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August 4, 2017

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

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 2018 Rates

In accordance with the PBR Plan and Commission Order G-115-17 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2018 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 2018 Rates

Volume 1 - Application

August 4, 2017

Table of Contents

List of Appendices

Index of Tables and Figures

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 fourth annual review of the PBR Plan and set FEI's delivery rates for 2018.

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, 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 2017 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 net O&M and capital savings. Overall, FEI proposes to distribute $3.462 million[2] in earnings sharing to customers in 2018. FEI achieved these savings while maintaining a high level of service quality as indicated by meeting the Service Quality Indicators (SQIs) approved in the PBR Decision.

The proposed delivery rates for 2018 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 0.5 percent decrease from 2017 delivery rates; however, FEI is proposing to maintain 2018 delivery rates at existing levels and capture the revenue surplus in the existing Revenue Surplus deferral account. This will avoid the volatility associated with a rate decrease in 2018 followed by a larger rate increase in 2019 when other large capital projects enter rate base.

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 2017. This is followed by a summary of FEI's proposed revenue requirement and rate changes for 2018 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

[1] PBR Decision, p. 138.
[2] This amount is pre-tax and includes both the estimated 2017 earnings sharing and adjustments related to 2016 actuals.

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. Maintain 2018 delivery rates at approved 2017 levels, holding the delivery charge and basic charge at existing levels;
2. The following deferral account approvals as described in Sections 7.5 and 12.4:
   - Creation of a rate base deferral account for the 2020 Revenue Requirement regulatory proceeding with an amortization period to be proposed when that application is filed.
   - Creation of a rate base deferral account for the Surrey Operating Agreement regulatory proceeding with a three-year amortization period.
   - A three-year amortization period for the existing 2016 Cost of Capital Application deferral account, commencing in 2018.
   - A name change of the 2017 Revenue Surplus account to the 2017-2018 Revenue Surplus account, the inclusion of a $5.177 million reduction to the deferral account balance in 2017 and an addition of the 2018 surplus of $3.824 million to the 2017-2018 Revenue Surplus account.
3. A Biomethane Variance Account (BVA) Rate Rider for 2018 in the amount of $0.026 per gigajoule (GJ) as calculated in Section 10.2.1;
4. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2018 in the amounts set out in Table 10-11 in Section 10.2.2; and
5. The transfer of the ending 2017 balances in the Rate Stabilization Deferral Account (RSDA) Phase-in Rider Balancing Account and Amalgamation Regulatory Account to the Residual Delivery Rate Riders deferral account as described in Section 10.2.3.

A draft order is included in Appendix D.

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.

1 **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 that it is not pursuing
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

Item	Description	Response or Reference
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.	Cumulative two-year dead band was exceeded in 2016 and dead band is projected to be exceeded for 2017. See section 1.4.4.

1.4 *EVALUATION OF THE PBR PLAN*

FEI has continued its productivity focus in 2017 and initiated additional projects to enhance the customer experience and improve productivity, in addition to the continuing initiatives from prior years. As a result of this focus and these initiatives, FEI was able to realize savings in O&M expenditures above those embedded in the formula. FEI continues to be challenged to meet growth and maintain the system within the capital formula amount. Overall, the savings achieved result in $3.462 million of earnings sharing that will be returned to customers in 2018, 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 the net savings while maintaining a high level of service quality.

1.4.1 Overview of O&M Savings

In 2017, FEI is projecting O&M expenses excluding items forecast outside of the PBR formula to be approximately $7.5 million lower than the formula amount. Table 1-2 below shows the formula O&M savings for each year of the PBR Plan and the cumulative to date. The table also show the embedded Productivity Improvement Factor (PIF) savings for the same years. The table shows that in addition to the cumulative formula O&M savings of approximately $37.4 million to the end of 2017 which are shared with customers, the cumulative PIF savings to the benefit of customers total to approximately $10.0 million.

Table 1-2: Formula O&M Savings 2014 to 2017 ($ millions)

	Actual	Formula	Variance	1.1% PIF
2014	$ 191.0	$ 198.5	$ 7.5	$ 2.2
2015	$ 225.4	$ 235.6	$ 10.2	$ 2.6
2016	$ 225.9	$ 238.1	$ 12.1	$ 2.6
* 2017	$ 232.9	$ 240.4	$ 7.5	$ 2.6
Cumulative Savings			$ 37.4	$ 10.0

* 2017 is projected.

The 2017 projected O&M savings of $7.5 million 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 $5.0 million of the accumulated O&M savings. Much of the remainder of the projected O&M savings 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, lower call volumes due to warmer weather) as the result of the continuing productivity focus throughout the Company, many of the efficiencies and savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

In 2017, which is past the mid-point of the PBR Plan which has achieved close to $50 million in O&M savings to date, FEI is faced with the increasingly difficult challenge of finding new productivity opportunities to meet the annual savings embedded in the formula, and to sustain the level of incremental O&M savings achieved in recent years. Contributing to the productivity challenge are new cost pressures the Company is experiencing. Following is discussion of two of the more significant cost pressures related to integrity digs and to cyber security.

Integrity Digs

FEI is experiencing incremental cost pressures related to integrity digs as the Company continues to improve its Integrity Management Program to manage aging infrastructure and meet the CSA Z662-15 standard and adopt industry practices deemed appropriate to FEI's system. A new defect assessment criterion for dents has resulted in incremental digs required to repair and manage these features. Additionally, increases to the number of integrity digs have resulted from running circumferential magnetic flux leakage in-line inspection (ILI) technology which has required excavations of imperfections and defects that were either not previously identified or were not previously identified as significant. In 2017, approximately $1.5

million of incremental O&M is projected to complete more integrity digs and to complete more complicated and higher cost digs, such as at water crossing sites. In future years, FEI is forecasting increasing numbers of integrity digs to manage its system in alignment with regulations, standards and industry practice.

Cyber Security

The cyber security landscape is changing at a rapid pace, contributing to incremental cost pressures as the Company responds to the evolving risks. While causing only a moderate pressure in 2017, O&M costs for cyber security are expected to increase in 2018 by approximately $0.7 million, along with additional and related capital expenditures. The incremental O&M funding is for third party services and additional headcount required to protect the Company's systems.

Cyber security is a collection of technologies, processes, practices and controls designed to protect networks, computers and data from attack, theft, damage or unauthorized access. FEI focuses on securing its systems and educating users on identifying different types of cyber-attacks. In order to ensure cyber security controls are adequate, there are annual cyber security audits and assessments on the overall system architecture, user awareness, as well as project specific vulnerability testing.

The use of technology, and particularly mobile technology, in every business area is increasing. This drives the need to continually review and update security practices and procedures. The cyber security environment is changing at a rapid pace and it is unknown what the next big vulnerability will be. Ransomware has become a billion-dollar industry which requires awareness training to be constantly updated to match this trend and the techniques used by criminals seeking to take advantage of IT system vulnerabilities. New tools, training and tests need to be built and executed to keep our employees informed and aware.

FEI uses a risk based approach to cyber security using industry proven methodologies and technologies to ensure an appropriate balance between cost and effective protection.

1.4.2 Staffing Levels

Staffing levels have declined from 2013 to 2015, and remained relatively stable between 2015 and 2016. Staffing levels are expected to increase in 2017. The projected increase of 57 headcount or 69 FTEs from 2016 to 2017 is comprised primarily of higher staffing for the following areas: approximately 50 FTEs in Operations and Engineering to meet operational and capital work requirements including approximately 5 FTEs for the start-up of the Tilbury LNG Expansion Facility; and approximately 10 FTEs in the Customer Service department to fill vacancies to meet call volume[3] expectations.

[3] For example, 2017 has seen a higher number of high bill inquiries and these calls take longer than an average call to address

Table 1-3: Employees at Year-End[4]

	Headcount	FTE
2013 Actual	1,764	1,679
2014 Actual	1,704	1,650
2015 Actual	1,656	1,573
2016 Actual	1,667	1,581
2017 Projected	1,724	1,650

As shown in Table 1-3 above, from 2013 Actual to 2017 Projected, total FTEs for the Company decreased by approximately 29, with the decreases estimated to contribute to O&M savings of approximately $3 million[5].

To-date, the largest FTE declines have been in the Customer Service area. Customer Service reductions have resulted from a management reorganization and reductions in staffing related to lower call volumes, in part due to annual fluctuations in weather. Included in the Customer Service reductions are positions related to Project Blue Pencil that occurred in 2015. These decreases have been offset by increased staffing in the Operations and Engineering area to meet operational and capital work requirements. FEI is growing and adding new assets that require maintenance to keep them operating safely and reliably. In addition, assets are aging and requiring additional maintenance and corrective work. Emergency calls, BC One Call tickets and activities around our pipelines are all increasing. Municipal agreements, codes, regulations, public expectation, and industry practices continue to evolve and drive additional work. New main and service installations are at high levels.

Additional headcount and FTE information as requested by the Commission in Order G-182-16 regarding FEI's Annual Review for 2017 Rates proceeding is provided in Appendix C-3.

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

[4] 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.

[5] 2013 Actual FTEs is used as the reference point for the start of the PBR Plan as a 2013 Base average FTEs is not available. The O&M savings are calculated by comparing the 2013 actual average FTEs to the 2017 projected average FTEs.

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.

FEI provides a summary below of the major initiatives undertaken or ongoing in 2017. A table for each initiative that has been implemented (initiatives 1 through 5 below) including a separate table for each phase of the Regionalization Initiative showing the requested information is provided in Appendix C2.

1. ***The Regionalization Initiative*** is aimed at both enhancing the customer experience and achieving a more efficient process in the field. In the first part of 2016, efforts continued on transitioning more functions to the regions. By the end of the first quarter of 2016, the Pre-requisition, Closing and Hazards functions were successfully transitioned into the regions. This phase represents the second phase of the Regionalization Initiative that began in 2014 with the transitioning of the Field Dispatch, and Planning and Design groups to the regional locations. The changes have enabled optimal decision making, and have been found to be more cost-effective and to serve customers better. As part of the Regionalization Initiative, detailed process reviews were undertaken and considerable streamlining achieved, which resulted in changes to workflow and a reduction in the number of hand-offs required to process work. The Regionalization Initiative improved the customer experience and made it easier for customers to conduct business with the Company. Technology was leveraged and adapted to improve the flow of job packages and get them to the resource assigned to complete the work.

   The first full year operating under a regional business model was 2015. Annual O&M savings in 2015 for the first phase were approximately $1.0 million compared to 2013 actuals. The second phase of the Regionalization Initiative in 2016 produced incremental annual O&M savings of approximately $1.1 million. FEI expects savings from both phases to be sustained in future years.

2. ***Project Blue Pencil*** is an initiative focused on reviewing and streamlining key customer-facing processes from the perspective of the customer. In 2014, a review was completed which found opportunities not only to improve the customer experience, but also to increase operational efficiencies at the same time. These improvements were completed in 2015, reducing operating costs in the contact center and billing operations departments by approximately $1 million annually as compared to 2013 actuals. In 2016, these operational savings have been sustained at approximately $1 million and are expected to continue into future years.

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. 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 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 permanent reduction in Compugen's costs to support FEI, the vendor and FEI share 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. When compared to 2015, savings in 2016 increased by $200 thousand to $2 million. The savings in 2016 were achieved through efficiencies, and so were not subject to sharing with Compugen. The Company is continuing to work with Compugen to identify efficiencies and expects the 2017 savings to be comparable to 2016.

4. ***The Online Service Application (OSA) initiative,*** which enables customers to make a self-serve online request for a new service line installation, has been proceeding as planned. The Company launched the OSA to a select group of builder/developers for field trials in July 2016. After garnering feedback and suggested improvements, a full launch of the application proceeded on the Company's external website in September 2016. In March 2017, the additional functionality of requesting a service line abandonment was added to the tool. Customers can go to the Company's website and use the tool to determine if gas service is available for their property, and, for simple service lines, obtain an estimate to install the service and proceed to scheduling the installation online. The tool offers additional functionality for the builder/developer community to manage their projects by tracking their multiple service line orders. To date, approximately 2,600 orders have been processed via the application producing savings of approximately $0.05 million in 2017.[6]

5. ***SAP Integration*** is an initiative to integrate the FEI and FortisBC Inc. (FBC) SAP systems, moving towards a common SAP platform for both companies. It will primarily include the integration of the Human Resources, Supply Chain and Finance systems in SAP. The benefits will include a simplified support model, alignment of processes, simpler business processes (i.e. employee expense processing and single sign-on), reduced licensing costs and integrated payroll. Reduction in support costs will be achieved through reduced annual contractor costs because internal resources will be able to displace the contractor support due to the simplified support requirements.

   The project has started with completion expected in the third quarter of 2018. The total cost of the project is estimated at $4.5 million. Based on the number of employees between the two companies (75% FEI, 25% FBC), approximately $3.4 million of the implementation costs will be allocated to FEI with the remaining $1.1 million to FBC. Total O&M savings for the project are expected to be approximately $0.9 million annually, with $0.6 million expected in FEI and $0.3 million FBC. The savings will start being realized in 2019.

[6] These savings reflect 700 orders that were fully automated and approximately 1,550 orders that required some form of manual intervention to the end of May 2017 and commencing in September of 2016. The remaining customer orders received through this application pertained to move requests and were not related to new service installations.

As part of its continuing efficiency and customer service focus, FEI invests in various information technology opportunities. Some examples are:

- The Planner Tool Box project is an initiative to enable a more effective and efficient means of creating work orders for customer driven projects by improving user-interaction and application functionality. The goal is to streamline and speed up the work order creation process, eliminate repetitive tasks, deliver improvements to user experience/interaction with information systems, and improve customer service. The project will be complete in the first quarter 2018 and will focus on quick win enhancements to CAFE (Customer Attraction Front End) that deliver immediate process improvements (i.e. reducing redundant data entry) for customer driven projects. Anticipated labour savings of $0.15 million per year are expected from reduced planner time required to process the different work orders that planners work on (i.e. alterations, install mains, meters, etc.).
- The "Automate Customer Moves" initiative will remove manual intervention in the back end for processing of requests and improve turnaround time for customers to complete follow on activities, such as registering for paperless billing, equal payment plans and other Company products and services. The project is currently underway and expected to be complete in 2017, with estimated annual savings of $0.2 million starting in 2018.
- FEI currently shares the use of its Entegrate[7] system (i.e. systems, infrastructure, support) in exchange for a fee paid by its affiliate FortisBC Midstream Inc. By being able to leverage economies of scale and IT support efficiencies, FEI provides this service without an increase to its own operating costs.
- The recent implementation of the Skype for Business communication system, improving video conferencing capabilities and reducing telephony costs, is an example of technology being introduced to improve productivity and reduce travel.

Details of other future initiatives will be provided in upcoming annual reviews as they reach implementation stage.

1.4.4 Overview of Capital Expenditures

FEI is projecting that capital expenditures will be above the formula in 2017.

1.4.4.1 Capital Spending Results

FEI's capital spending has been above the formula amount in each year of the PBR term to date, and this trend is expected to continue. Table 1-4 below shows the capital spending from 2014 to 2017.

[7] Entegrate is the software application used by FEI for optimizing its gas supply resources, including energy procurement, deal capture and invoicing and managing energy contracts.

Table 1-4: Capital Expenditures 2014 to 2017 ($ millions)

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Growth	24.231	21.478	2.753	45.776	28.480	17.296	47.500	33.262	14.238
Other	100.168	98.343	1.825	107.803	110.901	- 3.098	114.641	112.053	2.588
Pension/OPEB	3.915	3.915	-	4.324	4.324	-	4.075	4.075	-
Total	128.314	123.736	4.578	157.903	143.705	14.198	166.216	149.390	16.826
			3.70%			*9.88%*			*11.26%*

	2017			Cumulative		
	Projected	Formula	Variance	Projected	Formula	Variance
Growth	48.024	33.477	14.547	165.531	116.697	48.834
Other	139.775	113.104	26.671	462.387	434.401	27.986
Pension/OPEB	2.663	2.663	-	14.977	14.977	-
Total	190.462	149.244	41.218	642.895	566.075	76.820
			27.62%			*13.57%*

As shown in Table 1-4, Projected 2017 capital expenditures, excluding items forecast outside of the PBR formula, are $41.218 million higher than the formula amount. There are a number of contributing factors which are discussed below.

A contributing set of factors consists of reductions to the capital formula envelope. Specifically, in the Commission's PBR Decision and the subsequent decision that included Vancouver Island and Whistler regions in the PBR Plan, the approved PBR capital formula included the following decreases to the allowed spending as compared to what had been proposed:

1. The sustainment capital for the Vancouver Island region was reduced[8], resulting in an impact of $6.5 million in 2017 and $19.3 million cumulative;
2. The growth factor for service line additions (for the growth capital) and net customer additions (for the other capital) was reduced by one-half,[9] resulting in an impact of $4.7 million in 2017 and $7.7 million cumulative; and
3. The X factor was increased by 0.6 percent (from 0.5 percent to 1.1 percent), resulting in an impact of $0.9 million in 2017 and $3.3 million cumulative.

In response to the capital directives on page 17 of Order G-182-16, capital variances associated with reductions to the capital formula envelope are detailed by year in Appendix C4.

In addition to the formula-related pressures noted above, FEI has continued to experience other capital cost pressures in 2017 due to work that had been re-prioritized from previous years of the PBR term into 2017 and to manage unforeseen urgent and higher priority activities in 2017.

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[8] 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.

[9] In addition, the lag in timing of when customer growth is reflected in the formula as compared to when customers are actually added causes pressure on the formula in years of higher customer growth.

In response to the capital directives on page 17 of Appendix A to Order G-182-16, capital variances associated with Sustainment and Other Capital are detailed by year in Appendix C4.

FEI has sought to mitigate the impact of the above factors through a combination of seeking out efficiencies in capital spending and re-prioritizing projects for further evaluation. Examples of efficiency initiatives undertaken to date include the re-use of and scheduling of the purchase of materials, project scheduling and optimization of equipment procurement, negotiating rates with contractors, modification of the regulator replacement process and updates to station design requirements, in-line inspection run coordination and in-sourcing, the in-sourcing of application and infrastructure development and a focus on reducing design costs across various information system applications. Some of these cost savings were re-allocated into other programs to offset pressures. For 2017, FEI is continuing its capital productivity focus on a number of projects, by commencing engineering and procurement sooner than in previous years in order to better assess and schedule resourcing requirements for design and construction. This will allow FEI to effectively schedule construction with internal and external resources and execute earlier in the calendar year to allow for more flexible and efficient capital spending.

Described further in Appendix C4, FEI manages its capital investment plan to maintain a safe and reliable gas delivery system with an acceptable risk profile, to optimize resources and spending, and to achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some flexibility in timing. This is done with the understanding that conditions change and the plan must be capable of adapting. This plan flexibility allows FEI to manage and execute typically expected levels of unforeseen urgent work that come up throughout the year within the resource and budget constraints of the capital plan. Apart from this routine capital plan management, FEI would not consider deferring any significant capital spending to after the PBR period. FEI believes that deferring any significant capital spending to after the PBR period would result in increased risk exposure to the system and would ultimately result in higher costs to execute the work. Furthermore, deferral of projects to after the PBR period could lead to an accumulation of work that could exceed FEI's ability to execute in a timely manner.

FEI has been successful in mitigating some of the cost pressures through efficiencies and work prioritization. However, the cost pressures have exceeded the Company's ability to re-prioritize further work within the formula capital spending envelope without incurring more risk to the system. As well, previous work that was delayed is now considered essential or mandatory work and cannot be deferred further. To mitigate this risk exposure, FEI has increased its planned sustainment activities in 2017. This, combined with growth capital pressures from both higher activity levels and higher cost activities, has resulted in FEI forecasting its capital expenditures to be $41.2 million above the formula for 2017, which is outside of the capital dead band.

