	968	969
NGT	0	0	0	0	0	0	2	5	10	18	26	31
Total	885,707	899,450	916,341	929,114	937,261	946,574	953,943	942,872	953,295	964,971	975,730	986,202

FEI Customer Additions

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015F	2016F
Rate 1	13,860	12,744	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	9,708	9,461
Rate 2	2,186	877	1,198	1,330	446	128	511	577	1,329	1,173	1,015	1,026
Rate 3	-387	-122	-71	171	-31	37	-16	-104	-86	35	-83	-51
Rate 23	79	168	97	3	42	58	27	88	9	-7	118	30
Total	15,739	13,667	17,018	12,825	8,179	9,409	7,433	6,932	10,391	11,673	10,759	10,466

FEI Normalized Use Per Customer (Gjs)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015F	2016F
Rate 1	94.9	95.2	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	82.9	81.6
Rate 2	310.4	319.3	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	330.0	329.5
Rate 3	3,396	3,449	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,582	3,593
Rate 23	4,730	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,340	5,382

FEI Energy (Pjs)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015F	2016F
Rate 1	74.7	74.8	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	72.8	72.5
Rate 2	25.0	26.0	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	27.7	28.0
Rate 3	18.9	18.3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	18.2	18.1
Rate 23	5.0	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.7	9.0
Industrial	88.9	81.4	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6	75.9	78.1
Sub-Total	212.5	206.0	208.7	202.1	199.2	201.9	206.6	209.7	206.3	205.7	203.4	205.7
NGT	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	1.0	2.3
Total	212.5	206.0	208.7	202.1	199.2	201.9	206.7	209.9	206.6	206.5	204.4	207.9

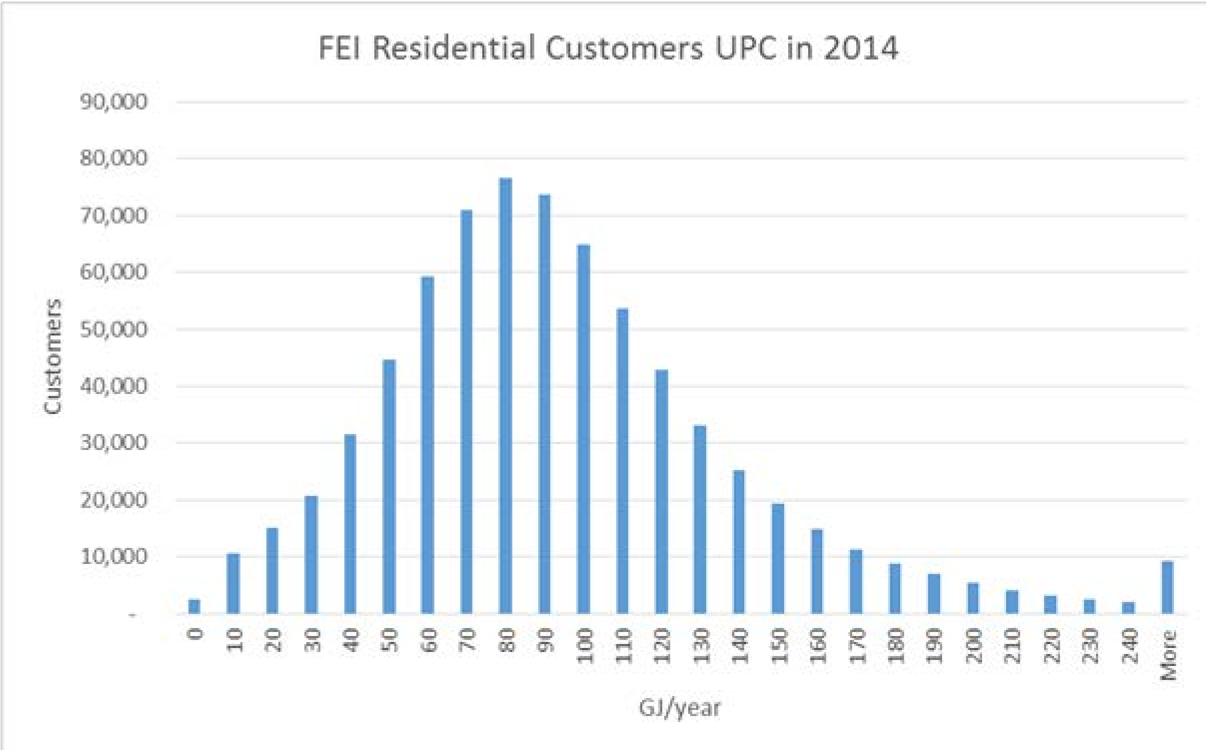
[2]

Table A1-5: FEI 2016 Industrial Forecast Demand by Region

Industrial	2016 Forecast Demand (PJs)
Mainland	57.86
Vancouver Island	20.20
Whistler	0.03
Total	78.09 [3]

[2] Historical industrial tables do not include Burrard Thermal demand.
[3] Does not include NGT and Burrard Thermal forecast demand.

1 **Figure A1-1: FEI Residential Customers UPC in 2014**



2

Appendix A-2

Historical Forecast and Consolidated Tables

September 3, 2015

Table of Contents

1. INTRODUCTION

Directive 12 in the Commission's Decision on FEI's Annual Review for 2015 Delivery Rates directed FEI to provide: "Historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals", with specific reference to Exhibit B-2, BCUC IR 1.5.1 in that proceeding which provided historical variances between FEI's forecast and actual demand forecast. In compliance with this aspect of Directive 12, this appendix provides historical and actual data, as well as the variance between forecast and actual, for FEI's demand forecast over the previous ten years. As discussed below, FEI has also provided an analysis of the historical variances between forecast and actual results including overall under and over variances and a comparison to a recent survey of gas utilities conducted by Itron.

In the data tables presented below, FEI provides 10 year of historical actual demand, forecast demand and variances for each customer class and service area and on an consolidated (or amalgamated) basis, for total demand, total net customers, net customer additions and use per customer. The data tables are also provided as fully-functional Excel file in Appendix A2-1.

In all cases the variance between forecast and actual values is calculated as follows:

$$Variance = \frac{(Forecast - Actual)}{Forecast}$$

In general, it is important to note that as the number of customers decreases and/or the demand from those customers increases in any given rate class, the variance is likely to increase. For example, the Rate Schedule 22 demand variance can be expected to be higher than the Rate Schedule 1 demand variance because there are far fewer Rate Schedule 22 customers and each Rate Schedule 22 customer consumes significantly more than a Rate Schedule 1 customer. For this reason, a small variance in the number of Rate Schedule 22 customers can have a significant effect on the demand and lead to high variance between forecast and actual demand.

The following sections that precede the data tables discuss the FEI variances between forecast and actual customers, customer additions, use rates and total demand for residential, commercial and industrial rate groups. FEI first examines the percentage of under and over forecasts over the past 10 years showing that the forecasts are not biased, and also shows that FEI's historical variances generally compare favourably to the 2014 survey results for gas utilities conducted by Itron. FEI then provides details on the variances by rate class and region. This is then followed by the detailed data tables containing historical actual and forecast demand and variances on a regional and amalgamated basis.

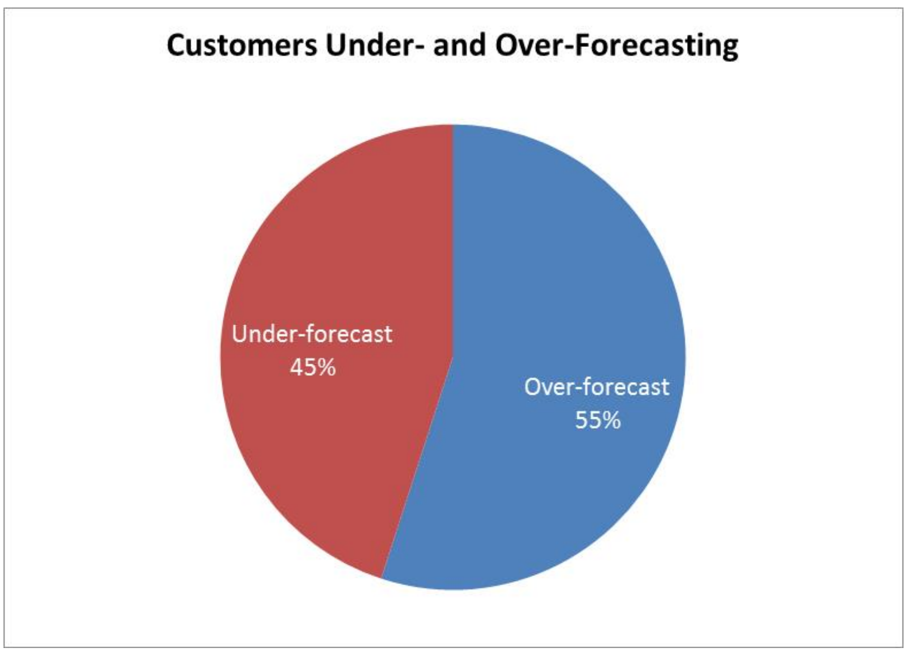
2. UNDER- AND OVER- FORECAST PERCENTAGES

Under-forecasting occurs when the forecast is less than the actual, resulting in a negative variance, whereas over-forecasting occurs when the forecast is more than the average actual consumption resulting in a positive variance. Since FEI's forecast methods (see Appendix A3) are based on recent actual data normalized for weather, it is reasonable to expect a balance between over- and under-forecasting. The following charts examine the over- and under-forecasting for customers, use rates and demand, and show that FEI's demand forecast has indeed produced a balance between over- and under- forecasts in the past 10 years. It is reasonable to conclude from these results that FEI's forecasting methods are not biased.

2.1 *TOTAL CUSTOMER COUNT*

Since 2005, the forecast of the total residential and commercial customer count (Rate Schedules 1/2/3 and 23) on an amalgamated basis has been over-forecast 22 times and under-forecast 18 times.

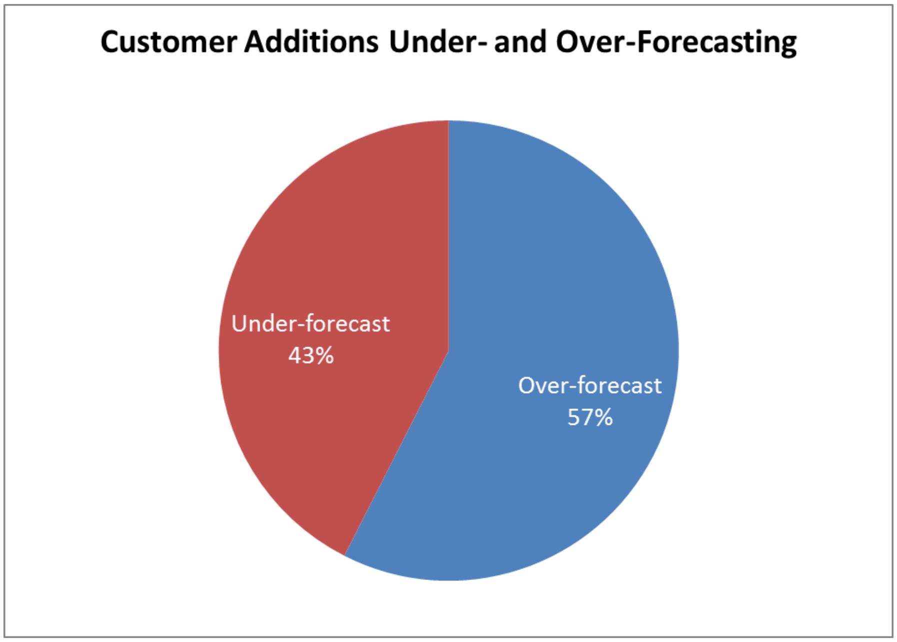
Figure A2-1: Customer Count Under-and-Over Forecasting



2.2 *CUSTOMER ADDITIONS*

Since 2005, the forecast of the total residential and commercial customer additions (Rate Schedules 1/2/3 and 23) has been over-forecast 23 times and under-forecast 17 times.

1 **Figure A2-2: Customer Additions Under-and-Over Forecasting**

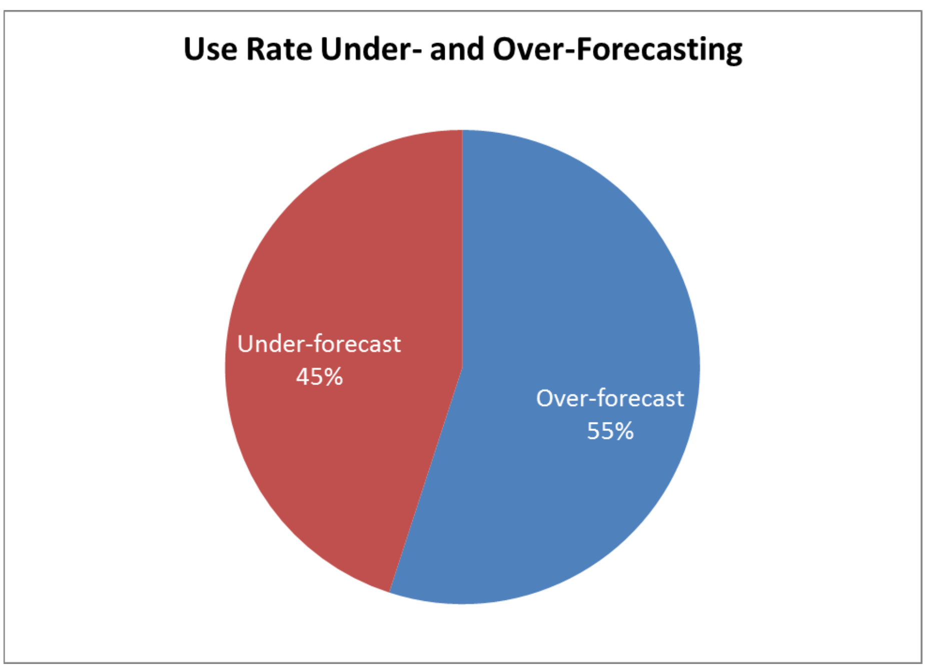


2

3 2.3 *USE PER CUSTOMER RATE*

4 Since 2005, the use per customer rate for all residential and commercial customers (Rate
5 Schedules 1/2/3 and 23) has been over-forecast 22 times and under-forecast 18 times.

6 **Figure A2-3: Use Rate Under-and-Over Forecasting**

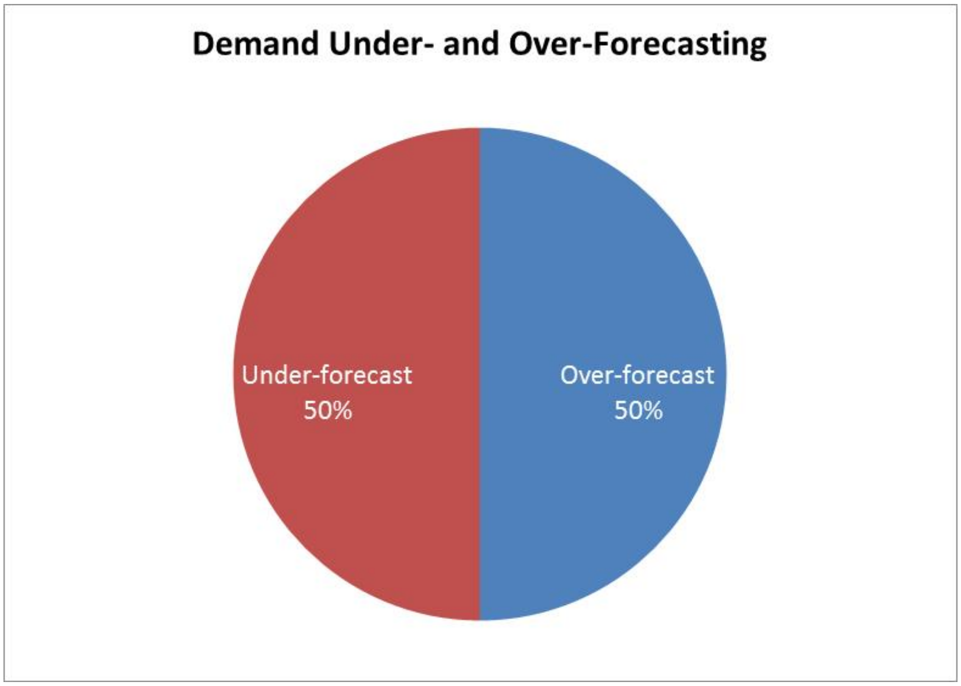


7

2.4 TOTAL DEMAND

Since 2005, the total demand, including all residential, commercial and industrial customers on an amalgamated basis, has been over-forecast 25 times and under-forecast 25 times.

Figure A2-4: Demand Under-and-Over Forecasting



3. COMPARISON TO ITRON SURVEY

Itron[1] published its "2014 Forecasting Benchmark and Outlook Survey" on September 16, 2014, which provides an indication of the average variance between actual and forecast demand for gas utilities. Itron reported that 12 gas utilities participated in the survey (FEI did not participate). Only summary results from the survey are available. At this time, the Itron survey results are the best source of comparison to other gas utilities of which FEI is aware.

The following table provides a summary comparison between FEI's demand forecast variances to the 2014 average variance reported from the Itron survey by rate group for the five years from 2010 through 2014:

Table A2-1: Demand Under-and-Over Forecasting

Class	Itron Survey	FEI				
	2014	2010	2011	2012	2013	2014
Residential	2.9%	-0.9%	-0.1%	0.3%	2.5%	1.3%
Commercial	4.0%	1.3%	-0.4%	-2.8%	-0.2%	4.1%
Industrial	6.4%	-1.6%	-10.5%	-11.8%	-11.1%	6.5%

Based on the 15 comparison points in the table above, FEI notes the following:

- In 5 out of 15 comparison points, FEI's forecast variance was worse than the survey average; however, in 2 of these comparisons, FEI was within 0.1% of the average.
- In 10 of the 15 comparisons, FEI's forecast variance was better than the survey average
- With the exception of 2013, the FEI residential demand forecast beat the survey average by more than 100%. In 2013, the FEI method was 0.4% better than the survey average.
- FEI's commercial forecast variance was significantly better than the survey average in 4 out of 5 years.
- FEI's industrial forecast was worse than the survey average in 4 out of 5 years. See Appendix A4 for a discussion of the industrial survey forecasting process for Rate Schedule 22 customers, including reasons for historical variances and improvements to demand forecast method.

The comparison between Itron's survey average and FEI's historical forecast variances are shown graphically in the following figures. In these figures, the Itron survey average is shown as both a positive and negative range in light green. FEI's forecast variance is better than the survey average when the red bar is within the green range. FEI will update these ranges in the future as better data becomes available.

[1] Itron is a world-leading technology and services company dedicated to the resourceful use of energy and water. Itron provides comprehensive solutions that measure, manage and analyze energy and water.

Figure A2-5: Residential Variance Compared to Benchmark

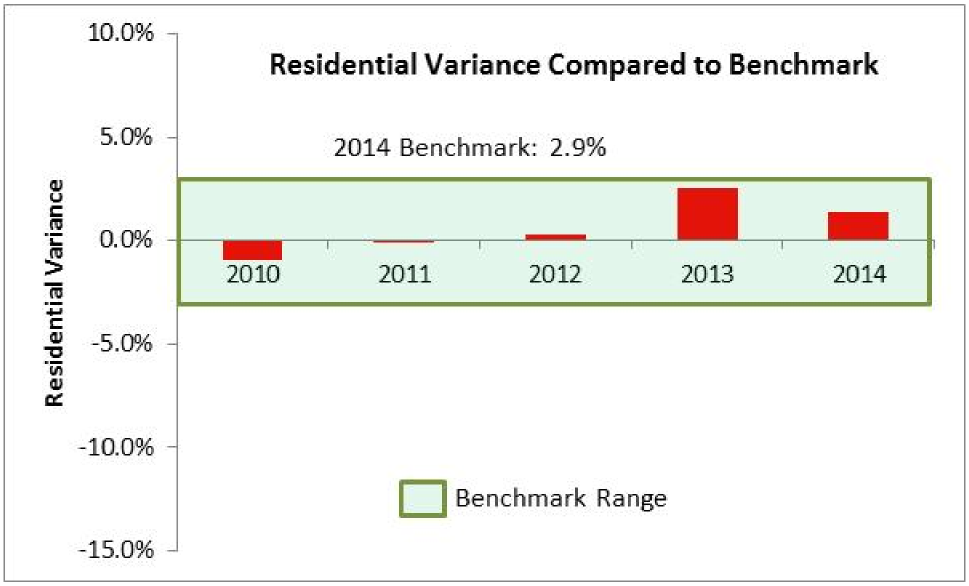
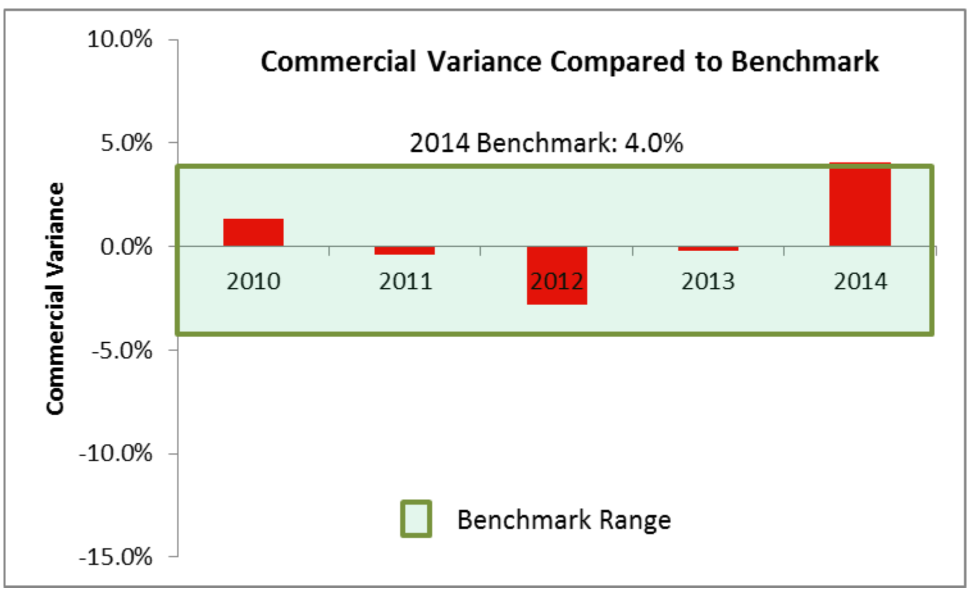
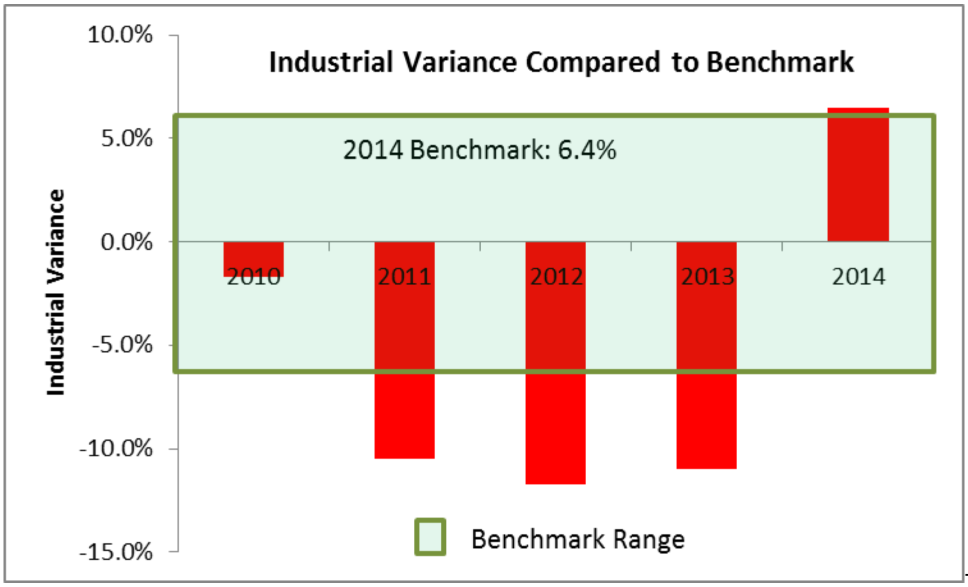


Figure A2-6: Commercial Variance Compared to Benchmark



1 **Figure A2-7: Commercial Variance Compared to Benchmark**

2 

4. AMALGAMATED VARIANCE ANALYSIS

The following sections consider the amalgamated variance for customers, annual use per customer and demand. Rate Schedules 1, 2, 3 and 23 are discussed in the customer and use per customer sections. Industrial customers and use rates are not forecast or part of the forecast methodology. Rate Schedules 1, 2, 3, 23 and industrial customers are discussed in the demand variance section.

The analysis considers both the single year variance and an average of three years. A three year average variance is simply the sum of three consecutive years divided by three.

4.1 *AMALGAMATED TOTAL CUSTOMER COUNT VARIANCE*

Figure A2-8: Amalgamated Total Customer Count Variance

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1	-0.2%	0.6%	0.4%	0.8%	0.2%	-0.5%	-0.3%	1.9%	1.9%	-0.8%
Rate Schedule 2	-2.1%	-0.3%	-0.8%	-0.8%	-0.5%	1.4%	1.8%	5.1%	3.7%	-2.1%
Rate Schedule 3	6.9%	-0.3%	-7.0%	-6.7%	-2.1%	3.6%	5.8%	6.0%	8.3%	-0.4%
Rate Schedule 23	2.9%	-15.2%	0.8%	8.2%	5.5%	-6.6%	-7.9%	0.4%	3.6%	6.9%

As shown in the above figure, the variance between actual and forecast residential (Rate Schedule 1) total customer counts has been less than 2% for 10 years. In 2014, the variance was less that 1%. As expected, the large number of customers in Rate Schedule 1 (873,661 customers in 2014) results in the lower total customer count variance, compared to the commercial rate schedules (i.e. Rate Schedules 2, 3 and 23). The three-year average variance between actual and forecast residential (Rate Schedule 1) total customer counts is very low at 1.0%.

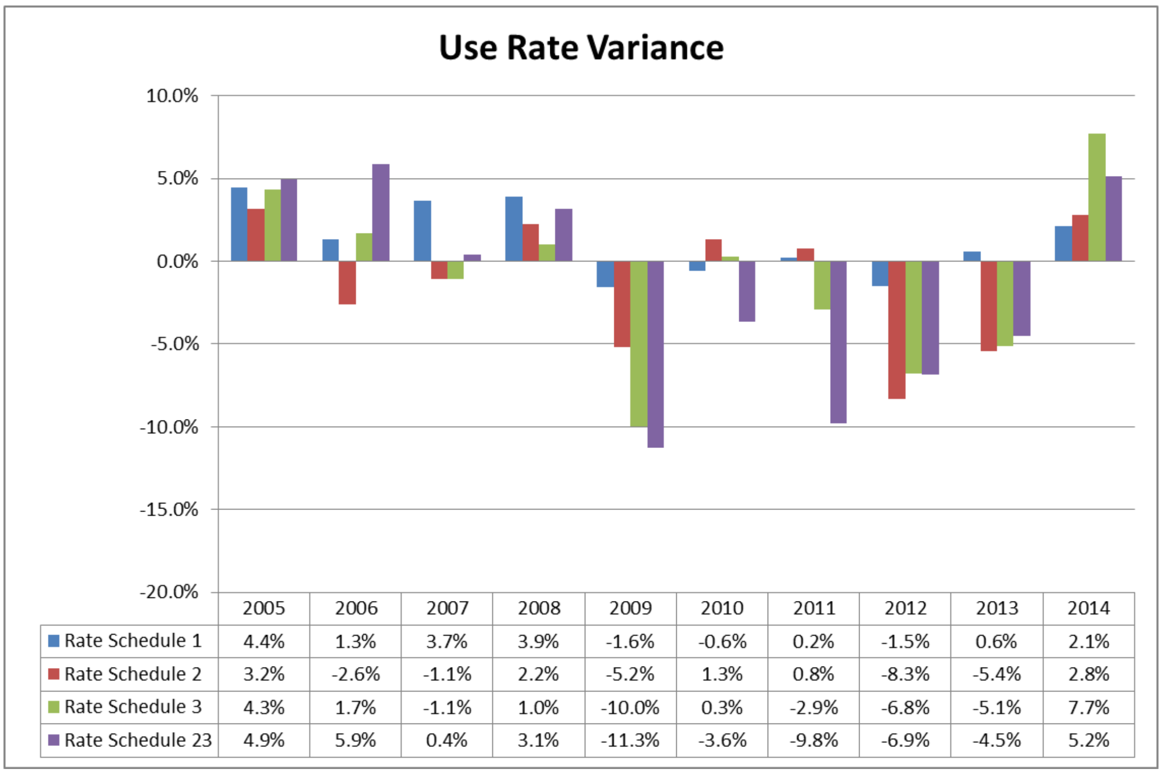
The Rate Schedule 2 total customer count variance improved in 2014 to -2.1% following higher variances in 2012 and 2013. The 2014 result was more typical of prior years. The three-year average variance is just 2.2%.

The Rate Schedule 3 total customer count variance declined to just -0.4% in 2014 following generally higher variances since 2005. The forecast year-end customer count for 2014 was 5,147, while the actual customer count was only 22 more at 5,169. The average variance from the prior three years (2012-2014) declined to 4.6% from 6.7% in 2011-2013 and 5.1% in 2010-2012.

While the Rate Schedule 23 customer count variance increased to 6.9% in 2014, the 2012 and 2013 variances were significantly lower. The average variance for the three-year period from 2012-2014 was just 3.6%.

4.2 *AMALGAMATED USE RATE VARIANCE*

Figure A2-9: Amalgamated Use Rate Variance



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1	4.4%	1.3%	3.7%	3.9%	-1.6%	-0.6%	0.2%	-1.5%	0.6%	2.1%
Rate Schedule 2	3.2%	-2.6%	-1.1%	2.2%	-5.2%	1.3%	0.8%	-8.3%	-5.4%	2.8%
Rate Schedule 3	4.3%	1.7%	-1.1%	1.0%	-10.0%	0.3%	-2.9%	-6.8%	-5.1%	7.7%
Rate Schedule 23	4.9%	5.9%	0.4%	3.1%	-11.3%	-3.6%	-9.8%	-6.9%	-4.5%	5.2%

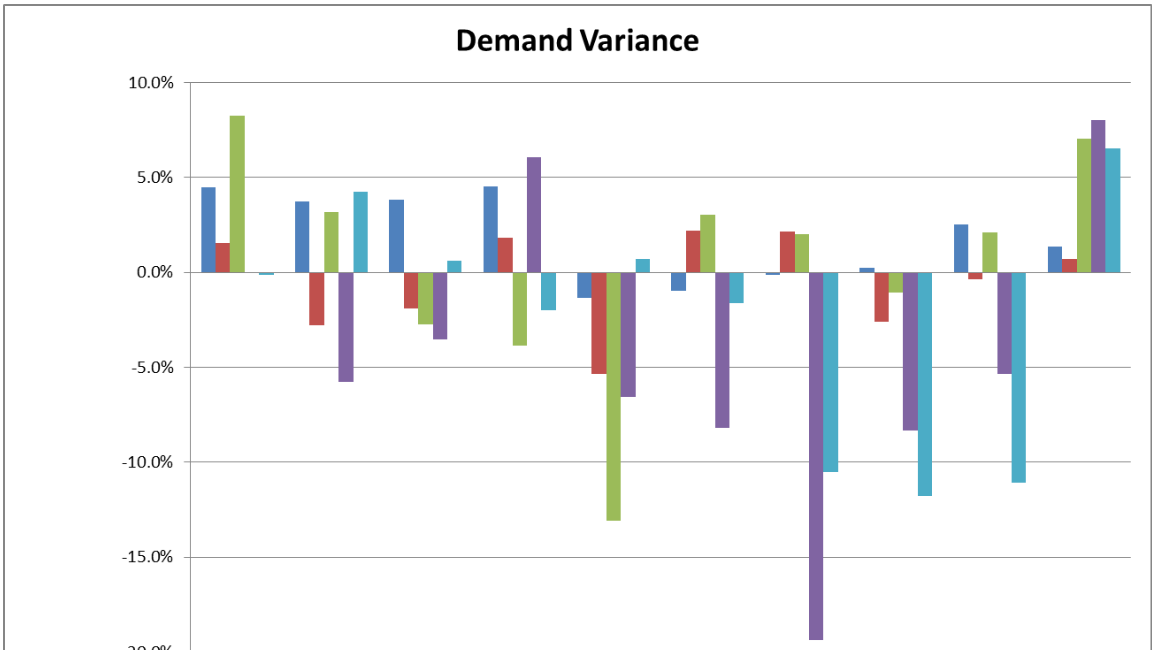
The Rate Schedule 1 use per customer forecast variance increased to 2.1% in 2014 from 0.6% in 2013 and -1.5% in 2012. The three-year average forecast variance remains very low at 0.4%, continuing a trend of sub 1% three-year average variances since 2008.

The Rate Schedule 2 use per customer forecast variance improved in 2014 to 2.8% following higher variances in 2012 and 2013. The 2014 result is more typical of years prior to 2012. The three-year average forecast variance is -3.7%.

The Rate Schedule 3 use per customer forecast variance increased to 7.7% in 2014 following lower variances since 2010. The average variance from the prior three years (2012-2014) declined to just -1.4% from -4.9% in 2011-2013 and -3.1% in 2010-2012.

The Rate Schedule 23 use per customer variance increased to 5.2% in 2014 from -4.5% in 2013. The average variance for the three-year period from 2012-2014 was -2.1%.

Figure A2-10: Amalgamated Demand Variance



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1	4.5%	3.7%	3.8%	4.5%	-1.4%	-0.9%	-0.1%	0.3%	2.5%	1.3%
Rate Schedule 2	1.6%	-2.8%	-1.9%	1.8%	-5.4%	2.2%	2.2%	-2.6%	-0.4%	0.7%
Rate Schedule 3	8.3%	3.2%	-2.7%	-3.8%	-13.1%	3.1%	2.0%	-1.0%	2.1%	7.0%
Rate Schedule 23	0.0%	-5.8%	-3.5%	6.1%	-6.6%	-8.2%	-19.4%	-8.3%	-5.3%	8.0%
Industrial	-0.1%	4.2%	0.6%	-2.0%	0.7%	-1.6%	-10.5%	-11.8%	-11.1%	6.5%

The demand forecast for residential and commercial rate schedules is a simple multiplication product of customers and use rate. The demand variances are presented here for completeness and to show industrial demand forecast variances

The Rate Schedule 1 demand variance decreased to 1.3% in 2014 from 2.5% in 2013. The three-year average variance from 2012-2014 is 1.4%.

The Rate Schedule 2 demand variance remained under 1% in 2013 and 2014 at -0.4% and 0.7%, respectively. The 2012 variance was higher due to the higher than normal use rate variance. The three-year average variance has exceeded 1% just once since 2005.

The Rate Schedule 3 demand variance increased to 7.0% in 2014 following lower variances since 2010. The higher variance was due to higher use rate variances. The average variance from the prior three years (2012-2014) was 2.7%.

The Rate Schedule 23 demand variance was 8% in 2014, up from -5.3% in 2013. However, the average variance for the three-year period from 2012-2014 was -1.9%. The higher variances are due to high use rate variances from 2011 and 2012 when customers in this rate schedule consumed more gas then expected based on recent historic actuals.

Demand variance for all customers in the industrial rate schedules declined to 6.5% in 2014. Prior variances were higher due to large customer fuel switching, both to and from natural gas.

5. DATA TABLES[2]

The tables provided below present the historical data in amalgamated form, unless specifically identified for a particular region. In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates Methodology Application, Section 4.2 as approved by Commission Order G-131-14.

5.1 *AMALGAMATED NET CUSTOMERS*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	794,865	814,441	828,303	842,919	846,375	849,539	857,592	870,980	880,331	866,852
Actual	796,724	809,468	825,262	836,583	844,306	853,492	860,403	854,050	863,189	873,661
Variance	(1,859)	4,973	3,041	6,336	2,069	(3,953)	(2,811)	16,930	17,142	(6,929)
Variance %	-0.2%	0.6%	0.4%	0.8%	0.2%	-0.5%	-0.3%	1.9%	1.9%	-0.8%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	79,532	81,855	82,591	83,957	84,667	86,383	87,262	85,482	85,627	81,923
Actual	81,214	82,091	83,289	84,619	85,065	85,193	85,704	81,123	82,452	83,625
Variance	(1,682)	(236)	(698)	(662)	(398)	1,190	1,558	4,359	3,175	(1,702)
Variance %	-2.1%	-0.3%	-0.8%	-0.8%	-0.5%	1.4%	1.8%	5.1%	3.7%	-2.1%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	5,891	5,345	4,942	5,116	5,316	5,671	5,785	5,553	5,597	5,147
Actual	5,482	5,360	5,290	5,460	5,429	5,466	5,451	5,220	5,134	5,169
Variance	409	(15)	(348)	(344)	(113)	205	334	333	463	(22)
Variance %	6.9%	-0.3%	-7.0%	-6.7%	-2.1%	3.6%	5.8%	6.0%	8.3%	-0.4%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	1,069	1,047	1,313	1,423	1,426	1,319	1,328	1,526	1,586	1,634
Actual	1,038	1,206	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522
Variance	31	(159)	10	117	78	(87)	(105)	6	57	112
Variance %	2.9%	-15.2%	0.8%	8.2%	5.5%	-6.6%	-7.9%	0.4%	3.6%	6.9%

5.2 *AMALGAMATED NET CUSTOMER ADDITIONS*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	12,664	15,829	16,267	14,603	9,827	7,012	7,724	8,984	9,352	6,647
Actual	13,860	12,744	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472
Variance	-1,196	3,085	473	3,282	2,104	-2,174	813	2,613	213	-3,825
Variance %	-9.4%	19.5%	2.9%	22.5%	21.4%	-31.0%	10.5%	29.1%	2.3%	-57.5%

[2] 2012 Customer count and additions adjusted for SAP integration.

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	461	675	588	796	618	830	877	145	145	411
Actual	2,186	877	1,198	1,330	446	128	511	577	1,329	1,173
Variance	-1,725	-202	-610	-534	172	702	366	-432	-1,184	-762
Variance %	-374%	-30%	-104%	-67%	28%	85%	42%	-298%	-817%	-185%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	129	-4	-284	14	14	105	114	44	44	4
Actual	-387	-122	-71	171	-31	37	-16	-104	-86	35
Variance	516	118	-213	-157	45	68	130	148	130	-31
Variance %	400%	-2950%	75%	-1121%	321%	65%	114%	336%	295%	-775%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	95	9	147	70	53	9	9	60	60	57
Actual	79	168	97	3	42	58	27	88	9	-7
Variance	16	-159	50	67	11	-49	-18	-28	51	64
Variance %	17%	-1767%	34%	96%	21%	-544%	-200%	-47%	85%	112%

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5.3 *AMALGAMATED USE PER CUSTOMER*

UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	99.3	96.5	95.7	92.4	87.7	87.9	86.5	86.3	85.2	86.0
Actual	94.9	95.2	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2
Variance	4.4	1.3	3.5	3.6	-1.4	-0.5	0.2	-1.3	0.5	1.8
Variance %	4.4%	1.3%	3.7%	3.9%	-1.6%	-0.6%	0.2%	-1.5%	0.6%	2.1%

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UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	320.5	311.1	318.7	325.4	309.0	320.5	320.2	315.0	314.5	340.0
Actual	310.4	319.3	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6
Variance	10.1	-8.2	-3.4	7.2	-16.1	4.3	2.5	-26.2	-17.1	9.4
Variance %	3.2%	-2.6%	-1.1%	2.2%	-5.2%	1.3%	0.8%	-8.3%	-5.4%	2.8%

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UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	3,549	3,507	3,527	3,573	3,164	3,496	3,487	3,450	3,435	3,872
Actual	3,396	3,449	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573
Variance	153	58	-38	34	-316	11	-101	-234	-175	299
Variance %	4.3%	1.7%	-1.1%	1.0%	-10.0%	0.3%	-2.9%	-6.8%	-5.1%	7.7%

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UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	4,975	4,979	4,796	4,850	4,391	4,680	4,680	4,901	4,927	5,546
Actual	4,730	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260
Variance	245	293	18	152	-495	-170	-458	-337	-222	286
Variance %	4.9%	5.9%	0.4%	3.1%	-11.3%	-3.6%	-9.8%	-6.9%	-4.5%	5.2%

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5.4 AMALGAMATED DEMAND

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	78.2	77.7	78.4	77.2	73.8	74.3	73.8	74.7	74.6	74.2
Actual	74.7	74.8	75.4	73.7	74.8	75	73.9	74.5	72.7	73.2
Variance	3.5	2.9	3	3.5	-1	-0.7	-0.1	0.2	1.9	1
Variance %	4.5%	3.7%	3.8%	4.5%	-1.4%	-0.9%	-0.1%	0.3%	2.5%	1.3%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	25.4	25.3	26.2	27.1	26.1	27.5	27.7	26.9	26.9	27.7
Actual	25.0	26.0	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5
Variance	0.4	-0.7	-0.5	0.5	-1.4	0.6	0.6	-0.7	-0.1	0.2
Variance %	1.6%	-2.8%	-1.9%	1.8%	-5.4%	2.2%	2.2%	-2.6%	-0.4%	0.7%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	20.6	18.9	18.3	18.2	16.8	19.6	19.9	19.1	19.1	19.9
Actual	18.9	18.3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5
Variance	1.7	0.6	-0.5	-0.7	-2.2	0.6	0.4	-0.2	0.4	1.4
Variance %	8.3%	3.2%	-2.7%	-3.8%	-13.1%	3.1%	2.0%	-1.0%	2.1%	7.0%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	5.0	5.2	5.7	6.6	6.1	6.1	6.2	7.2	7.5	8.7
Actual	5.0	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0
Variance	0	-0.3	-0.2	0.4	-0.4	-0.5	-1.2	-0.6	-0.4	0.7
Variance %	0.0%	-5.8%	-3.5%	6.1%	-6.6%	-8.2%	-19.4%	-8.3%	-5.3%	8.0%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Industrial										
Forecast	88.8	85	82.3	75.1	71.9	73.2	71.3	72.1	72.1	84.1
Actual	88.9	81.4	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6
Variance	-0.1	3.6	0.5	-1.5	0.5	-1.2	-7.5	-8.5	-8	5.5
Variance %	-0.1%	4.2%	0.6%	-2.0%	0.7%	-1.6%	-10.5%	-11.8%	-11.1%	6.5%

[3]

[3] Industrial demand excludes NGT and Burrard Thermal.

5.5 *MAINLAND NET CUSTOMERS*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	718,576	732,228	744,400	755,539	755,803	757,161	762,460	773,231	780,005	768,622
Actual	720,024	728,951	740,954	748,913	753,735	760,559	765,553	759,712	766,668	774,083
Variance	(1,448)	3,277	3,446	6,626	2,068	(3,398)	(3,093)	13,519	13,337	(5,461)
Variance %	-0.2%	0.4%	0.5%	0.9%	0.3%	-0.4%	-0.4%	1.7%	1.7%	-0.7%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	70,957	73,200	74,019	75,037	75,685	77,204	77,954	76,126	76,175	72,922
Actual	72,578	73,515	74,579	75,701	75,986	76,028	76,437	72,235	73,480	74,464
Variance	-1,621	-315	-560	-664	-301	1,176	1,517	3,891	2,695	-1,542
Variance %	-2.3%	-0.4%	-0.8%	-0.9%	-0.4%	1.5%	1.9%	5.1%	3.5%	-2.1%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	5,292	4,742	4,332	4,514	4,715	5,083	5,191	4,962	5,002	4,577
Actual	4,884	4,769	4,700	4,869	4,841	4,882	4,863	4,675	4,598	4,625
Variance	408	-27	-368	-355	-126	201	328	287	404	-48
Variance %	7.7%	-0.6%	-8.5%	-7.9%	-2.7%	4.0%	6.3%	5.8%	8.1%	-1.0%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	1,069	1,047	1,313	1,423	1,426	1,319	1,328	1,526	1,586	1,634
Actual	1,038	1,206	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522
Variance	31	-159	10	117	78	-87	-105	6	57	112
Variance %	2.9%	-15.2%	0.8%	8.2%	5.5%	-6.6%	-7.9%	0.4%	3.6%	6.9%

5.6 MAINLAND NET CUSTOMER ADDITIONS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	9,651	12,048	12,764	11,094	6,410	4,777	4,983	6,507	6,774	4,594
Actual	11,099	8,927	12,003	7,959	4,822	6,824	4,994	4,475	6,956	7,415
Variance	-1,448	3,121	761	3,135	1,588	-2,047	-11	2,032	-182	-2,821
Variance %	-15%	26%	6%	28%	25%	-43%	0%	31%	-3%	-61%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	374	622	523	626	480	713	750	49	49	331
Actual	1,996	937	1,064	1,122	285	42	409	325	1,245	984
Variance	-1,622	-315	-541	-496	195	671	341	-276	-1,196	-653
Variance %	-434%	-51%	-103%	-79%	41%	94%	45%	-563%	-2441%	-197%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	127	-7	-288	8	7	101	108	40	40	0
Actual	-392	-115	-69	169	-28	41	-19	-144	-77	27
Variance	519	108	-219	-161	35	60	127	184	117	-27
Variance %	409%	-1543%	76%	-2013%	500%	59%	118%	460%	293%	

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	95	9	147	70	53	9	9	60	60	57
Actual	79	168	97	3	42	58	27	88	9	-7
Variance	16	-159	50	67	11	-49	-18	-28	51	64
Variance %	17%	-1767%	34%	96%	21%	-544%	-200%	-47%	85%	112%

5.7 MAINLAND USE PER CUSTOMER

UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	103	101	100	96	91	92	90	91	90	91
Actual	99	97	96	93	93	93	90	92	89	89
Variance	4.7	3.8	3.8	3.6	-2.2	-0.9	-0.1	-1.4	0.6	1.9
Variance %	4.5%	3.8%	3.8%	3.7%	-2.4%	-1.0%	-0.1%	-1.5%	0.7%	2.1%

UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	317.1	307	314.2	321.9	303.3	317.8	317.8	308	306.4	333.6
Actual	304.9	314.3	316.5	312.2	320.6	311.3	313.7	337.6	329.6	330.4
Variance	12.2	-7.3	-2.3	9.7	-17.3	6.5	4.1	-29.6	-23.2	3.2
Variance %	3.8%	-2.4%	-0.7%	3.0%	-5.7%	2.0%	1.3%	-9.6%	-7.6%	1.0%

UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	3,426	3,391	3,394	3,429	2,976	3,346	3,347	3,334	3,316	3,769
Actual	3,264	3,314	3,426	3,420	3,372	3,370	3,484	3,566	3,517	3,529
Variance	162.0	77.0	-32.0	9.0	-396.0	-24.0	-137.0	-232.0	-201.0	240.0
Variance %	4.7%	2.3%	-0.9%	0.3%	-13.3%	-0.7%	-4.1%	-7.0%	-6.1%	6.4%

UPC, GJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	4,975	4,979	4,796	4,850	4,391	4,680	4,680	4,901	4,927	5,546
Actual	4,730	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260
Variance	245.0	293.0	18.0	152.0	-495.0	-170.0	-458.0	-337.0	-222.0	286.0
Variance %	4.9%	5.9%	0.4%	3.1%	-11.3%	-3.6%	-9.8%	-6.9%	-4.5%	5.2%

1 ## 5.8 MAINLAND DEMAND

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 1										
Forecast	73.6	72.9	73.6	72.0	68.5	69.2	68.6	69.9	69.8	69.5
Actual	70.3	70.0	70.6	68.8	70.0	70.0	68.9	69.8	68.1	68.5
Variance	3.3	2.9	2.9	3.2	(1.5)	(0.9)	(0.4)	0.1	1.7	1.0
Variance %	4.5%	4.0%	4.0%	4.4%	-2.2%	-1.3%	-0.5%	0.2%	2.5%	1.5%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 2										
Forecast	22.4	22.3	23.1	24.0	22.9	24.4	24.6	23.4	23.3	24.2
Actual	22.0	22.9	23.5	23.4	24.3	23.6	23.9	24.3	23.9	24.5
Variance	0.5	-0.6	-0.4	0.6	-1.4	0.8	0.7	-0.9	-0.6	-0.2
Variance %	2.1%	-2.7%	-1.6%	2.6%	-6.1%	3.1%	2.9%	-3.8%	-2.5%	-0.9%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 3										
Forecast	17.9	16.3	15.5	15.5	14.0	16.8	17.2	16.5	16.5	17.3
Actual	16.2	15.6	16.1	16.3	16.5	16.4	16.9	16.7	16.3	16.3
Variance	1.7	0.7	-0.6	-0.8	-2.5	0.4	0.3	-0.2	0.2	1.0
Variance %	9.5%	4.3%	-3.9%	-5.2%	-17.9%	2.4%	1.7%	-1.2%	1.2%	5.8%

Demand, PJs	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate Schedule 23										
Forecast	5.0	5.2	5.7	6.6	6.1	6.1	6.2	7.2	7.5	8.7
Actual	5.0	5.5	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0
Variance	0.0	-0.3	-0.2	0.4	-0.4	-0.5	-1.2	-0.6	-0.4	0.7
Variance %	0.0%	-5.8%	-3.5%	6.1%	-6.6%	-8.2%	-19.4%	-8.3%	-5.3%	8.0%

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5.9 VANCOUVER ISLAND NET CUSTOMERS

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS Accounts										
Forecast	74,251	80,080	81,732	85,256	88,394	90,106	92,811	95,460	98,023	95,858
Actual	74,655	78,453	82,210	85,536	88,321	90,671	92,554	92,067	94,173	97,162
Variance	-404	1,627	-478	-280	73	-565	257	3,393	3,850	-1,304
Variance (%)	-0.5%	2.0%	-0.6%	-0.3%	0.1%	-0.6%	0.3%	3.6%	3.9%	-1.4%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS Accounts										
Forecast	746	779	807	849	848	882	887	954	980	1,014
Actual	786	785	821	868	876	902	939	959	1,000	1,032
Variance	-40	-6	-14	-19	-28	-20	-52	-5	-20	-18
Variance (%)	-5.4%	-0.8%	-1.7%	-2.2%	-3.3%	-2.3%	-5.9%	-0.5%	-2.0%	-1.8%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF Accounts										
Forecast	7	7	7	6	6	6	6	6	6	6
Actual	7	6	5	6	6	6	14	6	6	4
Variance	0	1	2	0	0	0	-8	0	0	2
Variance (%)	0.0%	14.3%	28.6%	0.0%	0.0%	0.0%	-133.3%	0.0%	0.0%	33.3%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF Accounts										
Forecast	9	9	8	9	8	8	8	8	8	8
Actual	8	9	8	8	8	8	8	8	8	7
Variance	1	0	0	1	0	0	0	0	0	1
Variance (%)	11.1%	0.0%	0.0%	11.1%	0.0%	0.0%	0.0%	0.0%	0.0%	12.5%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C Accounts										
Forecast	1,485	1,503	1,505	1,469	1,467	1,356	1,361	1,396	1,408	1,308
Actual	1,493	1,474	1,454	1,446	1,360	1,372	1,360	1,263	1,264	1,264
Variance	-8	29	51	23	107	-16	1	133	144	44
Variance (%)	-0.5%	1.9%	3.4%	1.6%	7.3%	-1.2%	0.1%	9.5%	10.2%	3.4%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C Accounts										
Forecast	557	553	562	546	536	526	531	517	517	471
Actual	552	543	530	523	526	517	514	433	435	440
Variance	5	10	32	23	10	9	17	84	82	31
Variance (%)	0.9%	1.8%	5.7%	4.2%	1.9%	1.7%	3.2%	16.2%	15.9%	6.6%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C Accounts										
Forecast	141	135	130	141	144	121	124	121	121	127
Actual	129	140	142	146	124	121	119	133	95	100
Variance	12	-5	-12	-5	20	0	5	-12	26	27
Variance (%)	8.5%	-3.7%	-9.2%	-3.5%	13.9%	0.0%	4.0%	-9.9%	21.5%	21.3%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C										
Forecast	4,072	4,141	4,058	4,426	4,531	5,180	5,287	5,202	5,247	4,908
Actual	4,162	4,178	4,331	4,509	5,068	5,112	5,168	4,837	5,004	5,136
Variance	-90	-37	-273	-83	-537	68	119	365	243	-228
Variance (%)	-2.2%	-0.9%	-6.7%	-1.9%	-11.9%	1.3%	2.3%	7.0%	4.6%	-4.6%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C Accounts										
Forecast	1,862	1,832	1,815	1,807	1,759	1,405	1,410	1,451	1,463	1,420
Actual	1,823	1,773	1,741	1,728	1,415	1,427	1,434	1,382	1,394	1,414
Variance	39	59	74	79	344	-22	-24	69	69	6
Variance (%)	2.1%	3.2%	4.1%	4.4%	19.6%	-1.6%	-1.7%	4.8%	4.7%	0.4%

5.10 *VANCOUVER ISLAND NET CUSTOMER ADDITIONS*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS Acct.Additions										
Forecast	3,013	3,781	3,428	3,479	3,367	2,200	2,705	2,463	2,564	2,001
Actual	2,723	3,798	3,757	3,326	2,785	2,350	1,883	1,845	2,106	2,989
Variance	290	-17	-329	153	582	-150	822	618	458	-988
Variance (%)	0	0%	-10%	4%	17%	-7%	30%	25%	18%	-49%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS Acct.Additions										
Forecast		5	5	15	15	5	5	26	26	32
Actual	18	-1	36	47	8	26	37	35	41	32
Variance	-18	6	-31	-32	7	-21	-32	-9	-15	0
Variance (%)		120%	-620%	-213%	47%	-420%	-640%	-35%	-58%	0%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF Acct.Additions										
Forecast	0	0	0	0	0	0	0	0	0	0
Actual	0	-1	-1	1	0	0	8	0	0	-2
Variance	0	1	1	-1	0	0	-8	0	0	2
Variance (%)										

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF Acct.Additions										
Forecast	0	0	0	0	0	0	0	0	0	0
Actual	-1	1	-1	0	0	0	0	0	0	-1
Variance	1	-1	1	0	0	0	0	0	0	1
Variance (%)										

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C Acct.Additions										
Forecast	9	8	8	10	6	5	5	12	12	0
Actual	11	-19	-20	-8	-86	12	-12	64	1	0
Variance	-2	27	28	18	92	-7	17	-52	11	0
Variance (%)	0	338%	350%	180%	1533%	-140%	340%	-433%	92%	

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C Acct.Additions										
Forecast	2	3	4	5	3	5	5	0	0	0
Actual	4	-9	-13	-7	3	-9	-3	58	2	5
Variance	-2	12	17	12	0	14	8	-58	-2	-5
Variance (%)	-1	400%	425%	240%	0%	280%	160%			

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C Acct.Additions										
Forecast	3	1	0	1	1	0	3	0	0	0
Actual	-1	11	2	4	-22	-3	-2	-33	-38	0
Variance	4	-10	-2	-3	23	3	5	33	38	0
Variance (%)	1	-1000%		-300%	2300%		167%			

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C Acct.Additions										
Forecast	30	29	30	120	100	100	107	45	45	33
Actual	128	16	153	178	559	44	56	10	167	132
Variance	-98	13	-123	-58	-459	56	51	35	-122	-99
Variance (%)	-3	45%	-410%	-48%	-459%	56%	48%	78%	-271%	-300%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C Acct.Additions										
Forecast	46	10	10	20	8	5	5	12	12	11
Actual	40	-50	-32	-13	-313	12	7	36	12	20
Variance	6	60	42	33	321	-7	-2	-24	0	-9
Variance (%)	0	600%	420%	165%	4013%	-140%	-40%	-200%	0%	-82%

5.11 *VANCOUVER ISLAND USE PER CUSTOMER*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS UPC										
Forecast	60.7	58.9	57.6	59.3	58.6	55.0	54.9	48.6	46.9	45.0
Norm Actual	57.3	60.2	57.0	56.1	53.5	52.5	51.8	49.5	47.3	47.1
Variance	3.4	-1.3	0.6	3.2	5.1	2.5	3.1	-0.9	-0.5	-2.1
Variance (%)	5.7%	-2.2%	1.0%	5.4%	8.7%	4.5%	5.6%	-1.9%	-1.0%	-4.7%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS UPC										
Forecast	1,406	1,326	1,393	1,389	1,364	1,262	1,262	1,264	1,245	1,325
Norm Actual	1,350	1,387	1,367	1,296	1,261	1,301	1,343	1,246	1,152	1,074
Variance	56	-61	26	93	103	-39	-81	18	93	251
Variance (%)	4.0%	-4.6%	1.9%	6.7%	7.6%	-3.1%	-6.4%	1.4%	7.5%	18.9%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF UPC										
Forecast	33,786	37,532	38,968	25,000	29,245	22,061	22,061	10,189	10,189	20,532
Norm Actual	38,918	46,053	29,245	22,061	19,585	20,420	8,779	20,532	19,182	18,009
Variance	-5,132	-8,521	9,724	2,939	9,660	1,641	13,282	-10,343	-8,993	2,523
Variance (%)	-15.2%	-22.7%	25.0%	11.8%	33.0%	7.4%	60.2%	-101.5%	-88.3%	12.3%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF UPC										
Forecast	15,106	12,481	19,764	18,433	14,964	15,062	15,062	14,051	14,051	10,547
Norm Actual	18,366	17,103	14,964	16,344	12,197	13,946	14,938	10,547	10,890	11,367
Variance	-3,260	-4,622	4,800	2,089	2,767	1,116	124	3,504	3,162	-820
Variance (%)	-21.6%	-37.0%	24.3%	11.3%	18.5%	7.4%	0.8%	24.9%	22.5%	-7.8%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C UPC										
Forecast	885	898	907	916	930	981	981	1,049	1,075	1,069
Norm Actual	926	903	943	952	980	997	963	1,060	981	967
Variance	-41	-5	-36	-36	-50	-16	18	-11	94	102
Variance (%)	-4.7%	-0.6%	-4.0%	-3.9%	-5.3%	-1.6%	1.8%	-1.1%	8.7%	9.6%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C UPC										
Forecast	2,405	2,320	2,343	2,341	2,362	2,649	2,649	2,591	2,641	3,074
Norm Actual	2,365	2,295	2,406	2,359	2,430	2,490	2,475	2,935	2,728	2,623
Variance	40	25	-63	-18	-68	159	174	-344	-87	451
Variance (%)	1.7%	1.1%	-2.7%	-0.8%	-2.9%	6.0%	6.6%	-13.3%	-3.3%	14.7%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C UPC										
Forecast	17,553	16,636	17,951	18,188	17,694	19,699	19,699	16,342	16,342	14,286
Norm Actual	16,630	17,379	17,694	16,521	15,793	16,342	17,121	14,625	14,891	11,494
Variance	923	-743	257	1,667	1,901	3,357	2,578	1,717	1,451	2,791
Variance (%)	5.3%	-4.5%	1.4%	9.2%	10.7%	17.0%	13.1%	10.5%	8.9%	19.5%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C										
Forecast	65	66	67	73	80	79	79	110	115	106
Norm Actual	70	75	91	103	110	101	97	110	108	108
Variance	-5	-9	-24	-30	-30	-22	-18	1	7	-2
Variance (%)	-7.7%	-13.8%	-35.3%	-40.5%	-37.6%	-28.0%	-22.6%	0.5%	5.8%	-1.6%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C										
Forecast	293	295	295	307	313	345	345	347	355	370
Norm Actual	303	314	310	313	325	330	320	355	323	322
Variance	-10	-19	-15	-6	-12	15	25	-8	32	48
Variance (%)	-3.5%	-6.4%	-5.2%	-2.0%	-4.0%	4.3%	7.2%	-2.2%	9.1%	13.1%

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5.12 *VANCOUVER ISLAND DEMAND*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-RGS Energy PJs										
Forecast	4.4	4.6	4.6	4.9	5.1	4.9	5.0	4.6	4.5	4.3
Norm Actual	4.2	4.6	4.6	4.7	4.6	4.7	4.7	4.5	4.4	4.5
Variance	0.2	0.0	0.0	0.2	0.5	0.2	0.3	0.1	0.1	-0.2
Variance (%)	4.5%	0.0%	0.0%	4.1%	9.8%	4.1%	6.0%	2.2%	2.2%	-4.7%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-AGS Energy PJs										
Forecast	1.0	1.0	1.1	1.2	1.1	1.1	1.1	1.2	1.2	1.3
Norm Actual	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.1	1.1
Variance	0.0	-0.1	0.0	0.1	0.0	0.0	-0.1	0.0	0.1	0.2
Variance (%)	0.2%	-6.0%	1.2%	6.4%	4.0%	-4.2%	-10.9%	0.2%	5.1%	14.8%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-HLF Energy PJs										
Forecast	0.2	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Norm Actual	0.3	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Variance	0.0	0.0	0.1	0.0	0.1	0.0	0.0	-0.1	0.0	0.1
Variance (%)	-15.9%	-4.6%	39.7%	11.8%	33.0%	7.4%	7.1%	-101.5%	-60.3%	41.5%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-ILF Energy PJs										
Forecast	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1
Norm Actual	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Variance (%)	-20.4%	-35.3%	15.3%	21.2%	18.5%	7.4%	0.8%	24.9%	22.5%	-3.0%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-1C Energy PJs										
Forecast	1.3	1.3	1.3	1.3	1.4	1.3	1.3	1.5	1.5	1.4
Norm Actual	1.4	1.3	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.2
Variance	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.1
Variance (%)	-5.4%	1.1%	-2.1%	-2.8%	-1.1%	-2.5%	1.4%	8.1%	17.7%	10.0%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-2C Energy PJs										
Forecast	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.3	1.4	1.4
Norm Actual	1.3	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.2	1.1
Variance	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3
Variance (%)	2.8%	1.7%	1.3%	2.4%	-0.6%	6.0%	8.9%	4.3%	13.2%	18.5%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-LCS-3C Energy PJs										
Forecast	2.5	2.2	2.3	2.6	2.5	2.4	2.4	2.0	2.0	1.8
Norm Actual	2.2	2.3	2.5	2.4	2.2	2.0	2.0	2.0	1.7	1.1
Variance	0.3	-0.1	-0.2	0.2	0.4	0.4	0.4	0.0	0.2	0.7
Variance (%)	11.9%	-4.7%	-7.0%	7.0%	14.4%	15.4%	15.6%	-1.7%	12.2%	38.6%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-1C Energy PJs										
Forecast	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.6	0.6	0.5
Norm Actual	0.3	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Variance	0.0	0.0	-0.1	-0.1	-0.2	-0.1	-0.1	0.0	0.1	0.0
Variance (%)	-8.5%	-10.9%	-43.3%	-42.7%	-44.3%	-26.5%	-20.0%	7.2%	11.6%	-6.3%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
VI-SCS-2C Energy PJs										
Forecast	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Norm Actual	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.5
Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
Variance (%)	-1.4%	-3.2%	-3.1%	1.6%	5.6%	3.2%	5.7%	2.8%	13.5%	12.2%

1 ## 5.13 *WHISTLER NET CUSTOMERS*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1R Accounts										
Forecast	2,038	2,133	2,171	2,124	2,178	2,272	2,321	2,289	2,303	2,372
Norm Actual	2,045	2,064	2,098	2,134	2,250	2,262	2,296	2,271	2,348	2,416
Variance	-7	69	73	-10	-72	10	25	18	-45	-44
Variance (%)	-0.3%	3.2%	3.4%	-0.5%	-3.3%	0.4%	1.1%	0.8%	-2.0%	-1.9%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C Accounts										
Forecast	87	89	88	87	91	84	84	81	81	82
Norm Actual	87	83	83	82	83	81	83	82	81	86
Variance	0	6	5	5	8	3	1	-1	0	-4
Variance (%)	0.0%	6.7%	5.7%	5.7%	8.8%	3.6%	1.2%	-1.2%	0.0%	-4.9%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C Accounts										
Forecast	52	54	53	48	53	52	52	49	49	50
Norm Actual	51	48	51	50	51	49	50	50	49	49
Variance	1	6	2	-2	2	3	2	-1	0	1
Variance (%)	1.9%	11.1%	3.8%	-4.2%	3.8%	5.8%	3.8%	-2.0%	0.0%	2.0%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C Accounts										
Forecast	20	22	22	20	21	22	24	23	23	24
Norm Actual	21	20	20	20	23	23	24	24	24	24
Variance	-1	2	2	0	-2	-1	0	-1	-1	0
Variance (%)	-5.0%	9.1%	9.1%	0.0%	-9.5%	-4.5%	0.0%	-4.3%	-4.3%	0.0%

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	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C Accounts										
Forecast	183	181	173	161	166	171	175	187	192	202
Norm Actual	161	155	159	171	173	177	196	185	193	193
Variance	22	26	14	-10	-7	-6	-21	2	-1	9
Variance (%)	12.0%	14.4%	8.1%	-6.2%	-4.2%	-3.5%	-12.0%	1.1%	-0.5%	4.5%

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5.14 *WHISTLER NET CUSTOMER ADDITIONS*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS 1R Acct Additions										
Forecast			75	30	50	35	36	14	14	52
Norm Actual	38	19	34	36	116	12	34	51	77	68
Variance	-38	-19	41	-6	-66	23	2	-37	-63	-16
Variance (%)			55%	-20%	-132%	66%	6%	-264%	-450%	-31%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C Acct Additions										
Forecast			2	2	6	1	0	0	0	0
Norm Actual	-1	2	0	-1	1	-2	2	-1	-1	5
Variance	1	-2	2	3	5	3	-2	1	1	-5
Variance (%)			100%	150%	83%	300%				

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C Acct Additions										
Forecast	0	0	1	0	2	0	1	0	0	0
Norm Actual	0	-3	3	-1	1	-2	1	0	-1	0
Variance	0	3	-2	1	1	2	0	0	1	0
Variance (%)			-200%		50%		0%			

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C Acct Additions										
Forecast	0	0	0	0	1	0	0	0	0	0
Norm Actual	0	-1	0	0	3	0	1	0	0	0
Variance	0	1	0	0	-2	0	-1	0	0	0
Variance (%)					-200%					

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C Acct Additions										
Forecast	0	0	10	3	4	0	2	5	5	9
Norm Actual	-14	2	4	12	2	4	19	1	8	0
Variance	14	-2	6	-9	2	-4	-17	4	-3	9
Variance (%)			60%	-300%	50%		-850%	80%	-60%	100%

5.15 *WHISTLER USE PER CUSTOMER*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1R UPC										
Forecast	92.1	89.5	89.9	88.2	90.1	92.1	82.3	104.0	106.3	90.6
Norm Actual	93.3	85.8	95.7	89.9	82.6	99.5	94.7	89.4	87.3	87.6
Variance	-1.2	3.7	-5.8	-1.7	7.5	-7.4	-12.4	14.6	19.0	3.0
Variance (%)	-1.3%	4.1%	-6.5%	-1.9%	8.3%	-8.0%	-15.1%	14.0%	17.9%	3.3%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C UPC										
Forecast	1,066.0	1,094.0	1,116.0	1,140.0	1,198.0	1,248.0	1,185.0	1,724.5	1,793.0	1,405.3
Norm Actual	1,159.2	1,152.8	1,284.7	1,316.6	1,185.3	1,595.3	1,484.0	1,237.1	1,317.5	1,353.8
Variance	-93.2	-58.8	-168.7	-176.6	12.7	-347.3	-299.0	487.5	475.5	51.5
Variance (%)	-8.7%	-5.4%	-15.1%	-15.5%	1.1%	-27.8%	-25.2%	28.3%	26.5%	3.7%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C UPC										
Forecast	3,117.0	3,137.0	3,235.0	3,253.0	3,283.0	3,098.0	2,454.0	2,500.3	2,361.6	2,367.8
Norm Actual	3,430.0	3,211.7	3,214.1	2,749.7	2,454.4	2,802.7	2,657.7	2,606.2	2,647.5	2,658.4
Variance	-313.0	-74.7	20.9	503.4	828.6	295.4	-203.7	-105.9	-285.9	-290.6
Variance (%)	-10.0%	-2.4%	0.6%	15.5%	25.2%	9.5%	-8.3%	-4.2%	-12.1%	-12.3%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C UPC										
Forecast	12,693.0	13,232.0	13,117.0	13,146.0	11,853.0	10,972.0	9,175.0	6,187.4	5,167.1	6,167.7
Norm Actual	12,889.3	13,145.5	11,853.0	11,078.0	9,174.7	8,872.2	8,424.2	8,036.5	8,481.8	8,645.7
Variance	-196.3	86.5	1,264.1	2,068.0	2,678.3	2,099.8	750.8	-1,849.1	-3,314.7	-2,478.0
Variance (%)	-1.5%	0.7%	9.6%	15.7%	22.6%	19.1%	8.2%	-29.9%	-64.1%	-40.2%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C UPC										
Forecast	160.0	179.0	190.0	206.0	232.0	264.0	251.0	414.9	459.7	281.6
Norm Actual	211.5	219.4	265.1	315.6	251.0	338.0	302.3	287.1	294.4	306.9
Variance	-51.5	-40.4	-75.1	-109.6	-19.0	-74.0	-51.3	127.7	165.2	-25.3
Variance (%)	-32.2%	-22.6%	-39.5%	-53.2%	-8.2%	-28.0%	-20.5%	30.8%	35.9%	-9.0%

5.16 *WHISTLER DEMAND*

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS 1R Energy Pjs										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Norm Actual	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Variance (%)	-2.4%	6.5%	-3.6%	-2.0%	7.0%	-8.1%	-13.6%	12.4%	17.7%	1.4%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-1C Energy Pjs										
Forecast	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Norm Actual	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Variance (%)	-8.9%	-1.7%	-10.4%	-11.2%	6.2%	-26.0%	-21.5%	27.0%	25.8%	4.1%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-2C Energy Pjs										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Norm Actual	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Variance (%)	-9.7%	6.8%	6.4%	11.7%	27.6%	12.5%	-3.9%	-6.4%	-13.6%	-10.0%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-LGS-3C Energy Pjs										
Forecast	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1
Norm Actual	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Variance	0.0	0.0	0.1	0.0	0.1	0.0	0.0	-0.1	-0.1	-0.1
Variance (%)	-6.6%	3.2%	17.9%	15.7%	22.4%	12.9%	10.2%	-35.5%	-71.3%	-40.2%

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
W-SGS-1C Energy Pjs										
Forecast	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Norm Actual	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1
Variance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Variance (%)	-22.9%	-7.7%	-30.9%	-57.3%	-14.7%	-30.6%	-28.4%	28.8%	35.5%	-9.0%

Appendix A2-1

HISTORICAL FORECAST AND CONSOLIDATED TABLES

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix A3

Demand Forecast Methodology

September 3, 2015

Table of Contents

List of Tables and Figures

1. INTRODUCTION

In the 2015 Annual Review proceeding, FEI proposed to include in its next annual review application a description of its demand forecast methodology consistent with the detail provided in response to IRs in that proceeding. The Commission accepted this proposal and directed FEI to provide "a fulsome description of its demand forecast methodology." In this appendix, FEI provides a detailed description of its demand forecast methodology as directed.

FEI notes that it is in the process of conducting a review of alternatives to its demand forecast methods pursuant to Directives 3, 5 and 8 of the Commission's Decision on FEI's Annual Review of 2015 Delivery Rates. In Commission Letter L-30-15, FEI was granted an extension until the Annual Review for 2017 Delivery Rates to respond to these directives due to the time required to conduct the review of alternative methodologies. FEI will therefore report on alternatives to existing forecast methodologies, with recommendations to improve residential and commercial UPC forecasts and commercial net customer additions forecasts, in its Annual Review for 2017 Delivery Rates.

The following table shows the high level methodology used for each component of FEI's demand forecast.

Table A3-1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Time series, normalized historic UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg, historical additions	Prior year customers + customer adds	Time series, normalized historic UPC	Product of Customers and Use Rates
Industrial				Annual survey of industrial customers

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, and then describes each of FEI's forecast methods used to derive the 2016 demand forecast, in the following order:

- Residential Customer Additions

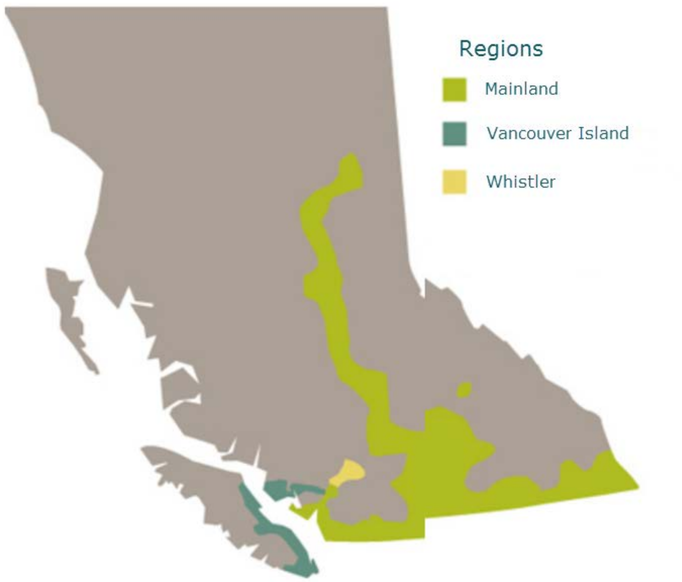
- Commercial Customer Additions
- Residential Use Rate
- Commercial Use Rate
- Residential and Commercial Demand Forecast
- Industrial Demand Forecast

2. BACKGROUND INFORMATION

2.1 FEI REGIONS

FEI is divided into three regions as shown in Figure A3-1.

Figure A3-1: 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 and Whistler 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 time frames:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year. For the 2016 Annual Review the latest calendar year for which full actual data exists is the 2014 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 a range of 2 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 2015 and the Seed Year forecast is based on the latest actual years, including 2014. As such, the 2015 Seed Year forecast in this Application will differ from the 2015 Forecast presented in the Annual Review for 2015 Delivery Rates, for which 2014 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 A3-2: 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 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 gigajoules 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 gigajoules 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 Gigajoules 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 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 multiplying 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 square method to minimize the sum of squared error (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The three non-linear models are tested to see which provides the best fit for each rate class by region. 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.

The following table was used to develop the parameters for Lower Mainland Rate Schedule 1 for 2014. In this table only 2013 data is shown. The actual analysis includes weather and use rate data from 2009 to 2013.

Table A3-3: LML Rate Schedule 1 Parameters

A	B	C	D	E
Date	**Avg Daily Temp**	**Actual Use Rate**	**Est. Act. UPC**	**SSE**
1/1/2013	2.74	16.29	16.14	0.02
2/1/2013	5.51	11.80	12.56	0.59
3/1/2013	7.19	10.96	10.56	0.16
4/1/2013	9.49	7.68	8.12	0.20
5/1/2013	13.24	4.71	5.04	0.11
6/1/2013	16.31	3.19	3.29	0.01
7/1/2013	18.26	2.70	2.49	0.04
8/1/2013	18.56	2.63	2.38	0.06
9/1/2013	15.61	3.34	3.64	0.09
10/1/2013	9.25	7.78	8.36	0.34
11/1/2013	6.15	11.21	11.79	0.33
12/1/2013	2.32	16.07	16.70	0.40

For each month (column A), the average daily temperature is recorded as well as the actual use rate (columns B and C). Excel Solver then runs iterations and changes the A/B/C parameters in the three models to calculate the estimated actual UPC in column D. The SSE between the actual recorded UPC in column C and the estimated UPC in column D is calculated and shown in column E. For example, in the case of 1/1/2013 the SSE is calculated as:

$$SSE = (16.29 - 16.14)^2 = 0.02$$

Excel Solver runs many iterations to develop the set of parameters that minimizes the SSE. The model with the lowest SSE is then used for the rate schedule being tested.

Once the parameters are know the model is able to predict monthly UPC values, given monthly temperatures.

FEI then uses 10-year average temperatures and 2014 actual temperatures to develop two estimated 2014 UPCs. The ratio of the estimated UPCs is the normalization factor.

Continuing with the above example Excel Solver was able to develop parameters for the Logit-3 model for Lower Mainland Rate Schedule 1 as follows:

Table A3-4: LML Rate Schedule 1 Logit-3 Model Parameters

A	33.535874
B	0.699134
C	-0.157911

The 2014 temperature inputs into the model are as follows:

Table A3-5: 2014 Temperature Inputs

10 Year Average January Daily Temperature, (degrees C)	4
2014 Average January Daily Temperature (degrees C)	4.3

Using the Logit-3 model and the above data results in the following estimated UPCs:

Table A3-6: Estimated Monthly UPCs

Estimated Monthly UPC based on 10 Year Normal January Weather (GJs)	14.487
Estimated UPC based on 2014 actual January weather (GJs)	14.099

The January 2014 Lower Mainland Rate Schedule 1 normalization factor is the ratio of these two estimated UPC values:

$$January\ 2014\ Lower\ Mainland\ Rate\ Schedule\ 1\ Normalization\ Factor = \frac{14.099}{14.487} = 0.97$$

The recorded actual UPC for January 2014 Lower Mainland Rate Schedule 1 was 13.725 GJs.

The normalized UPC for January 2014 Lower Mainland Rate Schedule 1 is then:

$$January\ 2014\ Lower\ Mainland\ Rate\ Schedule\ 1\ Normalized\ UPC = \frac{13.725}{0.97} = 14.143\ \ GJ$$

Similar calculations are performed for all residential and commercial rate schedules for all regions to generate monthly normalization factors.

The 2014 table of Normalization Factors is:

Table A3-7: 2014 Normalization Factors

	LML				INL				COL				RSK			VI			WH		
	RATE1	RATE2	RATE3	RATE23	RATE1	RATE2	RATE3	RATE23	RATE1	RATE2	RATE3	RATE23	RATE1	RATE2	RATE3	RATE1	RATE2	RATE3	RATE1	RATE2	RATE3
Jan	0.97	0.97	0.98	0.98	0.91	0.89	0.92	0.95	0.97	0.97	0.97	0.97	0.92	0.91	0.94	0.95	0.95	0.95	0.89	0.89	0.89
Feb	1.25	1.26	1.18	1.16	1.27	1.36	1.27	1.14	1.30	1.31	1.27	1.24	1.22	1.24	1.17	1.22	1.22	1.22	1.21	1.21	1.21
Mar	1.00	1.00	1.00	1.00	1.17	1.18	1.13	1.11	1.09	1.10	1.08	1.06	1.15	1.13	1.08	1.01	1.01	1.01	1.06	1.06	1.06
Apr	0.93	0.93	0.95	0.94	1.02	1.02	1.01	1.02	1.01	1.01	1.01	1.01	1.07	1.05	1.04	0.93	0.93	0.93	1.04	1.04	1.04
May	0.83	0.84	0.87	0.86	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.06	1.04	1.03	0.81	0.81	0.81	0.86	0.86	0.86
Jun	1.02	1.02	1.01	1.01	1.01	1.02	1.01	1.02	1.00	1.00	1.00	1.00	0.98	0.98	0.99	0.96	0.96	0.96	0.96	0.96	0.96
Jul	0.92	0.93	0.94	0.93	0.93	0.87	0.90	0.85	0.77	0.76	0.81	0.79	0.78	0.83	0.84	0.92	0.92	0.92	0.89	0.89	0.89
Aug	0.88	0.89	0.91	0.89	0.94	0.89	0.92	0.88	0.93	0.93	0.94	0.94	0.83	0.87	0.88	0.90	0.90	0.90	0.74	0.74	0.74
Sep	0.90	0.90	0.92	0.91	0.99	0.99	0.99	0.99	1.03	1.03	1.03	1.02	0.94	0.96	0.97	0.85	0.85	0.85	0.83	0.83	0.83
Oct	0.70	0.71	0.77	0.75	0.75	0.74	0.81	0.78	0.77	0.76	0.81	0.85	0.75	0.80	0.87	0.75	0.75	0.75	0.78	0.78	0.78
Nov	1.06	1.06	1.04	1.04	1.12	1.13	1.09	1.07	1.17	1.18	1.14	1.12	1.08	1.07	1.05	0.99	0.99	0.99	1.06	1.06	1.06
Dec	0.89	0.89	0.92	0.93	0.89	0.88	0.90	0.94	0.97	0.97	0.97	0.98	0.99	0.99	0.99	0.89	0.89	0.89	0.98	0.98	0.98

A similar table is developed for each year.

The normalization factors are applied to the monthly use rates by rate class and region to establish the normalized use rates used for forecasting.

3. RESIDENTIAL CUSTOMER ADDITIONS

As shown in Table A3-1 above, the residential demand forecast is the product of the number of customers and the use rate. The forecast number of customers is determined by using the actual customer additions[1] from the most recent year, and applying a forecast growth rate for customer additions.

This section describes the residential customer additions forecast methodology, beginning with a general description and followed by a step-by-step discussion of the forecast.

3.1 *GENERAL DESCRIPTION OF THE METHOD*

FEI's forecast of annual net customer additions is based on the correlation between FEI's net customer additions and the Conference Board of Canada (CBOC) forecast of housing starts. FEI begins with the most recent year of recorded FEI actual customer additions by rate schedule, region and housing type. FEI then calculates the annual customer growth rate from the CBOC forecast for single-family and mufti-family dwellings. FEI's forecast net customer additions are then calculated by applying the growth rates to the most recent actual customer counts.

Forecasting is completed at the annual and regional level. Based on historical seasonality, the annual forecast is distributed to create the monthly forecast that is then entered into FEI's Forecast Information System (FIS). The regional annual forecasts are then summed to create the amalgamated forecast.

3.2 *ACTUAL ANNUAL CUSTOMER ADDITIONS BY HOUSING TYPE*

The actual customer additions recorded in 2014 are used as the starting point for the forecast. The actual Lower Mainland Rate Schedule 1 additions in 2014 were:

Table A3-8: LML 2014 Actual Customer Additions

Lower Mainland	2014A
Actual Additions	4,641
SFD Additions	3,713
MFD Additions	928

The 2014 SFD and MFD Actual Customer Additions in the table above were calculated using the split between SFD and MFD in each of the Mainland subregions, Vancouver Island and Whistler, as shown in Table A3-9 below.