In response to one of the capital directives on page 17 of Appendix A to Order G-182-16, FEI's capital prioritization process is described in Appendix C4.

1.4.4.2 Treatment of Capital Spending outside of the Dead Band

In the Annual Review for 2017 Rates in Section 1.4.4.2, FEI reviewed the regulatory history for the capital dead band. Based on that regulatory history and as further explored during the review proceeding for that application, the functioning of the approved capital dead band is summarized below.

- The capital dead band places a limit on the extent to which there is earning sharing on variances from (either above or below) the capital formula amount;
- The threshold for the capital dead band is a one year 10 percent variance or a two-year cumulative 15 percent variance from the capital formula amount;
- If the capital dead band is exceeded, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the dead band from the formula-based amount, and the capital expenditure level utilized in calculating the earnings sharing is adjusted up or down by the same amount;
- The result of exceeding the capital dead band is that there is no earnings sharing for amounts outside of the dead band;
- If the capital dead band is exceeded, FEI will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year.

This treatment was approved by Order G-182-16[10]:

> **The Panel approves FEI's proposal to remove the amount of formula capital which has exceeded the cumulative dead-band from the earnings sharing calculation, and to add the amount of capital in excess of the dead-band to FEI's opening 2017 plant additions balance.**

In the same paragraph, the Panel stated the following regarding rebasing of the capital formula:

> The Panel does not consider it necessary at this time to undertake a detailed evaluation of FEI's approved formula capital spending envelope in the form of a re-basing hearing. The Panel notes that 2016 is the first instance of FEI exceeding the capital dead-band, and based on FEI's projected 2016 capital expenditures FEI expects to be within the annual 10 percent dead-band but in excess of the cumulative 15 percent dead-band. Further, the capital amount projected to exceed the cumulative dead-band is $6.118 million, which in the

[10] G-182-16, page 16.

> Panel's view is not significant enough to warrant the regulatory cost of a re-basing hearing.

Similarly, FEI is not recommending an increase to the annual capital formula amount for the remaining years of the PBR term. FEI does not believe that a lengthy process to review what capital items should be added into the capital formula is an efficient solution to the ongoing capital issues. By not adjusting the capital formula amount, the incentive properties of the PBR Plan remain intact and will remain consistent throughout the remainder of the PBR term. While FEI expects to continue to experience capital cost pressures, the dead band mechanism remains a reasonable way to deal with capital cost pressures by ensuring no sharing of negative earnings impacts with customers for capital expenditures in excess of 10 percent of the formula amount or 15 percent over two years.

To calculate the 2017 dead band adjustment, FEI notes that its actual 2016 capital exceeded the formula by approximately 5.12 percent, after the 2016 dead band adjustment. FEI is further projecting to exceed the 2017 formula by 27.62 percent as shown in Table 1-4. Therefore, the cumulative amount over the capital formula for calculating the two-year dead band adjustment is 32.74 percent. FEI must exclude from the Earnings Sharing calculation the greater of:

- The one-year capital dead band difference between the projected capital spending overage of 27.62 percent and the one year dead band limit of 10 percent, for a net adjustment of 17.62 percent; or
- The two-year capital dead band difference between the cumulative projected capital spending overage of 32.74 percent and the two year cumulative dead band limit of 15 percent, for a net adjustment of 17.74 percent.

Accordingly, FEI added 17.74 percent of its 2017 capital, or $26.473 million,[11] to its opening plant in service for 2018 so that the two-year cumulative capital variance is within the two-year dead band at 15 percent. FEI also reduced the cumulative capital expenditures utilized in the earning sharing mechanism by the same amount ($26.473 million), such that the earnings sharing with customers is increased (see Section 10 of the Application). In this way, there is no earnings sharing on the amount by which FEI exceeded the dead band. FEI has also included a true-up to the 2016 dead band adjustment in this Application. In FEI's Annual Review for 2017 Rates FEI had projected a 2016 dead band adjustment of $6.118 million that was added to 2017 opening plant balance for rate making purposes. The actual 2016 dead band adjustment is $9.176[12] million. Consequently, FEI has increased the 2017 opening balance plant for this Application by the actual 2016 dead band adjustment of $9.176 million. Both the 2016 Actual and the 2017 Projected dead band adjustments are included in rate base in calculating 2018 rates.

[11] $190.462 million actual spending less $26.473 million = $163.989 million revised spending. When compared to $149.244 million approved formula this results in a revised capital spending variance of 9.88% over one year and 15% over two years.

[12] Section 10, Table 10-2, Line 31

1.4.4.3 Conclusion on Capital Spending

FEI has evaluated its alternatives and believes that it is in the best long-term interest of customers to pursue the capital spending program it has planned that will result in the dead band being exceeded, not only in 2017, but in the remaining years of the PBR term. It is clear that the capital spending is required and it is the right thing to do to limit increasing risk exposure in the system, and avoid unplanned and urgent capital work that reduces productivity and drives up project costs by reducing FEI's ability to plan and execute the work.

1.4.5 Summary

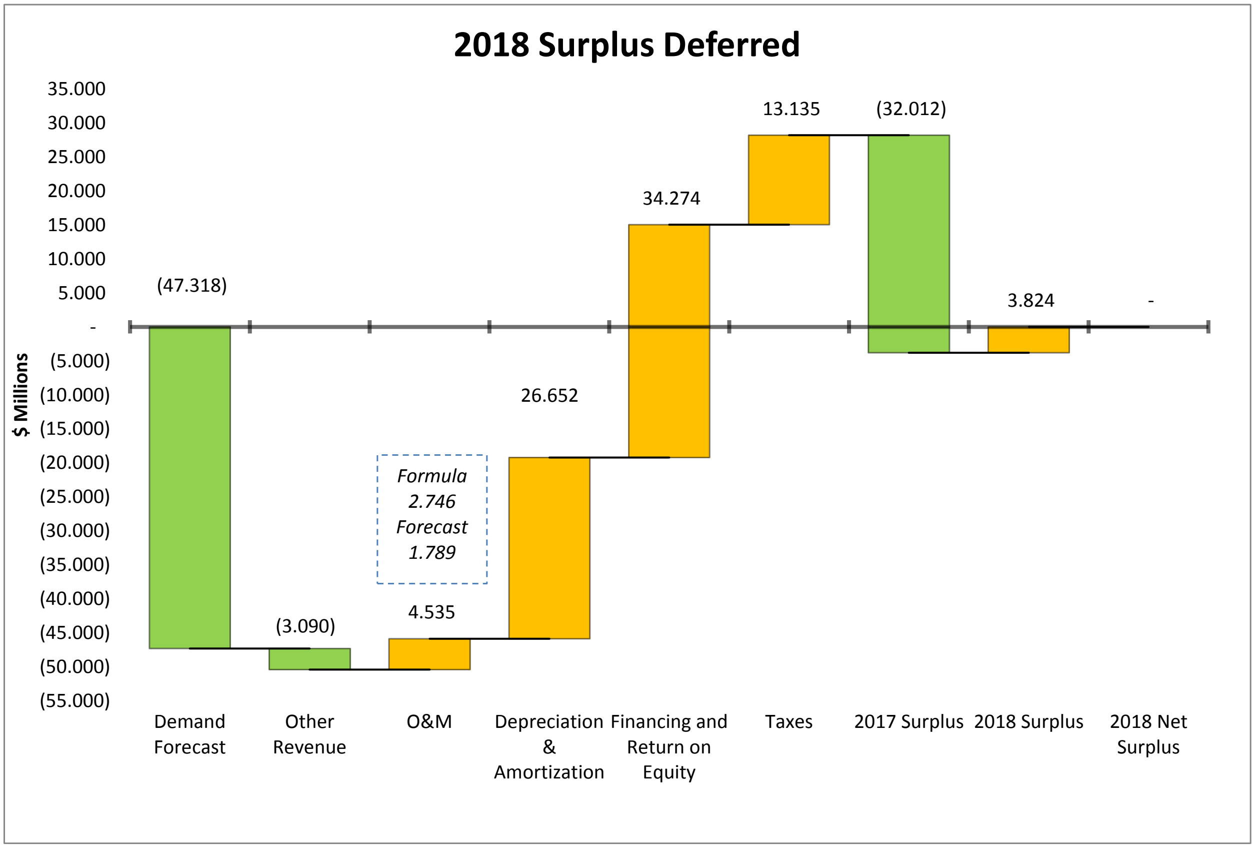
In summary, FEI's experience in 2014 through 2017 has resulted in the realization of earnings sharing on O&M, with increases in delivery rates that are in line with inflation. The first four years of PBR have also shown the challenges of the capital formula that are expected to continue and impact the remainder of the PBR term.

1.5 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2018*

The proposed delivery rates for 2018 flowing from the approved formulas and forecasts set out in the Application, including returning the forecast earnings sharing to customers, result in a 0.5 percent decrease from 2017 delivery rates; however, FEI is proposing to maintain 2018 delivery rates at existing levels and capture the revenue surplus in the existing Revenue Surplus deferral account.

The following chart summarizes the items that contribute to the 2018 surplus including the proposed addition to the Revenue Surplus account so that delivery rates are maintained at existing levels. The chart shows each item that increases the surplus in yellow and each item that decreases the surplus in green. The total is then the sum of all of the previous bars, and is shown at the end of the chart as zero.

Figure 1-1: 2018 Delivery Revenue Surplus ($ millions)[13]



Each of the categories is discussed briefly below.

1.5.1 Demand Forecast (Section 3)

In 2018, demand is forecast to increase, by 13.6 PJs from 2017 approved, with the main increases being 7.0 PJs for residential demand, 4.3 PJs for commercial demand, 2.1 PJs for industrial demand, and 0.2 PJs for Natural Gas for Transportation (NGT). Based on the existing rates for each rate schedule, FEI's 2018 revenue forecast at existing rates is $1,246.308 million and 2018 gross margin forecast is $822.033 million.

1.5.2 Other Revenue (Section 5)

Other revenue is forecast to decrease the 2018 deficiency by approximately $3 million, mainly due to an increase in SCP Third Party Revenue.

[13] Due to its relative size, the impact of increasing formula capital of approximately $0.252 million has not been isolated and is embedded within all capital-related revenue requirement categories.

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 2018, the formula incorporates an inflation factor (I Factor) of 1.679 percent, a productivity improvement factor (X Factor) of 1.1 percent and a customer growth factor of 0.715 percent for a total increase in formula O&M of 1.298 percent. O&M forecast outside of the formula is increasing by 7.7 percent over 2017 approved, primarily due to increases in pension and OPEB. The increase in total O&M expense net of capitalized overhead is $4.535 million.

1.5.4 Depreciation and Amortization (Section 7 and Section 12)

The increase in depreciation expense is primarily the result of commencement of the depreciation on the Tilbury Expansion and Coastal Transmission System (CTS) projects on January 1, 2018. There has also been an increase in amortization expense of $5.4 million. This is due to a number of factors, including an increase of $6.6 million resulting from a higher net salvage provision due to a higher asset base, a higher balance in the Energy Efficiency and Conservation incentives deferred and an increase in the amortization of the Pension and OPEB Variance deferral. These are offset by a $3.3 million increased credit amortization of the Flow-through Variance Account.

1.5.5 Financing and Return on Equity (Section 8)

FEI has forecast a mid-year long-term debt issue for 2018 of $150 million and is forecasting a short-term debt rate for 2018 of 2.10 percent, an increase from the 1.40 percent short term debt rate embedded in the 2017 Approved revenue requirement. Overall, interest expense is forecast to increase from 2017 by $12.157 million on a higher overall rate base.

Increases in rate base predominantly from the Tilbury Expansion and CTS projects have increased FEI's equity return by $22.117 million. FEI has utilized the approved 2018 capital structure and return on equity of 38.5 percent at 8.75 percent respectively.

1.5.6 Taxes (Section 9)

Property taxes are forecast to decrease by 0.4 percent or $0.293 million from 2017 Approved 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 2017. Taxes are forecast to increase in 2018 by $13.428 million primarily due to a higher delivery margin in 2018 and the impacts of the Tilbury Expansion and CTS projects offset by an increase in capital cost allowance deductions in 2018.

1.5.7 Service Quality Indicators

FEI's 2016 and June 2017 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2016, for those SQIs with benchmarks, seven performed at or better than the approved benchmarks with the remaining two performing better than the threshold and within the performance range. In 2017 June year to date, eight performed better than the approved benchmarks with one performing better than the threshold and within the performance range. For the four SQIs that are informational only, performance generally remains at a level consistent 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 2018 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 percent of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as [1 + $((SLA_{t-1}-SLA_{t-2})/SLA_{t-2}) \times 50\%)$].
- For all other cases, the growth factor is 50 percent 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 + $((AC_{t-1}-AC_{t-2})/ AC_{t-2}) \times 50\%)$].

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.

The Inflation Factor and Growth Factor calculations utilize these inputs, but as applied to 2018. FEI has used July 2015 through June 2017 inflation data for the 2018 rate change calculations using the CANSIM tables noted above, which are included in Appendix A1 of the Application.

As discussed below, the 2018 inflation factor based on prior year's BC-CPI and BC-AWE is 1.679 percent, and the SLA and AC Growth Factors are 11.302 percent and 0.715 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 uses inflation data from July through June and 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. The latest available month of May 2017 has been used as a placeholder for June 2017 for AWE-BC, as results for this period have not been released by Statistics Canada. Once results for this period are available, this placeholder will be replaced with actuals and included in an Evidentiary Update.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing CPI-BC of 1.979 percent and AWE-BC of 1.433 percent. Applying the 55 percent labour weighting, the calculation of the I-Factor is (1.979 percent x 45 percent) + (1.433 percent x 55 percent) = 1.679 percent.

Table 2-1: I-Factor Calculation

	CANSIM 326-0020 2002 = 100	*CANSIM 281-0063*	12 Mth Average		Year over year % change			
Date	**BC CPI index**	**BC AWE $**	**CPI index**	**AWE $**	**CPI %**	**AWE %**	**I Factor %**	**PBR Year**
Jul-2015	120.8	914.85						
Aug-2015	121.0	907.74						
Sep-2015	121.0	912.59						
Oct-2015	120.6	915.24						
Nov-2015	120.8	910.21						
Dec-2015	120.4	918.18						
Jan-2016	120.7	906.99						
Feb-2016	120.8	913.20						
Mar-2016	121.8	915.42						
Apr-2016	121.8	920.95						
May-2016	122.7	917.48						
Jun-2016	123.1	927.60	121.3	915.04				
Jul-2016	123.3	911.54						
Aug-2016	123.4	920.30						
Sep-2016	123.2	919.84						
Oct-2016	123.1	917.50						
Nov-2016	122.7	927.86						
Dec-2016	122.7	931.43						
Jan-2017	123.5	931.06						
Feb-2017	123.6	928.94						
Mar-2017	124.2	934.30						
Apr-2017	124.4	935.01						
May-2017	125.0	939.99						
Jun-2017	125.2	939.99	123.7	928.15	1.979%	1.433%	1.679%	2018

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 percent of the ratio of the service line additions (SLA) one year previous to the SLA two years previous, expressed as $[1 + ((SLA_{t-1}-SLA_{t-2})/SLA_{t-2}) \times 50\%)]$.
- For all other cases, the growth factor is 50 percent of the ratio of the average number of customers (AC) one year previous to the average number of customers two years previous expressed as $[1 + ((AC_{t-1}-AC_{t-2})/ AC_{t-2}) \times 50\%)]$.

The calculations for the Average Customer and Service Line Additions growth factors are provided in Tables 2-2 and 2-3 below.

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

	Total Average Customers	12 Month Avg Customers	AC Factor @ 50%	PBR Year
Jul-15	965,397			
Aug-15	965,359			
Sep-15	967,699			
Oct-15	971,075			
Nov-15	975,988			
Dec-15	979,243			
Jan-16	981,191			
Feb-16	981,838			
Mar-16	982,599			
Apr-16	982,618			
May-16	982,208			
Jun-16	982,322	976,461		
Jul-16	981,766			
Aug-16	982,078			
Sep-16	983,343			
Oct-16	985,701			
Nov-16	988,462			
Dec-16	991,573			
Jan-17	993,397			
Feb-17	994,305			
Mar-17	995,136			
Apr-17	995,859			
May-17	996,713			
Jun-17	996,691	990,419	0.715%	2018

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

	Total Service Line Additions	12 Month Sum	SLA Factor @ 50%	PBR Year
Jul-15	1,024			
Aug-15	685			
Sep-15	1,521			
Oct-15	1,327			
Nov-15	1,397			
Dec-15	1,127			
Jan-16	836			
Feb-16	707			
Mar-16	517			
Apr-16	994			
May-16	1,144			
Jun-16	843	12,122		
Jul-16	716			
Aug-16	895			
Sep-16	984			
Oct-16	1,407			
Nov-16	1,707			
Dec-16	1,552			
Jan-17	1,407			
Feb-17	1,152			
Mar-17	1,583			
Apr-17	981			
May-17	1,188			
Jun-17	1,290	14,862	11.302%	2018

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 2018 is provided in Table 2-4.

Table 2-4: Summary of Formula Drivers

	2018
Cost Drivers	
Service Line Additions Factor @ 50%	11.302%
Customer Growth Factor @ 50%	0.715%
Escalators	
CPI	1.979%
AWE	1.433%
Non Labour	45%
Labour	55%
CPI/AWE Inflation	1.679%
Productivity Factor	-1.100%
Net Inflation Factor	0.579%

In summary, the formula factor for O&M and for sustainment and other capital for 2018 is 101.298 percent, calculated as (1 + 0.715 percent) x (1 + 0.579 percent).

The formula factor for growth capital for 2018 is 111.946 percent, or (1 + 11.302 percent) x (1 + 0.579 percent). This calculation is based on growth in service line additions of 11.302 percent, with the cost per service line addition growing at a rate of 0.579 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 2018, as well as the revenue and margin at 2017 delivery rates and applicable 2017 commodity, storage and transport rates.[14] As described in detail below, FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years, and provides a reasonable estimate of future natural gas demand for 2018. FEI is forecasting an increase in consumption in 2018 compared to 2017 Approved demand. The total normalized demand is forecast to be approximately 228.2 PJs in 2018. The forecast for 2018 is up 13.6 PJs with the main increases being 7.0 PJs for residential demand, 4.3 PJs for commercial demand, 2.1 PJs for industrial demand and 0.2 PJs for Natural Gas for Transportation (NGT). Based on the 2017 rates for each customer class, FEI's 2018 revenue forecast is $1,246.308 million and FEI's 2018 gross margin forecast is $822.033 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 – Overview of Forecast Methods
- Section 3.3 – Use per Customer Forecast
- Section 3.4 – Net Customer Additions Forecast
- Section 3.5 – Total Demand Forecast
- Section 3.6 – Revenue and Margin Forecast
- Section 3.7 – Summary

In addition to the sections described above, FEI has included the following appendices related to the demand forecast:

- Appendix A1 – Conference Board of Canada Report

  Provides the data and source for the BC Housing Starts that are utilized in FEI's residential demand forecast.

- Appendix A2 – Historical Forecast and Consolidated Tables

  Provides historical forecast and actual data broken down by customer classes and service areas, as well as consolidated totals, including variance analysis and the results

[14] Order G-145-16 for the gas commodity rate effective October 1, 2016, Orders G-177-16 for storage and transport rates and G-182-16 for delivery rates effective January 1, 2017, and Order G-31-17 for the propane commodity rate effective April 1, 2017. The delivery rates do not include delivery rate riders which are set separately from the delivery rate.

of the Industrial Survey. Based on the 10 years of data shown in Section 3.4 of Appendix A2, the 10-year mean average percentage error of the aggregate demand forecast is 3.0 percent, which includes a residential demand forecast error of 2.4 percent and a commercial demand forecast error of 2.4 percent. Most recently, the aggregate demand forecast error for 2016 was 6.2 percent which includes a residential demand forecast error of 6.9 percent and a commercial demand forecast error of 4.5 percent.

- Appendix A3 – Demand Forecast Methods

  Provides a detailed description of FEI's demand forecast methods, including an explanation of the Industrial Survey. FEI's forecast methods are consistent with those used in previous applications.

3.2 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;[15]
- Average use per customer (UPC) forecast; and
- Industrial Forecast.

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

The forecast of industrial energy demand is based upon customer-specific forecasts obtained through an Industrial Survey as discussed in Section 3.5.3.

See Appendix A3 for a more detailed description of FEI's demand forecast methods.

The forecast NGT Demand is for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) volumes. The method 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 periods are shown:

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

- Actual Years: Actual years are those for which actual data exists for the full calendar year. The 2018 Annual Review is based on actual data up to and including 2016, the latest calendar year for which full actual data exists.
- 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 2017 and the Seed Year forecast is based on the latest actual years, including 2016. As such, the 2017 Seed Year forecast in this Application will differ from the 2017 Forecast presented in the Annual Review for 2017 Delivery Rates, for which 2016 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or two or more years depending on the filing.

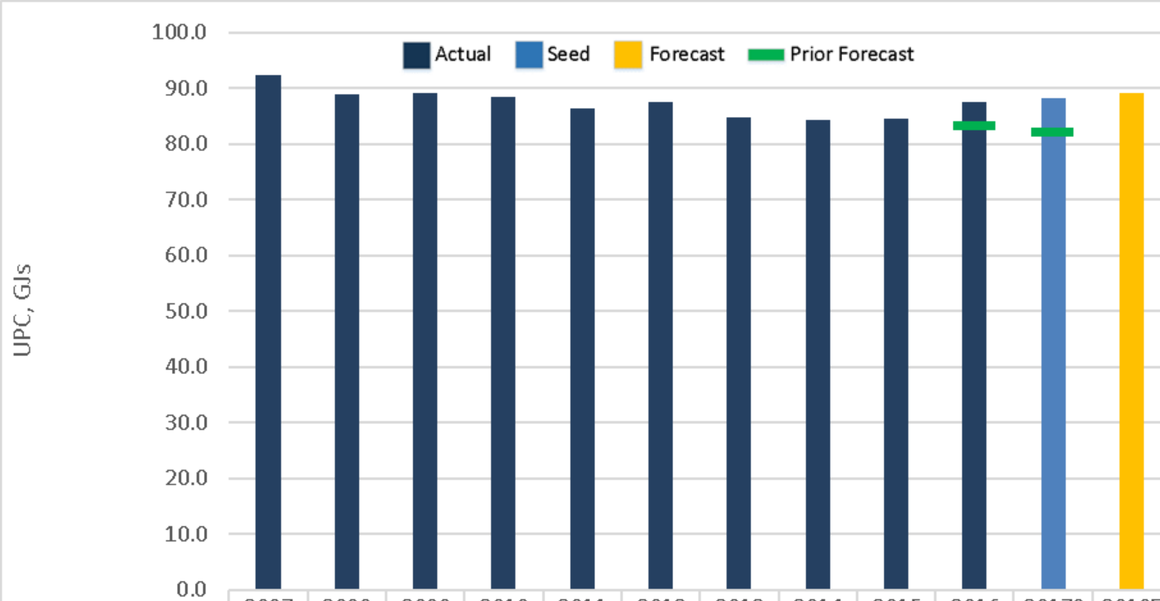
3.3 *RESIDENTIAL AND COMMERCIAL USE PER CUSTOMER FORECAST*

Individual UPC projections for each residential and commercial rate schedule are developed by considering the recent (three-year) historical weather-normalized UPC. The analysis of historical normalized residential use rates indicates an inclining trend for the residential and commercial rate schedules.

As shown in Figure 3-1, the Residential (Rate Schedule 1) UPC is forecast to increase by approximately 0.8 GJs (0.9 percent) in 2018.

FEI notes that the 2016 normalized Rate Schedule 1 consumption was 4.2 PJs higher than forecast. As the previous years' history did not indicate that UPC would increase in 2016, FEI has re-confirmed all of its normalization routines and billing data, and continues to investigate the reasons for the increase. At this time, FEI believes it is prudent to continue to use the existing forecast method. As a result, the Rate Schedule 1 normalized UPC is forecast to increase over the forecast period.

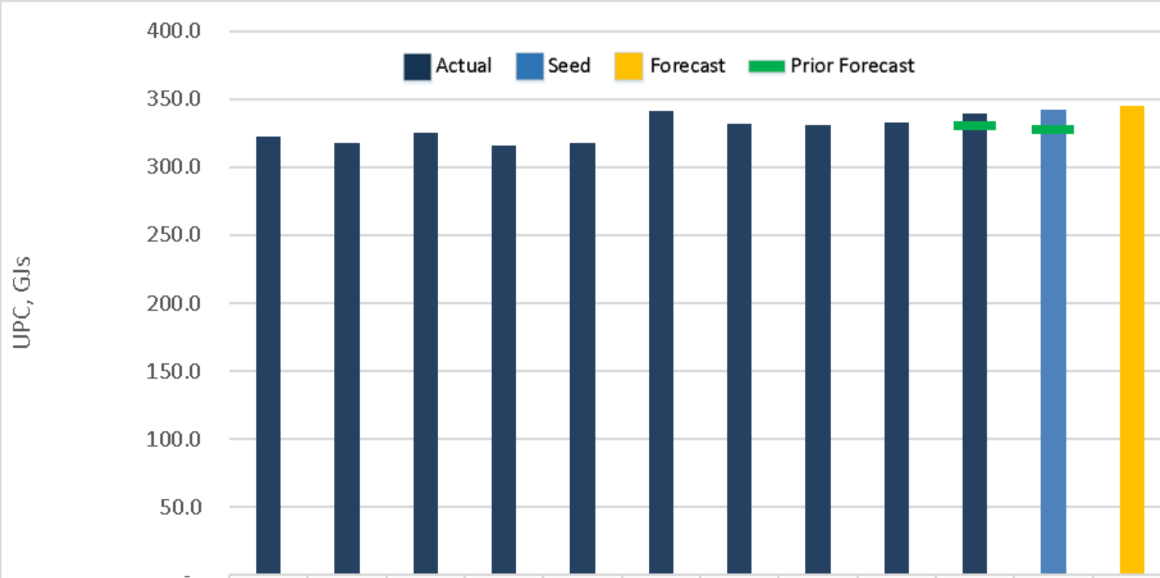
Figure 3-1: Rate Schedule 1 UPC



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Rate Schedule 1	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	88.3	89.1
Prior Year Forecast										83.3	82.2	

As shown in Figure 3-2, the Small Commercial (Rate Schedule 2) UPC is forecast to increase by 3.1 GJs (0.9 percent) in 2018.

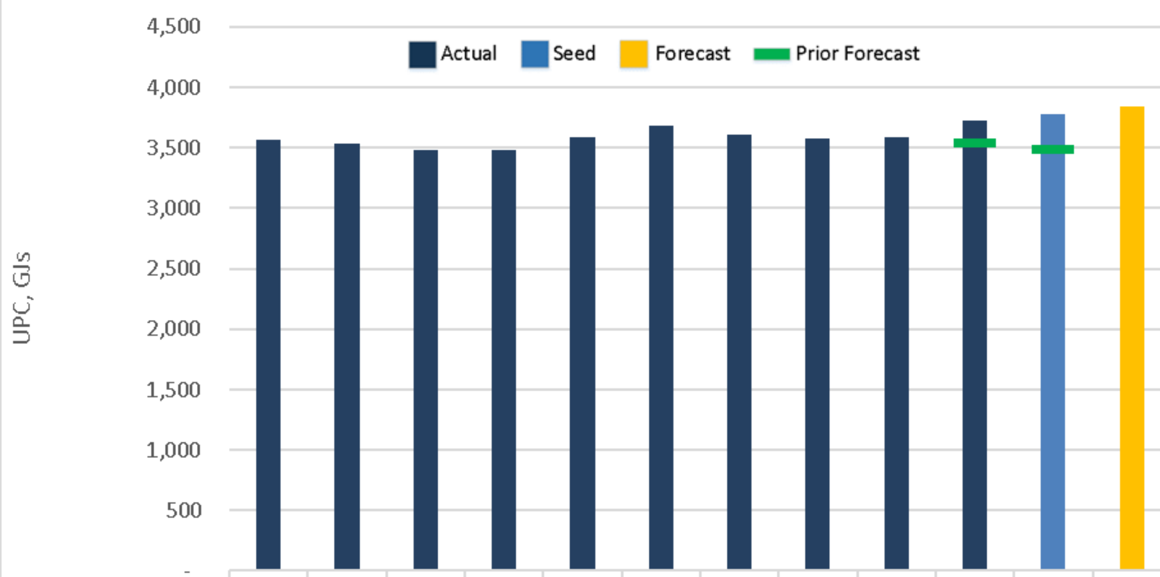
Figure 3-2: Rate Schedule 2 UPC



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Rate Schedule 2	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	342.1	345.2
Prior Year Forecast										330.5	328.4	

As shown in Figure 3-3, the Large Commercial (Rate Schedule 3) UPC is forecast to increase by 61 GJs (1.6 percent) in 2018.

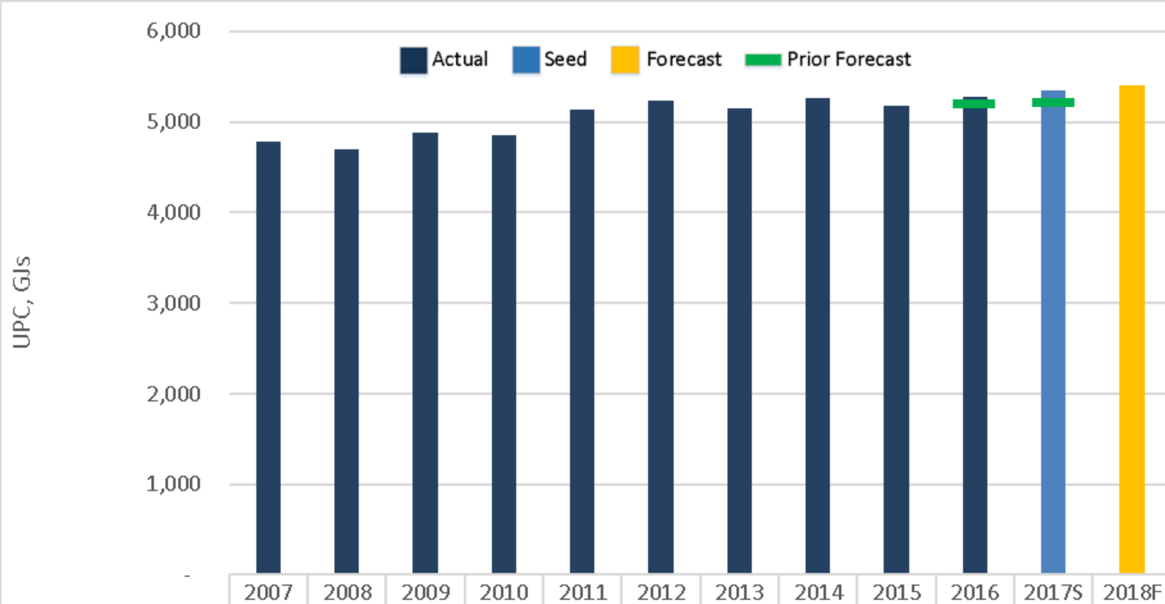
Figure 3-3: Rate Schedule 3 UPC



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Rate Schedule 3	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,781	3,842
Prior Year Forecast										3,540	3,488	

As shown in Figure 3-4, the Large Commercial Transportation (Rate Schedule 23) UPC is forecast to increase by 46 GJs (0.9 percent) in 2018.

Figure 3-4: Rate Schedule 23 UPC



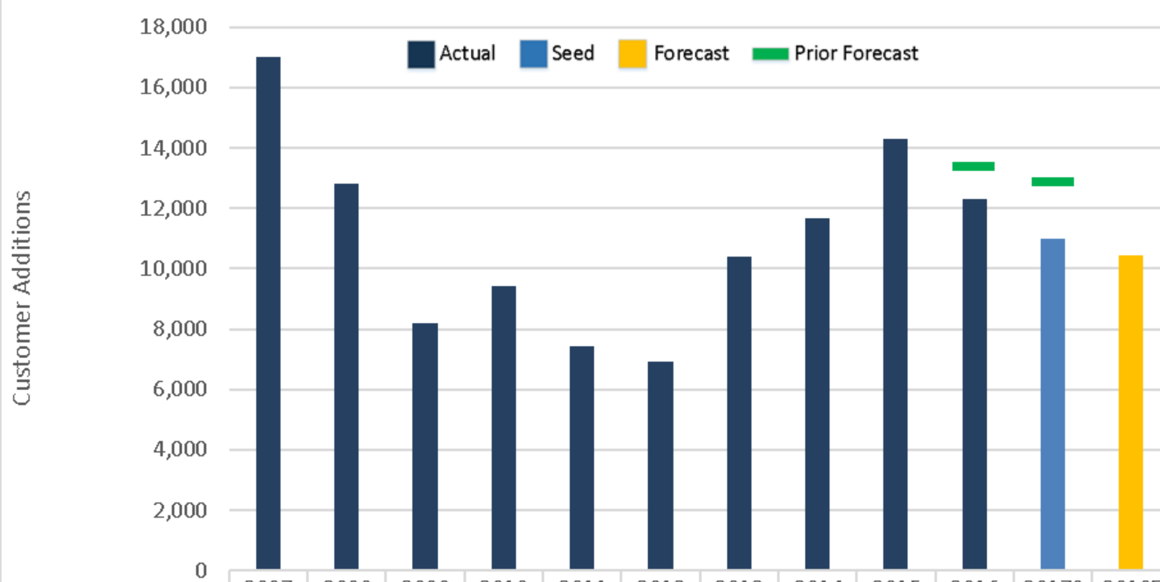
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Rate Schedule 23	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,353	5,399
Prior Year Forecast										5,209	5,227	

3.4 RESIDENTIAL AND COMMERCIAL NET CUSTOMER ADDITIONS FORECAST

The forecast of net customer additions is the next component in 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, with an additional large increase in 2015 up to above 14,000 net customer additions followed by a decrease of approximately 2,000 net customer additions in 2016. The Company is forecasting customer additions at 10,986 in 2017 and 10,435 in 2018.

Figure 3-5: Total Net Customer Additions

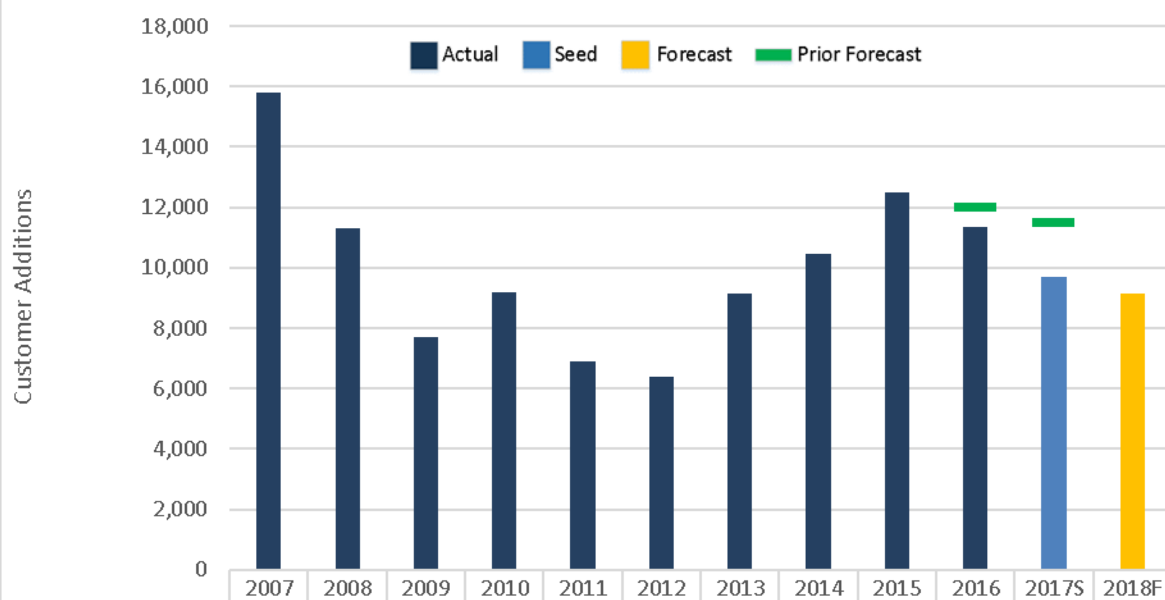


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Total	17,018	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	12,324	10,986	10,435
Prior Year Forecast										13,399	12,884	

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., 2014 to 2016).

Figure 3-6 provides the residential net customer additions for 2007 through 2018.

Figure 3-6: Residential Net Customer Additions

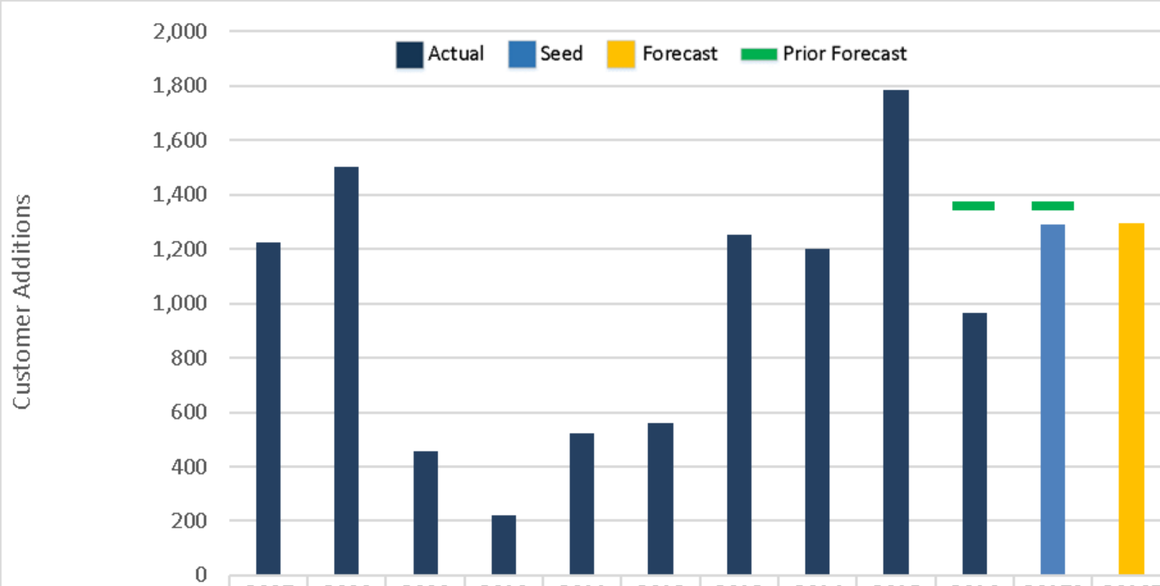


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Rate Schedule 1	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	9,696	9,141
Prior Year Forecast										12,036	11,522	

As shown in the preceding figure, residential net customer additions started to recover in 2013 but declined slightly last year. The 2017 and 2018 forecast of 9,696 and 9,141 additions is reflective of a lower CBOC housing starts forecast for BC.

Figure 3-7 provides the commercial net customer additions for 2007 through 2018.