1 Customer additions or "net" customer additions is the year-over-year change in the total number of customers.

Table A3-9: SFD/MFD Split

	% SFD	% MFD	Total
Lower Mainland	80%	20%	100%
Inland	88%	12%	100%
Columbia	85%	15%	100%
Revelstoke	100%		100%
Vancouver Island	87%	13%	100%
Whistler	100%	0%	100%

The SFD and MFD Additions were calculated as follows:

$$SFD\ Additions = 80\%\ \times 4{,}641 = 3{,}713$$

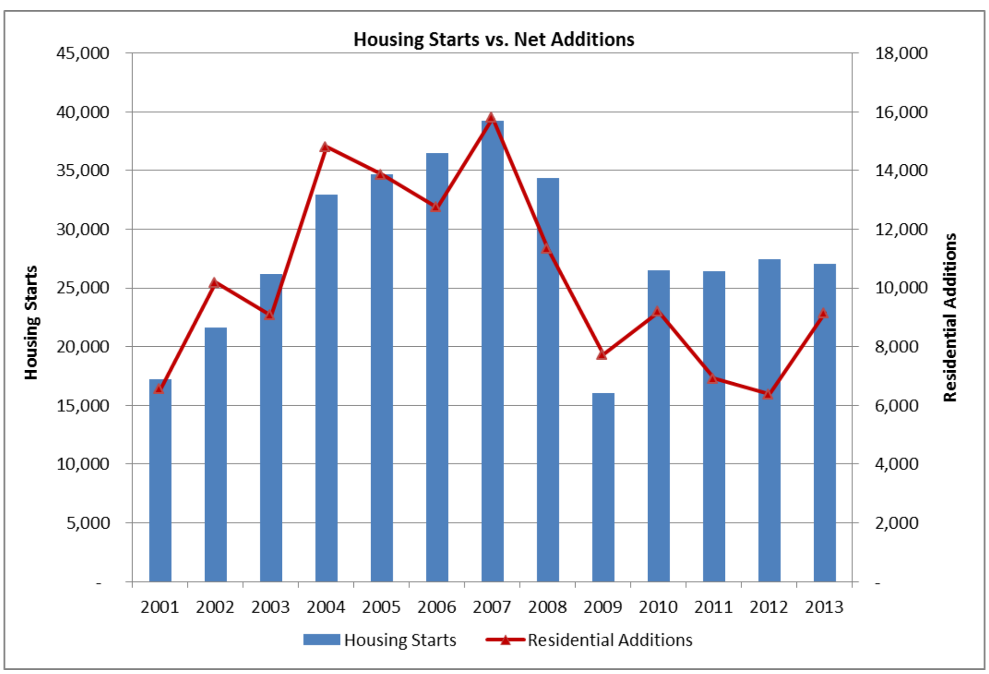
$$MFD\ Additions = 20\%\ \times 4{,}641 = 928$$

3.3 CBOC Housing Starts Forecast used to Develop Annual Growth Rate by Housing Type

FEI uses the most recent Provincial Medium Term Housing Starts Forecast from the (CBOC) to develop growth rates by housing type.

The following chart shows the correlation between actual housing starts and actual residential additions.

Figure A3-2: Residential Housing Starts vs. Net Additions



The correlation statistic (R) between the two data sets is 80%. Based on the strength of the correlation, FEI uses the CBOC forecast of housing starts in the residential customer additions methodology.

The CBOC forecast is also used because it provides a forecast for both single family dwellings (SFD) and multi-family dwellings (MFD).

The current CBOC housing starts forecast is as follows:

Table A3-10: CBOC Housing Starts Forecast

	2014	2015	2016
SFD	9,080	8,216	8,175
MFD	19,176	20,062	20,112
Total	28,256	28,277	28,286

FEI converts the CBOC housing starts forecast to annual growth rates. For example, the SFD percent for 2015 is calculated:

$$\frac{(8{,}216 - 9{,}080)}{9{,}080} = -9.5\%$$

The resulting SFD and MFD annual growth rates are shown below:

Table A3-11: CBOC SFD & MFD Annual Growth Rates

	2015	2016
SFD	-9.5%	-0.5%
MFD	4.6%	0.2%

3.4 *ANNUAL CUSTOMER ADDITIONS FORECAST*

With the known 2014 actual additions by housing type and the forecast growth rates by housing type, the following net additions forecast can be calculated by multiplying the actual SFD and MFD additions by the applicable growth rate:

Table A3-12: LML Actual & Forecast SFD & MFD Customer Additions

Lower Mainland	2014A	2015F	2016F
Actual Additions	4,641		
SFD Additions	3,713	3,360	3,343
MFD Additions	928	971	973
Total		4,331	4,316

For example, the SFD additions forecast calculation is as follows:

$$2015\ Forecast\ SFD\ Additions = 3{,}713 + (-9.5\%\ \times 3{,}713) = 3{,}360$$

$$2016\ Forecast\ SFD\ Additions = 3{,}360\ \times (-0.5\%\ \times 3{,}360) = 3{,}343$$

Similar calculations are completed for all sub-regions using the 2014 actual customer additions by sub-region and the housing type splits from section 3.3 above.

3.5 *SEASONALIZATION TO CALCULATE MONTHLY CUSTOMER ADDITIONS*

Customers are not added at the same rate throughout the year. As a result, the regional annual forecasts calculated above are seasonalized to calculate forecast monthly customer additions.

Continuing with the Lower Mainland example, historical actual customer additions by month for Rate Schedule 1 are as follows:

Table A3-13: LML Rate Schedule 1 Historical Monthly Customer Additions

Seasonalization	2012	2013	2014
Jan	1,027	820	1,587
Feb	17	385	727
Mar	(363)	82	594
Apr	(487)	(57)	4
May	(99)	(251)	(273)
Jun	(868)	(398)	(280)
Jul	(577)	(582)	(309)
Aug	(148)	100	(247)
Sep	753	393	(37)
Oct	1,330	1,310	875
Nov	1,067	1,397	1,271
Dec	761	1,072	729
Total	2,413	4,271	4,641

The actual customer additions are used to determine monthly percentages. A three-year average is then calculated as follows:

1 **Table A3-14: Seasonalization Monthly Percentages**

Seasonalization	2012	2013	2014	Average
Jan	42.6%	19.2%	34.2%	31.99%
Feb	0.7%	9.0%	15.7%	8.46%
Mar	-15.0%	1.9%	12.8%	-0.11%
Apr	-20.2%	-1.3%	0.1%	-7.14%
May	-4.1%	-5.9%	-5.9%	-5.29%
Jun	-36.0%	-9.3%	-6.0%	-17.11%
Jul	-23.9%	-13.6%	-6.7%	-14.73%
Aug	-6.1%	2.3%	-5.3%	-3.04%
Sep	31.2%	9.2%	-0.8%	13.20%
Oct	55.1%	30.7%	18.9%	34.88%
Nov	44.2%	32.7%	27.4%	34.77%
Dec	31.5%	25.1%	15.7%	24.11%
Total	100.0%	100.0%	100.0%	100.00%

2

3 Applying the three-year average seasonality to the annual forecast of customer additions results
4 in the following forecast of monthly customer additions.

5 **Table A3-15: LML Rate 1 Monthly Customer Additions Forecast**

Lower Mainland Monthly RS 1 Customer	2015	2016
Jan	1,385	1,380
Feb	367	365
Mar	(5)	(4)
Apr	(310)	(309)
May	(228)	(228)
Jun	(741)	(738)
Jul	(638)	(636)
Aug	(132)	(131)
Sep	572	570
Oct	1,510	1,505
Nov	1,506	1,501
Dec	1,045	1,041
Total	4,331	4,316

6

For example, the customer additions for January 2015 are calculated as follows:

Table A3-16: Customer Additions Calculation

January 2015 Customer Additions	=	Total annual forecast customer additions	X	Three-year average monthly percentage of customer additions
1,385	=	4,331	X	31.99%

3.6 *AGGREGATE CUSTOMER ADDITIONS FORECAST*

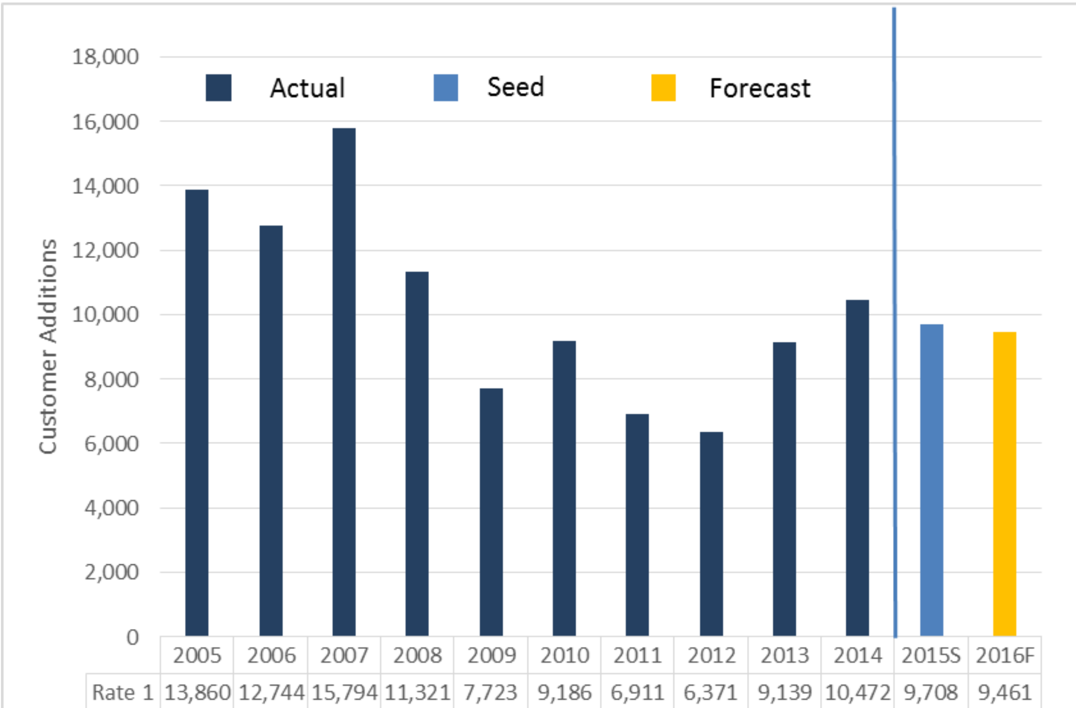
The above process is repeated for all regions and the results are aggregated. The following table shows the results for the 2016 Forecast.

Table A3-17: Aggregate Customer Additions 2016 Forecast

2016F	COLUMBIA	INLAND	LOWER MAINLAND	REVELSTOKE	VANCOUVER ISLAND	WHISTLER	Total
January	24	450	1,380	6	401	8	2,269
February	10	123	365	(1)	233	2	732
March	(6)	32	(4)	5	156	(2)	181
April	(15)	(97)	(309)	2	73	(3)	(349)
May	(16)	(150)	(228)	(1)	60	(4)	(339)
June	(26)	(308)	(738)	3	(97)	-	(1,166)
July	(21)	(175)	(636)	(1)	(67)	4	(896)
August	9	15	(131)	1	61	3	(42)
September	15	366	570	(3)	373	17	1,338
October	74	838	1,505	1	523	14	2,955
November	67	852	1,501	-	486	16	2,922
December	40	435	1,041	(1)	337	6	1,858
Total	**155**	**2,381**	**4,316**	**11**	**2,537**	**61**	**9,461**

The resulting Actual, Seed and Forecast customer additions are shown in the figure below.

Figure A3-3: Rate Schedule 1 Customer Additions Forecast



3.7 *CUSTOMER FORECAST*

The residential additions are then added to the December 2014 actual customer count to calculate the customer forecast for 2015 and 2016. The following table shows the Rate Schedule 1 customer forecast for all sub regions for 2016.

Table A3-18: Rate 1 Customer Count Forecast

Rate Schedule 1 Accounts	Columbia	Inland	Lower Mainland	Revelstoke	Vancouver Island	Whistler
January	20,960	217,760	542,815	1,298	100,322	2,483
February	20,970	217,883	543,180	1,297	100,555	2,485
March	20,964	217,915	543,176	1,302	100,711	2,483
April	20,949	217,818	542,867	1,304	100,783	2,480
May	20,933	217,668	542,639	1,303	100,843	2,476
June	20,907	217,360	541,901	1,306	100,746	2,476
July	20,886	217,185	541,265	1,305	100,679	2,480
August	20,895	217,200	541,134	1,306	100,739	2,483
September	20,910	217,566	541,704	1,303	101,112	2,500
October	20,984	218,404	543,209	1,304	101,635	2,514
November	21,051	219,256	544,710	1,304	102,121	2,530
December	21,091	219,691	545,751	1,303	102,458	2,536

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated using a three-year average of prior actuals additions at the region and rate class level. Inland Rate Schedule 2 is used below to illustrate the methodology. All other regions and rate schedules (Rate Schedules 2, 3 and 23) are calculated in the same way.

4.1 ACTUAL MONTH END CUSTOMER TOTALS

The starting point for the customer additions forecast is the actual month-end customer counts as recorded in FEI's billing system for each region and commercial rate schedule, as follows.

Table A3-19: Inland Rate 2 Customer Counts

Inland Rate Schedule 2 Customers	2011	2012	2013	2014
Jan	19,741	20,003	20,110	20,485
Feb	19,759	20,026	20,119	20,567
Mar	19,756	20,011	20,104	20,583
Apr	19,724	19,957	20,069	20,545
May	19,727	19,914	20,029	20,536
Jun	19,701	19,819	20,062	20,490
Jul	19,686	19,789	20,054	20,452
Aug	19,686	19,785	20,046	20,437
Sep	19,675	19,808	20,069	20,496
Oct	19,763	19,937	20,174	20,520
Nov	19,874	20,051	20,310	20,638
Dec	19,928	20,079	20,414	20,709

4.2 ACTUAL CUSTOMER ADDITIONS

The month-end customer totals are used to determine the monthly net additions for three years by calculating the difference between consecutive months. For example, January 2012 additions are calculated as the January 2012 month end less the December 2011 month end as follows:

$$January\ 2012\ Net\ Inland\ Rate\ Schedule\ 2\ Additions = 20{,}003 - 19{,}928 = 75$$

This process is repeated for 2012, 2013 and 2014 by month, by sub-region and for Rate Schedules 2, 3 and 23. The resulting actual customer additions for 2012, 2013 and 2014 are as follows:

Table A3-20: Inland Rate 2 Customer Additions

Inland Rate Schedule 2 Customer Additions	2012	2013	2014
Jan	75	31	71
Feb	23	9	82
Mar	(15)	(15)	16
Apr	(54)	(35)	(38)
May	(43)	(40)	(9)
Jun	(95)	33	(46)
Jul	(30)	(8)	(38)
Aug	(4)	(8)	(15)
Sep	23	23	59
Oct	129	105	24
Nov	114	136	118
Dec	28	104	71
Total	151	335	295

4.3 SEASONALIZATION

Once the regional and monthly additions have been calculated, three-year average seasonality factors can be calculated. For example, the January 2012 Inland Rate Schedule 2 seasonality factor is calculated as follows:

$$January\ 2012\ Inland\ Rate\ Schedule\ 2\ Seasonality = \frac{75}{151} = 50\%$$

The resulting three-year average seasonality factors are as follows:

Table A3-21: Inland Rate 2 Seasonalization

Inland Rate Schedule 2 Seasonalization	2012	2013	2014	3 Yr. Avg.
Jan	50%	9%	24%	28%
Feb	15%	3%	28%	15%
Mar	-10%	-4%	5%	-3%
Apr	-36%	-10%	-13%	-20%
May	-28%	-12%	-3%	-14%
Jun	-63%	10%	-16%	-23%
Jul	-20%	-2%	-13%	-12%
Aug	-3%	-2%	-5%	-3%
Sep	15%	7%	20%	14%
Oct	85%	31%	8%	42%
Nov	75%	41%	40%	52%
Dec	19%	31%	24%	25%
Total	100%	100%	100%	100%

4.4 ANNUAL FORECAST BASED ON THREE-YEAR AVERAGE CUSTOMER ADDITIONS

The actual customer additions discussed in section 4.2 above are used to develop three-year average customer additions by sub-region. The three-year average for Inland Rate Schedule 2 is as follows:

Table A3-22: Inland Rate 2 Forecast Customer Additions

Inland Rate Schedule 2 Forecast Customer Additions	Acct adds	3 Yr. Average
2012	151	
2013	335	
2014	295	260

The calculation of the Inland Rate Schedule 2 three-year average customer additions is as follows:

$$Inalnd\ Rate\ Schedule\ 2\ Customer\ Additions\ Forecast = \frac{151 + 335 + 295}{3} = 260\ customers/yr$$

The three-year average is used as the annual forecast commercial customer additions for both the seed and forecast years.

4.5 MONTHLY FORECAST OF ADDITIONS

The three-year average annual forecast is then converted into a monthly forecast using the seasonality factors discussed in 4.3 above, as follows:

Table A3-23: Inland Rate 2 Forecast Customer Additions

Inland Rate Schedule 2 Forecast Customer Additions	2015S	2016F
Jan	72	72
Feb	40	40
Mar	(8)	(8)
Apr	(51)	(51)
May	(38)	(38)
Jun	(60)	(60)
Jul	(30)	(30)
Aug	(9)	(9)
Sep	37	37
Oct	108	108
Nov	135	135
Dec	64	64
Total	260	260

For example, the January 2015 value is calculated as follows:

Table A3-24: Rate 2 Additions Forecast Calculation

January 2015 Inland rate Schedule 2 Customer Additions Forecast	=	Three-year average annual customer additions	X	January seasonality factor
72	=	260	X	28%

4.6 *MONTH END CUSTOMER FORECAST*

The month end forecast as entered into FIS starts with the 2014 December actual customer count (20,709 from section 4.1 above) and adds the monthly additions (from section 4.5 above). The monthly Inland Rate Schedule 2 customer forecast is as follows:

1 **Table A3-25: Monthly Inland Rate 2 Customer Count Forecast**

Inland Rate Schedule 2 Customer Forecast	2015S	2016F
Jan	20,781	21,041
Feb	20,821	21,081
Mar	20,813	21,073
Apr	20,762	21,022
May	20,724	20,984
Jun	20,664	20,925
Jul	20,634	20,894
Aug	20,625	20,885
Sep	20,662	20,922
Oct	20,770	21,030
Nov	20,905	21,166
Dec	20,969	21,230

2

5. RESIDENTIAL USE RATE

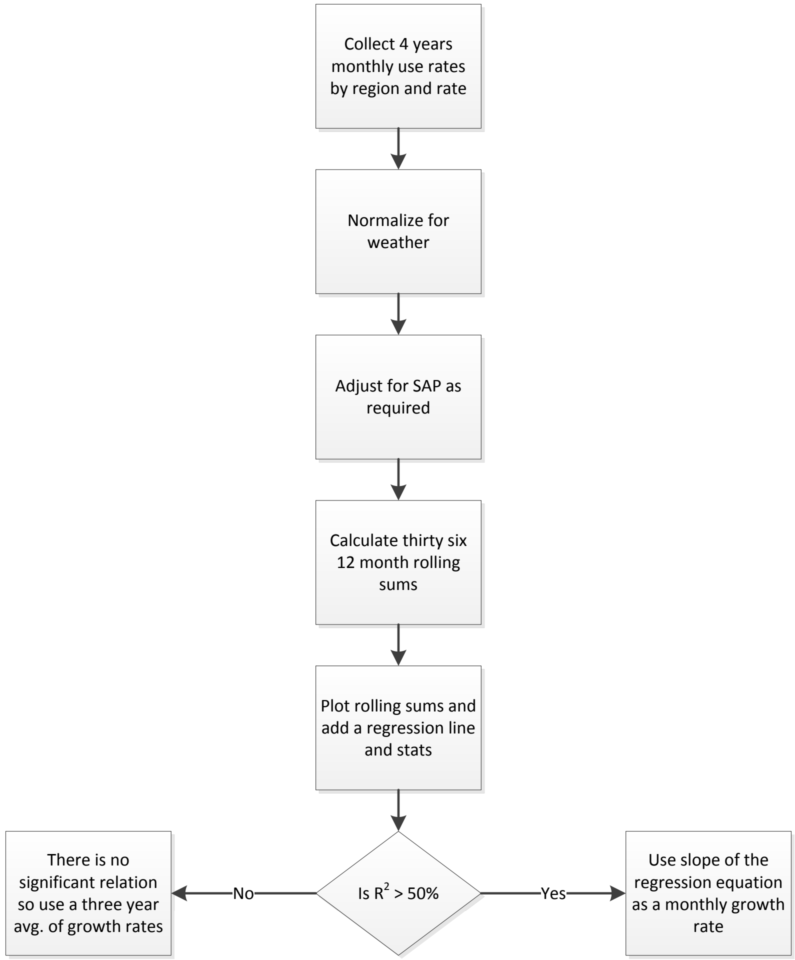
As indicated in Table A3-1 above, the Residential Demand Forecast is the product of the number of residential customers and the residential use rate. This section describes the method for forecasting the residential use rate.

5.1 *MONTHLY WEATHER-NORMALIZED ACTUAL UPCS*

FEI develops its residential use rate forecast based on four years of monthly use rates by region and rate class. The monthly UPC values are weather-normalized using the process set out in section 2.4 above.

The four years of monthly data is used to calculate 36, 12-month rolling UPC sums. These 12-month rolling UPC sums are then plotted and a regression analysis is conducted. If the resulting R^2 value is greater than 50%, then the slope of the regression equation is used to forecast the use rate for the Forecast Year. If the resulting R^2 value is 50% or less, then a three-year average of annual growth rates is used for the forecast

Figure A3-4: Rate Schedule 1 Use Rate Flow Chart



The following two sections provide an example where the regression method is used and an example where the three-year average method is used.

5.2 REGRESSION METHOD AS APPLIED TO LOWER MAINLAND

As discussed above, 12 month rolling UPC sums are prepared by summing up 12 consecutive monthly UPCs. By using 12 months, both winter and summer seasons are included. This method was introduced to reduce the effect of auto-correlation.

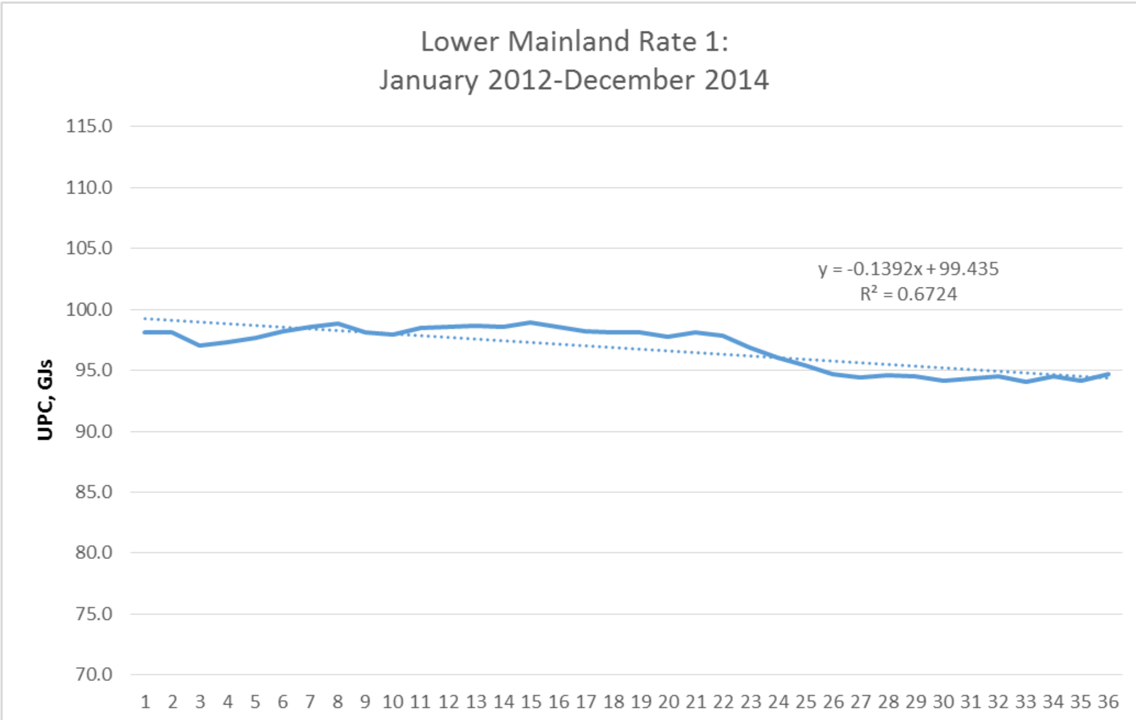
The following tables shows the 36, 12-month rolling UPCs developed for Lower Mainland Rate Schedule 1.

Table A3-26: LML 12-Month Rate 1 Rolling UPCs

Date	Monthly UPC	12 month Rolling UPC	Period	Date	Monthly UPC	12 month Rolling UPC	Period
Jan-11	14.8	100.2		Jan-13	14.7	98.7	13
Feb-11	12.5	99.8		Feb-13	12.3	98.6	14
Mar-11	12.1	100.0		Mar-13	11.3	98.9	15
Apr-11	8.0	99.6		Apr-13	7.9	98.5	16
May-11	4.9	99.3		May-13	5.0	98.2	17
Jun-11	3.0	98.9		Jun-13	3.5	98.2	18
Jul-11	2.3	98.3		Jul-13	2.6	98.1	19
Aug-11	2.8	98.2		Aug-13	2.7	97.8	20
Sep-11	3.9	98.6		Sep-13	3.6	98.2	21
Oct-11	7.3	98.6		Oct-13	6.9	97.8	22
Nov-11	11.5	98.6		Nov-13	11.0	96.8	23
Dec-11	15.2	98.4		Dec-13	14.5	96.0	24
Jan-12	14.6	98.2	1	Jan-14	14.1	95.4	25
Feb-12	12.4	98.1	2	Feb-14	11.5	94.7	26
Mar-12	11.0	97.0	3	Mar-14	11.0	94.4	27
Apr-12	8.3	97.3	4	Apr-14	8.1	94.6	28
May-12	5.3	97.7	5	May-14	4.9	94.5	29
Jun-12	3.5	98.2	6	Jun-14	3.1	94.2	30
Jul-12	2.7	98.6	7	Jul-14	2.8	94.4	31
Aug-12	3.1	98.8	8	Aug-14	2.9	94.5	32
Sep-12	3.2	98.1	9	Sep-14	3.1	94.0	33
Oct-12	7.2	98.0	10	Oct-14	7.3	94.5	34
Nov-12	12.0	98.5	11	Nov-14	10.7	94.2	35
Dec-12	15.3	98.6	12	Dec-14	15.0	94.7	36

By using four years of data 36 data points are plotted for the regression analysis. A regression line and regression statistics are added to the plot. A typical regression is presented below:

Figure A3-5: LML Rate 1 UPC regression Statistic



For the Lower Mainland, the residential UPC exhibits a regression statistic at 67% as shown in the preceding diagram. From the diagram the slope of the regression line is -0.1392 so the month over month UPC growth rate is -0.1392 GJs.

In this example, the 2014 Actual use rate is 47.3GJ. The 2015 seed use rate is then:

$$2015\ seed\ UPC = 94.7 + \left(12 \times (-0.1392)\right) = 93.03\ GJ$$ (rounded to 93.0 GJ)

For the 2016 Forecast, the growth rate is applied to the 2015 seed.

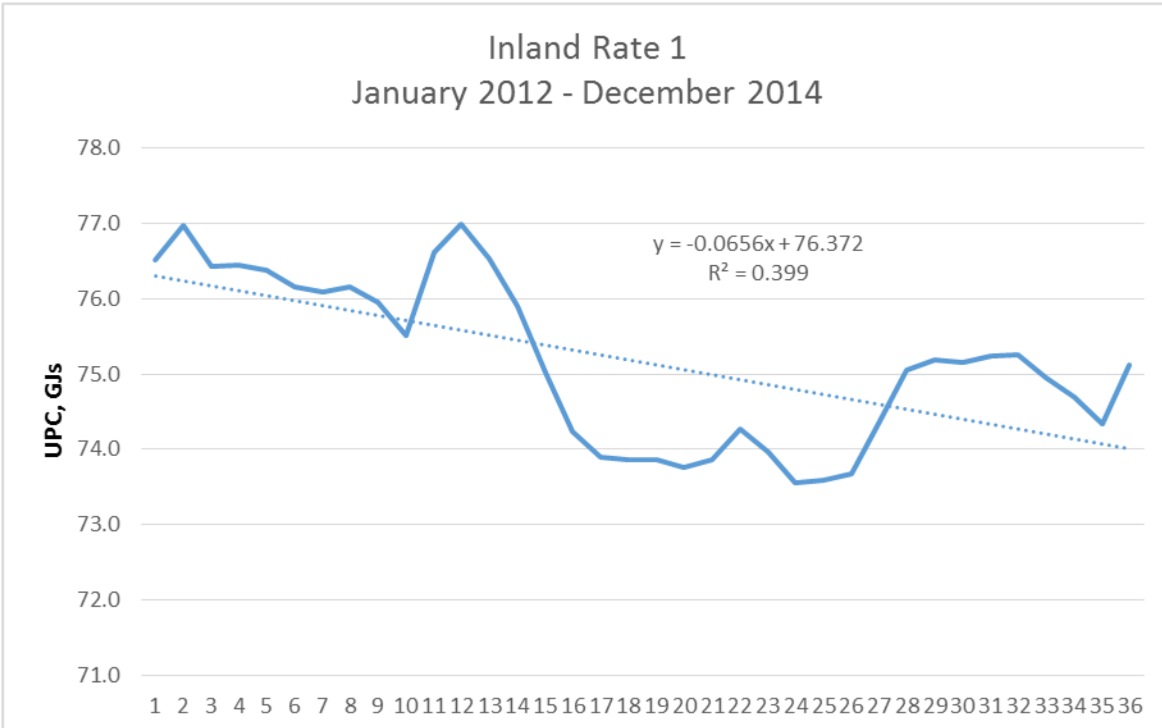
$$2016F\ UPC = 93.0 + \left(12 \times (-0.1392)\right) = 91.36\ GJ$$ (rounded to 91.4 GJ).

5.3 THREE YEAR AVERAGE OPTION AS APPLIED TO INLAND

If a statistically significant trend does not exist for a particular rate schedule in a particular region, then FEI uses a three-year average of the annual growth rates.

For Inland, the regression statistic is 39.9% as shown below, so a three year average method is used.

Figure A3-6: Inland Rate 1 UPC Regression Statistic



The following table shows the annual UPC values and growth rates used to calculate the three-year average growth rate:

Table A3-27: Annual UPC and Growth Rates

	2010	2011	2012	2013	2014
UPC	76.8	75.9	77.0	73.6	75.1
Growth		-1.2%	1.5%	-4.5%	2%
3 Yr avg	-0.29%				

As shown above, from the four annual use rates three annual growth rates can be calculated. For example for 2011 the growth rate is calculated as follows:

$$2011\ Growth\ rate = \frac{75.9}{76.8} - 1 = -1.2\%$$

This calculation is performed three times using the four UPC values to develop three annual UPC growth rates. These are shown in the table as -1.2%, 1.5% and -4.5%. The three-year average growth rate is then calculated as follows:

$$Three\ year\ average = \frac{-1.2 + 1.5 - 4.5}{3} = -0.29\%$$

The three-year average UPC growth rate for Inland Rate 1 is -0.29%.

The 2015 Seed Year use rate is developed by applying the three-year average growth rate to the 2014 Actual value as follows:

$$2015\ Seed = \frac{(100 - 0.29)}{100} \times 75.1 = 74.9\ GJs$$

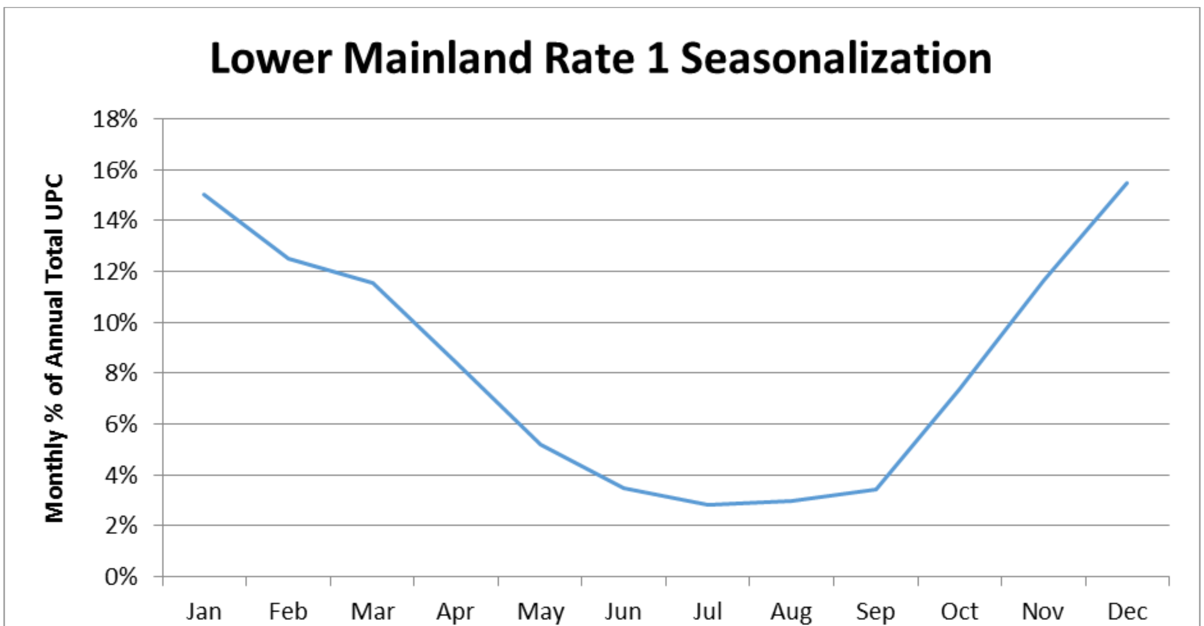
The 2016 Forecast use rate is developed by applying the three-year average growth rate to the 2015 Seed Year value as follows:

$$2016F = \frac{(100 - 0.29)}{100} \times 74.9 = 74.7GJs$$

5.4 *SEASONALIZATION*

Once the annual UPC forecasts for each region are complete they must be loaded into FIS to develop the load forecast by region. Because the FIS inputs are monthly, the annual forecasts must be "seasonalized". Seasonalization is the calculation that determines the proportion of demand consumed by month. The 12 seasonalization factors sum up to 100%. The seasonalization factors are developed from the prior three years actual data. The seasonalization table and plot for Lower Mainland Rate Schedule 1 is as follows:

Figure A3-7: LML Rate 1 Seasonalization Factors (%)

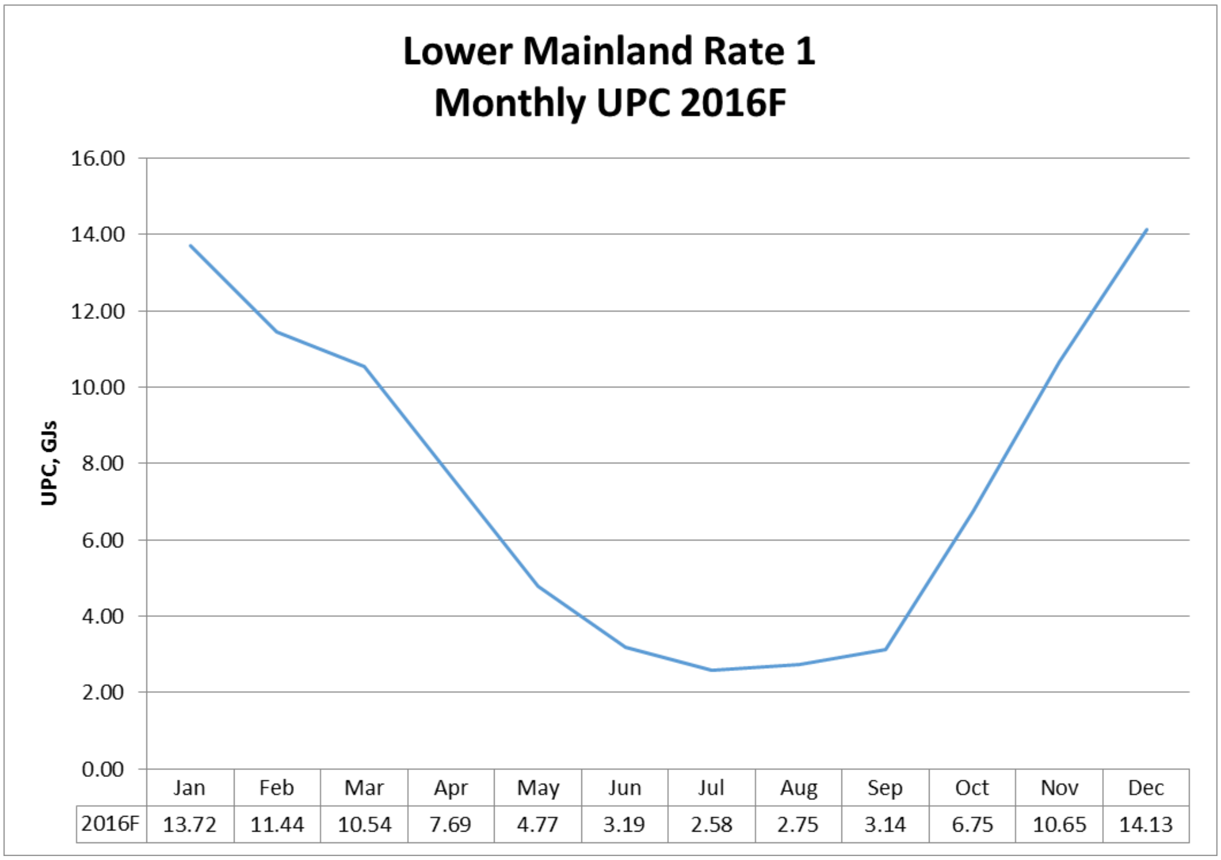


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Proportion	15%	13%	12%	8%	5%	3%	3%	3%	3%	7%	12%	15%

The above table and plot shows that 15% of the annual UPC is consumed in January while only 3% is consumed in July. Summing the monthly seasonalization factors results in 100%, which is always done as a check.

Once seasonalized, the annual Lower Mainland forecast UPC for the 2016 Forecast (91.4GJs) is shown in the following figure:

Figure A3-8: LML Rate 1 Monthly UPC (GJs)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016F	13.72	11.44	10.54	7.69	4.77	3.19	2.58	2.75	3.14	6.75	10.65	14.13

Note that the sum of the monthly use rates equals the annual forecast value of 91.4GJs (with rounding).

The methodology is completed for all sub-regions and results in the following table:

Table A3-28: Rate Schedule 1 UPC (GJs)

Rate Schedule 1 UPC, GJs	Columbia	Inland	Lower Mainland	Revelstoke	Vancouver Island	Whistler
January	12.71671	12.70699	13.72200	8.28703	7.10498	15.33616
February	10.44112	10.24001	11.43894	7.01449	5.64096	11.60775
March	9.02912	7.88519	10.54059	5.92789	5.33138	10.52287
April	6.38838	5.25913	7.68715	3.69610	3.82794	6.93678
May	3.94200	2.98976	4.77008	1.80224	2.36601	3.94912
June	2.42941	1.95627	3.19478	0.92148	1.63793	2.67849
July	1.85058	1.71407	2.58215	0.80670	1.29045	2.10538
August	1.74197	1.72520	2.74594	0.77152	1.28962	2.10218
September	2.75121	2.45434	3.13862	1.31535	1.64930	2.89051
October	6.19125	5.75539	6.75142	3.60683	3.32179	5.48545
November	9.45872	9.30639	10.65296	5.91702	5.15340	7.98713
December	13.02672	12.70221	14.13221	8.12740	6.46375	13.45072

5.5 *AMALGAMATION OF UPCS*

Once the use rates are seasonalized and developed for each region and each rate schedule (Rate Schedules 1, 2, 3 and 23) they are entered into FIS. Monthly regional use rates cannot simply be summed or averaged to provide the correct amalgamated use rate. The amalgamated use rate must be 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 schedule for all regions. The following example from Rate Schedule 1 shows the monthly sums of volumes from Lower Mainland, Inland, Columbia, Vancouver Island and Whistler.

Table A3-29: Rate Schedule 1 Volumes (TJs) for All Regions

Month	2015	2016
January	11,292	11,244
February	9,310	9,269
March	8,245	8,204
April	5,891	5,860
May	3,592	3,572
June	2,393	2,380
July	1,955	1,945
August	2,044	2,033
September	2,479	2,467
October	5,436	5,410
November	8,637	8,597
December	11,539	11,485

Similarly, the monthly customer sums are as follows:

Table A3-30: Rate Schedule 1 Customers for All Regions

Month	2015	2016
January	875,972	885,638
February	876,724	886,370
March	876,920	886,551
April	876,575	886,201
May	876,240	885,862
June	875,061	884,696
July	874,158	883,800
August	874,119	883,757
September	875,492	885,095
October	878,502	888,050
November	881,474	890,972
December	883,369	892,830

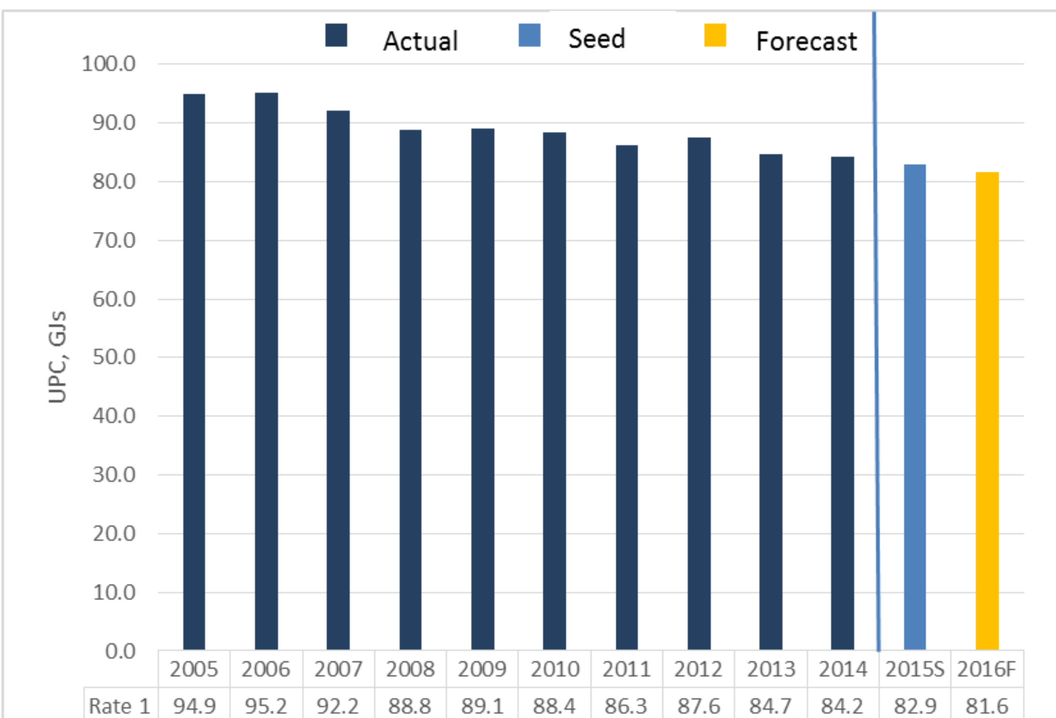
Using the relation above, the amalgamated monthly UPC is ratio of monthly demand to monthly customers, as follows:

Table A3-31: Rate Schedule 1 Use Rate for All Regions

Month	2015	2016
January	12.89	12.70
February	10.62	10.46
March	9.40	9.25
April	6.72	6.61
May	4.10	4.03
June	2.73	2.69
July	2.24	2.20
August	2.34	2.30
September	2.83	2.79
October	6.19	6.09
November	9.80	9.65
December	13.06	12.86
Annual UPC	**82.92**	**81.64**

Summing up the monthly amalgamated UPC values then results in the forecast annual value for Rate Schedule 1, as shown in the figure below:

Figure A3-9: Rate Schedule 1 UPC (GJs)



6. COMMERCIAL USE RATE

The following sections show in detail how the use rate methodology works for the commercial forecast and how the forecast values in Figure 3-2 in the Application were derived. The following methodology applies to all sub-regions and Rate Schedules 2, 3 and 23. The examples that follow use Rate Schedule 2.

6.1 *MONTHLY WEATHER-NORMALIZED ACTUAL UPCS*

FEI's commercial use rate forecast is developed in the same manner as the residential use rate forecast discussed above. The method is based on four years of monthly use rates by region and rate class. The monthly UPC values are weather-normalized using the process described in Section 2.4 above. As with the residential forecast discussed above, the four years of monthly data is used to calculate 36, 12-month rolling UPC sums. These 12-month rolling UPC sums are then plotted and a regression analysis is conducted. If the resulting R^2 value is greater than 50%, then the slope of the regression equation is used to forecast the use rate for the Forecast Year. If the resulting R^2 value is 50% or less, then a three-year average of annual growth rates is used for the forecast.

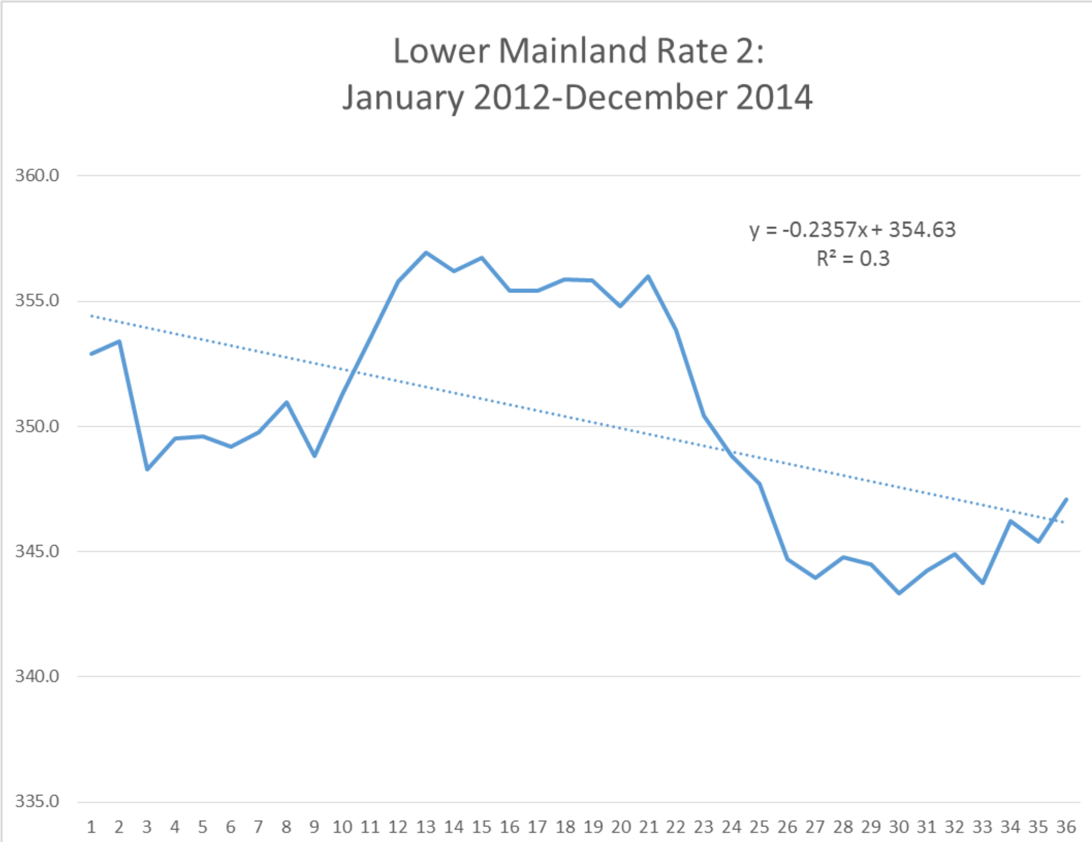
6.2 *REGRESSION METHOD*

None of the commercial rate classes in any of the sub-regions demonstrated a statistically significant trend in the current forecast. In the case that a region and rate class did result in a statistically significant trend the methodology as illustrated for Rate Schedule 1 in section 5.3 above would be used.

6.3 *THREE YEAR AVERAGE METHOD FOR COMMERCIAL UPC CALCULATION*

If a statistically significant trend does not exist then FEI uses a three-year average of the annual growth rates. For Lower Mainland, the regression statistic is 30%, so a three-year average method is used.

Figure A3-10: LML Rate 2 Regression Statistic



The following table shows the annual UPC and growth values used to calculate the three-year average growth rate:

Table A3-32: Annual UPC and Growth Rates

	2010	2011	2012	2013	2014
UPC	348.6	353.6	355.8	348.8	347.1
Growth		1.4%	0.6%	-2.0%	-0.5%
3 Yr avg	-0.6%				

As shown in the table above, from the four annual use rates, three annual growth rates can be calculated. For example, for 2011 the growth rate is calculated as follows:

$$2012\ Growth\ rate = \frac{355.8}{353.6} - 1 = 0.6\%$$

This calculation is performed three times using the four UPC values to develop three annual UPC growth rates. These are shown in the table as 0.6%, -2.0% and -0.5%. The three-year average growth rate is then calculated as follows:

$$Three\ year\ average = \frac{0.6 - 2.0 - 0.5}{3} = -0.6\%$$

As shown above, the three-year average UPC growth rate for Inland Rate Schedule 1 is -0.6%.

The 2015 Seed Year use rate is developed by applying the three-year average growth rate to the 2014 Actual value as follows:

$$2015\ Seed\ Year = \frac{(100 - 0.6)}{100} \times 347.1 = 345.0\ GJs$$

The 2016 Forecast use rate is developed by applying the three-year average growth rate to the 2015 Seed Year value as follows:

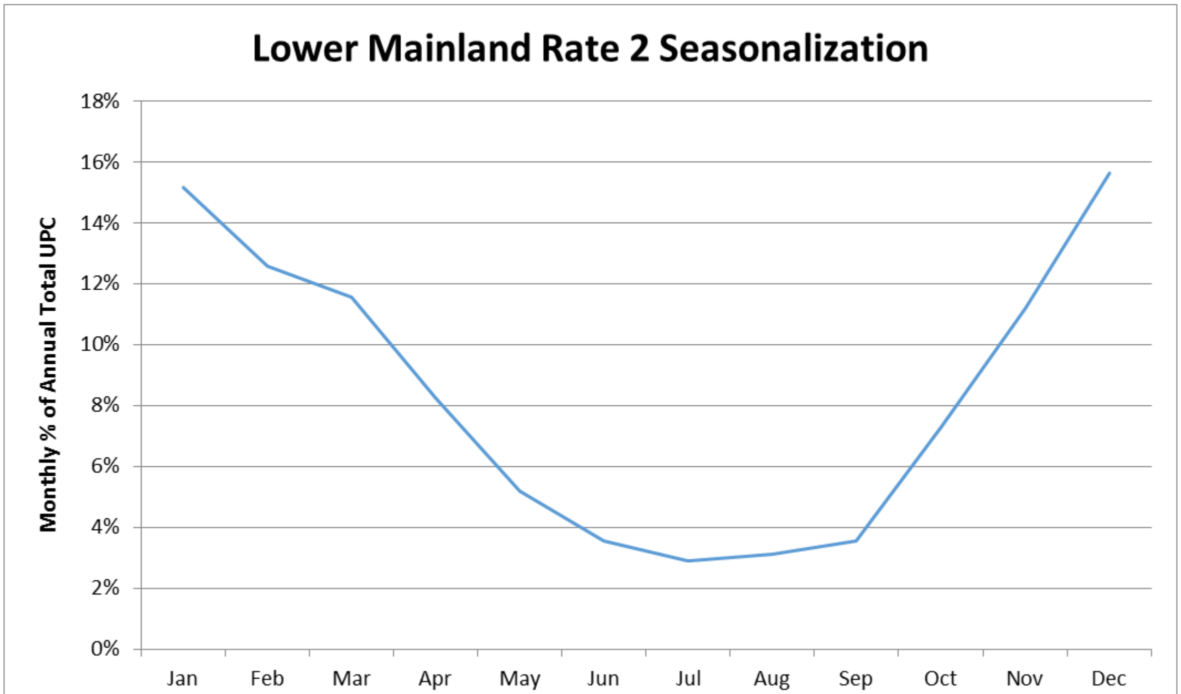
$$2016\ Forecast = \frac{(100 - 0.6)}{100} \times 345.0 = 342.9 GJs$$

6.4 *SEASONALIZATION*

Once the annual UPC forecasts for each region are complete they must be loaded into FIS to develop the load forecast by region and are seasonalized as described in section 3.4 above.

A seasonalization table and plot for Lower Mainland Rate Schedule 2 is as follows:

Figure A3-11: LML Rate 2 Seasonalization (%)

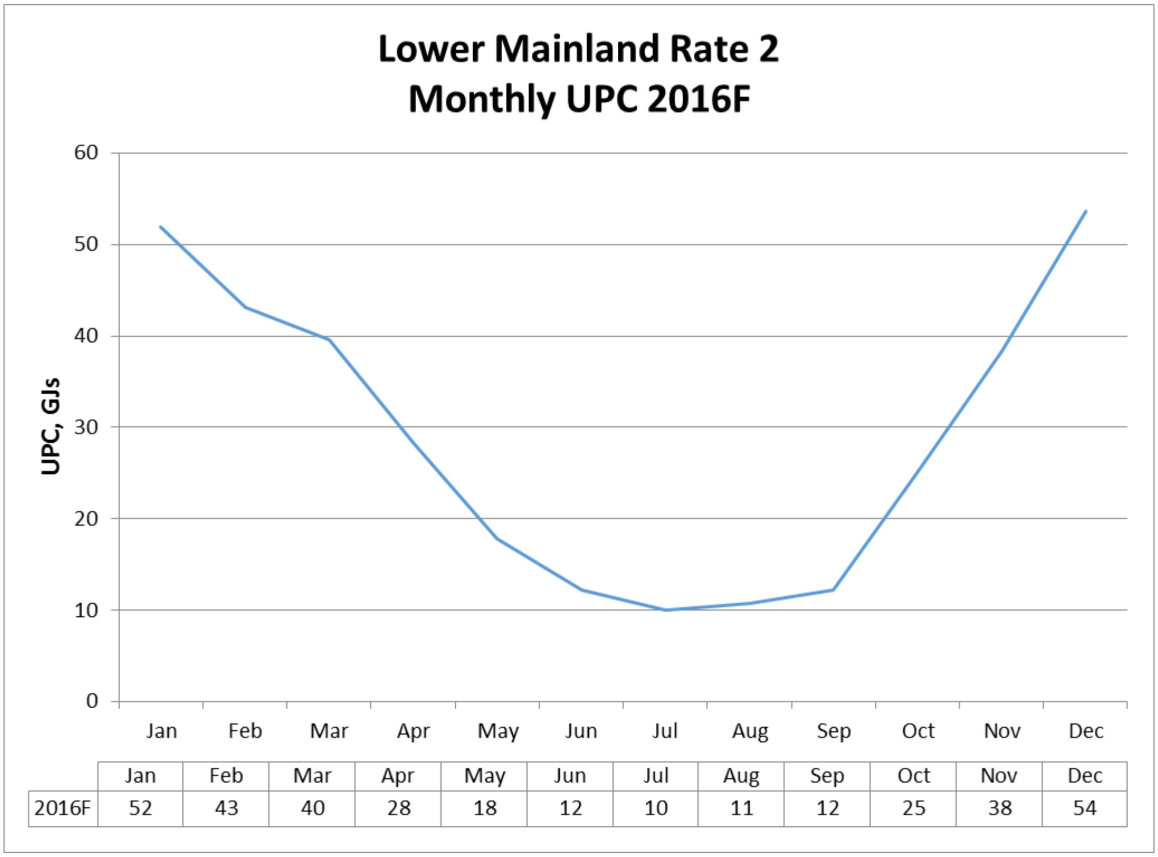


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Proportion	15%	13%	12%	8%	5%	4%	3%	3%	4%	7%	11%	16%

The above table and plot shows that 15% of the annual UPC is consumed in January while only 3% is consumed in July. Summing the monthly seasonalization factors results in 100.0%, which is always done as a check. Seasonalizing the data provides a better revenue forecast than using a straight average, especially for rate classes that are heat sensitive.

Once seasonalized the annual value of 342.9 GJs for 2016F looks like this:

Figure A3-12: LML Rate 2 Monthly UPC (GJs)



Note that the sum of the monthly use rates equals the annual forecast value of 342.9 GJs (with rounding).

6.5 *AMALGAMATION OF UPCS*

Once the use rates are seasonalized and developed for each region and each rate schedule (rates 1, 2, 3 and 23) they are entered into FIS. As discussed in section 5.5, the amalgamated use rate 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. The following example from Rate 2 shows the sum of volumes from Lower Mainland, Inland, Columbia, Vancouver Island and Whistler.

Table A3-33: Rate Schedule 2 Volumes (TJs) for All Regions

Month	2015	2016
January	4,329	4,375
February	3,558	3,596
March	3,152	3,185
April	2,191	2,213
May	1,358	1,372
June	930	940
July	783	792
August	825	834
September	970	981
October	2,009	2,030
November	3,158	3,192
December	4,456	4,503

Similarly, the monthly customer sums are as follows:

Table A3-34: Rate Schedule 2 Customers for All Regions

Month	2015	2016
January	84,099	85,124
February	84,209	85,235
March	84,145	85,171
April	83,818	84,845
May	83,556	84,583
June	83,230	84,256
July	83,059	84,084
August	82,964	83,989
September	83,116	84,142
October	83,521	84,547
November	84,180	85,205
December	84,641	85,667

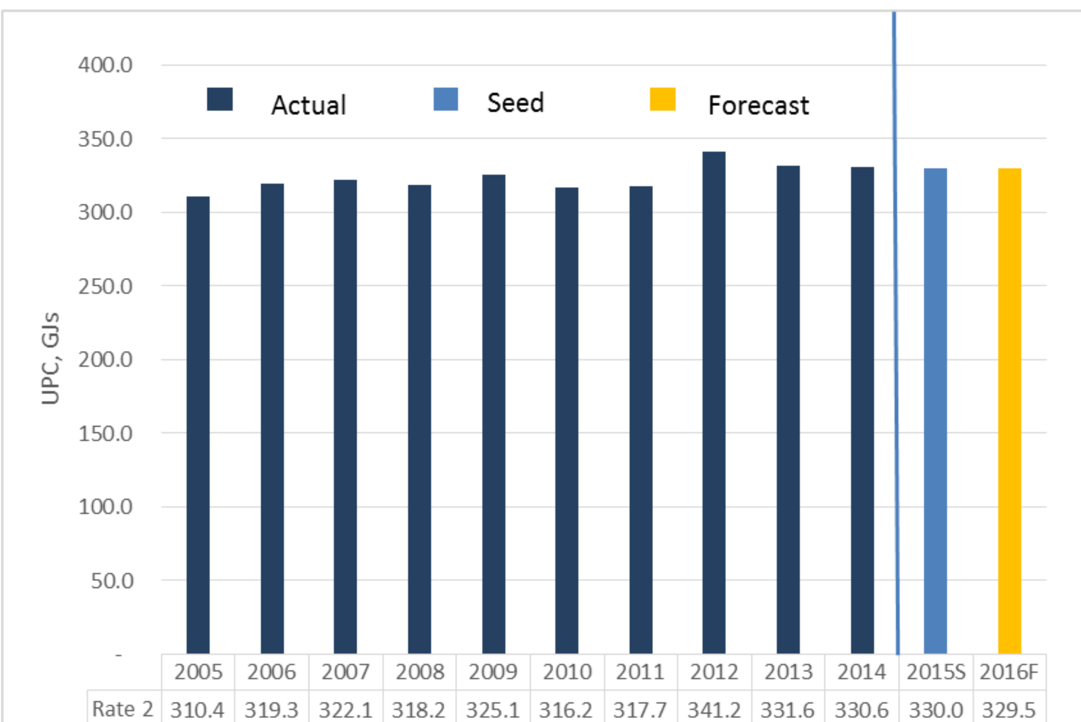
Using the relation above, the amalgamated monthly UPC is the monthly volumes divided by the monthly customers, resulting in the following:

Table A3-35: Rate Schedule 2 Use Rate for All Regions (GJs)

Month	2015	2016
January	51.47	51.39
February	42.25	42.19
March	37.46	37.39
April	26.14	26.09
May	16.25	16.22
June	11.17	11.15
July	9.43	9.42
August	9.95	9.93
September	11.68	11.66
October	24.05	24.01
November	37.52	37.46
December	52.64	52.56
Annual UPC	**330.0**	**329.5**

Summing up the monthly amalgamated UPC values results in the forecast annual value for Rate Schedule 2, as shown in Figure 3-2 of the filing:

Figure A3-13: Rate Schedule 2 UPC (GJs)



7. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the simple products of the monthly customer forecast and the matching 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.

Lower Mainland will be used as an example to demonstrate the method.

The Rate Schedule 1 customer forecast from section 3.7 is as follows:

Table A3-36: Rate 1 Customer Count Forecast

Rate Schedule 1 Accounts	Columbia	Inland	Lower Mainland	Revelstoke	Vancouver Island	Whistler
January	20,960	217,760	542,815	1,298	100,322	2,483
February	20,970	217,883	543,180	1,297	100,555	2,485
March	20,964	217,915	543,176	1,302	100,711	2,483
April	20,949	217,818	542,867	1,304	100,783	2,480
May	20,933	217,668	542,639	1,303	100,843	2,476
June	20,907	217,360	541,901	1,306	100,746	2,476
July	20,886	217,185	541,265	1,305	100,679	2,480
August	20,895	217,200	541,134	1,306	100,739	2,483
September	20,910	217,566	541,704	1,303	101,112	2,500
October	20,984	218,404	543,209	1,304	101,635	2,514
November	21,051	219,256	544,710	1,304	102,121	2,530
December	21,091	219,691	545,751	1,303	102,458	2,536

The Rate Schedule 1 use rate forecast from section 5.4:

Table A3-37: Rate 1 Use Rate Forecast

Rate Schedule 1 UPC, GJs	Columbia	Inland	Lower Mainland	Revelstoke	Vancouver Island	Whistler
January	12.71671	12.70699	13.72200	8.28703	7.10498	15.33616
February	10.44112	10.24001	11.43894	7.01449	5.64096	11.60775
March	9.02912	7.88519	10.54059	5.92789	5.33138	10.52287
April	6.38838	5.25913	7.68715	3.69610	3.82794	6.93678
May	3.94200	2.98976	4.77008	1.80224	2.36601	3.94912
June	2.42941	1.95627	3.19478	0.92148	1.63793	2.67849
July	1.85058	1.71407	2.58215	0.80670	1.29045	2.10538
August	1.74197	1.72520	2.74594	0.77152	1.28962	2.10218
September	2.75121	2.45434	3.13862	1.31535	1.64930	2.89051
October	6.19125	5.75539	6.75142	3.60683	3.32179	5.48545
November	9.45872	9.30639	10.65296	5.91702	5.15340	7.98713
December	13.02672	12.70221	14.13221	8.12740	6.46375	13.45072

The product of customers and use rate is the demand forecast:

Table A3-38: Demand Forecast

Rate Schedule 1 Energy, TJs	Columbia	Inland	Lower Mainland	Revelstoke	Vancouver Island	Whistler	Total (PJs)
January	266.5	2,767.1	7,448.5	10.8	712.8	38.1	11.2
February	219.0	2,231.1	6,213.4	9.1	567.2	28.8	9.3
March	189.3	1,718.3	5,725.4	7.7	536.9	26.1	8.2
April	133.8	1,145.5	4,173.1	4.8	385.8	17.2	5.9
May	82.5	650.8	2,588.4	2.3	238.6	9.8	3.6
June	50.8	425.2	1,731.3	1.2	165.0	6.6	2.4
July	38.7	372.3	1,397.6	1.1	129.9	5.2	1.9
August	36.4	374.7	1,485.9	1.0	129.9	5.2	2.0
September	57.5	534.0	1,700.2	1.7	166.8	7.2	2.5
October	129.9	1,257.0	3,667.4	4.7	337.6	13.8	5.4
November	199.1	2,040.5	5,802.8	7.7	526.3	20.2	8.6
December	274.7	2,790.6	7,712.7	10.6	662.3	34.1	11.5
Total							72.5

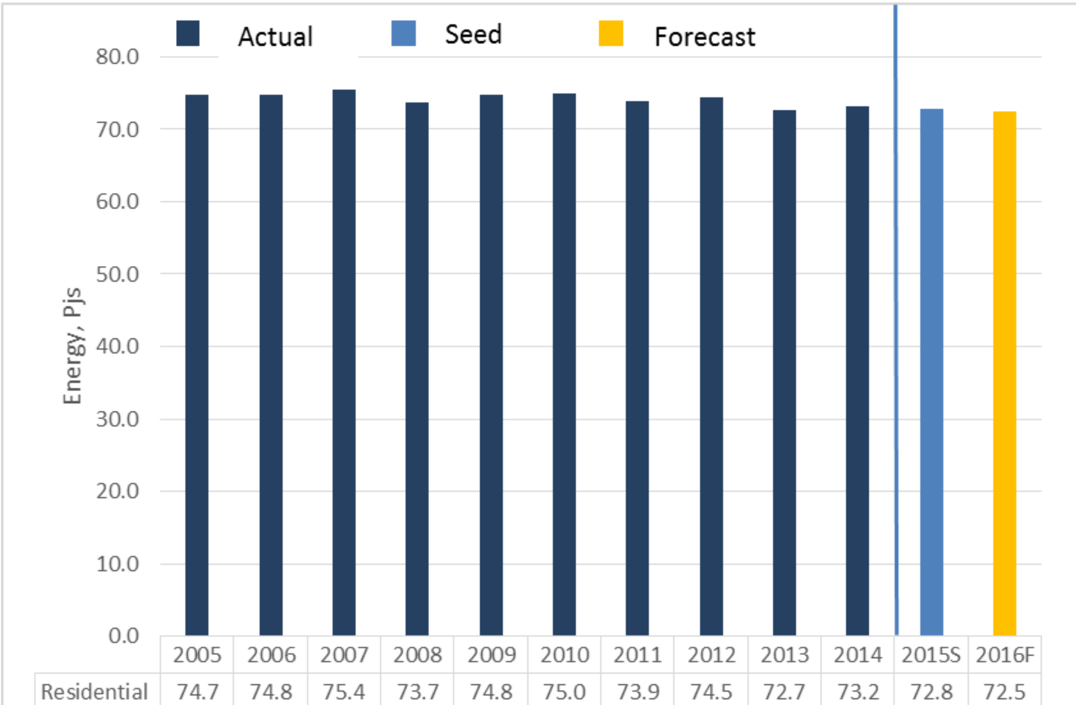
For example, the Columbia January 2016 value is calculated as:

Table A3-39: Columbia Energy Demand Calculation

Columbia January 2016 Energy Forecast	=	January 2016 Customers	X	January 2016 Rate Schedule 1 UPC
266.5 TJs	=	20,960	X	12.71671

The 2016 forecast total of 72.5 PJs is also shown in Figure 3-9 of the Application, which is reproduced below for reference.

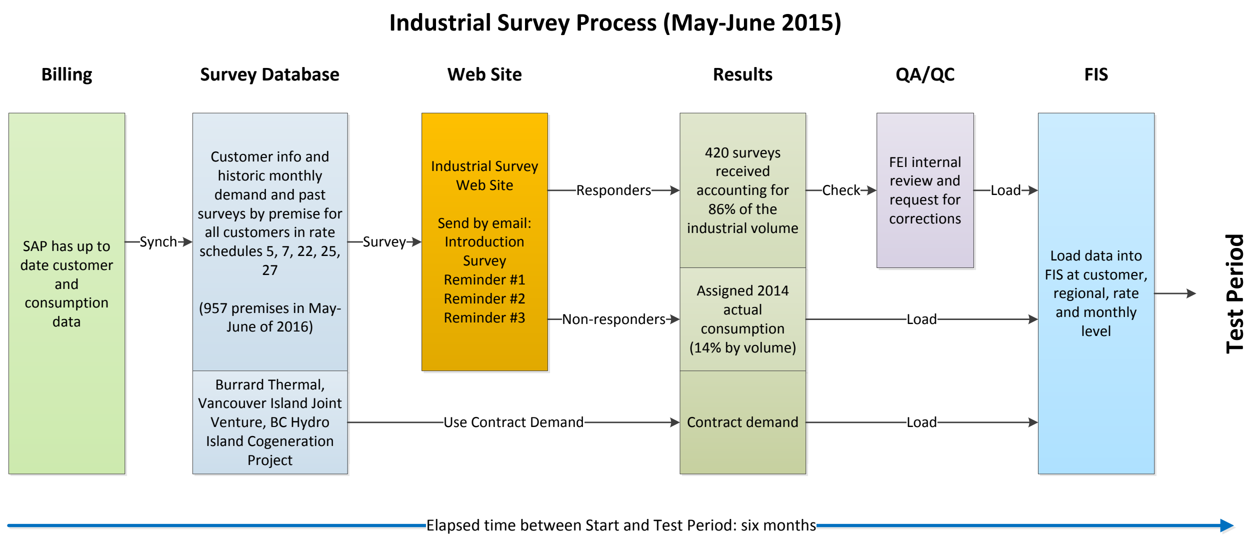
Figure A3-14: Annual Residential Demand (PJs)



8. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure A3-15: 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 six weeks duration) the survey responses are checked and then the data is loaded into the FIS system. The following sections describe the process in detail.

8.1 *CREATE THE SURVEY*

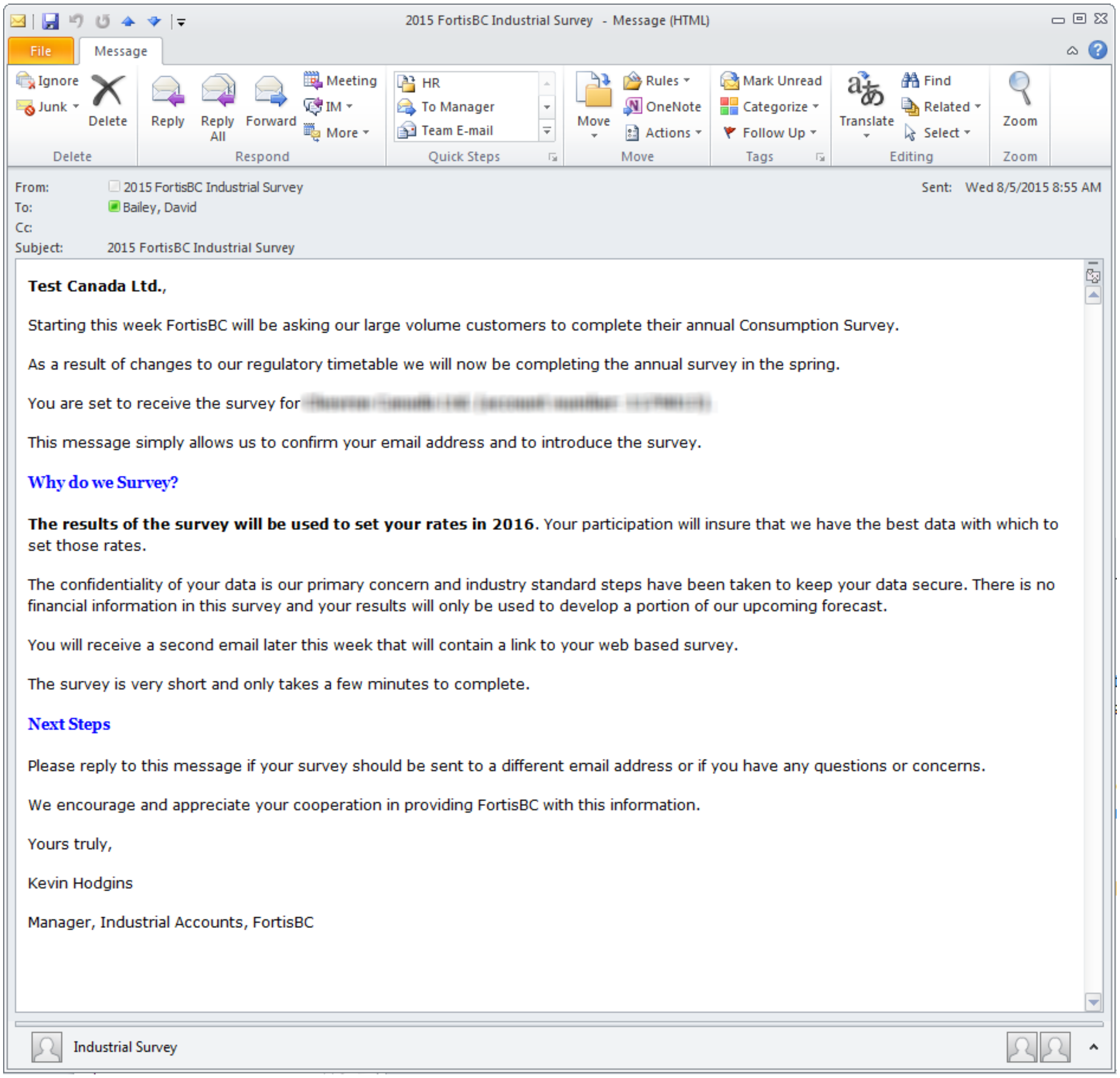
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

8.2 *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 above form letters and manages the send out. The following is an example of the introductory email.

Figure A3-16: Survey Introductory Email Example



2015 FortisBC Industrial Survey - Message (HTML)

From: 2015 FortisBC Industrial Survey
To: Bailey, David
Cc:
Subject: 2015 FortisBC Industrial Survey
Sent: Wed 8/5/2015 8:55 AM

Test Canada Ltd.,

Starting this week FortisBC will be asking our large volume customers to complete their annual Consumption Survey.

As a result of changes to our regulatory timetable we will now be completing the annual survey in the spring.

You are set to receive the survey for [redacted]

This message simply allows us to confirm your email address and to introduce the survey.

Why do we Survey?

The results of the survey will be used to set your rates in 2016. Your participation will insure that we have the best data with which to set those rates.

The confidentiality of your data is our primary concern and industry standard steps have been taken to keep your data secure. There is no financial information in this survey and your results will only be used to develop a portion of our upcoming forecast.

You will receive a second email later this week that will contain a link to your web based survey.

The survey is very short and only takes a few minutes to complete.

Next Steps

Please reply to this message if your survey should be sent to a different email address or if you have any questions or concerns.

We encourage and appreciate your cooperation in providing FortisBC with this information.

Yours truly,

Kevin Hodgins

Manager, Industrial Accounts, FortisBC

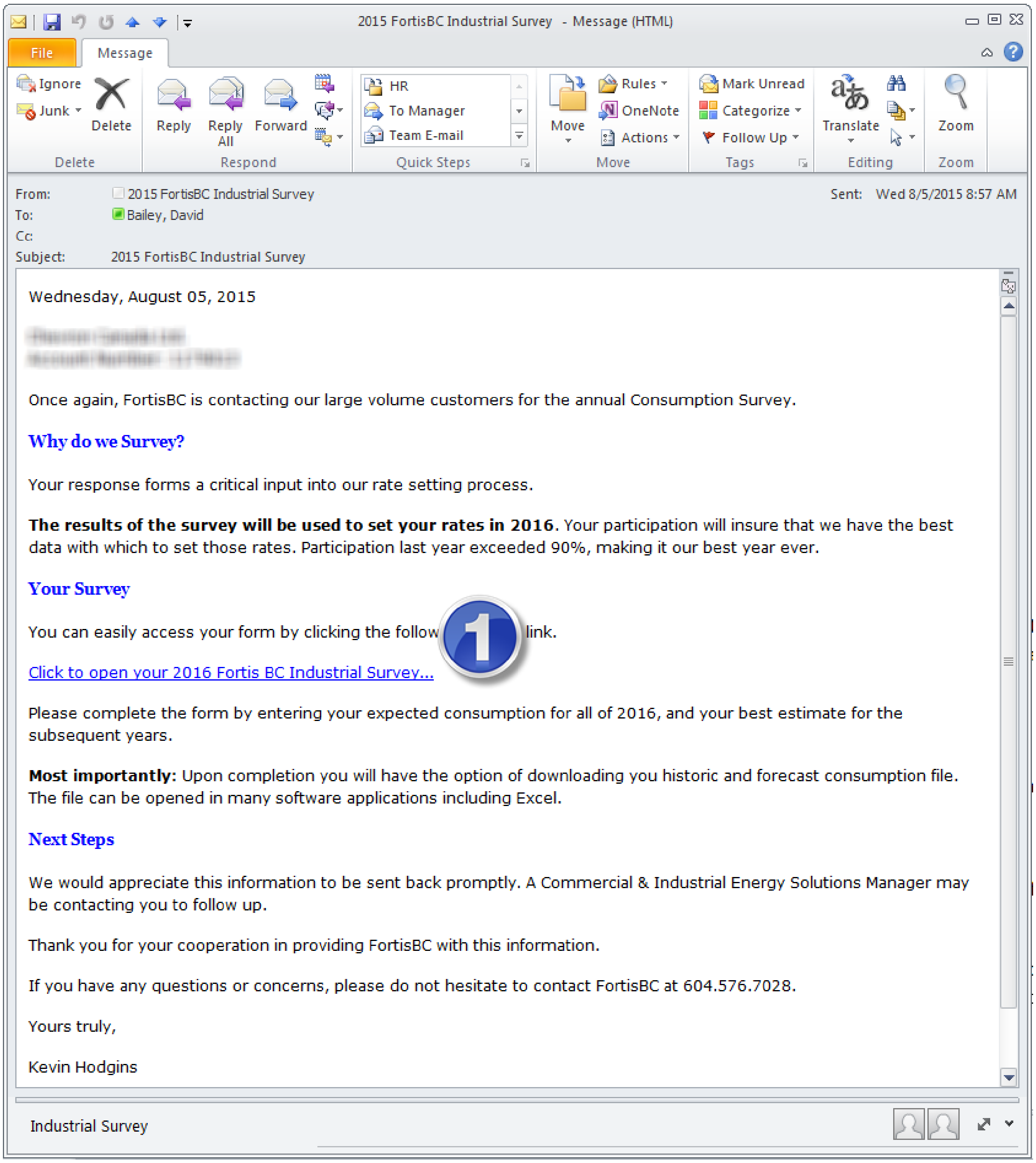
Industrial Survey

Replies to these emails are used to update the contact and other information in the survey web site.

8.3 *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 insures that customers cannot access surveys from other customers.

Figure A3-17: Survey Email Example



From: 2015 FortisBC Industrial Survey
Sent: Wed 8/5/2015 8:57 AM
To: Bailey, David
Cc:
Subject: 2015 FortisBC Industrial Survey

Wednesday, August 05, 2015

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 2016. Your participation will insure that we have the best data with which to set those rates. Participation last year exceeded 90%, making it our best year ever.

Your Survey

You can easily access your form by clicking the follow 1 link.

Click to open your 2016 Fortis BC Industrial Survey...

Please complete the form by entering your expected consumption for all of 2016, and your best estimate for the subsequent years.

Most importantly: Upon completion you will have the option of downloading you 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,

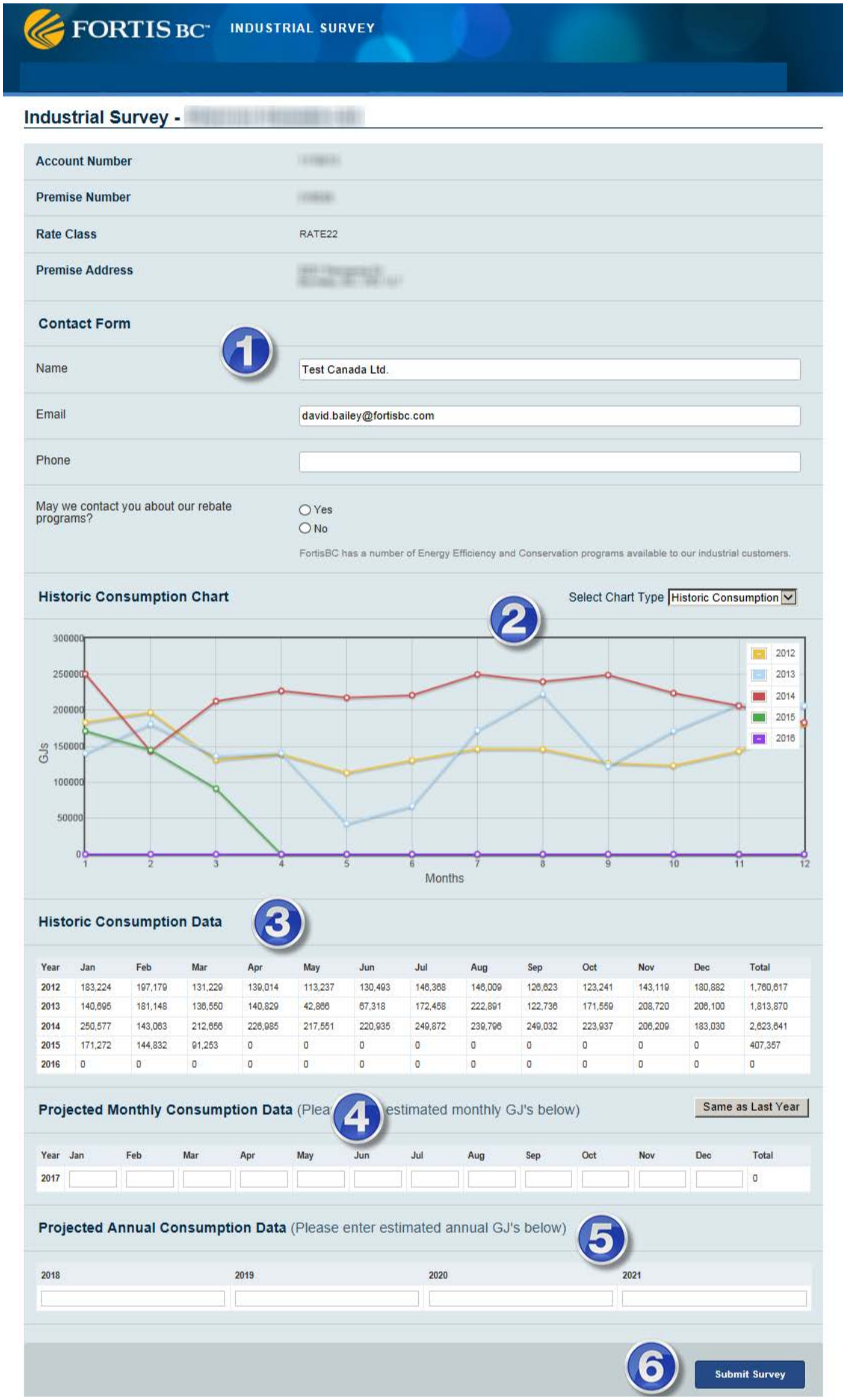
Kevin Hodgins

Industrial Survey

1 ## 8.4 *SURVEY FORM*

2 The following web form is displayed to the user after the link in the email has been clicked.

1 **Figure A3-18: Survey (Web) Form Example**



FORTIS BC INDUSTRIAL SURVEY

Industrial Survey - [illegible]

Account Number	[illegible]
Premise Number	[illegible]
Rate Class	RATE22
Premise Address	[illegible]

Contact Form 1

Name	Test Canada Ltd.
Email	david.bailey@fortisbc.com
Phone	
May we contact you about our rebate programs?	○ Yes ○ No FortisBC has a number of Energy Efficiency and Conservation programs available to our industrial customers.