Figure 3-7: Commercial Net Customers Additions



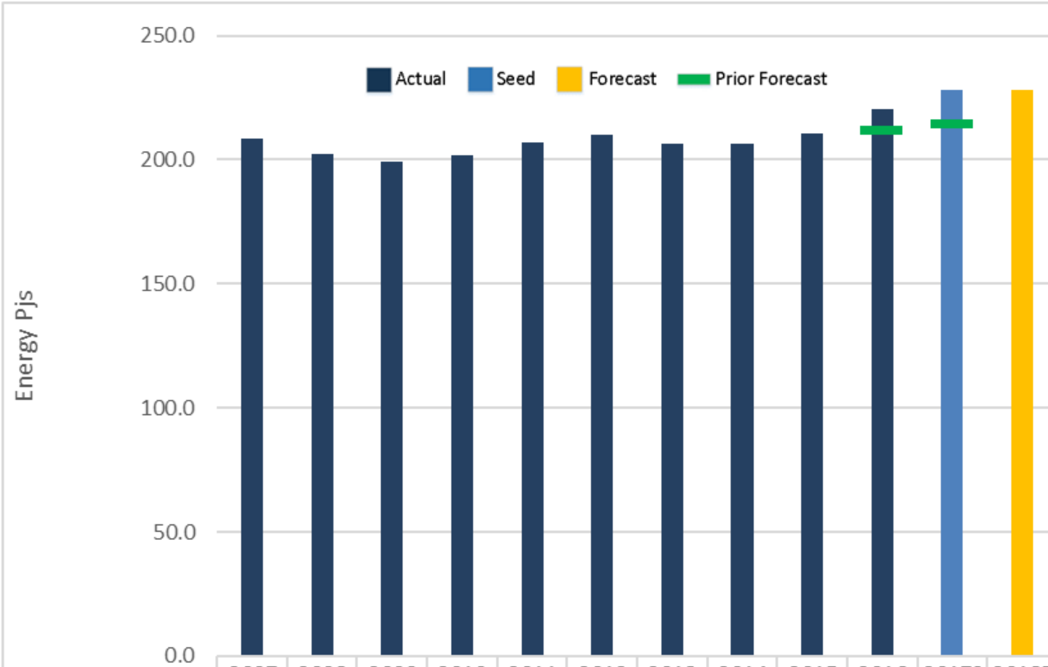
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Commercial	1,224	1,504	456	223	522	561	1,252	1,201	1,785	965	1,290	1,294
Prior Year Forecast										1,363	1,362	

As shown above, the Company is forecasting approximately 1,300 commercial net customer additions for 2018 based on three years of history (2014 to 2016).

3.5 *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 228.0 and 228.2 PJs, respectively, in 2017 and 2018.

Figure 3-8: Total Energy Demand in PJs



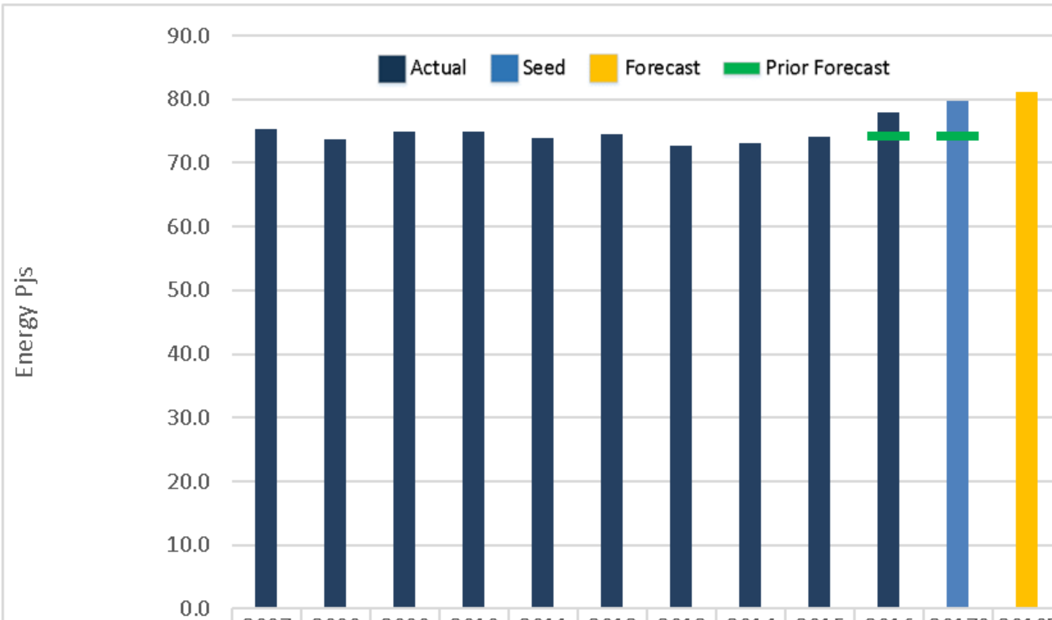
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Total Demand	208.7	202.1	199.2	201.9	206.7	209.9	206.6	206.5	210.6	220.6	228.0	228.2
2017 PBR Update										212.1	214.6	

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

3.5.1 Residential Demand

As shown below in Figure 3-9, the impact of the forecast 2018 residential use rate coupled with the net customer additions forecast results in an increased residential normalized energy demand forecast.

Figure 3-9: Normalized Residential Demand

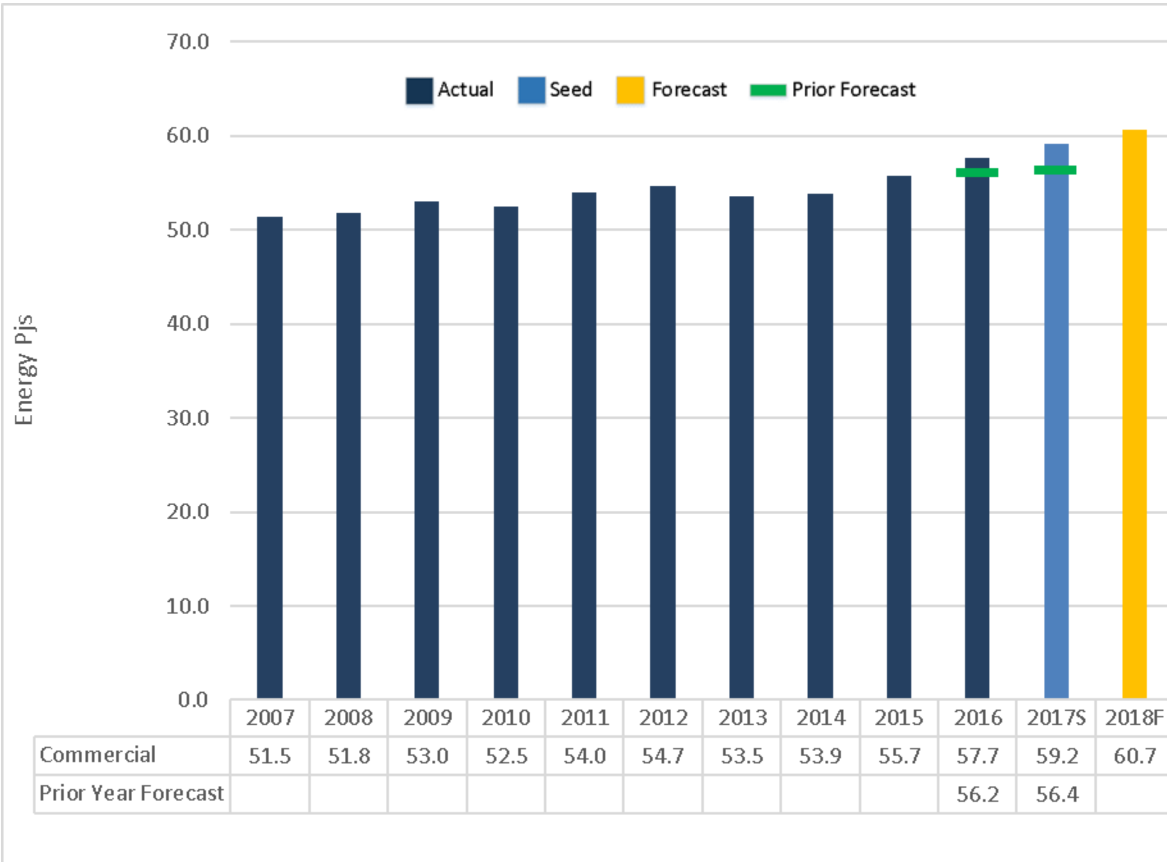


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Rate Schedule 1	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	77.9	79.7	81.2
Prior Year Forecast										74.3	74.3	

3.5.2 Commercial Demand

As seen in Figure 3-10 below, demand in the commercial rate schedules is also forecast to grow in 2018.

Figure 3-10: Commercial Demand



3.5.3 Industrial Demand

The demand for the majority of industrial customers is forecast using the Industrial Survey.

FEI's survey method is consistent with prior years and continues to include the improvements to the method resulting from FEI's review of its Demand Forecast Method for Rate Schedule 22, as reported in Appendix A4 of FEI's Annual Review for 2016 Rates Application.[16]

For the 2018 Forecast, customers completed the survey in May and June 2017. The survey was launched as close as possible to the filing date to mitigate potential variances in the forecast, particularly from Rate Schedule 22 customers. The survey needed to be complete by June 28, 2017 to allow sufficient time for internal review of the results, loading of data in FEI's

[16] Appendix A4 of FEI's Annual Review for 2016 Delivery Rates Application is available online at: http://www.bcuc.com/Documents/Proceedings/2015/DOC_44495_B-2_FEI_Annual-Review-2016-Rates-Application.pdf.

Forecasting Information System (FIS), preparing the forecast and drafting the Application. Since the survey requires approximately five weeks to complete, it was launched May 24, 2017.

As shown in Table 3-1 below, the response rate achieved in 2017 was 49 percent of industrial customers, representing approximately 89 percent of industrial volumes. Of the remaining industrial customers, 44 percent received the survey and three reminder letters but did not reply. This group represents 10 percent of the industrial demand. Surveys could not be delivered to 6 percent of the industrial customers due to issues such as incorrect email addresses. This group represents less than 1 percent of the total industrial load.

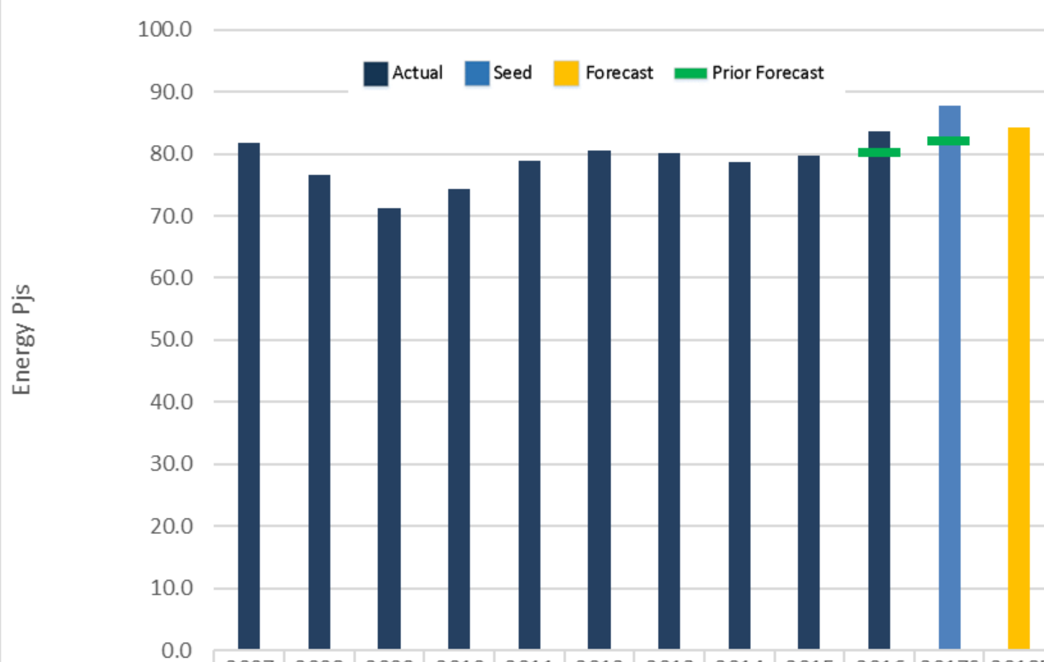
Table 3-1: Industrial Survey Response Rates

2017 Industrial Survey	Description	Customers	Demand
Survey completed	The survey was delivered and completed.	49.44%	88.59%
Survey delivered but not completed	The survey was delivered, but after three follow up emails was not completed.	44.43%	10.56%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	6.13%	0.85%
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 11 percent of the total industrial demand) was set to 2016 actual consumption in preparing the 2018 forecast.

As seen in Figure 3-11 below, the demand from the industrial rate schedules is forecast to be 84.3 PJs in 2018.

Figure 3-11: Industrial Demand[17]



	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
Industrial	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.7	84.3
2017 PBR Update										80.3	82.1	

The Industrial demand in the figure above includes demand under Rate Schedule 22. The 2018 forecast Rate Schedule 22 demand is 38.5 PJs, up approximately 0.3 PJs from the 2017 Approved demand.

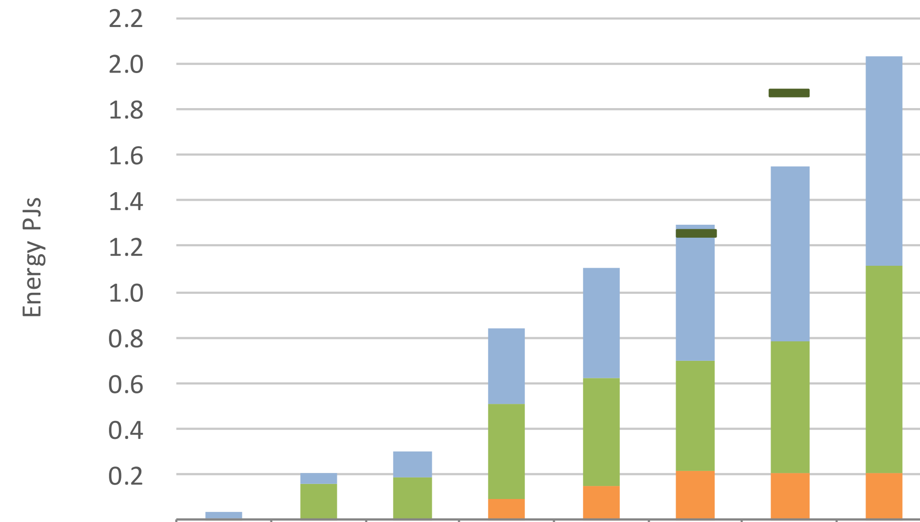
3.5.4 Natural Gas for Transportation and LNG Demand

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-incentive related demand for LNG supplied under Rate Schedule 46. The details of incentives and fuelling stations driving the NGT portion of this demand can be found in Appendix B1.

The following figure shows the 2011 to 2016 Actual, 2016 and 2017 Approved, 2017 Projected, and 2018 Forecast annual demand for CNG for Rates Schedules 3, 5, 23 and 25 (RS 3/5/23/25) and LNG for Rate Schedule 46 (RS 46).[18]

[17] Excludes Burrard Thermal and NGT.
[18] Rate Schedule 16 expired on December 31, 2014. Effective January 1, 2015, all LNG customers receive service under Rate Schedule 46.

Figure 3-12: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[19]



	2011A	2012A	2013A	2014A	2015A	2016A	2017P	2018F
RS 3/5/23/25 - CNG (NGT)	0.0	0.1	0.1	0.3	0.5	0.6	0.8	0.9
RS 46 - LNG (NGT)	0.0	0.2	0.2	0.4	0.5	0.5	0.6	0.9
RS 46 - LNG (Other)	-	-	-	0.1	0.1	0.2	0.2	0.2
Total CNG & LNG	0.0	0.2	0.3	0.8	1.1	1.3	1.6	2.0
Prior Year Forecast						1.3	1.9	

The currently projected 2017 demand is 0.3 PJs lower than the prior year Forecast 2017 demand, which is primarily due to the timing of the in-service dates of the five marine vessels for British Columbia Ferry Services Inc. (BC Ferries) and Seaspan Ferries Corp. (Seaspan). The five marine vessels were put into operation throughout 2017 at later dates than FEI originally anticipated in formulating the 2017 Forecast. These five marine vessels are expected to be in full service before the end of 2017, and will be operational for the full year in 2018.

The CNG-NGT demand is forecasted to increase by approximately 0.1 PJs in 2018 from the 2017 Projected level. This is primarily attributable to incremental load from existing customers including BC Transit and Coast Mountain Bus Company adding new natural gas buses, as well as new natural gas demand from United Parcel Service Canada (UPS). UPS will take delivery of and begin fuelling approximately 47 package courier service vehicles in the beginning of 2018.

The LNG-NGT demand is forecasted to increase by approximately 0.3 PJs in 2018 from the 2017 Projected level. This is primarily attributable to a full year of service for the five marine vessels for BC Ferries and Seaspan. These two customers are forecasted to add an

[19] Forecast includes all NGT related CNG and LNG demand, and Other LNG demand inclusive of contract and excess demand flowing through stations as well as spot volumes and third party station CNG/LNG volumes.

incremental 0.4 PJs to the annual LNG demand for RS 46 in 2018. This is offset by a small decrease in LNG demand for other RS46 LNG customers.

The forecast in demand for LNG-Other includes LNG used for non-NGT activities primarily related to the use of LNG for power generation in northern Canada and other non-NGT (i.e. non-transportation related) market segments. These customers are currently taking LNG on a spot basis (i.e. with no contract demand). In 2017, FEI expects to deliver approximately 0.2 PJs to these types of customers, and expects the RS 46-Other types of customers to maintain their consumption at that level for 2018.

3.6 *REVENUE AND MARGIN FORECAST*

The forecast of revenues and margins has been developed by considering the total energy forecast applied at 2017 delivery rates and applicable 2017 commodity and storage and transport rates.

3.6.1 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 rates for each customer class.

Table 3-2 below summarizes the approved, projected and forecast revenue for 2017 and 2018.

Table 3-2: Forecast Sales Revenue at Approved Rates

Revenue ($ millions)	Approved 2017	Projected 2017	Forecast 2018
Residential [1]	629.064	728.340	739.420
Commercial [2]	330.810	383.774	391.286
Industrial [3]	110.244	114.870	115.602
Total	**1,070.118**	**1,226.985**	**1,246.308**

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

3.6.2 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 2017 and 2018, by customer segment, at 2017 delivery rates.

Table 3-3: Forecast Gross Margin at Approved Rates

Margin ($ millions)	Approved 2017	Projected 2017	Forecast 2018
Residential [1]	452.786	476.143	484.373
Commercial [2]	221.003	229.790	235.158
Industrial [3]	100.926	102.707	102.502
Total	**774.715**	**808.640**	**822.033**

Notes:
[1] Rate Schedule 1
[2] Rate Schedules 2, 3, 23
[3] Rate Schedules 4, 5, 6, 46, 7, 22, 25, 27, Joint Venture, BC Hydro Island Generation

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.

3.7 SUMMARY

FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years, and provides a reasonable estimate of future natural gas demand for 2018. Based on these methods, FEI is forecasting an increase in consumption in 2018, with the total normalized demand projected to be approximately 228 PJs in 2018, up approximately 0.2 PJs from the 2017 projected consumption and up approximately 13.6 PJs from the 2017 Approved demand of 214.6 PJs. Based on the 2017 Approved rates for each customer class, FEI's 2018 revenue forecast is $1,246.308 million and 2018 gross margin forecast is $822.033 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, 2017) 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 October 1, 2016 pursuant to Commission Order G-145-16, dated September 8, 2016. 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, 2017 pursuant to Commission Order G-177-16, dated December 2, 2016.

The propane cost recovery rates for Revelstoke became effective April 1, 2017 pursuant to Commission Order G-31-17, dated March 9, 2017.

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[20]

Cost of Gas ($ millions)	Approved 2017	Projected 2017	Forecast 2018
Residential [1]	176.278	252.197	255.047
Commercial [2]	109.807	153.984	156.128
Industrial [3]	9.318	12.163	13.100
Total	**295.403**	**418.345**	**424.275**

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

[20] Biomethane commodity costs are excluded from the table because 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, seasonal and peaking supply, 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[21] 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.

[21] 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 2017, primarily due to an increase in SCP Third Party revenue.

Table 5-1: Other Revenue Components

Other Operating Revenue, ($ millions)			
	Approved 2017	Projected 2017	Forecast 2018
Late Payment Charge	2.180	2.646	2.688
Connection Charge	3.118	3.132	3.148
Other Recoveries	0.319	0.368	0.368
NGT Related Recoveries	4.507	3.633	4.297
Biomethane Other Revenue	0.448	0.390	0.532
SCP Third Party Revenue	14.347	14.347	16.976
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**42.958**	**42.555**	**46.048**

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.[22] 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 2018 forecast.

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

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

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

		Actual 2014	Actual 2015	Actual 2016	3 Yr Average
FEI	Late Payment Charge	2.842	2.545	2.326	
FEVI	Late Payment Charge	0.317			
FEW	Late Payment Charge	0.014			
		3.173	2.545	2.326	
FEI	Rates 1, 2, 3 Revenue	1,095.358	1,062.033	950.924	
FEVI	Rates 1, 2, 3 Revenue	153.892			
FEW	Rates 1, 2, 3 Revenue	12.026			
		1,261.276	1,062.033	950.924	
Total	**LPC Factor**	**0.2516%**	**0.2396%**	**0.2446%**	**0.2454%**

The Late Payment Charge factor of 0.2454 percent is multiplied by the forecast revenue for Rate Schedules 1 through 3 of $1,095.565 million to arrive at the forecast Late Payment Charge Revenue of $2.688 million for 2018.

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[23], the historical move ratio of 12.5 percent[24] and the projected or forecast number of average customers.

In 2018, 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 2018 forecast amounts in Connection Charge revenue:

Connection Charge of $25 * (Average Customers of 1,007,227) * Move Ratio of 12.5% = Connection Charge Revenue of $3.148 million.

5.2.3 Other Recoveries

Other recoveries consist of NSF returned cheque charges[25] as well as other miscellaneous income items. Consistent with past practice, the 2018 forecast of these items has been

[23] Currently referred to as the Application Fee of $25 in the FEI General Terms and Conditions (the GT&Cs) Standard Fees and Charges Schedule. As part of FEI's 2016 Rate Design Application, FEI has proposed to rename this charge the Application Charge and has proposed to reduce this charge to $15. If the proposed reduction to the Application Fee is approved, any variances in revenue will be recorded in the Flow-through deferral account.

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

determined based on the 2017 projected amounts of $0.080 million and $0.288 million, respectively, for a total forecast of $0.368 million.[26]

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: 2017 and 2018 NGT Related Recoveries

NGT Related Recoveries, ($ millions)			
	Approved 2017	Projected 2017	Forecast 2018
NGT Overhead and Marketing Recovery	0.332	0.304	0.320
NGT Tanker Rental Revenue	0.448	0.368	0.583
CNG & LNG Service Revenues	3.727	2.961	3.394
Total NGT Related Recoveries	**4.507**	**3.633**	**4.297**

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 2018 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 2018. Please refer to Appendix B, Section 5 for a more detailed discussion of each item.

5.2.5 Biomethane Other Revenue

The other revenue amount of $0.532 million in 2018 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[27]:

- Upgrading plant cost of service;

[25] Currently referred to as the Dishonoured Cheque Charge of $20 in the GT&Cs Standard Fees and Charges Schedule. As part of FEI's 2016 Rate Design Application, FEI has proposed to rename this charge the Returned Payment Charge and has proposed to reduce this charge to $7. If the proposed reduction to Dishonoured Cheque Charge is approved, any variances in revenue will be recorded in the Flow-through deferral account.

[26] 2017 projected amounts are based on six months of 2017 actual information that was available at time of preparing the forecast.

[27] The cost of procuring Biomethane supply does not need to be transferred because it is accounted for directly in the BVA.

- Interconnection cost of service for projects introduced after Order G-210-13; and
- Program overhead costs.[28]

For 2018, FEI has transferred the earned return on capital and tax component of the cost of service related to the existing upgrading plants, and the City of Surrey Landfill project interconnection forecasted to be in-service in 2017 to the BVA by crediting Other Revenue.

With respect to other Biomethane capital expenditures, FEI notes that there is a forecast capital expenditure of $0.840 million[29] 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 2017 Approved and 2018 Forecast O&M (Section 11, Schedule 20, Line 37, Column 4).

5.3 SOUTHERN CROSSING PIPELINE (SCP) THIRD PARTY REVENUE

The SCP Third Party Revenue for 2017 and 2018 includes the items shown in the table below.

Table 5-4: 2017 and 2018 SCP Revenue Components

Southern Crossing Pipeline Revenue, ($ millions)			
	Approved 2017	**Projected 2017**	**Forecast 2018**
Northwest Natural Gas Co. (NWN)	$ 6.421	$ 6.421	$ 6.482
MCRA	3.600	3.600	3.600
Net Other Mitigation - West to East Capacity	4.326	4.326	6.894
Total SCP Revenue	**$ 14.347**	**$ 14.347**	**$ 16.976**

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

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

[29] In Section 11, Schedule 4, Line 28, Column 4, the 2018 capital expenditure amount of $0.840 million includes $0.300 million for the one 2017 project shifted into 2018 and $0.540 million for the LuLu Island project, where the cost of service is recovered through the delivery margin as per Order G-210-13.

October 2020. Consistent with the PBR Application, the NWN revenues are recorded net of the costs for the Spectra Energy (Spectra) Kingsvale South Transportation (Spectra tolls are subject to change from time to time) and the Pacific Gas & Electric (PG&E) termination fees as shown in Table 5-5 below.

Table 5-5: Calculation of 2018 Northwest Natural Gas Co. Revenue

Forecast NWN Revenue, ($ millions)	
NWN Revenue	$ 8.994
Transportation Tolls [(A)]	(2.367)
PG&E Termination Fee	(0.145)
Net NWN Revenue	**$ 6.482**

Notes: (A) 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 term.

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 Other Mitigation Revenue

The mitigation revenue associated with the west to east capacity on SCP during the initial years of the PBR term was the result of the T-South Enhanced Service agreement between Spectra and FEI. The T-South Enhanced Service agreement expired on October 31, 2016.

In light of the expiry of the agreement with Spectra, the Company has been, and will continue, to seek opportunities to contract the west to east capacity. The forecast mitigation revenue for the SCP west to east capacity for 2018 is based on the current forward market price differentials for summer 2018 and reflect the existing pipeline capacity constraints within the region. These market conditions will change over time and mitigation revenues are expected to moderate as regional constraints are addressed. FEI forecasts generating net mitigation revenue in the amount of $6.894 million in 2018.

The mitigation revenue forecast is net of the cost of using FEI gas supply resources, such as Spectra Kingsvale South transportation capacity held in the midstream portfolio, to connect with the SCP system. The mitigation revenue net of the gas supply resource costs will be allocated to Other Revenue.

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.[30]

The LNG capacity assignment to the gas supply portfolios commenced in 2011 as a result of the Mt. Hayes LNG Facility becoming operational. The costs transferred to gas costs reflect 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).

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 represents a market valuation of avoided storage costs and transport costs on Northwest Pipeline. 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 Mt. Hayes cost allocations are being reviewed in the Rate Design Application that was filed on December 19, 2016.

5.5 SUMMARY

FEI has forecast the other revenue components for 2018 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 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 deferral account (for all other variances).

[30] The amount is the summation of $12.026 million as set out in the Mt. 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.

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 2018, the Formula O&M is $243.533 million, representing a 1.298 percent increase from the 2017 Formula O&M, entirely due to the formula drivers. O&M expenses forecast outside the formula are $31.080 million, representing a 7.681 percent increase from the amount approved for 2017. Overall the increase in Gross O&M Expense from 2017 to 2018 is 1.982 percent.

The components of 2018 O&M expense are shown in Table 6-1 below.

Table 6-1: 2018 O&M Expense

Line No.	Description	$ millions	Reference
1	Formula O&M	243.533	Table 6-2, Line 6
2	Forecast O&M	31.080	Table 6-3, Line 7
3	Total Gross O&M	274.613	
4	Capitalized Overhead (12%)	(32.954)	Section 11, Schedule 20, Line 38
5	Biomethane O&M transferred to BVA	(1.074)	Section 11, Schedule 20, Line 37
6			
7	Net O&M	240.585	

In the subsections below, FEI provides further details on its formula and forecast O&M expenses for 2018.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of Base O&M starts from a base of the 2017 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 2018 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.579 percent and one-half of the prior year's customer growth is 0.715 percent.

For 2018, the annual operating and maintenance expense under the formula is calculated as:

2017 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 2018 Formula O&M.

Table 6-2: Calculation of 2018 Formula O&M

Line No.	Description	Amount ($ millions)	Reference
1	2017 Formula O&M	240.412	FEI 2017 Rates Compliance Filing Schedule 20, Line 23, Column 4
2			
3	Net Inflation Factor	0.579%	Section 2, Table 2-4
4	Customer Growth Factor	0.715%	Section 2, Table 2-2
5			
6	2018 Formula O&M	243.533	Line 1 x (1 + Line 3) x (1 + Line 4)

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

The Formula O&M is then adjusted to add in pension and OPEB expense, insurance, O&M supporting Biomethane, NGT and Rate Schedule 46 O&M. These amounts are shown in Table 6-3 below along with a comparison to 2017.

Table 6-3: 2018 Forecast O&M ($ millions)

		2017		2018
Line No.	Description	Approved	Projected	Forecast
1	Pension/OPEB (O&M Portion)	15.826	15.826	17.077
2	Insurance	5.529	5.300	5.360
3	Biomethane O&M	0.976	1.044	1.121
4	NGT O&M	1.557	1.365	1.838
5	RS 46 O&M	4.975	4.880	5.684
6				
7	Forecast O&M	28.863	28.415	31.080

Each of these items that is 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, 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 2018 are based upon recent actuarial estimates using a range of assumptions at December 31, 2016 provided by the Company's actuary, Willis Towers Watson. Pension and OPEB expense is broken into O&M, Capital, Retirement Costs, and Core Market Administration Expense (CMAE) categories as shown in Table 6-4.

Table 6-4: 2017-2018 Pension and OPEB Expense ($ millions)

Line No.	Description	2017 Approved	2018 Forecast
1	O&M	15.826	17.077
2	Forecast Capital - Growth	0.676	0.795
3	Forecast Capital - Other	1.987	2.334
4	Retirement Costs	0.809	0.913
5	CMAE	0.246	0.278
6			
7	Total Pension & OPEB Expense	19.544	21.397

Overall, pension and OPEB expense for 2018 is forecasted to be $1.853 million higher than what was approved for 2017. This increase is primarily due to lower amortization of prior service credit, and higher service cost and interest cost partially offset by a higher expected return on assets.

The 2017 variance between approved and actual pension and OPEB expense and any 2018 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 in by the Commission in Order G-138-14.

As described in Section 12.3.1.2, FEI has included in Table 6-4 above the impact of adopting the accounting guidance in ASU 2017-07 related to pension and OPEB expense, which results in a decrease in O&M and offsetting increase in capital expenditures of $0.235 million. The details are set out in Table 12-2.

6.3.2 Insurance

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

The 2018 insurance expense is forecast at $5.360 million, a decrease of $0.169 million or 3 percent from what was approved for 2017. The 2018 Forecast is calculated by taking the known annual insurance premium of $5.229 million which is applicable to the first six months of 2018 and escalating that amount by five percent for the remaining six months[31]. 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.

[31] $5.229 million/2 = $2.615 million x 1.05 = $2.745 million. $2.615 million + $2.745 million = $5.360 million.

6.3.3 Biomethane O&M

A summary of the 2017 approved and projected and 2018 forecast Biomethane O&M, by project, is provided in Table 6-5 below:

Table 6-5: Biomethane O&M by Project ($ millions)

		2017		2018
Line No	Description	Approved	Projected	Forecast
1	Program Overhead	0.461	0.474	0.545
2	City of Surrey Landfill	0.011	0.005	0.011
3	Kelowna upgrader	0.312	0.312	0.318
4	Salmon Arm upgrader	0.125	0.210	0.200
5	New 2017 Project	0.003	-	-
6	**Sub-total - Transferred to BVA**	**0.912**	**1.001**	**1.074**
7				
8	Fraser Valley Biogas	0.011	0.011	0.011
9	Salmon Arm Landfill	0.011	0.011	0.011
10	Kelowna Landfill	0.011	0.011	0.011
11	Seabreeze Farms	0.011	0.011	0.011
12	Lulu Island WWTP	0.011	-	0.003
13	Dicklands Farm	0.011	-	-
14	**Sub-total - Recovered in delivery rates**	**0.065**	**0.043**	**0.047**
15				
16	**Total Biomethane O&M**	**0.976**	**1.044**	**1.121**

The 2018 forecast of total Biomethane O&M is $1.121 million as shown in the table above. Of this total, $1.074 million relates to upgrader O&M, interconnection O&M and program overhead[32] which is transferred to the BVA for recovery through the Biomethane Energy Recovery Charge (BERC). The remaining O&M of $0.047 million is the O&M associated with interconnection stations which pre-dated or were approved in Order G-210-13[33], and is recovered through delivery rates.

The 2018 forecast O&M of $1.121 million is $0.145 million higher than the 2017 Approved O&M primarily due to an increase in the amount of time existing staff are dedicated to the Biomethane Program. In addition, the 2018 forecast Salmon Arm upgrader cost is also higher as it is based on the 2017 projected costs and recent experience. This increase was partially offset by slightly lower O&M from the delay of the Lulu Island WWTP and Dicklands interconnections.

[32] The 2018 forecasted Program Overhead of $545 thousand is comprised of $312 thousand for Customer Education costs, $25 thousand in future development costs and $208 thousand for resourcing.

[33] These projects were Fraser Valley Biogas, Salmon Arm Landfill, Kelowna Landfill, Seabreeze Farms, Lulu Island WWTP, and Dicklands Farm.

The 2017 Projected O&M of $1.044 million is $0.068 million higher than the 2017 Approved O&M of $0.976 million due to an increase based on 2016 actual O&M experienced at Salmon Arm. This increase was partially offset by lower O&M due to the 7 month delay in commissioning the City of Surrey Biofuel Facility and associated FEI interconnection, delay of the Lulu Island, Dicklands, and one 2017 interconnection projects.

6.3.4 NGT O&M

NGT O&M is forecast to increase by $0.281 million from what was approved for 2017. The total NGT O&M of $1.838 million is composed of $1.455 million of NGT station O&M and $0.383 million of LNG tanker and related O&M (Appendix B Sections 5.3, 5.5.3 and 6.1.2, and Table B-16). These O&M costs are offset by NGT revenue as discussed in Appendix B Section 4.2. Please refer to Appendix B NGT for a discussion of these amounts.

6.3.5 Incremental O&M to Support Rate Schedule 46

The O&M costs to support Rate Schedule 46[34] include all incremental costs associated with the liquefaction of natural gas, the dispensing of LNG and the handling and loading of tankers to load 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, electricity power, fuel, applicable fees and administration.

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

[34] Information on Rate Schedule 46 and associated revenues is provided in Appendix B: NGT.

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

Line No.	Description	2017 Approved	2017 Projected	2018 Forecast
1	Tilbury Plant:			
2	Labour	1.480	1.678	2.540
3	Materials	0.150	0.143	0.056
4	Contractor	0.335	0.325	0.388
5	Power	2.590	2.392	2.280
6	Fuel Gas	0.160	0.142	0.086
7	Fees & Administration	0.120	0.120	0.160
8	Sub-total	4.835	4.800	5.510
9	Mt Hayes Plant:			
10	Labour	0.048	0.024	0.056
11	Materials	0.006	0.008	0.008
12	Contractor	0.010	0.008	0.013
13	Power	0.070	0.039	0.089
14	Fuel Gas	0.006	0.001	0.008
15	Sub-total	0.140	0.080	0.174
16	Forecast O&M	4.975	4.880	5.684

The O&M expense required for the operations of the expanded Tilbury LNG facility[35] and the Mt Hayes LNG facility is projected to be $4.880 million in 2017. The 2017 Projected expense is relatively unchanged from the 2017 Approved amount with a slight decrease of less than two percent. The variance is primarily due to a decrease in the power and fuel cost requirement due to lower 2017 Projected LNG demand than originally forecast as discussed in Section 4.1 of Appendix B, which is mostly offset by an increase in training-related labour costs for the Tilbury Expansion.

The 2018 Forecast O&M costs to support Rate Schedule 46 are estimated to increase from the 2017 Approved amount by approximately $0.709 million. The increase is primarily due to labour costs for the Tilbury Expansion coming into service and requiring additional staff for the operation and to fully support Rate Schedule 46 LNG sales. It is to be noted that the increase in labour costs is also expected to be mostly offset by a decrease in material, power and fuel gas costs in 2018. This is because the material, power and fuel gas costs approved for 2017 included the costs to initially fill the new LNG tank for the expansion of the Tilbury LNG facility. Since the new LNG tank will receive its initial fill in 2017, the material, power and fuel gas costs forecasted for 2018 are based on the LNG demand forecast only as discussed in Section 3.5.4.

[35] The expanded LNG facility is the phase 1A facilities defined in Direction No. 5 to the British Columbia Utilities Commission, B.C. Reg. 245/2013, as amended by B.C. Reg. 265/2014.

The $5.684 million forecast of O&M expense for the year 2018 assumes an average LNG supply of approximately 2,771 GJ per day from the Tilbury LNG Facility and an average supply of approximately 274 GJ per day from the Mt. Hayes LNG facility to meet the forecast LNG demand as described in Section 3.5.4.

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 $1.074 million of Biomethane O&M to the BVA, the net O&M expense is $240.585 million.

6.5 SUMMARY

Overall the increase in Gross O&M Expense from Approved 2017 to 2018 is 1.982 percent. The formula-driven O&M is increasing at a rate of 1.298 percent with the O&M forecast outside of the formula increasing at a rate of 7.681 percent. The capitalized overhead rate remains unchanged from 2017.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

The 2018 Rate Base for FEI is forecast to be $4.361 billion. Rate Base is composed of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income tax, and LILO benefit.

The 2018 Rate Base of FEI includes the full-year impacts of the 2017 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of capital additions, net of Contributions in Aid of Construction (CIAC) additions, resulting from regular capital expenditures, of $200.059 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $180.638 million;
- Full-year impact of the $460.522 million Tilbury Expansion Project;
- Full-year impact of the $169.748 million Coastal Transmission Project[36]; and
- Full-year impact of the capital formula dead band adjustment of $26.473 million[37] as discussed in Section 1.4.4.

In addition, various changes in deferred charges, working capital and other items reduce rate base by a net amount of $31.920 million.

Details of the 2018 forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 2018 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 2018, the formula-capital is $152.048 million[38], representing a 3.752 percent increase from 2017, entirely due to the formula drivers. Regular capital expenditures forecast outside the formula are $11.658 million, representing a 53.188 percent increase from 2017, primarily due to increased spending on NGT assets and higher pension & OPEB costs, partly offset by reduced Biomethane expenditures. Overall, gross regular capital expenditures are forecast to increase from 2017 to 2018 by 5.993 percent. The components of 2018 regular capital expenditures are shown in Table 7-1 below.

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[36] The rate base calculation assumes a mid-year addition for capital expenditures. This 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.

[37] $27.640 million included as an opening adjustment to Gross Plant in Section 11, Schedule 6.2, Line 35 and ($1.167) million recognized as an opening adjustment to CIAC in Section 11, Schedule 9, Line 6 = $26.473 million.