Historic Consumption Chart 2 Select Chart Type Historic Consumption

Historic Consumption Data 3

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	183,224	197,179	131,229	139,014	113,237	130,493	146,368	146,009	126,623	123,241	143,119	180,882	1,760,617
2013	140,695	181,148	136,550	140,829	42,866	67,318	172,458	222,891	122,736	171,559	208,720	206,100	1,813,870
2014	250,577	143,063	212,656	226,985	217,551	220,935	249,872	239,796	249,032	223,937	206,209	183,030	2,623,641
2015	171,272	144,832	91,253	0	0	0	0	0	0	0	0	0	407,357
2016	0	0	0	0	0	0	0	0	0	0	0	0	0

Projected Monthly Consumption Data (Plea 4 estimated monthly GJ's below) Same as Last Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2017													0

Projected Annual Consumption Data (Please enter estimated annual GJ's below) 5

2018	2019	2020	2021

6 Submit Survey

2

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 customers actual historic consumption is shown for the prior 5 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 show 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. The last update was in April of 2015. This will be updated again in April of 2016 in preparation for the 2016 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.

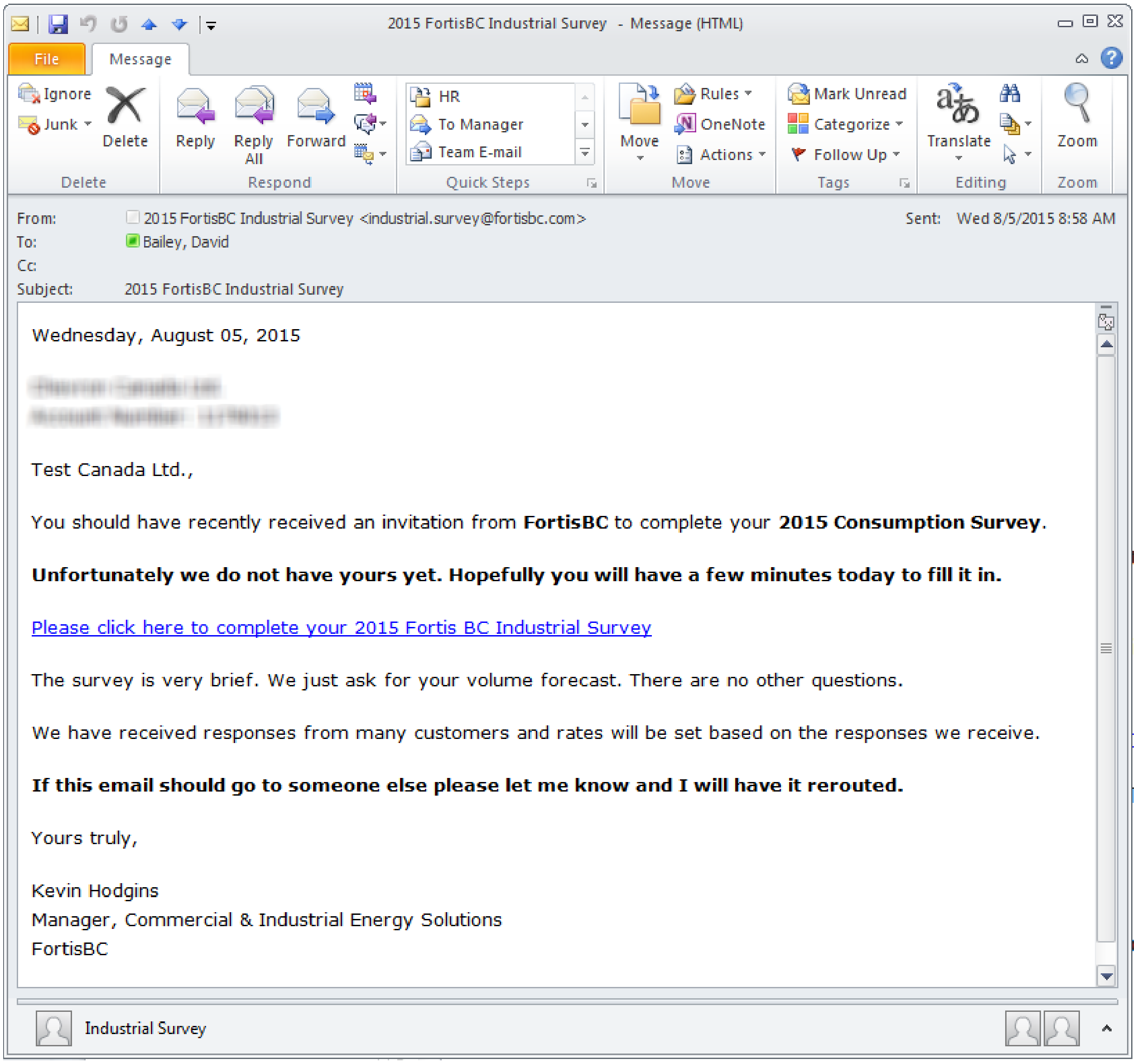
5) Annual forecasts are requested for the remaining 4 years of the survey.

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.

8.5 *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 A3-19: Example of Survey Reminder Email



2015 FortisBC Industrial Survey - Message (HTML)

From: 2015 FortisBC Industrial Survey <industrial.survey@fortisbc.com>
To: Bailey, David
Cc:
Subject: 2015 FortisBC Industrial Survey
Sent: Wed 8/5/2015 8:58 AM

Wednesday, August 05, 2015

[redacted]

Test Canada Ltd.,

You should have recently received an invitation from **FortisBC** to complete your **2015 Consumption Survey**.

Unfortunately we do not have yours yet. Hopefully you will have a few minutes today to fill it in.

Please click here to complete your 2015 Fortis BC Industrial Survey

The survey is very brief. We just ask for your volume forecast. There are no other questions.

We have received responses from many customers and rates will be set based on the responses we receive.

If this email should go to someone else please let me know and I will have it rerouted.

Yours truly,

Kevin Hodgins
Manager, Commercial & Industrial Energy Solutions
FortisBC

Industrial Survey

8.6 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 Rate Schedule 22) are more likely to reply to the survey.

The response rate is measured by counting the number of responses vs the number of customers in the survey. Some customers will not respond because the survey has been sent to an invalid email address and 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. The 2016 survey will be completed in the spring of 2016 and is not active at this time.

Figure A3-20: Example of Survey Results Dashboard

8.7 *REVIEWING THE SURVEYS*

Surveys from large volume customers in Rate Schedules 22 and 27 are reviewed by the Forecast manager and two 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 as required.

8.8 *CLOSING OFF THE SURVEY AND LOADING FIS*

Once the target response rate has been achieved the survey is closed and no further responses are solicited. 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 synch.

Customers that do not respond to the survey are assigned their prior years consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

9. 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 A4

Demand Forecast Methodology for Rate Schedule 22

September 3, 2015

Table of Contents

1. INTRODUCTION

In the Decision attached to Order G-138-14 (PBR Decision), the Commission directed FEI to develop a mechanism to adjust the Rate Schedule 22 demand forecast methodology to better reflect the impact of falling gas prices, for review at the 2015 Annual Review for 2016 rates.

This appendix details FEI's efforts in response to this directive to develop a mechanism to reduce Rate Schedule 22 variances in general, including variances due to falling gas prices. As discussed below, FEI first identified the primary sources of material variances in the forecast, which include fuel switching, business start up and chronic under or over forecasting. FEI then examined various alternative forecasting methods for a mechanism that could address these sources of variance. FEI also conducted an informal survey of other Canadian gas utilities to determine if there were other alternative methodologies available for use.

Based on the analysis conducted, FEI concludes that the traditional survey method remains the appropriate method for forecasting Rate Schedule 22 demand. However, FEI identified two improvements to the survey method to address the sources of variance. These are shortening the length of period between the survey and the test period and involving key account managers in a review of customers forecast, including customers that have been identified as chronic over or under forecasters of their demand.

2. POTENTIAL SOURCES OF VARIANCE

The first step in FEI's analysis was to identified the primary sources of variances between actual and forecast demand. Based on an analysis of historical customer data, the primary reasons for material variances from forecast have been from the following situations:

- **Fuel switching**: Fuel switching, whether to or from gas, introduces large variances because demand changes dramatically. Fuel switching can be driven by changes in the prices of either natural gas or competing fuels (e.g. coal). Fuel switching is the largest source of variance.
- **Business start-up**: Only active customers are included in the annual Industrial Survey. If a customer is not operating at the time of the survey, but then starts or resumes operations during the test period, the actual consumption will contribute directly to the variance. This is a significant source of variance in industries that are subject to international market conditions, such as forestry.
- **Chronic forecast variance by individual customers**: Annual variances can be influenced by customers that continually under or over-forecast. To help customers, FEI includes a chart on the industrial survey web site that shows the customers prior forecast and actual consumption. This has helped reduce the chronic over and under-forecasting. Analysis of recent data shows that a small number of customers consistently over or under-forecast.

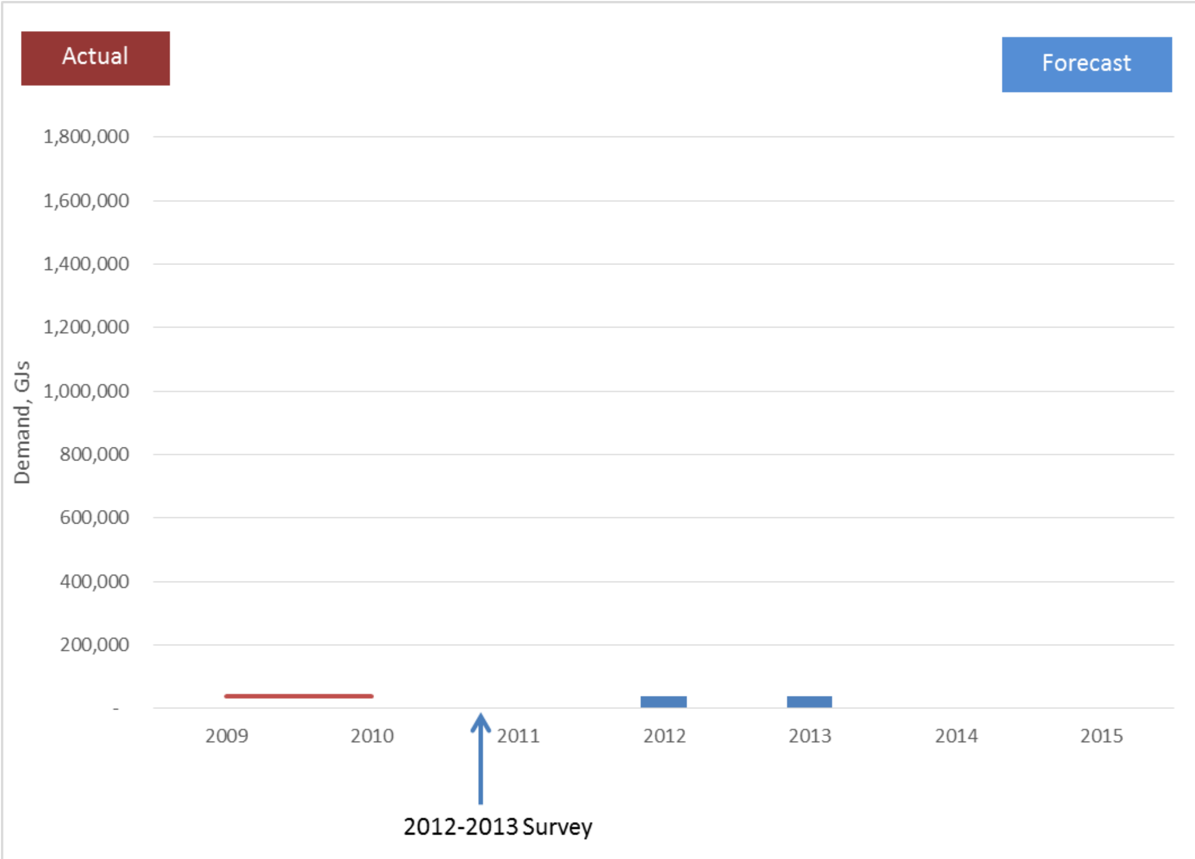
These three sources of variance are discussed in the following sections. Due to privacy concerns, all customer names have been removed.

2.1 *FUEL SWITCHING*

As noted above, fuel switching to or from natural gas to or from a competing fuel is the single largest source of variance in FEI's industrial demand. To illustrate the impact of fuel switching, the following discussion shows the history of one fuel switching customer and how the timing of the industrial demand survey and the fuel switching led to large positive and negative variances.

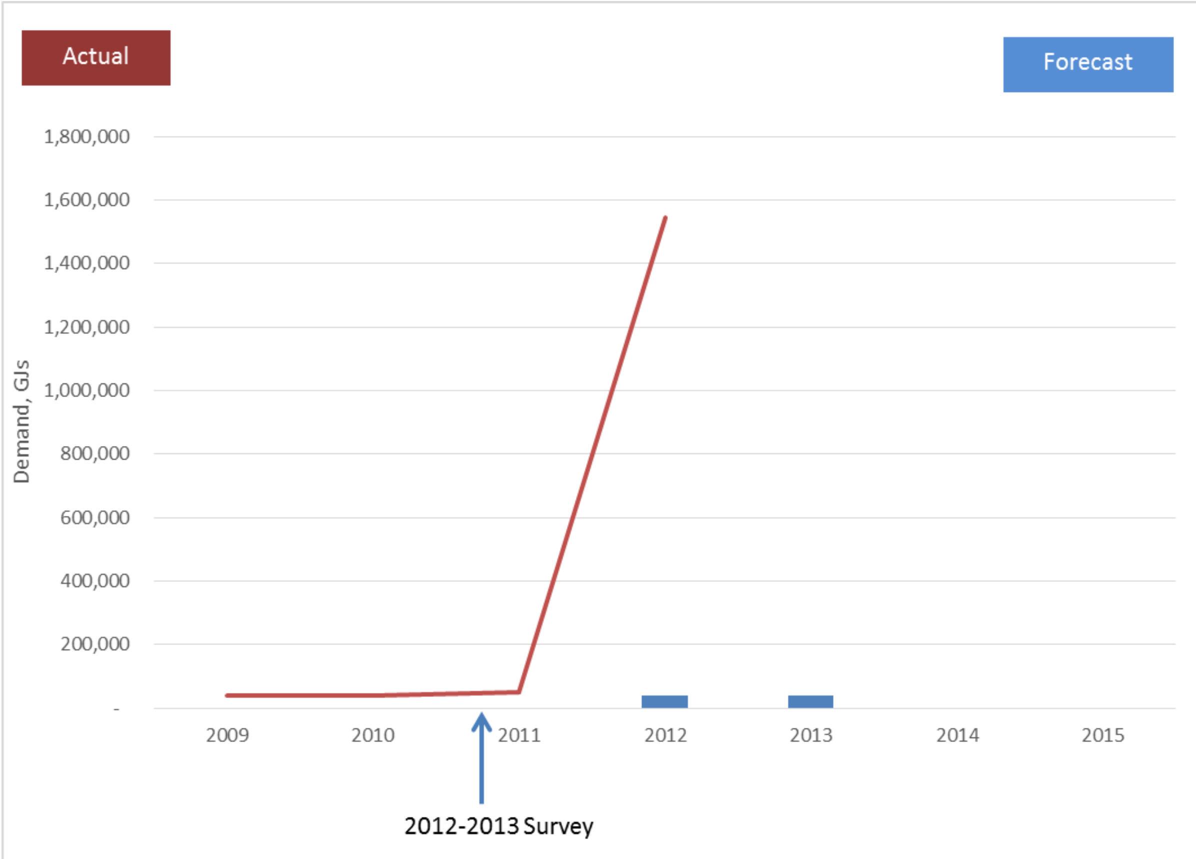
In late 2010, FEI conducted an industrial demand survey in preparation of the 2012-2013 RRA filing. The customer completed the survey assuming business as usual. The forecast from the customer looked reasonable in light of recent actual consumption (2009-2010), as shown in the figure below:

Figure A4-1: R22 Customer Actual and Forecast Demand



In 2011 it became profitable for the customer to change fuels because of a change in fuel costs. The changes in fuel costs can be related not only to natural gas, but can also be affected by the cost for competing fuels. By 2012, the actual consumption from this customer resulted in a large variance compared to the forecast submitted by the customer, as shown in the figure below:

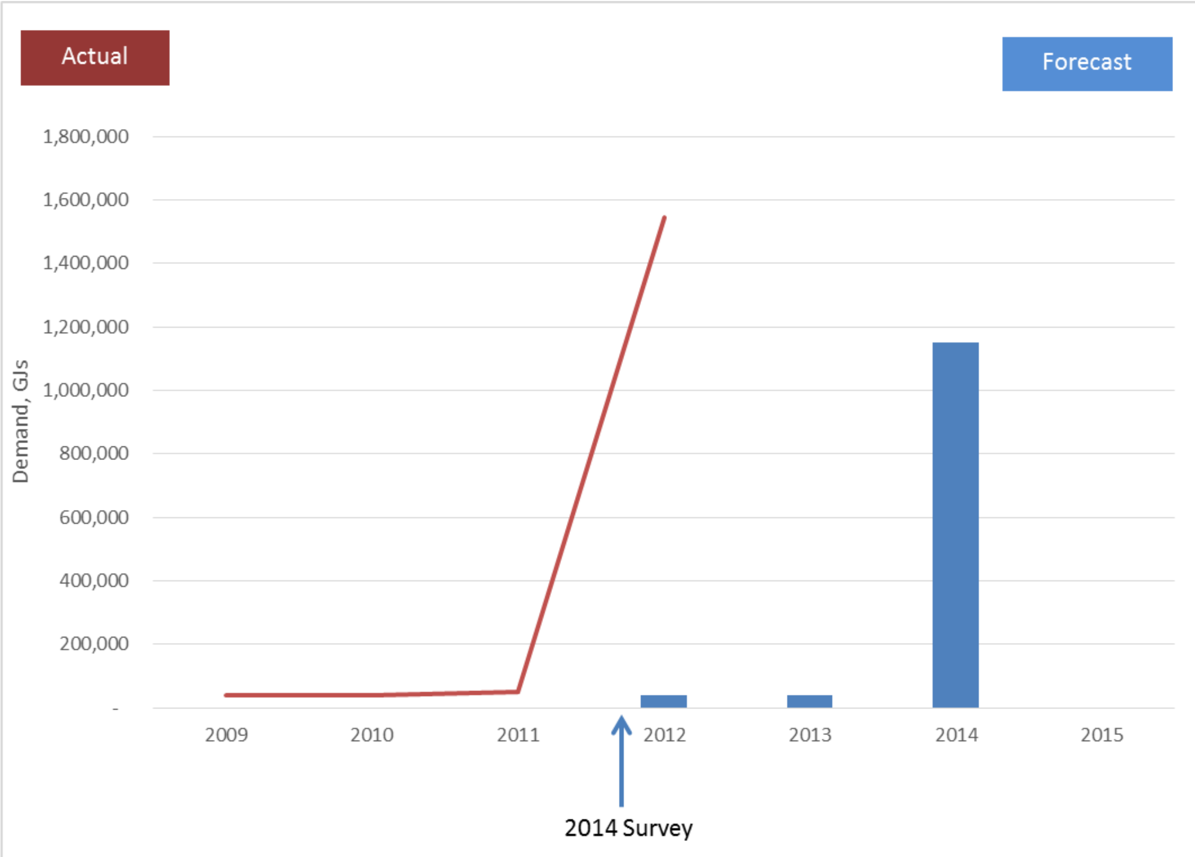
1 **Figure A4-2: R22 Customer Actual and Forecast Demand**



2

3 In late 2011 another industrial demand survey was conducted in preparation of the 2014
4 Forecast. Again, the customer completed the survey and their 2014 forecast was not
5 unreasonable compared to their actual consumption in 2012. The 2014 demand based on the
6 customers survey response, and actual consumption known at the time of the survey is shown
7 in the figure below:

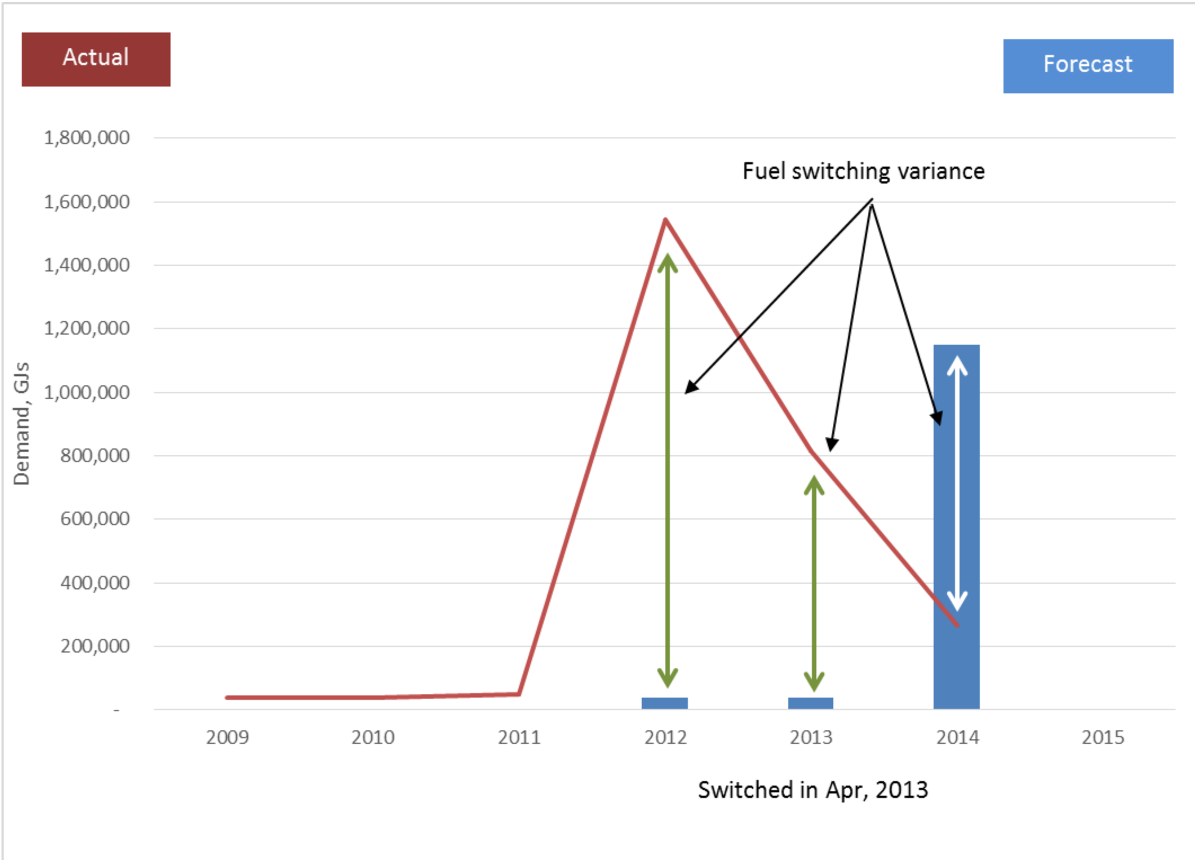
1 **Figure A4-3: R22 Customer Actual and Forecast Demand**



2

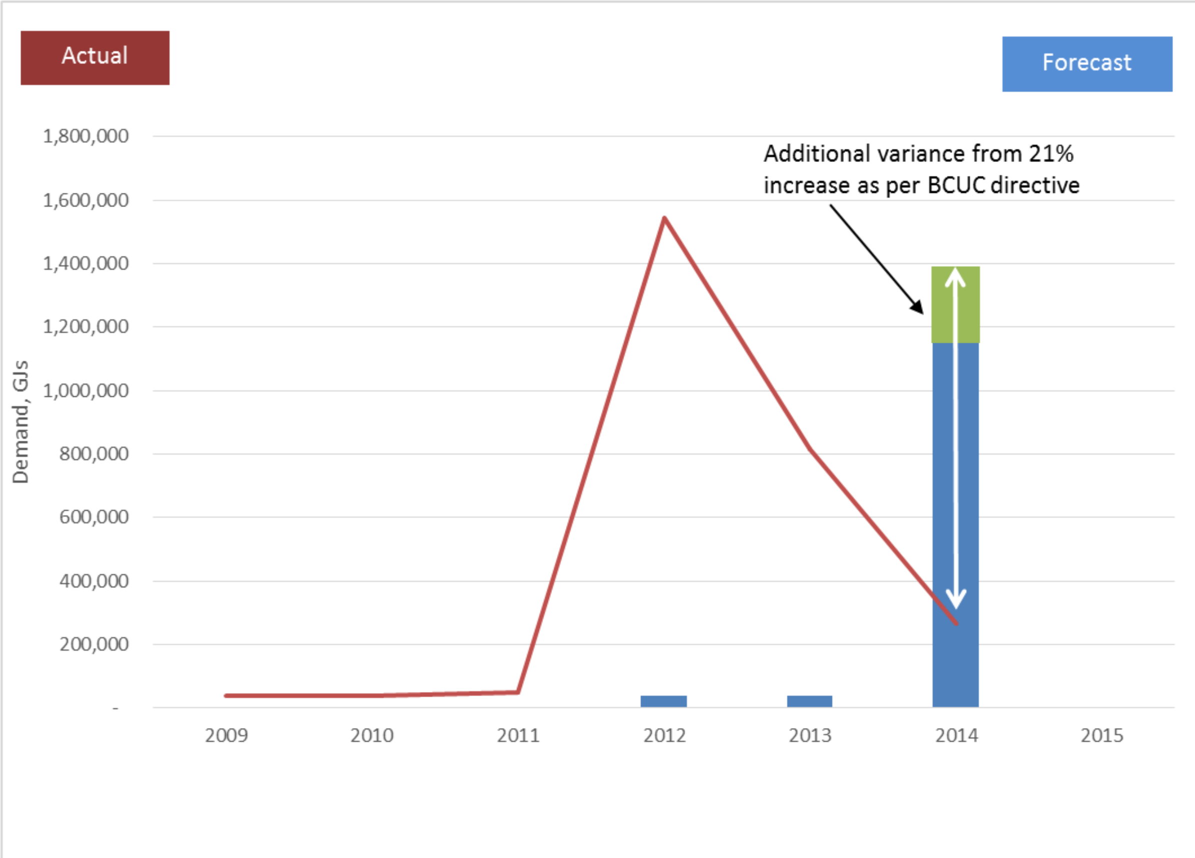
3 Shortly after completing the 2011 survey, it once again became profitable for the customer to
4 change fuels and as a result demand declined significantly. By 2014, the volume was
5 significantly less than the customer forecast in the survey, resulting in a large variance. This is
6 shown in the figure below:

Figure A4-4: R22 Customer Actual and Forecast Demand



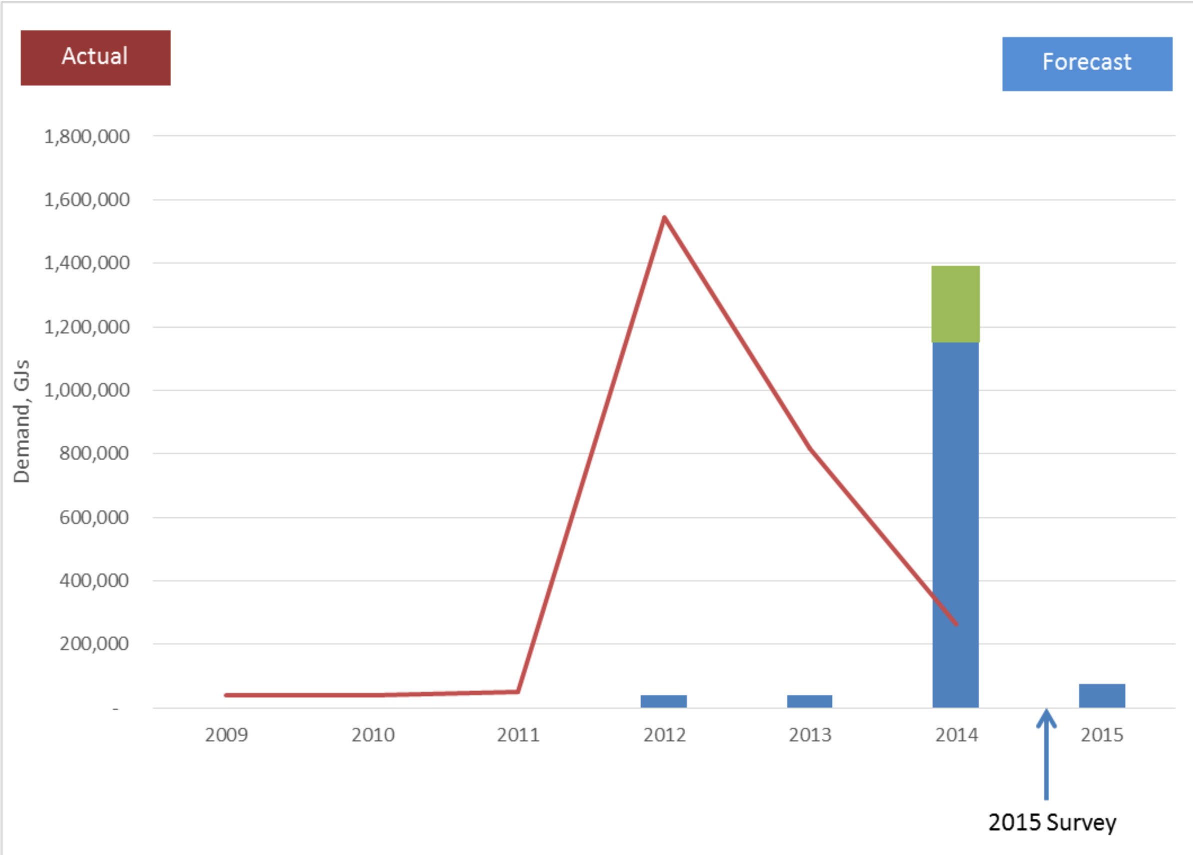
Based in part on the large variance experienced in 2012, as part of the PBR Decision in 2014, FEI was directed to increase the 2014 Rate Schedule 22 demand forecast by 21%. This added to the variance experienced in 2014 as shown in the figure below.

Figure A4-5: R22 Customer Actual and Forecast Demand



In late 2014, FEI conducted an industrial demand survey for the purpose of preparing the 2015 Forecast. Once again the customer forecast was reasonable compared to the actual consumption known at that time, as shown in the figure below:

Figure A4-6: R22 Customer Actual and Forecast Demand



Although the survey was completed close to the forecast year, once again fuel prices changed such that it was profitable for the customer to change fuels. The customer is using natural gas again as of mid-2015 and it is expected that the 2015 demand will exceed the 2015 Forecast based on the survey results. Nonetheless, conducting the annual survey closer in time to the test period should reduce (although not eliminate) the probability of variances between forecast and actual demand due to fuel switching.

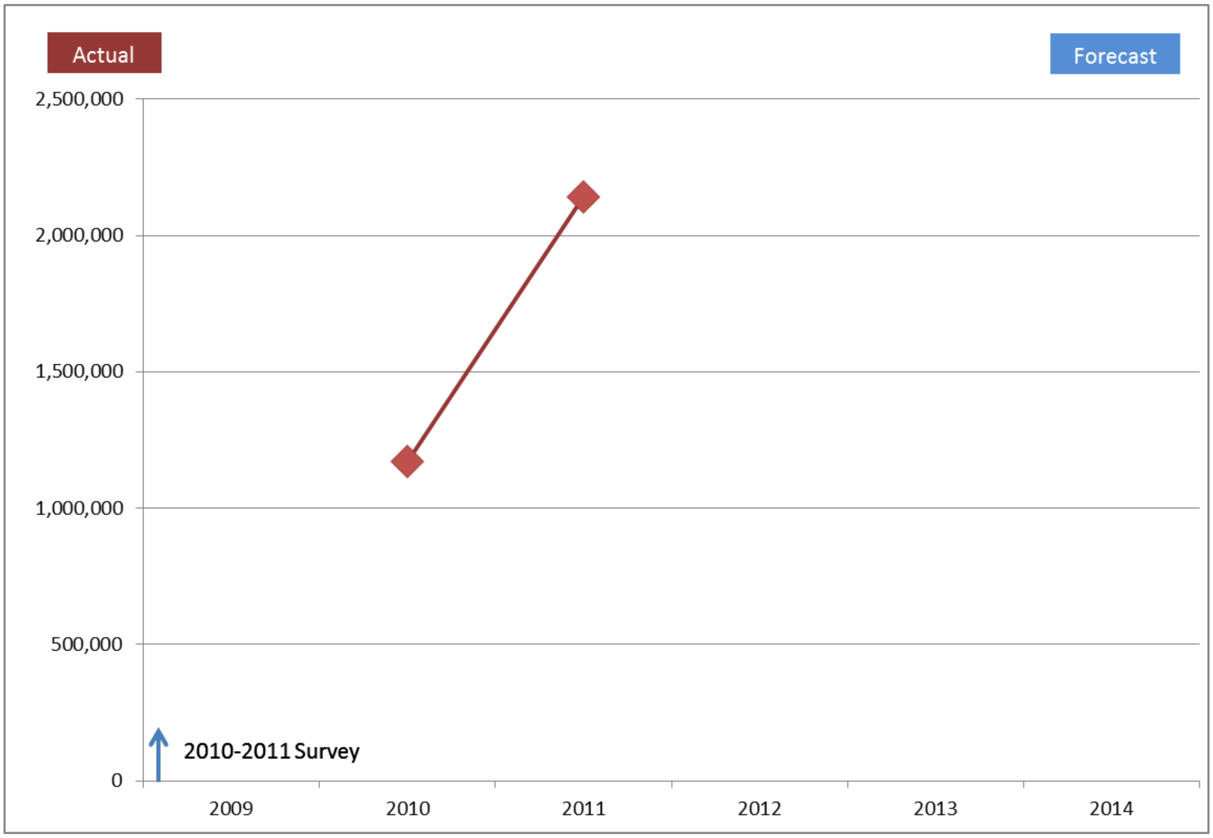
As this example shows, factors that are beyond the control of both FEI and the customer, such as fuel prices, can lead to significant variances due to customers switching fuels. FEI does not believe it is possible to forecast all the factors that are used by customers to determine if and when to switch fuels. It is unlikely that customers would divulge this information and, even if they did, FEI would need very accurate price forecasts for both gas and competing fuels to be able to forecast fuel switching.

2.2 *BUSINESS START UP*

Only active customers are included in the annual Industrial Survey. If a customer is not operating at the time of the survey, but then starts or resumes operations during the test period, the entire actual consumption of the customer will contribute to any forecast variance.

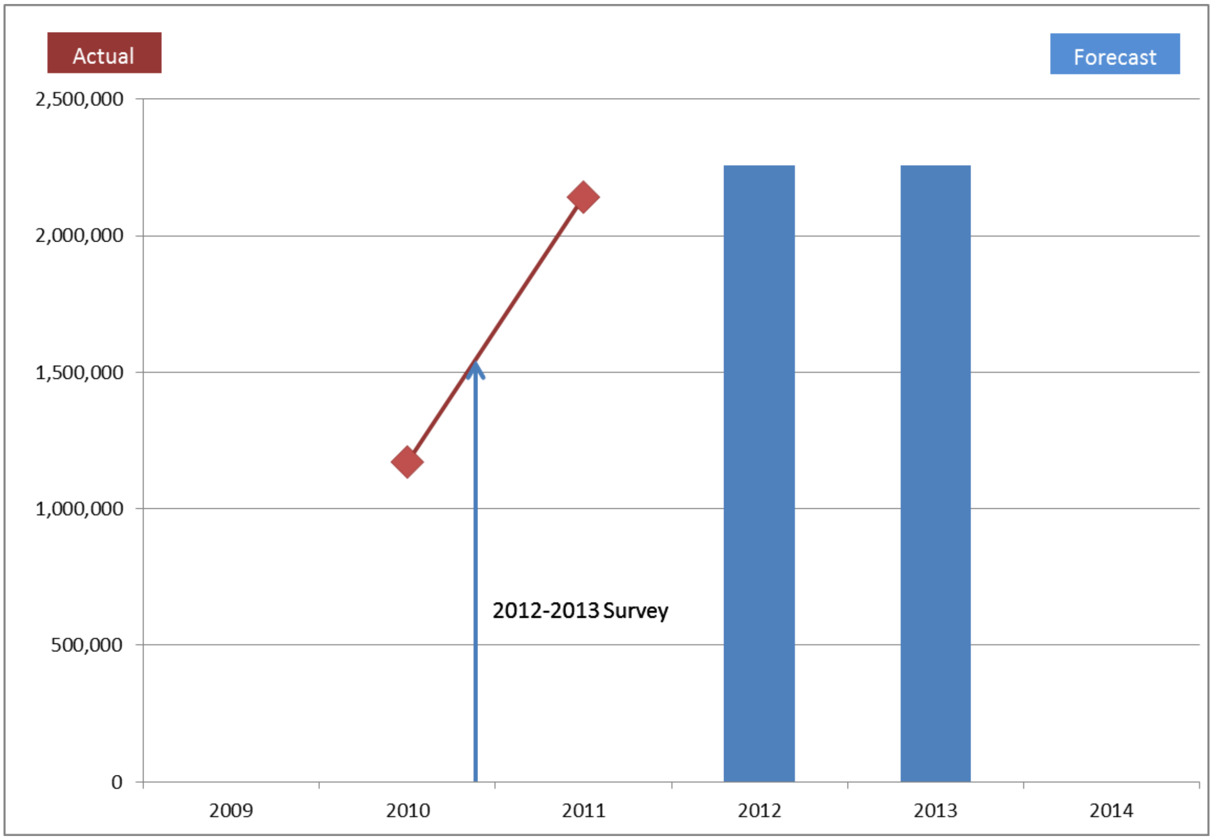
In the following example using a different customer than in the fuel-switching example above, the industrial demand survey for the 2010-2011 RRA was completed in 2009. At the time of that survey, the customer was not consuming gas and as a result was not surveyed and there was no demand forecast for the customer. However, in 2010, due to favorable market conditions, the customer's operations resumed and gas was consumed. In 2011 the volume exceeded 2 PJs. In both 2010 and 2011 all gas consumed was a variance since no demand was forecast for this customer, as shown in the figure below:

Figure A4-7: R22 Customer Actual and Forecast Demand



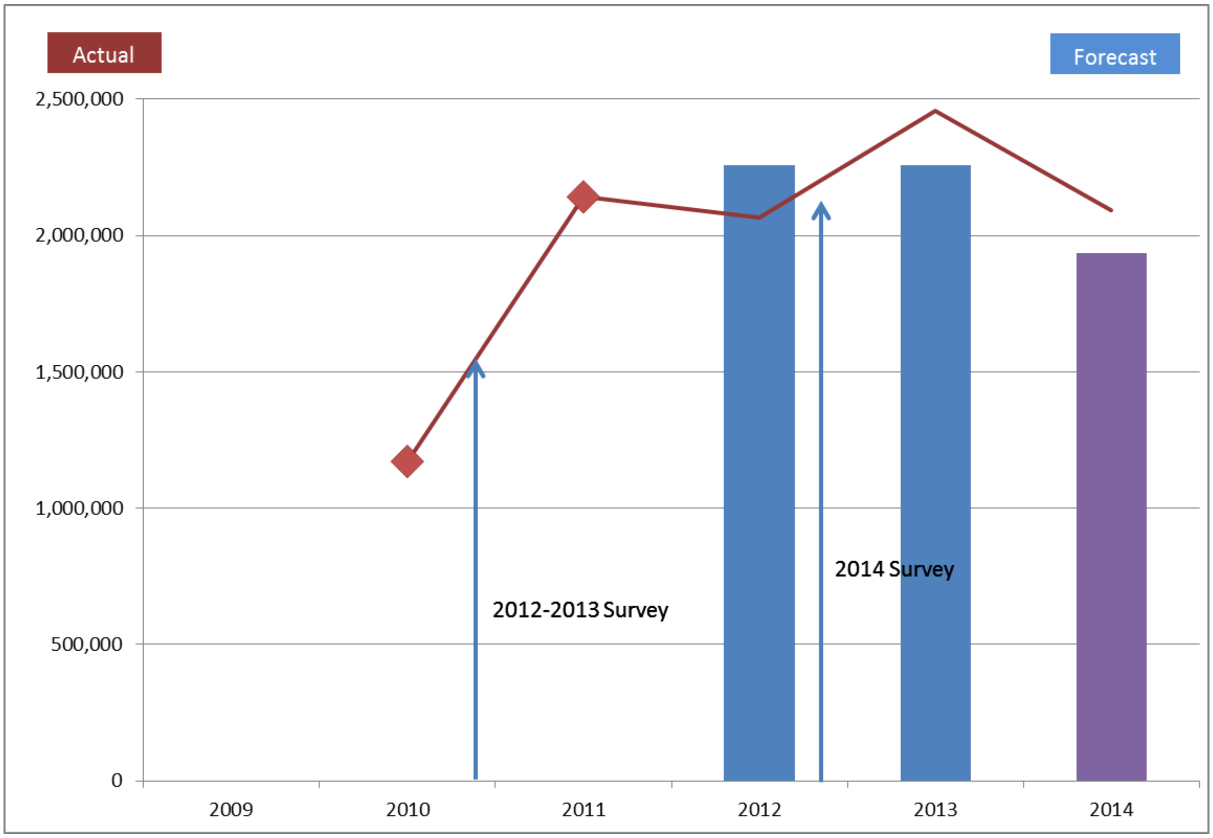
When the Industrial Survey for the 2012-2013 RRA was completed in 2010, the same customer prepared a forecast based on their projected 2011 year end volumes. The forecast, represented by the blue bars in the figure below, appeared reasonable compared to the 2011 actual consumption.

Figure A4-8: R22 Customer Actual and Forecast Demand



As shown in the figure below, the actual consumption of the customer in 2012 and 2013 was reasonably close to the forecast based on the survey. The 2014 Forecast (purple bar) based on the industrial demand survey taken in 2012 was also reasonable compared to the 2014 actual demand, as shown in the figure below.

Figure A4-9: R22 Customer Actual and Forecast Demand

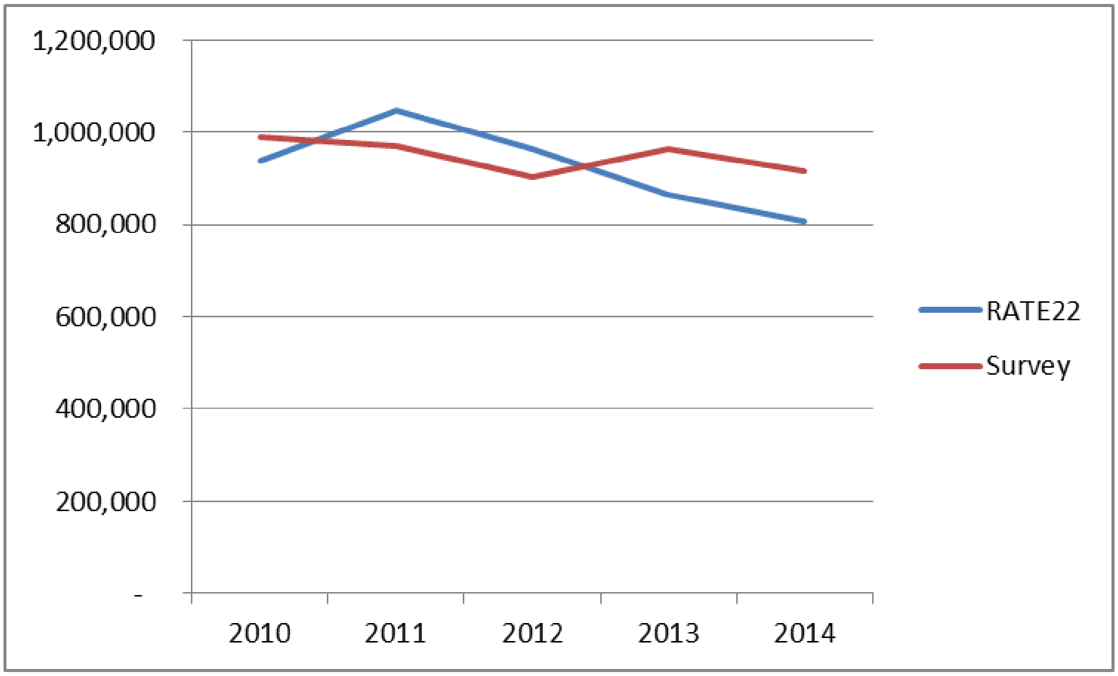


In this case the significant variance only occurred once as the customer resumed operation. Once the facility was operating the customer was able to use the Industrial Survey web site to provide reasonably accurate forecasts. From 2012 through 2014, the three-year average variance was 2.8%.

2.3 *CHRONIC FORECAST VARIANCE*

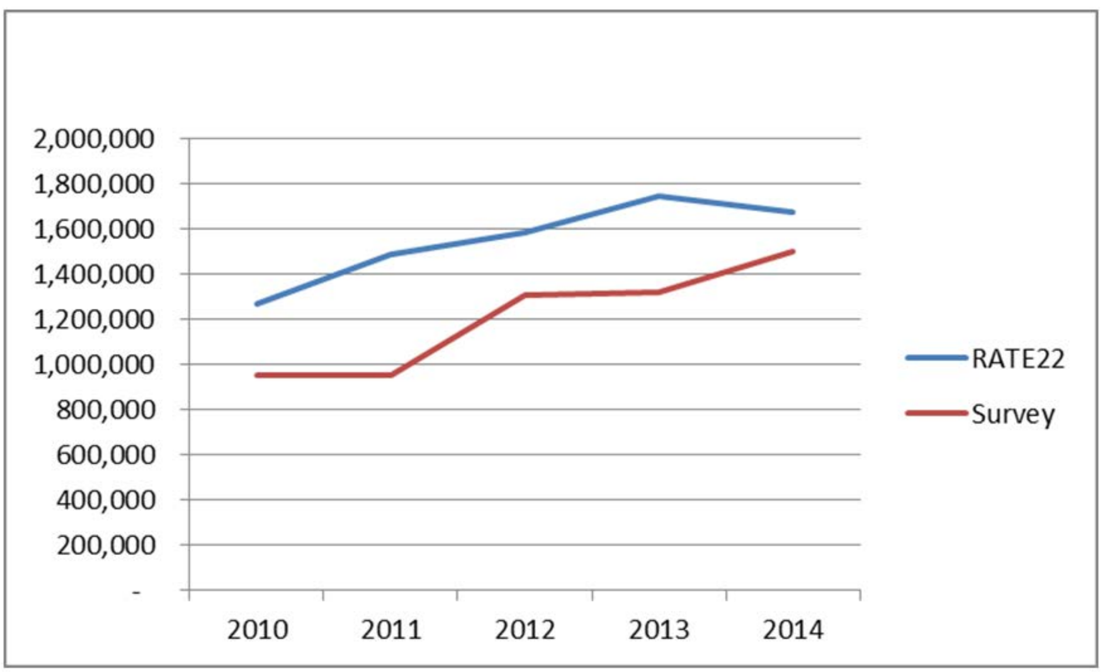
To test for the existence of chronic under- and over-forecasting FEI compared the actual consumption with survey responses for the past five years for all Rate Schedule 22 customers. A chronic forecast variance exists when a customer consistently under- or over-forecasts. For comparison, an example of a customer that does not exhibit chronic forecast variance is shown below. In 2010, 2013 and 2014 the customer provided forecasts that were higher than actual consumption, while in 2011 and 2012 the forecasts were less than the actual consumption.

Figure A4-10: R22 Customer Actual and Forecast Demand



An example of a customer that consistently consumed more than forecast is shown in the figure below.

Figure A4-11: R22 Customer Actual and Forecast Demand



In the past five years there appears to be a pattern of chronic under-forecasting with five Rate Schedule 22 customers.

3. REVIEW OF POTENTIAL ALTERNATIVE METHODS

Having identified the primary sources of variance, FEI's considered alternative forecasting methods for a mechanism to address the sources of variance. This section considers time series, econometric and survey forecast methods and discusses whether each method could be used as a mechanism to increase the accuracy of the Rate Schedule 22 forecast. Since the single largest source of variance is fuel switching, to be effective, an adjustment mechanism would need to have some predictive capability to forecast fuel switching at the customer level.

3.1 *TIME SERIES MODELS*

Time series models all rely on historical data to forecast future results. Time series models are effective when year-over-year changes are consistent as opposed to volatile. Examples of time series models include three-year averages, naïve (next year is the same as last year) and regressions.

Time series models are unable to predict fuel switching events as fuel switching events are not consistent and do not follow a similar pattern year over year. Therefore, fuel switching (or lack thereof) in prior years is not an indication that it will or will not happen during the test period.

Forecast models that include a "percent adjustment" can also be included in this class of forecasts. Percent adjustment models are also unable to predict fuel switching events because the percent adjustment is applied based on previous years experience, but fuel switching (or lack thereof) in prior years is not an indication that it will or will not happen during the test period. Percent adjustment models have an additional downside because the percent adjustment calculation is often driven by the behavior of a small number of customers, but then applied to all customers, including those that are providing accurate forecasts.

3.2 *ECONOMETRIC MODELS*

Econometric models rely on a statistical relationship between an economic quantity and FEI actual data. For example, FEI's forecast of residential customer additions makes use of a statistical relationship between provincial housing starts and net customer additions to the residential rate schedule. Once a statistical relationship is confirmed, then a forecast for the economic quantity (e.g. housing starts) can be used as a proxy for the FEI forecast being developed (e.g. residential net customer additions).

For Rate Schedule 22 customers, any economic quantity would need to consider fuel switching before a usable statistical relationship could exist. For example, the provincial gross domestic product (GDP) would not be a reasonable choice for an econometric model because it does not consider fuel switching by individual customers.

An econometric model based on a correlation to fuel prices is often suggested as a possible solution. In this case a statistical relationship needs to be developed between both natural gas and competing fuels and demand. Fuel switching behavior is at least partially driven by the fuel price of the current fuel used by a customer, and an alternative. For the customers under consideration, one of those fuels would be natural gas. For a fuel switching model to be successful, several issues need to be considered including:

1) The model could only be applied to customers with the ability to switch fuels. Other Rate Schedule 22 customers would need to be forecast using a different method.

2) The model would only be valid if fuel switching was the only driver. If the customer's demand for natural gas was driven by other factors, such as a demand for their product, then fuel switching alone would not predict their future demand. For example if natural gas costs were forecast to decline while competing fuel costs were forecast to increase, then the model would presumably forecast an increase in demand. However, if demand for goods produced fell then demand for gas (or the competing fuel) would presumably also fall, but this decline would not be predicted by the model.

3) FEI would need to understand the fuel switching business rules for each customer. No two customers that can fuel switch would do so at the same time because of many other factors involved in running each business. FEI would need to collect, maintain and model each customer independently.

4) Customers consider fuel switching business rules as a competitive advantage and it is unlikely that customers would be prepared to divulge this information to FEI. Without the complete set of business rules, models cannot be developed.

5) Customers are often subject to hedging contracts resulting in fuel choices being locked in for longer terms regardless of fuel prices. FEI would need to collect and maintain this data for each customer.

6) Even if a model could be developed, FEI would need to obtain fuel price forecasts for natural gas and all competing fuels. Any errors in these forecasts would lead directly to variances in the demand forecast for natural gas.

For the above reasons, the development of a fuel switching model is not feasible.

3.3 *SURVEYS*

The industrial survey allows FEI to communicate directly with the customer. The survey relies on the customer completing its own forecast using methods that the customer deems appropriate for their business.

The advantage of a survey is that it allows each customer to forecast their demand for natural gas using all the factors that are relevant to them. FEI then sums up all the customer forecasts for the rate schedule forecast.

Traditionally, FEI has conducted the industrial survey in the fall for inclusion in revenue requirement applications being prepared the following spring. The forecast is one of the first components of a revenue requirement application and therefore needs to be completed relatively early. As a result there can be a significant length of time between when the survey is conducted and the test period for the forecast, as discussed above with respect to fuel switching. The longer the length of time between the survey and the test period, the more likely that a customer will encounter conditions that make fuel switching profitable. This condition is further exacerbated for two year filings when the second year is even further from the survey.

For these reasons, the probability of variances from forecast due to fuel switching can be reduced by shortening the length of time between the survey and the test period. Additionally, a shorter time period between the survey and the test period allows the customer to consider all other factors in their forecast, such as short term demand for their products. A more timely survey should therefore increase the probability of the forecast being accurate.

A higher involvement between key account managers and customers at the time the survey is being completed can also lead to an improved forecast. This additional step was used for the first time in 2015 and resulted in an improved forecast from one customer. In this example, the survey was received and reviewed by an Industrial Marketing Manager. The manager was familiar with the customer but not aware of any changes to the business operation that would support the forecast submitted by the customer. A follow up was completed and the customer agreed that the survey was incorrect. The customer completed a new survey which was submitted and incorporated into the FIS model. The new survey was approximately 100,000 GJs higher than the original and comparable to prior forecasts and actual consumption.

4. OTHER UTILITIES

FEI completed an informal discussion with several other Canadian gas utilities, including Gaz Metro, Manitoba Hydro, Enbridge and Union Gas, in an attempt to determine if there was a significantly different method in use. In all four cases, direct customer-by-customer communication was used to forecast demand, through the use of a survey, email or discussions between account managers and large customers.

5. CONCLUSIONS AND RECOMMENDATIONS

From the analysis of individual Rate Schedule 22 customers, the largest variances in forecast demand are the result of fuel switching and business start-ups, with chronic over or under forecasting from some customers also contributing to material variances.

Based on its review of potential alternative methods, FEI concludes that the method that provides the best opportunity to improve the Rate Schedule 22 forecast is the survey method. A forecast built from communications with individual customers is an approach used by other large gas utilities in Canada.

Other common forecast methods are not likely to result in an improved forecast compared to a survey due to the inability of any method to accurately predict fuel switching at the customer level. While a fuel price correlation method would seem to offer the possibility of directly addressing the fuel switching issue, implementing and collecting the required data for the method would not be feasible and its predictive ability would likely be very limited in any case.

FEI also concludes that the following improvements can be made to the traditional survey approach to improve the likelihood of an accurate forecast:

First, FEI concludes that by shortening the time period between the survey and the test period the likelihood of fuel switching or business start-up happening between the survey and test period can be reduced, thus reducing the probability of forecast variance.

Second, FEI concludes that involving key account managers in the process offers the possibility of increasing the forecast accuracy. The key account managers will review each Rate Schedule 22 customer survey and then discuss the forecast and any risks (such as fuel switching) with the customer. Customers that are known to chronically under- or over-forecast will be identified so that the key account manager can specifically address the issue.

6. IMPLEMENTATION OF RECOMMENDATION FOR 2016 AND 2017 FORECASTS

FEI conducted the annual Industrial Survey in May-June of 2015 for the 2016 test period. This resulted in a 6-7 month time period between the forecast and the start of the test period. Customers who are able to fuel switch are more like to provide an accurate forecast in these circumstances. A customer by customer review of each survey was completed internally by Industrial marketing managers. The Industrial marketing manager analysis confirmed that all but one of the forecasts were directionally correct. The customer in question was contacted, identified the error and made the correction.

For the 2017 Industrial Survey (to be completed in the spring of 2016), FEI proposes to more fully involve the key account managers in the process. The key account managers will review the forecast with each customer and discuss any risks such as fuel switching and chronic under- and over-forecasting.

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Appendix B

Natural Gas for Transportation and LNG Service

September 3, 2015

Table of Contents

1. INTRODUCTION

This appendix provides details on FEI's 2016 revenue and cost forecasts for the Natural Gas for Transportation (NGT) program and related aspects of LNG service. Included in the demand and revenue section of the appendix are LNG volumes related to non-NGT for power generation.

The NGT program consists of the construction and maintenance of compressed natural gas (CNG) or liquefied natural gas (LNG) fueling stations and the provision of incentives to convert vehicles from diesel to CNG or LNG. With regard to LNG service, this appendix discusses the tanker transportation service available to LNG customers as well as capital expenditures at the Tilbury LNG facilitiy to support the growth of LNG demand.

The following table provides a brief summary of how each component of the NGT program relates to the 2016 forecast revenue requirement in this Application:

Table B-1: Connection between the NGT Program and the Revenue Requirement

Program Component	Connection to Revenue Requirement	Background
Vehicle[1] Conversion Incentives	Vehicle conversion incentives, and associated administrative costs, are included in a rate base deferral account and amortized through the delivery rates of non-bypass customers over a ten year period as approved by Order G-161-12.	The provision of incentives is a prescribed undertaking under section 2(1) of the Greenhouse Gas Reduction (Clean Energy Act) Regulation (GGRR).[2]
Demand and Revenue Forecast	The demand associated with CNG & LNG NGT and non-NGT customers is embedded in Rate Schedule 25 and Rate Schedule 46 and as such, included in the overall utility revenue and delivery margin forecast for 2016 as set out in Section 3 of the Application.	The 2016 demand and revenue forecast for CNG and LNG is based on (i) existing demand and (ii) incremental demand for 2016 determined by utilizing the forecast vehicle conversion incentives and fueling station additions as the primary inputs.

[1] The term 'Vehicle' is defined to include on-road trucks, buses, waste haulers, mine haul trucks and marine vessels.

[2] The setting of rates to recover the costs of prescribed undertakings is required under section 28 of the *Clean Energy Act*.

Program Component	Connection to Revenue Requirement	Background
Fueling Stations	Expenditures associated with fueling stations are included in the 2016 capital and O&M forecasts (Sections 6 and 7 of the Application). While the forecast capital and O&M is included in the delivery cost of service, the cost of service of fueling stations is offset by the rates recovered from fueling station customers (forecast fueling station recoveries are included in Application Section 5 Other Revenue). In addition, an overhead and marketing charge approved by the Commission in Order G-78-13 is applied to fueling station customers and the forecast of this recovery is also included in Application Section 5 Other Revenue.	If a fueling station does not qualify as a prescribed undertaking under the GGRR, FEI will apply for a CPCN for the construction and operation of that fueling station. For 2016, all of the fueling station additions are forecast to occur as prescribed undertakings under section 2(2) and 2(3) of the GGRR. The rate charged for each fueling station is approved separately by the Commision. That is, even a prescribed undertaking requires an application to and approval by the Commission.
Tanker Transportation Services	Operating costs associated with transportation service are forecast in O&M (Application Section 6). The capital costs for tankers are included in capital expenditures (Application Section 7). While the forecast capital and O&M is included in the delivery cost of service, the cost of service associated with the tankers is offset by the Tanker Transportation Charge approved in Rate Schedule 46. Forecast recoveries of this charge are included in Section 5 of the Application - Other Revenue.	The expenditures for tankers are a prescribed undertaking under section 2(3) of the GGRR.
Tilbury LNG Expansion	Expenditures associated with the expansion of the Tilbury LNG facility are included in the 2016 capital expenditure forecast.	The capital expenditures and cost recovery for the project were approved in Order In Council No. 557 and 749 for the Tilbury LNG expansion.

The remainder of this Appendix is organized as follows:

- Section 2- Background: describes the regulatory history of FEI's NGT program, the regulation enabling the expansion of the NGT market, and the tariffs under which CNG and LNG supply is provided.
- Section 3- Incentives: provides a forecast of the incentives that will be provided in 2016.

- Section 4- Forecast Demand and Revenue for CNG & LNG: provides a forecast of natural gas demand for NGT and non-NGT power generation and a discussion of the corresponding revenue and margin forecasts for 2016.

- Section 5- NGT Fueling Stations: provides a forecast of the costs and recoveries associated with fueling stations, including the number of stations, capital requirements for stations, and O&M forecasts for stations that will be constructed in 2016.

- Section 6- LNG Service: discusses the forecast costs and recoveries associated with the tanker transportation service as well as the forecast costs associated with the Tilbury Expansion project.

- Section 7- Conclusion: provides a summary of this appendix and a summary table showing the total O&M, capital and revenue forecast included in the 2016 forecast revenue requirement.

The organization of Sections 3 through 6 follows the business model for NGT. FEI provides incentives to customers for the purchase of CNG/LNG vehicles or the conversion of ferries, locomotives or minehaul trucks (Section 3). These vehicles in turn create demand for both CNG and LNG (Section 4). To deliver the CNG/LNG, some customers require a fueling station solution (Section 5). Finally, the demand for LNG necessitates that FEI produce LNG through the liquefaction of natural gas and, in some cases, transportation of LNG to the customer (Section 6).

2. BACKGROUND

2.1 NGT PROGRAM – GENERAL TERMS AND CONDITIONS (GT&C 12B)

On December 1, 2010, FEI filed an Application for Approval of GT&Cs for CNG and LNG Service. The proposed section 12B of FEI's GT&Cs was designed to facilitate the development of both CNG and LNG refueling stations on the FEI distribution system that would be owned and operated by FEI. The Commission approved revised GT&C 12B in Commission Order G-14-12 dated February 7, 2012

2.2 NGT PROGRAM – GGRR

On May 14, 2012, the Government of British Columbia enacted the GGRR, which enables public utilities to:

1. Provide grants or zero-interest loans (and related expenditures) of up to $62.0 million in total for the purchase of eligible natural gas vehicles operating in British Columbia (Prescribed Undertaking 1);
2. Make expenditures of up to $12.0 million to own and operate CNG fueling stations and infrastructures (Prescribed Undertaking 2); and
3. Make expenditures of up to $30.5 million to own and operate LNG fueling stations and infrastructure (Prescribed Undertaking 3).

The rate treatment of these expenditures was approved for FEI in Commission Order G-161-12 on October 29, 2012. Order G-161-12 approved the NGT Incentives Account to capture costs related to Prescribed Undertaking 1: Vehicle Incentives or Zero Interest Loans. Order G-161-12 also approved the Fueling Stations Variance Account to capture costs related to Prescribed Undertaking 2: CNG Stations and Prescribed Undertaking 3: LNG Stations.[3] Order G-161-12 also approved the recovery of the balances in these accounts from all non-bypass natural gas customers.

On April 11, 2013, the Commission issued Order G-56-13 which addressed non-grant related issues with respect to the GGRR. On the same date the Commission also issued its Reasons for Decision for Order G-161-12 and Order G-56-13, which provided directives with respect to Prescribed Undertakings 1 and 2.

[3] Subsequently, FEI requested to discontinue this deferral account effective January 1, 2017 and received approval to do so by the Commission in Order G-138-14.

FEI subsequently received approval for the rate treatment of "Phase 3" GGRR Incentives of $5.573 million in Commission Order G-67-13 dated April 30, 2013.[4] The Commission determined that FEI was to include these expenditures as part of the $62.0 million funding limit established for Prescribed Undertaking 1 under the GGRR. As a result, FEI is permitted to spend up to $56.427 million in additional funding associated with Prescribed Undertaking 1.

On November 27, 2013, the Lieutenant Governor in Council issued Order in Council No. 556 amending the GGRR. One of the amendments made to the GGRR was to include the ability for utilities to provide financial incentives to eligible operators of locomotives and mine haul trucks under Prescribed Undertaking 1.

The GGRR was amended again by Order in Council No. 297, dated June 3, 2015. The amendments to the GGRR allow for shifts in the allocation of incentives and investments within the previously-approved funding limits to promote continued development of a domestic market for natural gas in the transportation sector. These changes allow FEI to provide incentives up to 100% of the price differential between a natural gas and equivalent diesel vehicle for applicants received in 2015.[5] For 2016, FEI may provide up to 90% of the price differential.

The rates related to each new fueling station agreement constructed under the GGRR will be submitted in separate applications to the BCUC for review and approval.

2.3 *LNG AND CNG SUPPLY*

FEI is providing RS46 LNG supply to customers on both a firm (short and long term contract) and spot basis.

FEI has four Commission-approved CNG natural gas vehicle Tariffs:

1. Rate Schedule 6 Natural Gas Vehicle Service for companies that retail natural gas to customers with natural gas vehicles or fleet customers that use natural gas for their own fleet;
2. Rate Schedule 6A General Service Vehicle Refueling Service for transportation use only to provide on-site CNG vehicle refuelling services (applicable in the Lower Mainland service area only);
3. Rate Schedule 6P Public Service, which is a CNG fuelling service available to the general public at the FEI Surrey Operations Centre (16705 Fraser Highway, Surrey, BC); and,

[4] Pursuant to the directives in Order G-67-13, FEI transferred the $5.573 million for the 2010-2011 Incentives from the NGV Incentives deferral account approved by Order G-44-12 to the NGT Incentives Account approved by Order G-161-12. The NGV Incentives deferral account was closed subsequent to the transfer.

[5] 100% applicable to early adopters only as defined in OIC 297.

4. Rate Schedule 26 Natural Gas Vehicle Transportation Service for customers with consumption of greater than 2,000 GJ annually that will only use the gas to fuel vehicles.

In addition, FEI provides natural gas supply, under Commission-approved FEI Rate Schedules, and natural gas compression service to customers with natural gas fueled vehicles who have entered into a CNG Service Agreement.

3. VEHICLE INCENTIVES

As discussed in Section 2.2 above, the GGRR enables FEI to provide grants or zero-interest loans (and related expenditures) of up to $62.0 million in total for the purchase of eligible natural gas vehicles operating in British Columbia (Prescribed Undertaking 1).

Applicants are accepted every quarter and the fairness advisor ensures that the evaluation process and the provision of funds is conducted in an objective and fair manner. The fairness advisor is an independent consultant that reviews and provides comments on the program and the process to ensure that all decisions made by FEI are made objectively and encompass the elements of openness, competitiveness, transparency and compliance.

Table B-2 below provides a forecast of GGRR incentive awards to be paid out in 2015 and 2016 by category. This table reflects the forecast incentives that will be paid out and added to the NGT Incentives Deferral Account as approved by Order G-161-12. The balance in this deferral account has been approved to be recovered in the delivery rates of non-bypass customers over a period of ten years.

Table B-2: FEI Forecast GGRR (NGT) Incentive Deferral Additions ($millions)

Incentive Forecast		2015A		2015P		2016F
Total Vehicle Incentives	$	3.300	$	3.857	$	2.400
Marine, Mining & Rail	$	0.188	$	1.170	$	2.300
Admin, Education, Safety Training	$	0.782	$	0.782	$	0.798
Total	$	4.270	$	5.809	$	5.498

Typically there is a lag of approximately two years between the time an applicant applies for an incentive and when the vehicles are in service.

For the 2015 year end projection, FEI anticipates spending $5.809 million on incentives, administration, safety and training for all the commited applicants from 2013 and 2014. The increase in the projected incentives from the 2015 Approved amounts is mostly attributable to the addition and conversion of a new mining customer, Teck Resources. Of the $5.809 million, $3.857 million consists of incentives for 153 CNG Vehicles that have entered service in 2015 and incentives for a portion of the 24 CNG trucks expected to be in service in late 2015 or early 2016. A further $1.170 million consists of incentives for 6 mine haul trucks expected to be in service by the end of 2015. The remaining $0.782 million relates to administration, safety and training expenses.

For 2016, FEI forecasts that approximately $5.498 million in incentives will be provided across all sectors. FEI expects to make further penetration into the short sea marine and mine haul trucks segment for a total amount of $2.300 million. Most of the remaining incentives are for the 2014 commitments (the remaining portion of the 24 CNG trucks as noted above) and a smaller portion is related to the expected commitments from the 2015 round for CNG applicants and the

LNG diesel blending pilot authorized by Order in Council No. 297 to allow for dual fuel capability in vehicles. This pilot was introduced to address the current gap in the availability of incentives for dual-fuel 15L OEM engines.

The provision of incentives has a direct impact on the NGT demand and revenue forecast discussed further in Section 4 of this appendix below and, correspondingly, the forecast of fueling station additions discussed in Section 5 of this appendix below.

4. CNG & LNG DEMAND AND REVENUE

4.1 *FORECAST NGT & NON-NGT DEMAND*

Table B-3 below provides a forecast of total NGT demand in 2015 and 2016 based on the expected number of vehicles that will be added, in addition to existing vehicles that are in operation. Also included is non-NGT volumes, which is mainly related to demand power generation customers.[6] As directed in Decision G-86-15 FEI has now included a forecast of spot purchases in the total CNG & LNG demand.

The total CNG & LNG demand of 2,253,030 GJs consists of forecasted spot volumes of 889,130 GJs. The spot volumes consist of 106,904 GJs of demand related to non-NGT activities mostly for power generation, 46,800 GJs of demand related to third-party NGT fueling stations, and 735,426 GJ in new NGT demand related to marine vessels. Since FEI does not have a stable historical level of spot volumes on which to establish a demand forecast, FEI has primarily relied on specific customer information for its forecast. For the spot volumes related to the power generation customers FEI contacted the customers directly and received information on how much LNG would be required. Then, to be conservative in forecasting the resulting demand and supporting O&M, FEI reduced the demand by applying a percentage based on the 2015 projected as compared to the original forecast for these customers. A similar process was undertaken for the third-party fueling station demand forecasts. The forecast spot sales for marine vessels is discussed below.

In 2016, a significant portion of the total incremental increase in the total LNG demand is related to 998,077 GJs in new demand attributable to an agreement with Pugent Sound Energy (PSE) to provide LNG to one shipping vessel that will be operated by Totem Ocean Trailer (TOTE). This Rate Schedule 46 contract is between FEI and PSE, with PSE then providing the LNG to TOTE in the Port of Tacoma. The expected in service date of TOTE's marine vessel is April 1, 2016. Of the total 998,077 GJ in demand, 735,426 GJ is spot sales. The customer communicated that they estimated they will require approximately 131,330 GJs of LNG per month beginning in April. Since FEI could not guarantee firm demand until the Tilbury expansion is completed and in service, which is expected in November of 2016, the expected volumes for the seven months of April 1 to November 1 were forecast as spot sales. To calculate the 2015 Forecast for spot purchases, FEI applied an 80% probability factor to the expected spot volumes to allow for potential timing delays of possibly two months in the availability of LNG vessels or the in-service date for the Tilbury LNG facility.

[6] Spot Volumes for NWT Energy Corp, Westport Power, and Yukon Energy non-NGT are mainly for the purposes of power generation.

Table B-3: FEI Total Natural Gas Demand (GJ/Year) for NGT & Non-NGT[7]

GJ	2015A	2015P	2016F
CNG	401,493	480,297	586,224
LNG	482,884	434,691	1,559,902
Total NGT Demand	**884,377**	**914,988**	**2,146,126**
Non-NGT CNG/LNG Demand	-	87,046	106,904
Total CNG & LNG Demand	**884,377**	**1,002,034**	**2,253,030**

The incremental demand between 2015 and 2016 is 1,250,996 GJ. The following table provides a list of the number of vehicles and the demand that makes up this incremental load.

Table B-4: CNG/LNG 2016 Demand Additions[8]

Customer Fuel	No. of NG Vehicles	Vehicle In-Service Date	2016 Incremental
CNG	8	January 1, 2016	8,000
CNG	10	September 1, 2015	6,667
CNG	8	January 1, 2016	8,000
CNG	5	July 1, 2015	1,125
CNG	33	October 1, 2015	18,736
CNG	45	September 1, 2015	45,000
CNG	16	September 1, 2015	6,400
CNG	16	October 1, 2016	2,750
CNG	2	January 1, 2015	-
CNG	25	October 1, 2016	6,250
CNG	6	July 1, 2016	3,000
LNG	6	November 1, 2015	50,000
LNG	0	3rd Party Station Vol.	46,800
LNG	0	Non-NGT	17,605
LNG	0	Non-NGT	2,254
LNG	1	October 1, 2016	22,000
LNG	1	December 1, 2016	8,333
LNG	1	April 1, 2016	998,077
	183		**1,250,996**

FEI has estimated a vehicle in-service date of July 1, 2016 (midway through 2016) for customers that have not indicated when their trucks and buses will be in operation. For example, Canadian Linen has provided approximate consumption expected, but it is unclear on

[7] Spot volumes for non-NGT customers were not included in the CNG/LNG 2015 demand forecast table in the FEI's Annual Review for 2015 Delivery Rates Application.

[8] Pursuant to Order G105-15, the names of customers have been removed to preserve confidentiality.

when their vehicles will be in operation. FEI has assumed a mid-2016 in service date of July 1, 2016.

The incremental demand of 1,250,996 GJ will be in addition to the 1,002,034 GJ of forecast annual demand from existing customers. A significant portion of the incremental increase as discussed above is attributable to new LNG demand related to the agreement with PSE.

4.2 FORECAST REVENUE, COST OF GAS AND DELIVERY MARGIN

Currently, FEI delivers CNG and LNG through the GGRR and non-GGRR stations using Rate Schedules 25 and 46.[9] FEI has used the forecast volumes from this appendix to calculate the associated revenue, cost of gas and delivery margin at existing rates. The volumes presented in this appendix are for all CNG and LNG volumes from NGT and Non-NGT customers served under Rate Schedules 25 and 46. This includes customers for which FEI does not construct the fueling station.[10] The LNG (Rate Schedule 46) volumes also include volumes related to non-NGT customers for which FEI provides LNG, mainly for the purposes of power generation.

The following two tables identify, for the rate schedules listed above, the forecast of CNG and LNG volumes sold, associated delivery margin at 2015 rates[11], cost of gas at July 1, 2015 rates (applicable for Rate Schedule 46 only), and revenue (delivery margin plus cost of gas).

Table B-5: Rate Schedule 25 CNG Forecast

Volume, Revenue, Margin under RS 25		2015A		2015P		2016F
Demand (GJ)		401,493		480,297		586,224
Total Delivery Margin ($ millions)	$	0.326	$	0.617	$	0.728
Total Cost of Gas ($ millions)	$	-	$	-	$	-
Total Revenue ($ millions)	$	0.326	$	0.617	$	0.728

Table B-6: Rate Schedule 46 LNG Forecast[12]

Volume, Revenue, Margin under 46		2015A		2015P		2016F
Demand (GJ)		719,217		521,737		1,666,806
Total Delivery Margin ($ millions)	$	2.177	$	2.353	$	7.668
Total Cost of Gas ($ millions)	$	1.826	$	1.297	$	4.144
Total Revenue ($ millions)	$	4.003	$	3.650	$	11.811

9 As noted in Section 2.3 of this appendix above, Rate Schedule 6P applies to CNG provided at the Surrey Operations Centre for general public use only and as such has been excluded from this discussion. Please refer to Section 3 for the forecast of Rate Schedule 6P demand and revenues.

10 BC Transit in Nanaimo (CNG and station by Clean Energy) and Sutco and Arrow in Chilliwack (LNG and station by ENN Canada), and others Shell/ Ferus/ PSE/ CS (LNG).

11 For this purpose, delivery rates exclude the delivery rate riders which are calculated separately.

12 Total RS 46 demand as discussed in Section 3.5.4 and shown in Figure 3-12.

The volume, delivery margin, cost of gas and revenue forecasts are included in the financial schedules within this Application and serve to reduce the overall natural gas revenue requirement.

5. FUELING STATIONS

A large component of FEI's NGT program consists of provisions to construct CNG or LNG fueling stations for the purpose of providing suitable fueling capabilities for customers. FEI provides fueling station infrastructure under the two approved regulatory models discussed above - GT&C 12B and GGRR.

The approved GT&C 12B agreement sets out the terms for FEI's ownership and operation of fueling stations. GT&C 12B applies to "installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer/dehydrator, high pressure storage, dispensing equipment; and dispensing of compressed natural gas". For LNG assets, GT&C 12B applies to "installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and dispensing of liquefied natural gas."

The second way that FEI can provide fueling infrastructure is under the provisions of the GGRR. The GGRR enables public utilities to make expenditures of up to $12.0 million to own and operate CNG fueling stations and infrastructure and make expenditures of up to $30.5 million to own and operate LNG fueling stations and infrastructure.[13]

The following subsections discuss the existing approved fueling stations, forecast fueling station additions (including the forecast capital and operating costs embedded in the 2016 forecast revenue requirement) and the forecast recoveries related to fueling stations, which serve to offset the costs.

5.1 *APPROVED FUELING STATIONS*

To date, FEI has constructed seven CNG fueling stations in BC. The table below summarizes all CNG fueling stations constructed to date and the applicable regulatory model under which each station was constructed. The Waste Management agreement was developed based on previously proposed GT&Cs, and was accepted "on an exception basis only".

[13] $12.0 million and $30.5 million total investment per utility over the regulation period, which ends March 31, 2018.

Table B-7: CNG Fueling Stations Constructed by FEI

Customer	Order No.	Regulatory Model
BFI	C-6-12 and G-78-13	GT&C 12B
Waste Management	G-128-11 and G-229-13	GT&C 12B
Kelowna School District	G-158-13	GT&C 12B
Smithrite Disposal	G-72-14	GGRR
Cold Star	G-187-13	GGRR
For Less Disposal	G-128-14	GGRR
City of Vancouver	G-105-15	GGRR

Presently, CNG customers under FEI Tariff Supplements J-1 and J-2 in FEI's approved GT&C 12B and GGRR stations generate delivery revenues under Rate Schedule 25[14]. Revenues collected under Rate Schedule 25 include a fixed monthly charge, delivery and demand charges. Revenues generated by CNG customers positively impact delivery margin, which is a benefit to all non-bypass natural gas customers.

Presently, FEI has constructed and is operating LNG fueling stations for four customers: Vedder Transport (Vedder), Denwill Enterprises Inc. (Denwill), Arrow Transport (Arrow) and Wheeler Transport (Wheeler). The table below summarizes the approvals granted for each of these customers. All of the LNG fueling stations except Vedder were constructed under the GGRR.

Table B-8: LNG Fueling Stations Constructed by FEI

Customer	Order No.	Regulatory Model
Vedder	G-22-14	GT&C 12B
Denwill	G-34-14	GGRR
Arrow	G-33-14	GGRR
Wheeler	G-35-14	GGRR

The Vedder station is also being used to provide LNG fueling to Ledcor Resources and Transportation L.P., which was approved by Order G-57-14 on April 22, 2014. Denwill and Wheeler are also permitted to receive fuel from the Vedder station, approved on an permanent basis by Orders G-79-15 and G-80-15, respectively.

Denwill is receiving supply from the Arrow fueling station, which was approved on an permanent basis by Order G-57-15.

[14] Rate Schedule 25 is FEI's General Firm Service used to serve larger volume customers who use gas for more than space heating and generally has a higher load factor than residential and commercial customers due to customers' consumption patterns. On January 1, 2015 Cold Star commenced receiving service under Rate 5; however. for forecast consistency FEI has included their demand, revenue and margin within Rate Schedule 25.

5.2 *FORECAST FUELING STATIONS AND CAPITAL EXPENDITURES*

Based on the vehicle incentive expenditures to date and the forecast volume of natural gas demand for CNG and LNG, FEI is projecting one new LNG fueling station to be constructed in the remainder of 2015 (consistent with the 2015 Forecast) and forecasting two new CNG fueling stations to be constructed in 2016 to help serve additional demand. The following table provides the total projected and forecast number of FEI-owned stations as at December 31 for 2015 and 2016, respectively:

Table B-9: Forecast Total FEI Fueling Stations

	2015A	2015P	2016F
CNG Stations	7	7	9
LNG Stations	5	5	5
Total	**12**	**12**	**14**

The following table provides a summary of total capital expenditures projected in 2015 and forecast for 2016 related to fueling station additions.

Table B-10: NGT Fueling Station Capital Expenditures & Additions Forecast

$ millions	2015A	2015P	2016F
CNG Stations	$ 2.200	$ 2.200	$ 2.100
LNG Stations	0.800	1.955	-
Total	**$ 3.000**	**$ 4.155**	**$ 2.100**

Capital expenditures may differ from capital additions due to the lag between when capital dollars are spent and when the assets are placed into service; however, for the forecast fueling stations for 2015 and 2016, the expenditures occur the same year that the assets are placed into service. The 2016 capital additions for the CNG and LNG stations can be found in Section 11, Schedule 4, Line 22, Column 4, under the Natural Gas for Transportation heading.

In 2015, captial expenditures of a total of approximately $4.155 million are projected for CNG & LNG stations. The 2015 Projection is higher than 2015 Approved due to the capital costs to construct an LNG station for a new customer, which was not included in the 2015 Approved amount because discussions with this customer did not occur till late 2014 after the 2015 Annual Review had already been filed. The capital costs for this new customer is partially offset by the capital costs of another LNG station that was forecast but did not to proceed

In 2016, two CNG fueling stations are expected to be constructed for a total forecast cost of approximately $2.100 million. In 2016, FEI will apply to the Commission for approval of rates to recover the costs of these stations, if FEI is able to reach contractual agreements with these customers.

5.3 *FORECAST FUELING STATION OPERATIONS AND MAINTENANCE (O&M)*

Forecast O&M expenses related to the operation of the CNG and LNG fueling stations are recovered directly from the customer(s) of each fueling station through the rates charged to those customers as described in Section 5.4 below.

Based on FEI's experience in constructing and operating natural gas fueling stations, the forecast O&M expenses for existing fueling stations, the one new fueling station to be constructed in 2015 and the additional two new fueling stations that will be constructed in 2016, are provided in Table B-11 below.

Table B-11: Forecast Annual Fueling Station O&M

$ millions	2015A	2015P	2016F
CNG Stations	$ 0.360	$ 0.360	$ 0.424
LNG Stations	0.408	0.408	0.563
Station Subtotal	**$ 0.768**	**$ 0.768**	**$ 0.987**

5.4 *FORECAST FUELING STATION RECOVERIES*

The 2016 forecast also includes CNG and LNG service revenues and NGT overhead and marketing recoveries within Other Revenue that offset the forecast cost of service of the fueling stations. These two revenue items are described further below.