[38] From Table 7-1 $152.048 million = $37.476 million + 121.237 million - $6.665 million.

Table 7-1: 2018 Regular Capital Expenditures

Line No.	Description	$ millions	Reference
1	Formula Growth Capex	37.476	Table 7-2, Line 6
2	Formula Other Capex (before CIAC)	121.237	Table 7-3, Line 6 - CIAC amount from Line 5 below
3	Forecast Capex	11.658	Table 7-4, Line 6
4	Total Gross Regular Capex	170.371	
5	Less: Formula CIAC	(6.665)	Section 11, Schedule 4, Line 34 + 35
6			
7	Net Regular Capex	163.706	

In the subsections below, FEI provides further details on its formula and forecast capital expenditures for 2018.

7.2.1 Formula Capital Expenditures

The formula-driven portion of regular capital expenditures starts from a base of the 2017 approved formula capital, 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 2018 inflation based on prior year's BC-CPI and BC-AWE less the productivity improvement factor is 0.579 percent, one-half of the prior year's average customer growth is 0.715 percent, and one-half of the prior year's service line additions growth is 11.302 percent. In accordance with Order G-138-14, regular capital expenditure amounts will not be rebased to actual amounts during the PBR term, except that if the capital dead band is exceeded, FEI will make a recommendation in the Annual Review regarding whether there is a need to adjust (or "rebase") the capital formula amount for the following year, as described in Section 1.4.4.

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 2018, the annual capital expenditures under the formula are calculated as:

> 2018 Growth Capital = 2017 Growth capital x [(1 + (I Factor – X Factor)] x [1 + SLA customer growth][39]

> 2018 Other Capital = 2017 Other Capital x [(1 + (I Factor – X Factor)] x [1 + customer growth][40]

Tables 7-2 and 7-3 below show the calculation of the resulting 2018 formula capital expenditures.

[39] SLA customer growth factor as calculated in Section 2, Table 2-2. The formula may also be represented as 2018 Growth Capital = 2017 Growth capital per SLA x [(1 + (I Factor – X Factor)] x 2018 SLA.

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

Table 7-2: Calculation of 2018 Formula Growth Capital

Line No.	Description	($ millions)	Reference
1	2017 Formula Growth Capex Base	33.477	FEI 2017 Rates Compliance Filing Schedule 4 Line 21 Column 2
2			
3	Net Inflation Factor	0.579%	Section 2 Table 2-4
4	Customer Growth Factor	11.302%	Section 2 Table 2-3
5			
6	2018 Formula Growth Capex	37.476	Line 1 x (1 + Line 3) x (1 + Line 4)

Table 7-3: Calculation of 2018 Formula Other Capital

Line No.	Description	($ millions)	Reference
1	2017 Formula Other Capex Base	113.104	FEI 2017 Rates Compliance Filing Schedule 4 Line 21 Column 3
2			
3	Net Inflation Factor	0.579%	Section 2 Table 2-4
4	Customer Growth Factor	0.715%	Section 2 Table 2-2
5			
6	2018 Formula Other Capex	114.572	Line 3 x (1 + Line 5) x (1 + Line 6)

The formula Other Capital amount of $114.572 million is net of CIAC. The amount of CIAC is $6.665 million, which is required to be separated for purposes of the financial schedules and rate calculations. Therefore, the gross formula Other Capital amount is $121.237 million as shown in Table 7-1 above.

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, and 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 2017.

Table 7-4: 2018 Forecast Regular Capital Expenditures ($ millions)

		2017		2018
Line No.	Description	Approved	Projected	Forecast
1	Pension/OPEB (Capital Portion)	2.663	2.663	3.128
2	Biomethane Upgraders	-	0.750	-
3	Biomethane Interconnect	1.952	0.910	0.840
4	NGT Assets	2.995	3.487	7.690
5				
6	Forecast Regular Capex	7.610	7.810	11.658

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

- The forecast Pension and OPEB capital expenditures of $3.128 million represent the forecast capital portion of the total Pension and OPEB costs for 2018. Pension and OPEB costs are described in Section 6.3.1.
- The $0.750 million Biomethane Upgraders capital expenditures projected for 2017 is for the Kelowna Biomethane Upgrader. This investment was required to increase biomethane output and to install additional structures for safe worker access necessary for maintenance. This capital expenditure was not identified in the Annual Review for 2017 Rates because the changes to the plant were a result of operational experience gained in late 2016.
- The forecast Biomethane Interconnect capital expenditures of $0.840 million in 2018 are for two interconnection projects, consisting of the delayed Lulu Island Waste Water Treatment Plant ($0.540 million), and one other new 2017 project ($0.300 million) which is currently at the analysis and early negotiations stage. Only the Lulu Island project will be placed into service during 2018. The cost of service for the one new 2017 interconnection project will be recovered through the Biomethane Variance Account once in service, and the cost of service of the Lulu Island interconnection remains in the delivery margin as clarified in Commission Letter L-10-14, dated February 18, 2014 regarding Order No. G-210-13.
- The forecast NGT Assets capital expenditures of $7.690 million are the forecasts for NGT Fuelling Stations and Tankers (Appendix B, Section 7, Table B-16 amounts of $6.000 million and $1.690 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 2018, FEI is forecasting capital expenditures related to a number of such projects - the Tilbury Expansion Project, the three Coastal Transmission Projects, and the two Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Projects. Only the Tilbury Expansion Project and the Coastal Transmission Projects are forecast to be included in rate base and affect delivery rates in 2018. Each project is discussed below.

<u>TILBURY EXPANSION PROJECT</u>

The cost recovery of expenditures associated with the Tilbury Expansion Project is authorized by Direction No. 5 to the BCUC as amended by Orders in Council (OIC) Nos. 557(2013), 749(2014), and 162(2017). Under Direction No. 5, FEI can spend up to $425 million, plus AFUDC and feasibility and development costs, to construct storage and liquefaction facilities. FEI is forecasting the cost of the Tilbury Expansion Project to be within the authorized amount, at a total of $486 million as outlined in the table below ($425 million excluding AFUDC and feasibility and development costs). At this time, completion is expected in mid-2017 for the first $461 million of the costs ($400 million excluding AFUDC and feasibility and development costs), with the remaining $25 million plus AFUDC expected to be complete in future years.

Table 7-5: Tilbury Expansion Project ($ millions)

	Current Year	Future Years	Total
Capital Expenditures	400.000	25.000	425.000
Feasibility & Development	6.494	-	6.494
AFUDC	54.028	0.755	54.783
Total	460.522	25.755	486.277

In its Evidentiary Update to its Annual Review for 2017 Rates, FEI forecast the Tilbury Expansion Project to be completed in mid-2017 and added to rate base on January 1, 2018, as required by section 4(2)(a) of Direction No. 5 as it existed at the time.

In March of 2017, and after the completion of FEI's Annual Review for 2017 Rates proceeding, section 4(2)(a) of Direction No. 5 was amended by OIC No. 749, to remove the requirement that the Tilbury Expansion Project be added to rate base "*on January 1 of the year immediately following the year in which phase 1A facilities are completed*". This change to Direction No. 5 now gives the Commission flexibility on when the Tilbury Expansion Project can be added to rate base.

Given the change to Direction No. 5, FEI is now proposing to include the Tilbury Expansion Project in rate base upon its completion in 2017. In lieu of collecting AFUDC after project completion in 2017, FEI proposes that its equity return be captured as a reduction to its existing 2017 Revenue Surplus deferral account as described in Section 12.4.1.1.

As explained above, adding the Tilbury Expansion Project to rate base immediately after completion in 2017 was not forecast when 2017 rates were set, which followed the requirements of Direction No. 5 at the time. The unforecast addition of the Tilbury Expansion Project to rate base in 2017 would create differences in interest expense, income taxes, and equity return compared to the forecast of the same items included in 2017 rates. FEI's Flow-through deferral account would capture the differences between actual and forecast[41] interest expense and income tax expense, but not the difference in equity return. As FEI must have an opportunity to earn a fair return on its investment in the project,[42] the difference in the equity return under the proposed treatment must be captured and credited to FEI. FEI's proposal is that the equity return be captured as a reduction to FEI's 2017 Revenue Surplus deferral account as described in Section 12.4.1.1.

[41] Forecast and embedded in 2017 approved rates

[42] *British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1)*, Decision and Order G-75-13, dated May 10, 2013, p. 12: "The Commission Panel confirms that the approval of rates to meet the [Fair Return Standard] is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact."
The principles of the Fair Return Standard were established by the Supreme Court of Canada in the *Northwestern Utilities v. City of Edmonton* (1929) case. The Fair Return Standard is the legal test applied to ensure that investors receive the opportunity cost on their investment represented by the rate of return investors could expect to earn elsewhere without bearing more risk."

In summary, FEI's is proposing to add the Tilbury Expansion Project to rate base after completion in 2017. However, to provide the utility with an opportunity to earn a fair return on its investment, FEI must be provided with an equity return in lieu of AFUDC. FEI's proposal that the equity return be captured as a reduction to FEI's 2017 Revenue Surplus deferral account achieves this and results in an overall beneficial result that is fair to both FEI and its customers.

COASTAL TRANSMISSION PROJECTS

The Coastal Transmission Projects for which there will be capital expenditures in 2017 and 2018 are the Cape Horn to Coquitlam, Nichol to Port Mann and Nichol to Roebuck projects. These projects involve the installation of 11 kilometres of transmission pressure pipeline in Surrey and Coquitlam and are intended to increase security of supply by reducing the number of single points of failure. Cost recovery in rates for these projects is authorized by Direction No. 5 to the BCUC, as amended by OIC Nos. 557, 749 and 162. FEI anticipates spending $133.662 million on these projects in 2017 and a further $1.261 million[43] in 2018 for site clean-up, restoration and inspection, with total forecasted spending of $169.748 million including AFUDC on all three projects. These projects are expected to be in-service by December 2017. Based on the current forecast completion dates, these projects will be added to rate base January 1, 2018.

LMIPSU CPCN

The LMIPSU CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU includes the Coquitlam Gate IP Project which will address an increasing number of gas leaks on the Coquitlam Gate IP line and restore operational flexibility and resiliency to the Metro Vancouver IP system and the Fraser Gate IP Project which will provide required seismic upgrades to the Fraser Gate IP line. Both the Fraser Gate IP and the Coquitlam Gate IP Projects are expected to be in-service by the end of 2018. The estimated capital cost for the LMIPSU Projects, including AFUDC and abandonment/demolition costs, is $253.954 million. FEI forecasts expenditures of $59.539 million and $164.618 million[44] in 2017 and 2018, respectively. Based on current forecast completion dates, these projects will be added to rate base January 1, 2019, and are therefore not included in 2018 delivery rates.

7.3 *2018 PLANT ADDITIONS*

The 2018 Plant Additions are comprised of (i) FEI's 2018 regular capital expenditures from Section 7.2 above plus the Coastal Transmission Projects, (ii) 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, (iii) AFUDC, and (iv) 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.

[43] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 12.
[44] Excluding AFUDC and as shown in the financial schedules in Section 11, Schedule 5, Line 11.

Table 7-6: Reconciliation of Capital Expenditures to Plant Additions

Line No.	Description	$ millions	Source
1	Formula Growth Capex	37.476	Table 7-2
2	Formula Other Capex	114.572	Table 7-3
3	Forecast Capex	11.658	Table 7-4
4	Total Net Regular Capex	163.706	
5	Formula CIAC	6.665	Table 7-1
6	Total Gross Regular Capex	170.371	
7	Capitalized Overheads	32.954	Table 6-1
8	AFUDC	2.399	Section 11, Schedule 5, Line 23
9	Total Regular Additions to Plant	**205.724**	
10			
11	Special Projects and CPCN Capex	190.879	Section 11, Schedule 5, Line 28
12	Special Projects and CPCN AFUDC	10.561	Section 11, Schedule 5, Line 29
13	Change in Special Projects and CPCN Work in Progress	(31.693)	Section 11, Schedule 5, Line 31
14	Total Special Projects and CPCN Additions to Plant	**169.747**	
15			
16	Total 2018 Plant Additions	**375.471**	

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 2018 were approved by Order G-119-16, and are based on the utility's most recent depreciation study. 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 2018 depreciation expense is calculated as $180.666 million[45].

7.5 *DEFERRED CHARGES*

On May 3, 2017, the Commission issued its Regulatory Account Filing Checklist[46]. The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the Commission.

The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account;

[45] $189.466 million depreciation expense as calculated in Section 11 Schedule 21, Line 5 less $8.800 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

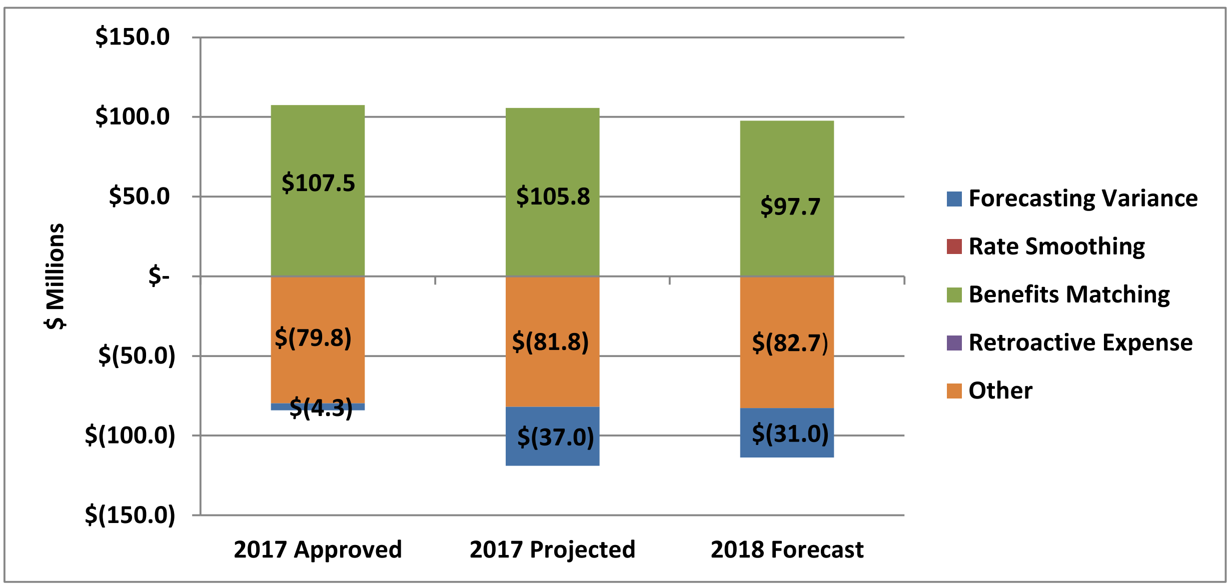
[46] Log No. 53608, Appendix B.

or (e) other. In Section 11, Schedule 11, FEI has reclassified its existing rate base deferral accounts in accordance with this classification.

The forecast mid-year balance of unamortized deferred charges in rate base for FEI is a credit of $16.002 million in 2018 and this balance is driven largely by the balances in several deferral accounts including the net variance between the Pension and OPEB Funding accounts, the Net Salvage Provision account, Midstream Cost Reconciliation Account, Commodity Cost Reconciliation Account, and Revenue Stabilization Adjustment Mechanism while partially offset by the Energy Efficiency and Conservation, Greenhouse Gas Reductions Regulation Incentives, Gains and Losses on Asset Disposition, Whistler Pipeline Conversion and 2011 Customer Service O&M and COS deferrals.

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 2018 amortization expense is calculated as $45.512 million[47]. The section below includes a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

[47] Total of Section 11, Schedule 11.1, Line 26, Column 6 and Schedule 12, Line 24, Column 6.

7.5.1 New Deferral Accounts

FEI is seeking approval of two new rate base deferral accounts to capture the FEI portion of the costs related to the 2020 Revenue Requirement application and City of Surrey Operating Agreement application. Table 7-7 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to deferral accounts for regulatory proceedings generally, and the deferral accounts requested in sections 7.5.1.1 and 7.5.1.2 below.

Table 7-7: Deferral Account Filing Considerations

Item	Consideration	Determination
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	FEI requests the establishment of two new deferral accounts to capture the FEI portion of the costs related to its next revenue requirement application following the current PBR term and the costs related to the City of Surrey Operating Agreement application.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the Commission.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the PBR formula O&M since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FEI considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is more simple to track and report on.

Item	Consideration	Determination
IV	Address:	
a)	whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the Commission and the degree of involvement of interveners.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FEI forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the PBR Plan. See sections 7.5.1.1 and 7.5.1.2.
d)	any impact on intergenerational equity	Generally FEI recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. See sections 7.5.1.1 and 7.5.1.2. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FEI classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the Commission's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula

Item	Consideration	Determination
		O&M Expense.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally FEI amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. See sections 7.5.1.1 and 7.5.1.2.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	Deferral account approvals and disposition are generally determined in revenue requirements proceedings. Where requested within CPCN or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.5.1.1 2020 Revenue Requirement Proceeding

FEI's portion of the costs related to the next revenue requirement application following the end of the current PBR term will include the costs of the benchmarking study discussed below.

In its order approving the 2014-2019 PBR Plan, the Commission's review of the appropriate stretch factor (X Factor) included the following observation and directive:

> A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed **prior to the application for the next phase of the PBR**. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**[48]

Further, the Commission directed[49]

> **that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study.** As a result of this consultation, the Panel

[48] Order G-139-14, pages 79-80.
[49] Order G-139-14, page 80.

> expects that agreement be reach on the broad terms and parameters of the study. **Fortis is directed to report the results of this consultation to the Commission prior to starting the study.**

FBC and FEI jointly began the benchmarking consultation with interveners in 2017 and anticipate completing the benchmarking study by year end 2018 at an estimated cost of $0.030 million in 2017 and $0.070 million in 2018 for each utility, for a combined total cost of $0.200 million for both utilities. The benchmarking study will inform the 2020 revenue requirements and/or next generation PBR filing which will be submitted in 2019. Forecast costs for the remainder of the application and its regulatory review will be updated at a later time.

FEI will propose the disposition of this account in a future application.

7.5.1.2 City of Surrey Operating Agreement Application

On May 18, 2017, FEI filed an application with the Commission for Approval of the Operating Terms between the City of Surrey of Surrey and FEI. As part of the proceeding, FEI expects to incur approximately $0.200 million in 2017 and a further $0.040 million in 2018 related to customer notification costs, legal costs and Commission costs.

FEI is seeking approval of a rate base deferral account to capture the actual costs related to the regulatory proceeding and to amortize the costs over three years beginning in 2018. FEI believes a three-year amortization period is appropriate given it is consistent with other recovery periods for regulatory proceeding related costs. Additionally, while the benefits of the Operating Agreement should extend much longer than the suggested recovery period, the materiality of the costs is a consideration and, therefore, FEI believes three years is an appropriate recovery period.

7.5.2 Existing Deferral Accounts

FEI provides a discussion below of an existing deferral account, and requests disposition of the account through amortization into delivery rates over a three-year period starting in 2018.

7.5.2.1 2016 Cost of Capital Application

The 2016 Cost of Capital proceeding deferral account was approved by the Commission in FEI's Annual Review of 2015 Delivery Rates Decision[50]. After completion of that proceeding and as part of FEI's Annual Review for 2017 Delivery Rates Application, FEI requested approval to amortize the balance of the existing 2016 Cost of Capital Application deferral account over three years beginning in 2017[51]. At the Annual Review for 2017 Rates Workshop, FEI was asked by Commission staff to compare the 2016 Cost of Capital proceeding with similar proceedings in terms of the number of oral hearing days, number of information requests,

[50] Order G-86-15.
[51] FEI Annual Review for 2017 Rates, Section 7.5.2, p. 63.

number of experts/consultants used, number of hours billed, and the rate charged per hour. FEI has reproduced in Table 7-8 below the response provided in its response to the Annual Review for 2017 Rates Workshop Undertaking No. 5[52]:

Table 7-8: Annual Review 2017 Rates – Response to Undertaking No. 5

Applicaton	FEI 2016 Cost of Capital	FEI-FBC 2014-2019 PBR*	FEU 2012-2013 RRA	2012 GCOC Stage 1*
Commission Costs	$ 150,000 (1)	$ 318,079	$ 389,430	$ 500,000 (2)
Intervener PACA	249,799	513,720	351,020	477,650
FEI Experts/Consultants **	833,755	455,758	299,053	1,095,879
Legal Costs	453,945	946,431	489,233	528,314
Other/Misc.	18,767	21,548	32,240	6,953
Total:	**$ 1,706,266**	**$ 2,255,536**	**$ 1,560,976**	**$ 2,608,797**
Limited Oral Hearing Scope	Yes	Yes	No	No
# Oral Hearing Days***	3	7	8	7
# IRs	561	3,534	1,665	956
# Rounds of IRs	2	3	3	2
# FEI Experts	1	1	1	4
# Hours Billed	1,915	Approx. 1,300	Approx. 800	Approx. 3,000
Rate per Hour****	$55-725 USD	$300-$400 USD	$90-$205 CAD	$100-$500 USD

Note (1) Forecast not yet final
Note (2) Commission's direct costs $500,000 through the levy
** total costs, before allocations to other utilties*
*** reflects converson to $CAD where applicable. Average annual exchange rates were as follows:*

2016	*0.76512*
2014	*0.90226*
2012	*1.00170*

**** Oral hearing days include both Company and Expert witness panels, with the exception of 2016 Cost of Capital*
***** hourly rates dependent on the experience and level of support used*

As FEI previously noted, had the 2012 exchange rate been in place in 2016, the $833,755 paid for Experts/Consultants would have been $638,999.

The Commission Panel acknowledged the impact of the change in exchange rates on FEI's expert/consultant costs and directed that FEI provide additional information and explanations for the amount of expert/consultant and external legal costs incurred in the 2016 Cost of Capital proceeding as part of its Annual Review for 2018 Delivery Rates Application. The Commission requested FEI address the following five items[53].

1. An explanation as to why there was such a broad range in the rate per hour charged by FEI's expert/consultant (i.e. $55-725 USD) in the 2016 Cost of Capital proceeding.
2. An explanation as to why the upper range of the hourly rate charged by FEI's expert/consultant was approximately $225 USD per hour higher than the upper range of

[52] Exhibit B-11.
[53] Order G-182-16, Appendix A, p. 12.

the hourly rate charged by FEI's experts/consultants in the 2012 GCOC Stage 1 proceeding.

3. A breakdown of the hours charged by the expert/consultant in the 2016 Cost of Capital proceeding at each hourly rate and the supporting descriptions of the activities performed.
4. The total FEI proceeding costs for the FEI-FBC 2014-2019 PBR proceeding and the 2012 GCOC Stage 1 proceeding after allocations to other utilities.
5. A detailed explanation for why the external legal costs in the 2016 Cost of Capital proceeding were only approximately 15 percent lower than in the 2012 GCOC Stage 1 proceeding given the difference in Oral Hearing days, the number of IRs, and the length of the proceedings. This response should include a comparison of the number of hours billed and the number of legal counsel used in the 2016 Cost of Capital proceeding versus the 2012 GCOC Stage 1 proceeding.

The following are FEI's responses to the five items.

Items 1 & 2:

An explanation as to why there was such a broad range in the rate per hour charged by FEI's expert/consultant (i.e. $55-725 USD) in the 2016 Cost of Capital proceeding and why the upper range of the hourly rate charged by FEI's expert/consultant was approximately $225 USD per hour higher than the upper range of the hourly rate charged by FEI's experts/consultants in the 2012 GCOC Stage 1 proceeding.

<u>Response:</u>

FEI conducted a thorough review of the 2016 Cost of Capital proceeding's invoices and provides in Table 7-9 below updated information to the response to Workshop Undertaking No. 5 based on final actual costs. As indicated in Table 7-9 below, FEI has revised the hourly rate range from $55-$725 USD to the actual charged hourly rate range of $55-$500 USD. The hourly rate range of $55-$725 USD was based upon the engagement letter with the consultant and not the actual invoices for services performed throughout the engagement. The engagement letter with the consultant included a standard hourly rate schedule and was not specific to the actual personnel who would provide services under the engagement. For example, the hourly rate in the standard rate schedule included charges for 12 levels of positions which may have been used during the engagement, ranging from project assistant at the low end to the CEO position at the high end. Based on the actual invoiced rates, the upper range of hourly rate actually charged to FEI by its expert/consultant in both 2012 GCOC Stage 1 proceeding and 2016 FEI Cost of Capital proceeding was $500 USD.

Table 7-9: Response to Undertaking No. 5 – Updated for Actual Costs

Applicaton	FEI 2016 Cost of Capital	FEI-FBC 2014-2019 PBR*	FEU 2012-2013 RRA	2012 GCOC Stage 1*
Commission Costs	$ 144,829 (1)	$ 318,079	$ 389,430	$ 500,000 (2)
Intervener PACA	249,799	513,720	351,020	477,650
FEI Experts/Consultants **	833,755	455,758	299,053	1,095,879
Legal Costs	456,008 (1)	946,431	489,233	528,314
Other/Misc.	18,767	21,548	32,240	6,953
Total:	**$ 1,703,158**	**$ 2,255,536**	**$ 1,560,976**	**$ 2,608,797**
Limited Oral Hearing Scope	Yes	Yes	No	No
# Oral Hearing Days***	3	7	8	7
# IRs	561	3,534	1,665	956
# Rounds of IRs	2	3	3	2
# FEI Experts	1	1	1	4
# Hours Billed	2,027.5 (1)	Approx. 1,300	Approx. 800	Approx. 3,000
Rate per Hour****	$55-$500 USD (1)	$300-$400 USD	$90-$205 CAD	$100-$500 USD

Note (1) Amounts updated to reflect final actuals

Note (2) Commission's direct costs $500,000 through the levy

** total costs, before allocations to other utilties*

*** Includes disbursements and expenses. Reflects converson to $CAD where applicable. Average annual exchange rates were as follows:*

2016	*0.76512*
2014	*0.90226*
2012	*1.00170*

**** Oral hearing days include both Company and Expert witness panels, with the exception of 2016 Cost of Capital*

***** hourly rates dependent on the experience and level of support used*

Item 3:

A breakdown of the hours charged by the expert/consultant in the 2016 Cost of Capital proceeding at each hourly rate and the supporting descriptions of the activities performed.

<u>Response:</u>

The requested cost breakdown is provided in Table 7-10.

Table 7-10: 2016 Cost of Capital Proceeding – Breakdown of Hours, Rates, & Activities

Rate Class	# Hours	Hourly Rates (USD)	Total Labour: (USD)	Work Performed
SVP - Senior Vice President	354.75	$500	$ 177,375.00	Preliminary preparation work, review prior evidence and decisions, review jurisdictional information, prepare evidence outline; draft evidence and review; meetings, finalize filings, review and draft IR responses, review Intervener Evidence, draft Intervener IRs, prepare Rebuttal evidence, support counsel at hearing, testify at the hearing, support cross examination, support arguments
SPM - Senior Project Manager	1,040.25	$300-$315	$ 324,392.50	Research, review evidence, drafting, analysis, develop testimony, historical evidence, background research; meetings, edit evidence, finalize evidence, draft IR responses, review Intervener Evidence, Draft Intervener IRs, hearing support and preparation, support rebuttal evidence, support arguments
PM - Senior Project Manager	54.50	$295	$ 16,077.50	Review reports, review past evidence, draft evidence, review analysis, support IRs, research, draft IR responses, review Intervener evidence, support Intervener IRs, support Rebuttal, assist hearing prep, support hearing
SC - Senior Consultant	10.25	$250	$ 2,562.50	Data analysis, support for IRs, support for Rebuttal, support hearing
C - Consultant	199.25	$220	$ 43,835.00	Research, drafting evidence, analysis, updates, data gathering, support evidence, IRs
A - Analyst	245.25	$225-$235	$ 55,468.75	Research, data analysis, modeling; support evidence, IRs, Rebuttal
PA - Project Assistant	123.25	$55-$70	$ 7,996.95	Admin support
Total Labour (USD):	**2,027.50**	**$55-$500**	**$ 627,708.20**	
Disbursements			$ 12,379.36	
Foreign Exchange			$ 193,667.44	
Total Costs (CAD):			**$ 833,755.00**	

As indicated in the Table 7-10 above, the majority of hours billed were at the Senior Project Manager level with an hourly rate in the range of $300-$315 USD. As a result, the average hourly rate charged to FEI by its consultant is calculated to be approximately $310 USD.

Item 4:

The total FEI proceeding costs for the FEI-FBC 2014-2019 PBR proceeding and the 2012 GCOC Stage 1 proceeding after allocations to other utilities.

<u>Response:</u>

The two proceedings' costs before and after allocations to other utilities are provided in Table 7-11 below.

Table 7-11: Total Proceeding Costs Before & After Allocations

Proceeding	Total Costs ($CAD)	Costs after allocation to other utilities ($CAD)
2012 GCOC Stage 1	$2,608,797	$2,304,179
FEI-FBC 2014-2019 PBR	$2,255,536	$1,877,072

Item 5:

A detailed explanation for why the external legal costs in the 2016 Cost of Capital proceeding were only approximately 15 percent lower than in the 2012 GCOC Stage 1 proceeding given the difference in Oral Hearing days, the number of IRs, and the length of the proceedings. This response should include a comparison of the number of hours billed and the number of legal counsel used in the 2016 Cost of Capital proceeding versus the 2012 GCOC Stage 1 proceeding.

Response:

A comparative analysis of legal costs for 2016 Cost of Capital proceeding and 2012 GCOC Stage 1 proceeding should consider three separate items:

1. Provincial Sales Tax (PST) vs. Harmonized Sales Tax (HST):

The legal cost for 2012 GCOC Stage 1 proceeding was recorded under the HST regime. As such, invoices included HST at 12 percent on all costs (labour and disbursements). HST was considered a refundable tax credit as companies claim it back as a refundable input tax credit from the government. Therefore, the legal cost for 2012 GCOC Stage 1 proceeding provided in the Table 7-11 above excludes any HST amounts. In April 2013, British Columbia returned to the PST regime. Under the PST regime, the 2016 Cost of Capital proceeding legal invoices included GST at 5 percent on all costs (labour and disbursements) and an additional PST at 7 percent on labour costs. While the 5 percent GST is a refundable input tax credit, the 7 percent PST paid by FEI is not recoverable from the government and, as a result, is included in the total legal costs for the 2016 Cost of Capital proceeding.

Therefore, the 2016 Cost of Capital proceeding legal cost includes an additional PST amount of approximately $30 thousand. After excluding the PST amount, the 2016 Cost of Capital proceeding legal costs are approximately 19 percent lower than the legal costs for the 2012 GCOC Stage 1 proceeding.

2. Billed hours

A breakdown of the labour portion of legal costs by the number of hours billed in each position, for both the 2016 Cost of Capital proceeding and the 2012 GCOC Stage 1 proceeding, is provided in Tables 7-12 and 7-13 below.

Table 7-12: 2012 GCOC Stage 1 Proceeding Legal Costs Breakdown

Rate Class	# Hours	Hourly Rate ($CAD)	Total Labour ($CAD)
SP - Senior Partner	1,010.1	$425-$450	$ 434,342.50
JP - Junior Partner	20.3	$300-$325	$ 6,352.50
A - Associate	278.8	$260-$290	$ 76,484.00
L - Library Student	0.6	$195-$210	$ 120.00
Total Labour:	**1,309.8**	**$195-$450**	**$ 517,299.00**
Disbursements			$ 11,014.88
Total:			**$ 528,313.88**

Table 7-13: 2016 Cost of Capital Proceeding Legal Costs Breakdown

Rate Class	# Hours	Hourly Rate ($CAD)	Total Labour ($CAD)
SP - Senior Partner	593.60	$465-$520	$ 304,225.00
A - Associate	313.80	$315-$375	$ 116,779.50
Total Labour:	**907.40**	**$315-$520**	**$ 421,004.50**
Disbursements			$ 5,559.05
PST			$ 29,444.28
Total:			**$ 456,007.83**

Compared to the 2012 GCOC Stage 1 proceeding, the total number of hours billed by FEI's external counsel in the 2016 Cost of Capital proceeding decreased by more than 30 percent. This decrease can be explained by a reduction in the number of information requests and fewer oral hearing days. The breakdown of billed hours also demonstrates an approximate 40 percent decrease in the number of billed hours at the Senior Partner level and an approximate 15 percent increase in the number of hours billed at the Associate level. This highlights the efforts made by management to efficiently use the available resources' expertise and minimize the total billed amount.

3. Billing Rates

As stated above, compared to 2012 GCOC Stage 1 proceeding, the total number of billed hours in the 2016 Cost of Capital proceeding decreased by more than 30 percent while the total legal cost decreased by approximately 19 percent (excluding PST). The reasons that total legal costs decreased less than the total number of billed hours reflects changes to the allocation and distribution of work between the Senior Partner and Associate positions. The total average hourly rates charged by the Senior Partner and Associate positions increased by approximately 18 percent between 2012 and 2016. This increase is due to hourly wage inflation over the period as well as an increase in the experience level of counsel during the period which caused hourly charge out rates to increase. For instance, at the time of the 2012 GCOC Stage 1 proceeding, the Associate working on the proceeding was considered a junior Associate with little direct experience in Cost of Capital proceedings; as such, more hours were required to complete the work, however at reduced hourly rates. In the 2016 Cost of Capital proceeding, the same Associate now had four to five additional years of experience which in turn resulted in improvement in efficiency of the Associate and a significant reduction in number of hours required at the Senior Partner level (40 percent decrease) as more responsibility was handled at the Associate level.

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 Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). 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 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 2017 Q2 gas cost report and historical volumes. Materials and supplies and refundable contributions are forecast based on 2017 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. FEI has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11, and discussed two new accounts and the disposition of one other account 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 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-129-16. The 2018 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 2018 (which is equal to its after-tax weighted average cost of capital) is 5.65 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-129-16, 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, 2016. As part of order G-129-16, the Commission issued an indefinite suspension of the Automatic Adjustment Mechanism.

FEI has therefore prepared this Application using an ROE of 8.75 percent and a common equity percentage of 38.5 percent.

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 debt.

8.3.1 Long-Term Debt

FEI is a public issuer of long-term debt. During December 2016, FEI issued long term debt of $150 million at a rate of 3.78 percent for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Corporation's capital expenditure program. FEI plans to issue additional long-term debt of approximately $150 million in 2017, and $150 million in 2018, which will be used for the same purpose. The 2017 debt issuance is reflected in the financial schedules in November 2017 at a rate of 3.60 percent[54]. The 2018 debt issuance is reflected in the financial schedules in July 2018 at a rate of 4.00 percent[55]. The exact timing, amount and rate of the 2017 and 2018 issuances will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and

[54] As shown in the financial schedules in Section 11, Schedule 27, Line 13
[55] As shown in the financial schedules in Section 11, Schedule 27, Line 14

amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral 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 2022[56]. The credit facility provides FEI with short term liquidity 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 2018 at an estimated issue rate of approximately 4.00 percent based on a 30 year GOC rate of 2.73 percent and an indicative spread of 1.29 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. As CDOR is not forecast by economists, 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.

The 3-month T-Bill rate is projected to increase from 0.69 percent in 2017 to approximately 1.22 percent in 2018. The short-term borrowing rate forecast is shown in Table 8-1 below.

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

FEI Short Term Interest Rate	2017	2018
3 Month T-Bill Rate[1]	0.69%	1.22%
Spread to CDOR	0.39%	0.39%
CDOR Rate	1.09%	1.61%

[56] As at July 27, 2017, credit facility extended to August 24, 2022.

FEI Short Term Interest Rate	2017	2018
Spread to CP	-0.18%	-0.18%
CP Dealer Commission	0.10%	0.10%
Standby Fee on Undrawn Credit[2]	0.71%	0.46%
Upfront Fee on Undrawn Credit	0.19%	0.12%
FEI Short Term Rate (Rounded)	1.90%	2.10%

Note 1 - 3 month T-Bill rate for 2017 based on a composite of actual historical rates up to June 15, 2017 and forecasted rates for the remainder of the year.

Note 2 - A Standby fee of 16 bps is charged on undrawn credit facility amounts, and has been reflected into the short term rate as if the forecast amount payable had been converted to a rate applied to commercial paper borrowings.

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.

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 2018 long-term debt schedule for FEI can be found in Section 11, Schedule 27.

FEI's Flow-through deferral 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)

FEI applies AFUDC to projects that are greater than 3 months in duration and greater than $100 thousand. Based on the above information, FEI's AFUDC Rate for 2018 (which is equal to its after-tax weighted average cost of capital) is 5.65 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2018

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	4.98%	2.10%	1.55%	2.10%
Long Term Debt	56.52%	5.26%	3.89%	5.26%
Common Equity	38.50%	11.82%	8.75%	8.75%
Weighted Average	100.00%	7.63%	5.65%	6.45%

8.4 SUMMARY

FEI's capital structure and ROE have been forecast for 2018 at the same percentages as approved for 2017. FEI's debt financing costs on rate base are primarily determined by embedded rates on long-term debt and short-term debt; these rates remain relatively 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 basis consistent with prior years. In 2018, property taxes are forecast to decrease by 0.4 percent from 2017 Approved, while income tax is forecast to increase by 37.7 percent compared to 2017 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 2018 of $67.157 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 2017	Projected 2017	Forecast 2018
Distribution Assets	$ 24.958	$ 23.459	$ 24.143
Transmission Assets	17.845	17.976	18.945
Gas Storage Assets	7.712	8.052	8.389
Manufactured Gas Assets	0.031	0.029	0.030
General Assets	3.991	4.246	4.499
In-Lieu	12.629	11.164	10.880
OGC Fees	0.295	0.290	0.290
Total Property Taxes	$ 67.461	$ 65.216	$ 67.176
Less: Property Tax Transferred to BVA	(0.011)	(0.006)	(0.019)
Net Property Tax Expense	$ 67.450	$ 65.210	$ 67.157
Forecast Change from 2017 Approved			-0.4%
Forecast Change from 2017 Projected			3.0%

As shown in the table above, in 2018 property taxes are forecast to decrease by 0.4 percent from 2017 Approved and increase 3.0 percent compared to 2017 Projected. In general, the increase from 2017 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 expected to change on average as follows:
    a. Municipal rates are expected to increase by 1.5 percent;
    b. School rates are expected to decrease by 0.7 percent;
    c. Rural rates are expected to increase by 1.0 percent; and
    d. Other rates are expected to increase by 2.0 percent.
2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to decrease by 2.50 percent. As grants in-lieu of taxes are based on a fixed percentage of revenues, the overall decrease in revenues reported to municipalities decreases 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 1.25 percent increase in assessed values of distribution lines and services plus additional new construction of approximately $17.6 million;
    b. A 5.0 percent increase in assessed values of transmission lines;
    c. A 2.0 percent increase in assessed values for LNG assets plus an expected increase of approximately $35 million for new construction at the Tilbury LNG facility; and
    d. Land value changes which are expected to range from a 3.0 percent increase in the assessed value for right of ways to a 5.0 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 2018, which is unchanged from 2017. 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 2018 is forecast to increase by $13.428 million or 37.7 percent compared to 2017 Approved. This increase is primarily due to a higher delivery margin in 2018 and the impacts of the Tilbury Expansion and CTS projects offset by an increase in capital cost allowance deductions in 2018.

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 introduced an LNG income tax on net income from LNG facilities in BC. The new LNG income tax was expected to 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 legislation is not yet in force.