5.4.1 CNG and LNG Service Revenue Forecast

Based on the existing eleven CNG and LNG fueling stations idenitifed in Tables B-7 and B-8 above as well as the additional three forecast fueling stations discussed in Section 5.2 above, FEI has forecast fueling station recoveries of $2.401 million in 2016, which compares to 2015 projected recoveries of $1.791 million. The 2016 forecast uses the approved fueling station rates for the existing eleven fueling stations and estimates of fueling station rates for the three fueling stations forecast to be added (one in late 2015 and two in 2016).

Table B-12 below provides a break down between CNG and LNG station recoveries by customer. The forecast revenue for Teck Resources, UPS and Canadian Linen are based on fueling station rates that are not yet approved. As mentioned in Table B-1 of this appendix, all rates applicable to fueling stations are subject to a separate approval process with the Commission.

Table B-12: CNG and LNG Service Revenue Forecast ($millions)[15], [16]

CNG / LNG Service Revenue	2015A	2015P	2016F
CNG			
Customer 1	$ 0.265	$ 0.264	$ 0.269
Customer 2	0.109	0.173	0.177
Customer 3	0.053	0.053	0.054
Customer 4	0.176	0.175	0.178
Customer 5	0.156	0.156	0.159
Customer 6	0.041	0.035	0.041
Customer 7	0.136	0.068	0.273
Customer 8	-	-	0.046
Customer 9	-	-	0.033
Total CNG	**$ 0.936**	**$ 0.923**	**$ 1.230**
LNG			
Customer 1	$ 0.343	$ 0.342	$ 0.349
Customer 2	0.125	0.059	0.060
Customer 3	0.121	0.142	0.145
Customer 4	0.163	0.157	0.160
Customer 5	0.112	0.112	0.114
Customer 6	0.091	-	-
Customer 7	-	0.056	0.342
Total LNG	$ 0.954	**$ 0.867**	**$ 1.170**
Total CNG / LNG Service Revenue	**$ 1.890**	**$ 1.791**	**$ 2.401**

5.4.2 NGT Overhead and Marketing Recoveries Forecast

Pursuant to Order G-78-13, FEI has forecast a recovery of overhead and marketing (OH&M) costs from NGT customers. The approved OH&M rate of $0.52 per GJ is multiplied by applicable[17] CNG and LNG sales volumes to arrive at a total forecast of $0.263 million in 2016, as shown in Table B-13 below. As required by Directive 5 of Order G-105-15, FEI filed a letter regarding the calculation of the OH&M charge on August 21, 2015 proposing that the existing OH&M rate of $0.52 per GJ remains in place. Any changes in revenue resulting from a change in the OH&M charge over the test period would be captured in the flow through variance deferral account.

[15] Excludes compression revenue from Surrey Operations Pump. Other Revenue Schedule 20, Line 10 includes compression revenue from the Surrey Operations CNG pump of $0.025 million for a total of $2.426 million in 2016.
[16] Pursuant to Order G105-15, the names of customers have been removed to preserve confidentiality.
[17] This volume is limited to CNG and LNG contract volume delivered through an FEI-owned CNG or LNG fueling station.

Table B-13: NGT Overhead and Marketing Forecast

NGT Overhead and Marketing Revenue	2015A	2015P	2016F
Applicable Volume (GJ)	436,092	426,020	505,131
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	$ 0.227	$ 0.222	$ 0.263

6. ENABLING LNG DEMAND FULFILMENT

Two aspects of LNG service that are interrelated with the NGT program are:

- The tanker transportation service provided to LNG customers; and,
- LNG facility upgrades and expansions.

Tanker Transportation Service is approved under Rate Schedule 46 and tanker expenditures are a prescribed undertaking under the GGRR[18] for which cost recovery is provided in section 18 of the Clean Energy Act. Approval to undertake capital expenditures at the two FEI-owned LNG facilities was provided in Order in Council 295 and 556 for the Mt. Hayes Load Out Facility and Order in Council 557 and 749 for the expansion of the Tilbury LNG facility.

6.1 *TANKER TRANSPORTATION SERVICE*

6.1.1 Tanker Capital Expenditure Forecast

FEI is projecting approximately $1.386 million in capital expenditures in 2015 and forecasting $4.774 million in 2016, for a total of eight LNG tanker trailers over the two years to service growing LNG demand. In addition to the 2015 LNG load growth, FEI is forecasting incremental load growth of 1,250,996 GJ in 2016, 1,028,410 GJ of which is related to new Marine load. The first marine vessels will begin operation in Q2 2016 and will be phased in over the following months.[19]

Although the Marine demand will come into operation in 2016, FEI will need to place orders and pay deposit amounts of approximately $1.386 million to vendors for the requried LNG tanker trailers in 2015 due to the long lead and order time for these assets. The balance of amounts due is typically paid to vendors when the asset is delivered, which is expected to be in 2016.

The six tri-axle tankers that will be purchased in 2015 have been optimized to have a larger capacity than that of FEI's existing tanker purchased in 2014 and will include customized marine fittings and pumps in order to serve specific requirements of the marine customers. These six LNG tankers will be used to service the marine load and will have to be customized to provide truck-to-ship LNG bunkering to BC Ferries and Seaspan. The estimated approximate capital cost for each of these tankers is approximately $0.770 million each, which is higher in cost than FEI's existing standard tankers. The tankers are forecast to be placed into service in 2016 and the costs of the tankers will be offset by the Rate Schedule 46 LNG Tanker Charge. FEI expects to apply to the Commission for an updated Tanker fee for this specialized equipment to be

[18] Prescribed Undertaking 2.

[19] Pugent Sound Energy will begin purchasing LNG under RS46 starting in Q2 2016 to provide LNG supply to a marine vessel in Tacoma. BC Ferries will put into operation 3 marine vessels beginning in Q4 2016, and Seaspan will put into operation 2 marine vessels in Q4 2016.

included in the Rate Schedule 46 table of charges. It is estimated the Tanker Charge for use of these specialized tankers will be approximately $380 per day vs the current $259 per day for the use of FEI's standard tankers. FEI forecasts to place an order of two more specialized tankers in 2016 at a cost of $0.770 million each to service additional forecasted demand that is expected to come online in 2016 and beyond.

6.1.2 Tanker O&M Forecast

FEI is forecasting 2016 O&M expenses of $0.113 million for LNG tanker trailers and $0.085 million for Emergency Response and Preparedness (ERAP) coverage, which is required to respond to emergency situations related to the transport of LNG from FEI's facilities to customers' sites. Although LNG is sold under Rate Schedule 46 as free-on-board (FOB) at the LNG facility, under Transport Canada Regulations, as the producer of a dangerous good, FEI is required to provide a registered Emergency Response Assistance Plan (ERAP) for the LNG product while in transit. The plans lay out the process, checklist and roles and responsibilities of those resources that would be involved in responding to an LNG emergency. Resources include LNG plant personnel that provide the role of technical advisors, and incident responders with support from Quantum Murray, an emergency response contractor that has been trained on LNG.

6.1.3 Tanker Rental Revenue Forecast

Tanker rental revenues are the revenues FEI collects from customers when FEI uses an FEI-owned tanker to deliver LNG to a customer. The 2015 projected deliveries are lower than the 2015 Approved as a result of ENN Canada reducing the amount of deliveries it requires. FEI has forecast its 2016 tanker rental revenues related to the existing tankers as shown in Table B-14 below based on the 2015 projected tanker deliveries plus additional deliveries to account for incremental 2016 forecast LNG volumes. As decribed in Section 6.1.1 of this appendix, FEI is acquiring six new larger tri-axle tankers to service the expected marine load. Due to higher capital costs, the rate on these tankers for rental deliveries is expected to be approximately $380 per delivery. The table below summarizes the expected revenue per the current rate, and the projected new rate to be charged on the new larger tri-axle tankers. The current tanker rental rate is set through Rate Schedule 46[20].

[20] Order In Council 557.

Table B-14: Tanker Rental Revenue

Tanker Rental Revenue	2015A	2015P	2016F
Tanker Rental Deliveries	828	648	768
Rate ($/Delivery)	$ 259	$ 259	$ 264
Sub Total ($ millions)	$ 0.215	$ 0.168	$ 0.203
Larger Tri-Axle Tanker Rental Deliveries	-	-	744
Rate ($/Delivery)	$ -	$ -	$ 380
Sub Total ($ millions)	$ -	$ -	$ 0.283
Total Tanker Rental Revenue ($millions)	$ 0.215	$ 0.168	$ 0.486

6.2 *LNG FACILITY UPGRADES AND EXPANSIONS*

Capital expenditures at the Mt. Hayes and Tilbury LNG facilities have been approved to support the growth of LNG demand and the NGT market, and are discussed further below.

6.2.1 Mt. Hayes

The Mt Hayes load-out project was the addition of tanker loading equipment at the facility with the capital expenditures occurring in 2014. The project was placed into service in 2015 at a cost of $4.800 million.

6.2.2 Tilbury Expansion

The first phase of the expansion project at the Tilbury facility is the addition of up to 40 terajoules per day of liquefaction capability and storage capability of between 1.0 PJ and 1.1. PJ to support the growth of LNG demand for domestic use. The project is expected to be completed in 2016 at an estimated cost of $400 million[21] and enter rate base on January 1, 2017. The 2015 and 2016 forecast spending for this project is $177.850 million and $80.565 million, respectively. This is in addition to the 2013 and 2014 actual capital spending of $136.253 million.

[21] Excluding AFUDC and development costs.

7. CONCLUSION

The following table provides a summary of the total O&M, capital and revenue forecast included in the 2016 forecast revenue requirement.

Table B-15: Summary of 2016 Forecast Revenues and Costs ($ millions)

Particular	2016	Reference
Incentives (deferral additions)	$ 5.498	Section 11, Schedule 11, Line 13, Column 4
Capital Expenditures		
Fueling Stations	2.100	Section 11, Schedule 4, Line 22, Column 4
Tankers	4.774	Section 11, Schedule 4, Line 22, Column 4
Tilbury Expansion	80.565	Section 11, Schedule 5, Line 14, Column 2
Total Capital Expenditures	$ 87.439	
Revenue		
Delivery Margin	$ 8.396	Appendix B, Table B-5 and B-6
Fueling Station	2.401	Appendix B, Table B-12
Overhead & Marketing	0.263	Section 11, Schedule 20, Line 7, Column 3
Tanker Rental	0.486	Section 11, Schedule 20, Line 6, Column 3
Total Revenue	$ 11.545	
O&M		
Fueling Stations	$ 0.987	Appendix B, Table B-11
Tankers	0.113	Appendix B, Section 6.1.2
ERAP	0.085	Appendix B, Section 6.1.2
Total O&M	$ 1.185	

FEI has made significant progress in contracting with NGT customers for CNG and LNG fueling station services as well as adding demand to the distribution system through natural gas vehicles. Through the issuance of incentives under the GGRR, FEI expects to continue to add natural gas demand to the distribution system by advancing both CNG and LNG applications for transportation which may also lead to an increased demand for fueling stations as the network required for infrastructure expands over the next number of years.

Appendix C

PRIOR YEAR DIRECTIVES

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-101-12 – FEI KINGSVALE-OLIVER REINFORCEMENT PROJECT (KORP) STAGE 2A PROJECT DEVELOPMENT COSTS AND ACCOUNTING TREATMENT DECISION (DATED JULY 23, 2012)					
1.	3, 8, 9	No. 3	***FEI KORP Stage 2a Deferral Account:*** FEI is directed to establish a new non-rate base deferral account for recording of Stage 2a feasibility expenses with treatment of interest rate and deferral period to be determined at the next Revenue Requirement.	Due to a delay in the project to late 2018, FEI will propose disposition in a future Annual Review.	N/A
G-198-13 – FEW REFUND CUSTOMERS DIFFERENCE BETWEEN INTERIM AND PERMANENT DELIVERY RATES FROM JAN 1, 2010 TO OCT 31, 2010					
2.	2	No. 2	The Commission directs FortisBC Energy (Whistler) Inc. to effect the refund by making reasonable efforts to contact inactive customers, and to then hold any unreturned funds in an interest bearing account for two years. Any remaining uncollected refunds must be addressed within the next revenue requirement application.	Completed – disposition proposed.	Section 12.4.1
G-138-14 – FEI MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
3.	82	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	Not yet started.	N/A
4.	194	90	***Rate Schedule 22 Demand:*** The Commission Panel further directs FEI to develop a mechanism to adjust the Rate Schedule 22 demand forecast methodology to better reflect the impact of falling gas prices, for review at the 2015 Annual Review.	Completed - adjustments proposed.	Appendix A4

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
5.	217	99	***Accounting Changes:*** The Panel directs FEI to communicate any accounting policy changes/updates to the Commission and other stakeholders as part of its Annual Review process during the PBR period.	Ongoing during PBR period.	Section 12.3
G-86-15 –	***FEI ANNUAL REVIEW FOR 2015 DELIVERY RATES***				
6.	8	3	***Residential Use Per Customer*** The Panel directs FEI to review alternative methodologies and develop one that overcomes the identified shortcomings and more accurately predicts actual average UPC for the next annual review.	Will be filed in the annual review for 2017 delivery rates per Letter L-30-15.	N/A
7.	9	5	***Commercial Use Per Customer*** The Panel directs FEI to include commercial customers as part of its review of alternative methodologies for forecasting UPC for the next annual review.	Will be filed in the annual review for 2017 delivery rates per Letter L-30-15.	N/A
8.	10	8	***Commercial Customer Additions*** The Panel directs FEI to consider alternative methods for forecasting commercial customer additions which are appropriately sensitive to the business cycle. FEI is to provide an analysis of these alternatives in its next annual review application.	Will be filed in the annual review for 2017 delivery rates per Letter L-30-15.	N/A
9.	13	11	***Spot Purchases*** In future annual reviews, FEI is directed 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.	Ongoing during PBR period	Appendix B Section 4.1
10.	14	12	***Demand Forecast Presentation*** The Panel accepts FEI's proposal to include in its next Annual Review application a fulsome description of its demand forecast methodology. The Panel also directs FEI to include information that in this proceeding was obtained through staff and intervener information requests as well as the analyses of alternative forecasting methodologies directed in this Decision. This information is to include: • Historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals; • The results along with an explanation of various aspects of the Industrial Survey used by FEI to forecast industrial demand; Furthermore, the Panel directs FEI to include the most recent ten years of historical actual data where possible.	Completed - information provided.	Section 3 (10 years of historical data); Appendix A1 (Historical forecast and actual data); and Appendix A3 (Industrial survey explanation)

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
11.	19	14	***Safety Service Quality Indicators*** 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 Panel also agrees that with regard to the SQI Public Contact with Pipelines, the number of line damages and the number of calls to BC One Call would be helpful and directs FEI to also provide this information in future annual reviews.	Ongoing during PBR period	Section 13.2.1 and 13.2.3
12.	19	15	***Historical Service Quality Indicators*** FEI is directed to provide SQI results from 2009 onward for future annual reviews.	Ongoing during PBR period	Section 13.2.1, 13.2.2 and 13.2.3
13.	19	16	***Transmission Reportable Incidents Service Quality Indicator*** For subsequent annual reviews, FEI is directed to report the number of Transmission Reportable Incidents in each of the severity levels.	Ongoing during PBR period	Section 13.2.3
14.	19	17	***GHG Emissions*** With regard to including the Estimated Annual GHG Emissions (in tCO2e) reported by the Company to the Ministry of Environment, the Panel has no objection, and directs FEI to provide this information in future annual reviews.	Ongoing during PBR period	Section 13.3
15.	26	22	***Long Term Resource Plan Deferral Account*** The Panel rejects FEI's request for approval of the 2017 LTRP Application deferral account at this time pending further review at the next annual review. The Panel directs FEI in its next annual review application to provide a more detailed budget and justification for its requested 2017 LTRP application costs.	Completed - more detailed budget and justification provided	Appendix C2

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
16.	27	23	***Long Term Resource Plan Budget*** The Panel directs FEI to provide the following specific information in its upcoming annual review application: • The total forecast spending for 2016 on preparation of the LTRP; • A description of each key activity that FEI intends to undertake in developing the LTRP, and the reasons why these activities are deemed as "incremental" to Base O&M. For each key activity identified, provide the following: ○ Budget amounts for 2016 and project totals, with comparisons to the 2014 LTRP amounts; ○ Breakdowns of internal versus external resource budgets, including the estimated percentage of 2016 spending related to external consultants versus internal staff, with descriptions of the role(s) undertaken by each group, again with comparisons to 2014 experience; ○ The number of hours forecast to be spent by external consultants on the LTRP in 2016 ○ compared to the number of hours forecast to be spent by internal staff; and ○ Whether FEI plans to hire additional permanent employees to perform LTRP-related work, including an estimated number of new employees to be hired for 2016.	Completed	Appendix C2
17.	25	29	***FEW 2014 Revenue Surplus/Deficiency Deferral Account*** The Panel approves the amortization of the balance in the FEW 2014 Revenue Surplus/Deficiency deferral account into rates for all natural gas customers in 2015. The Panel further approves any remaining balance at the end of 2015 in this deferral account to be amortized into rates in 2016. The Panel directs FEI to discontinue the FEW 2014 Revenue Surplus/Deficiency deferral account effective January 1, 2017.	Completed	Section 11 Schedule 11.1, Line 35
18.	34	28	***Reporting on Initiatives during PBR Term*** The Panel directs FEI to continue to provide in each annual review application the information that was provided in response to BCUC IRs 1.2.9 (Regionalization Initiative) and 1.3.3 (Project Blue Pencil) and to update these tables for actual results as this data becomes available. The same analysis is to be performed on new initiatives that are implemented during the PBR term.	Completed	Appendix C3

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
19.	35	30	***Number of Employees*** The Panel directs FEI to include in its annual review filings both the total year-end number of employees and the total year-end number of Full Time Equivalent Employees.	Completed	Table 1-2 in Section 1.4.1
G-97-15 – FEI FORT NELSON 2015-2016 REVENUE REQUIREMENTS AND RATES DECISION					
20.	17	14	***Reallocation of Capital Between the Entities:*** The Panel is not persuaded that the allocated amounts being charged to FEFN for Intangible Plant additions are appropriate...FEI is further ordered to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how these costs can be most appropriately and equitably handled going forward given the current PBR Plan in place.	Completed	Section 7.2.1.1
21.	20	16	***Communication and Line Heater Fuel Costs*** The Panel considers moving the communication and line heater fuel costs to Of concern to the Panel is the movement of communication and line heater fuel costs which were previously centralized in FEI to FEFN… In addition, FEI is directed to identify any other cases where FEI Base Capital or O&M amounts have been allocated to FEFN since approval of the PBR Plan. FEI is further directed to address this issue in its Annual Review of 2016 Delivery Rates Application and to provide a proposal as to how the communication and line heater fuel costs can be most appropriately and equitably handled going forward given the current PBR Plan.	Completed	Section 6.2.1

Appendix C2

Long Term Resource Plan

Deferral Account

September 3, 2015

Table of Contents

1. INTRODUCTION

This appendix provides further information as directed by the Commission in support of FEI's request for a 2017 Long Term Resource Plan (LTRP) Application deferral account. As described in Section 7.5.1.3 of the Application, FEI proposes that the deferral account would capture the external costs of preparing the 2017 LTRP Application that are incremental to costs included in FEI's Base O&M.

In its decision on FEI's Annual Review of 2015 Delivery Rates, the Panel accepted that there would be costs for the 2017 LTRP that would be incremental to those included in FEI's Base O&M, but rejected FEI's request for approval of a 2017 LTRP Application deferral account pending further review.

FEI's proposed deferral account will capture the external activities and costs for the 2017 LTRP that are incremental to FEI's regular activities in completing the LTRP. FEI considers its regular activities to be those activities undertaken in order to file its 2010 LTRP (which the Commission accepted by Order G-14-11, referred to hereafter as the "2010 LTRP Decision") and prior LTRPs and which continue to be undertaken for future LTRPs as part of Base O&M costs. These regular activities have never been tracked by FEI separately from other O&M activity; therefore, historical data from which to estimate future spending is not available. Further, these regular activities are undertaken by many people in multiple departments and often coincide with other activities being conducted by those departments. Seeking estimates of time and resources dedicated to regular LTRP activities as distinct from other activities for each person in each department would be a significant undertaking. FEI does not propose to capture any of the costs of such regular activities in the proposed deferral account.

In its decision on FEI's Annual Review of 2015 Delivery Rates, the Commission discussed the content of the deferral account as follows:

> "The Panel is also of the view that costs eligible for deferral account treatment are largely restricted to the use of external resources (i.e. as opposed to those aspects of the filing developed by internal staff). The Panel views the deduction of $0.600 million from Base O&M in the FEI PBR Decision as having removed allowances for incremental external resources that might be incurred in preparing an LTRP, but in no way reducing FEI's internal resource capacity to carry out ongoing regulatory work, including the preparation from time to time of LTRP applications."[1]

In light of the Commission's statement concerning restricting eligible deferral costs to external resources, and given the history of regulatory process around the incremental LTRP activities and costs, FEI is proposing to limit deferral account spending for the next LTRP to *external resources* utilized for completing incremental LTRP activities. Ongoing regular activities, as well

[1] FEI Annual Review of 2015 Delivery Rates Decision. Order G-86-15. Page 27.

as any incremental LTRP requirements that have not been identified in this appendix as requiring incremental funding, will be completed within the existing Base O&M.

However, FEI clarifies that the incremental costs approved by the Commission for the 2012-2013 RRA test period were utilized both for internal and external resources. When FEI made its request for incremental LTRP related funding within the 2012-2013 RRA, based on the directives contained in the 2010 LTRP Decision, it provided the Commission with an explanation of what those funds would be used for[2]. That explanation included both internal and external resources. When the Commission approved incremental funding of $0.400 million in 2012 and $0.600 million in 2013 there were no stipulations that these funds be used strictly for external resources. Hence, FEI completed the incremental tasks required for the 2014 LTRP by both increasing internal resources and utilizing external resources. The subsequent removal of $0.600 for LTRP activities from Base O&M made in the PBR Decision therefore necessitated a reduction in internal resources as well as a suspension of further LTRP work on incremental activities by external resources. Specifically, two FTE positions created during the 2012-2013 test period and dedicated to work on LTRP activities were removed from base O&M at the outset of the PBR Plan and are no longer available to work on incremental LTRP activities. This means that some of the incremental activities for the 2014 LTRP that were undertaken by internal staff and which are still required for the next LTRP will now be completed by external resources.

In its decision on FEI's Annual Review of 2015 Delivery Rates, the Panel directed FEI in its next annual review application to provide a more detailed budget and justification for its requested 2017 LTRP application costs. Specifically, Directive 23 stated:

> The Panel directs FEI to provide the following specific information in its upcoming annual review application:
>
> - The total forecast spending for 2016 on preparation of the LTRP;
> - A description of each key activity that FEI intends to undertake in developing the LTRP, and the reasons why these activities are deemed as "incremental" to Base O&M. For each key activity identified, provide the following:
>   - Budget amounts for 2016 and project totals, with comparisons to the 2014 LTRP amounts;
>   - Breakdowns of internal versus external resource budgets, including the estimated percentage of 2016 spending related to external consultants versus internal staff, with descriptions of the role(s) undertaken by each group, again with comparisons to 2014 experience;

[2] 2012-2013 RRA Proceeding. Exhibit B-1, page 216 Table 5.3-41.

    - The number of hours forecast to be spent by external consultants on the LTRP in 2016 compared to the number of hours forecast to be spent by internal staff; and

- Whether FEI plans to hire additional permanent employees to perform LTRP - related work, including an estimated number of new employees to be hired for 2016.

In the following sections, FEI addresses each of the Commission's requests for further information, beginning with an explanation of why there are incremental spending requirements on the LTRP followed by a description of FEI's estimate of total incremental costs for the next LTRP, a detailed description of key incremental activities and a discussion of whether FEI plans to hire any permanent employees for LTRP-related work.

2. EXPLANATION OF SOURCE OF INCREMENTAL SPENDING ON THE LTRP

The reason why FEI is faced with the need to conduct LTRP activities that are not included as part of the regular LTRP activities included in Base O&M is clear from a review of the history of how these incremental activities have come to be part of the resource planning process and why the costs for completing them are not included in Base O&M.

The 2010 LTRP Decision marked a turning point in the Commission's view of the LTRP for FEI. FEI's 2010 LTRP reflected the content presented in previous LTRPs filed and accepted by the Commission. In the 2010 LTRP Decision, the Commission accepted the 2010 LTRP, but determined that it would like to see additional analysis and discussion in the LTRP to provide an understanding of the issues and challenges anticipated and additional support for programs and initiatives over the 20-year planning horizon. It therefore directed FEI (then referred to as the Terasen Utilities) to incorporate a number of new items in the 2014 LTRP, namely:

- The extent to which markets will be transformed.
- The extent to which Terasen can contribute to overall British Columbia GHG reduction objectives.
- The impact the Company's contributions to GHG reduction will have on demand.
- The importance new technology and new initiatives will have on the overall business, and their significance in terms of percentage share of its traditional business.
- An outline of what initiatives are currently planned or being considered and the status.
- The impact Terasen's efforts have, and expect to have, on meeting British Columbia's energy objectives.
- The key drivers impacting the need and timing for human, physical and other (information technology, capital etc.) resource requirements...[3];
- An analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time.
- Greater coordination between EEC planning and the development of future resource plans, allowing for a more detailed presentation of future EEC programs over a longer time period with expected impacts to be included as part of the LTRP process.

[3] BCUC Decision on the Terasen Utilities 2010 Long Term Resource Plan, Order No. G-14-11. p.24.

- Development of a limited number of scenarios detailing the impacts of varying degrees of EEC Planning measures on the demand forecast and GHG emission reductions.
- An outline of the impact of the implementation of New Initiatives on the demand forecast and GHG emission reductions..."[4].
- A description of the new end-use forecasting methodology, how it compares with Terasen's traditional demand forecasting approach, and reconciliation of the results of the two different approaches.
- The development of a most likely or reference case demand forecast and outline of the underlying assumptions taking into account potential legislative, regulatory or market transformation changes.
- An integration of the reference case demand forecast with the EEC scenarios and a description of the impacts.
- A detailed outline of New Initiatives and their impact on future demand and GHG reduction targets backed by rigorous analysis of potential scenarios.
- A description of the impact of each scenario on future resource requirements with consideration of the variables which could further affect these scenarios.[5]

In FEI's 2012-2013 RRA, FEI requested an increase to its O&M in order to complete the new activities directed by the Commission in the 2010 LTRP Decision. In its Decision on the 2012-2013 RRA, the Commission agreed with FEI that it would take additional resources to complete the necessary analyses for the next LTRP, and approved a total of $400,000 in O&M in 2012 and a total of $600,000 in O&M in 2013 to complete the incremental items directed by the Commission for the 2014 LTRP.

FEU filed the 2014 LTRP on March 25, 2014. At that time, FEI's 2014-2018 PBR Application was before the Commission and at issue in that proceeding was the setting of the Base O&M for the PBR Period.

While the Commission was deliberating on the 2014 LTRP, the Commission issued the PBR Decision and directed FEI to remove the $600,000 in annual O&M expenditures for LTRP related activities from FEI's proposed Base O&M for the PBR period, as follows:

> "…the Panel does not consider it reasonable to approve the incremental spending that was approved in the 2012–2013 FEU RRA Decision. This is because the next LTRP is not expected to be in front of the Commission for another five years. **The Commission**

[4] BCUC Decision on the Terasen Utilities 2010 Long Term Resource Plan, Order No. G-14-11. p.25.
[5] BCUC Decision on the Terasen Utilities 2010 Long Term Resource Plan, Order No. G-14-11, p.25.

Panel therefore directs FEI to further reduce the Base O&M for the LTRP by $600,000."[6]

Consequently, there is currently no funding in FEI's Base O&M to support any of the incremental activities directed by the Commission in the 2010 LTRP Decision for the 2014 LTRP.

Further, when the Commission issued the 2014 LTRP Decision, FEI was directed to submit the next LTRP in 2017, 2.5 years earlier than the expectation expressed by the Panel issuing the PBR Decision. In addition, FEI was directed to include further incremental items that were not included in previous LTRPs, as follows:

- A detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods.
- Continue use of the Traditional Method as a parallel approach until such time as the Commission approves a new end-use method as a substitute.[7]
- The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario.
- Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:
    - Total Resource Cost/modified Total Resource Cost test results;
    - Utility Cost Test result, expressed as a ratio and $/GJ;
    - Delivery rate impact;
    - Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers;
    - Estimated gas (GJ) and GHG emission reductions.[8]
- a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments.[9].
- A contingency plan(s) that outlines the impact(s) to FEU's System Resource Needs and Alternatives based on potential changes in supply, demand, market conditions

6 BCUC Order No. G-138-14. p.210.
7 BCUC Order No. G-189-14. p.15.
8 BCUC Order No. G-189-14. p.27.
9 BCUC Order No. G-189-14. p.28.

and significant new developments in the industry that were not identified in the LTRP as being associated with the Reference Case or most-likely forecast[10].

- A description of its long term vision for price risk management and provides broad principles which can be used to inform the PRMP.[11]
- (i) an analysis of the GHG targets as set out in British Columbia's energy objectives and an estimate of the portion of the required reduction that the Company believes it can reasonably attain over time; and (ii) an outline of the impact of the implementation of new initiatives on the demand forecast and GHG emission reductions.[12]

As well, the Commission cited a number of items it "encouraged" FEI to include in its next LTRP that were not required to be included in previous LTRPs:

- A more complete analysis and justification of the new customer additions forecasted in the Reference Case. Furthermore, for all scenarios based on different economic growth assumptions, the forecasts for new customer additions should reflect those changed assumptions."[13]
- A more complete and fulsome analysis of the potential for new Industrial LNG demand over the entire forecast horizon.
- An integrated treatment of its peak demand forecasts as a foundation for further discussion of capacity responses.
- A more complete and fulsome analysis of the potential for new Industrial LNG peak demand and the impacts on peak demand levels over the forecast horizon.

As the 2014 LTRP Decision was issued after the PBR Decision, these requirements were not contemplated when FEI's Base O&M was set for the PBR Period.

It is therefore clear that there are no resources in the FEI's Base O&M that reflect the incremental activities required by the Commission in its 2010 and 2014 LTRP Decisions.

In order to determine resourcing requirements for the incremental activities, FEI reviewed all of the incremental items directed by both the 2010 LTRP and 2014 LTRP Decisions as well as any information requests related to those directives and the discussion surrounding those directives in each of the various decisions. This allowed FEI to understand the outcomes that the Commission is seeking from future LTRPs regarding these directives, and compare that to

[10] BCUC Order No. G-189-14. p. 34.
[11] BCUC Order No. G-189-14. p. 37.
[12] BCUC Order No. G-189-14. p. 42.
[13] BCUC Order No. G-189-14. p. 17.

similar activities undertaken for the LTRP or other projects. In some cases FEI has supplemented those estimates with information from consultant proposals and determined that among the incremental items listed above, those discussed through the remainder of this Appendix involve substantial undertakings that will require additional resources beyond the current Base O&M.

3. TOTAL FORECAST SPENDING FOR 2016

The Commission directed FEI to provide its estimate of total spending in 2016 to prepare the LTRP. FEI interprets this direction to mean an estimate of all spending related to the next LTRP, including costs related to regular LTRP activities and incremental activities as described above, and including costs related to both internal and external resources. FEI cannot provide a meaningful estimate on total costs for the following reasons.

FEI has stated in previous submissions regarding the incremental costs for the LTRP that many different people in several different departments around the company work on various aspects of the regular activities undertaken to prepare an LTRP. For example, in the 2012-2013 RRA proceeding, FEI estimated that 30 to 40 individual staff members were involved in LTRP related work[14]. The total number of people involved in these regular activities will change somewhat from one LTRP to the next, depending on the issues that need to be addressed within each LTRP. FEI does not have a "Long Term Resource Planning Group" to which it can assign the majority of LTRP related tasks and address changing issues from one LTRP to the next. Nor does FEI have a specified Long Term Resource Planning budget within Base O&M to cover all of the regular LTRP activities. Rather, FEI has one manager that, among other tasks, coordinates the LTRP related activities of the various other groups that work on the LTRP and the company must manage that workload within the greater Base O&M budget.

Assigning analytical work or other activities that need to be completed for the LTRP is therefore up to managers in each of the departments and has always been done as part of Base O&M activities. FEI does not typically require each of its managers or analysts to track their time spent on LTRP related activities as separate and distinct from other activities that are part of Base O&M. Since this information has not been historically tracked, there is no existing information from which an estimate of future spending on the LTRP could easily be drawn.

The only way, therefore, to acquire a meaningful estimate of such costs is to ask each manager and/or analyst to carefully review all of their activities and estimate the time and costs of only those activities related to the preparation of the LTRP. This is a task that would take each manager/analyst some time if an accurate estimate is to be derived. Adding to the complexity of estimating costs is the fact that LTRP related activities may or may not be integrally linked with other tasks performed by that group as part of their Base O&M activity, making the allocation of hours for those interrelated activities somewhat subjective.

Conducting such a survey in a way that results in a meaningful cost estimate is therefore a more substantial undertaking than it may appear. FEI is hopeful that the Commission has a clearer understanding of the challenge behind this undertaking and agrees that providing a total estimate of LTRP costs is not required. Instead, FEI has focused the remainder of this discussion specifically on those items considered to be incremental to Base O&M and requiring additional resources outside of Base O&M, which would be captured in the proposed deferral

[14] 2012-2013 RRA Proceeding, BCUC IR 1.68.2.

account. FEI submits that this information is sufficient for the Commission to make its decision regarding the requested deferral account.

3.1 TOTAL INCREMENTAL LTRP COSTS FOR 2016

Table 1 provides a summary of those tasks and activities that are incremental activities and for which FEI is requesting that costs be captured in the proposed deferral account.

Table 1: Summary of Anticipated Expenditures

	Activity	2016 Expenditure Estimate	Total Expenditure Estimate (based on upper estimate)
1.	Scenario Development	$ 75,000	$ 75,000
2.	Comparison of End-use Demand Forecasting Methodologies	$ 45,000	$ 45,000
3.	Alternative Residential and Commercial Customer Additions Forecast	$ 25,000	$ 25,000
4.	End-Use Demand Forecast	$ 95,000	$ 180,000
5.	Alternative Industrial customer Additions and Demand Analysis	$ 95,000	$ 145,000
6.	Impact of New End-use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts	$ 70,000	$ 150,000
7.	Incremental Consultation Activities	$ 30,000	$ 50,000
8.	DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios	$ 60,000	$ 200,000
9.	Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities	$ 10,000	$ 80,000
10.	Infrastructure Contingency Plans	$ 0	$ 70,000
11.	Analysis of Impact on GHG Targets	$ 0	$ 30,000
	Total	**$ 505,000**	**$ 1,050,000**

3.2 DESCRIPTIONS AND COSTS FOR INCREMENTAL LTRP ACTIVITIES AND WHY THEY ARE DEEMED INCREMENTAL

The Commission directed FEI to describe each key activity that FEI intends to undertake in developing the LTRP, the reasons why these activities are incremental to Base O&M and, for each activity:

- *Budget amounts for 2016 and project totals, with comparisons to the 2014 LTRP amounts;*

- *Breakdowns of internal versus external resource budgets, including the estimated percentage of 2016 spending related to external consultants versus internal staff, with descriptions of the role(s) undertaken by each group, again with comparisons to 2014 experience;*
- *The number of hours forecast to be spent by external consultants on the LTRP in 2016 compared to the number of hours forecast to be spent by internal staff.*

In Table 1 above, FEI has listed each of the key incremental activities that FEI intends to outsource in developing the LTRP. A more detailed description of each activity is provided below, including the information requested by the Commission where available. FEI notes the following with respect to the activity descriptions:

- *Comparisons to the 2014 LTRP:* With respect to comparison to 2014 LTRP costs, many of the incremental activities for the 2014 LTRP were conducted in-house rather than being outsourced. Since, as described above, FEI does not track internal costs for work specific to the LTRP separate from other ongoing work, FEI is not able to provide the comparative information for the 2014 LTRP in all cases. In addition, some of the activities are being conducted for the first time for the 2017 LTRP and there is therefore no relevant cost comparison to the 2014 LTRP.
- *Breakdowns of internal versus external resource budgets:* All of the incremental activities for which FEI is requesting deferral account treatment for the costs are expected to be completed by external resources. FEI expects that it will be able to manage the hiring and contracting of this work, as well as the integration of this work into the LTRP, within the current Base O&M such that the cost estimates provided are entirely for external resources.
- *Hours spent by external resources compared to internal resources:* An estimate of the number of hours to be spent by external consultants on these activities is presented along with the activity descriptions and cost estimates below. FEI has provided descriptions of associated work that will need to be completed by internal staff; however, since work completed by internal staff will be part of Base O&M, FEI has not developed estimates of hours spent by internal staff on incremental activities separate from other Base O&M activities.

As discussed above, none of the incremental activities identified in Table 1 were included, or required to be included, within the 2010 or earlier LTRPs. The costs to complete the incremental activities required by the 2010 LTRP Decision were explicitly excluded from FEI's Base O&M, while the more recent incremental activities directed by the Commission in the 2014 LTRP Decision were determined after FEI's Base O&M was set. In short, each of the incremental activities identified is required in order to meet the Commission's directions for the 2017 LTRP and the costs for completing these activities are not included in FEI's Base O&M.

3.2.1 Activity Descriptions:

i) Scenario Development

Description: This activity is the development of alternative future scenarios with varying conditions that could impact both the number of customers and their demand. In addition to creating a reference, high and low forecast cases, this activity will require expert advice on how varying future conditions could affect the planning environment, public policy and customer behavior among other factors. Critical uncertainties will be identified around which to examine the potential impact on FEI's business and operating environment. This activity may require stakeholder consultation in addition to Advisory Group workshops. This activity was not conducted prior to the completion of the 2010 LTRP and is necessary to inform the end-use demand forecasting process.

Consultant Activities:

- Review, identify and prioritize a full range of factors that could impact future planning for natural gas service;
- Review external sources of energy planning scenarios in BC and other jurisdictions in North America;
- Identify top priority uncertainties that could drive a reasonable range future scenarios conditions;
- Prepare draft scenarios for review with internal and external stakeholders;
- Ensure scenarios are developed sufficiently to allow future demand forecasting and contingency planning around each;
- Participate in internal and external stakeholder consultation on scenarios; and
- Prepare draft and final reports.

Cost Estimates: FEI's cost and time estimate for this activity is based on previous costs and cost estimates for external consulting services for assisting with demand forecasting activities, that are similar in nature and required expertise to the development of future scenarios.

- *2016 Potential Cost Estimate:* $50,000 - 75,000
- *Total Potential Cost Estimate:* $50,000 - 75,000
- *External Consulting Hours:* 375 – 425

Comparative Costs for 2014 LTRP: Not available – this activity was completed largely by internal resources for the 2014 LTRP and therefore not separately tracked.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data to consultant;
- Facilitate internal and external consultation opportunities;
- Integrate scenario development with other aspects of the LTRP; and
- Review report(s).

ii) Comparison of End-use Demand Forecasting Methodologies

Description: This activity is a detailed review of demand forecasting methodologies used by gas utilities in other jurisdictions. Conducting this review is required by Directive 5 of the 2014 LTRP Decision. The scope of the activity is based on the discussion provided in the Commission's 2014 LTRP Decision (pages 13 through 15).

Consultant Activities:

- Identify a full list of forecasting entities in BC and other jurisdictions;
- Conduct in-depth interviews of forecasting staff and obtain forecasting methodology samples wherever possible;
- Conduct interviews with regulatory bodies in other jurisdiction to determine how forecasting methodologies are regulated;
- Determine if forecasting standards and/or best practices exist;
- Review FEI's forecasting methodologies to determine if they are in line with typical/best forecasting practice and standards;
- Make recommendations on forecasting methodologies; and
- Prepare draft and final reports.

Cost Estimates: FEI's cost and time estimate for this activity is based on a consultant's proposal, as follows:

- *2016 Potential Cost Estimate:* $45,000
- *Total Potential Cost Estimate:* $45,000

- *External Consulting Hours:* 230 – 250

Comparative Costs for 2014 LTRP: Not available - this activity was not undertaken for the 2014 LTRP.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data to consultant;
- Integrate demand forecast adjustments, if any, with other aspects of the LTRP; and
- Review report(s).

iii) Alternative Residential and Commercial Customer Additions Forecast

Description: In the 2014 and prior LTRPs, FEI based its residential customer additions forecast on the Conference Board of Canada housing starts forecast and an expected market capture rate based on historical experience. The commercial customer additions forecast for the 2014 LTRP was based on average annual additions from the prior three years. The Commission panel has outlined that it expects future LTRP filings to 'show forecast variability in new customer additions for all scenarios based on different economic growth assumptions'[15]. FEI intends to seek consultant expertise on how best to identify and incorporate appropriate economic factors into the customer additions forecast and to provide alternative forecasts to FEI's traditional customer additions forecast methodology for up to 5 different scenarios.

Consultant Activities:

- Review socio-economic factors that could impact customer additions over the next 20-year period;
- Prioritize factors that are most likely to impact FEI customer additions;
- Review future condition scenario recommendations;
- Recommend alternative customer growth forecasts that match future scenarios; and
- Prepare draft and final reports.

[15] Commission Order G-189-14, Reasons for Decision, 2014 LTRP p16.

Cost Estimates: Cost and time estimate based on previous costs and cost estimates for external consulting services for assisting with demand forecasting activities, and which the FEI believes are similar in nature and required expertise to the development of future scenarios.

- *2016 Potential Cost Estimate:* $25,000
- *Total Potential Cost Estimate:* $25,000
- *External Consulting Hours:* 100 - 150

Comparative Costs for 2014 LTRP: Not available – this activity was not undertaken for the 2014 LTRP.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data to consultant;
- Facilitate any related internal and external consultation activities;
- Integrate alternative customer forecasts with demand forecast and other aspects of the LTRP; and
- Review report(s).

iv) End-Use Demand Forecast

Description: This activity is to develop an end-use based long-term residential, commercial and industrial customer forecast of demand for the LTRP. The long-term, end-use demand forecast was first undertaken in the 2014 LTRP in order to meet Commission directives from the 2010 LTRP Decision[16].

Consultant Activities:

- Identify a preferred end-use demand forecast model;
- Tailor the model to meet the needs of FEI in the BC context;
- Identify/acquire appropriate inputs into the demand forecast model;
- Test the model validity;

[16] BCUC Order No. G-14-11. p. 25.

- Participate in reviewing modelling methodology with internal and external stakeholders;
- Conduct modelling, including QA/QC of modelling outputs;
- Provide modelling results to FEI; and
- Prepare draft and final reports and necessary supporting documentation for LTRP filing.

Cost Estimates: FEI's cost and time estimate for this activity is based on costs incurred for similar work during the 2014 LTRP. A range of costs is presented since the review of alternative end-use methodologies that the Commission has directed FEI to undertake may result in a different methodology being employed for the 2017 LTRP for which the costs are not yet known. The low end of the range represents the potential for some cost savings if the same methodology is used as in the 2014 LTRP, and the high end of the range represents cost increases if an alternative, more costly methodology is selected.

- *2016 Potential Cost Estimate:* $75,000 - $95,000
- *Total Potential Cost Estimate:* $120,000 - $180,000
- *External Consulting Hours:* 600 – 750

Comparative Costs for 2014 LTRP: $147,000

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data to consultant;
- Facilitate internal and external consultation opportunities;
- Integrate end-use demand forecast with other aspects of the LTRP; and
- Review demand forecasts and supporting documentation and provide feedback to consultants.

v) Alternative Industrial Customer Additions and Demand Analysis

Description: In the 2014 LTRP Decision, the Commission Panel encouraged FEI to provide a more complete analysis and justification of new industrial customer additions forecasted beyond those known potential additions that FEI could reasonably expect to enter into formal contracts for service. This activity will require a range of scenarios based on different economic growth assumptions.

Consultant Activities:

- Identify a full range of economic and industry factors that could impact industrial customer growth over the next 20 years for a range of industry sectors;
- Prioritize those factors that are most likely to influence FEI industrial customer additions;
- Review future scenario conditions for each of the LTRP future scenarios;
- Make recommendations regarding alternative industrial customer addition and demand forecasts;
- Participate in reviewing any industrial customer additions and demand forecast recommendations with internal and external stakeholders; and
- Prepare draft and final reports.

Cost Estimates: Cost and time estimate based on a review of similar work previously completed for FEI in different sectors, as well as a review of proposals for consulting work of a similar nature. A formal request for proposals has not been conducted for this portion of LTRP tasks.

- *2016 Potential Cost Estimate:* $95,000
- *Total Potential Cost Estimate:* $145,000
- *External Consulting Hours:* 600 - 725

Comparative Costs for 2014 LTRP: Not available – this activity was not undertaken as part of the 2014 LTRP.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data to consultant;
- Facilitate internal and external consultation opportunities;
- Integrate industrial forecast development with other aspects of the LTRP; and
- Review report(s).

vi) Impact of New End-use Trends on Time-of-Day Use and Linking the Annual and Peak Demand Forecasts

Description: In the 2014 LTRP Decision, the Commission identified the following areas as opportunities to establish stronger linkages between the two forecasts for readers of the LTRP:

- the number of customers, by class;
- how new insights on evolving customer consumption patterns might affect time-of-day demand as well as annual demand; and
- how changes in base load annual demand under different scenarios translate into changes in base load peak demand under the same scenario assumptions.[17]

As explained by FEI in the 2014 LTRP proceeding, due to the coarse granularity of metering information available to analyze peak and time-of-day customer usage, these trends and linkages are difficult to discern. FEI will need to retain third-party consulting services with experience in identifying and modelling recent end-use trends on peak natural gas demand in order to comment on the opportunities to establish stronger linkages cited by the Commission and potentially use this information to derive additional peak demand alternative forecasts.

Consultant Activities:

- Obtain/review industry data on how new energy equipment and technology trends can impact peak versus annual demand;
- Review available data on energy equipment and technology trends in North America and globally that may impact the BC marketplace;
- Conduct any necessary engineering analysis building energy modelling to supplement existing information on how new technologies are impacting peak demand and time-of-day natural gas use;
- Assist FEI with integrating study results into peak demand forecast modelling;
- If necessary, participate in any internal and external stakeholder consultation activities to discuss study results; and
- Present and report on study results.

[17] 2014 LTRP Decision, Order No. G-189-14. p. 22.

Cost Estimates: Cost and time estimate based on a review of similar work previously completed for FEI in different sectors as well as a range of past proposals for consulting services. A formal request for proposals has not been conducted for this portion of LTRP tasks.

- *2016 Potential Cost Estimate:* $70,000
- *Total Potential Cost Estimate:* $100,000 – $150,000
- *External Consulting Hours:* 600 - 750

Comparative Costs for 2014 LTRP: Not available – this activity was not undertaken as part of the 2014 LTRP.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data, peak demand modelling details to consultant;
- Facilitate internal and external consultation opportunities, where necessary;
- Integrate peak demand and modelling recommendations where applicable with other aspects of the LTRP; and
- Review report(s).

vii) Incremental Consultation Activities

Description: Prior to the 2014 LTRP, FEI typically held 2 to 3 broad stakeholder and First Nation consultation workshops. For the 2014 LTRP, as part of making improvements to the quality of consultation and stakeholder engagement informing the LTRP, FEI established a Resource Planning Advisory Group (RPAG) and conducted regular workshops throughout the planning process. Additionally, FEI conducted a series of half-day workshops in numerous communities throughout its service territory in order to gain input on broad resource planning issues. Both of these activities have improved the quality and value of stakeholder and First Nations input into FEI's long term planning efforts. In the 2010 LTRP Decision, the Commission agreed that establishing an RPAG would be beneficial to the planning process[18] and in the decision on the 2012-2013 RRA, approved O&M spending for a number of incremental items for completing the 2014 LTRP that included increased stakeholder consultation[19]. As stated above, all incremental

[18] 2010 LTRP Decision, Order G-14-11, p.13.
[19] FEU 2012 – 2013 RRA Decision. Order No. G-44-12. pp. 56-59.

O&M related to the 2014 LTRP activities (including the increased stakeholder consultation) was removed from FEI's Base O&M in the PBR Decision.

Cost Estimates: Cost estimate includes the cost for external facilities, travel and external stakeholder expenses as experienced during the 2014 LTRP process, and does not include FEI staff time.

- *2016 Potential Cost Estimate:* $30,000.
- *Total Potential Cost Estimate:* $50,000.
- *External Consulting Hours:* N/A. Cost for external consultants who might need to attend these events are captured in the costs for those consulting activities elsewhere in this summary.

Comparative Costs for 2014 LTRP: Approximately $63,000.

Internal Activities: Coordinate, manage and conduct all LTRP specific stakeholder consultation activities.

viii) DSM Portfolio Scenario Analysis Including Alternative DSM Funding and Savings Scenarios

Description: In its 2010 LTRP Decision, the Commission directed FEI to provide in its next LTRP (the 2014 LTRP):

- greater coordination between EEC planning and the development of future resource plans, allowing for a more detailed presentation of future EEC programs over a longer time period with expected impacts to be included as part of the LTRP process; and
- development of a limited number of scenarios detailing the impacts of varying degrees of EEC Planning measures on the demand forecast and GHG emission reductions[20].

To meet this requirement, FEI retained external consultants to examine all cost effective demand side measures and estimate savings that could be achieved under the different future scenarios developed for the purposes of the long term annual demand forecast. The results of the analysis were included in the 2014 LTRP, which was accepted by the Commission. In the 2014 LTRP Decision, Directive 8, the Commission also directed FEI to include in its next LTRP:

[20] 2010 LTRP Decision, Order G-14-11, p.24.

- The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a ‘reference’ DSM funding scenario with ‘high DSM’ and ‘low DSM’ scenarios that are relative to the reference scenario;
- Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:
    - Total Resource Cost/modified Total Resource Cost test results;
    - Utility Cost Test result, expressed as a ratio and $/GJ;
    - Delivery rate impact; and
    - Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers.

A significant difference between the 2014 LTRP and what FEI is required to provide in the next LTRP is the analysis of potential energy savings based on different funding amounts. FEI anticipates that the work conducted for the DSM analysis included in the 2014 LTRP will need to be repeated for the 2017 LTRP. In addition, FEI will need to retain consulting services to analyze different potential funding amounts set within different future scenarios that also inform the annual and peak demand forecasts. The requirement for examining different DSM funding levels across different future scenarios increases the complexity of the analysis required.

Consultant Activities:

- Analysis of annual energy savings, by end-use for each future scenario and all end-uses, that can be applied to the pre-DSM annual demand forecasts;
- Analysis of peak energy savings or increases, by end-use and all end-uses, for each future scenario that can be applied to the pre-DSM peak demand scenarios;
- Development of high-level, long term DSM recommendations that can be used to inform future shorter term DSM plans for which funding approval will be sought in separate DSM applications to the Commission;
- Participation in any necessary internal and external stakeholder consultation activities to review DSM analysis results and scenario recommendations; and
- Preparation of draft and final reports.

Cost Estimates: Cost estimate based on costs incurred during 2014 LTRP as well as costs and proposals received by FEI for work of a similar nature on other projects and assessed for the expanded scope of work beyond that conducted for the 2014 LTRP.

- *2016 Potential Cost Estimate:* $ 60,000
- *Total Potential Cost Estimate:* $ 150,000 - $200,000
- *External Consulting Hours:* 650 - 800

Comparative Costs for 2014 LTRP: $86,000 for consulting fees

Internal Activities:

- Retain consultant and manage contract;
- Provide background information and utility data, including Conservation Potential Review results to consultant;
- Facilitate internal and external consultation opportunities;
- Integrate DSM analysis and recommendations with other aspects of the LTRP; and
- Review report(s).

ix) Analyze and Report on Peak Demand Infrastructure Avoidance / Deferral Opportunities.

Description: In its 2014 LTRP Decision, Directive 9, the Commission directed FEI to provide a more fulsome analysis of opportunities for DSM to be cost effectively used to replace or defer infrastructure investments. In the 2014 LTRP and IR responses, FEI explained the difficulty in doing so for DSM activities other than load curtailment, due to the lack of reliable information about how the many different end-use technologies and trends impact peak demand. Therefore, to comply with this directive FEI anticipates needing external expertise in energy modeling and having recent experience in other jurisdictions in analyzing natural gas infrastructure avoidance from DSM activities (if such experience exists).

Consultant Activities:

- Review all end-use, peak demand and peak reduction analyses conducted for the LTRP;
- Review and understand FEI gas system modelling in order to help conduct peak modelling activity;
- Obtain and review any modelling of impacts of natural gas peak demand savings in other jurisdiction on infrastructure avoidance or deferral;

- Conduct any additional modelling needed to identify infrastructure avoidance opportunities based on each demand scenario and for each DSM scenario; and
- Make recommendations and prepare final reports for FEI's system planning activities on potential infrastructure avoidance/deferral under each future scenario, demand forecast and DSM scenario.

Cost Estimates: Cost estimates for this work are based on FEI's estimation of the work requirements and familiarity with costs for outsourcing engineering studies.

- *2016 Potential Cost Estimate:* $ 10,000
- *Total Potential Cost Estimate:* $ 70,000 - $80,000
- *External Consulting Hours:* 350 - 450

Comparative Costs for 2014 LTRP: Not Available – this activity was not conducted for the 2014 LTRP.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information, utility data and system modelling details to consultant;
- Integrate facility modelling results and recommendations where applicable with other aspects of the LTRP; and
- Review report(s).

x) Infrastructure Contingency Plans

Description: In its 2014 LTRP Decision, Directives 10 and 11, the Commission accepted FEI's System Resource Plan, but directed FEI to include in its next LTRP a contingency plan or plans that outline the impact of changes in supply, demand, market conditions and significant new developments in the industry on system resource needs and alternative solutions not identified as part of the reference case demand forecast. Substantial additional work over and above that undertaken for the 2014 LTRP will be required to analyze, select and document additional contingency plans. Although the Commission has stated that this analysis at a minimum should take into account high and low alternate scenarios, the description of different planning environment conditions described by the Commission in this directive implies that the analysis will need to consider a broader range of alternative peak demand scenarios. As such, FEI anticipates seeking additional external engineering assistance to meet this directive.

Consultant Activities:

- Identify changes in supply, demand, market conditions or industry developments that may impact FEI's infrastructure planning;
- Prioritize such changes and identify those most likely to impact FEI's infrastructure planning and those impacts which would have the most significant impact on infrastructure planning;
- Confirm if such changes are already captured in FEI's future scenarios and demand forecasts;
- Work with FEI's System Planning group to conduct any necessary modelling and identify contingency plans for an appropriate range of demand scenarios and market/industry conditions; and
- Prepare draft and final reports.

Cost Estimates: Cost estimates for this work are based on FEI's estimation of the work requirements and familiarity with costs for outsourcing engineering studies.

- *2016 Potential Cost Estimate:* $ 0
- *Total Potential Cost Estimate:* $50,000 – $70,000
- *External Consulting Hours:* 300 - 400

Comparative Costs for 2014 LTRP: Not Available – this activity was not conducted for the 2014 LTRP.

Internal Activities:

- Retain consultant and manage contract;
- Provide background information, utility data and system modelling details to consultant;
- Integrate contingency modelling results and recommendations where applicable with other aspects of the LTRP; and
- Review report(s).

xi) Analysis of Impact on GHG Targets

Description: As directed by the Commission in the 2010 LTRP Decision, this activity is to prepare an analysis of GHG targets set out in BC's energy objectives, an estimate of the impact that the Company believes it can have on those targets over time, and an outline of the impact that implementing any new initiatives might have on the demand forecast and GHG emission reductions.

Consultant Activity:

- Conduct a review and summary of all GHG reductions that might result from various FEI initiatives and under all reported demand forecast and future scenarios;
- Review and report on any changes to energy and emission objectives at the local, provincial or federal government levels;
- Analyze the extent to which each FEI initiative or activity, as well as overall GHG emission reductions, will impact the objectives of local, provincial and federal policies and targets, with particular focus on BC policy amendments;
- Where BC energy and emission policy changes have not been implemented, develop alternative policy scenarios against which to measure the impact of FEI's intiatives;
- Conduct internal and external consultations/presentations as necessary; and
- Provide recommendations in a final report.

Cost Estimate: The extent of the analysis required to meet this directive remains uncertain, since the provincial government has embarked on a review of its energy and climate action policies through the Climate Leadership Plan review. As such, FEI's estimate of potential costs and hours required is correspondingly uncertain.

- *2016 Potential Cost Estimate:* $ 0
- *Total Potential Cost Estimate:* $15,000 - $30,000
- *External Consulting Hours:* 80 - 150

Comparative Costs for 2014 LTRP: Not available. This activity was completed largely by internal resources for the 2014 LTRP and therefore not tracked separately.

Internal Activities:

- Retain consultant and manage contract;

- Provide background information, utility data and reporting requirements to consultant;
- Integrate consultant recommendations where applicable with other aspects of the LTRP; and
- Review report(s).

3.3 WHETHER FEI PLANS TO HIRE ADDITIONAL PERMANENT EMPLOYEES TO PERFORM LTRP - RELATED WORK

As indicated above, the Commission directed FEI to provide an explanation of whether FEI plans to hire additional permanent employees to perform LTRP-related work, including an estimated number of new employees to be hired for 2016.

FEI does not anticipate hiring additional permanent employees in 2016 or 2017 to perform LTRP-related work.

As directed by the Commission, FEI provides below a table for each of the major productivity initiatives that FEI has implemented as discussed in Section 1.4, in the format equested by the Commission.

Table D-1: Regionalization Initiative

	2014	2015+
Activities undertaken	• Operations Supervisor recruitment and training • Dispatcher relocation, recruitment and training • Planner relocations • Process review and modification • IT infrastructure modifications • Facilities modifications	None
Organizational changes	• Dispatch staff decreases • Operations staff increases due to hiring of Operations Supervisors • Operations staff decreases due to retirements and terminations not replaced • Planners staff re-allocated to Operations	None
O&M expenditures incurred or expected to be incurred	**$0.9 million** This included costs for a number of activities including employee development/ training, IT and facilities.	None
Capital expenditures incurred or expected to be incurred	**$1.3 million** This includes costs for IT, facilities and communications.	None
Anticipated savings	**$1.0 million** approximately. As discussed in the response to BCUC IR 1.2.1 in the annual review for 2015 delivery rates, it is difficult to separate Regionalization savings from the savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.	Ongoing

1 **Table D-2: Project Blue Pencil**

	2014	2015	2016+
Processes Reviewed	High Bill Inquiry Emergency Collections Meter Exchange New Construction		
Organizational Changes	Contact center and billing operations will experience a FTE reduction as a result.	Contact center and billing operations will experience a FTE reduction as a result.	Contact center and billing operations will experience a FTE reduction as a result.
O&M expenditures expected to be incurred	$0 Incremental O&M costs	$0 Incremental O&M costs	$0 Incremental O&M costs
Capital expenditures expected to be incurred	<$100 thousand	<$200 thousand	$0
Annual Savings - Labour	< $100 thousand	Approximately $1 million annual contact centre and billing operations O&M savings.	Approximately $1 million annual contact center and billing operations O&M savings.
Annual Savings – non-Labour	$0	$0.	$0

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1 **Table D-3: Review of Technical and Infrastructure Support Provider**

	2014	2015	2016+
Services Contract update and change	This is an initiative to review the existing agreement with the Company's technical and infrastructure service provider responsible for providing Information Systems (IS) Customer and Infrastructure Services to FEI. This includes the employee Help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. For each new efficiency identified, on a one-time basis (i.e. first full year savings), the vendor shares in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies. Additionally, the new contract provides dedicated support resources rather than a distributed support service resulting in quicker response times and better understanding of the Company's requirements.		
Organizational Changes	Contract awarded to Compugen after RFP process. Transitioned from incumbent third party provider, Telus, to successful bid proponent Compugen.	Compugen takes over support contract.	
Capital expenditures incurred	$1.1 million to replace the Service Request system that required replacement to complete the transition.	$400K to complete the project to replace the Service Request system.	$0
Annual Savings – non-Labour	$0	$1.8 million	$2 million

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Appendix D

DEPRECIATION STUDY

2014 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALSRELATED TO GAS PLANT
AS AT DECEMBER 31, 2014

Prepared by:

FORTISBC ENERGY INC.
Surrey, British Columbia

2014 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS AT DECEMBER 31, 2014

GANNETT FLEMING CANADA ULC

Calgary, Alberta

August 21, 2015

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, British Columbia V4N 0E8

Attention: Mr. James Wong
Director, Finance and Planning

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the gas utility plant of FortisBC Energy Inc. as of December 31, 2014. The depreciation study has developed depreciation rates for the FortisBC Energy Inc. systems. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and net salvage, 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, 2014. The depreciation rates are based on the straight-line method, the remaining life basis, using the average service life group procedure. A periodic review of the depreciation rates using the same estimates and methods is recommended.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK/hac
Project #059460

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FORTISBC ENERGY INC.
DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to FortisBC Energy Inc.'s ("FortisBC") request, Gannett Fleming Canada ULC ("Gannett Fleming") conducted a depreciation study related to the surviving plant of natural gas utility plant as of December 31, 2014. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking objectives.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, and forecasting net salvage characteristic for each depreciable group of assets.

The last depreciation study conducted by Gannett Fleming provided separate annual accrual rates developed for the provision applicable to the average service life and net salvage components of depreciation expense for each of the FortisBC Energy Inc., FortisBC Energy Inc. (Vancouver Island) Inc., and FortisBC (Whistler) Inc. systems. The current depreciation study has provided annual accrual rates for the combined FortisBC natural gas system[1]. As such, Table 1A, as presented in the Results section of this report, provides for the recovery of the original cost of assets in service. Table 1B provides for the recovery of the estimated costs of retirement.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of 2014 as summarized by Tables 1A and 1B of the study by account detail. Supporting data and calculations are provided as well within the study.

Finally, this study results in an annual depreciation expense accrual of $185.4 million when applied to depreciable plant balances as of December 31, 2014. The report study results are summarized at an aggregate functional group level as follows:

[1] Please note that all references through this document to the previous study relate to the amalgamated results of all three utilities.

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

PLANT GROUP	ORIGINAL COST $'s	ANNUAL ACCRUAL %'s	ANNUAL ACCRUAL $'s
(1)	(2)	(3)	(4)
INTANGIBLE	142,411,398	13.64	19,420,920
MANUFACTURING	5,905,997	2.74	162,068
LNG	258,855,336	3.09	8,003,282
TRANSMISSION	1,496,578,392	2.09	31,293,227
DISTRIBUTION	2,997,226,526	3.57	107,068,511
BIO GAS	10,789,808	4.36	470,649
NG FOR TRANSPORTATION	11,811,679	5.03	593,716
GENERAL	275,696,133	6.69	18,432,566
TOTAL PLANT IN SERVICE	**5,199,275,269**	**3.57**	**185,444,939**

PART I. INTRODUCTION

FORTISBC ENERGY INC.

DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for FortisBC Energy Inc. to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of gas plant at December 31, 2014. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to gas plant in service as of December 31, 2014.

The service life and net salvage estimates resulting from the study were based on: informed engineering judgment which incorporated analyses of historical plant retirement data as recorded through 2014; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the gas industry, including knowledge of service lives and net salvage estimates used for other gas companies.

PLAN OF REPORT

Part I. Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II. Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life and net salvage studies. Part III. Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV. Results of Study, presents summaries by depreciable group of annual and accrued depreciation. Part V presents the results of the Retirement Rate and Service Life Statistics and Part VI presents Net Salvage Analysis. Detailed tabulations of annual and accrued depreciation are presented in Part VII of this report. An overview of Iowa curves and the Retirement Rate Analysis are set forth in Appendix A of the report. An overview of the net salvage analysis is presented in Appendix B of this report.

BASIS OF THE STUDY

Depreciation

For most accounts, the annual and accrued depreciation were calculated by the straight line method using the average service life procedure and applied on a remaining life basis. For certain General Plant and other 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 and salvage.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. Many gas utilities in North America have received approval to adopt amortization accounting for these accounts.

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 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 our studies of other gas utilities. 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 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 depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity.

PART II. DEVELOPMENT OF DEPRECIATIONS PARAMETERS

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility 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 causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in demand, and the requirements of public authorities.

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 natural 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 in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

<u>Survivor Curves</u>

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 the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and relative height of the modes. The left-moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical-moded curves are those in which the greatest frequency of retirement occurs at average service life. The right-moded curves are those in which the greatest frequency occurs to the right of, or after, the average service life. The origin-moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age 0. The letter designation of each family of curves (L, S, R or O) represents the mode of the associated frequency curve with respect to the average service life. The numerical subscripts represent the relative heights of the modes of the frequency curves within each family.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix A of this report.

Survivor Curve and Net Salvage Judgments

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel and on the knowledge Gannett Fleming developed through the completion of numerous gas utility studies.

The estimates of net salvage were based in part on historical data related to actual retirement activity for the years 1959 through 2014 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 both annual and five-year moving average bases. The net salvage estimates are expressed as percentages of the original cost of plant. A detailed discussion of the methods and procedures followed in the net salvage study is presented in Appendix B to this report.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Gannett Fleming 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 475.00 – Distribution - Systems - Mains, is the largest account studied and represents 25% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1924 through 2014 were analyzed by the retirement rate method. The original and smooth survivor curve is plotted on page V-37. Typical service lives for distribution mains range from 50 to 66 years.

In previous studies Gannett Fleming recommended the Iowa 64-R2. The statistical analysis of this account has indicated a best fit of historic retirements consistent with the 64-R2.5 Iowa curve. Since the last study, this account has continued to incur retirements at a consistent rate which provide for a reliable statistical indication of average service life characteristics. To date, this account has experienced nearly $46 million of retirement activity. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than the historic indications. Furthermore, operations staff has indicated that it would be expected that the life of the FortisBC distribution mains would be in the range of other industry peers and with the FortisBC Transmission mains.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 50 years of age, with large retirement rates through to age 75 resulting in a slightly more rectangular retirement dispersion pattern. In order to better fit to this retirement pattern, Gannett Fleming has recommended a slightly higher moded Iowa 64-R2.5 survivor curve to better reflect the experienced retirement rates as compared to the previous estimate of the 64-R2. This minor increase in the mode of the Iowa curve combined with a small increase in the average service life expectation provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is therefore recommended for this account.

This account has witnessed a significant amount of net salvage (i.e. cost of removal) activity since 2002, ranging from 0 percent to over negative 86 percent with a full depth band (i.e. cumulative from 2002 to 2014) value of negative 24 percent. A three-year moving average indicates a range from negative 1 percent to over negative 69 percent with the most recent five-year average being negative 46 percent. In the last depreciation study, Gannett Fleming recommended negative 20 percent to represent the net salvage expectation. The discussions held with the company operations and engineering staff indicated that the historical indications would be reasonable future expectations for the equipment in this account. Considering the historical results and the comments from the operations and engineering staff, Gannett Fleming recommends that a small modification to negative 25 percent would best represent the future net salvage expectations for the equipment in this account. It is noted that the change to negative 25 percent is considered by Gannett Fleming to moderate and conservative, but within the range of the peer comparison analysis.

Account 465.00 – Transmission - Pipeline, represents approximately 22% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1957 through 2014 were studied. The original survivor curve as plotted on page V-16 indicates only a modest level of retirements through age 45. Typical service lives for transmission mains of Canadian peer utilities range from 60 to 65 years. Previous depreciation studies have indicated a 65-R3 Iowa curve for this account.

The Retirement Rate Analysis as presented at pages V-17 and V-18 of this report and discussions with the operations and engineering staff have indicated that to date the pipe has experienced only a limited level of retirement activity. However, the retirement activity to date of over $19 Million of originally installed cost, has provided some data upon which a life analysis can be made, particularly when combined with the experience of the operations staff.

The company has indicated that there are no major replacements expected during the immediate planning horizon and that the historical indications are indicative of the future. In the last depreciation study Gannett Fleming recommended an Iowa 65-R3 curve. This dispersion pattern is judged to still represent the historic retirement activity. The Iowa 65-R3 survivor curve, selected in this study to represent the life characteristics for this account, is within the typical range of lives used for transmission mains in the industry, and conforms to the expectations of management.

This account has witnessed a significant amount of net salvage (i.e. cost of removal) activity since 2002, ranging from 0% to over negative 100% with a full depth band (i.e. cumulative from 2002 to 2014) value of negative 24 percent. A three-year moving average indicates a range from negative 0 percent to negative 94 percent with the most recent five year average being negative 32 percent. All the bands indicate a higher level of negative net salvage in the more recent years compared to the earlier years. In the last depreciation study, Gannett Fleming recommended negative 10 percent to represent the net salvage expectation. The discussions held with the company operations and engineering staff indicated that the historical indications would be reasonable future expectations for the equipment in this account. Based upon the historical results and the comments from the operations and engineering staff, Gannett Fleming recommends that a moderate and conservative change to negative 20 percent would best represent the future net salvage expectations for the equipment in this account, and is within the range of the peer comparison analysis.

Account 473.00 – Distribution - Services, represents 20% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1900 through 2014 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page V-30.

In the last depreciation study Gannett Fleming recommended the Iowa 50-R1. Since the last study, this account has continued to incur retirements due to a number of retirement programs, which provides for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $93 million of retirement activity. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than historic patterns. Furthermore, operations staff has indicated that it would be expected that the life of the FortisBC distribution services would be in the range of other industry peers. Typical service lives for peer Canadian distribution services range from 40 to 57 years.

The retirement rate analysis indicates a significant rate of retirement activity as plant reaches 35 years of age, with large retirement rates through to age 75. In order to fit this retirement pattern, Gannett Fleming has recommended the Iowa 45-R1 survivor. This combination of the R1 Iowa curve and a 45 year average service life expectation provides a reasonable interpretation of the original survivor curve, and falls within the range of typical service lives for this account and is, therefore recommended for this account.

This account has witnessed a significant amount of net salvage (i.e. cost of removal) activity since 2002, ranging from 0% to over negative 200 percent with a full depth band (i.e. cumulative from 2002 to 2014) value of negative 102 percent. A three-year moving average indicates a range from negative 11 percent to over negative 200 percent with the most recent five year average being negative 179 percent. All the bands indicate a higher level of negative net salvage in the more recent years compared to the earlier years. In the last depreciation study, Gannett Fleming recommended negative 50 percent to represent the net salvage expectation. The discussions held with the company operations and engineering staff indicated that the historical indications would be reasonable future expectations for the equipment in this account. To reflect the increased historical indications, Gannett Fleming views that a moderate and conservative increase to the recommended net value is appropriate. Considering the historical results and the comments from the operations and engineering staff, Gannett Fleming recommends that a moderate and conservative negative 60 percent would best represent the future net salvage expectations for the equipment in this account. The negative 60 percent net salvage recommendation is within the range of the peer comparison analysis. However, it is noted that if the recent trend continues, increased amounts of net negative salvage will be required in future reviews.

<u>Account 478.10 – Distribution - Meters</u>, represents 4% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1963 through 2014 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page V-43. Typical service lives for gas distribution meters range from 20 to 32 years. In recent years, the gas distribution industry has

been moving toward increased use of digital metering and Automated Meter Reading (AMR) technology. Additionally, in early 2010, Measurement Canada has announced more stringent metering testing guidelines. The new testing guidelines place increasingly strict criteria on the test results as the age of the meters increase.

Interviews with the operational metering staff have indicated that the implementation of the new Measurement Canada requirements will result in residential meters being retired before they reach 20 years of age. In the experience of Gannett Fleming, this assumption is consistent with the metering experts across Canada, all of whom have indicated that residential meters will no longer be tested when they reach 15 to 20 years of age. Operations staff did indicate that the meters related to commercial and industrial customers are expected to last beyond 20 years, and would likely be refurbished when removed for testing. It is estimated that these larger commercial and industrial meters comprise approximately five percent of the investment in this account.

Since the previous Gannett Fleming study, which recommended an Iowa 20-R2.5 curve to represent the retirement characteristics for this account, FortisBC has continued the program to replace older electro-mechanical meters with newer technology digital metering equipment. This account is experiencing significant change in the technology associated with the assets within this account. Therefore, given the future expectation that residential meters will be retired prior to reaching an age of 20 years, Gannett Fleming is recommending a small reduction in the average service from the Iowa 20-R2.5 to the Iowa 18-R2.5 to represent the future life expectations for the equipment in this account. This account will be closely monitored over the next few years to determine if a further shortening of the average service life estimate becomes necessary.

Account 474.00 – Distribution - Meters/Regulator Installations, represents 4% of FortisBC's depreciable plant. The retirements, additions and other plant transactions for the period 1959 through 2014 were analyzed by the retirement rate method. The original and smooth survivor curves are plotted on page V-34.

In the last depreciation study Gannett Fleming recommended the Iowa 22-R2.5. Since the last study, this account has continued to incur retirements due to a number of retirement programs, which provides for a reliable statistical indication of average service life characteristics. To date, this account has experienced over $76 million of retirement activity. Discussions with operating and engineering staff have not indicated any specific reasons to believe that the future retirement trends in this account will be significantly different than historic patterns.

The retirement rate analysis indicates a consistent rate of retirement activity throughout the plant's 40-year life. In order to fit this retirement pattern, Gannett Fleming has recommended the Iowa 20-S0 survivor curve. This combination of the S0 Iowa curve and a 20-year average service life expectation provides a reasonable interpretation of the original survivor curve, and is consistent with management's expectations and is, therefore recommended for this account.

This account has witnessed a significant amount of net salvage (i.e. cost of removal) activity since 2002, ranging from 0% to over negative 200 percent with a full depth band (i.e. cumulative from 2002 to 2014) value of negative 25 percent. A three-year moving average indicates a range from negative 1 percent to over negative 400 percent with the most recent five year average being negative 75 percent. All the bands indicate a higher level of negative net salvage in the more recent years compared to the earlier years. In the last depreciation study, Gannett Fleming recommended negative 10 percent to represent the net salvage expectation. The discussions held with the company operations and engineering staff indicated that the historical indications would be reasonable future expectations for the equipment in this account. Based upon the historical results and the comments from the operations and engineering staff, Gannett Fleming recommends that negative 20 percent would best represent the future net salvage expectations for the equipment in this account. The negative 20 percent net salvage recommendation is within the range of the peer comparison analysis. However, it is noted that if the recent trend continues, increased amounts of net negative salvage will be required.

Account 466.00 - Transmission - Compressor Equipment, represents approximately 3% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1965 through 2014 were analyzed by the retirement rate method. The original survivor curve as plotted on page V-19 indicates only a reasonable level of historical retirements through age 22, and a smaller rate of retirement from ages 22 through 40.

In previous depreciation studies, Gannett Fleming has recommended a 35-R3 Iowa curve. Typical service lives for compression equipment range from 32 to 42 years. The compression units, utilized by FortisBC are Solar units which have proven to be reliable both at FortisBC and within the industry as a whole. As such, it is expected that these units would perform at the longer end of the range of average service lives. However, the high rate of retirement ratios beginning at approximately age 15, need to be recognized. Gannett Fleming recommends a slight increase in the mode from an R3 to an R4. This combined with the previous 35-year average service life provides a good fit to the historical indications. As such, an adjustment to the Iowa 35-R4, selected in this study, provides a reasonable interpretation of the historical data, and is within the range of lives used in the industry and anticipated by management.

Account 477.10 – Distribution – Measuring and Regulating Equipment, represents approximately 2% of the depreciable plant studied. The retirements, additions and other plant transactions for the period 1957 through 2014 were analyzed by the retirement rate method. The original survivor curve as plotted on page V-40 indicates a consistent rate of retirement activity throughout the plant's 57-year life.

In previous depreciation studies, Gannett Fleming has recommended a 26-R2 Iowa curve. With the significant amount of retirement activity and the results from the survivor curve fit, Gannett Fleming is recommending an increase in the average service from 26 years to 30 years while maintaining the previous R2 Iowa curve. The discussions held with the company operations and engineering staff indicated that the historical indications would be reasonable future expectations for the equipment in this account. The resultant 30-R2 Iowa curve provides an excellent interpretation of the original survivor curve for this account.

This account has witnessed a significant amount of net salvage (i.e. cost of removal) activity since 2000, ranging from 0% to over negative 200 percent with a full depth band (i.e. cumulative from 2000 to 2014) value of negative 9 percent. A three-year moving average indicates a range from negative 1 percent to negative 29 percent with the most recent five year average being negative 7 percent. In the last depreciation study, Gannett Fleming recommended 0 percent to represent the net salvage expectation. The discussions held with the company operations and engineering staff indicated that the historical indications would be reasonable future expectations for the equipment in this account. Based upon the historical results and the comments from the operations and engineering staff, Gannett Fleming recommends that negative 10 percent would best represent the future net salvage expectations for the equipment in this account. The negative 10 percent net salvage recommendation is within the range of the peer comparison analysis.

Account 467.20 – Transmission – Telemetry Equipment, represents less than 1% of the depreciable plant studied. In previous depreciation studies, Gannett Fleming has recommended a 15-L1 Iowa curve. The discussions held with the company operations and engineering staff indicated that the previous life parameter selection was not reasonable for the current equipment in this account. The company's expectations were that approximately one half of the previous life parameter would be more applicable for Telemetry Equipment. As such, based on the company's expectations, the 8-L1 Iowa curve is recommended for the expected life parameters for this account.

Other Accounts

The above analysis provides the consideration relating to almost 81% of the depreciable plant. The accounts related to the remaining 19% of the depreciable plant studied as of December 31, 2014 were analyzed using similar methods and considered similar factors including review of operational comments, peer reviews and experience of Gannett Fleming.

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

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CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

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 service life and equal life group procedures.

In the average service life procedure, the rate of annual depreciation is based on the average service life of the group, and 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 service life 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 service life procedure is widely used throughout North America and was used in order to conform to past Company practices and approvals by the British Columbia Utilities Commission.

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 distribution of 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 continues to be appropriate for a certain number of accounts that represent numerous units of property, but a very small portion of depreciable gas plant in service. The accounts and their amortization periods are as follows:

ACCOUNT	TITLE	AMORTIZATION PERIOD, YEARS
402.01	Computer Software Application 8 Years	8
402.02	Computer Software Application 5 Years	5
483.10	Computer Hardware	5
483.20	Computer Software (12.5%)	8
483.30	Office Equipment	15
483.40	Furniture	20
486.00	Small Tools/Equipment	20
487.20	NGV Cylinders	15
488.10	Telephone Equipment	15
488.20	Radio Equipment	15
474.02	New Meter Installations	22

For the purpose of calculating annual amortization amounts as of December 31, 2014, 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. 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. The 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.

PART IV. RESULTS OF STUDY

PART IV. RESULTS OF STUDY

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.

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 natural gas utilities. The results of the statistical analysis of service life are presented in the section beginning on page V-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, 2014 are presented in account sequence starting on page VII-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.

TABLE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2014
DEPRECIATION RELATED TO LIFE

ACCOUNT	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2014	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	INTANGIBLE PLANT								
401.01	FRANCHISES AND CONSENTS	40-SQ	0	297,252	193,752	103,500	16,036	5.39	6.5
402.01	COMPUTER SOFTWARE APPLICATION 8 YRS	8-SQ	0	115,499,934	48,704,636	66,795,298	14,437,492	12.50 *	4.8
402.02	COMPUTER SOFTWARE APPLICATION 5 YRS	5-SQ	0	24,645,164	10,911,469	13,733,695	4,929,033	20.00 *	3.1
402.03	INTANGIBLE PLANT	40-SQ	0	1,906,591	957,282	949,309	38,359	2.01	24.7
402.11	INTANGIBLE PLANT	40-SQ	0	62,457	62,457	-	-	-	-
	TOTAL INTANGIBLE PLANT			**142,411,398**	**60,829,596**	**81,581,802**	**19,420,920**		
	MANUFACTURING PLANT								
432.00	STRUCTURES	40-SQ	0	991,630	213,529	778,101	28,002	2.82	27.8
433.00	EQUIPMENT	20-SQ	0	459,212	148,367	310,845	21,404	4.66	14.5
434.00	HOLDERS	40-SQ	0	2,954,850	373,534	2,581,317	72,347	2.45	35.7
436.00	COMPRESSOR EQUIPMENT	25-SQ	0	366,583	75,325	291,258	13,475	3.68	21.6
437.00	MEASURING AND REGULATING EQUIPMENT	20-SQ	0	1,133,722	625,531	508,191	26,562	2.34	19.1
	TOTAL MANUFCTURING PLANT			**5,905,997**	**1,436,285**	**4,469,712**	**161,790**		
	LNG PLANT								
442.00	STRUCTURES	25-L2	0	5,165,898	2,938,220	2,227,678	156,291	3.03	14.3
442.01	STRUCTURES - MT. HAYES	25-R3	0	17,309,159	2,474,617	14,834,542	671,944	3.88	22.1
443.00	EQUIPMENT	40-L4	0	16,498,616	9,794,114	6,704,502	310,378	1.88	21.6
443.05	EQUIPMENT - MT. HAYES	60-R5	0	60,112,269	3,595,459	56,516,810	991,523	1.65	57.0
448.10	PIPING	40-R3	0	11,488,418	1,028,667	10,459,751	282,238	2.46	37.1
448.20	PRE-TREATMENT	25-R3	0	28,713,520	4,113,590	24,599,929	1,114,632	3.88	22.1
448.30	LIQUEFACTION EQUIPMENT	40-R3	0	28,713,520	2,570,994	26,142,526	705,411	2.46	37.1
448.40	SEND OUT EQUIPMENT	40-R2	0	22,960,238	2,055,848	20,904,391	560,289	2.44	37.3
448.50	SUBSTATION AND ELECTRICAL	40-R2	0	21,643,950	1,938,069	19,705,881	528,166	2.44	37.3
448.60	CONTROL ROOM	15-R3	0	5,900,055	1,409,478	4,490,578	371,429	6.30	12.1
449.00	OTHER EQUIPMENT	27-R3	0	25,130,604	12,106,576	13,024,029	962,034	3.83	13.5
449.01	OTHER EQUIPMENT - MT. HAYES	35-R3	0	3,578,672	4,883	3,573,789	102,183	2.86	35.0
465.30	MAINS - MT. HAYES	65-SQ	0	6,298,635	404,332	5,894,303	95,069	1.51	62.0
467.00	MEASURING AND REGULATING EQUIPMENT - MT. HAYES	36-S0.5	0	5,341,781	779,900	4,561,881	137,572	2.58	33.2
	TOTAL LNG PLANT			**258,855,336**	**45,214,747**	**213,640,590**	**6,989,159**		
	TRANSMISSION PLANT								
462.00	COMPRESSOR STRUCTURES	30-R4	0	29,554,186	13,019,368	16,534,818	1,036,254	3.51	16.0
463.00	MEASURING AND REGULATING STRUCTURES	38-S2	0	14,207,228	5,797,342	8,409,887	324,803	2.29	25.9
464.00	OTHER STRUCTURES	30-R4	0	6,502,692	2,209,322	4,293,370	238,318	3.66	18.0
465.00	PIPELINE	65-R3	0	1,161,935,514	322,414,348	839,521,166	17,116,585	1.47	49.0
465.11	INTERMEDIATE PIPE - WHISTLER	65-R3	0	42,284,799	3,277,836	39,006,963	648,863	1.53	60.1
466.00	COMPRESSOR EQUIPMENT	35-R4	0	174,208,157	69,489,527	104,718,629	5,032,207	2.89	20.8
467.10	MEASURING AND REGULATING EQUIPMENT	36-S0.5	0	50,624,840	19,039,117	31,585,724	1,221,686	2.41	25.9
467.20	TELEMETRY EQUIPMENT	8-L1	0	12,702,778	6,471,397	6,231,381	1,238,892	9.75	5.0
467.31	INTERMEDIATE PRESSURE - MEASURING AND REGULATING EQUIPMENT - WHISTLER	36-S0.5	0	313,344	62,669	250,675	7,983	2.55	31.4
468.00	COMMUNICATION EQUIPMENT	19-R3	0	4,244,853	3,843,012	401,841	23,852	0.56	16.8
	TOTAL TRANSMISSION PLANT			**1,496,578,392**	**445,623,938**	**1,050,954,454**	**26,889,443**		
	DISTRIBUTION PLANT								
472.00	STRUCTURES	36-R1.5	0	22,265,444	7,111,780	15,153,664	537,668	2.41	28.2
473.00	SERVICES	45-R1	0	1,031,930,810	169,209,225	862,721,585	25,324,443	2.45	34.1
474.00	METER/REGULATOR INSTALLATIONS	20-S0	0	199,417,979	54,152,817	145,265,162	11,937,714	5.99	12.2
474.02	NEW METER INSTALLATIONS	22-SQ	0	68,254,951	3,662,213	64,592,738	3,102,498	4.55 *	21.0
475.00	SYSTEMS - MAINS	64-R2.5	0	1,315,124,578	362,120,024	953,004,554	20,242,413	1.54	47.1
476.00	NGV FUEL EQUIPMENT	7-L0	0	1,110,125	1,551,790	(441,666)	-	-	-
477.10	MEASURING AND REGULATING ADDITIONS	30-R2	0	108,110,154	39,203,485	68,906,669	3,297,227	3.05	20.9
477.20	TELEMETRY	16-L1	0	10,186,273	5,945,244	4,241,030	287,377	2.82	14.8
477.30	MEASURING AND REGULATING EQUIPMENT	15-R2.5	0	163,151	219,911	(56,760)	-	-	-
478.10	METERS	18-R2.5	0	228,519,730	100,812,295	127,707,435	16,196,705	7.09	7.9
478.20	INSTRUMENTS	35-R5	0	12,143,331	4,865,036	7,278,295	362,679	2.99	20.1
	TOTAL DISTRIBUTION PLANT			**2,997,226,526**	**748,853,820**	**2,248,372,706**	**81,288,724**		

FORTISBC ENERGY INC.

TABLE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2014
DEPRECIATION RELATED TO LIFE

ACCOUNT	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2014	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	BIO GAS								
472.20	BIO GAS - STRUCTURES AND IMPROVEMENTS	36-R1.5	0	554,606	23,734	530,872	15,094	2.72	35.2
474.10	BIO GAS - METER/REGULATOR INSTALLATIONS	19-S0	0	178,229	4,544	173,685	9,331	5.24	18.6
475.10	BIO GAS - MAINS	65-R2.5	0	1,388,032	8,974	1,379,057	21,507	1.55	64.1
477.40	BIO GAS - MEASURING AND REGULATING	30-R2	0	1,620,377	91,150	1,529,227	52,520	3.24	29.1
478.30	BIO GAS - METERS	18-R2.5	0	10,926	2,509	8,416	549	5.02	15.3
418.10	BIO GAS - PURIFICATION OVERHAUL	20-SQ	0	20,423	-	20,423	1,021	5.00	20.0
418.20	BIO GAS - PURIFICATION UPGRADER	20-SQ	0	7,017,216	263,370	6,753,846	343,434	4.89	19.7
418.30	BIO GAS - STRUCTURES AND IMPROVEMENTS - POST 2013	36-R1.5	0	-	-	-	-	2.78 **	-
418.40	BIO GAS - REGULATING AND METER INSTALLATIONS - POST 2013	19-S0	0	-	-	-	-	5.26 **	-
418.50	BIO GAS - MAINS - LAND - POST 2013	65-R2.5	0	-	-	-	-	1.54 **	-
418.60	BIO GAS - MEASURING AND REGULATING - POST 2013	30-R2	0	-	-	-	-	6.67 **	-
418.70	BIO GAS - METERS - POST 2013	18-R2.5	0	-	-	-	-	4.78 **	-
	TOTAL BIO GAS			**10,789,808**	**394,281**	**10,395,526**	**443,456**		
	NG FOR TRANSPORTATION								
476.10	CNG DISP EQUIPMENT	20-SQ	0	5,650,910	660,450	4,990,461	282,546	5.00 *	18.4
476.20	LNG DISP EQUIPMENT	20-SQ	0	4,120,206	207,626	3,912,580	206,010	5.00 *	19.9
476.30	CNG FOUNDATION	20-SQ	0	827,141	77,902	749,238	41,357	5.00 *	18.5
476.40	LNG FOUNDATION	20-SQ	0	897,463	52,598	844,865	44,873	5.00 *	19.9
476.50	LNG PUMPS	10-SQ	0	62,632	12,005	50,628	6,263	10.00 *	9.0
476.60	CNG DEHYDRATOR	20-SQ	0	253,327	22,716	230,611	12,666	5.00 *	18.4
	TOTAL NG FOR TRANSPORTATION			**11,811,679**	**1,033,296**	**10,778,383**	**593,716**		
	GENERAL PLANT								
482.10	STRUCTURES (FRAME)	20-R2.5	0	18,809,676	6,165,550	12,644,126	1,136,559	6.04	11.1
482.20	STRUCTURES (MASONRY)	50-R2.5	0	108,522,328	20,696,465	87,825,862	2,121,584	1.95	41.4
483.10	COMPUTER HARDWARE	5-SQ	0	41,308,322	16,722,561	24,585,761	8,261,664	20.00 *	3.2
483.20	COMPUTER SOFTWARE (12.5%)	8-SQ	0	5,757,824	2,081,336	3,676,488	719,728	12.50 *	5.9
483.30	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	3,901,127	1,851,733	2,049,395	260,075	6.67 *	5.3
483.40	FURNITURE	20-SQ	0	19,019,220	10,009,665	9,009,555	950,961	5.00 *	10.5
484.00	VEHICLES	6-L0.5	0	10,063,916	4,983,838	5,080,079	1,061,432	10.55	4.8
485.10	HEAVY WORK EQUIPMENT	12-L0.5	0	897,258	390,373	506,885	57,202	6.38	8.9
485.20	HEAVY MOBILE EQUIPMENT	8-L2	0	4,219,017	1,557,354	2,661,663	415,429	9.85	6.4
486.00	SMALL TOOLS/EQUIPMENT	20-SQ	0	48,317,938	21,823,736	26,494,202	2,415,897	5.00 *	11.3
487.20	NGV CYLINDERS	15-SQ	0	24,167	14,748	9,419	1,611	6.67 *	7.2
488.10	TELEPHONE EQUIPMENT	15-SQ	0	6,053,746	3,655,815	2,397,931	403,583	6.67 *	3.2
488.20	RADIO EQUIPMENT	15-SQ	0	8,801,592	2,814,037	5,987,556	586,773	6.67 *	12.1
	TOTAL GENERAL PLANT			**275,696,133**	**92,767,210**	**182,928,922**	**18,392,499**		
	TOTAL DEPRECIABLE PLANT			**5,199,275,270**	**1,396,153,173**	**3,803,122,095**	**154,179,706**		
	PLANT NOT STUDIED								
175.00	UNAMORTIZED CONVERSION/EXPENSE			885,988					
178.00	ORGANIZATIONAL COSTS			728,114					
430.00	MANUFACTURING PLANT - LAND			31,008					
440.00	LNG GAS PLANT - LAND			16,247,087					
460.00	TRANSMISSION PLANT - LAND			10,626,627					
461.02	MT. HAYES - LAND RIGHTS			610,017					
461.13	IP - LAND RIGHTS - WHISTLER			23,738					
465.10	TRANSMISSION PIPELINE - BYRON CREEK			1,354,756					
465.20	TRANSMISSION PLANT - INSPECTION			18,172,540					
466.01	TRANSMISSION PLANT - LAND RIGHTS			52,191,190					
461.12	TRANSMISSION PLANT - LAND RIGHTS - BYRON CREEK			16,166					
466.10	TRANSMISSION PLANT - COMPRESSOR OVERHAUL			3,856,349					
467.30	TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT - BYRON CREEK			38,716	10,431				
470.00	DISTRIBUTION SYSTEMS - LAND			4,207,335					
471.01	DISTRIBUTION SYSTEMS - LAND RIGHTS			3,208,032	10,185				
471.11	DISTRIBUTION SYSTEMS - LAND RIGHTS - BYRON CREEK			1,140					
472.10	DISTRIBUTION SYSTEMS - STRUCTURES - BYRON CREEK			114,963					
480.00	GENERAL PLANT - LAND			29,362,820					
482.30	GENERAL PLANT - STRUCTURES - LEASED			4,949,376					
484.10	CAPTIAL LEASE VEHICLE			28,133,835					
	TOTAL PLANT NOT STUDIED			**174,759,799**	**20,616**				
	TOTAL PLANT			**5,374,035,068**	**1,396,173,788**				

Notes:
* Rates determined as reciprocal of Average Service Life.
** Rates based on current vintage theoretical values.

FORTISBC ENERGY INC.

TABLE 1B. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2014
DEPRECIATION RELATED TO NET SALVAGE

ACCOUNT	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2014	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	INTANGIBLE PLANT								
401.01	FRANCHISES AND CONSENTS	40-SQ	0	297,252	-	-	-	-	6.5
402.01	COMPUTER SOFTWARE APPLICATION 8 YRS	8-SQ	0	115,499,934	-	-	-	- *	4.8
402.02	COMPUTER SOFTWARE APPLICATION 5 YRS	5-SQ	0	24,645,164	-	-	-	- *	3.1
402.03	INTANGIBLE PLANT	40-SQ	0	1,906,591	-	-	-	-	24.7
402.11	INTANGIBLE PLANT	40-SQ	0	62,457	-	-	-	-	0.0
	TOTAL INTANGIBLE PLANT			**142,411,398**	-	-	-		
	MANUFACTURING PLANT								
432.00	STRUCTURES	40-SQ	0	991,630	-	-	-	-	27.8
433.00	EQUIPMENT	20-SQ	0	459,212	-	-	-	-	14.5
434.00	HOLDERS	40-SQ	0	2,954,850	-	-	-	-	35.7
436.00	COMPRESSOR EQUIPMENT	25-SQ	0	366,583	-	-	-	-	21.6
437.00	MEASURING AND REGULATING EQUIPMENT	20-SQ	0	1,133,722	(4,903)	4,903	278	0.03	19.1
	TOTAL MANUFCTURING PLANT			**5,905,997**	**(4,903)**	**4,903**	**278**		
	LNG PLANT								
442.00	STRUCTURES	25-L2	(10)	5,165,898	258,218	258,371	18,666	0.36	14.2
442.01	STRUCTURES - MT. HAYES	25-R3	(10)	17,309,159	-	1,730,916	78,407	0.45	22.1
443.00	EQUIPMENT	40-L4	(20)	16,498,616	1,762,026	1,537,697	73,444	0.45	21.5
443.05	EQUIPMENT - MT. HAYES	60-R5	(20)	60,112,269	-	12,022,454	210,920	0.35	57.0
448.10	PIPING	40-R3	(10)	11,488,418	-	1,148,841	31,000	0.27	37.1
448.20	PRE-TREATMENT	25-R3	(10)	28,713,520	-	2,871,352	130,102	0.46	22.1
448.30	LIQUEFACTION EQUIPMENT	40-R3	(20)	28,713,520	-	5,742,704	154,957	0.54	37.1
448.40	SEND OUT EQUIPMENT	40-R2	(10)	22,960,238	-	2,296,023	61,539	0.27	37.3
448.50	SUBSTATION AND ELECTRICAL	40-R2	(20)	21,643,950	-	4,328,790	116,022	0.54	37.3
448.60	CONTROL ROOM	15-R3	0	5,900,055	-	-	-	-	12.1
449.00	OTHER EQUIPMENT	27-R3	(10)	25,130,604	1,201,644	1,311,416	97,238	0.39	13.5
449.01	OTHER EQUIPMENT - MT. HAYES	35-R3	(10)	3,578,672	-	357,867	10,233	0.28	35.0
465.30	MAINS - MT. HAYES	65-SQ	(20)	6,298,635	0	1,259,727	20,319	0.32	62.0
467.00	MEASURING AND REGULATING EQUIPMENT - MT. HAYES	36-S0.5	(7)	5,341,781	0	373,924	11,276	0.21	33.2
	TOTAL LNG PLANT			**258,855,336**	**3,221,889**	**35,240,082**	**1,014,123**		
	TRANSMISSION PLANT								
462.00	COMPRESSOR STRUCTURES	30-R4	(3)	29,554,186	793,577	93,048	(5,499)	(0.02)	16.1
463.00	MEASURING AND REGULATING STRUCTURES	38-S2	(15)	14,207,228	190,652	1,940,432	82,123	0.57	25.4
464.00	OTHER STRUCTURES	30-R4	(5)	6,502,692	79,706	245,429	13,927	0.22	18.0
465.00	PIPELINE	65-R3	(20)	1,161,935,514	27,853,454	204,533,649	4,290,255	0.37	48.8
465.11	INTERMEDIATE PIPE - WHISTLER	65-R3	(20)	42,284,799	-	8,456,960	140,680	0.34	60.1
466.00	COMPRESSOR EQUIPMENT	35-R4	(2)	174,208,157	6,400,575	(2,916,412)	(212,780)	(0.12)	21.1
467.10	MEASURING AND REGULATING EQUIPMENT	36-S0.5	(7)	50,624,840	780,557	2,763,181	110,841	0.22	25.8
467.20	TELEMETRY EQUIPMENT	8-L1	0	12,702,778	230	(231)	(109)	-	5.0
467.31	INTERMEDIATE PRESSURE - MEASURING AND REGULATING EQUIPMENT - WHISTLER	36-S0.5	(7)	313,344	-	21,934	699	0.22	31.4
468.00	COMMUNICATION EQUIPMENT	19-R3	0	4,244,853	266,711	(266,710)	(16,353)	(0.38)	18.0
	TOTAL TRANSMISSION PLANT			**1,496,578,392**	**36,365,462**	**214,871,280**	**4,403,784**		
	DISTRIBUTION PLANT								
472.00	STRUCTURES	36-R1.5	(10)	22,265,444	338,363	1,888,182	69,939	0.32	28.0
473.00	SERVICES	45-R1	(60)	1,031,930,810	62,944,276	556,214,210	16,554,263	1.61	33.9
474.00	METER/REGULATOR INSTALLATIONS	20-S0	(20)	199,417,979	241,779	39,641,817	3,533,573	1.77	12.0
474.02	NEW METER INSTALLATIONS	22-SQ	0	68,254,951	(284,719)	284,719	-	- *	21.0
475.00	SYSTEMS - MAINS	64-R2.5	(25)	1,315,124,578	66,562,998	262,218,147	5,674,023	0.43	46.9
476.00	NGV FUEL EQUIPMENT	7-L0	0	1,110,125	457,383	(457,383)	-	-	0.0
477.10	MEASURING AND REGULATING ADDITIONS	30-R2	(10)	108,110,154	1,357,574	9,453,442	499,186	0.46	20.6
477.20	TELEMETRY	16-L1	(5)	10,186,273	(11,548)	520,861	42,797	0.42	14.4
477.30	MEASURING AND REGULATING EQUIPMENT	15-R2.5	0	163,151	-	-	-	-	0.0
478.10	METERS	18-R2.5	0	228,519,730	2,435,172	(2,435,172)	(593,994)	(0.26)	8.0
478.20	INSTRUMENTS	35-R5	0	12,143,331	-	-	-	-	20.1
	TOTAL DISTRIBUTION PLANT			**2,997,226,526**	**134,041,278**	**867,328,823**	**25,779,787**		

FORTISBC ENERGY INC.

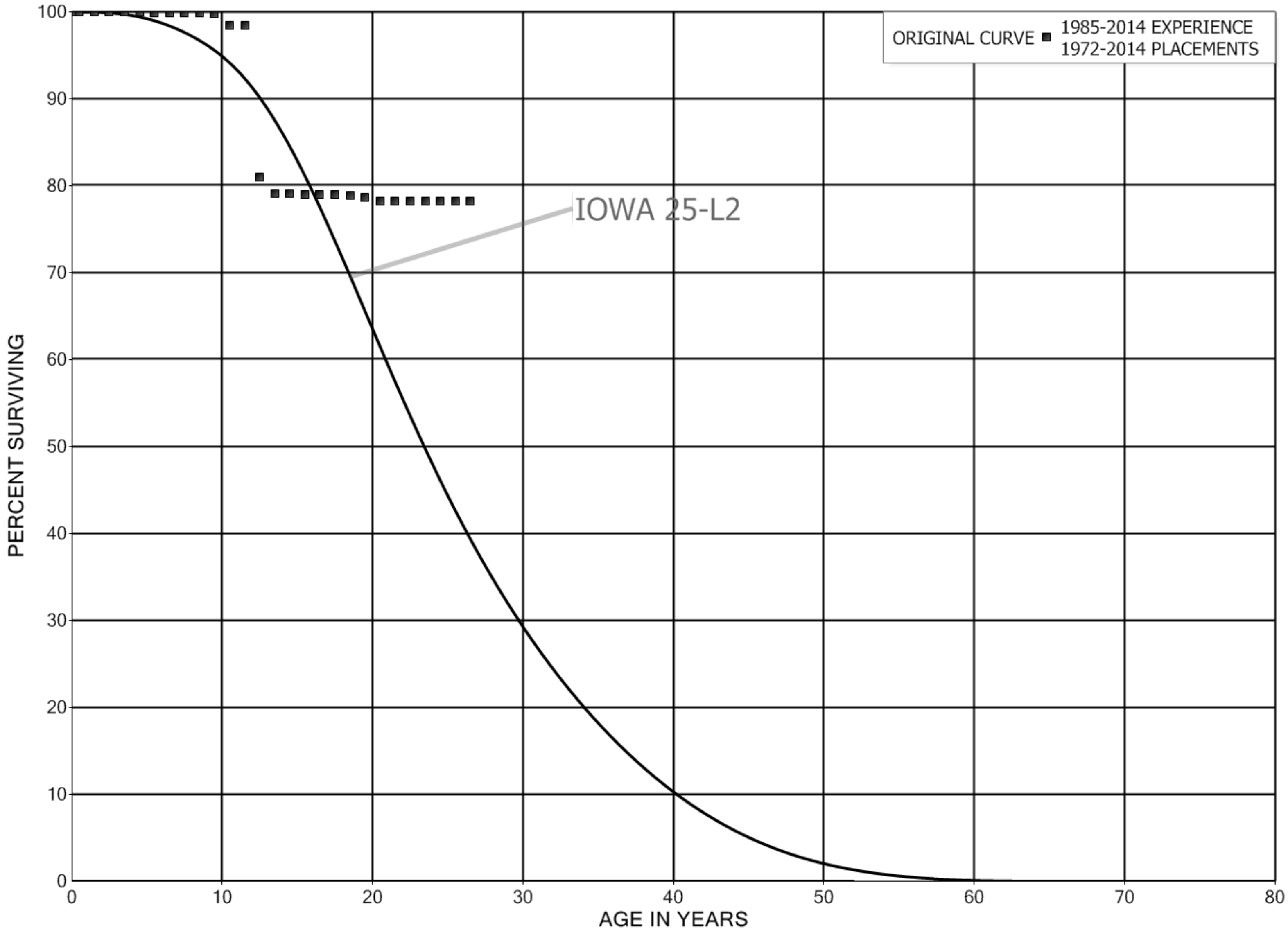
TABLE 1B. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2014
DEPRECIATION RELATED TO NET SALVAGE

ACCOUNT	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AT DECEMBER 31, 2014	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	BIO GAS								
472.20	BIO GAS - STRUCTURES AND IMPROVEMENTS	36-R1.5	(10)	554,606	265	55,196	1,573	0.29	35.2
474.10	BIO GAS - METER/REGULATOR INSTALLATIONS	19-S0	(25)	178,229	-	44,557	2,406	1.35	18.6
475.10	BIO GAS - MAINS	65-R2.5	(25)	1,388,032	2,405	344,604	5,375	0.39	64.1
477.40	BIO GAS - MEASURING AND REGULATING	30-R2	0	1,620,377	51	(51)	(1)	-	29.1
478.30	BIO GAS - METERS	18-R2.5	0	10,926	323	(323)	(23)	(0.21)	15.4
418.10	BIO GAS - PURIFICATION OVERHAUL	20-SQ	0	20,423	-	-	-	-	20.0
418.20	BIO GAS - PURIFICATION UPGRADER	20-SQ	(5)	7,017,216	-	350,861	17,863	0.26	19.7
418.30	BIO GAS - STRUCTURES AND IMPROVEMENTS - POST 2013	36-R1.5	(10)	-	-	-	-	0.28 **	-
418.40	BIO GAS - REGULATING AND METER INSTALLATIONS - POST 2013	19-S0	(25)	-	-	-	-	1.32 **	-
418.50	BIO GAS - MAINS - LAND - POST 2013	65-R2.5	(25)	-	-	-	-	0.38 **	-
418.60	BIO GAS - MEASURING AND REGULATING - POST 2013	30-R2	0	-	-	-	-	- **	-
418.70	BIO GAS - METERS - POST 2013	18-R2.5	0	-	-	-	-	- **	-
	TOTAL BIO GAS			**10,789,808**	**3,045**	**794,844**	**27,193**		
	NG FOR TRANSPORTATION								
476.10	CNG DISP EQUIPMENT	20-SQ	0	5,650,910	(1,447)	1,447	-	- *	18.4
476.20	LNG DISP EQUIPMENT	20-SQ	0	4,120,206	-	-	-	- *	19.9
476.30	CNG FOUNDATION	20-SQ	0	827,141	-	-	-	- *	18.5
476.40	LNG FOUNDATION	20-SQ	0	897,463	-	-	-	- *	19.9
476.50	LNG PUMPS	10-SQ	0	62,632	-	-	-	- *	9.0
476.60	CNG DEHYDRATOR	20-SQ	0	253,327	-	-	-	- *	18.4
	TOTAL NG FOR TRANSPORTATION			**11,811,679**	**(1,447)**	**1,447**	**-**		
	GENERAL PLANT								
482.10	STRUCTURES (FRAME)	20-R2.5	0	18,809,676	-	-	-	-	11.1
482.20	STRUCTURES (MASONRY)	50-R2.5	(10)	108,522,328	(502)	10,852,735	268,776	0.25	41.3
483.10	COMPUTER HARDWARE	5-SQ	0	41,308,322	-	-	-	- *	3.2
483.20	COMPUTER SOFTWARE (12.5%)	8-SQ	0	5,757,824	-	-	-	- *	5.9
483.30	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	3,901,127	-	-	-	- *	5.3
483.40	FURNITURE	20-SQ	0	19,019,220	-	-	-	- *	10.5
484.00	VEHICLES	6-L0.5	4	10,063,916	-	(402,557)	(100,758)	(1.00)	4.9
485.10	HEAVY WORK EQUIPMENT	12-L0.5	5	897,258	-	(44,863)	(6,094)	(0.68)	9.0
485.20	HEAVY MOBILE EQUIPMENT	8-L2	15	4,219,017	-	(632,853)	(121,857)	(2.89)	6.9
486.00	SMALL TOOLS/EQUIPMENT	20-SQ	0	48,317,938	-	-	-	- *	11.3
487.20	NGV CYLINDERS	15-SQ	0	24,167	-	-	-	- *	7.2
488.10	TELEPHONE EQUIPMENT	15-SQ	0	6,053,746	-	-	-	- *	3.2
488.20	RADIO EQUIPMENT	15-SQ	0	8,801,592	(6,800)	6,800	-	- *	12.1
	TOTAL GENERAL PLANT			**275,696,133**	**(7,302)**	**9,779,262**	**40,067**		
	TOTAL DEPRECIABLE PLANT			**5,199,275,270**	**173,618,021**	**1,128,020,641**	**31,265,232**		
	PLANT NOT STUDIED								
175.00	UNAMORTIZED CONVERSION/EXPENSE			885,988					
178.00	ORGANIZATIONAL COSTS			728,114					
430.00	MANUFACTURING PLANT - LAND			31,008					
440.00	LNG GAS PLANT - LAND			16,247,087					
460.00	TRANSMISSION PLANT - LAND			10,626,627					
461.02	MT. HAYES - LAND RIGHTS			610,017					
461.13	IP - LAND RIGHTS - WHISTLER			23,738					
465.10	TRANSMISSION PIPELINE - BYRON CREEK			1,354,756					
465.20	TRANSMISSION PLANT - INSPECTION			18,172,540					
466.01	TRANSMISSION PLANT - LAND RIGHTS			52,191,190					
461.12	TRANSMISSION PLANT - LAND RIGHTS - BYRON CREEK			16,166					
466.10	TRANSMISSION PLANT - COMPRESSOR OVERHAUL			3,856,349					
467.30	TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT - BYRON CREEK			38,716					
470.00	DISTRIBUTION SYSTEMS - LAND			4,207,335					
471.01	DISTRIBUTION SYSTEMS - LAND RIGHTS			3,208,032					
471.11	DISTRIBUTION SYSTEMS - LAND RIGHTS - BYRON CREEK			1,140					
472.10	DISTRIBUTION SYSTEMS - STRUCTURES - BYRON CREEK			114,963					
480.00	GENERAL PLANT - LAND			29,362,820					
482.30	GENERAL PLANT - STRUCTURES - LEASED			4,949,376					
484.10	CAPTIAL LEASE VEHICLE			28,133,835					
	TOTAL PLANT NOT STUDIED			**174,759,799**					
	TOTAL PLANT			**5,374,035,068**	**173,618,021**				

Notes:
* Rates determined as reciprocal of Average Service Life.
** Rates based on current vintage theoretical values.

PART V. SERVICE LIFE STATISTICS

FORTISBC ENERGY INC.
ACCOUNT 442.00 - LNG PLANT - STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

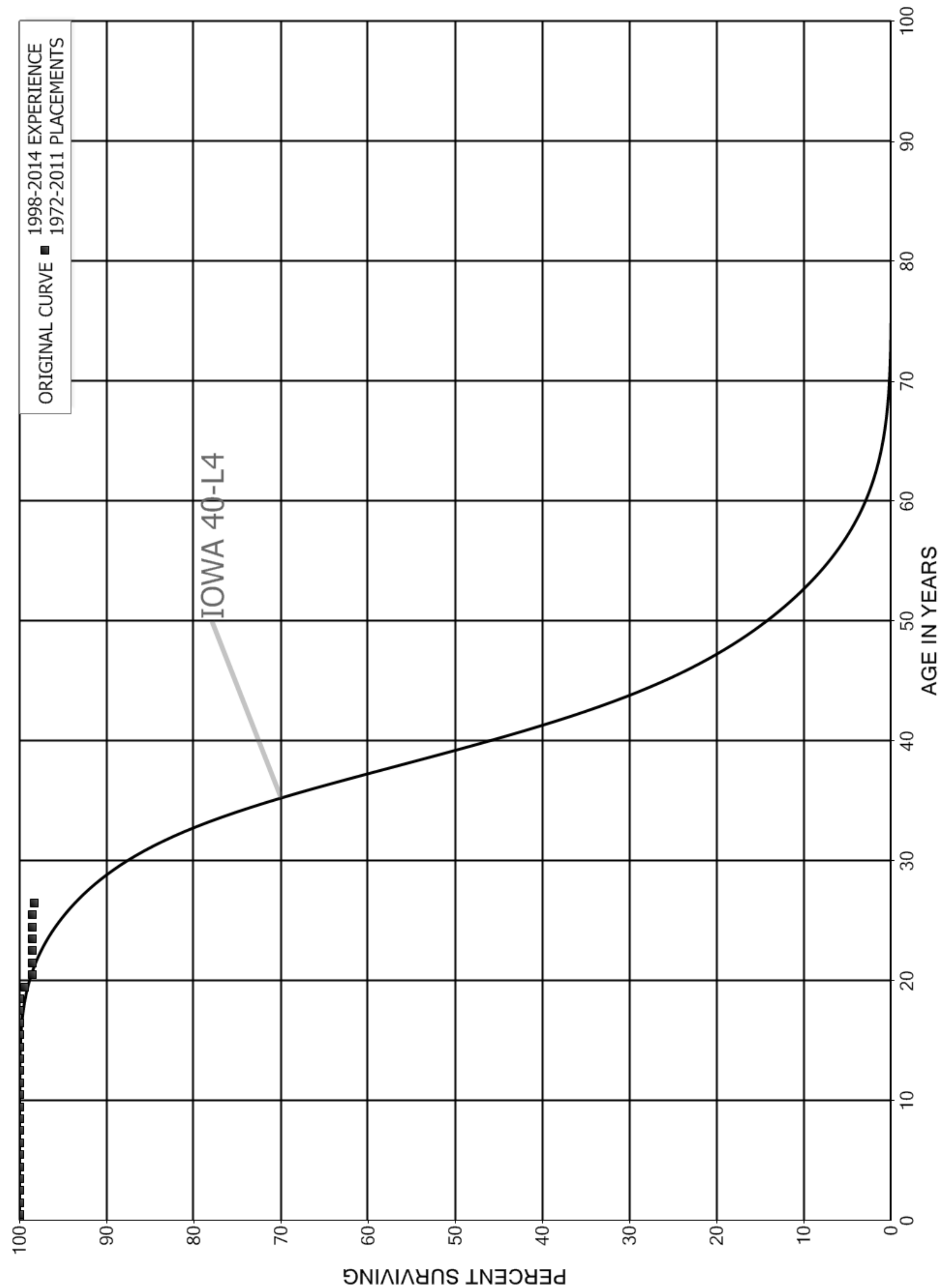
ACCOUNT 442.00 - LNG PLANT - STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2014 EXPERIENCE BAND 1985-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	23,259,293		0.0000	1.0000	100.00
0.5	23,027,358		0.0000	1.0000	100.00
1.5	23,004,742		0.0000	1.0000	100.00
2.5	23,004,742		0.0000	1.0000	100.00
3.5	5,743,699		0.0000	1.0000	100.00
4.5	5,668,816	11,458	0.0020	0.9980	100.00
5.5	5,657,358		0.0000	1.0000	99.80
6.5	5,631,369		0.0000	1.0000	99.80
7.5	5,360,767		0.0000	1.0000	99.80
8.5	5,347,155	1,000	0.0002	0.9998	99.80
9.5	4,557,697	61,358	0.0135	0.9865	99.78
10.5	4,479,343		0.0000	1.0000	98.44
11.5	3,775,087	669,121	0.1772	0.8228	98.44
12.5	3,119,523	74,954	0.0240	0.9760	80.99
13.5	2,949,750		0.0000	1.0000	79.04
14.5	2,631,001	2,477	0.0009	0.9991	79.04
15.5	2,494,631		0.0000	1.0000	78.97
16.5	2,097,885		0.0000	1.0000	78.97
17.5	1,851,772	1,959	0.0011	0.9989	78.97
18.5	1,807,033	6,000	0.0033	0.9967	78.88
19.5	1,668,452	10,373	0.0062	0.9938	78.62
20.5	1,573,517		0.0000	1.0000	78.13
21.5	1,565,423		0.0000	1.0000	78.13
22.5	1,454,996		0.0000	1.0000	78.13
23.5	1,453,071		0.0000	1.0000	78.13
24.5	1,453,071		0.0000	1.0000	78.13
25.5	1,453,071		0.0000	1.0000	78.13
26.5					78.13

FORTISBC ENERGY INC.
ACCOUNT 443.00 - LNG PLANT - EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

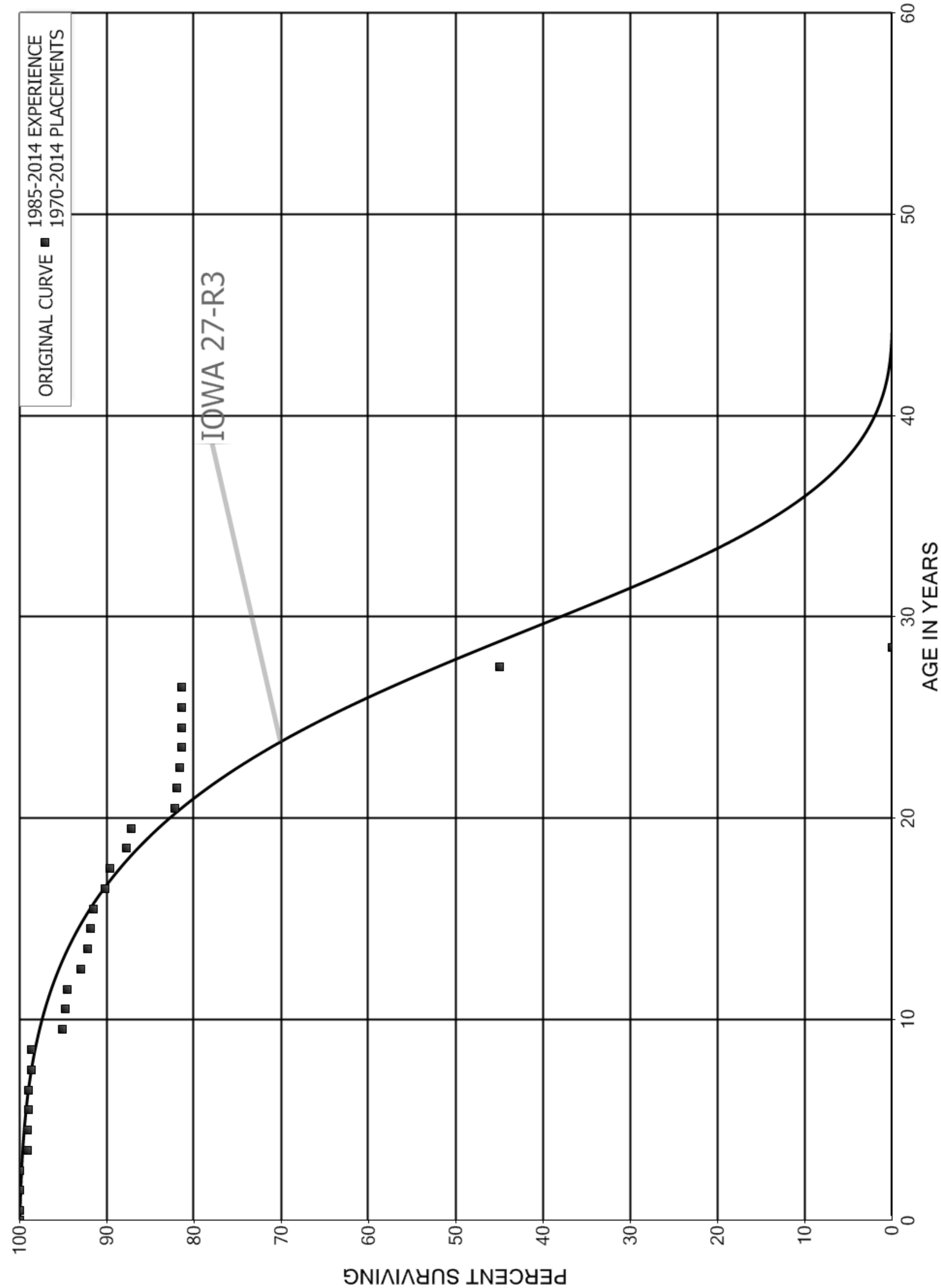
ACCOUNT 443.00 - LNG PLANT - EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1972-2011 EXPERIENCE BAND 1998-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	66,889,390		0.0000	1.0000	100.00
0.5	67,073,994		0.0000	1.0000	100.00
1.5	67,467,467		0.0000	1.0000	100.00
2.5	67,467,467		0.0000	1.0000	100.00
3.5	7,350,598		0.0000	1.0000	100.00
4.5	7,425,758	1,000	0.0001	0.9999	100.00
5.5	7,426,492		0.0000	1.0000	99.99
6.5	7,456,439		0.0000	1.0000	99.99
7.5	7,456,178		0.0000	1.0000	99.99
8.5	7,404,680		0.0000	1.0000	99.99
9.5	16,456,701	12,708	0.0008	0.9992	99.99
10.5	16,369,548		0.0000	1.0000	99.91
11.5	16,186,007		0.0000	1.0000	99.91
12.5	10,881,937		0.0000	1.0000	99.91
13.5	10,779,642		0.0000	1.0000	99.91
14.5	10,697,721		0.0000	1.0000	99.91
15.5	9,950,987	1,734	0.0002	0.9998	99.91
16.5	9,846,829		0.0000	1.0000	99.89
17.5	9,662,224		0.0000	1.0000	99.89
18.5	9,268,752	44,685	0.0048	0.9952	99.89
19.5	9,224,067	79,648	0.0086	0.9914	99.41
20.5	9,144,419		0.0000	1.0000	98.55
21.5	9,081,967		0.0000	1.0000	98.55
22.5	9,081,967		0.0000	1.0000	98.55
23.5	9,052,020		0.0000	1.0000	98.55
24.5	9,052,020		0.0000	1.0000	98.55
25.5	9,079,360	27,340	0.0030	0.9970	98.55
26.5					98.26

FORTISBC ENERGY INC.
ACCOUNT 449.00 - LNG PLANT - OTHER EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

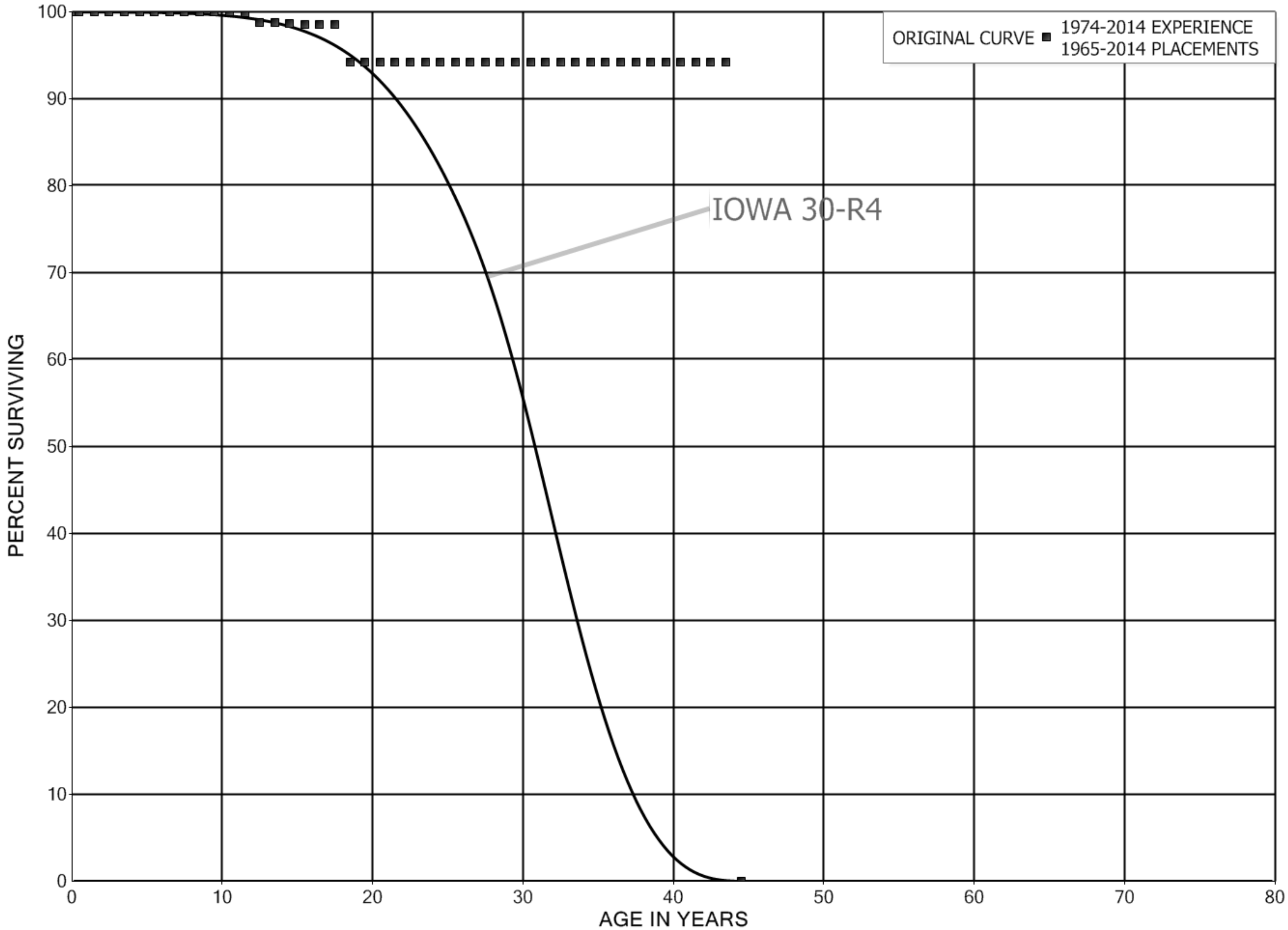
ACCOUNT 449.00 - LNG PLANT - OTHER EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2014 EXPERIENCE BAND 1985-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	31,328,897	500	0.0000	1.0000	100.00
0.5	27,714,740		0.0000	1.0000	100.00
1.5	27,688,089	1	0.0000	1.0000	100.00
2.5	27,019,945	258,133	0.0096	0.9904	100.00
3.5	26,711,841	48	0.0000	1.0000	99.04
4.5	26,087,355	10,802	0.0004	0.9996	99.04
5.5	24,292,786	21,004	0.0009	0.9991	99.00
6.5	20,114,372	56,589	0.0028	0.9972	98.92
7.5	19,698,704	9,223	0.0005	0.9995	98.64
8.5	19,383,729	698,665	0.0360	0.9640	98.59
9.5	18,486,077	70,887	0.0038	0.9962	95.04
10.5	18,383,094	25,930	0.0014	0.9986	94.67
11.5	16,561,107	286,493	0.0173	0.9827	94.54
12.5	16,149,403	123,449	0.0076	0.9924	92.90
13.5	16,058,920	67,845	0.0042	0.9958	92.19
14.5	15,093,401	41,927	0.0028	0.9972	91.81
15.5	14,402,176	215,295	0.0149	0.9851	91.55
16.5	14,168,321	85,676	0.0060	0.9940	90.18
17.5	14,001,515	300,308	0.0214	0.9786	89.64
18.5	12,899,295	71,537	0.0055	0.9945	87.71
19.5	9,956,240	578,265	0.0581	0.9419	87.23
20.5	9,182,328	27,751	0.0030	0.9970	82.16
21.5	6,817,686	21,715	0.0032	0.9968	81.91
22.5	6,233,044	20,000	0.0032	0.9968	81.65
23.5	5,658,581		0.0000	1.0000	81.39
24.5	5,658,581		0.0000	1.0000	81.39
25.5	5,658,581	9	0.0000	1.0000	81.39
26.5	121,635	54,471	0.4478	0.5522	81.39
27.5	67,164	67,164	1.0000		44.94
28.5					

FORTISBC ENERGY INC.
ACCOUNT 462.00 - TRANSMISSION PLANT - COMPRESSOR STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 462.00 - TRANSMISSION PLANT - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2014 EXPERIENCE BAND 1974-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	30,150,474		0.0000	1.0000	100.00
0.5	30,214,336		0.0000	1.0000	100.00
1.5	29,552,263	1,338	0.0000	1.0000	100.00
2.5	27,619,186		0.0000	1.0000	100.00
3.5	27,052,666	1,225	0.0000	1.0000	100.00
4.5	26,826,124	7,893	0.0003	0.9997	99.99
5.5	26,368,475	6,379	0.0002	0.9998	99.96
6.5	26,185,296	2,414	0.0001	0.9999	99.94
7.5	24,521,618	659	0.0000	1.0000	99.93
8.5	24,495,861	3,363	0.0001	0.9999	99.93
9.5	24,492,498	3,380	0.0001	0.9999	99.91
10.5	24,321,397	6,438	0.0003	0.9997	99.90
11.5	24,203,583	288,000	0.0119	0.9881	99.87
12.5	21,987,109	1,162	0.0001	0.9999	98.68
13.5	21,200,269	15,868	0.0007	0.9993	98.68
14.5	16,836,519	14,083	0.0008	0.9992	98.60
15.5	14,272,215	1,961	0.0001	0.9999	98.52
16.5	10,941,205	3,140	0.0003	0.9997	98.51
17.5	10,543,133	458,159	0.0435	0.9565	98.48
18.5	9,652,000		0.0000	1.0000	94.20
19.5	5,027,371		0.0000	1.0000	94.20
20.5	3,580,341		0.0000	1.0000	94.20
21.5	2,397,634		0.0000	1.0000	94.20
22.5	2,146,598		0.0000	1.0000	94.20
23.5	293,960		0.0000	1.0000	94.20
24.5	262,661		0.0000	1.0000	94.20
25.5	260,102		0.0000	1.0000	94.20
26.5	257,546		0.0000	1.0000	94.20
27.5	257,546		0.0000	1.0000	94.20
28.5	257,546		0.0000	1.0000	94.20
29.5	257,546		0.0000	1.0000	94.20
30.5	256,651		0.0000	1.0000	94.20
31.5	256,651		0.0000	1.0000	94.20
32.5	255,405		0.0000	1.0000	94.20
33.5	255,405		0.0000	1.0000	94.20
34.5	254,790		0.0000	1.0000	94.20
35.5	254,790		0.0000	1.0000	94.20
36.5	248,874		0.0000	1.0000	94.20
37.5	248,807		0.0000	1.0000	94.20
38.5	248,807		0.0000	1.0000	94.20

FORTISBC ENERGY INC.

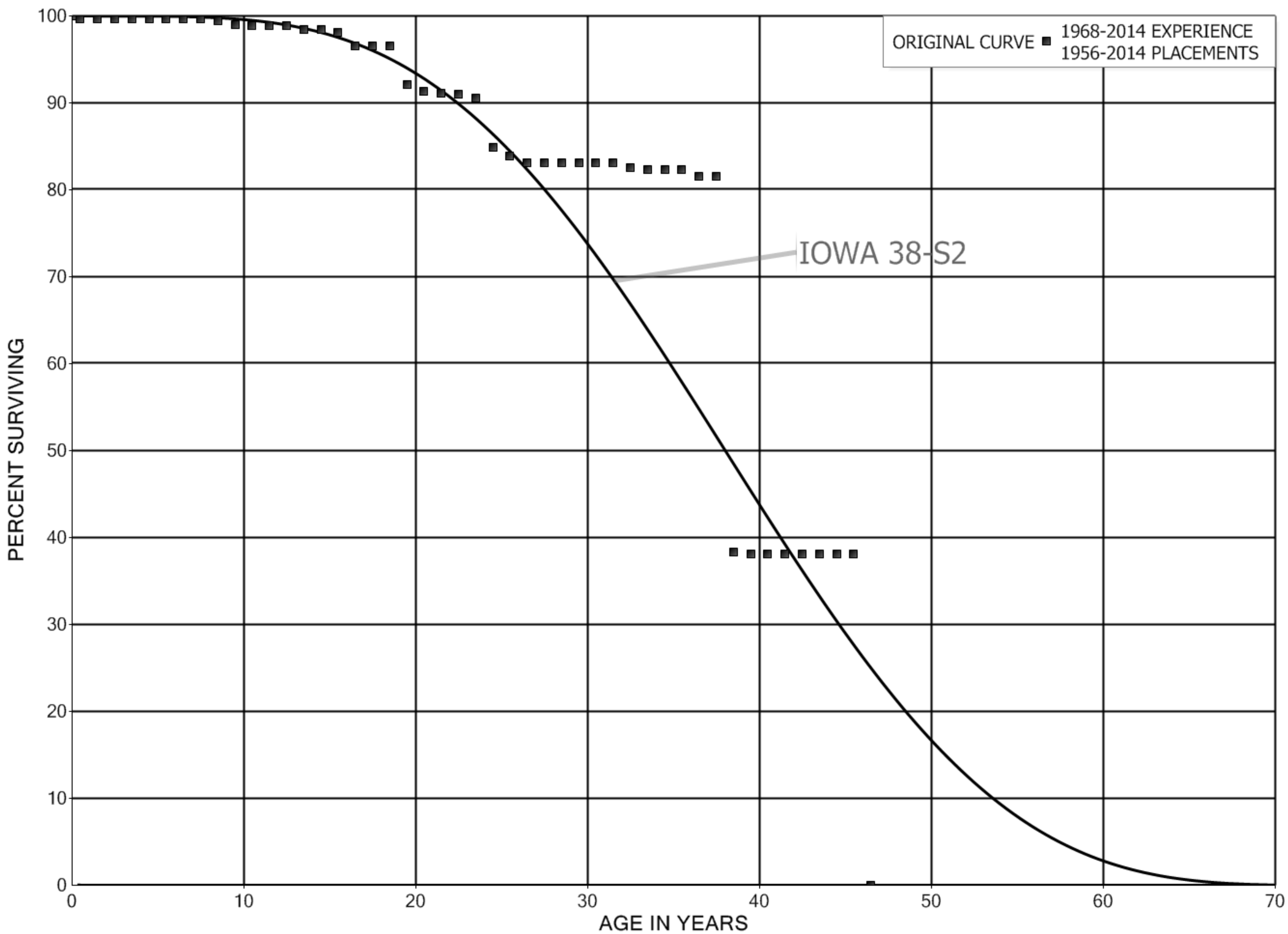
ACCOUNT 462.00 - TRANSMISSION PLANT - COMPRESSOR STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2014 EXPERIENCE BAND 1974-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	242,648		0.0000	1.0000	94.20
40.5	242,648		0.0000	1.0000	94.20
41.5	27,247		0.0000	1.0000	94.20
42.5	27,247		0.0000	1.0000	94.20
43.5	27,247	27,247	1.0000		94.20
44.5					

FORTISBC ENERGY INC.
ACCOUNT 463.00 - TRANSMISSION PLANT - MEASURING AND REGULATING STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 463.00 - TRANSMISSION PLANT - MEASURING AND REGULATING STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2014 EXPERIENCE BAND 1968-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,793,570	53,753	0.0036	0.9964	100.00
0.5	14,614,071	3	0.0000	1.0000	99.64
1.5	13,715,698	23	0.0000	1.0000	99.64
2.5	13,581,501	142	0.0000	1.0000	99.64
3.5	13,447,099	167	0.0000	1.0000	99.64
4.5	13,173,975	617	0.0000	1.0000	99.63
5.5	12,879,146	244	0.0000	1.0000	99.63
6.5	12,770,244	6,386	0.0005	0.9995	99.63
7.5	11,006,412	17,727	0.0016	0.9984	99.58
8.5	9,204,188	48,726	0.0053	0.9947	99.42
9.5	9,005,595	4,013	0.0004	0.9996	98.89
10.5	8,635,319	544	0.0001	0.9999	98.85
11.5	8,485,093	437	0.0001	0.9999	98.84
12.5	7,674,196	36,190	0.0047	0.9953	98.84
13.5	7,532,145	955	0.0001	0.9999	98.37
14.5	7,131,884	22,233	0.0031	0.9969	98.36
15.5	6,489,462	100,090	0.0154	0.9846	98.05
16.5	6,268,840	113	0.0000	1.0000	96.54
17.5	6,047,093	59	0.0000	1.0000	96.54
18.5	5,695,553	265,851	0.0467	0.9533	96.54
19.5	4,957,264	41,956	0.0085	0.9915	92.03
20.5	4,844,112	10,287	0.0021	0.9979	91.25
21.5	4,659,769	6,227	0.0013	0.9987	91.06
22.5	4,391,888	18,950	0.0043	0.9957	90.94
23.5	352,209	22,385	0.0636	0.9364	90.54
24.5	324,575	3,756	0.0116	0.9884	84.79
25.5	318,916	3,000	0.0094	0.9906	83.81
26.5	128,940		0.0000	1.0000	83.02
27.5	120,536		0.0000	1.0000	83.02
28.5	119,171		0.0000	1.0000	83.02
29.5	116,128		0.0000	1.0000	83.02
30.5	107,212		0.0000	1.0000	83.02
31.5	107,212	622	0.0058	0.9942	83.02
32.5	105,343	322	0.0031	0.9969	82.54
33.5	105,021		0.0000	1.0000	82.28
34.5	103,359		0.0000	1.0000	82.28
35.5	103,359	1,000	0.0097	0.9903	82.28
36.5	102,359		0.0000	1.0000	81.49
37.5	102,359	54,267	0.5302	0.4698	81.49
38.5	48,092	230	0.0048	0.9952	38.29

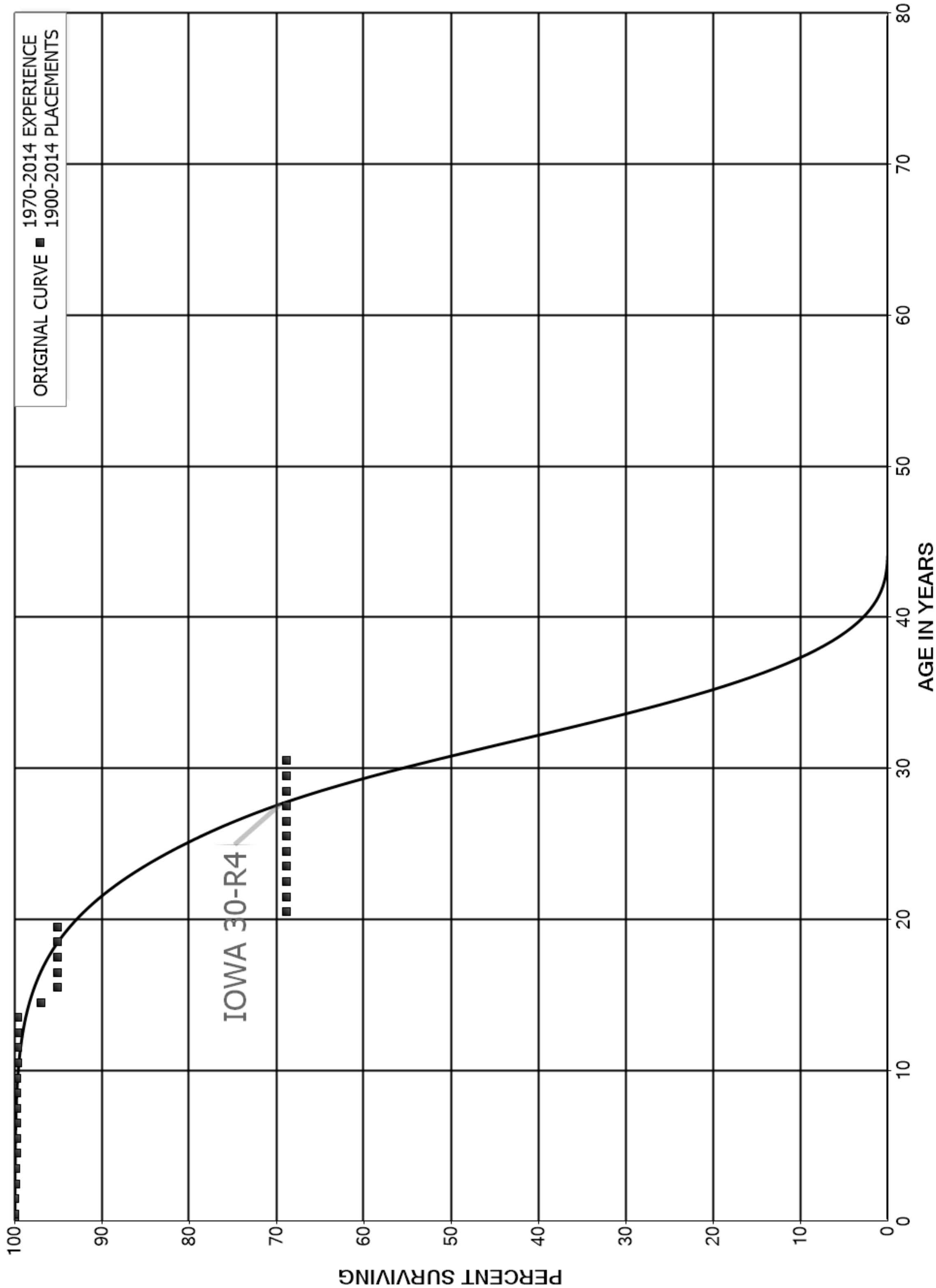
ACCOUNT 463.00 - TRANSMISSION PLANT - MEASURING AND REGULATING STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2014 EXPERIENCE BAND 1968-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	47,862		0.0000	1.0000	38.10
40.5	35,325		0.0000	1.0000	38.10
41.5	35,325		0.0000	1.0000	38.10
42.5	4,697		0.0000	1.0000	38.10
43.5	4,697		0.0000	1.0000	38.10
44.5	4,697		0.0000	1.0000	38.10
45.5	4,697	4,697	1.0000		38.10
46.5					

FORTISBC ENERGY INC.
ACCOUNT 464.00 - TRANSMISSION PLANT - OTHER STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

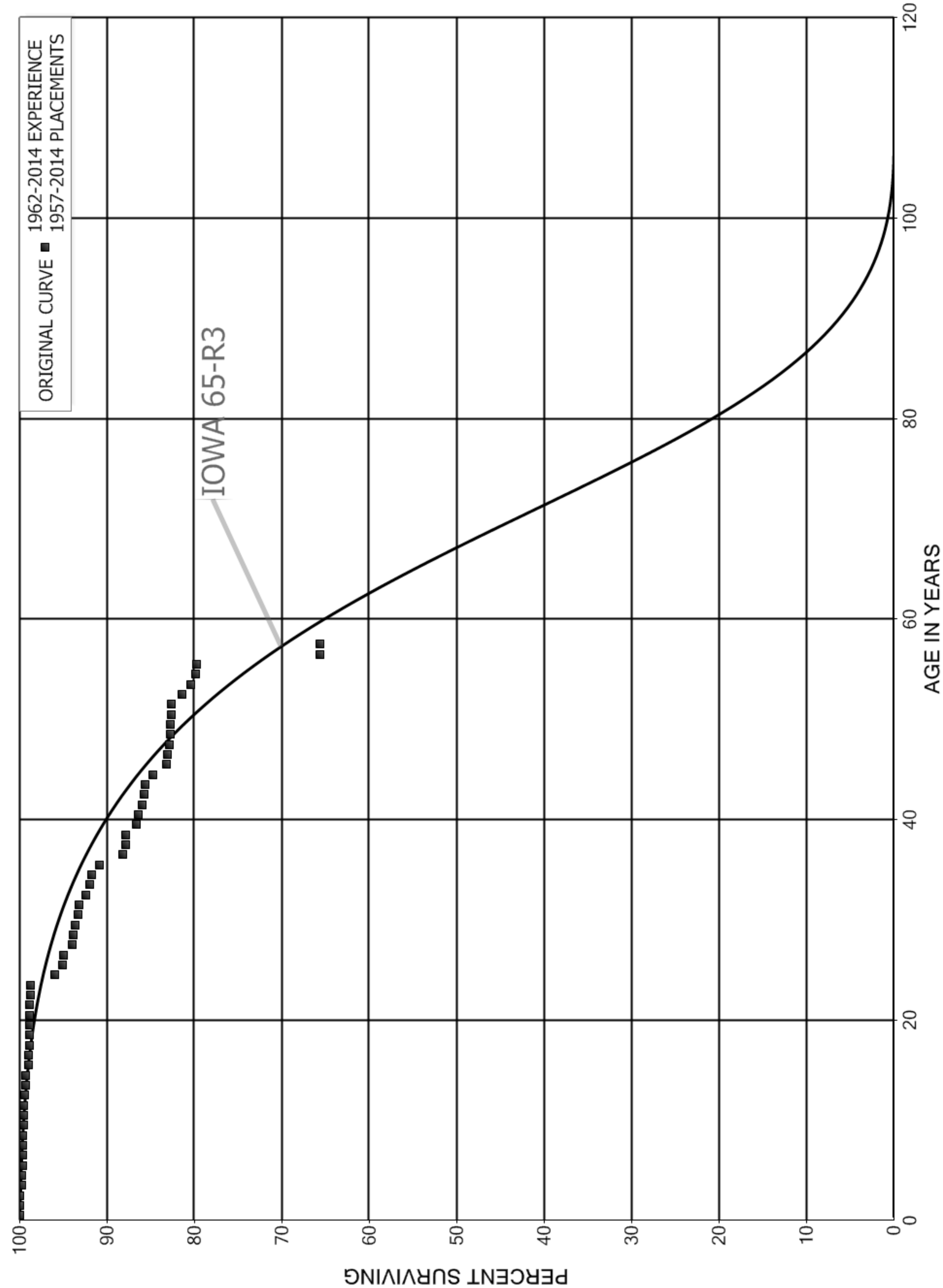
ACCOUNT 464.00 – TRANSMISSION PLANT – OTHER STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2014 EXPERIENCE BAND 1970-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,247,192		0.0000	1.0000	100.00
0.5	6,228,556		0.0000	1.0000	100.00
1.5	5,915,565	7,358	0.0012	0.9988	100.00
2.5	5,900,915	4,055	0.0007	0.9993	99.88
3.5	5,896,860	7,453	0.0013	0.9987	99.81
4.5	5,889,407		0.0000	1.0000	99.68
5.5	5,866,415		0.0000	1.0000	99.68
6.5	5,866,252		0.0000	1.0000	99.68
7.5	5,761,871		0.0000	1.0000	99.68
8.5	5,523,670		0.0000	1.0000	99.68
9.5	5,235,256	643	0.0001	0.9999	99.68
10.5	4,679,818		0.0000	1.0000	99.67
11.5	4,668,989	70	0.0000	1.0000	99.67
12.5	4,131,212		0.0000	1.0000	99.67
13.5	297,923	8,017	0.0269	0.9731	99.67
14.5	184,481	3,713	0.0201	0.9799	96.99
15.5	39,406		0.0000	1.0000	95.03
16.5	36,396		0.0000	1.0000	95.03
17.5	28,263		0.0000	1.0000	95.03
18.5	24,455		0.0000	1.0000	95.03
19.5	24,455	6,746	0.2759	0.7241	95.03
20.5	17,709		0.0000	1.0000	68.82
21.5	8,154		0.0000	1.0000	68.82
22.5	8,154		0.0000	1.0000	68.82
23.5	8,154		0.0000	1.0000	68.82
24.5	6,584		0.0000	1.0000	68.82
25.5	3,011		0.0000	1.0000	68.82
26.5	3,011		0.0000	1.0000	68.82
27.5	2,004		0.0000	1.0000	68.82
28.5	2,004		0.0000	1.0000	68.82
29.5	2,004		0.0000	1.0000	68.82
					68.82

FORTISBC ENERGY INC.
ACCOUNT 465.00 - TRANSMSSION PLANT - PIPELINE
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANSMSSION PLANT - PIPELINE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1962-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,097,806,178	120,950	0.0001	0.9999	100.00
0.5	1,075,023,210	240,793	0.0002	0.9998	99.99
1.5	1,054,117,930	211,413	0.0002	0.9998	99.97
2.5	1,040,838,900	2,231,944	0.0021	0.9979	99.95
3.5	995,938,572	342,123	0.0003	0.9997	99.73
4.5	985,415,405	377,896	0.0004	0.9996	99.70
5.5	975,829,679	68,177	0.0001	0.9999	99.66
6.5	963,825,360	235,985	0.0002	0.9998	99.65
7.5	955,025,546	232,832	0.0002	0.9998	99.63
8.5	942,261,770	533,029	0.0006	0.9994	99.60
9.5	930,398,144	183,645	0.0002	0.9998	99.55
10.5	916,621,080	253,603	0.0003	0.9997	99.53
11.5	898,403,489	706,802	0.0008	0.9992	99.50
12.5	871,818,495	926,792	0.0011	0.9989	99.42
13.5	824,569,833	224,700	0.0003	0.9997	99.32
14.5	504,687,842	1,759,132	0.0035	0.9965	99.29
15.5	490,452,702	119,753	0.0002	0.9998	98.94
16.5	476,628,488	208,308	0.0004	0.9996	98.92
17.5	468,326,148	198,990	0.0004	0.9996	98.88
18.5	457,990,301	117,708	0.0003	0.9997	98.83
19.5	453,081,606	53,544	0.0001	0.9999	98.81
20.5	450,825,512	16,452	0.0000	1.0000	98.80
21.5	444,019,605	62,329	0.0001	0.9999	98.79
22.5	386,862,205	194,019	0.0005	0.9995	98.78
23.5	82,346,369	2,360,277	0.0287	0.9713	98.73
24.5	73,845,132	627,492	0.0085	0.9915	95.90
25.5	72,609,655	147,230	0.0020	0.9980	95.09
26.5	37,479,155	388,747	0.0104	0.9896	94.89
27.5	35,464,667	44,757	0.0013	0.9987	93.91
28.5	31,769,985	69,768	0.0022	0.9978	93.79
29.5	30,943,512	83,697	0.0027	0.9973	93.58
30.5	30,755,353	36,110	0.0012	0.9988	93.33
31.5	30,228,918	270,170	0.0089	0.9911	93.22
32.5	29,346,389	156,744	0.0053	0.9947	92.39
33.5	28,127,306	57,463	0.0020	0.9980	91.89
34.5	27,386,014	254,438	0.0093	0.9907	91.71
35.5	27,121,762	793,901	0.0293	0.9707	90.85
36.5	25,979,176	118,234	0.0046	0.9954	88.20
37.5	25,664,627		0.0000	1.0000	87.79
38.5	24,781,537	325,708	0.0131	0.9869	87.79

FORTISBC ENERGY INC.

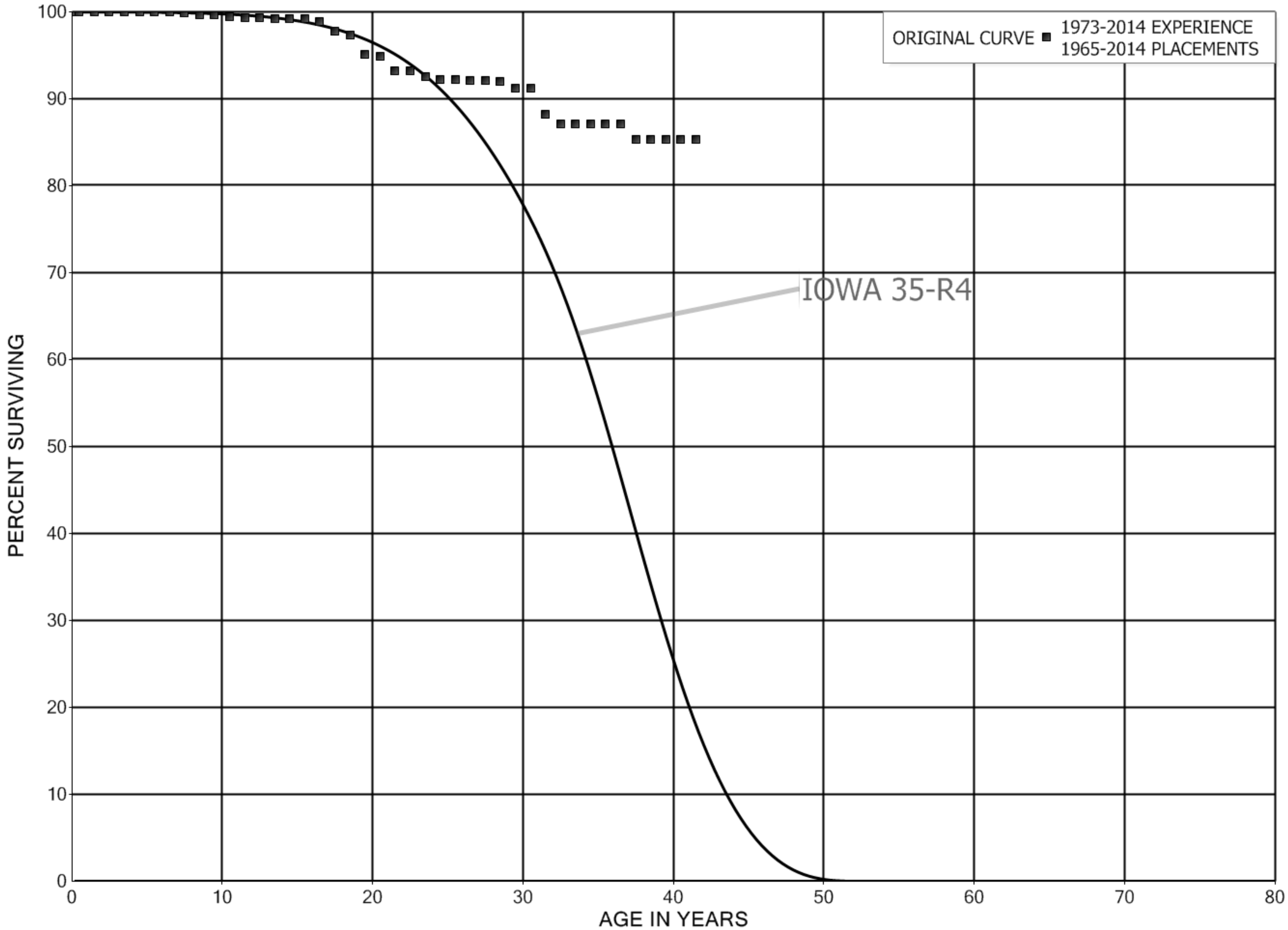
ACCOUNT 465.00 - TRANSMSSION PLANT - PIPELINE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1962-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	24,400,090	81,120	0.0033	0.9967	86.64
40.5	24,301,099	98,214	0.0040	0.9960	86.35
41.5	23,805,626	62,472	0.0026	0.9974	86.00
42.5	23,104,169	47,236	0.0020	0.9980	85.78
43.5	20,773,629	201,380	0.0097	0.9903	85.60
44.5	20,208,342	385,898	0.0191	0.9809	84.77
45.5	18,227,340	19,368	0.0011	0.9989	83.15
46.5	17,915,232	53,471	0.0030	0.9970	83.06
47.5	17,386,477	15,361	0.0009	0.9991	82.82
48.5	17,162,795		0.0000	1.0000	82.74
49.5	17,162,795	22,300	0.0013	0.9987	82.74
50.5	17,092,728	10,775	0.0006	0.9994	82.64
51.5	16,989,423	246,592	0.0145	0.9855	82.58
52.5	14,817,004	182,361	0.0123	0.9877	81.39
53.5	14,511,057	99,394	0.0068	0.9932	80.38
54.5	14,394,055	26,670	0.0019	0.9981	79.83
55.5	13,838,137	2,441,010	0.1764	0.8236	79.69
56.5	14,547		0.0000	1.0000	65.63
57.5					65.63

FORTISBC ENERGY INC.
ACCOUNT 466.00 - TRANSMISSION PLANT - COMPRESSOR EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 466.00 - TRANSMISSION PLANT - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2014 EXPERIENCE BAND 1973-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	178,391,790	35	0.0000	1.0000	100.00
0.5	177,589,792	556	0.0000	1.0000	100.00
1.5	176,169,287	758	0.0000	1.0000	100.00
2.5	173,272,896	2,978	0.0000	1.0000	100.00
3.5	169,452,321	1,513	0.0000	1.0000	100.00
4.5	165,846,566	16,949	0.0001	0.9999	100.00
5.5	164,747,254	23,569	0.0001	0.9999	99.99
6.5	161,427,053	206,181	0.0013	0.9987	99.97
7.5	143,092,078	260,667	0.0018	0.9982	99.84
8.5	142,391,501	62,334	0.0004	0.9996	99.66
9.5	140,461,486	305,855	0.0022	0.9978	99.62
10.5	137,818,136	101,825	0.0007	0.9993	99.40
11.5	137,017,573	11,150	0.0001	0.9999	99.33
12.5	130,518,636	139,310	0.0011	0.9989	99.32
13.5	124,745,155	6,869	0.0001	0.9999	99.21
14.5	74,006,894	37,088	0.0005	0.9995	99.21
15.5	66,928,985	187,037	0.0028	0.9972	99.16
16.5	60,632,820	677,697	0.0112	0.9888	98.88
17.5	56,482,976	285,588	0.0051	0.9949	97.78
18.5	54,187,630	1,220,411	0.0225	0.9775	97.28
19.5	48,130,286	135,051	0.0028	0.9972	95.09
20.5	28,569,734	480,963	0.0168	0.9832	94.82
21.5	23,003,888	510	0.0000	1.0000	93.23
22.5	20,223,516	160,085	0.0079	0.9921	93.23
23.5	2,672,235	9,084	0.0034	0.9966	92.49
24.5	2,632,677	374	0.0001	0.9999	92.17
25.5	2,612,221	1,436	0.0005	0.9995	92.16
26.5	2,597,279	655	0.0003	0.9997	92.11
27.5	2,509,029	4,049	0.0016	0.9984	92.09
28.5	2,497,371	22,073	0.0088	0.9912	91.94
29.5	2,474,010		0.0000	1.0000	91.13
30.5	2,470,536	79,374	0.0321	0.9679	91.13
31.5	2,360,119	29,977	0.0127	0.9873	88.20
32.5	2,330,142		0.0000	1.0000	87.08
33.5	2,327,132		0.0000	1.0000	87.08
34.5	2,327,132		0.0000	1.0000	87.08
35.5	2,324,291		0.0000	1.0000	87.08
36.5	1,546,218	32,582	0.0211	0.9789	87.08
37.5	1,464,608		0.0000	1.0000	85.24
38.5	1,452,220		0.0000	1.0000	85.24

FORTISBC ENERGY INC.

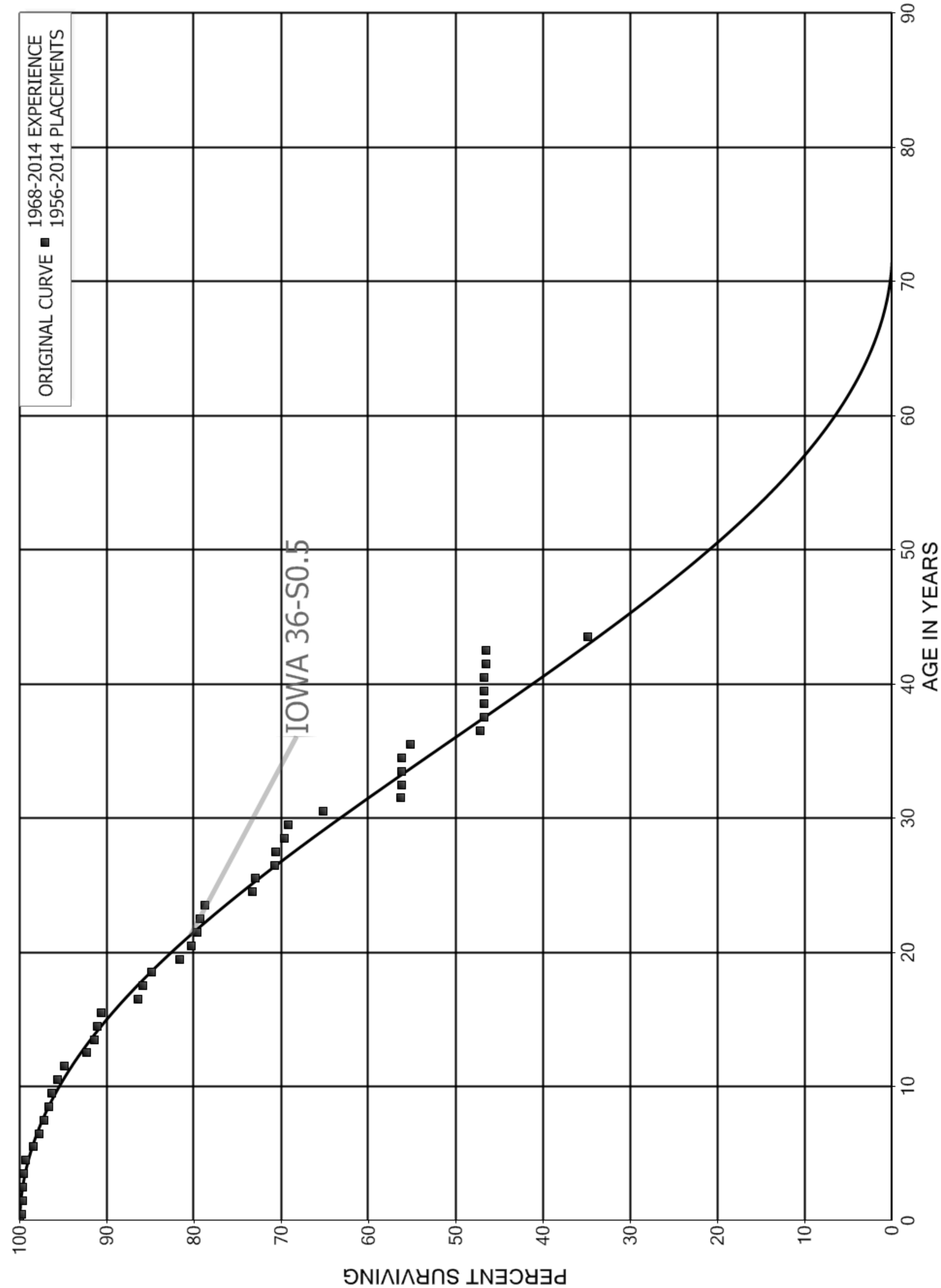
ACCOUNT 466.00 - TRANSMISSION PLANT - COMPRESSOR EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2014 EXPERIENCE BAND 1973-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,449,467		0.0000	1.0000	85.24
40.5	1,161,436		0.0000	1.0000	85.24
41.5					85.24

FORTISBC ENERGY INC.
ACCOUNT 467.10 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 467.10 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2014 EXPERIENCE BAND 1968-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	57,133,490	178,113	0.0031	0.9969	100.00
0.5	55,691,486	12,133	0.0002	0.9998	99.69
1.5	53,349,155	29,770	0.0006	0.9994	99.67
2.5	49,913,893	68,444	0.0014	0.9986	99.61
3.5	48,525,901	109,969	0.0023	0.9977	99.47
4.5	48,045,361	405,247	0.0084	0.9916	99.25
5.5	46,979,952	321,108	0.0068	0.9932	98.41
6.5	45,225,663	272,673	0.0060	0.9940	97.74
7.5	43,934,414	219,247	0.0050	0.9950	97.15
8.5	41,673,123	151,312	0.0036	0.9964	96.67
9.5	40,980,927	275,322	0.0067	0.9933	96.31
10.5	39,562,693	323,216	0.0082	0.9918	95.67
11.5	35,039,924	962,947	0.0275	0.9725	94.89
12.5	31,737,421	307,634	0.0097	0.9903	92.28
13.5	30,437,566	98,887	0.0032	0.9968	91.38
14.5	26,359,941	125,050	0.0047	0.9953	91.09
15.5	24,348,339	1,134,478	0.0466	0.9534	90.65
16.5	21,999,544	143,250	0.0065	0.9935	86.43
17.5	18,729,309	229,302	0.0122	0.9878	85.87
18.5	17,525,757	668,138	0.0381	0.9619	84.82
19.5	15,531,166	247,356	0.0159	0.9841	81.58
20.5	14,308,869	111,890	0.0078	0.9922	80.28
21.5	12,703,716	58,490	0.0046	0.9954	79.66
22.5	10,960,457	72,098	0.0066	0.9934	79.29
23.5	1,907,789	133,595	0.0700	0.9300	78.77
24.5	1,774,194	8,317	0.0047	0.9953	73.25
25.5	1,708,715	50,354	0.0295	0.9705	72.91
26.5	541,805	1,249	0.0023	0.9977	70.76
27.5	528,937	7,442	0.0141	0.9859	70.60
28.5	483,685	3,232	0.0067	0.9933	69.60
29.5	373,024	21,090	0.0565	0.9435	69.14
30.5	323,881	44,228	0.1366	0.8634	65.23
31.5	279,653	800	0.0029	0.9971	56.32
32.5	263,664		0.0000	1.0000	56.16
33.5	261,830		0.0000	1.0000	56.16
34.5	261,830	4,450	0.0170	0.9830	56.16
35.5	257,380	37,550	0.1459	0.8541	55.21
36.5	216,342	2,124	0.0098	0.9902	47.15
37.5	213,179		0.0000	1.0000	46.69
38.5	213,179		0.0000	1.0000	46.69

FORTISBC ENERGY INC.

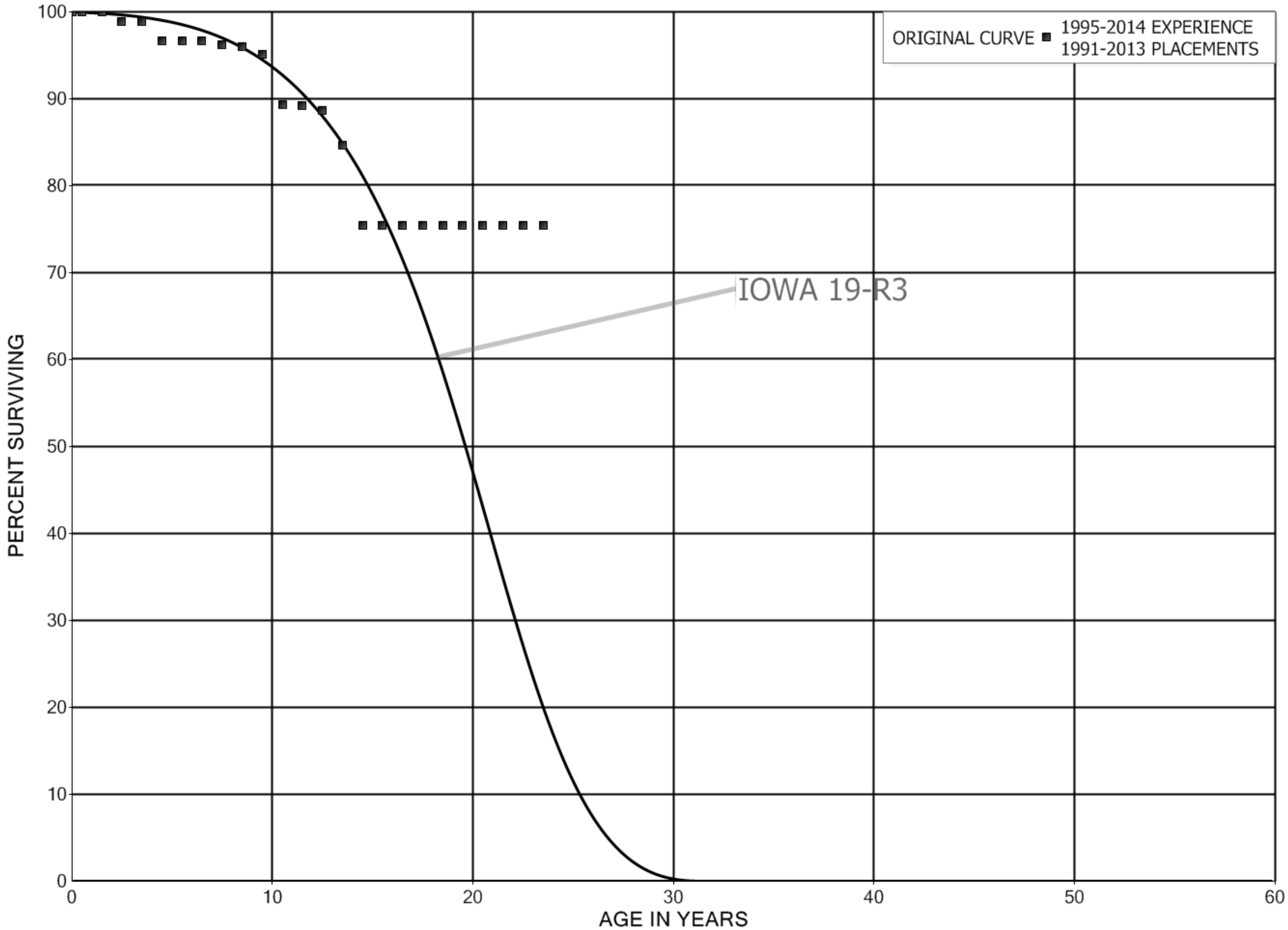
ACCOUNT 467.10 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2014 EXPERIENCE BAND 1968-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	212,181		0.0000	1.0000	46.69
40.5	195,591	670	0.0034	0.9966	46.69
41.5	194,921		0.0000	1.0000	46.53
42.5	69,896	17,501	0.2504	0.7496	46.53
43.5					34.88

FORTISBC ENERGY INC.
ACCOUNT 468.00 - TRANSMISSION PLANT - COMMUNICATIONS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

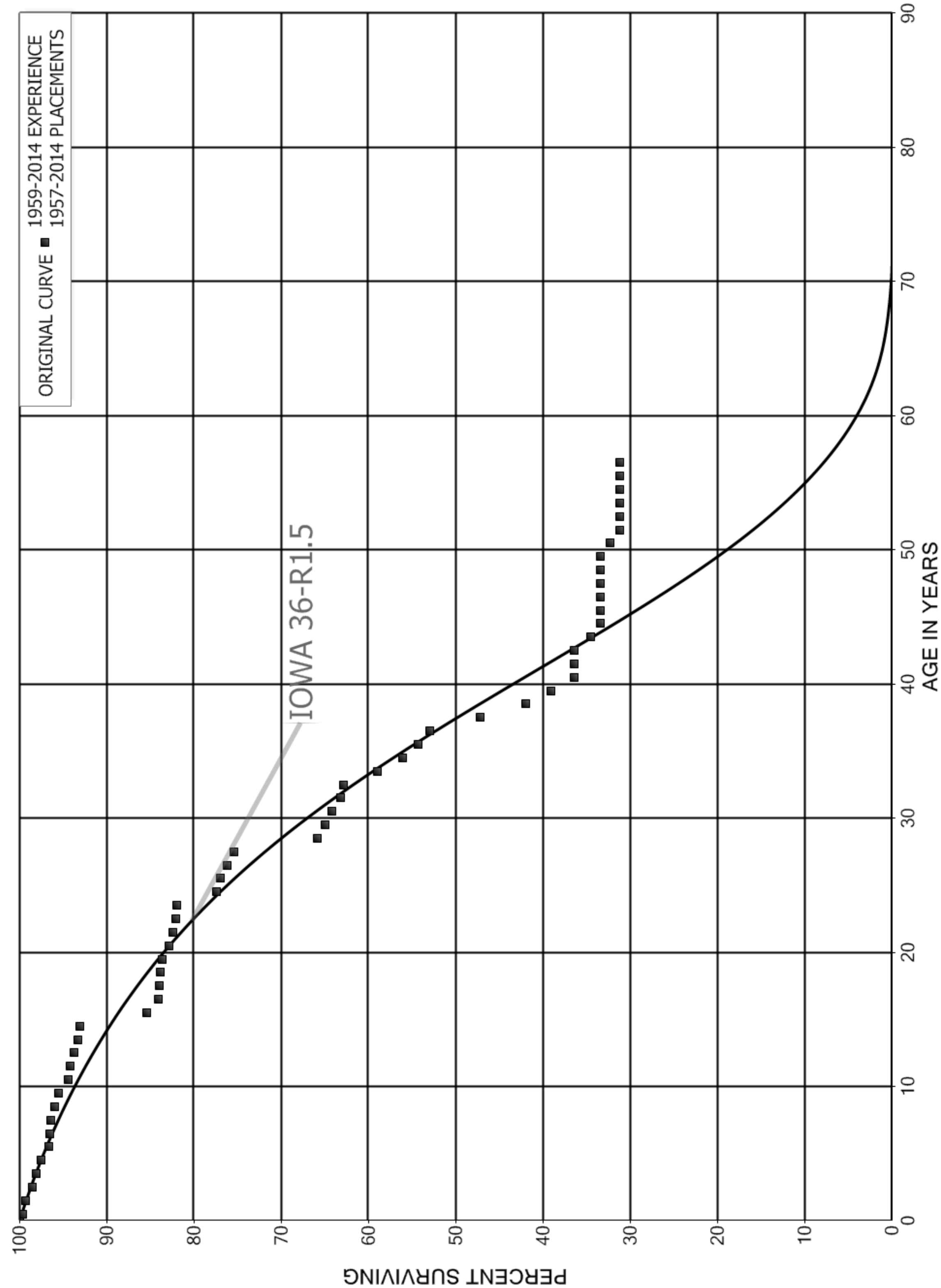
ACCOUNT 468.00 - TRANSMISSION PLANT - COMMUNICATIONS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1991-2013 EXPERIENCE BAND 1995-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,750,344		0.0000	1.0000	100.00
0.5	2,766,364		0.0000	1.0000	100.00
1.5	2,725,292	30,284	0.0111	0.9889	100.00
2.5	2,701,269	106	0.0000	1.0000	98.89
3.5	4,483,903	101,196	0.0226	0.9774	98.88
4.5	4,381,680		0.0000	1.0000	96.65
5.5	4,120,915	849	0.0002	0.9998	96.65
6.5	4,077,933	19,877	0.0049	0.9951	96.63
7.5	3,800,568	6,274	0.0017	0.9983	96.16
8.5	3,777,338	37,644	0.0100	0.9900	96.00
9.5	3,739,693	225,386	0.0603	0.9397	95.05
10.5	3,509,386	4,902	0.0014	0.9986	89.32
11.5	2,894,582	17,333	0.0060	0.9940	89.19
12.5	2,711,120	122,320	0.0451	0.9549	88.66
13.5	2,389,435	262,835	0.1100	0.8900	84.66
14.5	2,124,192		0.0000	1.0000	75.35
15.5	2,121,179		0.0000	1.0000	75.35
16.5	2,078,098		0.0000	1.0000	75.35
17.5	2,016,481		0.0000	1.0000	75.35
18.5	2,012,674		0.0000	1.0000	75.35
19.5	1,987,661		0.0000	1.0000	75.35
20.5	1,975,584		0.0000	1.0000	75.35
21.5	1,963,378		0.0000	1.0000	75.35
22.5	1,958,059		0.0000	1.0000	75.35
23.5					75.35

FORTISBC ENERGY INC.
ACCOUNT 472.00 - DISTRIBUTION PLANT - STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 472.00 - DISTRIBUTION PLANT - STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1959-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,571,854	90,918	0.0037	0.9963	100.00
0.5	24,099,857	75,898	0.0031	0.9969	99.63
1.5	23,149,369	184,496	0.0080	0.9920	99.32
2.5	21,967,449	109,637	0.0050	0.9950	98.52
3.5	19,820,539	113,207	0.0057	0.9943	98.03
4.5	19,230,625	173,283	0.0090	0.9910	97.47
5.5	18,505,872	24,271	0.0013	0.9987	96.59
6.5	17,427,393	22,560	0.0013	0.9987	96.47
7.5	16,457,881	57,852	0.0035	0.9965	96.34
8.5	13,937,224	78,003	0.0056	0.9944	96.00
9.5	11,622,331	130,422	0.0112	0.9888	95.47
10.5	10,238,138	21,341	0.0021	0.9979	94.40
11.5	9,888,102	49,907	0.0050	0.9950	94.20
12.5	9,615,848	41,035	0.0043	0.9957	93.72
13.5	8,982,705	21,584	0.0024	0.9976	93.32
14.5	8,426,857	700,750	0.0832	0.9168	93.10
15.5	7,276,963	105,820	0.0145	0.9855	85.36
16.5	6,697,512	14,283	0.0021	0.9979	84.12
17.5	5,751,305	10,401	0.0018	0.9982	83.94
18.5	4,734,100	9,211	0.0019	0.9981	83.79
19.5	3,802,000	33,860	0.0089	0.9911	83.62
20.5	3,001,042	15,987	0.0053	0.9947	82.88
21.5	2,754,088	10,791	0.0039	0.9961	82.44
22.5	2,005,876	4,553	0.0023	0.9977	82.11
23.5	990,194	55,398	0.0559	0.9441	81.93
24.5	890,733	3,875	0.0044	0.9956	77.34
25.5	860,006	8,894	0.0103	0.9897	77.01
26.5	833,676	9,489	0.0114	0.9886	76.21
27.5	678,404	85,832	0.1265	0.8735	75.34
28.5	475,904	6,623	0.0139	0.9861	65.81
29.5	453,497	5,032	0.0111	0.9889	64.89
30.5	421,755	6,871	0.0163	0.9837	64.17
31.5	373,650	1,676	0.0045	0.9955	63.13
32.5	346,565	21,189	0.0611	0.9389	62.85
33.5	248,944	12,262	0.0493	0.9507	59.00
34.5	229,486	7,637	0.0333	0.9667	56.10
35.5	218,475	5,185	0.0237	0.9763	54.23
36.5	213,275	23,097	0.1083	0.8917	52.94
37.5	190,178	21,057	0.1107	0.8893	47.21
38.5	166,933	11,575	0.0693	0.9307	41.98

FORTISBC ENERGY INC.

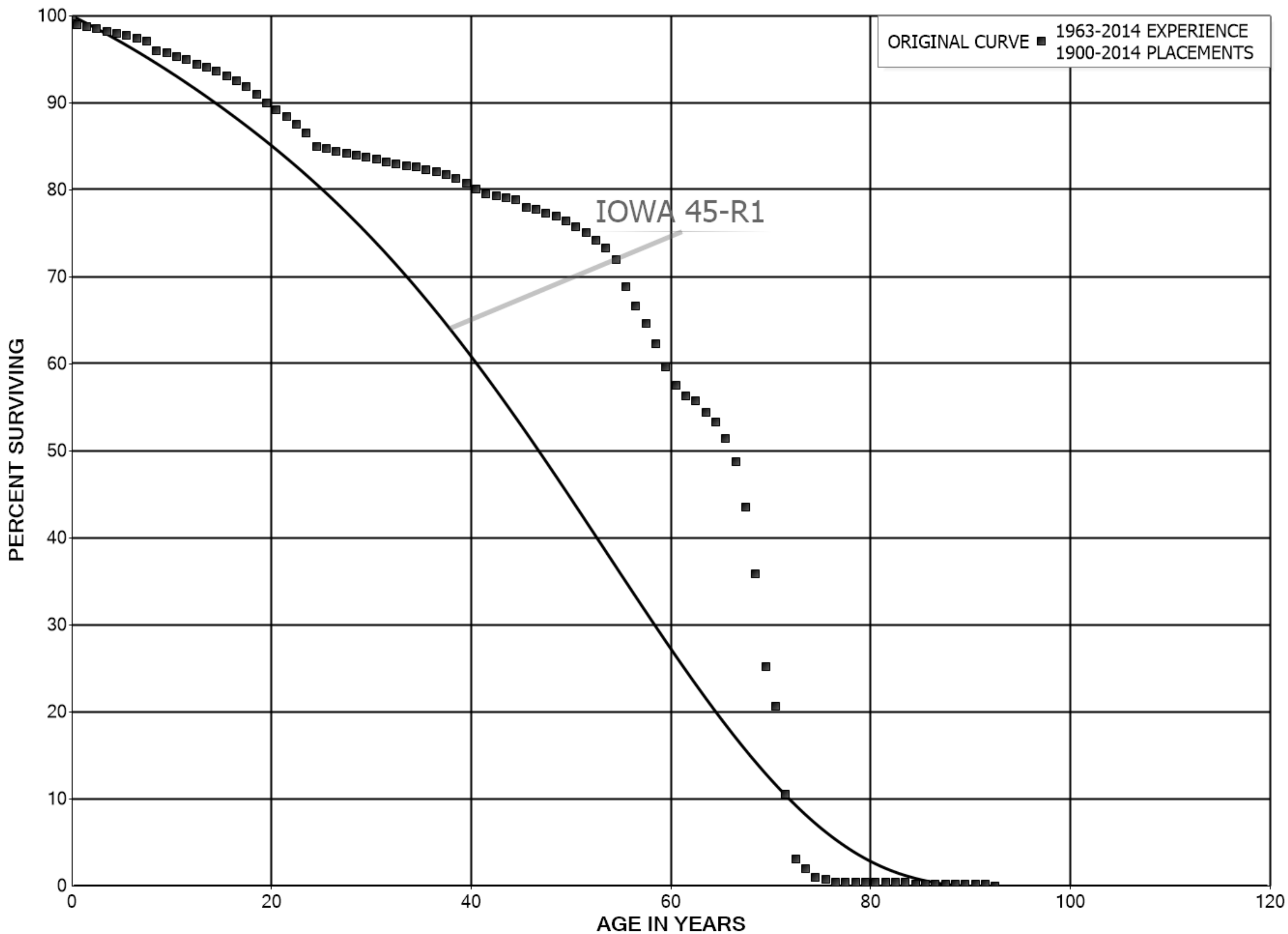
ACCOUNT 472.00 - DISTRIBUTION PLANT - STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1959-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	148,619	10,276	0.0691	0.9309	39.07
40.5	124,199		0.0000	1.0000	36.37
41.5	110,219		0.0000	1.0000	36.37
42.5	106,164	5,444	0.0513	0.9487	36.37
43.5	99,308	3,313	0.0334	0.9666	34.50
44.5	80,944		0.0000	1.0000	33.35
45.5	79,110		0.0000	1.0000	33.35
46.5	63,621		0.0000	1.0000	33.35
47.5	63,621		0.0000	1.0000	33.35
48.5	63,621		0.0000	1.0000	33.35
49.5	63,062	2,024	0.0321	0.9679	33.35
50.5	61,038	2,101	0.0344	0.9656	32.28
51.5	58,937		0.0000	1.0000	31.17
52.5	43,528		0.0000	1.0000	31.17
53.5	21,818		0.0000	1.0000	31.17
54.5	21,818		0.0000	1.0000	31.17
55.5	21,818		0.0000	1.0000	31.17
56.5					31.17

FORTISBC ENERGY INC.
ACCOUNT 473.00 - DISTRIBUTION PLANT - SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 473.00 - DISTRIBUTION PLANT - SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,121,418,402	11,950,824	0.0107	0.9893	100.00
0.5	1,065,054,208	2,328,163	0.0022	0.9978	98.93
1.5	1,019,082,289	2,721,309	0.0027	0.9973	98.72
2.5	974,234,202	2,467,567	0.0025	0.9975	98.45
3.5	937,222,392	2,421,170	0.0026	0.9974	98.21
4.5	900,064,681	2,499,615	0.0028	0.9972	97.95
5.5	864,655,203	2,717,044	0.0031	0.9969	97.68
6.5	816,488,187	2,438,486	0.0030	0.9970	97.37
7.5	770,723,395	8,537,181	0.0111	0.9889	97.08
8.5	726,156,433	2,185,569	0.0030	0.9970	96.01
9.5	689,613,294	2,982,848	0.0043	0.9957	95.72
10.5	658,193,354	2,818,382	0.0043	0.9957	95.30
11.5	630,536,880	3,242,865	0.0051	0.9949	94.90
12.5	603,342,020	2,106,851	0.0035	0.9965	94.41
13.5	579,395,632	3,161,759	0.0055	0.9945	94.08
14.5	547,717,287	3,047,421	0.0056	0.9944	93.56
15.5	519,440,105	3,055,160	0.0059	0.9941	93.04
16.5	487,376,644	3,766,841	0.0077	0.9923	92.50
17.5	449,640,349	4,210,418	0.0094	0.9906	91.78
18.5	408,891,378	4,479,528	0.0110	0.9890	90.92
19.5	366,722,505	2,853,485	0.0078	0.9922	89.93
20.5	325,584,121	3,010,212	0.0092	0.9908	89.23
21.5	281,439,240	2,853,606	0.0101	0.9899	88.40
22.5	240,233,867	2,652,860	0.0110	0.9890	87.50
23.5	212,399,192	3,932,200	0.0185	0.9815	86.54
24.5	190,416,303	447,529	0.0024	0.9976	84.94
25.5	173,088,426	614,514	0.0036	0.9964	84.74
26.5	161,382,961	449,450	0.0028	0.9972	84.44
27.5	137,917,549	356,835	0.0026	0.9974	84.20
28.5	127,734,113	345,908	0.0027	0.9973	83.98
29.5	104,703,721	367,241	0.0035	0.9965	83.76
30.5	91,319,676	277,535	0.0030	0.9970	83.46
31.5	76,792,520	221,962	0.0029	0.9971	83.21
32.5	65,148,118	149,835	0.0023	0.9977	82.97
33.5	52,981,395	129,557	0.0024	0.9976	82.78
34.5	44,861,256	139,615	0.0031	0.9969	82.57
35.5	39,079,008	124,570	0.0032	0.9968	82.32
36.5	33,554,158	131,615	0.0039	0.9961	82.06
37.5	28,857,652	160,028	0.0055	0.9945	81.73
38.5	23,656,526	163,108	0.0069	0.9931	81.28

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DISTRIBUTION PLANT - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,019,388	166,472	0.0083	0.9917	80.72
40.5	16,138,792	103,870	0.0064	0.9936	80.05
41.5	13,127,237	41,197	0.0031	0.9969	79.53
42.5	11,010,806	29,320	0.0027	0.9973	79.28
43.5	9,365,410	27,306	0.0029	0.9971	79.07
44.5	7,755,770	88,452	0.0114	0.9886	78.84
45.5	6,939,648	22,236	0.0032	0.9968	77.94
46.5	6,201,657	29,934	0.0048	0.9952	77.69
47.5	5,472,666	26,289	0.0048	0.9952	77.32
48.5	4,769,697	33,072	0.0069	0.9931	76.95
49.5	4,073,348	36,504	0.0090	0.9910	76.41
50.5	3,264,930	29,981	0.0092	0.9908	75.73
51.5	2,420,965	28,438	0.0117	0.9883	75.03
52.5	1,798,762	22,338	0.0124	0.9876	74.15
53.5	1,776,425	30,602	0.0172	0.9828	73.23
54.5	1,394,636	60,664	0.0435	0.9565	71.97
55.5	88,461	2,800	0.0317	0.9683	68.84
56.5	85,661	2,689	0.0314	0.9686	66.66
57.5	82,972	2,938	0.0354	0.9646	64.57
58.5	80,034	3,372	0.0421	0.9579	62.28
59.5	76,662	2,777	0.0362	0.9638	59.66
60.5	73,885	1,500	0.0203	0.9797	57.50
61.5	72,385	777	0.0107	0.9893	56.33
62.5	71,874	1,686	0.0235	0.9765	55.72
63.5	70,188	1,480	0.0211	0.9789	54.42
64.5	68,708	2,377	0.0346	0.9654	53.27
65.5	66,331	3,544	0.0534	0.9466	51.43
66.5	62,787	6,635	0.1057	0.8943	48.68
67.5	56,152	10,001	0.1781	0.8219	43.53
68.5	46,151	13,679	0.2964	0.7036	35.78
69.5	32,472	5,866	0.1806	0.8194	25.18
70.5	26,606	13,087	0.4919	0.5081	20.63
71.5	13,519	9,566	0.7076	0.2924	10.48
72.5	3,953	1,500	0.3795	0.6205	3.06
73.5	2,453	1,200	0.4892	0.5108	1.90
74.5	1,253	287	0.2291	0.7709	0.97
75.5	966	400	0.4141	0.5859	0.75
76.5	566		0.0000	1.0000	0.44
77.5	566		0.0000	1.0000	0.44
78.5	566		0.0000	1.0000	0.44

FORTISBC ENERGY INC.

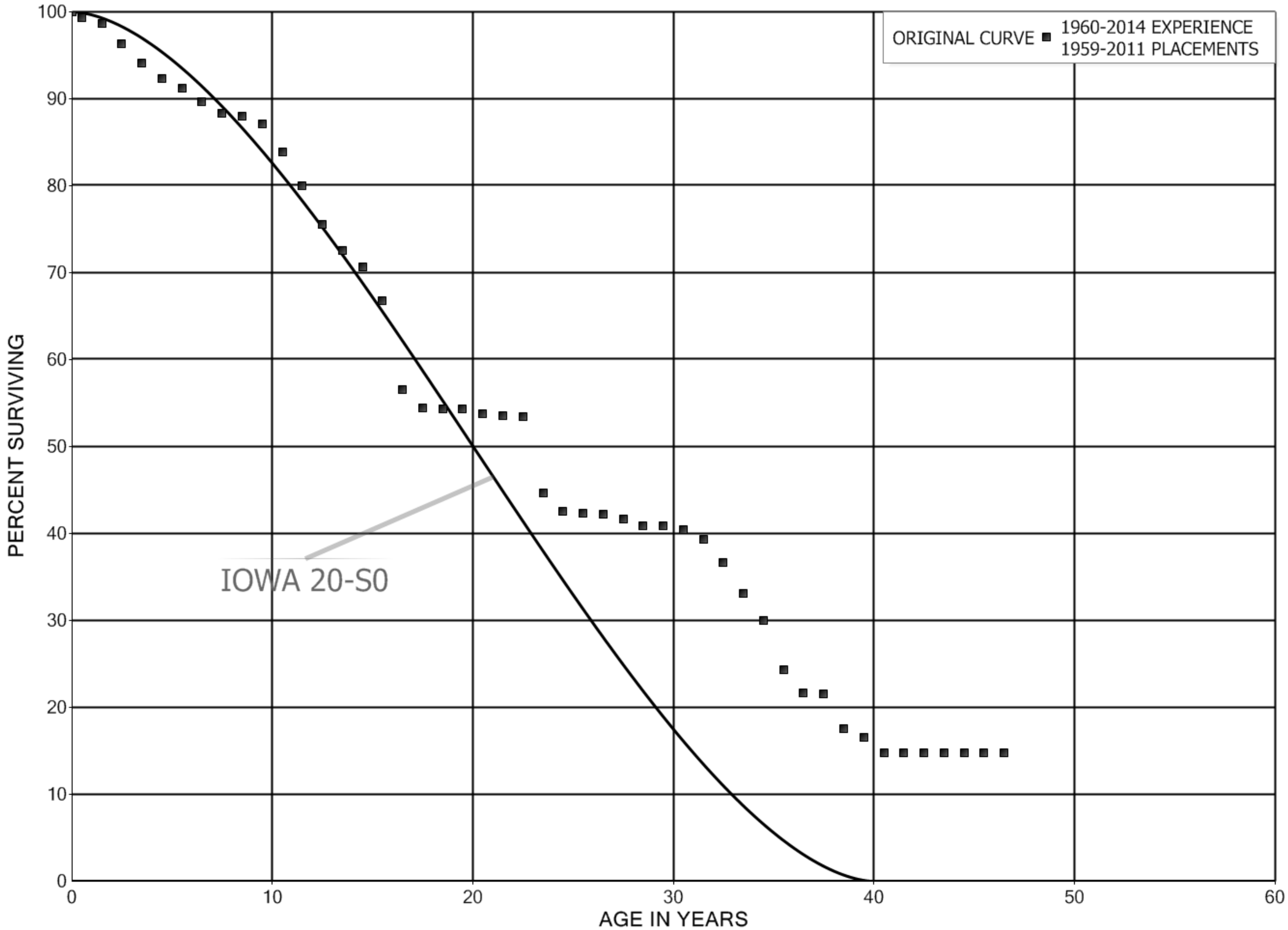
ACCOUNT 473.00 - DISTRIBUTION PLANT - SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	566		0.0000	1.0000	0.44
80.5	566		0.0000	1.0000	0.44
81.5	566		0.0000	1.0000	0.44
82.5	566		0.0000	1.0000	0.44
83.5	566	300	0.5300	0.4700	0.44
84.5	266		0.0000	1.0000	0.21
85.5	266		0.0000	1.0000	0.21
86.5	266		0.0000	1.0000	0.21
87.5	266		0.0000	1.0000	0.21
88.5	266		0.0000	1.0000	0.21
89.5	266		0.0000	1.0000	0.21
90.5	266		0.0000	1.0000	0.21
91.5	266	266	1.0000		0.21
92.5					

FORTISBC ENERGY INC.
ACCOUNT 474.00 - METER/REGULATOR INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 474.00 - METER/REGULATOR INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1959-2011 EXPERIENCE BAND 1960-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	275,639,063	1,890,773	0.0069	0.9931	100.00
0.5	273,760,542	1,776,458	0.0065	0.9935	99.31
1.5	271,984,085	6,574,329	0.0242	0.9758	98.67
2.5	265,409,756	6,058,122	0.0228	0.9772	96.28
3.5	233,499,551	4,395,621	0.0188	0.9812	94.09
4.5	211,340,558	2,704,925	0.0128	0.9872	92.32
5.5	194,688,348	3,258,844	0.0167	0.9833	91.13
6.5	181,328,398	2,767,517	0.0153	0.9847	89.61
7.5	166,534,310	607,692	0.0036	0.9964	88.24
8.5	154,789,467	1,522,028	0.0098	0.9902	87.92
9.5	143,018,043	5,364,996	0.0375	0.9625	87.05
10.5	128,598,286	5,839,509	0.0454	0.9546	83.79
11.5	116,045,932	6,547,133	0.0564	0.9436	79.98
12.5	102,471,991	3,990,006	0.0389	0.9611	75.47
13.5	91,175,731	2,350,255	0.0258	0.9742	72.53
14.5	82,394,349	4,571,511	0.0555	0.9445	70.66
15.5	69,400,328	10,597,012	0.1527	0.8473	66.74
16.5	54,333,525	2,109,391	0.0388	0.9612	56.55
17.5	44,887,547	29,371	0.0007	0.9993	54.36
18.5	38,416,281	33,063	0.0009	0.9991	54.32
19.5	23,633,200	231,412	0.0098	0.9902	54.27
20.5	15,214,509	62,396	0.0041	0.9959	53.74
21.5	12,301,102	35,479	0.0029	0.9971	53.52
22.5	10,126,408	1,669,785	0.1649	0.8351	53.37
23.5	8,243,546	382,938	0.0465	0.9535	44.57
24.5	7,569,169	33,335	0.0044	0.9956	42.50
25.5	7,144,052	23,350	0.0033	0.9967	42.31
26.5	6,853,814	87,773	0.0128	0.9872	42.17
27.5	6,607,263	122,778	0.0186	0.9814	41.63
28.5	6,269,751	1,578	0.0003	0.9997	40.86
29.5	6,088,603	60,073	0.0099	0.9901	40.85
30.5	1,207,419	34,080	0.0282	0.9718	40.44
31.5	1,148,484	79,302	0.0690	0.9310	39.30
32.5	885,661	85,243	0.0962	0.9038	36.59
33.5	668,613	62,990	0.0942	0.9058	33.07
34.5	605,107	113,769	0.1880	0.8120	29.95
35.5	490,432	54,147	0.1104	0.8896	24.32
36.5	336,344	2,875	0.0085	0.9915	21.64
37.5	324,482	59,587	0.1836	0.8164	21.45
38.5	264,895	14,522	0.0548	0.9452	17.51

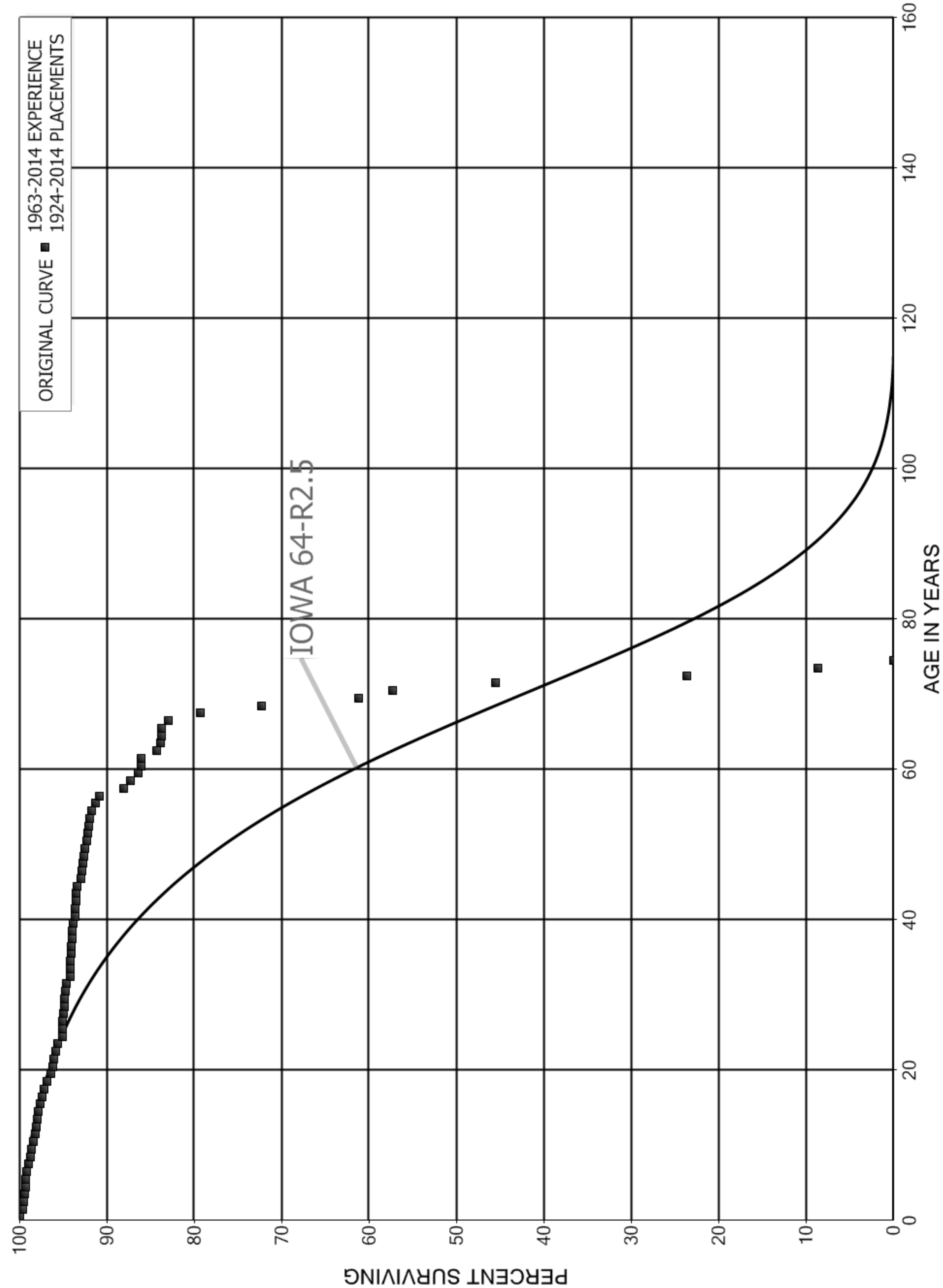
ACCOUNT 474.00 - METER/REGULATOR INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1959-2011 EXPERIENCE BAND 1960-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	247,673	27,369	0.1105	0.8895	16.55
40.5	205,775		0.0000	1.0000	14.72
41.5	178,630		0.0000	1.0000	14.72
42.5	148,099		0.0000	1.0000	14.72
43.5	148,099		0.0000	1.0000	14.72
44.5	101,120		0.0000	1.0000	14.72
45.5	101,120		0.0000	1.0000	14.72
46.5					14.72

FORTISBC ENERGY INC.
ACCOUNT 475.00 - DISTRIBUTION PLANT - SYSTEMS - MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 475.00 - DISTRIBUTION PLANT - SYSTEMS - MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,353,142,596	494,414	0.0004	0.9996	100.00
0.5	1,317,359,022	4,582,589	0.0035	0.9965	99.96
1.5	1,278,078,295	1,594,996	0.0012	0.9988	99.62
2.5	1,251,181,333	1,095,812	0.0009	0.9991	99.49
3.5	1,230,144,474	1,088,900	0.0009	0.9991	99.40
4.5	1,204,931,250	984,990	0.0008	0.9992	99.32
5.5	1,168,053,275	1,202,220	0.0010	0.9990	99.24
6.5	1,127,280,101	2,684,114	0.0024	0.9976	99.13
7.5	1,087,583,178	2,011,481	0.0018	0.9982	98.90
8.5	1,052,374,233	881,750	0.0008	0.9992	98.71
9.5	1,023,220,090	2,466,759	0.0024	0.9976	98.63
10.5	994,189,964	1,847,253	0.0019	0.9981	98.39
11.5	961,052,940	1,676,979	0.0017	0.9983	98.21
12.5	931,860,558	1,058,051	0.0011	0.9989	98.04
13.5	896,637,766	1,166,121	0.0013	0.9987	97.93
14.5	863,294,240	1,225,261	0.0014	0.9986	97.80
15.5	821,653,611	1,821,951	0.0022	0.9978	97.66
16.5	780,554,611	1,931,609	0.0025	0.9975	97.45
17.5	735,165,908	2,967,929	0.0040	0.9960	97.20
18.5	688,469,569	3,332,692	0.0048	0.9952	96.81
19.5	634,666,673	1,024,386	0.0016	0.9984	96.34
20.5	584,270,672	809,107	0.0014	0.9986	96.19
21.5	539,733,119	988,244	0.0018	0.9982	96.05
22.5	459,913,334	1,207,582	0.0026	0.9974	95.88
23.5	405,714,188	2,183,305	0.0054	0.9946	95.63
24.5	373,724,365	152,662	0.0004	0.9996	95.11
25.5	356,873,525	133,022	0.0004	0.9996	95.07
26.5	343,736,008	179,012	0.0005	0.9995	95.04
27.5	316,852,291	385,846	0.0012	0.9988	94.99
28.5	297,543,145	287,489	0.0010	0.9990	94.87
29.5	279,249,080	240,769	0.0009	0.9991	94.78
30.5	253,310,976	226,112	0.0009	0.9991	94.70
31.5	199,362,198	820,472	0.0041	0.9959	94.61
32.5	164,380,932	55,050	0.0003	0.9997	94.23
33.5	144,991,512	95,915	0.0007	0.9993	94.19
34.5	126,647,243	70,582	0.0006	0.9994	94.13
35.5	109,238,941	38,970	0.0004	0.9996	94.08
36.5	99,267,660	61,394	0.0006	0.9994	94.05
37.5	90,459,974	69,841	0.0008	0.9992	93.99
38.5	80,612,902	45,109	0.0006	0.9994	93.91

FORTISBC ENERGY INC.

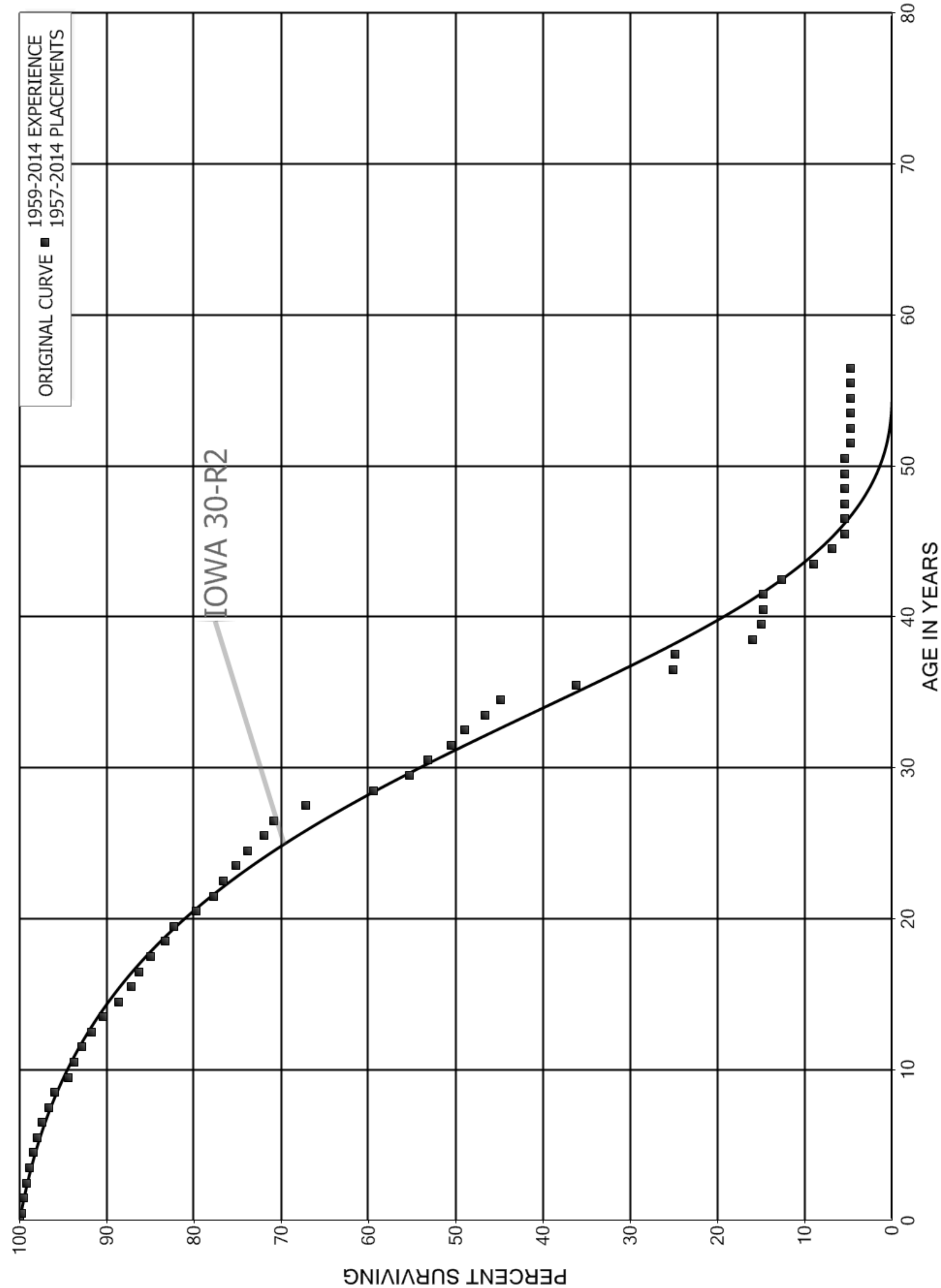
ACCOUNT 475.00 - DISTRIBUTION PLANT - SYSTEMS - MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	74,190,766	164,004	0.0022	0.9978	93.86
40.5	64,534,527	48,025	0.0007	0.9993	93.65
41.5	57,131,501	41,068	0.0007	0.9993	93.59
42.5	49,976,910	28,286	0.0006	0.9994	93.52
43.5	45,418,712	9,816	0.0002	0.9998	93.46
44.5	35,190,157	187,558	0.0053	0.9947	93.44
45.5	27,202,686	43,951	0.0016	0.9984	92.95
46.5	23,780,700	15,875	0.0007	0.9993	92.80
47.5	20,897,218	29,610	0.0014	0.9986	92.73
48.5	16,307,811	18,356	0.0011	0.9989	92.60
49.5	13,716,678	28,242	0.0021	0.9979	92.50
50.5	10,440,229	10,590	0.0010	0.9990	92.31
51.5	7,083,271	9,614	0.0014	0.9986	92.21
52.5	5,287,233	5,979	0.0011	0.9989	92.09
53.5	4,688,762	11,985	0.0026	0.9974	91.99
54.5	4,258,375	23,898	0.0056	0.9944	91.75
55.5	125,508	621	0.0049	0.9951	91.24
56.5	124,887	3,684	0.0295	0.9705	90.78
57.5	121,203	1,132	0.0093	0.9907	88.11
58.5	120,071	1,196	0.0100	0.9900	87.28
59.5	118,875	484	0.0041	0.9959	86.41
60.5	118,391		0.0000	1.0000	86.06
61.5	118,391	2,400	0.0203	0.9797	86.06
62.5	115,991	732	0.0063	0.9937	84.32
63.5	115,259	104	0.0009	0.9991	83.79
64.5	115,155		0.0000	1.0000	83.71
65.5	115,155	1,051	0.0091	0.9909	83.71
66.5	114,104	5,097	0.0447	0.9553	82.95
67.5	109,007	9,619	0.0882	0.9118	79.24
68.5	99,388	15,233	0.1533	0.8467	72.25
69.5	84,155	5,371	0.0638	0.9362	61.17
70.5	78,784	16,139	0.2049	0.7951	57.27
71.5	62,645	30,099	0.4805	0.5195	45.54
72.5	32,546	20,729	0.6369	0.3631	23.66
73.5	11,817	11,817	1.0000		8.59
74.5					

FORTISBC ENERGY INC.
ACCOUNT 477.10 - DISTRIBUTION PLANT - MEASURING AND REGULATING ADDITIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 477.10 - DISTRIBUTION PLANT - MEASURING AND REGULATING ADDITIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1959-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	123,705,320	343,490	0.0028	0.9972	100.00
0.5	121,410,247	269,898	0.0022	0.9978	99.72
1.5	113,775,946	393,510	0.0035	0.9965	99.50
2.5	108,211,533	338,454	0.0031	0.9969	99.16
3.5	103,802,145	476,311	0.0046	0.9954	98.85
4.5	99,780,731	417,339	0.0042	0.9958	98.39
5.5	94,375,838	526,394	0.0056	0.9944	97.98
6.5	90,352,814	739,624	0.0082	0.9918	97.43
7.5	84,070,202	647,560	0.0077	0.9923	96.64
8.5	75,531,369	1,216,992	0.0161	0.9839	95.89
9.5	69,462,356	449,480	0.0065	0.9935	94.35
10.5	65,252,582	641,097	0.0098	0.9902	93.74
11.5	57,160,246	686,480	0.0120	0.9880	92.82
12.5	53,305,946	747,586	0.0140	0.9860	91.70
13.5	47,980,830	964,910	0.0201	0.9799	90.42
14.5	43,708,868	722,837	0.0165	0.9835	88.60
15.5	40,701,506	409,411	0.0101	0.9899	87.13
16.5	37,883,269	575,422	0.0152	0.9848	86.26
17.5	33,884,888	681,072	0.0201	0.9799	84.95
18.5	29,978,946	331,524	0.0111	0.9889	83.24
19.5	24,835,553	798,520	0.0322	0.9678	82.32
20.5	20,881,563	517,260	0.0248	0.9752	79.67
21.5	18,483,311	261,005	0.0141	0.9859	77.70
22.5	15,440,374	286,923	0.0186	0.9814	76.60
23.5	11,970,417	221,275	0.0185	0.9815	75.18
24.5	11,634,644	287,066	0.0247	0.9753	73.79
25.5	11,014,380	166,930	0.0152	0.9848	71.97
26.5	3,800,526	199,367	0.0525	0.9475	70.88
27.5	3,116,215	358,985	0.1152	0.8848	67.16
28.5	2,137,274	148,270	0.0694	0.9306	59.42
29.5	1,896,890	74,532	0.0393	0.9607	55.30
30.5	1,684,038	81,643	0.0485	0.9515	53.13
31.5	1,403,210	45,452	0.0324	0.9676	50.55
32.5	1,170,385	53,729	0.0459	0.9541	48.91
33.5	1,100,994	43,097	0.0391	0.9609	46.67
34.5	978,960	188,195	0.1922	0.8078	44.84
35.5	718,763	222,123	0.3090	0.6910	36.22
36.5	492,299	2,938	0.0060	0.9940	25.03
37.5	480,874	171,715	0.3571	0.6429	24.88
38.5	282,914	19,357	0.0684	0.9316	15.99

FORTISBC ENERGY INC.

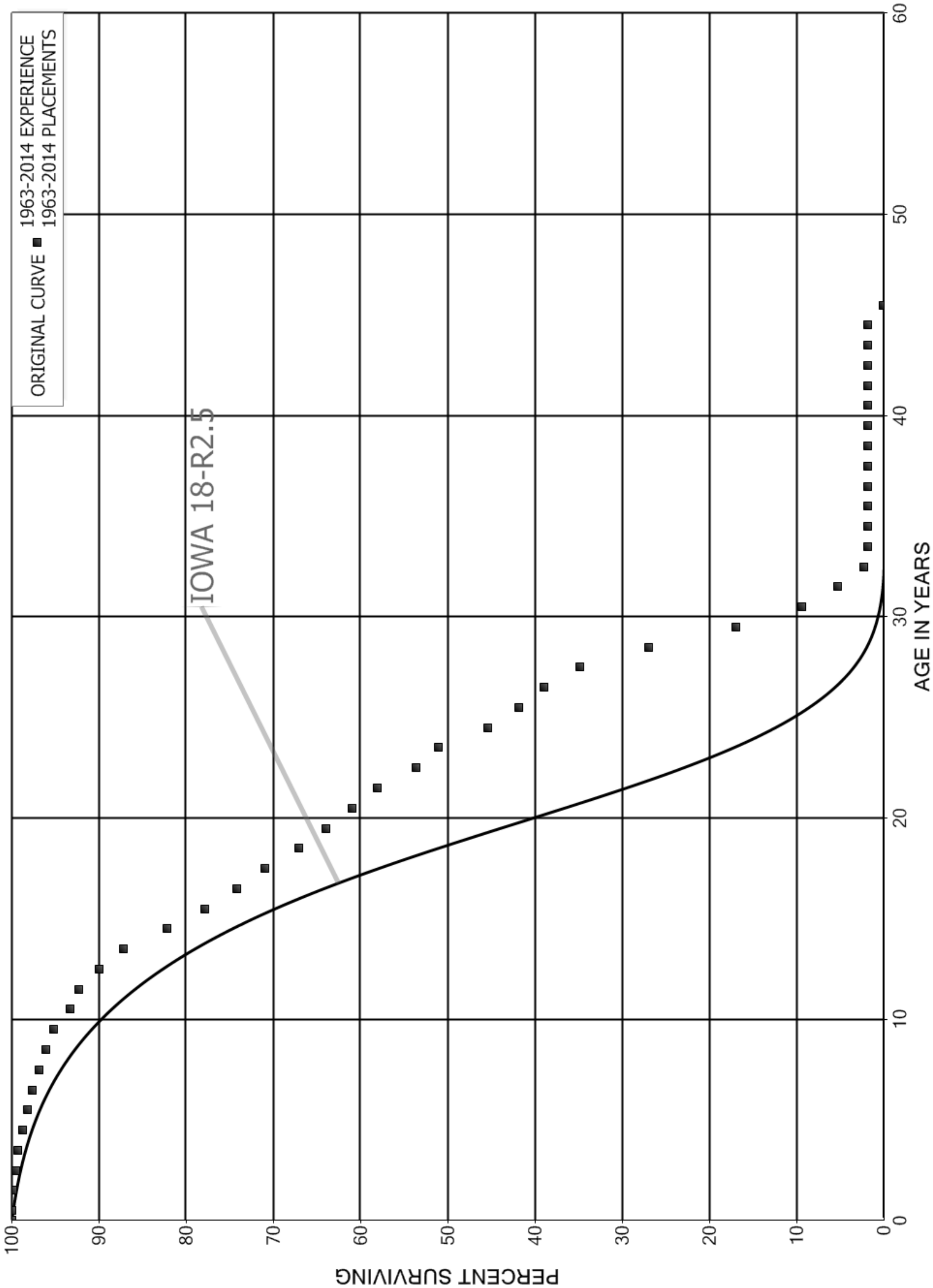
ACCOUNT 477.10 - DISTRIBUTION PLANT - MEASURING AND REGULATING ADDITIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1959-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	261,006	3,088	0.0118	0.9882	14.90
40.5	249,130	300	0.0012	0.9988	14.72
41.5	162,238	22,833	0.1407	0.8593	14.71
42.5	139,405	40,318	0.2892	0.7108	12.64
43.5	93,633	22,263	0.2378	0.7622	8.98
44.5	65,095	13,855	0.2128	0.7872	6.85
45.5	49,595		0.0000	1.0000	5.39
46.5	49,595		0.0000	1.0000	5.39
47.5	49,595		0.0000	1.0000	5.39
48.5	49,055		0.0000	1.0000	5.39
49.5	48,270		0.0000	1.0000	5.39
50.5	48,056	6,204	0.1291	0.8709	5.39
51.5	40,513		0.0000	1.0000	4.69
52.5	40,513		0.0000	1.0000	4.69
53.5	40,513		0.0000	1.0000	4.69
54.5	40,513		0.0000	1.0000	4.69
55.5	40,513		0.0000	1.0000	4.69
56.5					4.69

FORTISBC ENERGY INC.
ACCOUNT 478.10 - DISTRIBUTION PLANT - METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 478.10 - DISTRIBUTION PLANT - METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1963-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	308,482,710	194,470	0.0006	0.9994	100.00
0.5	298,068,520	377,804	0.0013	0.9987	99.94
1.5	286,192,414	765,002	0.0027	0.9973	99.81
2.5	274,672,278	779,377	0.0028	0.9972	99.54
3.5	263,494,340	1,340,233	0.0051	0.9949	99.26
4.5	253,914,494	1,632,320	0.0064	0.9936	98.76
5.5	244,482,037	1,139,911	0.0047	0.9953	98.12
6.5	236,100,390	1,921,972	0.0081	0.9919	97.66
7.5	225,057,689	1,953,727	0.0087	0.9913	96.87
8.5	215,172,690	1,888,625	0.0088	0.9912	96.03
9.5	204,989,246	4,070,418	0.0199	0.9801	95.18
10.5	187,765,372	2,024,796	0.0108	0.9892	93.29
11.5	169,348,527	4,349,632	0.0257	0.9743	92.29
12.5	153,773,751	4,655,876	0.0303	0.9697	89.92
13.5	142,796,837	8,280,008	0.0580	0.9420	87.20
14.5	127,335,681	6,703,332	0.0526	0.9474	82.14
15.5	111,371,786	5,252,767	0.0472	0.9528	77.82
16.5	99,966,132	4,382,608	0.0438	0.9562	74.15
17.5	87,171,097	4,648,400	0.0533	0.9467	70.90
18.5	73,518,226	3,501,413	0.0476	0.9524	67.11
19.5	62,674,540	2,868,367	0.0458	0.9542	63.92
20.5	55,838,640	2,718,480	0.0487	0.9513	60.99
21.5	49,488,641	3,729,816	0.0754	0.9246	58.02
22.5	43,017,463	2,111,575	0.0491	0.9509	53.65
23.5	38,436,667	4,265,465	0.1110	0.8890	51.02
24.5	22,414,305	1,752,781	0.0782	0.9218	45.36
25.5	15,593,836	1,057,989	0.0678	0.9322	41.81
26.5	1,793,825	187,992	0.1048	0.8952	38.97
27.5	1,537,999	348,232	0.2264	0.7736	34.89
28.5	1,127,122	421,739	0.3742	0.6258	26.99
29.5	644,387	287,219	0.4457	0.5543	16.89
30.5	355,269	152,679	0.4298	0.5702	9.36
31.5	202,439	114,772	0.5669	0.4331	5.34
32.5	87,667	18,397	0.2099	0.7901	2.31
33.5	69,144		0.0000	1.0000	1.83
34.5	69,144		0.0000	1.0000	1.83
35.5	69,144		0.0000	1.0000	1.83
36.5	69,144		0.0000	1.0000	1.83
37.5	69,144		0.0000	1.0000	1.83
38.5	69,144		0.0000	1.0000	1.83

FORTISBC ENERGY INC.

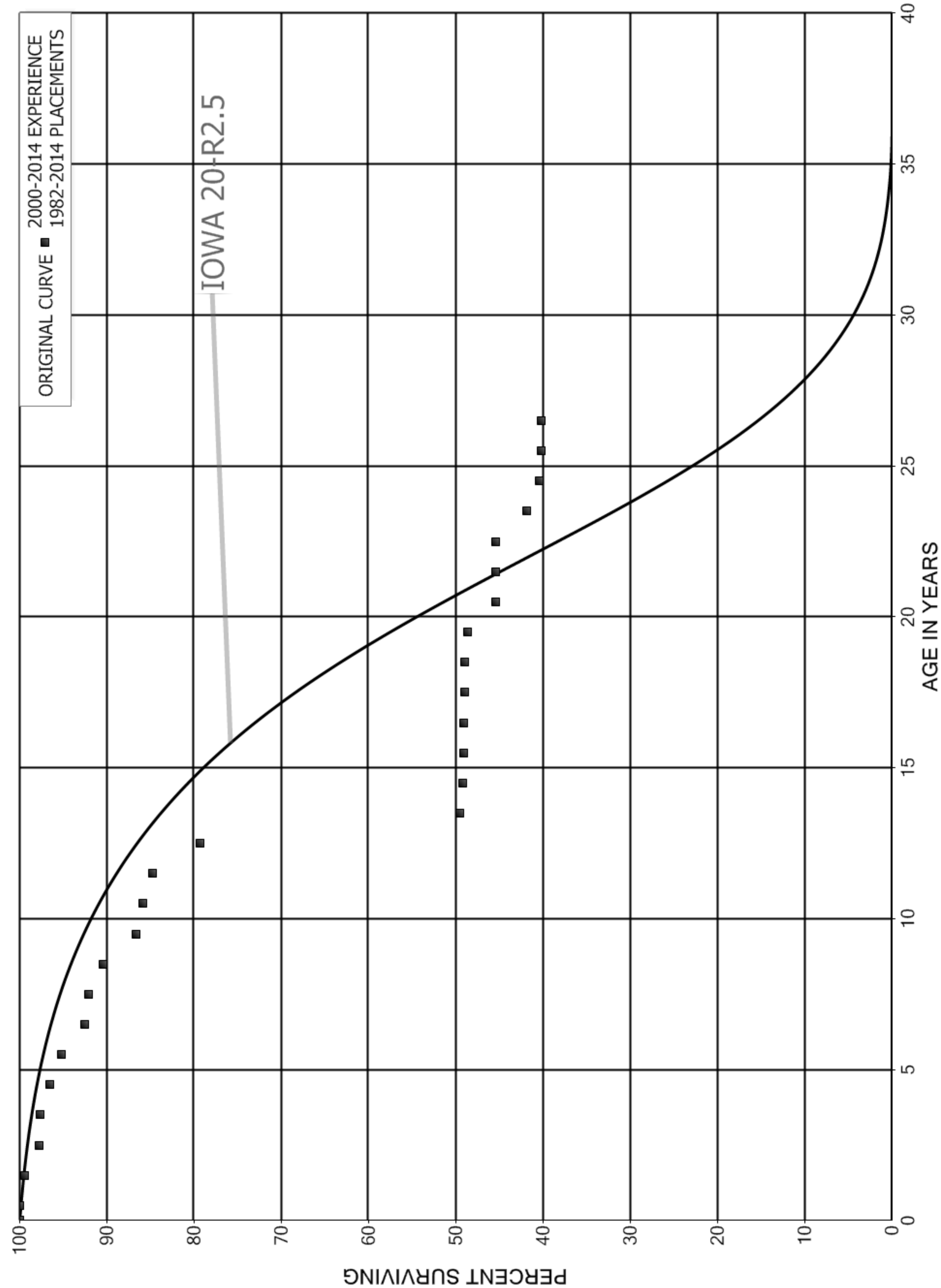
ACCOUNT 478.10 - DISTRIBUTION PLANT - METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1963-2014 EXPERIENCE BAND 1963-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	68,282		0.0000	1.0000	1.83
40.5	68,282		0.0000	1.0000	1.83
41.5	68,282		0.0000	1.0000	1.83
42.5	66,972		0.0000	1.0000	1.83
43.5	65,289		0.0000	1.0000	1.83
44.5	65,206	64,789	0.9936	0.0064	1.83
45.5					0.01

FORTISBC ENERGY INC.
ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

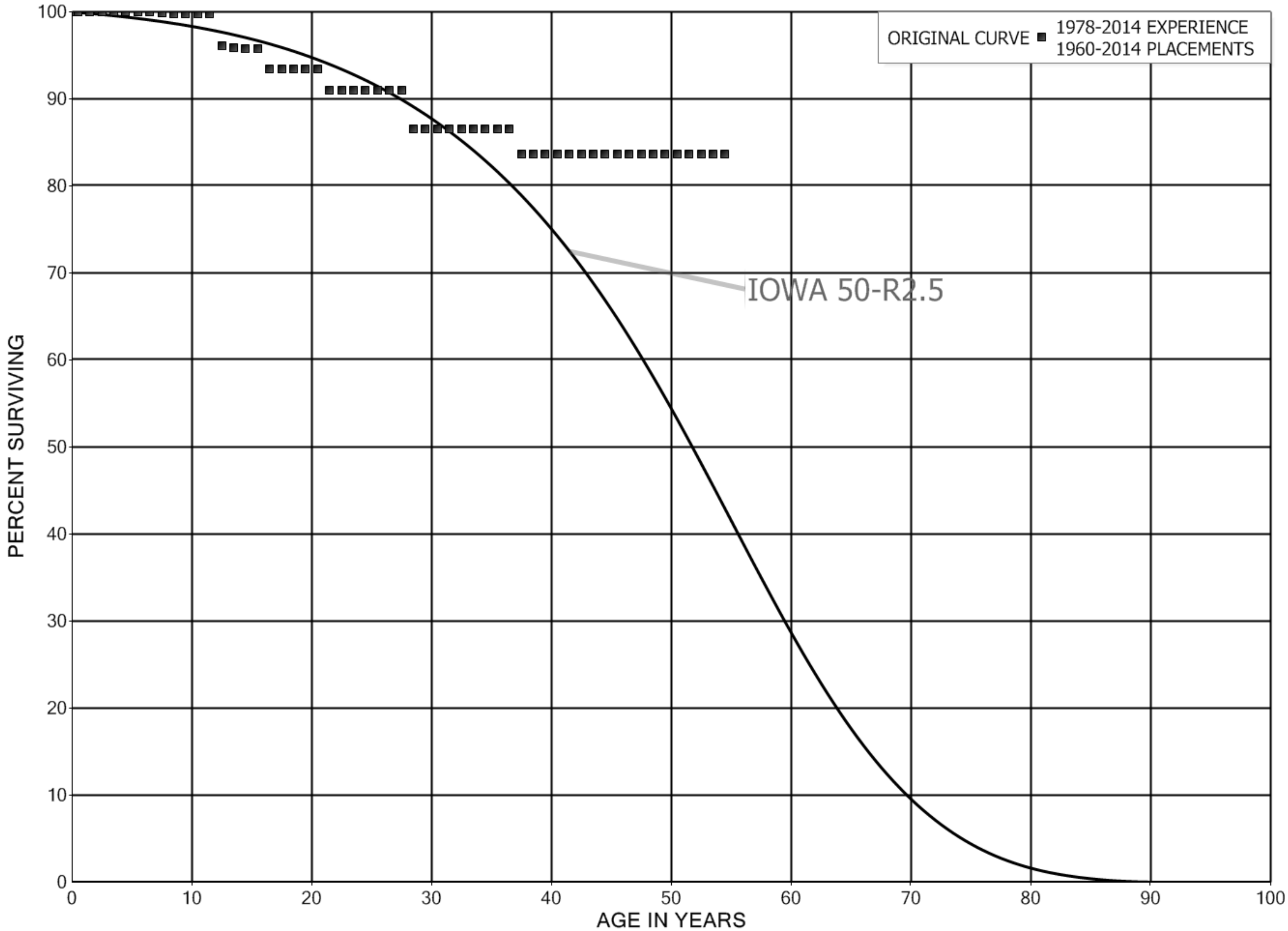
ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2014 EXPERIENCE BAND 2000-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,787,264	1,593	0.0001	0.9999	100.00
0.5	12,355,432	74,690	0.0060	0.9940	99.99
1.5	10,821,042	177,885	0.0164	0.9836	99.38
2.5	9,869,266	19,013	0.0019	0.9981	97.75
3.5	8,201,961	84,405	0.0103	0.9897	97.56
4.5	8,690,620	128,651	0.0148	0.9852	96.56
5.5	8,598,421	234,553	0.0273	0.9727	95.13
6.5	8,361,418	39,255	0.0047	0.9953	92.53
7.5	8,680,764	156,358	0.0180	0.9820	92.10
8.5	8,892,623	370,654	0.0417	0.9583	90.44
9.5	8,287,798	75,021	0.0091	0.9909	86.67
10.5	8,130,291	113,876	0.0140	0.9860	85.89
11.5	14,251,014	911,273	0.0639	0.9361	84.68
12.5	12,358,495	4,636,905	0.3752	0.6248	79.27
13.5	6,693,017	50,650	0.0076	0.9924	49.53
14.5	6,418,760	14,372	0.0022	0.9978	49.15
15.5	6,264,854		0.0000	1.0000	49.04
16.5	5,803,316	12,595	0.0022	0.9978	49.04
17.5	5,740,762	3,408	0.0006	0.9994	48.93
18.5	4,776,082	28,873	0.0060	0.9940	48.91
19.5	2,312,325	150,670	0.0652	0.9348	48.61
20.5	1,233,993	1,909	0.0015	0.9985	45.44
21.5	1,225,808		0.0000	1.0000	45.37
22.5	1,141,376	90,309	0.0791	0.9209	45.37
23.5	755,712	24,783	0.0328	0.9672	41.78
24.5	730,608	3,316	0.0045	0.9955	40.41
25.5	727,292		0.0000	1.0000	40.23
26.5					40.23

FORTISBC ENERGY INC.
ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2014 EXPERIENCE BAND 1978-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	109,925,971	12,000	0.0001	0.9999	100.00
0.5	109,881,752	40,054	0.0004	0.9996	99.99
1.5	108,952,609	396	0.0000	1.0000	99.95
2.5	95,427,086		0.0000	1.0000	99.95
3.5	86,561,044	6,229	0.0001	0.9999	99.95
4.5	85,567,787	32,473	0.0004	0.9996	99.95
5.5	83,433,677	4,411	0.0001	0.9999	99.91
6.5	82,403,010	85,556	0.0010	0.9990	99.90
7.5	79,198,012	34,252	0.0004	0.9996	99.80
8.5	78,032,820	38,626	0.0005	0.9995	99.75
9.5	26,332,200	1,840	0.0001	0.9999	99.71
10.5	25,322,586	6,520	0.0003	0.9997	99.70
11.5	23,825,188	856,492	0.0359	0.9641	99.67
12.5	22,452,661	67,312	0.0030	0.9970	96.09
13.5	21,140,485	20,937	0.0010	0.9990	95.80
14.5	20,468,761		0.0000	1.0000	95.71
15.5	20,241,621	477,881	0.0236	0.9764	95.71
16.5	18,387,395	10,000	0.0005	0.9995	93.45
17.5	18,016,399		0.0000	1.0000	93.40
18.5	13,650,780		0.0000	1.0000	93.40
19.5	9,386,923		0.0000	1.0000	93.40
20.5	5,622,958	150,222	0.0267	0.9733	93.40
21.5	5,330,943		0.0000	1.0000	90.90
22.5	2,017,938		0.0000	1.0000	90.90
23.5	1,990,314		0.0000	1.0000	90.90
24.5	1,875,474		0.0000	1.0000	90.90
25.5	1,422,800		0.0000	1.0000	90.90
26.5	895,606		0.0000	1.0000	90.90
27.5	892,256	42,784	0.0480	0.9520	90.90
28.5	849,226		0.0000	1.0000	86.54
29.5	848,139		0.0000	1.0000	86.54
30.5	802,601		0.0000	1.0000	86.54
31.5	791,560		0.0000	1.0000	86.54
32.5	783,805		0.0000	1.0000	86.54
33.5	774,836		0.0000	1.0000	86.54
34.5	769,915		0.0000	1.0000	86.54
35.5	464,087		0.0000	1.0000	86.54
36.5	443,730	15,000	0.0338	0.9662	86.54
37.5	419,803		0.0000	1.0000	83.62
38.5	171,033		0.0000	1.0000	83.62

FORTISBC ENERGY INC.

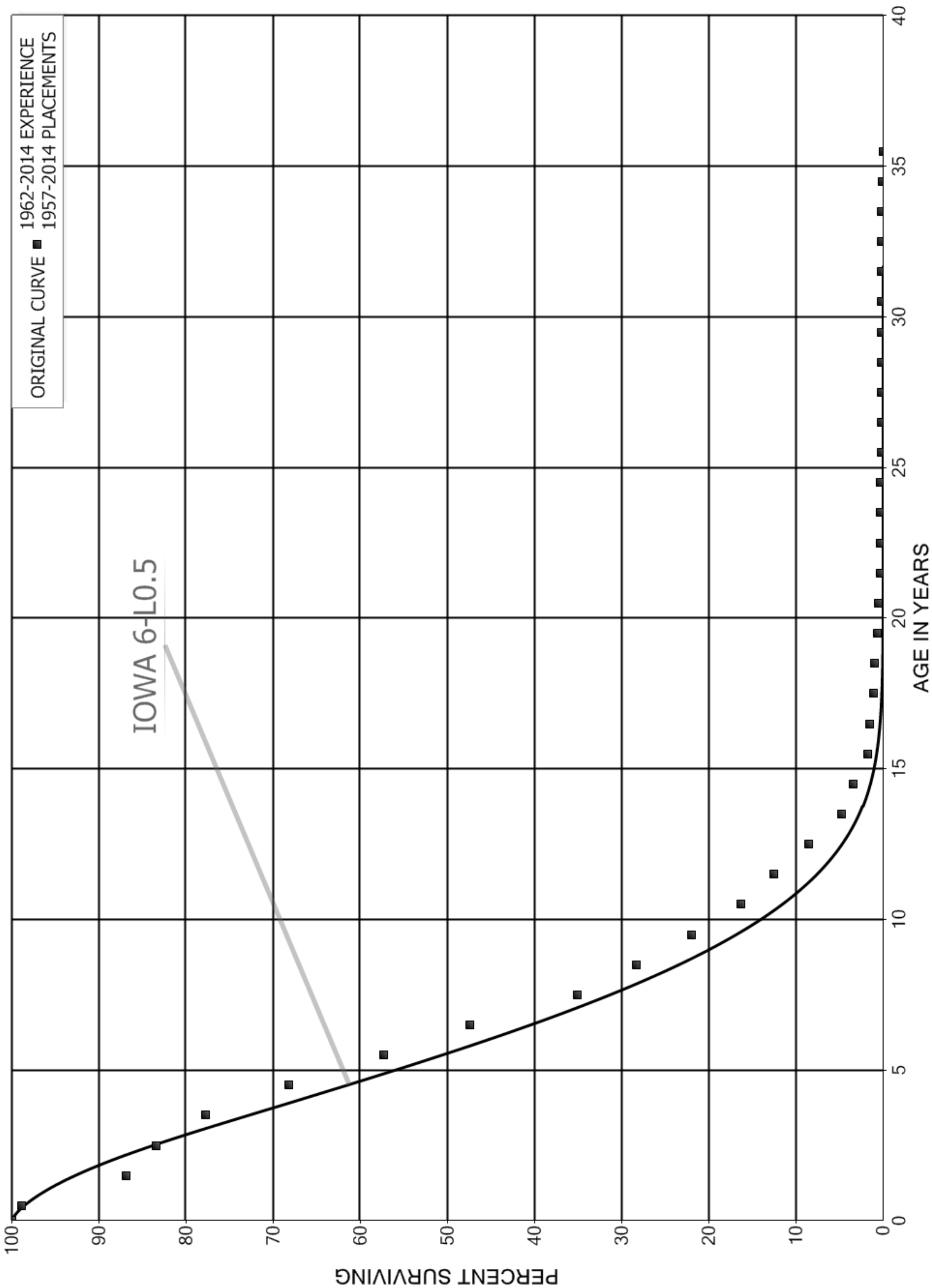
ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2014 EXPERIENCE BAND 1978-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	170,852		0.0000	1.0000	83.62
40.5	170,163		0.0000	1.0000	83.62
41.5	170,163		0.0000	1.0000	83.62
42.5	170,163		0.0000	1.0000	83.62
43.5	170,163		0.0000	1.0000	83.62
44.5	156,331		0.0000	1.0000	83.62
45.5	156,331		0.0000	1.0000	83.62
46.5	156,331		0.0000	1.0000	83.62
47.5	85,734		0.0000	1.0000	83.62
48.5	85,734		0.0000	1.0000	83.62
49.5	85,734		0.0000	1.0000	83.62
50.5	85,734		0.0000	1.0000	83.62
51.5	85,734		0.0000	1.0000	83.62
52.5	85,734		0.0000	1.0000	83.62
53.5	85,734		0.0000	1.0000	83.62
54.5					83.62

FORTISBC ENERGY INC.
ACCOUNT 484.00 - GENERAL PLANT - VEHICLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

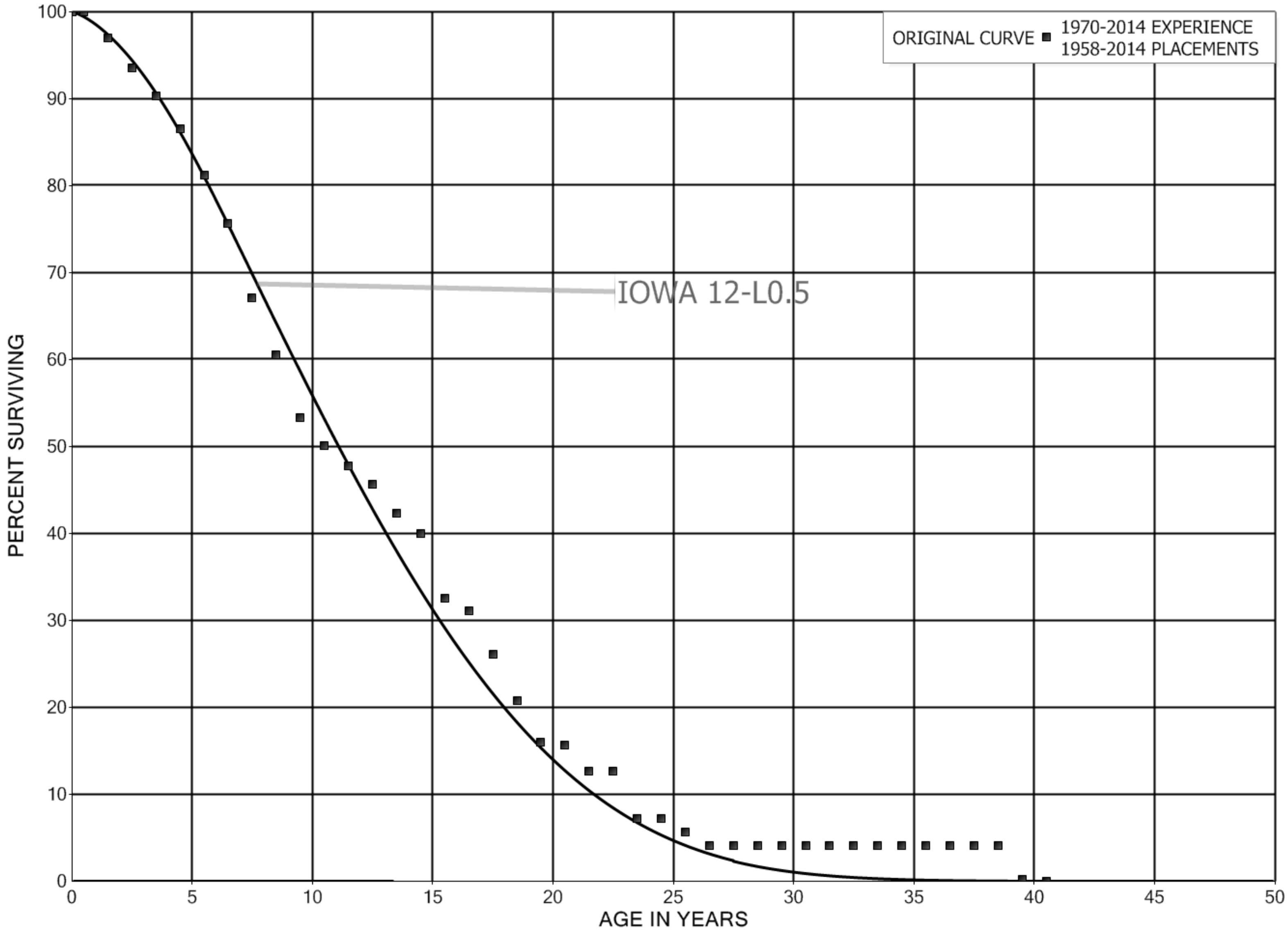
ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1962-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	30,572,991	339,619	0.0111	0.9889	100.00
0.5	28,312,508	3,452,073	0.1219	0.8781	98.89
1.5	23,554,439	930,789	0.0395	0.9605	86.83
2.5	21,826,858	1,480,989	0.0679	0.9321	83.40
3.5	19,378,523	2,397,699	0.1237	0.8763	77.74
4.5	15,788,704	2,505,126	0.1587	0.8413	68.12
5.5	12,394,003	2,155,080	0.1739	0.8261	57.31
6.5	9,481,864	2,461,152	0.2596	0.7404	47.35
7.5	6,754,665	1,303,598	0.1930	0.8070	35.06
8.5	4,617,757	1,034,784	0.2241	0.7759	28.29
9.5	3,234,264	831,886	0.2572	0.7428	21.95
10.5	2,268,366	521,792	0.2300	0.7700	16.31
11.5	1,563,227	508,987	0.3256	0.6744	12.56
12.5	869,479	383,570	0.4411	0.5589	8.47
13.5	479,246	139,605	0.2913	0.7087	4.73
14.5	332,642	160,622	0.4829	0.5171	3.35
15.5	172,020	27,336	0.1589	0.8411	1.73
16.5	144,684	36,543	0.2526	0.7474	1.46
17.5	108,141	10,589	0.0979	0.9021	1.09
18.5	97,552	41,165	0.4220	0.5780	0.98
19.5	56,387	10,920	0.1937	0.8063	0.57
20.5	45,467	19,252	0.4234	0.5766	0.46
21.5	26,215	1,254	0.0478	0.9522	0.26
22.5	24,961	367	0.0147	0.9853	0.25
23.5	24,594		0.0000	1.0000	0.25
24.5	24,594	3,721	0.1513	0.8487	0.25
25.5	20,873		0.0000	1.0000	0.21
26.5	20,873		0.0000	1.0000	0.21
27.5	20,873	384	0.0184	0.9816	0.21
28.5	20,489		0.0000	1.0000	0.21
29.5	20,489		0.0000	1.0000	0.21
30.5	20,489	3,441	0.1679	0.8321	0.21
31.5	17,048		0.0000	1.0000	0.17
32.5	17,048	385	0.0226	0.9774	0.17
33.5	16,663	7,823	0.4695	0.5305	0.17
34.5	8,840	8,840	1.0000		0.09
35.5					

FORTISBC ENERGY INC.
ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

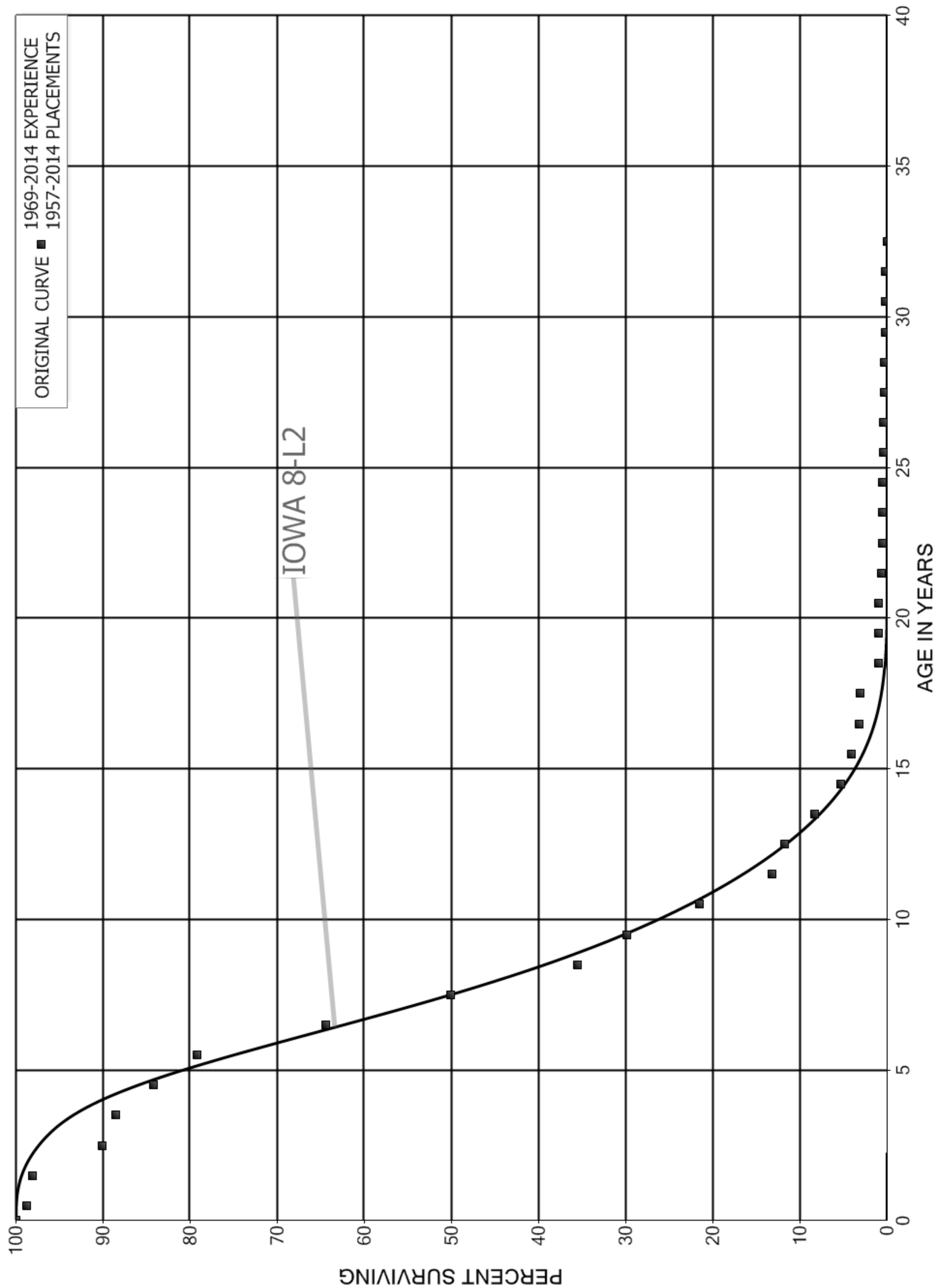
ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1958-2014 EXPERIENCE BAND 1970-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,141,576	325	0.0002	0.9998	100.00
0.5	2,196,259	67,465	0.0307	0.9693	99.98
1.5	2,125,691	74,412	0.0350	0.9650	96.91
2.5	1,798,357	61,430	0.0342	0.9658	93.52
3.5	1,654,721	70,598	0.0427	0.9573	90.33
4.5	1,504,504	92,838	0.0617	0.9383	86.47
5.5	1,411,667	95,878	0.0679	0.9321	81.14
6.5	1,283,120	146,019	0.1138	0.8862	75.63
7.5	1,125,555	109,889	0.0976	0.9024	67.02
8.5	974,863	116,540	0.1195	0.8805	60.48
9.5	824,375	49,894	0.0605	0.9395	53.25
10.5	786,591	36,511	0.0464	0.9536	50.02
11.5	686,395	30,434	0.0443	0.9557	47.70
12.5	632,340	45,607	0.0721	0.9279	45.59
13.5	570,227	30,871	0.0541	0.9459	42.30
14.5	526,373	98,676	0.1875	0.8125	40.01
15.5	411,448	18,288	0.0444	0.9556	32.51
16.5	340,373	54,188	0.1592	0.8408	31.06
17.5	253,457	51,939	0.2049	0.7951	26.12
18.5	180,989	41,845	0.2312	0.7688	20.77
19.5	119,901	2,493	0.0208	0.9792	15.97
20.5	117,408	22,597	0.1925	0.8075	15.63
21.5	45,161		0.0000	1.0000	12.62
22.5	38,761	16,706	0.4310	0.5690	12.62
23.5	22,055		0.0000	1.0000	7.18
24.5	22,055	4,653	0.2110	0.7890	7.18
25.5	17,402	4,800	0.2758	0.7242	5.67
26.5	12,602		0.0000	1.0000	4.10
27.5	12,602		0.0000	1.0000	4.10
28.5	12,602		0.0000	1.0000	4.10
29.5	12,602		0.0000	1.0000	4.10
30.5	12,602		0.0000	1.0000	4.10
31.5	12,602		0.0000	1.0000	4.10
32.5	12,602		0.0000	1.0000	4.10
33.5	12,602		0.0000	1.0000	4.10
34.5	12,602		0.0000	1.0000	4.10
35.5	12,602		0.0000	1.0000	4.10
36.5	12,602		0.0000	1.0000	4.10
37.5	12,602		0.0000	1.0000	4.10
38.5	12,602	12,109	0.9609	0.0391	4.10
39.5	493	493	1.0000		0.16
40.5					

FORTISBC ENERGY INC.
ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



FORTISBC ENERGY INC.

ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2014 EXPERIENCE BAND 1969-2014

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,389,226	95,257	0.0129	0.9871	100.00
0.5	5,593,961	33,718	0.0060	0.9940	98.71
1.5	5,470,018	450,545	0.0824	0.9176	98.12
2.5	4,809,154	84,272	0.0175	0.9825	90.03
3.5	4,495,975	220,140	0.0490	0.9510	88.46
4.5	3,638,981	214,821	0.0590	0.9410	84.13
5.5	2,958,246	551,801	0.1865	0.8135	79.16
6.5	2,234,403	498,677	0.2232	0.7768	64.39
7.5	1,599,333	464,735	0.2906	0.7094	50.02
8.5	1,069,932	170,918	0.1597	0.8403	35.49
9.5	811,287	225,652	0.2781	0.7219	29.82
10.5	423,848	164,262	0.3875	0.6125	21.52
11.5	228,136	24,538	0.1076	0.8924	13.18
12.5	203,598	60,683	0.2981	0.7019	11.76
13.5	113,451	41,190	0.3631	0.6369	8.26
14.5	72,261	16,144	0.2234	0.7766	5.26
15.5	56,117	11,951	0.2130	0.7870	4.08
16.5	44,166	1,419	0.0321	0.9679	3.21
17.5	42,747	29,983	0.7014	0.2986	3.11
18.5	12,764		0.0000	1.0000	0.93
19.5	12,764	1	0.0001	0.9999	0.93
20.5	12,763	4,280	0.3353	0.6647	0.93
21.5	8,483	1,812	0.2136	0.7864	0.62
22.5	6,671		0.0000	1.0000	0.49
23.5	6,671	323	0.0484	0.9516	0.49
24.5	6,348	1,079	0.1700	0.8300	0.46
25.5	5,269	74	0.0140	0.9860	0.38
26.5	5,195	1,509	0.2905	0.7095	0.38
27.5	3,686		0.0000	1.0000	0.27
28.5	3,686	729	0.1978	0.8022	0.27
29.5	2,957		0.0000	1.0000	0.22
30.5	2,957		0.0000	1.0000	0.22
31.5	2,957	2,957	1.0000		0.22
32.5					

PART VI. NET SALVAGE STATISTICS

FORTISBC ENERGY INC.

ACCOUNT 432.00 - MANUFACTURING - STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2004		13,473						13,473-	
2005		583						583-	
2006	14,056		0		0		0		0
2007									
2008									
2009									
2010		86,809						86,809-	
2011		86,320-						86,320	
2012									
2013									
2014	6,075		0		0		0		0
TOTAL	20,130	14,544	72		0		0	14,544-	72-
THREE-YEAR MOVING AVERAGES									
04-06	4,685	4,685	100		0		0	4,685-	100-
05-07	4,685	194	4		0		0	194-	4-
06-08	4,685		0		0		0		0
07-09									
08-10		28,936						28,936-	
09-11		163						163-	
10-12		163						163-	
11-13		28,773-						28,773	
12-14	2,025		0		0		0		0
FIVE-YEAR AVERAGE									
10-14	1,215	98	8		0		0	98-	8-

FORTISBC ENERGY INC.

ACCOUNT 433.00 - MANUFACTURING - EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010		50,733						50,733-	
2011		50,478-						50,478	
2012									
2013									
2014									
TOTAL		255						255-	
THREE-YEAR MOVING AVERAGES									
10-12		85						85-	
11-13		16,826-						16,826	
12-14									
FIVE-YEAR AVERAGE									
10-14		51						51-	

FORTISBC ENERGY INC.

ACCOUNT 434.00 - MANUFACTURING - HOLDERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010		82,642						82,642-	
2011		82,173-						82,173	
2012									
2013									
2014	1,000		0		0		0		0
TOTAL	1,000	469	47		0		0	469-	47-
THREE-YEAR MOVING AVERAGES									
10-12		156						156-	
11-13		27,391-						27,391	
12-14	333		0		0		0		0
FIVE-YEAR AVERAGE									
10-14	200	94	47		0		0	94-	47-

FORTISBC ENERGY INC.

ACCOUNT 436.00 - MANUFACTURING - COMPRESSOR EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2010		1,097						1,097-	
2011		1,086-						1,086	
2012									
2013									
2014									
TOTAL		11						11-	

THREE-YEAR MOVING AVERAGES

10-12		4						4-	
11-13		362-						362	
12-14									

FIVE-YEAR AVERAGE

10-14		2						2-	

FORTISBC ENERGY INC.

ACCOUNT 437.00 - MANUFACTURING - MEASURING AND REGULATING EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	27,548		0		0		0		0
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010		11,574						11,574-	
2011		11,476-						11,476	
2012									
2013									
2014	4,012	4,903	122		0		0	4,903-	122-
TOTAL	31,559	5,000	16		0		0	5,000-	16-
THREE-YEAR MOVING AVERAGES									
01-03	9,183		0		0		0		0
02-04									
03-05									
04-06									
05-07									
06-08									
07-09									
08-10		3,858						3,858-	
09-11		32						32-	
10-12		32						32-	
11-13		3,825-						3,825	
12-14	1,337	1,634	122		0		0	1,634-	122-
FIVE-YEAR AVERAGE									
10-14	802	1,000	125		0		0	1,000-	125-

FORTISBC ENERGY INC.

ACCOUNT 442.00 - LNG - STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2006	1,959		0		0		0		0
2007	17,458		0		0		0		0
2008	6,000	2,000	33		0		0	2,000-	33-
2009									
2010									
2011									
2012									
2013									
2014									
TOTAL	25,417	2,000	8		0		0	2,000-	8-
THREE-YEAR MOVING AVERAGES									
06-08	8,472	667	8		0		0	667-	8-
07-09	7,819	667	9		0		0	667-	9-
08-10	2,000	667	33		0		0	667-	33-
09-11									
10-12									
11-13									
12-14									
FIVE-YEAR AVERAGE									
10-14									

FORTISBC ENERGY INC.

ACCOUNT 443.00 - LNG - EQUIPMENT

SUMMARY OF BOOK SALVAGE

		COST OF		G R O S S	S A L V A G E			NET	
	REGULAR	REMOVAL		REUSE		FINAL		SALVAGE	
YEAR	RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2002		3,000						3,000-	
2003	12,708		0		0		0		0
2004									
2005									
2006	44,685		0		0		0		0
2007	80,648		0		0		0		0
2008	1,734		0		0		0		0
2009									
2010									
2011									
2012									
2013									
2014									
TOTAL	139,775	3,000	2		0		0	3,000-	2-
THREE-YEAR MOVING AVERAGES									
02-04	4,236	1,000	24		0		0	1,000-	24-
03-05	4,236		0		0		0		0
04-06	14,895		0		0		0		0
05-07	41,778		0		0		0		0
06-08	42,356		0		0		0		0
07-09	27,461		0		0		0		0
08-10	578		0		0		0		0
09-11									
10-12									
11-13									
12-14									
FIVE-YEAR AVERAGE									
10-14									

FORTISBC ENERGY INC.

ACCOUNT 449.00 - LNG - OTHER EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	30,000		0		0		0		0
2002									
2003	96,616		0		0		0		0
2004									
2005	214,983		0		0		0		0
2006	111,600		0		0		0		0
2007	196,414		0		0		0		0
2008	1,297,755	283,859	22		0	79,166	6	204,693-	16-
2009	82,431		0		0		0		0
2010		552						552-	
2011		8,558						8,558-	
2012									
2013		1,802						1,802-	
2014									
TOTAL	2,029,799	294,771	15		0	79,166	4	215,605-	11-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-03	42,205		0		0		0		0
02-04	32,205		0		0		0		0
03-05	103,866		0		0		0		0
04-06	108,861		0		0		0		0
05-07	174,332		0		0		0		0
06-08	535,256	94,620	18		0	26,389	5	68,231-	13-
07-09	525,534	94,620	18		0	26,389	5	68,231-	13-
08-10	460,062	94,804	21		0	26,389	6	68,415-	15-
09-11	27,477	3,037	11		0		0	3,037-	11-
10-12		3,037						3,037-	
11-13		3,453						3,453-	
12-14		601						601-	

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14		2,182						2,182-	

FORTISBC ENERGY INC.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2008	13,400		0		0		0		0
2009	40,138		0		0		0		0
2010									
2011		173						173-	
2012	349,500	8,368	2		0		0	8,368-	2-
2013		1,391						1,391-	
2014									
TOTAL	403,038	9,932	2		0		0	9,932-	2-
THREE-YEAR MOVING AVERAGES									
08-10	17,846		0		0		0		0
09-11	13,379	58	0		0		0	58-	0
10-12	116,500	2,847	2		0		0	2,847-	2-
11-13	116,500	3,311	3		0		0	3,311-	3-
12-14	116,500	3,253	3		0		0	3,253-	3-
FIVE-YEAR AVERAGE									
10-14	69,900	1,986	3		0		0	1,986-	3-

FORTISBC ENERGY INC.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	26,672		0		0		0		0
2002									
2003	75,177		0		0		0		0
2004	86,997	15,037	17		0		0	15,037-	17-
2005									
2006	50,237		0		0		0		0
2007	40,820		0		0		0		0
2008									
2009	4,405		0		0		0		0
2010	219,500	181,034	82		0		0	181,034-	82-
2011	10,000	4,137-	41-		0		0	4,137	41
2012	7,325	7,669	105		0		0	7,669-	105-
2013	4,641		0		0		0		0
2014									
TOTAL	525,774	199,602	38		0		0	199,602-	38-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-03	33,950		0		0		0		0
02-04	54,058	5,012	9		0		0	5,012-	9-
03-05	54,058	5,012	9		0		0	5,012-	9-
04-06	45,745	5,012	11		0		0	5,012-	11-
05-07	30,352		0		0		0		0
06-08	30,352		0		0		0		0
07-09	15,075		0		0		0		0
08-10	74,635	60,345	81		0		0	60,345-	81-
09-11	77,968	58,966	76		0		0	58,966-	76-
10-12	78,942	61,522	78		0		0	61,522-	78-
11-13	7,322	1,177	16		0		0	1,177-	16-
12-14	3,989	2,556	64		0		0	2,556-	64-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14	48,293	36,913	76		0		0	36,913-	76-

FORTISBC ENERGY INC.

ACCOUNT 464.00 - TRANSMISSION - OTHER STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	70		0		0		0		0
2002									
2003		15,490						15,490-	
2004									
2005									
2006									
2007	6,746		0		0		0		0
2008									
2009	11,730		0		0		0		0
2010									
2011									
2012									
2013		14,534						14,534-	
2014	643		0		0		0		0
TOTAL	19,190	30,025	156		0		0	30,025-	156-
THREE-YEAR MOVING AVERAGES									
01-03	23	5,163			0		0	5,163-	
02-04		5,163						5,163-	
03-05		5,163						5,163-	
04-06									
05-07	2,249		0		0		0		0
06-08	2,249		0		0		0		0
07-09	6,159		0		0		0		0
08-10	3,910		0		0		0		0
09-11	3,910		0		0		0		0
10-12									
11-13		4,845						4,845-	
12-14	214	4,845			0		0	4,845-	
FIVE-YEAR AVERAGE									
10-14	129	2,907			0		0	2,907-	

FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANSMSSION - PIPELINE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	719		0		0		0		0
2001	1,219,906		0		0		0		0
2002	657,746	5,259	1		0		0	5,259-	1-
2003	1,850,075		0		0		0		0
2004	682,967	80,507	12		0		0	80,507-	12-
2005	749,466	36,935	5		0		0	36,935-	5-
2006	576,912	7,635	1		0		0	7,635-	1-
2007	124,402		0		0		0		0
2008	67,495	47,528	70		0		0	47,528-	70-
2009	703,198	752,187	107		0		0	752,187-	107-
2010	321,324	171,010	53		0		0	171,010-	53-
2011	861,075	845,270	98		0		0	845,270-	98-
2012	3,131,294	154,110	5		0		0	154,110-	5-
2013	488,034	129,806	27		0		0	129,806-	27-
2014	4,026,900	1,486,283	37		0		0	1,486,283-	37-
TOTAL	15,461,515	3,716,529	24		0		0	3,716,529-	24-
THREE-YEAR MOVING AVERAGES									
00-02	626,124	1,753	0		0		0	1,753-	0
01-03	1,242,576	1,753	0		0		0	1,753-	0
02-04	1,063,596	28,589	3		0		0	28,589-	3-
03-05	1,094,169	39,147	4		0		0	39,147-	4-
04-06	669,782	41,692	6		0		0	41,692-	6-
05-07	483,593	14,857	3		0		0	14,857-	3-
06-08	256,270	18,388	7		0		0	18,388-	7-
07-09	298,365	266,572	89		0		0	266,572-	89-
08-10	364,006	323,575	89		0		0	323,575-	89-
09-11	628,532	589,489	94		0		0	589,489-	94-
10-12	1,437,898	390,130	27		0		0	390,130-	27-
11-13	1,493,468	376,395	25		0		0	376,395-	25-
12-14	2,548,743	590,066	23		0		0	590,066-	23-
FIVE-YEAR AVERAGE									
10-14	1,765,725	557,296	32		0		0	557,296-	32-

FORTISBC ENERGY INC.

ACCOUNT 466.00 - TRANSMSSION - COMPRESSOR EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	10,826		0		0		0		0
2002									
2003	57,131	12,923	23		0		0	12,923-	23-
2004		2,000						2,000-	
2005	67,044		0		0		0		0
2006									
2007									
2008	62,641	3,523	6		0		0	3,523-	6-
2009		19,228						19,228-	
2010	449,859	2,280	1		0		0	2,280-	1-
2011	714,672	19,452	3		0		0	19,452-	3-
2012	94,949	5,542	6		0		0	5,542-	6-
2013	1,329,229	1,566	0		0		0	1,566-	0
2014	160,000		0		0		0		0
TOTAL	2,946,351	66,514	2		0		0	66,514-	2-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-03	22,652	4,308	19		0		0	4,308-	19-
02-04	19,044	4,974	26		0		0	4,974-	26-
03-05	41,392	4,974	12		0		0	4,974-	12-
04-06	22,348	667	3		0		0	667-	3-
05-07	22,348		0		0		0		0
06-08	20,880	1,174	6		0		0	1,174-	6-
07-09	20,880	7,584	36		0		0	7,584-	36-
08-10	170,833	8,344	5		0		0	8,344-	5-
09-11	388,177	13,654	4		0		0	13,654-	4-
10-12	419,827	9,091	2		0		0	9,091-	2-
11-13	712,950	8,853	1		0		0	8,853-	1-
12-14	528,059	2,369	0		0		0	2,369-	0

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14	549,742	5,768	1		0		0	5,768-	1-

FORTISBC ENERGY INC.

ACCOUNT 467.10 - TRANSMSSION - MEASURING AND REGULATING EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	251,311		0		0		0		0
2002	178,402		0		0		0		0
2003	309,532		0		0		0		0
2004	1,928,908	77,340	4		0		0	77,340-	4-
2005	139,586	9,763	7		0		0	9,763-	7-
2006	206,490	47,392	23		0		0	47,392-	23-
2007	275,309		0		0		0		0
2008	26,600	6,720	25		0		0	6,720-	25-
2009	231,628	2,015	1		0		0	2,015-	1-
2010	737,851	4,685	1		0		0	4,685-	1-
2011	127,225	1,442	1		0		0	1,442-	1-
2012	283,137	32,994	12		0		0	32,994-	12-
2013	214,307	102,828	48		0		0	102,828-	48-
2014	75,754	43,173	57		0		0	43,173-	57-
TOTAL	4,986,041	328,353	7		0		0	328,353-	7-

THREE-YEAR MOVING AVERAGES

01-03	246,415		0		0		0		0
02-04	805,614	25,780	3		0		0	25,780-	3-
03-05	792,675	29,034	4		0		0	29,034-	4-
04-06	758,328	44,831	6		0		0	44,831-	6-
05-07	207,129	19,052	9		0		0	19,052-	9-
06-08	169,466	18,037	11		0		0	18,037-	11-
07-09	177,846	2,912	2		0		0	2,912-	2-
08-10	332,026	4,473	1		0		0	4,473-	1-
09-11	365,568	2,714	1		0		0	2,714-	1-
10-12	382,737	13,040	3		0		0	13,040-	3-
11-13	208,223	45,755	22		0		0	45,755-	22-
12-14	191,066	59,665	31		0		0	59,665-	31-

FIVE-YEAR AVERAGE

10-14	287,655	37,025	13		0		0	37,025-	13-

FORTISBC ENERGY INC.

ACCOUNT 467.20 - TRANSMSSION - TELEMETRY EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	121,625		0		0		0		0
2001	1,877,759		0		0		0		0
2002									
2003	72,642		0		0		0		0
2004	47,359		0		0		0		0
2005	57,476		0		0		0		0
2006	1,337,511		0		0		0		0
2007	300		0		0		0		0
2008									
2009	7,104		0		0		0		0
2010									
2011	7,903	500	6		0		0	500-	6-
2012	5,000		0		0		0		0
2013	37,706		0		0		0		0
2014									
TOTAL	3,572,385	500	0		0		0	500-	0
THREE-YEAR MOVING AVERAGES									
00-02	666,461		0		0		0		0
01-03	650,134		0		0		0		0
02-04	40,000		0		0		0		0
03-05	59,159		0		0		0		0
04-06	480,782		0		0		0		0
05-07	465,096		0		0		0		0
06-08	445,937		0		0		0		0
07-09	2,468		0		0		0		0
08-10	2,368		0		0		0		0
09-11	5,002	167	3		0		0	167-	3-
10-12	4,301	167	4		0		0	167-	4-
11-13	16,870	167	1		0		0	167-	1-
12-14	14,235		0		0		0		0
FIVE-YEAR AVERAGE									
10-14	10,122	100	1		0		0	100-	1-

FORTISBC ENERGY INC.

ACCOUNT 468.00 - TRANSMSSION - COMMUNICATIONS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2001	13,824		0		0	9,443	68	9,443	68
2002									
2003	211,562		0		0		0		0
2004									
2005									
2006	8,844		0		0		0		0
2007									
2008									
2009									
2010	33,038		0		0		0		0
2011	229,969	13,103	6		0		0	13,103-	6-
2012									
2013	225,244		0		0		0		0
2014									
TOTAL	722,481	13,103	2		0	9,443	1	3,660-	1-
THREE-YEAR MOVING AVERAGES									
01-03	75,129		0		0	3,148	4	3,148	4
02-04	70,521		0		0		0		0
03-05	70,521		0		0		0		0
04-06	2,948		0		0		0		0
05-07	2,948		0		0		0		0
06-08	2,948		0		0		0		0
07-09									
08-10	11,013		0		0		0		0
09-11	87,669	4,368	5		0		0	4,368-	5-
10-12	87,669	4,368	5		0		0	4,368-	5-
11-13	151,738	4,368	3		0		0	4,368-	3-
12-14	75,081		0		0		0		0
FIVE-YEAR AVERAGE									
10-14	97,650	2,621	3		0		0	2,621-	3-

FORTISBC ENERGY INC.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	13,168		0		0		0		0
2001	104,190		0		0		0		0
2002	40,060		0		0		0		0
2003	78,668		0		0		0		0
2004	953		0		0		0		0
2005		3,678						3,678-	
2006	50,994	4,276	8		0		0	4,276-	8-
2007	54,535		0		0		0		0
2008	80,293	26,516	33		0		0	26,516-	33-
2009	35,094	39,152	112		0		0	39,152-	112-
2010	3,308	243	7		0		0	243-	7-
2011	18,154	4,133	23		0		0	4,133-	23-
2012		187						187-	
2013	92,192	2,400	3		0		0	2,400-	3-
2014	66,668		0		0		0		0
TOTAL	638,277	80,584	13		0		0	80,584-	13-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
00-02	52,473		0		0		0		0
01-03	74,306		0		0		0		0
02-04	39,894		0		0		0		0
03-05	26,540	1,226	5		0		0	1,226-	5-
04-06	17,316	2,652	15		0		0	2,652-	15-
05-07	35,176	2,652	8		0		0	2,652-	8-
06-08	61,941	10,264	17		0		0	10,264-	17-
07-09	56,641	21,889	39		0		0	21,889-	39-
08-10	39,565	21,970	56		0		0	21,970-	56-
09-11	18,852	14,509	77		0		0	14,509-	77-
10-12	7,154	1,521	21		0		0	1,521-	21-
11-13	36,782	2,240	6		0		0	2,240-	6-
12-14	52,953	862	2		0		0	862-	2-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14	36,064	1,392	4		0		0	1,392-	4-

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	1,800,475		0		0		0		0
2001	1,098,971		0		0		0		0
2002	2,474,792	588,456	24		0		0	588,456-	24-
2003	343,211	211,987	62		0		0	211,987-	62-
2004	2,332,842	3,531,097	151		0		0	3,531,097-	151-
2005	2,485,696	3,551,042	143		0		0	3,551,042-	143-
2006	13,164,951	1,630,153	12		0		0	1,630,153-	12-
2007	9,140,075		0		0		0		0
2008	3,702,055	5,404,860	146		0		0	5,404,860-	146-
2009	4,319,221	5,440,566	126		0		0	5,440,566-	126-
2010	3,171,509	7,393,063	233		0		0	7,393,063-	233-
2011	4,414,701	12,179,045	276		0		0	12,179,045-	276-
2012	5,320,515	11,036,649	207		0		0	11,036,649-	207-
2013	5,105,091	10,120,174	198		0		0	10,120,174-	198-
2014	9,452,463	8,438,368	89		0		0	8,438,368-	89-
TOTAL	68,326,569	69,525,461	102		0		0	69,525,461-	102-
THREE-YEAR MOVING AVERAGES									
00-02	1,791,413	196,152	11		0		0	196,152-	11-
01-03	1,305,658	266,814	20		0		0	266,814-	20-
02-04	1,716,948	1,443,847	84		0		0	1,443,847-	84-
03-05	1,720,583	2,431,375	141		0		0	2,431,375-	141-
04-06	5,994,497	2,904,098	48		0		0	2,904,098-	48-
05-07	8,263,574	1,727,065	21		0		0	1,727,065-	21-
06-08	8,669,027	2,345,004	27		0		0	2,345,004-	27-
07-09	5,720,450	3,615,142	63		0		0	3,615,142-	63-
08-10	3,730,928	6,079,496	163		0		0	6,079,496-	163-
09-11	3,968,477	8,337,558	210		0		0	8,337,558-	210-
10-12	4,302,242	10,202,919	237		0		0	10,202,919-	237-
11-13	4,946,769	11,111,956	225		0		0	11,111,956-	225-
12-14	6,626,023	9,865,064	149		0		0	9,865,064-	149-
FIVE-YEAR AVERAGE									
10-14	5,492,856	9,833,460	179		0		0	9,833,460-	179-

FORTISBC ENERGY INC.

ACCOUNT 474.00 - DISTRIBUTION - METER/REGULATOR INSTALLATIONS

SUMMARY OF BOOK SALVAGE

		COST OF REMOVAL		GROSS SALVAGE				NET SALVAGE	
				REUSE		FINAL			
YEAR	REGULAR RETIREMENTS	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	95,683		0		0		0		0
2001	2,428,481		0		0		0		0
2002	6,270,257	53,023	1		0		0	53,023-	1-
2003	3,267,469	14,989	0		0		0	14,989-	0
2004	4,930,968	247,468	5		0		0	247,468-	5-
2005	6,813,560	217,139	3		0		0	217,139-	3-
2006	8,240,670	211,256	3		0		0	211,256-	3-
2007	5,860,519		0		0		0		0
2008	7,010,448	900,663	13		0		0	900,663-	13-
2009	7,349,546	1,320,731	18		0	12,236	0	1,308,495-	18-
2010	17,660,406	2,490,045	14		0		0	2,490,045-	14-
2011	68,245	2,717,111			0		0	2,717,111-	
2012	1,078,773	2,994,079	278		0		0	2,994,079-	278-
2013	851,997	3,478,502	408		0		0	3,478,502-	408-
2014	899,228	3,679,458	409		0		0	3,679,458-	409-
TOTAL	72,826,251	18,324,463	25		0	12,236	0	18,312,227-	25-
THREE-YEAR MOVING AVERAGES									
00-02	2,931,474	17,674	1		0		0	17,674-	1-
01-03	3,988,736	22,671	1		0		0	22,671-	1-
02-04	4,822,898	105,160	2		0		0	105,160-	2-
03-05	5,003,999	159,865	3		0		0	159,865-	3-
04-06	6,661,733	225,288	3		0		0	225,288-	3-
05-07	6,971,583	142,798	2		0		0	142,798-	2-
06-08	7,037,212	370,640	5		0		0	370,640-	5-
07-09	6,740,171	740,464	11		0	4,079	0	736,386-	11-
08-10	10,673,467	1,570,479	15		0	4,079	0	1,566,401-	15-
09-11	8,359,399	2,175,962	26		0	4,079	0	2,171,884-	26-
10-12	6,269,142	2,733,745	44		0		0	2,733,745-	44-
11-13	666,339	3,063,231	460		0		0	3,063,231-	460-
12-14	943,333	3,384,013	359		0		0	3,384,013-	359-
FIVE-YEAR AVERAGE									
10-14	4,111,730	3,071,839	75		0		0	3,071,839-	75-

FORTISBC ENERGY INC.

ACCOUNT 475.00 - DISTRIBUTION - SYSTEMS - MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	4,430,340		0		0		0		0
2001	485,250		0		0		0		0
2002	1,000,236	63,210	6		0		0	63,210-	6-
2003	96,226	23,024	24		0		0	23,024-	24-
2004	424,865	364,611	86		0		0	364,611-	86-
2005	816,133	532,849	65		0		0	532,849-	65-
2006	2,701,842	139,634	5		0		0	139,634-	5-
2007	2,163,435		0		0		0		0
2008	2,444,452	474,834	19		0		0	474,834-	19-
2009	3,350,956	592,027	18		0		0	592,027-	18-
2010	1,212,065	531,511	44		0		0	531,511-	44-
2011	1,414,525	766,407	54		0		0	766,407-	54-
2012	1,563,776	1,311,699	84		0		0	1,311,699-	84-
2013	1,683,240	620,950	37		0		0	620,950-	37-
2014	4,103,990	1,357,998	33		0		0	1,357,998-	33-
TOTAL	27,891,330	6,778,753	24		0		0	6,778,753-	24-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
00-02	1,971,942	21,070	1		0		0	21,070-	1-
01-03	527,237	28,745	5		0		0	28,745-	5-
02-04	507,109	150,282	30		0		0	150,282-	30-
03-05	445,742	306,828	69		0		0	306,828-	69-
04-06	1,314,280	345,698	26		0		0	345,698-	26-
05-07	1,893,803	224,161	12		0		0	224,161-	12-
06-08	2,436,576	204,823	8		0		0	204,823-	8-
07-09	2,652,948	355,620	13		0		0	355,620-	13-
08-10	2,335,824	532,791	23		0		0	532,791-	23-
09-11	1,992,515	629,981	32		0		0	629,981-	32-
10-12	1,396,788	869,872	62		0		0	869,872-	62-
11-13	1,553,847	899,685	58		0		0	899,685-	58-
12-14	2,450,335	1,096,882	45		0		0	1,096,882-	45-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14	1,995,519	917,713	46		0		0	917,713-	46-

FORTISBC ENERGY INC.

ACCOUNT 477.10 - DISTRIBUTION - MEASURING AND REGULATING ADDITIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	346,633		0		0		0		0
2001	2,262,537		0		0		0		0
2002	799,436	43,803	5		0		0	43,803-	5-
2003	977,723	45,686	5		0		0	45,686-	5-
2004	63,872	158,470	248		0		0	158,470-	248-
2005	503,761	40,275	8		0		0	40,275-	8-
2006	986,927	34,302	3		0		0	34,302-	3-
2007	563,389		0		0		0		0
2008	882,542	356,214	40		0		0	356,214-	40-
2009	521,037	104,228	20		0		0	104,228-	20-
2010	277,280	23,126	8		0		0	23,126-	8-
2011	392,040	42,042	11		0		0	42,042-	11-
2012	1,101,785	59,878	5		0		0	59,878-	5-
2013	422,122	50,946	12		0		0	50,946-	12-
2014	483,083	21,385	4		0		0	21,385-	4-
TOTAL	10,584,166	980,355	9		0		0	980,355-	9-
THREE-YEAR MOVING AVERAGES									
00-02	1,136,202	14,601	1		0		0	14,601-	1-
01-03	1,346,565	29,830	2		0		0	29,830-	2-
02-04	613,677	82,653	13		0		0	82,653-	13-
03-05	515,119	81,477	16		0		0	81,477-	16-
04-06	518,187	77,682	15		0		0	77,682-	15-
05-07	684,692	24,859	4		0		0	24,859-	4-
06-08	810,953	130,172	16		0		0	130,172-	16-
07-09	655,656	153,480	23		0		0	153,480-	23-
08-10	560,286	161,189	29		0		0	161,189-	29-
09-11	396,786	56,465	14		0		0	56,465-	14-
10-12	590,368	41,682	7		0		0	41,682-	7-
11-13	638,649	50,955	8		0		0	50,955-	8-
12-14	668,997	44,070	7		0		0	44,070-	7-
FIVE-YEAR AVERAGE									
10-14	535,262	39,475	7		0		0	39,475-	7-

FORTISBC ENERGY INC.

ACCOUNT 477.20 - DISTRIBUTION - TELEMETRY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	17,499		0		0		0		0
2001	80,431		0		0		0		0
2002	251,623		0		0		0		0
2003	68,932		0		0		0		0
2004		227						227-	
2005									
2006	1,008	2,382	236		0		0	2,382-	236-
2007	32,413		0		0		0		0
2008	5,000		0		0		0		0
2009	54,840		0		0		0		0
2010	3,222		0		0		0		0
2011	149,241	831	1		0		0	831-	1-
2012	85,025	15	0		0		0	15-	0
2013	9,941	11,533	116		0		0	11,533-	116-
2014	108,594		0		0		0		0
TOTAL	867,771	14,987	2		0		0	14,987-	2-
THREE-YEAR MOVING AVERAGES									
00-02	116,518		0		0		0		0
01-03	133,662		0		0		0		0
02-04	106,852	76	0		0		0	76-	0
03-05	22,977	76	0		0		0	76-	0
04-06	336	870	259		0		0	870-	259-
05-07	11,141	794	7		0		0	794-	7-
06-08	12,807	794	6		0		0	794-	6-
07-09	30,751		0		0		0		0
08-10	21,021		0		0		0		0
09-11	69,101	277	0		0		0	277-	0
10-12	79,163	282	0		0		0	282-	0
11-13	81,403	4,126	5		0		0	4,126-	5-
12-14	67,853	3,849	6		0		0	3,849-	6-
FIVE-YEAR AVERAGE									
10-14	71,205	2,476	3		0		0	2,476-	3-

FORTISBC ENERGY INC.

ACCOUNT 478.10 - DISTRIBUTION - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	418,424		0		0		0		0
2001	2,284,414		0		0		0		0
2002	3,531,074		0		0		0		0
2003	2,018,918		0		0		0		0
2004	2,729,515		0		0	78,811	3	78,811	3
2005	4,879,690		0		0		0		0
2006	3,916,552		0		0		0		0
2007	3,022,852		0		0		0		0
2008	4,782,171	69,432-	1-		0	284,774	6	354,206	7
2009	4,143,930	71,292	2		0	66,136	2	5,156-	0
2010	6,433,600	147,607	2		0	136,306	2	11,301-	0
2011	4,759,675	135,914	3		0	241,924	5	106,011	2
2012	8,509,300	117,023	1		0	172,166	2	55,143	1
2013	8,250,035	211,511	3		0	360,326	4	148,815	2
2014	6,633,512	153,078	2		0	329,250	5	176,172	3
TOTAL	66,313,661	766,993	1		0	1,669,693	3	902,700	1

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
00-02	2,077,971		0		0		0		0
01-03	2,611,469		0		0		0		0
02-04	2,759,836		0		0	26,270	1	26,270	1
03-05	3,209,374		0		0	26,270	1	26,270	1
04-06	3,841,919		0		0	26,270	1	26,270	1
05-07	3,939,698		0		0		0		0
06-08	3,907,192	23,144-	1-		0	94,925	2	118,069	3
07-09	3,982,984	620	0		0	116,970	3	116,350	3
08-10	5,119,900	49,822	1		0	162,405	3	112,583	2
09-11	5,112,402	118,271	2		0	148,122	3	29,851	1
10-12	6,567,525	133,514	2		0	183,465	3	49,951	1
11-13	7,173,003	154,816	2		0	258,139	4	103,323	1
12-14	7,797,615	160,537	2		0	287,247	4	126,710	2

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14	6,917,224	153,027	2		0	247,994	4	94,968	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 PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	1,255,720		0		0		0		0
2001	5,462,958		0		0		0		0
2002	143,025	613	0		0		0	613-	0
2003	86,535		0		0		0		0
2004						800		800	
2005	1,200		0		0		0		0
2006	28,711		0		0		0		0
2007	6,655		0		0		0		0
2008	258,882	11,410	4		0		0	11,410-	4-
2009	1,909	450	24		0		0	450-	24-
2010	4,888		0		0		0		0
2011	154,534		0		0		0		0
2012									
2013									
2014									
TOTAL	7,405,016	12,474	0		0	800	0	11,674-	0
THREE-YEAR MOVING AVERAGES									
00-02	2,287,234	204	0		0		0	204-	0
01-03	1,897,506	204	0		0		0	204-	0
02-04	76,520	204	0		0	267	0	62	0
03-05	29,245		0		0	267	1	267	1
04-06	9,970		0		0	267	3	267	3
05-07	12,189		0		0		0		0
06-08	98,083	3,803	4		0		0	3,803-	4-
07-09	89,149	3,953	4		0		0	3,953-	4-
08-10	88,560	3,953	4		0		0	3,953-	4-
09-11	53,777	150	0		0		0	150-	0
10-12	53,140		0		0		0		0
11-13	51,511		0		0		0		0
12-14									
FIVE-YEAR AVERAGE									
10-14	31,884		0		0		0		0

FORTISBC ENERGY INC.

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	876,365		0		0		0		0
2001	213,291		0		0		0		0
2002	5,545		0		0		0		0
2003	60,624		0		0		0		0
2004									
2005									
2006	106,637		0		0		0		0
2007	26,804		0		0		0		0
2008	511,877	134,252	26		0		0	134,252-	26-
2009	40,000	100,978	252		0		0	100,978-	252-
2010									
2011									
2012		45-						45	
2013		547						547-	
2014									
TOTAL	1,841,144	235,732	13		0		0	235,732-	13-
THREE-YEAR MOVING AVERAGES									
00-02	365,067		0		0		0		0
01-03	93,153		0		0		0		0
02-04	22,056		0		0		0		0
03-05	20,208		0		0		0		0
04-06	35,546		0		0		0		0
05-07	44,480		0		0		0		0
06-08	215,106	44,751	21		0		0	44,751-	21-
07-09	192,894	78,410	41		0		0	78,410-	41-
08-10	183,959	78,410	43		0		0	78,410-	43-
09-11	13,333	33,659	252		0		0	33,659-	252-
10-12		15-						15	
11-13		167						167-	
12-14		167						167-	
FIVE-YEAR AVERAGE									
10-14		100						100-	

FORTISBC ENERGY INC.

ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	1,582,820		0		0		0		0
2001	34,001		0		0		0		0
2002	239,632		0		0		0		0
2003	30,578		0		0		0		0
2004	260,925		0		0		0		0
2005	14,890		0		0		0		0
2006	7,381		0		0		0		0
2007	93,297		0		0		0		0
2008	40,268	7,617-	19-		0	4,000	10	11,617	29
2009	32,635	1,081	3		0	13,825	42	12,744	39
2010	169,164		0		0	29,791	18	29,791	18
2011	872,023		0		0		0		0
2012	580,467		0		0		0		0
2013	300,515		0		0		0		0
2014	376,446		0		0	145,085	39	145,085	39
TOTAL	4,635,042	6,536-	0		0	192,701	4	199,237	4

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
00-02	618,818		0		0		0		0
01-03	101,404		0		0		0		0
02-04	177,045		0		0		0		0
03-05	102,131		0		0		0		0
04-06	94,399		0		0		0		0
05-07	38,523		0		0		0		0
06-08	46,982	2,539-	5-		0	1,333	3	3,872	8
07-09	55,400	2,179-	4-		0	5,942	11	8,120	15
08-10	80,689	2,179-	3-		0	15,872	20	18,050	22
09-11	357,941	360	0		0	14,539	4	14,178	4
10-12	540,551		0		0	9,930	2	9,930	2
11-13	584,335		0		0		0		0
12-14	419,143		0		0	48,362	12	48,362	12

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
10-14	459,723		0		0	34,975	8	34,975	8

FORTISBC ENERGY INC.

ACCOUNT 485.10 – HEAVY WORK EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	13,523		0		0		0		0
2001									
2002	6,318		0		0		0		0
2003									
2004									
2005									
2006	26,600		0		0		0		0
2007									
2008									
2009									
2010	12,429		0		0		0		0
2011	45,146		0		0		0		0
2012	46,290		0		0		0		0
2013	66,482		0		0		0		0
2014	24,491		0		0		0		0
TOTAL	241,280		0		0		0		0
THREE-YEAR MOVING AVERAGES									
00-02	6,614		0		0		0		0
01-03	2,106		0		0		0		0
02-04	2,106		0		0		0		0
03-05									
04-06	8,867		0		0		0		0
05-07	8,867		0		0		0		0
06-08	8,867		0		0		0		0
07-09									
08-10	4,143		0		0		0		0
09-11	19,192		0		0		0		0
10-12	34,622		0		0		0		0
11-13	52,640		0		0		0		0
12-14	45,755		0		0		0		0
FIVE-YEAR AVERAGE									
10-14	38,968		0		0		0		0

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 PCT	GROSS SALVAGE REUSE AMOUNT	GROSS SALVAGE REUSE PCT	GROSS SALVAGE FINAL AMOUNT	GROSS SALVAGE FINAL PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2005	4,280		0		0		0		0
2006	35,407		0		0		0		0
2007	1		0		0		0		0
2008									
2009									
2010									
2011	5,699		0		0		0		0
2012	19,035		0		0		0		0
2013	79,630		0		0		0		0
2014									
TOTAL	144,053		0		0		0		0
THREE-YEAR MOVING AVERAGES									
05-07	13,229		0		0		0		0
06-08	11,803		0		0		0		0
07-09			0		0		0		0
08-10									
09-11	1,900		0		0		0		0
10-12	8,245		0		0		0		0
11-13	34,788		0		0		0		0
12-14	32,888		0		0		0		0
FIVE-YEAR AVERAGE									
10-14	20,873		0		0		0		0

PART VII. DETAILED DEPRECIATION CALCULATIONS

FORTISBC ENERGY INC.

ACCOUNT 401.01 - INTANGIBLE - FRANCHISES AND CONSENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1959	2,931.00	2,858	2,620	311	1.00	311
1960	88,488.40	86,276	79,080	9,408	1.00	9,408
1962	4,804.00	4,684	4,293	511	1.00	511
1963	230.00	224	205	25	1.00	25
1964	50.00	49	45	5	1.00	5
1969	848.00	827	758	90	1.00	90
1970	452.00	441	404	48	1.00	48
1971	260.00	254	233	27	1.00	27
1972	300.00	292	268	32	1.00	32
1973	50.00	49	45	5	1.00	5
1976	823.00	782	717	106	2.00	53
1987	8,238.78	5,561	5,097	3,142	13.00	242
1990	1,082.17	649	595	487	16.00	30
1991	186,139.77	107,030	98,104	88,036	17.00	5,179
1992	2,554.74	1,405	1,288	1,267	18.00	70
	297,251.86	211,381	193,752	103,500		16,036

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 5.39

FORTISBC ENERGY INC.

ACCOUNT 402.01 - COMPUTER SOFTWARE APPLICATION - 8 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 8-SQUARE						
2004	545,668.16	477,460	487,617	58,051	1.00	58,051
2005	1,448,029.28	1,267,026	1,293,979	154,050	1.00	154,050
2006	7,468,830.51	6,535,227	6,674,248	794,583	1.00	794,583
2007	2,085,588.81	1,824,890	1,863,710	221,879	1.00	221,879
2008	9,786,375.74	7,339,782	7,495,918	2,290,458	2.00	1,145,229
2009	7,527,396.47	4,704,623	4,804,702	2,722,694	3.00	907,565
2010	3,963,669.03	1,981,835	2,023,994	1,939,675	4.00	484,919
2011	55,797,399.35	20,924,025	21,369,131	34,428,268	5.00	6,885,654
2012	5,293,418.31	1,323,355	1,351,506	3,941,912	6.00	656,985
2013	10,495,385.62	1,311,923	1,339,831	9,155,555	7.00	1,307,936
2014	11,088,172.76		0	11,088,173	8.00	1,386,022
	115,499,934.04	47,690,146	48,704,636	66,795,298		14,002,873

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.8   12.12

FORTISBC ENERGY INC.

ACCOUNT 402.02 - COMPUTER SOFTWARE APPLICATION - 5 YRS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
2009	997,726.40	798,181	864,716	133,010	1.00	133,010
2010	3,271,915.11	2,617,532	2,835,725	436,190	1.00	436,190
2011	7,273,572.92	4,364,144	4,727,930	2,545,643	2.00	1,272,822
2012	3,924,245.09	1,569,698	1,700,545	2,223,700	3.00	741,233
2013	3,611,701.59	722,340	782,553	2,829,149	4.00	707,287
2014	5,566,003.14		0	5,566,003	5.00	1,113,201
	24,645,164.25	10,071,895	10,911,469	13,733,695		4,403,743

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.1 17.87

FORTISBC ENERGY INC.

ACCOUNT 402.03 - INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1991	694,036.53	399,071	500,587	193,450	17.00	11,379
2001	687,554.78	223,455	280,298	407,257	27.00	15,084
2003	500,000.00	137,500	172,477	327,523	29.00	11,294
2009	25,000.00	3,125	3,920	21,080	35.00	602
	1,906,591.31	763,151	957,282	949,309		38,359

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.7 2.01

FORTISBC ENERGY INC.

ACCOUNT 402.11 - INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1970	62,456.53	60,895	62,457			
	62,456.53	60,895	62,457			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

FORTISBC ENERGY INC.

ACCOUNT 432.00 - MANUFACTURING - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	358,775.13	215,265	169,834	188,941	16.00	11,809
1992	1,967.78	1,082	854	1,114	18.00	62
1996	899.39	405	320	579	22.00	26
1997	797.53	339	267	531	23.00	23
1998	2,668.96	1,068	843	1,826	24.00	76
1999	6,436.48	2,414	1,905	4,531	25.00	181
2000	13,624.40	4,769	3,762	9,862	26.00	379
2001	1,019.52	331	261	759	27.00	28
2002	44,609.77	13,383	10,559	34,051	28.00	1,216
2004	437.00	109	86	351	30.00	12
2005	11,641.25	2,619	2,066	9,575	31.00	309
2006	1,293.03	259	204	1,089	32.00	34
2007	666.81	117	92	575	33.00	17
2008	12,598.31	1,890	1,491	11,107	34.00	327
2011	20,591.32	1,544	1,218	19,373	37.00	524
2012	488,711.14	24,436	19,279	469,432	38.00	12,353
2013	24,703.50	618	488	24,216	39.00	621
2014	188.62		0	189	40.00	5
	991,629.94	270,648	213,529	778,101		28,002

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.8   2.82

FORTISBC ENERGY INC.

ACCOUNT 433.00 - MANUFACTURING - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1994	5,018.55	4,768	5,019			
1996	3,868.62	3,482	3,666	203	2.00	102
1997	13,895.12	11,811	12,434	1,461	3.00	487
1999	108,001.17	81,001	85,271	22,730	5.00	4,546
2000	5,687.97	3,982	4,192	1,496	6.00	249
2002	3,008.60	1,805	1,900	1,109	8.00	139
2005	6,458.40	2,906	3,059	3,399	11.00	309
2012	310,358.83	31,036	32,672	277,687	18.00	15,427
2013	2,914.86	146	154	2,761	19.00	145
	459,212.12	140,937	148,367	310,845		21,404

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.5 4.66

FORTISBC ENERGY INC.

ACCOUNT 434.00 - MANUFACTURING - HOLDERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 40-SQUARE						
NET SALVAGE PERCENT.. 0						
1990	239,942.82	143,966	157,766	82,177	16.00	5,136
1992	102,238.92	56,231	61,621	40,618	18.00	2,257
1996	860.87	387	424	437	22.00	20
1997	763.37	324	355	408	23.00	18
1998	680.66	272	298	383	24.00	16
1999	681.40	256	281	400	25.00	16
2000	544.40	191	209	335	26.00	13
2001	10,282.20	3,342	3,662	6,620	27.00	245
2002	590.33	177	194	396	28.00	14
2011	330,932.50	24,820	27,199	303,734	37.00	8,209
2012	2,172,248.27	108,612	119,025	2,053,223	38.00	54,032
2013	91,239.63	2,281	2,500	88,740	39.00	2,275
2014	3,845.12		0	3,846	40.00	96
	2,954,850.49	340,859	373,534	2,581,317		72,347

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.7 2.45

FORTISBC ENERGY INC.

ACCOUNT 436.00 - MANUFACTURING - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1992	1,382.72	1,217	1,383			
1995	51,926.19	39,464	45,304	6,622	6.00	1,104
2012	310,358.83	24,829	28,503	281,856	23.00	12,255
2013	2,914.86	117	135	2,780	24.00	116
	366,582.60	65,627	75,325	291,258		13,475

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.6   3.68

FORTISBC ENERGY INC.

ACCOUNT 437.00 - MANUFACTURING - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1992	290,389.70	275,870	290,390			
1996	789.15	710	789			
1997	699.77	595	700			
1998	623.95	499	624			
1999	624.63	468	625			
2000	499.05	349	499			
2001	1,086.26	706	1,086			
2002	541.14	325	541			
2003	10,181.08	5,600	10,181			
2011	124,082.62	18,612	104,269	19,814	17.00	1,166
2012	310,357.95	31,036	173,871	136,487	18.00	7,583
2013	132,273.32	6,614	37,053	95,220	19.00	5,012
2014	261,573.61		0	261,574	20.00	13,079
	1,133,722.23	341,384	620,628	513,094		26,840

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.1 2.37

FORTISBC ENERGY INC.

ACCOUNT 442.00 - LNG - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 25-L2
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1988	1,453,071.43	991,634	1,227,264	371,115	9.49	39,106
1991	1,924.79	1,252	1,549	568	10.22	56
1992	110,426.95	70,598	87,373	34,097	10.47	3,257
1993	8,093.70	5,082	6,290	2,613	10.73	244
1994	84,561.94	52,016	64,376	28,642	11.02	2,599
1995	132,581.49	79,803	98,766	47,074	11.32	4,158
1996	42,779.92	25,129	31,100	15,958	11.65	1,370
1997	246,113.24	140,560	173,960	96,765	12.02	8,050
1998	396,745.70	219,607	271,790	164,630	12.42	13,255
1999	133,892.83	71,461	88,441	58,841	12.87	4,572
2000	318,749.06	162,970	201,695	148,929	13.38	11,131
2001	94,819.16	46,185	57,159	47,142	13.93	3,384
2002	36,534.09	16,798	20,790	19,397	14.55	1,333
2003	704,255.73	302,745	374,683	399,998	15.23	26,264
2004	16,996.28	6,760	8,366	10,330	15.96	647
2005	788,457.87	286,557	354,648	512,656	16.74	30,625
2006	13,612.01	4,456	5,515	9,458	17.56	539
2007	270,602.22	78,583	97,256	200,406	18.40	10,892
2008	30,362.10	7,655	9,474	23,924	19.27	1,242
2010	74,883.19	12,883	15,944	66,428	21.09	3,150
2014	206,434.58		0	227,078	25.00	9,083
	5,165,898.28	2,582,734	3,196,439	2,486,049		174,957

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.2 3.39

FORTISBC ENERGY INC.

ACCOUNT 442.01 - LNG - STRUCTURES - MT. HAYES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. -10						
2011	17,261,042.79	2,225,294	2,473,533	16,513,614	22.07	748,238
2013	22,616.08	975	1,084	23,794	24.02	991
2014	25,499.99			28,050	25.00	1,122
	17,309,158.86	2,226,269	2,474,617	16,565,458		750,351

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.1 4.33

FORTISBC ENERGY INC.

ACCOUNT 443.00 - LNG - EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-L4						
NET SALVAGE PERCENT.. -20						
1988	9,052,020.29	6,767,290	8,118,935	2,743,489	15.08	181,929
1991	29,946.64	20,142	24,165	11,771	17.58	670
1993	62,452.26	38,708	46,439	28,504	19.34	1,474
1996	393,472.04	211,058	253,213	218,953	22.12	9,898
1997	184,604.19	93,705	112,421	109,104	23.08	4,727
1998	102,424.92	49,010	58,799	64,111	24.05	2,666
1999	746,733.77	335,582	402,609	493,472	25.02	19,723
2000	81,921.07	34,382	41,249	57,056	26.01	2,194
2001	102,295.11	39,895	47,863	74,891	27.00	2,774
2002	5,304,069.89	1,909,465	2,290,847	4,074,037	28.00	145,501
2003	183,540.37	60,568	72,665	147,583	29.00	5,089
2004	198,778.25	59,633	71,544	166,990	30.00	5,566
2006	51,498.10	12,360	14,829	46,969	32.00	1,468
2007	260.44	55	66	247	33.00	7
2011	4,599.00	414	497	5,022	37.00	136
	16,498,616.34	9,632,267	11,556,141	8,242,199		383,822

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.5   2.33

FORTISBC ENERGY INC.

ACCOUNT 443.05 - LNG - EQUIPMENT - MT. HAYES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R5						
NET SALVAGE PERCENT.. -20						
2011	60,112,269.35	3,606,736	3,595,459	68,539,264	57.00	1,202,443
	60,112,269.35	3,606,736	3,595,459	68,539,264		1,202,443

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 57.0 2.00

FORTISBC ENERGY INC.

ACCOUNT 448.10 - LNG - PIPING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. -10						
2011	11,488,418.05	928,839	1,028,667	11,608,592	37.06	313,238
	11,488,418.05	928,839	1,028,667	11,608,592		313,238

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.1 2.73

FORTISBC ENERGY INC.

ACCOUNT 448.20 - LNG - PRE-TREATMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. -10						
2011	28,713,519.62	3,701,747	4,113,590	27,471,281	22.07	1,244,734
	28,713,519.62	3,701,747	4,113,590	27,471,281		1,244,734

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.1 4.34

FORTISBC ENERGY INC.

ACCOUNT 448.30 - LNG - LIQUEFACTION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. -20						
2011	28,713,519.62	2,532,532	2,570,994	31,885,230	37.06	860,368
	28,713,519.62	2,532,532	2,570,994	31,885,230		860,368

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.1 3.00

FORTISBC ENERGY INC.

ACCOUNT 448.40 - LNG - SEND OUT EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. -10						
2011	22,960,238.37	1,698,484	2,055,848	23,200,414	37.31	621,828
	22,960,238.37	1,698,484	2,055,848	23,200,414		621,828

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.3   2.71

FORTISBC ENERGY INC.

ACCOUNT 448.50 - LNG - SUBSTATION AND ELECTRICAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. -20						
2011	21,643,950.36	1,746,667	1,938,069	24,034,671	37.31	644,188
	21,643,950.36	1,746,667	1,938,069	24,034,671		644,188

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.3   2.98

FORTISBC ENERGY INC.

ACCOUNT 448.60 - LNG - CONTROL ROOM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R3						
NET SALVAGE PERCENT.. 0						
2011	5,900,055.25	1,144,611	1,409,478	4,490,578	12.09	371,429
	5,900,055.25	1,144,611	1,409,478	4,490,578		371,429

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.1 6.30

FORTISBC ENERGY INC.

ACCOUNT 449.00 - LNG - OTHER EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 27-R3						
NET SALVAGE PERCENT.. -10						
1988	5,536,937.17	4,752,946	4,645,520	1,445,111	5.93	243,695
1991	554,462.83	438,232	428,327	181,582	7.60	23,892
1992	562,926.89	430,475	420,745	198,475	8.23	24,116
1993	2,336,891.81	1,725,143	1,686,152	884,429	8.88	99,598
1994	195,647.09	139,091	135,947	79,265	9.55	8,300
1995	2,871,517.51	1,958,375	1,914,112	1,244,557	10.26	121,302
1996	801,912.30	523,052	511,230	370,874	10.99	33,746
1997	81,130.05	50,439	49,299	39,944	11.74	3,402
1998	18,560.60	10,957	10,709	9,708	12.51	776
1999	649,297.54	362,406	354,215	360,012	13.30	27,069
2000	964,847.19	506,690	495,238	566,094	14.11	40,120
2001	21,505.53	10,566	10,327	13,329	14.94	892
2002	357,001.87	163,046	159,361	233,341	15.79	14,778
2003	1,799,856.75	758,933	741,780	1,238,062	16.65	74,358
2004	32,356.13	12,483	12,201	23,391	17.53	1,334
2005	198,987.18	69,477	67,907	150,979	18.43	8,192
2006	305,886.62	95,458	93,300	243,175	19.34	12,574
2007	359,087.89	98,603	96,374	298,623	20.26	14,740
2008	4,157,417.12	982,360	960,158	3,613,001	21.20	170,425
2009	1,849,724.98	365,493	357,232	1,677,465	22.15	75,732
2010	627,350.21	99,676	97,423	592,662	23.10	25,656
2011	64,069.35	7,648	7,475	63,001	24.07	2,617
2012	668,179.44	53,353	52,147	682,850	25.04	27,270
2013	26,659.00	1,064	1,040	28,285	26.02	1,087
2014	88,391.34		0	97,230	27.00	3,601
	25,130,604.39	13,615,966	13,308,219	14,335,445		1,059,272

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5 4.22

FORTISBC ENERGY INC.

ACCOUNT 449.01 - LNG - OTHER EQUIPMENT - MT. HAYES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -10						
2011	33,247.62	3,072	4,883	31,689	32.06	988
2014	3,545,424.12			3,899,967	35.00	111,428
	3,578,671.74	3,072	4,883	3,931,656		112,416

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.0 3.14

FORTISBC ENERGY INC.

ACCOUNT 465.30 - LNG - MAINS - MT. HAYES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 65-SQUARE						
NET SALVAGE PERCENT.. -20						
2011	6,298,635.39	348,818	404,332	7,154,030	62.00	115,388
	6,298,635.39	348,818	404,332	7,154,030		115,388

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 62.0 1.83

FORTISBC ENERGY INC.

ACCOUNT 467.00 - LNG - MEASURING AND REGULATING EQUIPMENT - MT. HAYES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-S0.5						
NET SALVAGE PERCENT.. -7						
2011	5,341,780.82	450,912	779,900	4,935,805	33.16	148,848
	5,341,780.82	450,912	779,900	4,935,805		148,848

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.2   2.79

FORTISBC ENERGY INC.

ACCOUNT 462.00 - TRANSMISSION - COMPRESSOR STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 30-R4
NET SALVAGE PERCENT.. -3

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	215,401.10	214,393	211,683	10,180	1.01	10,079
1975	6,158.28	6,024	5,948	395	1.51	262
1977	67.03	64	63	6	2.03	3
1978	5,916.53	5,627	5,556	538	2.30	234
1980	614.64	572	565	68	2.88	24
1982	1,246.15	1,131	1,117	167	3.56	47
1984	895.28	787	777	145	4.39	33
1988	2,555.92	2,047	2,021	612	6.67	92
1989	2,559.08	1,991	1,966	670	7.34	91
1990	31,298.71	23,609	23,311	8,927	8.03	1,112
1991	1,852,637.56	1,351,647	1,334,560	573,657	8.75	65,561
1992	251,036.89	176,775	174,540	84,028	9.49	8,854
1993	1,182,706.65	801,568	791,435	426,753	10.26	41,594
1994	1,447,030.17	941,467	929,565	560,876	11.05	50,758
1995	4,624,628.27	2,878,646	2,842,256	1,921,111	11.87	161,846
1996	432,974.21	257,022	253,773	192,190	12.71	15,121
1997	394,931.89	222,781	219,965	186,815	13.57	13,767
1998	3,329,048.96	1,776,181	1,753,727	1,675,193	14.46	115,850
1999	2,550,221.28	1,281,843	1,265,639	1,361,089	15.36	88,613
2000	4,347,881.76	2,048,069	2,022,178	2,456,140	16.28	150,869
2001	785,677.98	345,007	340,646	468,602	17.21	27,228
2002	1,928,474.22	783,944	774,033	1,212,295	18.16	66,756
2003	111,375.93	41,604	41,078	73,639	19.12	3,851
2004	167,721.21	57,065	56,344	116,409	20.09	5,794
2006	52,844.97	14,442	14,259	40,171	22.04	1,823
2007	1,661,264.19	397,540	392,515	1,318,587	23.03	57,255
2008	176,799.50	36,299	35,840	146,263	24.02	6,089
2009	449,756.30	77,052	76,078	387,171	25.01	15,481
2010	225,317.46	30,866	30,476	201,601	26.01	7,751
2011	566,520.02	58,352	57,614	525,902	27.00	19,478
2012	1,931,739.12	132,653	130,976	1,858,715	28.00	66,383
2013	662,072.62	22,729	22,442	659,493	29.00	22,741
2014	154,812.60		0	159,457	30.00	5,315
	29,554,186.48	13,989,797	13,812,946	16,627,866		1,030,755

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.1 3.49

FORTISBC ENERGY INC.

ACCOUNT 463.00 - TRANSMISSION - MEASURING AND REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-S2						
NET SALVAGE PERCENT.. -15						
1972	30,628.34	27,678	30,025	5,198	8.14	639
1974	12,536.32	11,055	11,992	2,425	8.86	274
1980	1,662.26	1,342	1,456	456	11.33	40
1982	1,246.15	970	1,052	381	12.27	31
1984	8,916.23	6,670	7,236	3,018	13.28	227
1985	3,043.26	2,228	2,417	1,083	13.81	78
1986	1,364.56	976	1,059	510	14.36	36
1987	8,403.96	5,867	6,364	3,301	14.93	221
1988	186,976.94	127,148	137,929	77,094	15.53	4,964
1989	1,902.24	1,258	1,365	823	16.14	51
1990	5,248.61	3,371	3,657	2,379	16.78	142
1991	4,020,729.51	2,501,728	2,713,859	1,909,980	17.44	109,517
1992	261,654.07	157,420	170,768	130,134	18.12	7,182
1993	174,055.32	100,977	109,539	90,625	18.83	4,813
1994	71,195.96	39,731	43,100	38,775	19.56	1,982
1995	472,438.09	252,778	274,212	269,092	20.32	13,243
1996	351,481.11	179,765	195,008	209,195	21.10	9,914
1997	221,633.75	107,987	117,144	137,735	21.90	6,289
1998	120,531.61	55,700	60,423	78,188	22.73	3,440
1999	620,189.29	270,645	293,594	419,624	23.58	17,796
2000	399,305.88	163,742	177,626	281,576	24.45	11,516
2001	105,861.23	40,559	43,998	77,742	25.34	3,068
2002	810,460.26	288,193	312,630	619,399	26.25	23,596
2003	203,948.97	66,783	72,446	162,095	27.18	5,964
2004	366,262.99	109,513	118,799	302,403	28.12	10,754
2005	154,564.20	41,725	45,263	132,486	29.08	4,556
2006	1,785,497.10	429,575	466,000	1,587,322	30.05	52,823
2007	1,757,445.92	370,703	402,137	1,618,926	31.03	52,173
2008	109,305.21	19,814	21,494	104,207	32.01	3,255
2009	294,211.30	44,431	48,198	290,145	33.01	8,790
2010	335,640.83	40,629	44,074	341,913	34.00	10,056
2011	150,303.34	13,646	14,803	158,046	35.00	4,516
2012	134,458.66	8,138	8,828	145,799	36.00	4,050
2013	898,378.10	27,192	29,498	1,003,637	37.00	27,125
2014	125,746.51		0	144,608	38.00	3,805
	14,207,228.08	5,519,937	5,987,993	10,350,319		406,926

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.4 2.86

FORTISBC ENERGY INC.

ACCOUNT 464.00 - TRANSMISSION - OTHER STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 30-R4
NET SALVAGE PERCENT.. -5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	7,845.44	7,960	6,832	1,406	1.01	1,392
1975	1,992.26	1,987	1,706	386	1.51	256
1978	6,315.00	6,122	5,255	1,376	2.30	598
1979	10,826.17	10,390	8,918	2,449	2.58	949
1983	8,868.78	8,086	6,941	2,371	3.95	600
1984	3,199.30	2,868	2,462	897	4.39	204
1987	18,636.05	15,635	13,420	6,148	6.03	1,020
1988	12,898.76	10,533	9,041	4,503	6.67	675
1989	5,246.07	4,161	3,572	1,936	7.34	264
1990	4,177.22	3,212	2,757	1,629	8.03	203
1991	26,130.83	19,435	16,682	10,755	8.75	1,229
1993	9,555.00	6,602	5,667	4,366	10.26	426
1994	43,742.33	29,012	24,902	21,027	11.05	1,903
1995	565.90	359	308	286	11.87	24
1996	76,883.05	46,526	39,935	40,792	12.71	3,209
1997	17,012.33	9,783	8,397	9,466	13.57	698
1998	3,010.54	1,637	1,405	1,756	14.46	121
1999	191,806.97	98,282	84,360	117,037	15.36	7,620
2000	105,424.54	50,624	43,453	67,243	16.28	4,130
2001	3,833,288.66	1,715,958	1,472,881	2,552,072	17.21	148,290
2002	537,707.52	222,828	191,263	373,330	18.16	20,558
2003	10,828.76	4,124	3,540	7,830	19.12	410
2004	554,794.63	192,429	165,170	417,364	20.09	20,775
2005	288,414.54	90,245	77,461	225,374	21.06	10,702
2006	238,200.38	66,362	56,962	193,148	22.04	8,764
2007	104,381.11	25,463	21,856	87,744	23.03	3,810
2008	163.42	34	29	143	24.02	6
2009	22,991.57	4,015	3,446	20,695	25.01	827
2012	7,291.71	510	438	7,218	28.00	258
2013	331,857.79	11,614	9,969	338,482	29.00	11,672
2014	18,635.78		0	19,568	30.00	652
	6,502,692.41	2,666,796	2,289,028	4,538,799		252,245

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.0 3.88

FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANSMISSION - PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 65-R3
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1957	14,547.23	12,800	12,869	4,588	17.34	265
1958	11,921,221.63	10,359,303	10,414,869	3,890,597	17.93	216,988
1959	1,238,599.27	1,062,599	1,068,299	418,020	18.53	22,559
1960	17,607.69	14,904	14,984	6,145	19.15	321
1961	127,805.46	106,696	107,268	46,099	19.78	2,331
1962	2,269,197.45	1,867,595	1,877,613	845,424	20.42	41,402
1963	92,529.62	75,026	75,428	35,608	21.08	1,689
1964	47,767.60	38,149	38,354	18,967	21.74	872
1966	208,320.66	161,105	161,969	88,016	23.11	3,809
1967	475,284.04	361,511	363,450	206,891	23.80	8,693
1968	768,609.24	574,538	577,620	344,711	24.51	14,064
1969	1,602,701.87	1,176,736	1,183,048	740,194	25.23	29,338
1970	363,907.47	262,284	263,691	172,998	25.96	6,664
1971	2,283,303.02	1,614,469	1,623,129	1,116,835	26.70	41,829
1972	7,701,102.16	5,340,098	5,368,742	3,872,581	27.44	141,129
1973	409,455.57	278,176	279,668	211,679	28.20	7,506
1974	32,703.80	21,760	21,877	17,368	28.96	600
1975	64,059.91	41,700	41,924	34,948	29.74	1,175
1976	17,356,855.61	11,048,541	11,107,804	9,720,423	30.52	318,494
1977	282,686.47	175,823	176,766	162,458	31.31	5,189
1978	350,257.34	212,676	213,817	206,492	32.11	6,431
1979	47,298.96	28,021	28,171	28,588	32.91	869
1980	730,273.32	421,584	423,845	452,483	33.73	13,415
1981	1,380,365.89	775,975	780,137	876,302	34.55	25,363
1982	650,988.73	355,979	357,888	423,298	35.38	11,964
1983	511,904.99	271,987	273,446	340,840	36.22	9,410
1984	484,286.28	249,805	251,145	329,999	37.06	8,904
1985	1,077,972.54	538,926	541,817	751,750	37.92	19,825
1986	3,699,334.06	1,791,395	1,801,004	2,638,197	38.77	68,047
1987	1,848,467.17	865,415	870,057	1,348,104	39.64	34,009
1988	35,533,910.57	16,065,734	16,151,909	26,488,784	40.51	653,883
1989	692,963.11	302,046	303,666	527,890	41.39	12,754
1990	6,656,592.02	2,792,094	2,807,070	5,180,840	42.28	122,536
1991	305,665,995.25	123,189,509	123,850,284	242,948,910	43.17	5,627,726
1992	57,405,074.66	22,181,321	22,300,299	46,585,791	44.07	1,057,086
1993	6,910,030.80	2,555,191	2,568,897	5,723,140	44.97	127,266
1994	2,899,855.51	1,023,591	1,029,081	2,450,746	45.88	53,416
1995	33,238,405.82	11,168,104	11,228,009	28,658,078	46.80	612,352
1996	12,779,412.24	4,076,888	4,098,756	11,236,539	47.72	235,468
1997	9,998,296.55	3,017,966	3,034,154	8,963,802	48.65	184,251
1998	16,475,216.40	4,690,099	4,715,256	15,055,004	49.58	303,651
1999	12,476,008.49	3,335,136	3,353,025	11,618,185	50.52	229,972
2000	319,657,291.07	79,905,372	80,333,977	303,254,772	51.46	5,893,019
2001	46,350,958.97	10,782,160	10,839,994	44,781,157	52.40	854,602
2002	25,952,974.89	5,581,862	5,611,803	25,531,767	53.35	478,571

FORTISBC ENERGY INC.

ACCOUNT 465.00 - TRANSMISSION - PIPELINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -20						
2003	17,982,986.90	3,548,978	3,568,014	18,011,570	54.31	331,644
2004	13,593,419.67	2,444,369	2,457,480	13,854,624	55.26	250,717
2005	11,330,597.83	1,836,645	1,846,497	11,750,220	56.22	209,004
2006	12,530,943.72	1,806,711	1,816,402	13,220,730	57.19	231,172
2007	8,563,828.53	1,081,406	1,087,207	9,189,387	58.16	158,002
2008	11,936,142.82	1,293,544	1,300,482	13,022,889	59.13	220,242
2009	9,207,830.20	832,903	837,371	10,212,025	60.10	169,917
2010	10,322,595.21	748,925	752,942	11,634,172	61.07	190,506
2011	57,045,049.41	3,106,445	3,123,108	65,330,951	62.05	1,052,876
2012	15,181,008.03	552,164	555,125	17,662,085	63.03	280,217
2013	20,683,396.40	374,287	376,295	24,443,781	64.02	381,815
2014	22,805,314.36		0	27,366,377	65.00	421,021
	1,161,935,514.48	348,399,026	350,267,802	1,044,054,815		21,406,840

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.8 1.84

FORTISBC ENERGY INC.

ACCOUNT 465.11 - TRANSMISSION - INTERMEDIATE PIPE - WHISTLER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -20						
2008	8,227.20	892	767	9,106	59.13	154
2009	42,030,839.72	3,801,942	3,268,721	47,168,287	60.10	784,830
2010	133,828.28	9,710	8,348	152,246	61.07	2,493
2014	111,904.24			134,285	65.00	2,066
	42,284,799.44	3,812,544	3,277,836	47,463,923		789,543

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 60.1 1.87

FORTISBC ENERGY INC.

ACCOUNT 466.00 - TRANSMISSION - COMPRESSOR EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 35-R4
NET SALVAGE PERCENT.. -2

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1973	1,161,436.28	1,084,134	1,146,318	38,347	2.97	12,911
1974	288,030.63	266,428	281,710	12,081	3.26	3,706
1975	2,752.84	2,521	2,666	142	3.57	40
1976	12,388.65	11,225	11,869	767	3.91	196
1977	49,027.94	43,893	46,411	3,597	4.28	840
1978	778,072.63	687,517	726,952	66,682	4.68	14,248
1979	2,841.36	2,474	2,616	282	5.12	55
1981	3,009.83	2,531	2,676	394	6.15	64
1983	31,042.02	25,014	26,449	5,214	7.35	709
1984	3,474.57	2,734	2,891	653	8.00	82
1985	1,287.81	988	1,045	269	8.68	31
1986	7,609.26	5,684	6,010	1,751	9.37	187
1987	87,594.98	63,589	67,236	22,111	10.09	2,191
1988	13,505.80	9,513	10,059	3,717	10.83	343
1989	20,082.21	13,707	14,493	5,991	11.58	517
1990	30,473.35	20,106	21,259	9,824	12.36	795
1991	17,391,196.01	11,069,148	11,704,059	6,034,961	13.16	458,584
1992	2,779,861.98	1,702,098	1,799,728	1,035,731	13.99	74,034
1993	5,084,883.10	2,988,975	3,160,419	2,026,162	14.83	136,626
1994	19,425,500.80	10,931,588	11,558,609	8,255,402	15.69	526,157
1995	4,836,932.85	2,597,923	2,746,936	2,186,736	16.57	131,970
1996	2,009,758.55	1,026,740	1,085,632	964,322	17.47	55,199
1997	3,472,147.04	1,681,759	1,778,222	1,763,368	18.38	95,939
1998	6,109,127.88	2,795,179	2,955,507	3,275,803	19.30	169,731
1999	7,040,821.35	3,028,568	3,202,283	3,979,355	20.24	196,608
2000	50,731,392.07	20,417,427	21,588,543	30,157,477	21.19	1,423,194
2001	5,634,170.57	2,109,900	2,230,921	3,515,933	22.15	158,733
2002	6,487,787.69	2,248,046	2,376,991	4,240,552	23.11	183,494
2003	698,737.94	222,160	234,903	477,810	24.09	19,834
2004	2,337,494.41	677,125	715,964	1,668,280	25.06	66,571
2005	1,867,681.49	487,137	515,078	1,389,957	26.05	53,357
2006	439,909.79	102,175	108,036	340,672	27.03	12,603
2007	18,414,661.89	3,745,885	3,960,743	14,822,212	28.02	528,987
2008	3,315,847.99	577,877	611,023	2,771,142	29.02	95,491
2009	1,082,920.40	157,480	166,513	938,066	30.01	31,258
2010	3,606,902.77	419,411	443,468	3,235,573	31.01	104,340
2011	3,817,924.42	333,779	352,924	3,541,359	32.00	110,667
2012	2,907,689.35	169,468	179,188	2,786,655	33.00	84,444
2013	1,419,948.95	41,379	43,753	1,404,595	34.00	41,312
2014	802,227.23		0	818,272	35.00	23,379
	174,208,156.68	71,773,285	75,890,103	101,802,217		4,819,427

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.1   2.77

FORTISBC ENERGY INC.

ACCOUNT 467.10 - TRANSMISSION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 36-S0.5
NET SALVAGE PERCENT.. -7

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1971	52,395.12	40,303	49,720	6,343	10.12	627
1972	125,024.32	94,758	116,898	16,878	10.50	1,607
1974	16,590.56	12,185	15,032	2,720	11.29	241
1975	998.36	721	889	179	11.69	15
1977	1,038.54	725	894	217	12.51	17
1978	3,487.48	2,390	2,948	784	12.94	61
1981	1,834.03	1,186	1,463	499	14.24	35
1982	15,188.66	9,620	11,868	4,384	14.69	298
1984	28,053.01	17,001	20,973	9,044	15.61	579
1985	107,429.56	63,574	78,428	36,522	16.09	2,270
1986	37,810.22	21,835	26,937	13,520	16.57	816
1987	11,619.01	6,537	8,064	4,368	17.07	256
1988	1,116,555.43	611,622	754,528	440,186	17.57	25,053
1989	57,162.09	30,446	37,560	23,603	18.08	1,305
1991	8,980,570.24	4,497,687	5,548,572	4,060,638	19.15	212,044
1992	1,684,769.34	816,733	1,007,563	795,140	19.69	40,383
1993	1,493,263.12	698,586	861,811	735,981	20.26	36,327
1994	974,941.16	439,589	542,299	500,888	20.83	24,046
1995	1,326,452.36	574,818	709,124	710,180	21.42	33,155
1996	974,251.07	404,814	499,399	543,050	22.02	24,662
1997	3,126,984.59	1,242,624	1,532,963	1,812,911	22.63	80,111
1998	1,214,316.37	459,452	566,803	732,516	23.27	31,479
1999	1,886,551.70	677,910	836,304	1,182,306	23.91	49,448
2000	3,978,738.51	1,350,485	1,666,026	2,591,224	24.58	105,420
2001	992,221.07	316,730	390,734	670,943	25.26	26,561
2002	2,339,555.84	698,152	861,275	1,642,050	25.96	63,253
2003	4,199,552.53	1,164,586	1,436,691	3,056,830	26.67	114,617
2004	1,142,912.35	291,800	359,979	862,937	27.41	31,483
2005	540,884.04	125,877	155,288	423,458	28.17	15,032
2006	2,079,593.79	436,377	538,336	1,686,829	28.94	58,287
2007	1,023,026.17	190,347	234,822	859,816	29.74	28,911
2008	1,433,181.46	231,728	285,871	1,247,633	30.56	40,826
2009	668,341.23	91,379	112,730	602,395	31.40	19,185
2010	557,931.90	61,854	76,306	520,681	32.27	16,135
2011	1,399,067.08	118,098	145,692	1,351,310	33.16	40,751
2012	3,416,053.98	194,931	240,476	3,414,702	34.08	100,197
2013	2,349,186.61	68,421	84,408	2,429,222	35.02	69,367
2014	1,267,307.27		0	1,356,019	36.00	37,667
	50,624,840.17	16,065,881	19,819,674	34,348,905		1,332,527

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.8 2.63

FORTISBC ENERGY INC.

ACCOUNT 467.20 - TRANSMISSION - TELEMETRY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 8-L1
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1972	20,657.58	18,075	20,516	142	1.00	142
1974	2,092.39	1,831	2,078	14	1.00	14
1976	8,260.32	7,228	8,204	56	1.00	56
1978	14,078.53	12,319	13,983	96	1.00	96
1979	1,440.46	1,260	1,430	10	1.00	10
1980	27,834.89	24,356	27,645	190	1.00	190
1981	1,654.26	1,447	1,642	12	1.00	12
1982	8,407.98	7,357	8,350	58	1.00	58
1984	8,673.99	7,590	8,615	59	1.00	59
1985	34,907.66	30,544	34,669	239	1.00	239
1986	13,700.85	11,988	13,607	94	1.00	94
1987	7,999.60	7,000	7,945	55	1.00	55
1988	7,794.38	6,820	7,741	53	1.00	53
1989	960.12	840	953	7	1.00	7
1991	117,323.96	102,658	116,521	803	1.00	803
1992	92,120.01	80,605	91,490	630	1.00	630
1993	122,632.08	107,303	121,793	839	1.00	839
1994	151,736.81	132,770	150,699	1,038	1.00	1,038
1995	289,843.56	248,541	282,103	7,741	1.14	6,790
1996	120,568.42	100,675	114,270	6,298	1.32	4,771
1997	205,181.68	166,197	188,640	16,542	1.52	10,883
1998	98,463.61	77,294	87,731	10,733	1.72	6,240
1999	1,865,795.96	1,415,673	1,606,840	258,956	1.93	134,174
2000	372,797.36	272,608	309,420	63,377	2.15	29,478
2001	479,373.79	336,760	382,235	97,139	2.38	40,815
2002	156,418.32	104,996	119,174	37,244	2.63	14,161
2003	104,929.43	67,155	76,223	28,706	2.88	9,967
2004	439,319.72	266,338	302,303	137,017	3.15	43,497
2005	22,377.46	12,755	14,477	7,900	3.44	2,297
2006	1,139,124.34	605,160	686,878	452,246	3.75	120,599
2007	105,467.10	51,811	58,807	46,660	4.07	11,464
2008	176,830.37	79,132	89,818	87,012	4.42	19,686
2009	135,743.49	54,467	61,822	73,921	4.79	15,432
2010	117,666.55	41,183	46,744	70,923	5.20	13,639
2011	3,266,394.36	943,171	1,070,534	2,195,860	5.69	385,916
2012	651,160.02	136,744	155,209	495,951	6.32	78,473
2013	1,413,710.67	159,042	180,519	1,233,192	7.10	173,689
2014	899,335.91		0	899,336	8.00	112,417
	12,702,777.99	5,701,693	6,471,628	6,231,150		1,238,783

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.0 9.75

FORTISBC ENERGY INC.

ACCOUNT 467.31 - TRANSMISSION - INTERMEDIATE PRESSURE - MEASURING AND REGULATING EQUIPMENT - WHISTLER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-S0.5						
NET SALVAGE PERCENT.. -7						
2009	313,343.70	42,842	62,669	272,609	31.40	8,682
	313,343.70	42,842	62,669	272,609		8,682

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.4 2.77

FORTISBC ENERGY INC.

ACCOUNT 468.00 - TRANSMISSION - COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 19-R3						
NET SALVAGE PERCENT.. 0						
1991	1,958,059.29	1,717,942	1,958,059			
1992	5,318.92	4,580	5,319			
1993	12,206.04	10,285	12,206			
1994	12,077.12	9,922	12,077			
1995	25,012.13	19,970	25,012			
1996	3,807.61	2,940	3,808			
1997	61,617.36	45,824	61,617			
1998	43,080.18	30,700	43,080			
1999	3,013.81	2,046	3,014			
2000	2,407.88	1,549	2,408			
2001	199,364.98	120,773	199,365			
2002	166,128.70	94,168	166,129			
2003	609,903.24	320,681	609,903			
2004	4,920.95	2,380	4,921			
2006	16,956.15	6,702	16,956			
2007	257,488.01	89,850	257,488			
2008	42,132.78	12,706	42,133			
2009	260,764.97	66,015	260,765			
2010	1,027.09	209	1,027			
2011	294,713.93	45,292	294,714			
2012	12.65	1	9	4	17.04	
2013	264,839.14	13,660	129,712	135,127	18.02	7,499
	4,244,852.93	2,618,195	4,109,722	135,131		7,499

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.0 0.18

FORTISBC ENERGY INC.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 36-R1.5
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1958	21,817.93	20,960	24,000			
1961	21,710.46	20,306	23,882			
1962	15,408.41	14,275	16,949			
1965	559.36	503	615			
1968	15,488.52	13,455	17,037			
1969	1,834.27	1,574	2,017	1	7.91	
1970	15,051.61	12,753	16,341	216	8.27	26
1971	1,411.99	1,181	1,513	40	8.63	5
1972	4,054.62	3,344	4,285	175	9.01	19
1973	13,979.73	11,362	14,558	820	9.40	87
1974	14,144.35	11,319	14,503	1,056	9.81	108
1975	6,738.60	5,306	6,799	613	10.23	60
1976	2,188.00	1,694	2,171	236	10.66	22
1978	15.33	11	14	3	11.57	
1979	3,374.00	2,469	3,164	547	12.05	45
1980	7,195.67	5,158	6,609	1,306	12.54	104
1981	76,431.46	53,598	68,676	15,399	13.05	1,180
1982	25,409.62	17,415	22,314	5,637	13.57	415
1983	41,233.93	27,592	35,354	10,003	14.10	709
1984	26,710.02	17,425	22,327	7,054	14.65	482
1985	15,784.38	10,027	12,848	4,515	15.21	297
1986	116,667.82	72,046	92,314	36,021	15.79	2,281
1987	145,783.14	87,397	111,983	48,378	16.38	2,953
1988	17,436.24	10,133	12,984	6,196	16.98	365
1989	26,851.43	15,096	19,343	10,194	17.60	579
1990	44,063.07	23,939	30,673	17,796	18.22	977
1991	1,011,128.36	529,549	678,521	433,720	18.86	22,997
1992	737,421.65	371,562	476,089	335,075	19.51	17,175
1993	230,966.97	111,646	143,054	111,010	20.18	5,501
1994	767,097.82	355,100	454,996	388,812	20.85	18,648
1995	922,888.65	408,040	522,829	492,349	21.53	22,868
1996	1,006,804.44	423,923	543,180	564,305	22.22	25,396
1997	931,923.87	372,179	476,880	548,236	22.93	23,909
1998	473,631.84	178,873	229,193	291,802	23.64	12,344
1999	449,144.12	159,744	204,683	289,376	24.36	11,879
2000	534,263.30	178,264	228,413	359,277	25.08	14,325
2001	592,107.88	184,180	235,993	415,326	25.82	16,085
2002	222,346.98	64,134	82,176	162,406	26.56	6,115
2003	328,695.14	87,278	111,831	249,734	27.31	9,144
2004	1,253,770.52	303,799	389,263	989,885	28.07	35,265
2005	2,236,890.90	490,074	627,940	1,832,640	28.83	63,567
2006	2,462,803.99	481,621	617,110	2,091,974	29.60	70,675
2007	946,952.02	162,612	208,358	833,289	30.38	27,429
2008	1,054,207.72	155,900	199,757	959,871	31.16	30,805
2009	551,470.55	68,244	87,442	519,176	31.95	16,250

FORTISBC ENERGY INC.

ACCOUNT 472.00 - DISTRIBUTION - STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-R1.5						
NET SALVAGE PERCENT.. -10						
2010	476,707.19	47,341	60,659	463,719	32.75	14,159
2011	2,037,272.74	152,522	195,429	2,045,571	33.55	60,971
2012	997,424.53	49,987	64,049	1,033,118	34.36	30,067
2013	903,998.80	22,652	29,025	965,374	35.18	27,441
2014	454,180.42		0	499,599	36.00	13,878
	22,265,444.36	5,819,562	7,450,143	17,041,846		607,607

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.0 2.73

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R1						
NET SALVAGE PERCENT.. -60						
1959	1,245,510.94	1,460,078	893,491	1,099,327	12.03	91,382
1960	351,186.54	406,438	248,719	313,179	12.45	25,155
1962	593,764.29	669,234	409,536	540,487	13.30	40,638
1963	813,984.13	904,721	553,642	748,733	13.74	54,493
1964	771,914.07	845,610	517,469	717,594	14.19	50,570
1965	663,576.26	716,312	438,345	623,377	14.64	42,580
1966	676,680.24	719,381	440,224	642,464	15.10	42,547
1967	699,055.87	731,492	447,635	670,854	15.57	43,086
1968	715,754.95	737,010	451,012	694,196	16.04	43,279
1969	727,669.76	736,600	450,761	713,511	16.53	43,165
1970	1,582,334.36	1,574,182	963,317	1,568,418	17.02	92,151
1971	1,616,362.93	1,579,872	966,799	1,619,382	17.51	92,483
1972	2,075,233.62	1,990,763	1,218,243	2,102,131	18.02	116,655
1973	2,908,085.45	2,736,950	1,674,870	2,978,067	18.53	160,716
1974	3,714,124.19	3,426,918	2,097,094	3,845,505	19.05	201,864
1975	3,474,030.41	3,139,912	1,921,462	3,636,987	19.58	185,750
1976	5,042,597.21	4,460,803	2,729,778	5,338,378	20.12	265,327
1977	4,572,457.25	3,957,114	2,421,547	4,894,385	20.66	236,902
1978	5,412,567.45	4,578,339	2,801,704	5,858,404	21.21	276,210
1979	5,650,599.34	4,667,124	2,856,036	6,184,923	21.77	284,103
1980	8,004,960.72	6,449,565	3,946,796	8,861,141	22.34	396,649
1981	12,026,588.68	9,445,971	5,780,440	13,462,102	22.91	587,608
1982	11,429,774.61	8,741,492	5,349,336	12,938,303	23.49	550,800
1983	14,253,565.56	10,602,144	6,487,957	16,317,748	24.08	677,647
1984	13,019,180.77	9,406,306	5,756,167	15,074,522	24.68	610,799
1985	22,686,363.25	15,906,589	9,734,000	26,564,181	25.28	1,050,798
1986	9,827,887.94	6,674,158	4,084,235	11,640,386	25.90	449,436
1987	23,017,138.58	15,132,019	9,260,004	27,567,418	26.51	1,039,888
1988	11,091,651.40	7,043,465	4,310,232	13,436,410	27.14	495,078
1989	16,883,124.87	10,343,007	6,329,379	20,683,621	27.77	744,819
1990	18,054,461.39	10,656,176	6,521,022	22,366,116	28.40	787,539
1991	25,185,152.86	14,282,601	8,740,204	31,556,041	29.05	1,086,266
1992	38,353,355.88	20,864,226	12,767,814	48,597,555	29.70	1,636,281
1993	41,138,169.99	21,428,708	13,113,248	52,707,824	30.35	1,736,666
1994	38,287,157.36	19,044,951	11,654,513	49,604,939	31.01	1,599,643
1995	37,690,934.44	17,863,694	10,931,646	49,373,849	31.67	1,559,010
1996	36,538,942.07	16,447,201	10,064,826	48,397,481	32.34	1,496,521
1997	33,971,223.51	14,482,068	8,862,268	45,491,690	33.01	1,378,118
1998	29,010,101.02	11,676,450	7,145,376	39,270,786	33.68	1,165,997
1999	25,233,973.59	9,546,113	5,841,721	34,532,637	34.36	1,005,024
2000	28,519,617.62	10,099,595	6,180,424	39,450,964	35.04	1,125,884
2001	21,848,413.89	7,201,237	4,406,780	30,550,682	35.73	855,043
2002	23,960,865.01	7,309,789	4,473,208	33,864,176	36.42	929,824
2003	24,843,052.10	6,969,172	4,264,769	35,484,114	37.11	956,187
2004	28,443,156.73	7,271,436	4,449,738	41,059,313	37.81	1,085,938

FORTISBC ENERGY INC.

ACCOUNT 473.00 - DISTRIBUTION - SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R1						
NET SALVAGE PERCENT.. -60						
2005	34,365,670.24	7,929,947	4,852,713	50,132,359	38.51	1,301,801
2006	36,032,844.27	7,418,154	4,539,522	53,113,029	39.21	1,354,579
2007	43,329,960.57	7,826,431	4,789,366	64,538,571	39.92	1,616,698
2008	45,507,836.90	7,070,826	4,326,975	68,485,564	40.63	1,685,591
2009	33,096,959.87	4,295,191	2,628,432	50,326,704	41.35	1,217,091
2010	34,894,445.87	3,635,164	2,224,530	53,606,583	42.07	1,274,224
2011	36,541,765.82	2,871,306	1,757,089	56,709,736	42.79	1,325,303
2012	42,641,881.91	2,243,986	1,373,202	66,853,809	43.52	1,536,163
2013	43,728,605.30	1,150,237	703,885	69,261,883	44.26	1,564,887
2014	45,164,535.88			72,263,257	45.00	1,605,850
	1,031,930,809.73	379,368,228	232,153,501	1,418,935,795		41,878,706

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.9   4.06

FORTISBC ENERGY INC.

ACCOUNT 474.00 - DISTRIBUTION - METER/REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 20-S0
NET SALVAGE PERCENT.. -20

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1968	101,120.35	115,277	72,248	49,096	1.00	49,096
1970	46,978.65	53,556	33,566	22,808	1.00	22,808
1972	30,530.56	34,805	21,814	14,823	1.00	14,823
1973	27,145.72	30,946	19,395	13,180	1.00	13,180
1974	14,528.69	16,563	10,381	7,053	1.00	7,053
1975	2,700.12	3,078	1,929	1,311	1.00	1,311
1977	8,986.39	10,191	6,387	4,397	1.10	3,997
1978	99,941.85	111,055	69,602	50,328	1.48	34,005
1979	906.16	987	619	468	1.85	253
1980	515.70	550	345	274	2.23	123
1981	131,804.92	137,525	86,192	71,974	2.61	27,576
1982	183,521.08	187,192	117,320	102,905	3.00	34,302
1983	24,854.31	24,785	15,534	14,291	3.38	4,228
1984	4,821,110.90	4,691,905	2,940,589	2,844,744	3.78	752,578
1985	179,569.86	170,555	106,893	108,591	4.17	26,041
1986	214,733.50	198,800	124,595	133,085	4.57	29,121
1987	158,778.06	143,091	89,680	100,854	4.98	20,252
1988	266,888.54	234,115	146,728	173,538	5.38	32,256
1989	391,782.11	333,798	209,203	260,936	5.80	44,989
1990	291,438.74	240,962	151,020	198,706	6.22	31,946
1991	213,076.97	170,802	107,048	148,644	6.64	22,386
1992	2,139,214.12	1,659,602	1,040,133	1,526,924	7.07	215,972
1993	2,851,011.86	2,136,548	1,339,053	2,082,161	7.51	277,252
1994	8,187,278.94	5,919,403	3,709,907	6,114,828	7.95	769,161
1995	14,750,018.00	10,266,013	6,434,087	11,265,935	8.40	1,341,183
1996	6,441,895.46	4,305,763	2,698,580	5,031,695	8.86	567,911
1997	7,336,587.75	4,696,883	2,943,709	5,860,196	9.33	628,102
1998	4,469,790.49	2,732,830	1,712,765	3,650,984	9.81	372,170
1999	8,422,509.53	4,906,954	3,075,368	7,031,643	10.29	683,347
2000	6,431,127.21	3,553,841	2,227,322	5,490,031	10.79	508,807
2001	7,306,254.07	3,813,865	2,390,289	6,377,216	11.30	564,355
2002	7,026,807.38	3,448,757	2,161,462	6,270,707	11.82	530,517
2003	6,712,845.17	3,077,168	1,928,574	6,126,840	12.36	495,699
2004	9,054,760.93	3,851,895	2,414,124	8,451,589	12.91	654,654
2005	10,249,396.16	4,009,564	2,512,941	9,786,334	13.48	725,989
2006	11,137,151.05	3,962,598	2,483,505	10,881,076	14.07	773,353
2007	12,026,571.23	3,831,666	2,401,445	12,030,440	14.69	818,954
2008	10,101,106.55	2,836,391	1,777,670	10,343,658	15.32	675,173
2009	13,947,284.80	3,355,717	2,103,151	14,633,591	15.99	915,171
2010	17,763,372.02	3,527,806	2,211,005	19,105,041	16.69	1,144,700
2011	25,852,082.89	3,986,391	2,498,418	28,524,081	17.43	1,636,493
	199,417,978.79	86,790,193	54,394,596	184,906,979		15,471,287

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.0   7.76

FORTISBC ENERGY INC.

ACCOUNT 475.00 - DISTRIBUTION - SYSTEMS – MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 64-R2.5
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1959	4,108,969.02	3,534,330	3,461,637	1,674,574	19.96	83,896
1960	418,402.47	355,072	347,769	175,234	20.55	8,527
1961	592,493.13	495,983	485,782	254,834	21.14	12,055
1962	1,786,423.46	1,474,157	1,443,837	789,192	21.75	36,285
1963	3,346,368.30	2,721,518	2,665,542	1,517,418	22.36	67,863
1964	3,248,206.90	2,601,733	2,548,221	1,512,038	22.99	65,769
1965	2,572,776.92	2,028,570	1,986,847	1,229,124	23.63	52,015
1966	4,559,797.29	3,537,377	3,464,621	2,235,126	24.28	92,056
1967	2,867,607.68	2,187,662	2,142,667	1,441,843	24.94	57,812
1968	3,378,034.31	2,532,850	2,480,755	1,741,788	25.61	68,012
1969	7,799,912.83	5,744,831	5,626,672	4,123,219	26.29	156,836
1970	10,218,738.80	7,390,575	7,238,567	5,534,856	26.97	205,223
1971	4,529,912.00	3,214,312	3,148,201	2,514,189	27.67	90,863
1972	7,113,523.23	4,948,878	4,847,090	4,044,814	28.38	142,523
1973	7,355,000.75	5,014,915	4,911,769	4,281,982	29.09	147,198
1974	9,492,234.68	6,338,677	6,208,304	5,656,989	29.81	189,768
1975	6,377,026.81	4,167,467	4,081,751	3,889,533	30.54	127,359
1976	9,789,048.07	6,255,814	6,127,146	6,109,164	31.28	195,306
1977	8,767,021.54	5,474,238	5,361,645	5,597,132	32.03	174,747
1978	9,970,234.37	6,079,475	5,954,434	6,508,359	32.78	198,547
1979	17,349,313.30	10,321,540	10,109,249	11,577,393	33.54	345,182
1980	18,263,838.77	10,590,972	10,373,139	12,456,659	34.31	363,062
1981	19,344,617.16	10,922,938	10,698,277	13,482,494	35.09	384,226
1982	34,166,283.28	18,771,383	18,385,297	24,322,557	35.87	678,075
1983	53,724,300.37	28,677,360	28,087,530	39,067,845	36.67	1,065,390
1984	25,697,571.28	13,320,657	13,046,680	19,075,284	37.46	509,217
1985	18,006,679.42	9,049,032	8,862,913	13,645,436	38.27	356,557
1986	18,924,032.65	9,210,800	9,021,354	14,633,687	39.08	374,455
1987	26,704,705.28	12,569,905	12,311,370	21,069,512	39.90	528,058
1988	13,006,895.03	5,911,471	5,789,885	10,468,734	40.73	257,028
1989	16,698,661.07	7,318,606	7,168,078	13,705,248	41.56	329,770
1990	29,807,420.12	12,580,967	12,322,204	24,937,071	42.39	588,277
1991	52,991,982.28	21,486,924	21,044,985	45,194,993	43.24	1,045,213
1992	78,833,387.31	30,655,348	30,024,835	68,516,899	44.09	1,554,024
1993	43,731,291.42	16,279,520	15,944,686	38,719,428	44.94	861,581
1994	49,372,235.12	17,550,595	17,189,618	44,525,676	45.80	972,176
1995	50,470,204.36	17,082,902	16,731,544	46,356,211	46.67	993,276
1996	43,728,464.25	14,058,155	13,769,010	40,891,570	47.54	860,151
1997	43,457,093.19	13,223,993	12,952,005	41,369,361	48.42	854,386
1998	39,287,020.19	11,279,795	11,047,794	38,060,981	49.30	772,028
1999	40,630,057.78	10,958,942	10,733,541	40,054,031	50.19	798,048
2000	32,177,951.87	8,120,106	7,953,093	32,269,347	51.08	631,741
2001	34,188,151.98	8,026,096	7,861,017	34,874,173	51.98	670,915
2002	27,517,757.94	5,976,513	5,853,589	28,543,608	52.88	539,781
2003	31,289,771.15	6,239,571	6,111,237	33,000,977	53.79	613,515

FORTISBC ENERGY INC.

ACCOUNT 475.00 - DISTRIBUTION - SYSTEMS – MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 64-R2.5
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2004	26,583,872.43	4,828,628	4,729,314	28,500,527	54.70	521,033
2005	28,273,291.17	4,632,932	4,537,643	30,803,971	55.61	553,929
2006	33,197,464.15	4,843,510	4,743,890	36,752,940	56.53	650,149
2007	37,035,103.34	4,737,716	4,640,271	41,653,608	57.45	725,041
2008	39,601,724.56	4,346,784	4,257,380	45,244,776	58.38	775,005
2009	35,989,915.42	3,296,676	3,228,871	41,758,523	59.31	704,072
2010	24,139,275.32	1,772,728	1,736,267	28,437,827	60.24	472,075
2011	24,375,540.34	1,342,483	1,314,871	29,154,554	61.18	476,537
2012	25,811,733.88	952,776	933,179	31,331,488	62.11	504,452
2013	35,315,810.82	648,487	635,149	43,509,615	63.06	689,972
2014	37,139,427.50			46,424,284	64.00	725,379
	1,315,124,578.06	437,685,245	428,683,022	1,215,222,701		25,916,436

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.9 1.97

FORTISBC ENERGY INC.

ACCOUNT 476.00 - DISTRIBUTION - NGV FUEL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L0						
NET SALVAGE PERCENT.. 0						
1996	63,432.30	48,481	63,432			
1997	56,248.13	41,624	56,248			
1998	50,153.69	35,895	50,154			
1999	50,208.17	34,715	50,208			
2000	266,663.32	177,142	266,663			
2001	40,654.46	25,844	40,654			
2002	43,497.59	26,347	43,498			
2010	143,508.79	40,798	143,509			
2011	394,542.76	90,745	394,543			
2012	1,215.46	207	900,264	899,049-		
	1,110,124.67	521,798	2,009,173	899,049-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

FORTISBC ENERGY INC.

ACCOUNT 477.10 - DISTRIBUTION - MEASURING AND REGULATING ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 30-R2
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1958	40,513.10	43,079	44,564			
1963	1,338.85	1,412	1,473			
1964	214.27	224	236			
1965	784.71	811	863			
1966	540.28	553	590	4	2.08	2
1969	1,644.28	1,631	1,739	70	2.95	24
1970	6,275.03	6,157	6,564	339	3.24	105
1971	5,454.34	5,292	5,642	358	3.54	101
1973	86,591.83	82,138	87,564	7,687	4.13	1,861
1974	8,788.62	8,237	8,781	886	4.44	200
1975	2,550.61	2,360	2,516	290	4.76	61
1976	26,245.35	23,972	25,556	3,314	5.09	651
1977	8,487.30	7,646	8,151	1,185	5.43	218
1978	4,340.83	3,853	4,108	667	5.79	115
1979	72,002.42	62,940	67,098	12,105	6.16	1,965
1980	78,936.45	67,872	72,356	14,474	6.55	2,210
1981	15,662.48	13,232	14,106	3,123	6.96	449
1982	187,372.91	155,339	165,601	40,509	7.39	5,482
1983	199,185.61	161,918	172,614	46,490	7.83	5,937
1984	138,319.42	110,056	117,326	34,825	8.30	4,196
1985	92,113.15	71,670	76,405	24,919	8.78	2,838
1986	619,955.84	470,772	501,871	180,080	9.29	19,384
1987	484,944.22	358,828	382,532	150,907	9.82	15,367
1988	7,046,924.67	5,074,751	5,409,988	2,341,629	10.36	226,026
1989	333,198.16	233,105	248,504	118,014	10.92	10,807
1990	114,497.94	77,625	82,753	43,195	11.51	3,753
1991	3,183,033.50	2,087,952	2,225,882	1,275,455	12.11	105,322
1992	2,781,931.65	1,761,622	1,877,994	1,182,131	12.73	92,862
1993	1,880,992.26	1,146,959	1,222,727	846,364	13.37	63,303
1994	3,155,470.69	1,848,907	1,971,045	1,499,973	14.02	106,988
1995	4,811,868.90	2,701,205	2,879,646	2,413,410	14.69	164,289
1996	3,224,869.89	1,728,733	1,842,933	1,704,424	15.38	110,821
1997	3,422,959.24	1,747,078	1,862,489	1,902,766	16.08	118,331
1998	2,408,826.07	1,165,872	1,242,889	1,406,820	16.80	83,739
1999	2,284,524.46	1,043,715	1,112,663	1,400,314	17.54	79,835
2000	3,307,052.58	1,421,163	1,515,045	2,122,713	18.28	116,122
2001	4,577,529.65	1,839,540	1,961,059	3,074,224	19.04	161,461
2002	3,167,820.12	1,182,430	1,260,541	2,224,061	19.82	112,213
2003	7,451,239.00	2,565,462	2,734,936	5,461,427	20.61	264,989
2004	3,760,294.38	1,185,760	1,264,091	2,872,233	21.40	134,216
2005	4,852,021.02	1,384,102	1,475,535	3,861,688	22.22	173,793
2006	7,891,272.84	2,013,853	2,146,888	6,533,512	23.04	283,573
2007	5,542,987.97	1,245,859	1,328,160	4,769,127	23.87	199,796
2008	3,496,630.79	676,948	721,667	3,124,627	24.72	126,401
2009	4,987,553.67	808,298	861,694	4,624,615	25.58	180,790

FORTISBC ENERGY INC.

ACCOUNT 477.10 - DISTRIBUTION - MEASURING AND REGULATING ADDITIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2						
NET SALVAGE PERCENT.. -10						
2010	3,545,102.21	462,767	493,337	3,406,275	26.44	128,830
2011	4,070,933.77	400,022	426,447	4,051,580	27.32	148,301
2012	5,170,903.09	341,280	363,825	5,324,168	28.20	188,800
2013	7,392,410.34	243,950	260,065	7,871,586	29.10	270,501
2014	2,165,043.49		0	2,381,548	30.00	79,385
	108,110,154.25	38,048,950	40,561,059	78,360,111		3,796,413

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.6 3.51

FORTISBC ENERGY INC.

ACCOUNT 477.20 - DISTRIBUTION - TELEMETRY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 16-L1						
NET SALVAGE PERCENT.. -5						
1959	202.89	200	213			
1969	9,476.34	9,285	9,950			
1971	140.82	135	148			
1973	2,713.40	2,539	2,849			
1976	195.90	177	206			
1979	14,378.32	12,417	15,097			
1982	17,668.21	14,563	18,552			
1983	49,062.59	39,764	51,516			
1984	2,366.11	1,885	2,484			
1985	37,831.32	29,594	39,723			
1986	71,707.63	55,058	75,293			
1987	606.69	457	637			
1988	49,307.96	36,371	51,773			
1989	8,939.14	6,453	9,386			
1990	14,049.49	9,912	14,752			
1991	47,391.77	32,656	49,761			
1992	67,459.98	45,333	70,833			
1993	96,223.82	62,957	101,035			
1994	220,454.52	140,187	231,477			
1995	268,810.63	165,998	282,251			
1996	1,337,834.70	800,694	1,404,726			
1997	555,475.29	321,516	583,249			
1998	303,648.07	169,580	318,830			
1999	279,364.29	150,151	293,333			
2000	272,146.98	140,377	277,964	7,790	8.14	957
2001	382,456.58	188,493	373,240	28,339	8.49	3,338
2002	147,324.27	69,224	137,072	17,618	8.84	1,993
2003	372,716.00	166,325	329,345	62,007	9.20	6,740
2004	110,303.11	46,472	92,020	23,798	9.58	2,484
2005	31,141.55	12,303	24,362	8,337	9.98	835
2006	189,560.91	69,664	137,944	61,095	10.40	5,875
2007	47,814.20	16,128	31,935	18,270	10.86	1,682
2008	191,400.25	57,904	114,657	86,313	11.39	7,578
2009	108,270.60	28,563	56,558	57,126	11.98	4,768
2010	443,077.92	97,410	192,884	272,348	12.65	21,529
2011	341,644.36	58,515	115,867	242,860	13.39	18,137
2012	1,066,202.57	125,945	249,388	870,125	14.20	61,276
2013	1,441,962.07	87,058	172,386	1,341,674	15.08	88,970
2014	1,584,942.07		0	1,664,189	16.00	104,012
	10,186,273.32	3,272,263	5,933,696	4,761,891		330,174

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.4   3.24

FORTISBC ENERGY INC.

ACCOUNT 477.30 - DISTRIBUTION - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R2.5						
NET SALVAGE PERCENT.. 0						
1989	50,316.16	46,962	50,316			
1991	253.68	233	254			
1995	12,447.44	10,647	12,447			
1999	5,185.29	3,948	5,185			
2000	1,661.74	1,211	1,662			
2001	44,063.55	30,492	44,064			
2003	49,223.00	29,993	105,983	56,760-		
	163,150.86	123,486	219,911	56,760-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

FORTISBC ENERGY INC.

ACCOUNT 478.10 - DISTRIBUTION - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-R2.5						
NET SALVAGE PERCENT.. 0						
1969	416.84	394	353	64	1.00	64
1970	83.78	79	71	13	1.00	13
1971	1,682.65	1,589	1,425	258	1.00	258
1972	1,310.33	1,238	1,110	200	1.00	200
1975	861.69	814	730	132	1.00	132
1981	126.00	119	107	19	1.00	19
1983	150.97	143	128	23	1.00	23
1984	1,898.90	1,793	1,607	292	1.00	292
1985	60,995.50	57,031	51,129	9,866	1.17	8,432
1986	62,645.44	57,808	51,826	10,819	1.39	7,783
1987	67,834.10	61,767	55,375	12,459	1.61	7,739
1988	12,742,021.60	11,446,540	10,261,957	2,480,065	1.83	1,355,227
1989	5,067,688.13	4,487,742	4,023,313	1,044,375	2.06	506,978
1990	11,756,897.51	10,254,601	9,193,369	2,563,529	2.30	1,114,578
1991	2,469,220.69	2,118,048	1,898,855	570,366	2.56	222,799
1992	2,741,361.70	2,310,365	2,071,269	670,093	2.83	236,782
1993	3,631,519.29	2,998,037	2,687,775	943,744	3.14	300,555
1994	3,967,532.85	3,200,490	2,869,277	1,098,256	3.48	315,591
1995	7,342,274.03	5,763,685	5,167,211	2,175,063	3.87	562,032
1996	9,004,470.70	6,853,393	6,144,147	2,860,324	4.30	665,192
1997	8,412,425.85	6,178,422	5,539,027	2,873,399	4.78	601,129
1998	6,152,888.07	4,337,786	3,888,876	2,264,012	5.31	426,368
1999	9,260,562.96	6,230,322	5,585,556	3,675,007	5.89	623,940
2000	7,181,147.24	4,583,942	4,109,558	3,071,589	6.51	471,826
2001	6,321,039.16	3,806,656	3,412,712	2,908,327	7.16	406,191
2002	11,225,143.63	6,329,746	5,674,691	5,550,453	7.85	707,064
2003	16,392,048.63	8,587,630	7,698,910	8,693,139	8.57	1,014,369
2004	13,153,456.15	6,342,860	5,686,448	7,467,008	9.32	801,181
2005	8,294,819.30	3,645,075	3,267,852	5,026,967	10.09	498,213
2006	7,931,272.17	3,132,853	2,808,639	5,122,633	10.89	470,398
2007	9,120,729.24	3,187,148	2,857,316	6,263,413	11.71	534,877
2008	7,241,735.78	2,188,597	1,962,103	5,279,633	12.56	420,353
2009	7,800,137.57	1,980,377	1,775,431	6,024,707	13.43	448,601
2010	8,239,613.69	1,689,121	1,514,317	6,725,297	14.31	469,972
2011	10,398,560.84	1,611,777	1,444,977	8,953,584	15.21	588,664
2012	10,755,134.10	1,117,351	1,001,718	9,753,416	16.13	604,676
2013	11,498,302.26	600,441	538,302	10,960,000	17.06	642,438
2014	10,219,720.48			10,219,720	18.00	567,762
	228,519,729.82	115,165,780	103,247,467	125,272,263		15,602,711

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0 6.83

FORTISBC ENERGY INC.

ACCOUNT 478.20 - DISTRIBUTION - INSTRUMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 35-R5
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1983	361,761.94	303,052	289,239	72,523	5.68	12,768
1984	2,933.10	2,400	2,291	642	6.36	101
1985	5,631.05	4,490	4,285	1,346	7.09	190
1986	23,355.78	18,117	17,291	6,065	7.85	773
1987	96,807.57	72,854	69,533	27,275	8.66	3,150
1988	115,160.76	83,903	80,079	35,082	9.50	3,693
1989	93,986.33	66,113	63,100	30,886	10.38	2,976
1990	165,438.23	112,167	107,054	58,384	11.27	5,180
1991	344,502.95	224,516	214,283	130,220	12.19	10,683
1992	754,659.62	471,557	450,063	304,597	13.13	23,199
1993	835,661.00	499,483	476,717	358,944	14.08	25,493
1994	901,190.00	513,678	490,265	410,925	15.05	27,304
1995	785,627.00	425,810	406,401	379,226	16.03	23,657
1996	655,670.92	337,015	321,654	334,017	17.01	19,637
1997	407,431.51	197,779	188,764	218,668	18.01	12,141
1998	53,827.57	24,607	23,485	30,343	19.00	1,597
1999	354,932.07	152,113	145,180	209,752	20.00	10,488
2000	253,791.63	101,517	96,890	156,902	21.00	7,472
2001	375,867.06	139,608	133,245	242,622	22.00	11,028
2002	356,603.79	122,265	116,692	239,912	23.00	10,431
2003	1,390,662.14	437,071	417,149	973,513	24.00	40,563
2004	1,363,377.05	389,530	371,775	991,602	25.00	39,664
2005	288,290.84	74,131	70,752	217,539	26.00	8,367
2006	508,057.41	116,127	110,834	397,223	27.00	14,712
2007	447,712.81	89,543	85,462	362,251	28.00	12,938
2008	308,436.81	52,875	50,465	257,972	29.00	8,896
2009	53,796.50	7,685	7,335	46,462	30.00	1,549
2010	174,068.52	19,894	18,987	155,082	31.00	5,003
2011	291,813.18	25,011	23,871	267,942	32.00	8,373
2012	118,228.13	6,756	6,448	111,780	33.00	3,387
2013	199,737.95	5,707	5,447	194,291	34.00	5,714
2014	54,309.85		0	54,310	35.00	1,552
	12,143,331.07	5,097,374	4,865,036	7,278,295		362,679

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.1 2.99

FORTISBC ENERGY INC.

ACCOUNT 472.20 - BIO GAS - STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 36-R1.5						
NET SALVAGE PERCENT.. -10						
2010	136,986.21	13,604	22,051	128,634	32.75	3,928
2013	47,985.30	1,202	1,948	50,836	35.18	1,445
2014	369,634.57		0	406,598	36.00	11,294
	554,606.08	14,806	23,999	586,068		16,667

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.2 3.01

FORTISBC ENERGY INC.

ACCOUNT 474.10 - BIO GAS - METER/REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 19-S0						
NET SALVAGE PERCENT.. -25						
2010	21,779.73	4,714	4,544	22,681	15.71	1,444
2014	156,449.24		0	195,561	19.00	10,293
	178,228.97	4,714	4,544	218,242		11,737

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.6 6.59

FORTISBC ENERGY INC.

ACCOUNT 475.10 - BIO GAS - MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R2.5						
NET SALVAGE PERCENT.. -25						
2010	73,652.86	5,326	2,615	89,451	61.24	1,461
2011	45,881.36	2,497	1,226	56,126	62.17	903
2012	422,265.80	15,349	7,538	520,294	63.11	8,244
2014	846,231.62			1,057,790	65.00	16,274
	1,388,031.64	23,172	11,379	1,723,661		26,882

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 64.1   1.94

FORTISBC ENERGY INC.

ACCOUNT 477.40 - BIO GAS - MEASURING AND REGULATING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R2						
NET SALVAGE PERCENT.. 0						
2010	275,549.82	32,699	59,135	216,415	26.44	8,185
2011	4,049.98	362	655	3,395	27.32	124
2012	316.05	19	34	282	28.20	10
2013	578,338.21	17,350	31,377	546,961	29.10	18,796
2014	762,122.57		0	762,123	30.00	25,404
	1,620,376.63	50,430	91,201	1,529,176		52,519

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.1 3.24

FORTISBC ENERGY INC.

ACCOUNT 478.30 - BIO GAS - METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-R2.5						
NET SALVAGE PERCENT.. 0						
2010	7,334.33	1,504	2,568	4,766	14.31	333
2013	2,963.75	155	264	2,700	17.06	158
2014	627.52		0	627	18.00	35
	10,925.60	1,659	2,832	8,093		526

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.4 4.81

FORTISBC ENERGY INC.

ACCOUNT 418.10 - BIO GAS - PURIFICATION OVERHAUL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2014	20,423.22			20,423	20.00	1,021
	20,423.22			20,423		1,021

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.0 5.00

FORTISBC ENERGY INC.

ACCOUNT 418.20 - BIO GAS - PURIFICATION UPGRADER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. -5						
2013	2,444,884.49	128,356	263,370	2,303,759	19.00	121,250
2014	4,572,331.59		0	4,800,948	20.00	240,047
	7,017,216.08	128,356	263,370	7,104,707		361,297

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.7   5.15

FORTISBC ENERGY INC.

ACCOUNT 482.10 - GENERAL PLANT - STRUCTURES (FRAME)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2.5						
NET SALVAGE PERCENT.. 0						
1988	727,292.32	628,017	527,292	200,000	2.73	73,260
1990	321.21	269	226	95	3.28	29
1991	295,355.52	242,339	203,471	91,885	3.59	25,595
1992	84,431.17	67,756	56,889	27,542	3.95	6,973
1993	6,275.90	4,914	4,126	2,150	4.34	495
1994	927,662.45	705,951	592,726	334,936	4.78	70,070
1995	2,434,883.71	1,794,509	1,506,695	928,189	5.26	176,462
1996	961,272.12	683,464	573,846	387,426	5.78	67,029
1997	106,930.77	72,980	61,275	45,656	6.35	7,190
1998	461,537.95	301,154	252,853	208,685	6.95	30,027
1999	139,534.49	86,581	72,695	66,839	7.59	8,806
2000	223,606.97	131,257	110,205	113,402	8.26	13,729
2001	1,028,572.60	567,772	476,709	551,864	8.96	61,592
2002	981,245.96	506,323	425,116	556,130	9.68	57,451
2003	229,116.44	109,632	92,049	137,067	10.43	13,142
2004	82,486.33	36,253	30,439	52,047	11.21	4,643
2005	234,491.77	93,679	78,654	155,838	12.01	12,976
2006	159,826.07	57,298	48,108	111,718	12.83	8,708
2007	115,250.00	36,477	30,627	84,623	13.67	6,190
2008	104,998.31	28,717	24,111	80,887	14.53	5,567
2009	1,023,089.86	234,799	197,140	825,950	15.41	53,598
2010	2,055,035.13	380,181	319,205	1,735,830	16.30	106,493
2011	2,770,368.16	386,466	324,483	2,445,885	17.21	142,120
2012	986,553.97	92,243	77,448	909,106	18.13	50,144
2013	2,006,047.99	94,284	79,162	1,926,886	19.06	101,096
2014	663,489.16		0	663,489	20.00	33,174
	18,809,676.33	7,343,315	6,165,550	12,644,126		1,136,559

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.1 6.04

FORTISBC ENERGY INC.

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 50-R2.5
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1960	85,734.03	74,974	74,596	19,711	10.25	1,923
1967	70,596.50	56,844	56,557	21,099	13.40	1,575
1970	13,832.70	10,648	10,594	4,622	15.01	308
1974	688.62	494	492	265	17.37	15
1975	181.34	128	127	72	18.00	4
1976	248,769.72	171,631	170,765	102,882	18.64	5,519
1977	8,927.00	6,029	5,999	3,821	19.30	198
1978	20,357.44	13,454	13,386	9,007	19.96	451
1979	305,827.48	197,540	196,544	139,866	20.64	6,776
1980	4,921.37	3,104	3,088	2,326	21.33	109
1981	8,968.67	5,517	5,489	4,377	22.04	199
1982	7,755.47	4,649	4,626	3,905	22.75	172
1983	11,041.06	6,444	6,412	5,733	23.47	244
1984	45,537.81	25,837	25,707	24,385	24.21	1,007
1985	1,086.55	599	596	599	24.95	24
1986	246.00	131	130	141	25.71	5
1987	3,350.06	1,734	1,725	1,960	26.47	74
1988	527,194.04	263,977	262,646	317,267	27.24	11,647
1989	452,674.55	218,796	217,693	280,249	28.03	9,998
1990	114,839.26	53,511	53,241	73,082	28.82	2,536
1991	27,623.86	12,385	12,323	18,063	29.62	610
1992	3,313,005.15	1,426,381	1,419,188	2,225,118	30.43	73,123
1993	141,792.70	58,489	58,194	97,778	31.25	3,129
1994	3,763,964.63	1,483,905	1,476,421	2,663,940	32.08	83,041
1995	4,263,857.08	1,603,125	1,595,040	3,095,203	32.91	94,051
1996	4,365,619.35	1,560,709	1,552,838	3,249,343	33.75	96,277
1997	446,730.18	151,352	150,589	340,814	34.60	9,850
1998	1,376,344.34	440,265	438,045	1,075,934	35.46	30,342
1999	227,140.28	68,310	67,966	181,888	36.33	5,007
2000	650,787.40	183,262	182,338	533,528	37.20	14,342
2001	1,244,864.63	326,453	324,807	1,044,544	38.08	27,430
2002	516,034.79	125,335	124,703	442,935	38.96	11,369
2003	1,490,878.55	332,913	331,234	1,308,732	39.85	32,841
2004	1,078,369.99	219,448	218,341	967,866	40.75	23,751
2005	51,661,993.90	9,490,308	9,442,446	47,385,747	41.65	1,137,713
2006	1,130,939.61	185,112	184,178	1,059,856	42.56	24,903
2007	3,203,886.93	459,566	457,248	3,067,028	43.48	70,539
2008	1,026,255.73	126,660	126,021	1,002,860	44.39	22,592
2009	2,101,637.06	216,385	215,294	2,096,507	45.32	46,260
2010	987,028.26	81,430	81,019	1,004,712	46.25	21,724
2011	8,866,730.99	550,092	547,318	9,206,086	47.18	195,127

FORTISBC ENERGY INC.

ACCOUNT 482.20 - GENERAL PLANT - STRUCTURES (MASONRY)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R2.5						
NET SALVAGE PERCENT.. -10						
2012	13,525,308.54	559,407	556,587	14,321,252	48.12	297,615
2013	1,137,858.01	23,531	23,412	1,228,232	49.06	25,035
2014	41,146.01		0	45,260	50.00	905
	108,522,327.64	20,800,864	20,695,963	98,678,597		2,390,360

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.3 2.20

FORTISBC ENERGY INC.

ACCOUNT 484.00 - GENERAL PLANT - VEHICLES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 6-L0.5						
NET SALVAGE PERCENT.. +4						
2000	7,000.00	5,062	6,720			
2001	6,661.85	4,679	6,395			
2002	184,761.50	125,343	177,371			
2003	183,346.57	119,395	176,013			
2004	134,011.79	82,980	128,651			
2005	348,708.62	204,204	334,760			
2006	833,310.02	455,987	787,316	12,662	2.58	4,908
2007	266,047.78	134,515	232,256	23,150	2.84	8,151
2008	757,058.34	348,852	602,334	124,442	3.12	39,885
2009	889,575.48	364,373	629,133	224,859	3.44	65,366
2010	1,198,613.82	425,748	735,105	415,564	3.78	109,938
2011	977,188.41	287,687	496,726	441,375	4.16	106,100
2012	1,039,062.77	227,759	393,253	604,247	4.63	130,507
2013	1,305,996.58	160,895	277,805	975,952	5.23	186,607
2014	1,932,572.58		0	1,855,270	6.00	309,212
	10,063,916.11	2,947,479	4,983,838	4,677,522		960,674

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.9 9.55

FORTISBC ENERGY INC.

ACCOUNT 485.10 - GENERAL PLANT - HEAVY WORK EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

SURVIVOR CURVE.. IOWA 12-L0.5
NET SALVAGE PERCENT.. +5

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1992	6,400.00	4,124	5,961	119	3.86	31
1993	49,650.75	31,249	45,168	2,000	4.05	494
1995	19,242.50	11,486	16,602	1,678	4.46	376
1996	20,529.03	11,897	17,196	2,307	4.68	493
1997	32,729.25	18,371	26,554	4,539	4.91	924
1998	52,786.37	28,584	41,316	8,831	5.16	1,711
1999	16,249.22	8,477	12,253	3,184	5.41	589
2000	12,982.28	6,496	9,389	2,944	5.68	518
2001	16,506.95	7,893	11,409	4,273	5.96	717
2002	23,621.28	10,753	15,543	6,897	6.25	1,104
2003	63,686.00	27,427	39,644	20,858	6.56	3,180
2005	33,948.14	12,874	18,608	13,643	7.21	1,892
2006	40,804.49	14,311	20,685	18,079	7.57	2,388
2007	12,040.27	3,880	5,608	5,830	7.93	735
2008	32,668.31	9,491	13,719	17,316	8.33	2,079
2010	79,618.56	17,334	25,055	50,583	9.25	5,468
2011	82,206.26	14,188	20,508	57,588	9.82	5,864
2012	252,922.43	31,036	44,860	195,416	10.45	18,700
2013	3,103.00	204	295	2,653	11.17	238
2014	45,562.75		0	43,285	12.00	3,607
	897,257.84	270,075	390,373	462,022		51,108

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.0 5.70

FORTISBC ENERGY INC.

ACCOUNT 485.20 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF DECEMBER 31, 2014

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 8-L2						
NET SALVAGE PERCENT.. +15						
2001	29,463.87	19,128	25,044			
2003	38,786.72	23,202	32,969			
2004	186,443.66	106,378	158,477			
2005	148,469.18	80,925	126,199			
2006	66,492.85	34,547	56,390	129	3.11	41
2007	136,392.75	67,242	109,758	6,176	3.36	1,838
2008	175,242.84	80,995	132,206	16,750	3.65	4,589
2009	472,973.65	199,506	325,649	76,379	4.03	18,953
2010	648,963.18	237,196	387,170	164,449	4.56	36,063
2011	242,682.55	70,651	115,322	90,958	5.26	17,292
2012	221,039.84	44,622	72,835	115,049	6.10	18,860
2013	90,225.29	9,395	15,335	61,356	7.02	8,740
2014	1,761,840.78		0	1,497,564	8.00	187,196
	4,219,017.16	973,787	1,557,354	2,028,810		293,572

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.9   6.96

APPENDIX A

ESTIMATION OF SURIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

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. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. 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 presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

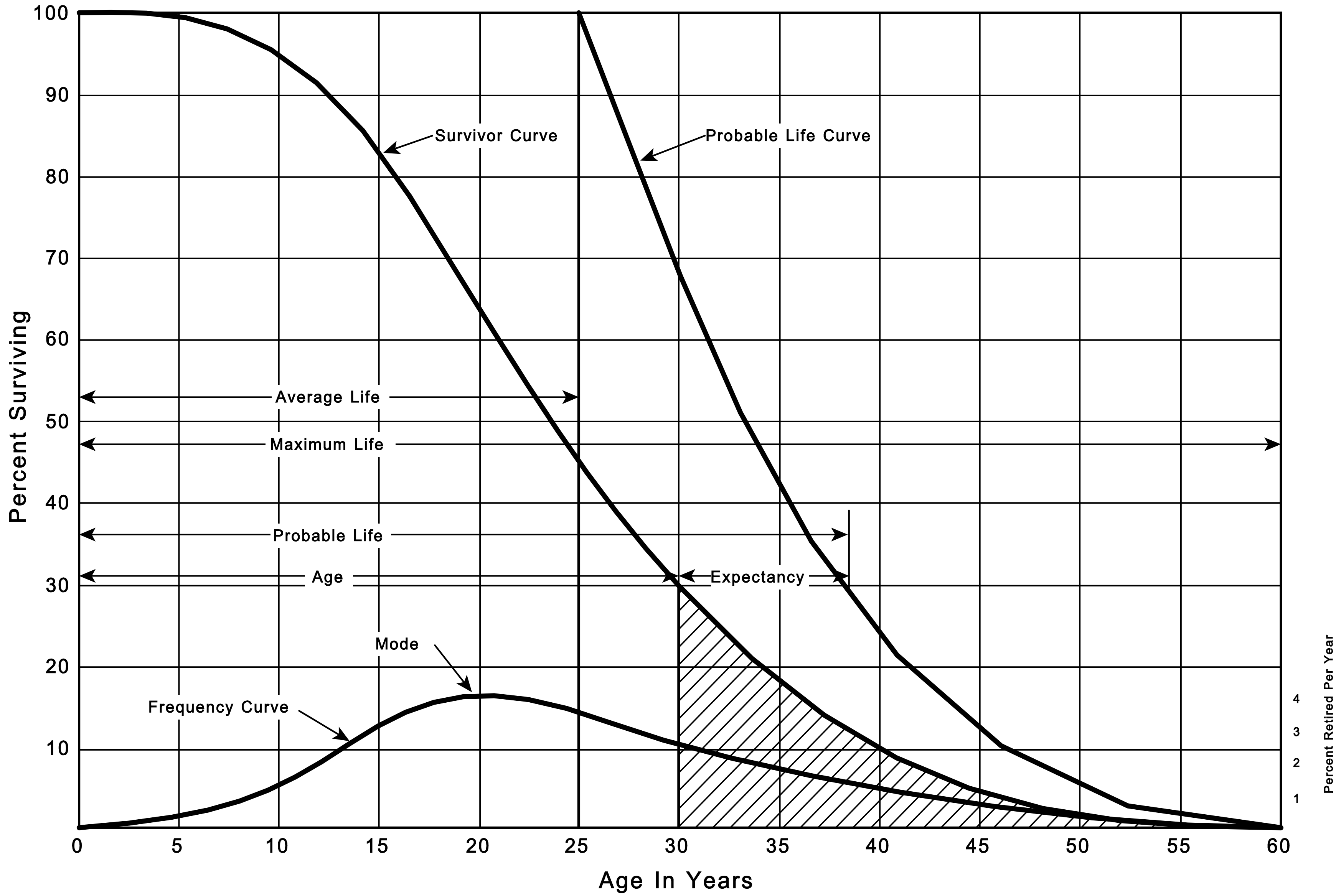


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

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[1] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3] 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.

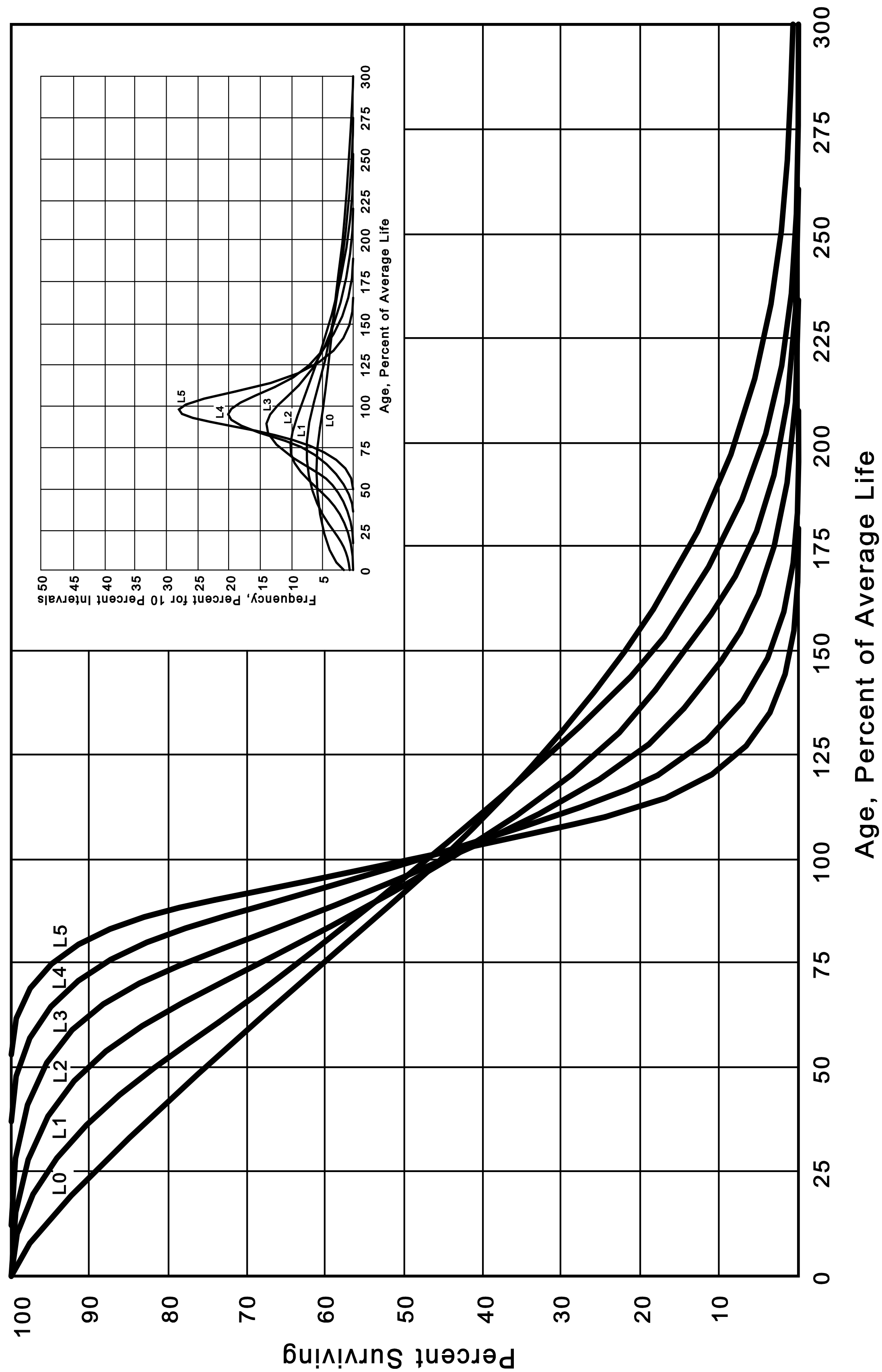


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

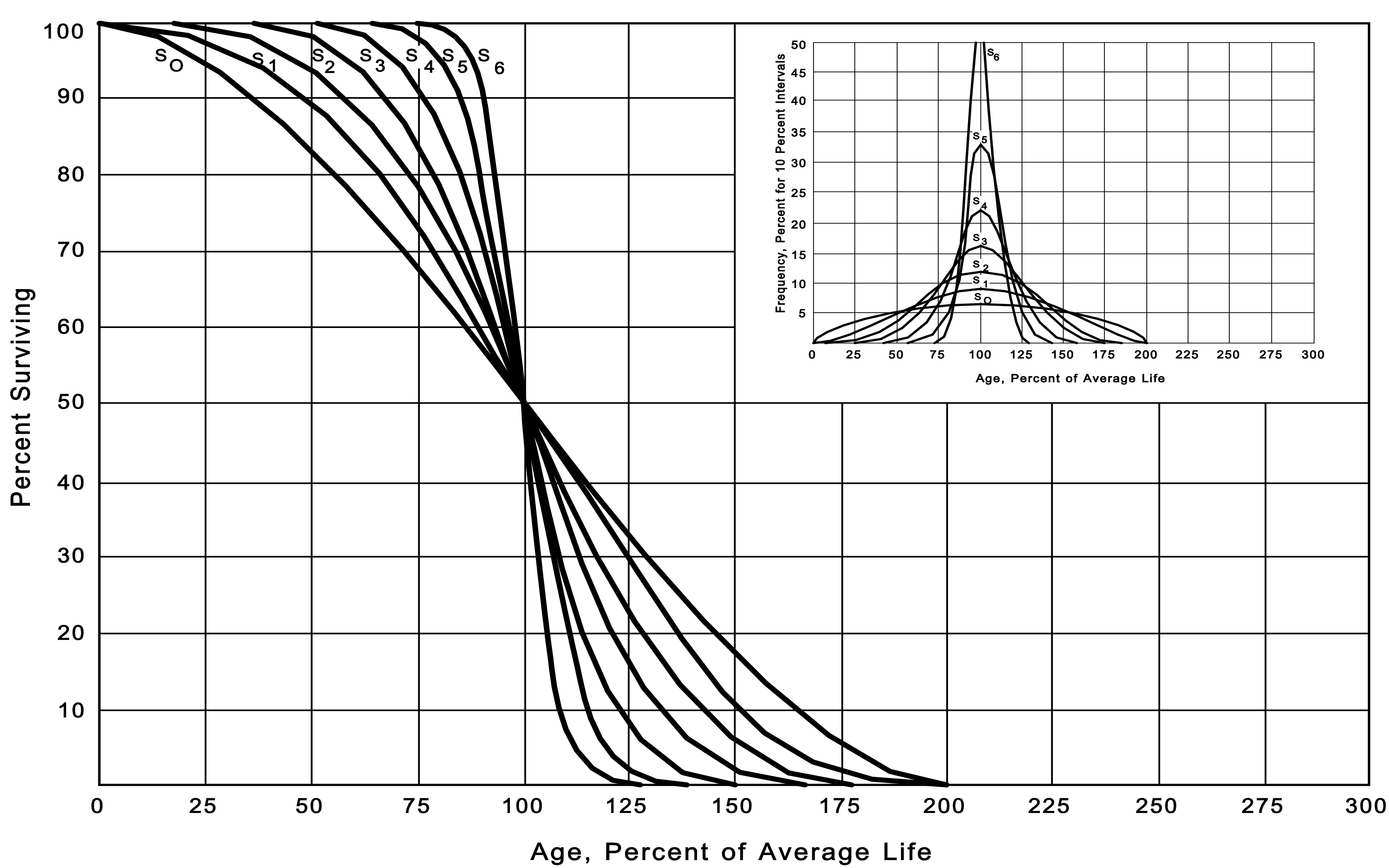


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

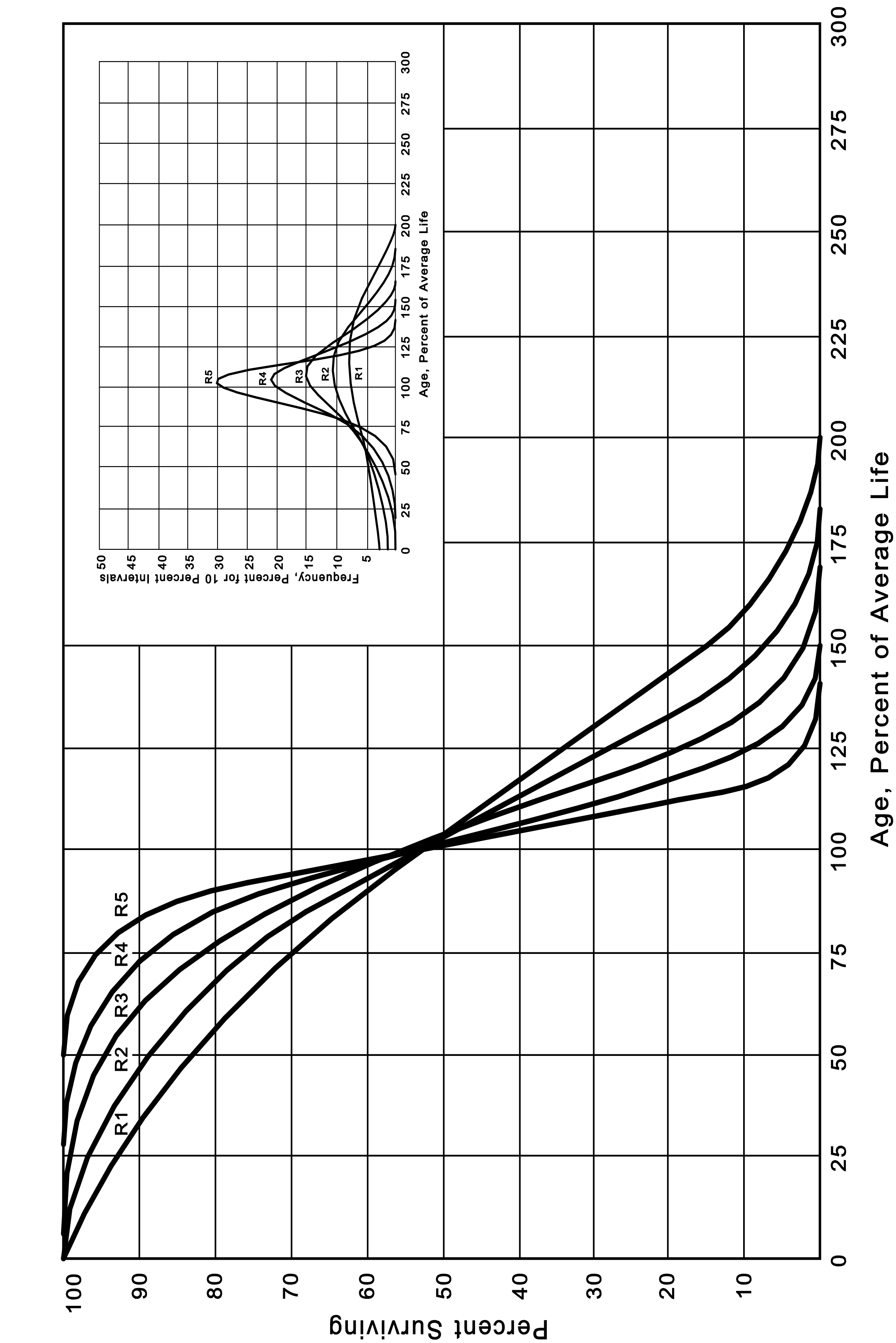


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

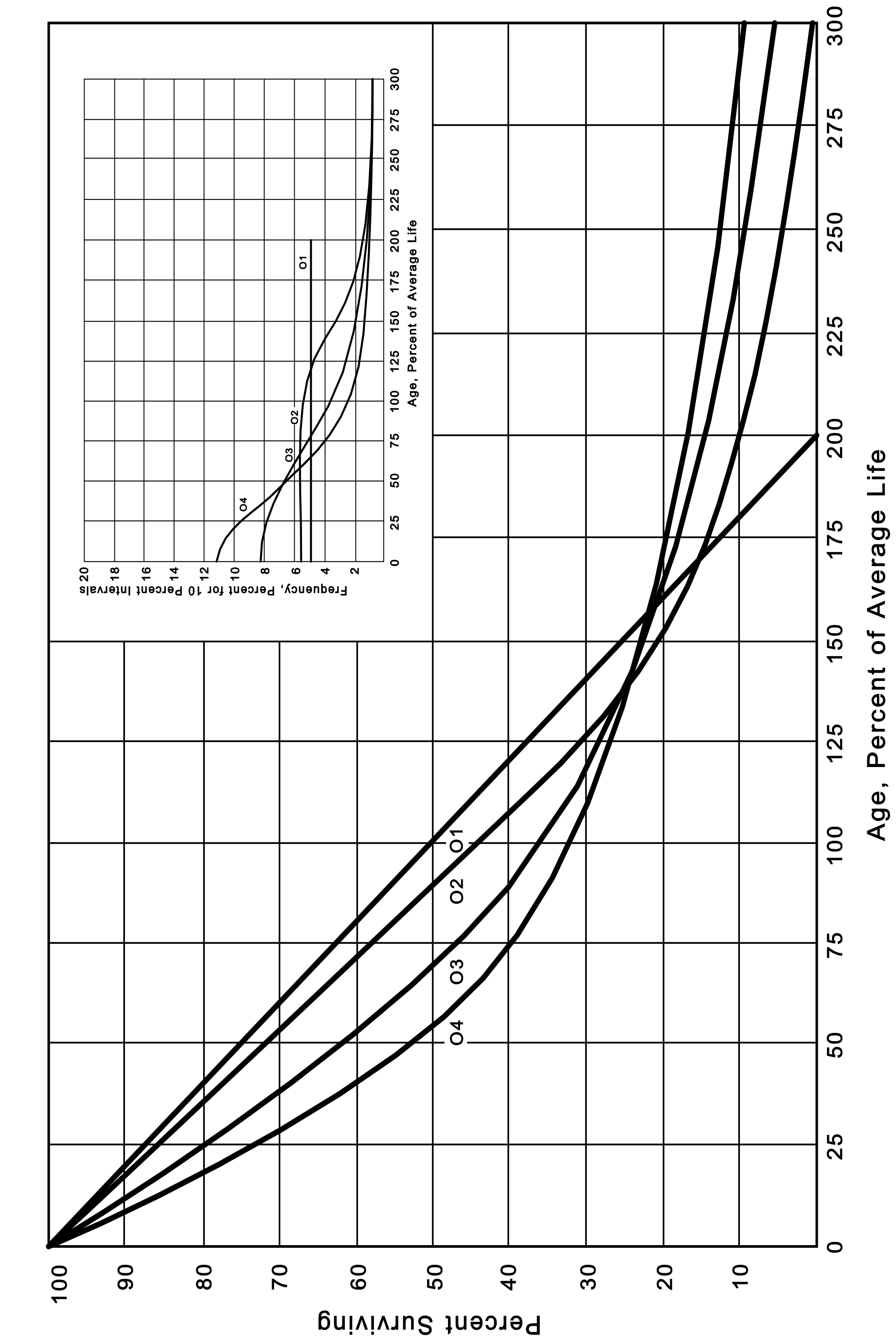


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. 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.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2005-2014 during which there were placements during the years 2000-2014. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, 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 dollars invested in 2000 were

[4]Winfrey, Robley, Supra Note 1.
[5]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[6]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014

Placement Band 2000-2014

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1999	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2000	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2001	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2002	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2003	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2004	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2005		5	11	12	13	14	15	16	18	20	113	7½-8½
2006			6	12	13	15	16	17	19	19	124	6½-7½
2007				6	13	15	16	17	19	19	131	5½-6½
2008					7	14	16	17	19	20	143	4½-5½
2009						8	18	20	22	23	146	3½-4½
2010							9	20	22	25	150	2½-3½
2011								11	23	25	151	1½-2½
2012									11	24	153	½-1½
2013										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 Placement Band 2000-2014

Year Placed (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)	2009 (6)	2010 (7)	2011 (8)	2012 (9)	2013 (10)	2014 (11)	Total During Age Interval (12)	Age Interval (13)
	Acquisitions, Transfers and Sales, Thousands of Dollars — During Year											
1999	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2000	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2001	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2002	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2003	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2004	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2005		-	-	-	-	-	-	-	-	-	-	7½-8½
2006			-	-	-	-	-	-	-	-	-	6½-7½
2007				-	-	-	-	(12)[b]	-	-	-	5½-6½
2008					-	-	-	-	22[a]	-	-	4½-5½
2009						-	-	(19)[b]	-	-	10	3½-4½
2010							-	-	-	-	-	2½-3½
2011								-	-	(102)[c]	(121)	1½-2½
2012									-	-	-	½-1½
2013												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.

retired in 2005. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to 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 2005 retirements of 2000 installations and ending with the 2014 retirements of the 2009 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

In Schedule 2, other transactions which affect the group are recorded in a similar manner. 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 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 on the following page. The surviving plant at the beginning of each year from 2005 through 2014 is recorded by year in the portion of the table headed "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

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2005-2014
SUMMARIZED BY AGE INTERVAL

Experience Band 2005-2014 | Placement Band 2000-2014

Year Placed (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)	2009 (6)	2010 (7)	2011 (8)	2012 (9)	2013 (10)	2014 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year											
1999	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2000	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2001	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2002	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2003	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2004	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2005		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2006			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2007				580[a]	574	561	546	530	501	482	3,057	5½-6½
2008					660[a]	653	639	623	628	609	3,789	4½-5½
2009						750[a]	742	724	685	663	4,332	3½-4½
2010							850[a]	841	821	799	4,955	2½-3½
2011								960[a]	949	923	5,719	1½-2½
2012									1,080[a]	1,069	6,579	½-1½
2013										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

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 2006 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 2005-2014, 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.

Original Life Table

The original life table, illustrated in Schedule 4 on the following page, 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% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2005-2014 Placement Band 2000-2014

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	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	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

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.

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.

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% 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 percents 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 AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

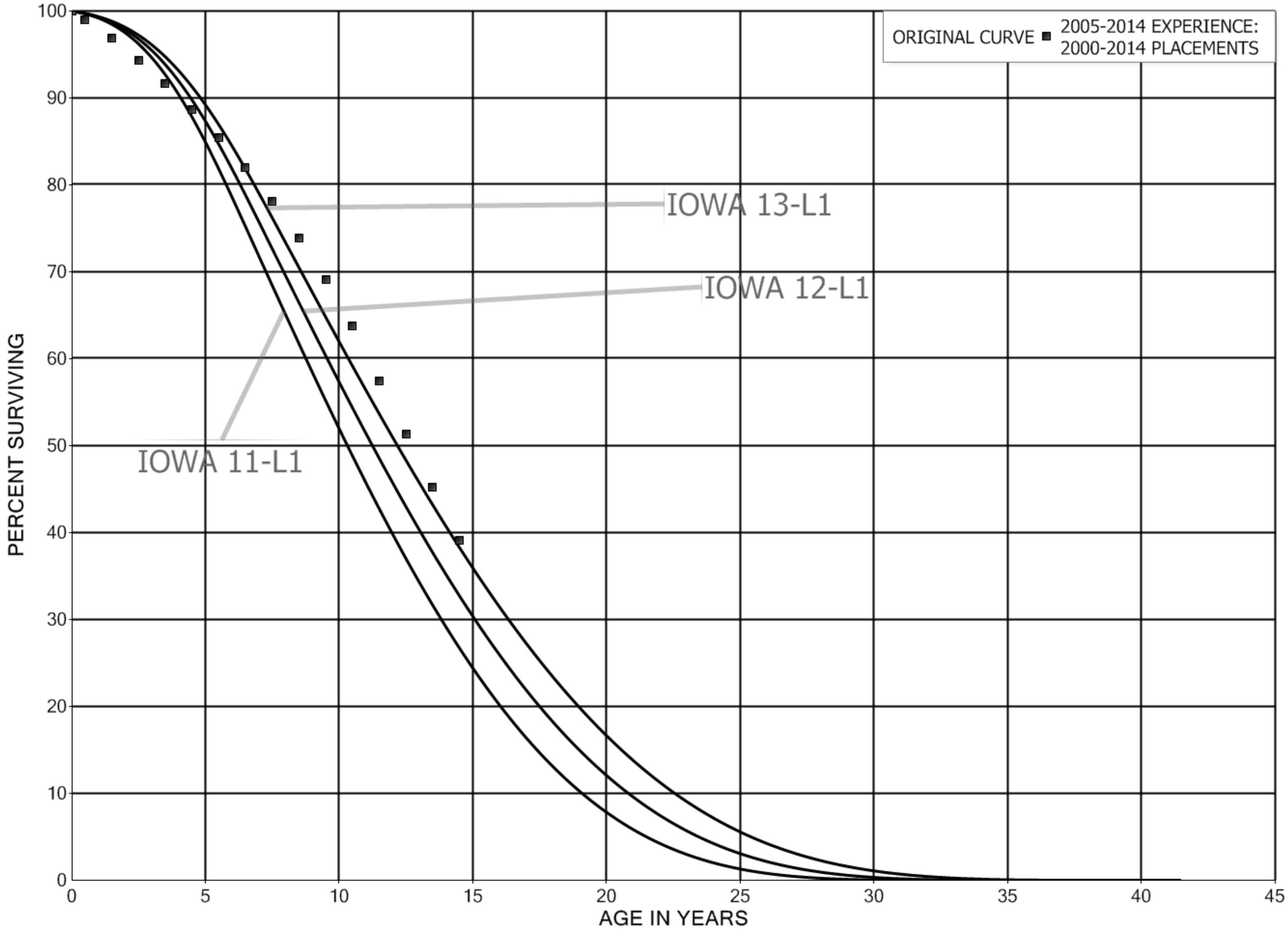


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

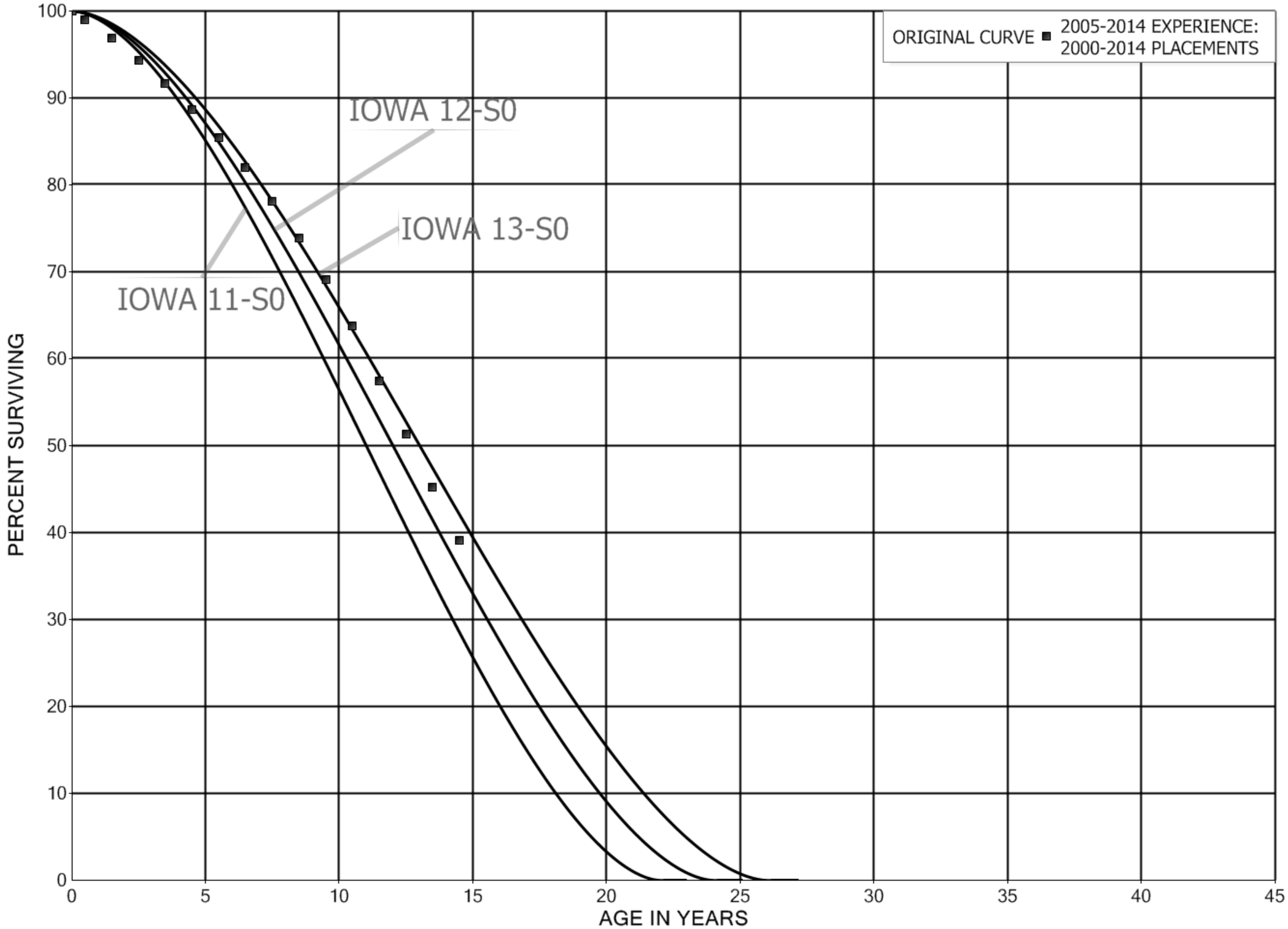


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

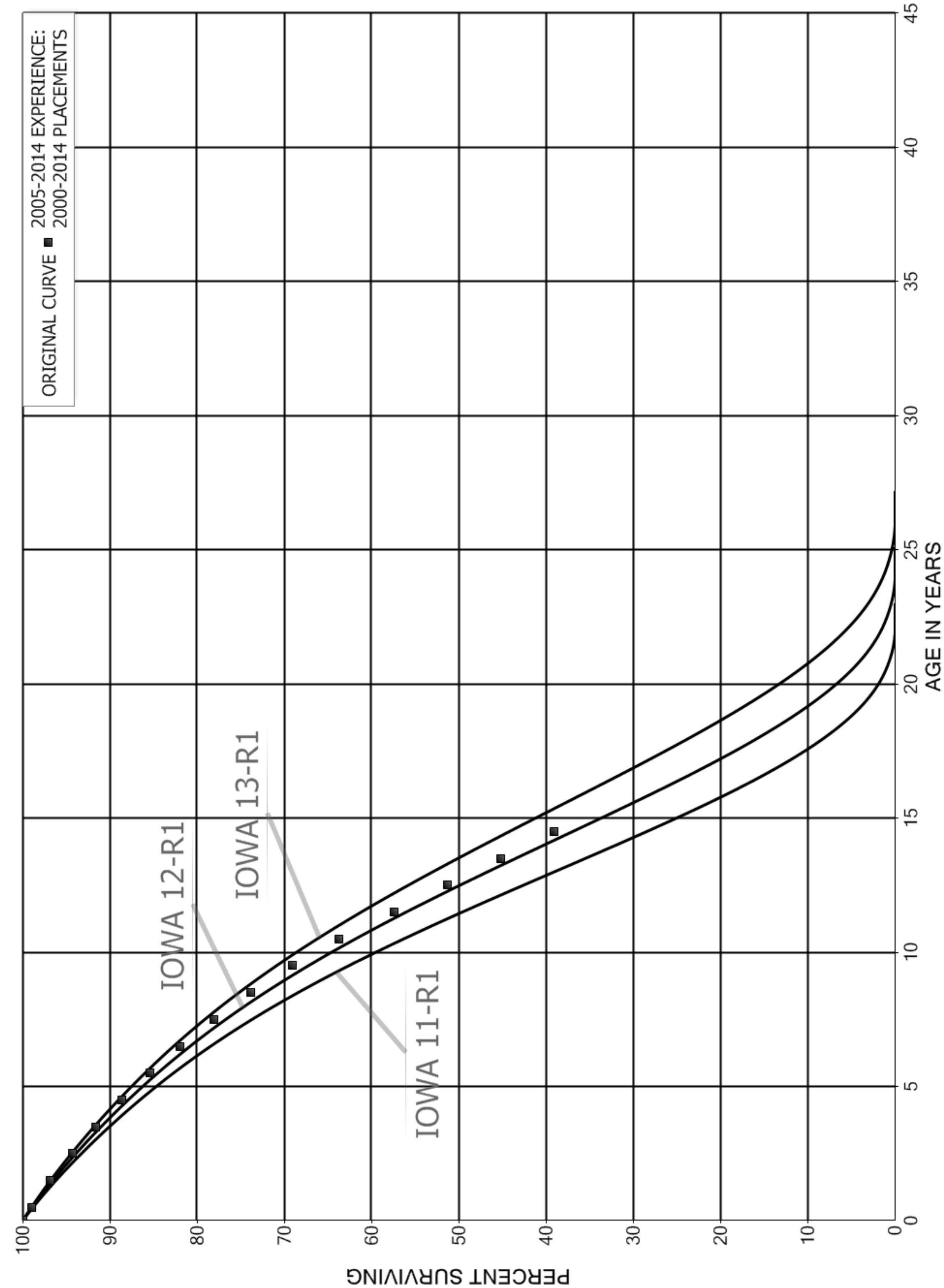
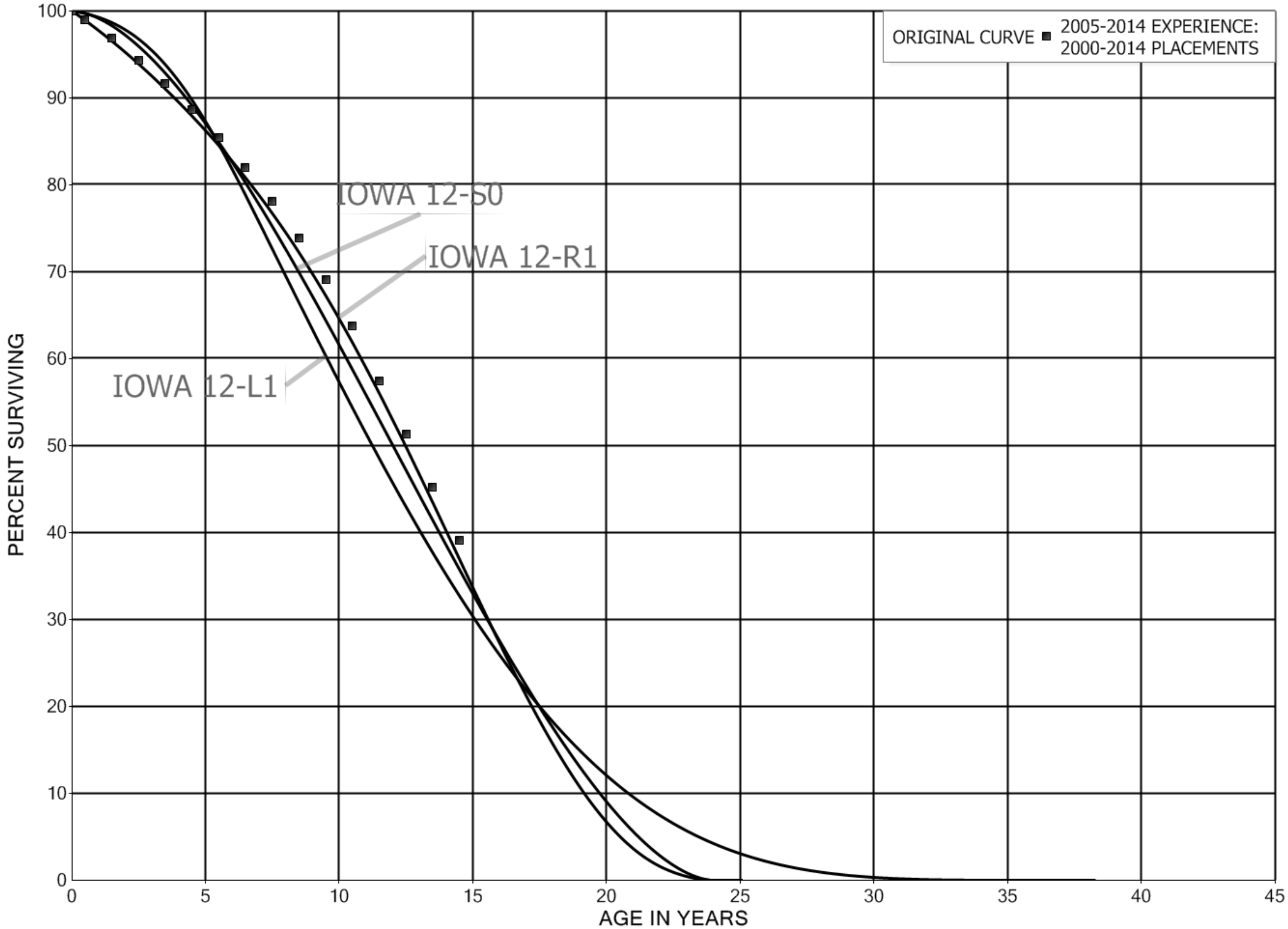


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



APPENDIX B

ESTIMATION OF NET SALVAGE

ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Gannett Fleming, in part on historical data, and in part through a comparison to peer companies. Gross salvage and cost of removal as recorded to the depreciation reserve account and related to experienced retirements are used. Percentages of the cost of plant retired are calculated for each component of net salvage 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 proceed (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 percentage results.

The estimation of the net salvage percentages developed using the traditional approach, includes the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis are 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.

4. 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.

5. 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 Gannett Fleming, a net salvage percentage is determined for each account.

6. The net salvage percentage is then used in the depreciation rate calculations in the technical update.

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Gannett Fleming
100 Years of Excellence Delivered **As Promised**

August 10, 2015

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, British Columbia V4N 0E8

Attention: Mr. James Wong
Director, Finance and Planning

Ladies and Gentlemen:

As per your request, I have reviewed the question of whether the expected gains and losses are anticipated in the depreciation rates included in the depreciation study currently being prepared by Gannett Fleming. I understand that this request results from a directive from the BCUC Decision G-44-12 which states:

> *"When the Utilities obtain future depreciation studies, the study expert should incorporate this loss-forecast schedule into the study and should explain how the amounts have been taken into account in the asset class depreciation rates."*

During our current depreciation study, Gannett Fleming recommended the continued use of calculating depreciation rates using the Average Service Life ("ASL") group depreciation procedure on a remaining life basis. In this calculation, the depreciation rate is determined by calculating the composite remaining life for each account and then developing a depreciation rate that recovers the net book value (adjusted for net salvage requirements) over the composite remaining life of each account. Specifically inherent in this calculation is the determination of the net book value that should be used for the determination of the depreciation rates.

With the recommended continued use of the ASL procedure as noted above, the retirement transaction assumes that all assets are fully depreciated as at the time of retirement, and therefore there is no gain or loss amount booked. To the extent that it is not expected that all assets will retire at the precise estimated average service life, but rather will retire based on a retirement dispersion curve around the average service life estimate, the actual depreciation expense allocated to any asset will not precisely match to the original cost of the asset at the time of

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retirement, resulting in an implied gain or loss. However, because the depreciation rates as recommended in the current depreciation study have been influenced by the actual differences between original cost and amounts booked to the accumulated depreciation account, the expectation of future differences in the accumulated depreciation expense and original costs of assets at the time of retirement are included in the currently recommended depreciation rates.

Further, I understand with the exception of the years 2010 to 2013 where deferral account treatment was directed for accounting of FortisBC Energy Inc. asset gains and losses, that implied historical gains and losses have been included in the accumulated depreciation balances that have been provided to Gannett Fleming to use in the development of the depreciation rates. I also understand that it is the intention of FortisBC Energy Inc. to continue the practice of debiting the accumulated depreciation account for the entire original costs of assets at time of retirement. As such, any implied gains or losses will continue to be included in the accumulated depreciation account. I note that this treatment is consistent with the treatment of regulated utilities throughout North America. One of the widely recognized publications in the field of depreciation was published by the National Association of Regulatory Utility Commissioners ("NARUC") titled "Public Utility Depreciation Practices". This NARUC document describes group depreciation in detail and specifically notes the following:

> *"Under group depreciation, no gain or loss is recognized for retirement of individual assets. Upon retirement of an asset group, the cost of the asset is debited to the accumulated depreciation account and credited to the asset account. Under group depreciation, since the accumulated depreciation relates to the entire group rather than to specific assets within the group, no gain or loss is recognized".*[1]

Given the group accounting concept as described above, regulated utilities rarely attempt to forecast a gain or loss on retirement transactions.

Lastly, as Gannett Fleming recommends the periodic completion (usually three to five years) of full depreciation studies to review depreciation rates, the rates are adjusted in a timely manner, providing a comparable outcome to that desired by including forecast implied gains and losses in depreciation rates. In these periodic depreciation studies, any variances in the differences between original costs of assets and the amount charged to the accumulated depreciation account over the actual life of the asset are updated. As such, future depreciation rates will be consistently adjusting for variances in the accumulated depreciation account. The on-going nature of the re-calculations of depreciation rates, combined with the expectation of future re-calculations (i.e. every three to five years) serve to ensure that implied gains and losses on individual asset retirements are reflected in

[1] Public Utiltiy Practices, Complied and Edited by Staff SubCommittee on Depreciation of the Finance and Technology Commiittee of the National Association of Regulatory Utility Commissioners, page 49.

depreciation rates in a timely manner. While actual gains and losses are reflected on an after the fact basis (i.e. upon retirement of an asset), the approach avoids the complexities of forecasting gains and losses and accounting for forecast error.

If you have any questions on my review or the conclusions reached as a result of this review, please call me at (403) 257-5946.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK/hac

Appendix E

DRAFT ORDER

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
for Approval of 2016 Delivery Rates
Pursuant to the Multi-Year Performance Based Ratemaking Plan
Approved for 2014 through 2019 by Order G-138-14

BEFORE:

(Date)

WHEREAS:

A. On September 15, 2014, the British Columbia Utilities Commission (Commission) issued its Decision and Order G-138-14 (the PBR Decision) approving for FortisBC Energy Inc. (FEI) a Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2019;

B. Pursuant to the PBR Decision, under the PBR Plan, FEI is to conduct an Annual Review process to set rates for each year;

C. On September 3, 2015, FEI submitted an application for its Annual Review of 2016 Delivery Rates (the Application);

D. The Commission has reviewed the Application and concludes that approval is warranted.

NOW THEREFORE pursuant to Section 59 to 61 of the *Utilities Commission Act*, the Commission orders as follows:

1. Interim delivery rates for all non-bypass customers effective January 1, 2016, resulting in an increase of 2.22 per cent compared to 2015 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at existing levels.
2. The creation of rate base deferral accounts for the following upcoming regulatory proceedings as described in Section 7.5 of the Application:
    1. 2015 System Extension Application;
    2. BERC Rate Methodology Application; and
    3. 2017 Long-term Resource Plan Application.
3. The Rate Stabilization Deferral Account riders for Mainland customers effective January 1, 2016, in the amounts set out in Table 10-5 in Section 10 of the Application.
4. The Phase-in Rate riders effective January 1, 2016, in the amounts set out in Table 10-7 for Mainland customers and 10-9 for Vancouver Island and Whistler customers in Section 10 of the Application.
5. The Revenue Stabilization Adjustment Mechanism riders effective January 1, 2016, in the amounts set out in Table 10-10 in Section 10 of the Application.
6. Depreciation rates in the amounts set out in Table 12-2 in Section 12 of the Application.
7. The 2016 revenue requirement impact of the difference between the updated depreciation rates and the existing depreciation rates for Fort Nelson to be captured in the existing Fort Nelson Revenue Surplus/Deficit deferral account.
8. Net salvage rates in the amounts set out in Table 12-3 in Section 12 of the Application.
9. The transfer of the balance in the FEW Rider B Refund deferral account to the Residual Rate Riders deferral account as described in Section 12.4.1 of the Application.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2015.

BY ORDER