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 5.0 per cent in 2037 and thereafter). The new tax will apply to income earned at the existing Tilbury Facility, the Tilbury Expansion and the Mt. Hayes LNG Facility on Vancouver Island.

Along with the LNG income tax legislation, the provincial government has also provided a Natural Gas Tax Credit (NGTC) against the current 11 percent BC corporate income tax. The NGTC is effectively equal to the lesser of (i) 3.0 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 less than 8 percent.

Because the LNG income tax legislation is not yet in force, estimates of the LNG income tax and NGTC have not been included in forecast 2018 rates. If the legislation comes into force before FEI files for its final rates later in 2017, FEI will update the financial schedules to include the forecast impacts of the tax and the difference between the forecast and actual tax will be captured in the Flow-through deferral account.

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. For 2018, FEI is proposing to distribute a $3.462 million pre-tax credit ($2.562 million after tax) as shown in Table 10-1 below. This amount is composed of:

- 2017 projected sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth;
- A correction to the 2015 adjustment for actual customer growth included in 2017 Annual Review;
- The true-up of the 2016 projected earnings sharing to actual; and
- Financing on the deferral account balance.

Table 10-1: Summary of Earnings Sharing to be Returned in 2018 ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2017 Projected Sharing	(2.081)	Table 10-2, Line 50
2	2016 Actual Customer Growth adjustment	0.082	Table 10-3, Line 34
3	2015 Actual Customer Growth adjustment - correction	(0.027)	Table 10-4, Line 17
4	2016 Projected vs. Actual ending balance true-up	(0.361)	Table 10-5, Line 3
5	Financing	(0.174)	Table 10-6, Line 5
6			
7	**2018 after-tax amount returned to customers**	**(2.562)**	
8	**2018 pre-tax amount returned to customers**	**(3.462)**	Line 7 / 0.74

Each of these items is discussed in the sections below.

10.1.1 2017 Projected Sharing

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[57] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[58]) 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 2017 formula-driven O&M savings at $7.5 million, and 2017 capital expenditures in excess of the formula of $41.218 million. The $41.218 million excess 2017 capital expenditures will exceed the dead band by $26.473 million, such that FEI has removed the $26.473 million amount above the dead band in the calculation of 2017 earnings sharing, as shown in Line 31 of Table 10-2 below.

[57] Excluding items that are reforecast outside of the formula.

[58] Ibid.

Table 10-2: Calculation of 2017 Projected Earnings Sharing ($millions)

Line No.	Particulars						Reference
1	Approved Formula O&M	240.412					G-182-16
2							
3	Actual/Projected Gross O&M	261.327					
4	Less: O&M Tracked outside of Formula						
5	Pension/OPEB (O&M portion)	15.826					
6	Insurance	5.300					
7	Biomethane	1.044					
8	NGT O&M	1.365					
9	RS 16/46 O&M	4.880					
10	Total	28.415					Sum of Lines 5 through 9
11							
12	Actual/Projected Base O&M	232.912					Line 3 - Line 10
13							
14	O&M Subject to Sharing	(7.500)					Line 12 - Line 1
15							
16			Annual Capital Expenditures				
17		Cumulative	2014	2015	2016	2017	Note 1
18							
19	Formula CapEx	551.097	119.821	139.380	145.315	146.581	
20							
21	Total Regular CapEx	707.081	144.932	174.489	182.976	204.684	
22	Less: CapEx tracked outside of formula						
23	Pension and OPEB	14.977	3.915	4.324	4.075	2.663	
24	Biomethane	8.012	3.656	1.350	1.346	1.660	
25	NGT	20.707	5.816	5.607	5.797	3.487	
26	CIAC	23.639	4.419	6.336	6.309	6.575	
27	AFUDC	11.829	2.727	3.293	3.309	2.500	
28	Total	79.165	20.533	20.911	20.836	16.885	Sum of Lines 23 through 27
29							
30	Actual/Projected Base CapEx	627.916	124.399	153.578	162.140	187.799	Line 21 - Line 28
31	Dead Band Adjustment	(35.649)		-	(9.176)	(26.473)	Adjustment to stay within deadband
32	Actual/Projected Base CapEx for ESM Calculation	592.267	124.399	153.578	152.964	161.326	Line 30 + Line 31
33							
34	Actual/Projected Cumulative Base CapEx Variance	41.170	4.578	14.198	7.649	14.745	Line 32 - Line 19
35							
36	Single Year Deadband % Variance (after adjustment)		3.70%	9.88%	5.12%	9.88%	Line 34 / (Line 19 + Line 23)
37	Two year Cumulative Deadband % Variance (after adjustment)			13.58%	15.00%	15.00%	Line 36 sum of two years
38							
39	Equity Component of Rate Base	38.5%					
40	Approved Return on Equity	8.75%					
41	After Tax Return on CapEx Subject to Sharing	1.387					Product of Lines 34, 39 & 40
42	Tax Rate	26.0%					
43							
44	Before Tax Return on CapEx Subject to Sharing	1.874					Line 41 / (1 - Line 42)
45							
46	Total before tax Sharing Amount	(5.625)					Line 14 + Line 44
47	Sharing percentage	50%					G-138-14
48							
49	2017 Projected Earnings Sharing (pre-tax)	(2.813)					Line 46 x Line 47
50	2017 Projected Earnings Sharing (after-tax)	(2.081)					Line 49 x 0.74

Notes

1 2014, 2015 & 2016 are actual results from BCUC Annual Report, 2017 is projected results

10.1.2 Actual Customer Growth Adjustment

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 of $0.111 million debit ($0.082 million debit after-tax) for 2016 as shown in Table 10-3 below based on its actual customer additions.

Table 10-3: Calculation of Earnings Sharing Adjustment for Actual Customer Growth

Line No.	Particulars	$ millions	Reference
1	Average Customers 2016	983,807	
2	Average Customers 2015	968,765	
3	Growth in Average Customers	15,042	Line 1 - Line 2
4	Average Customer Growth	1.553%	Line 3 / Line 2
5		50%	G-138-14
6	Average Customer Growth to be recast in Formula	0.776%	Line 4 x Line 5
7	2016 Net Inflation Factor	0.469%	G-193-15 Compliance filing, Section 11, Schedule 3, Line 9, Column 5
8	2015 Reforecast Sustainment/Other Capital	$ 112.646	Table 10-4, Line 9, Corrected
9	2016 Reforecast Formulaic Sustainment/Other Capital	$ 114.053	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2016 Year Formulaic Sustainment/Other Capital	112.053	G-193-15 Compliance filing, Section 11, Schedule 4, Line 16, Column 3
11	Sustainment/Other Capital Increase from actual growth	$ 2.000	Line 9 - Line 10
12			
13			
14	Service Line Additions 2016	12,288	
15	Service Line Additions 2015	12,399	
16	Growth in Average Customers	(111)	Line 14 - Line 15
17	Average Customer Growth	-0.90%	Line 16 / Line 15
18		50%	G-138-14
19	Average Customer Growth used in Formula	-0.45%	Line 18 x Line 17
20	2015 Reforecast Service Line Additions	11,603	2017 Annual Review of Rates Table 10-3, Line 21
21	2016 ReForecast Service Line Additions	11,551	Line 20 x (1 + Line 19)
22	Service Line Addition Cost per Customer ($)	2,985	
23	2016 Reforecast Formulaic Growth Capital	$ 34.478	Line 21 x Line 22 / 1000000
24	2016 Formulaic Growth Capital	33.262	G-193-15 Compliance filing, Section 11, Schedule 4, Line 16, Column 2
25	Growth Capital Increase from actual growth	$ 1.216	Line 23 - Line 24
26			
27			
28	Increase in Capital Requirements from Actual Growth	$ 3.217	Line 11 + Line 25
29	Mid Year	$ 1.608	Line 28 / 2
30			
31	Equity Cost Component	3.37%	G-193-15
32	Debt Cost Component	3.53%	G-193-15
33	Earned Return on incremental Capital Requirements (pre-tax)	$ 0.111	Line 29 x (Line 31 + Line 32)
34	Earned Return on incremental Capital Requirements (after-tax)	$ 0.082	Line 33 x 0.74

When calculating the actual customer growth adjustment for this Application, FEI noted an error in the average customer count used for the 2015 actual customer growth adjustment in the Annual Review for 2017 Rates Application. FEI has corrected the error and included an adjustment to the earnings sharing to be returned in 2018. The error was a transposition of 2 digits in 2015 Average Customers (Line 1, Table 10-3) which resulted in the average customer count for 2015 being 18,000 too high, which caused a greater than required adjustment to the 2016 projected earnings sharing amount of $0.037 million pre-tax ($0.027 million after tax). FEI has included the adjustment in Table 10-1 above and has provided details of the calculation in Table 10-4 below.

Table 10-4: Correction to 2015 Adjustment for Actual Customer Growth

Line No.	Particulars	Corrected	Filed in 2016 Annual Review for 2017 Rates	Difference	Notes
1	Average Customers 2015	968,765	986,765	(18,000)	Transposed 2015 Average Customers
2	Average Customers 2014	959,193	959,193	-	
3	Growth in Average Customers	9,572	27,572	(18,000)	
4	Average Customer Growth	0.998%	2.874%		
5		50%	50%		
6	Average Customer Growth to be recast in Formula	0.499%	1.437%		
7	2015 Net Inflation Factor	0.201%	0.201%		
8	2014 Reforecast Sustainment/Other Capital	$ 111.862	$ 111.862		
9	2015 Reforecast Formulaic Sustainment/Other Capital	$ 112.646	$ 113.698	$ (1.052)	
10	2015 Year Formulaic Sustainment/Other Capital	110.901	110.901		
11	Sustainment/Other Capital Increase from actual growth	$ 1.745	$ 2.797	$ (1.052)	
12	Mid Year	$ 0.873	$ 1.398	$ (0.526)	
13					
14	Equity Cost Component	3.37%	3.37%	3.37%	
15	Debt Cost Component	3.64%	3.64%	3.64%	
16	Earned Return on incremental Capital Requirements (pre-tax)	$ 0.061	$ 0.098	$ (0.037)	
17	Earned Return on incremental Capital Requirements (after-tax)	$ 0.045	$ 0.073	$ (0.027)	Correction included in 2018 ESM

10.1.3 True-Up for 2016 Actual Earnings Sharing

In FEI's 2016 Annual Report to the Commission, FEI calculated the final 2016 earnings sharing based on the final 2016 results. The final amount of earnings sharing for 2016 was $4.045 million, which was $0.361 million higher than the $3.684 million projected for 2016, as shown in Table 10-5 below. As a result, FEI is increasing its 2018 earning sharing by the after-tax amount of $0.361 million as shown in Table 10-1 above.

Table 10-5: Calculation of 2016 Actual Earnings Sharing true-up ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2016 Actual Earnings Sharing account ending balance	(4.045)	2016 FEI BCUC Annual Report
2	2016 Projected Earnings Sharing account ending balance	(3.684)	Annual Review of 2017 Rates Compliance Filing financial schedules, Schedule 12, Line 8, Column 2
3	**2016 Earnings Sharing account true-up**	**(0.361)**	

10.1.4 Financing

FEI has calculated the financing on the deferral account balances that result from the amounts described above. As the balances are positive, financing consists of credits to customers at FEI's WACC. As shown in Table 10-6 below, FEI has calculated a $0.104 million credit to true-up for 2017 projected financing and a forecast $0.070 million credit for 2018 financing. This results in a total after-tax financing adjustment of $0.174 million to be distributed to customers as shown in Table 10-1 above.

Table 10-6: Calculation of Earnings Sharing financing ($millions)

Line No.	Particulars	After-tax Amount	Reference
1	2017 Projected Earnings Sharing financing	(0.205)	
2	Less: 2017 Forecasted Earnings Sharing financing	(0.101)	Annual Review of 2017 Rates Compliance Filing financial schedules, Schedule 12, Line 11, Column 4
3	2017 Earnings Sharing financing true-up	(0.104)	
4	Add: 2018 Forecasted Earnings Sharing financing	(0.070)	Section 11, Schedule 12, Line 20, Column 4
5	**2017/2018 Financing Adjustments**	**(0.174)**	

10.1.5 Summary of Earnings Sharing

After calculating the 2017 projected earnings sharing and including the adjustments described above, FEI proposes to distribute $3.462 million to customers in 2018 as a reduction in 2018 revenue requirements through amortization of the projected 2018 opening after-tax balance of $2.562 million in the Earnings Sharing deferral account.

As part of the Annual Review for 2019 Rates, the earnings sharing for 2017 will be subject to similar true-ups as described above which account for the actual O&M and capital expenditure amounts for 2017, as well as impacts, if any, associated with non-performance of Service Quality Metrics, based on final 2017 results.

10.2 *RATE RIDERS*

There are two delivery rate riders that are set this year through the annual review process. These are the BVA Rate Rider and the RSAM Rate Riders. Additionally, in this section FEI provides information on the remaining balances in the RSDA and Phase-In deferral accounts, which were approved to enable the transition of FEI's Mainland, Vancouver Island and Whistler service areas to common rates. Each of these is discussed below.

10.2.1 BVA Rate Rider

On August 12, 2016, the Commission issued Order G-133-16 and the accompanying Decision in the matter of the Biomethane Energy Recovery Charge (BERC) Rate Methodology Application (2016 Biomethane Decision). The 2016 Biomethane Decision approved the Short Term BERC rate based on a premium of $7 per GJ above the Conventional Gas Cost (defined as the sum of the Commodity Cost Recovery Charge, the carbon tax and any other taxes applicable to conventional natural gas sales). The Long Term BERC rate is to be set at a $1 per GJ discount to the Short Term BERC rate.

FEI also received approval to amortize/transfer the net of tax year-end balance in the BVA, after adjustment for the value of unsold biomethane quantities, to a BVA Rate Rider Account for recovery from, or refund to, all non-bypass customers via a delivery rate rider effective January 1 of the subsequent year.

In the 2016 Biomethane Decision, FEI was directed to provide the following information:

- A continuity schedule showing the breakdown of the forecast December 31st balance in the BVA to be recovered by the BVA Rate Rider by year including sufficient supporting details.
- The calculation of the BVA Rate Rider by rate class.
- A continuity schedule showing the forecast, actual and variance (actual – forecast) biomethane revenues and volumes sold (GJ) by rate class, type of contract (short term/long term) and year.
- Number of customers in each rate class.

FEI provides the requested information below for the closing 2017 balance of the BVA Rate Rider Account, and the calculation of the BVA Rate Riders for 2018.

10.2.1.1 BVA Rate Rider Account

The cumulative BVA Rate Rider Account balance at the end of December 31, 2017 is projected to be a debit of $5.176 million before-tax and consists of both the actual 2016 after-tax balance of $2.203 million and a projected 2017 after-tax addition of $1.627 million transferred from the BVA, both grossed up for the current tax rate of 26 percent[59].

[59] $2.203 million + $1.627 million = $3.830 million divided by (1 – 0.26) = $5.176 million

Table 10-7: BVA Rate Rider Account

Line No	BVA Continuity		2016 Actual ($000s)	2017 Projected (a) ($000s)	2017 Variance (g)
1	**BVA Opening Balance**	(b)			
2	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		$ 1,784.3	341.0	
3	Pre-Tax Adjustment for Unsold Biomethane at January 1,	(c)	(896.9)	(341.0)	
4	Pre-Tax Adjustment for Unsold Biomethane		$ 887.4	$ -	
5					
6	Tax Recovery	26%	(230.7)	-	
7	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ 656.7	$ -	
8					
9	**BVA BVA Activities:**				
10	Biomethane Costs Incurred		$ 3,680.8	$ 4,197.0	
11	Biomethane Costs Recovered		(2,147.1)	(2,321.7)	
12	Change in Unsold Biomethane Quantity		555.9	323.6	
13	Total Activities - Pre-Tax		$ 2,089.5	$ 2,198.9	
14					
15	**BVA Ending Balance at December 31,**				
16	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)				
17	Line 2 + Line 10 + Line 11		$ 3,317.9	$ 2,216.3	
18	Pre-Tax Adjustment for Unsold Biomethane at December 31,	(e)			
19	Line 3 + Line 12		(341.0)	(17.4)	
20	Pre-Tax Balance After Adjustment for Unsold Biomethane)		**$ 2,976.9**	**$ 2,198.9**	
21					
22	Tax Recovery	26%	(774.0)	(571.7)	
23					
24	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ 2,202.9	$ 1,627.2	
25					
26	**Transfer to BVA Rate Rider Account**	(f)	**$ (2,202.9)**	**$ (1,627.2)**	
27					
28	Net of Tax Balance (After transfer to BVA Rider Account)		$ -	$ -	

Notes

(a) The annual forecast is the current 2017 forecast provided in this 2018 PBR Annual Review

(b) Recorded opening balance reconciles to the December 31, 2015 balance in the FortisBC Energy Inc. 2015 BVA Status Report filed on April 29, 2016. Forecast opening balance as per the FortisBC Energy Inc. 2015 Fourth Quarter Report on the BVA and BERC filed on November 13, 2015.

(c)

Calculation of Adjustment for Unsold Biomethane at January 1, 2016	Recorded
December 31, 2015 Quantity Unsold (in TJ)	62.2
January 1, 2016 effective BERC rate (in $/GJ)	$ 14.414
Value of Unsold Biomethane at January 1, 2016	$ 896.9

(d) Deferral accounts are reported on a net of tax basis. When the tax rate changes from that of the prior year, a tax adjustment is required to restate the pre-tax opening balances for the current year.

(e)

Calculation of Adjustment for Unsold Biomethane at December 31, 2016	Recorded	2017 Projected
December 31, 2015 Quantity Unsold (in TJ)	62.2	32.3
December 2016 Quantity Purchased (in TJ)	133.7	189.2
2016 Quantity Sold (in TJ)	(163.60)	(219.9)
Total Quantity Unsold at December 31, 2016 (in TJ)	32.3	1.6
BERC rate in effect at forecast (2016 Second Quarter Report on the BVA and BERC) (in $/GJ)		
January 1, 2017 effective BERC rate (in $/GJ)	$ 10.540	$ 10.540
Value of Unsold Biomethane at December 31, 2016	$ 341.0	$ 17.4

(f) Pursuant to Order G-133-16, and the Decision issued concurrently, the net of tax balance at December 31, 2016, after adjustment for the value of unsold biomethane quantities, was transferred to the BVA Rate Rider Account for recovery from / refund to all non-bypass customers.

(g) Since this is the first BVA Rider filed subsequent to Decision G-133-16, no actual to forecast variance is applicable for 2017 until the true-up in 2019

10.2.1.2 BVA Rate Rider Calculation

As discussed in section 10.2.1.1 above, the cumulative BVA Rate Rider for recovery in 2018 is forecast at $5.176 million before-tax and is forecast to be recovered from non-bypass customers based on 2018 volumes. In order to calculate a BVA Rate Rider, the projected BVA Rate Rider Account balance of $5.176 million is divided by the forecast 2018 non-bypass throughput of

196,021 TJ, for a BVA Rate Rider of approximately $0.026 cents per GJ. Any difference between the actual and forecast BVA Rider collected will be trued up in the subsequent year. Details of the BVA Rate Rider calculation are provided in Table 10-8 below.

Table 10-8: 2018 BVA Rate Rider Calculation

Line No	Particulars	($000s)	BVA Rider Rider Projected 2017 ($000s)	Non-Bypass Forecast 2018 Vol (TJ)
1	**Transfers From BVA to BVA Rider Account**	Net of Tax	Grossed Up	
2	**Net-Tax Balance Dec 31, 2016 Actual** (Grossed up for tax)	2,202.9	**$ 2,976.9**	
3	**Net-Tax Dec 31, 2017 Projected** (Grossed up for tax)	1,627.2	**$ 2,198.9**	
4	**Total BVA Rider**	3,830.1	**$ 5,175.8**	**196,020.8**
5				
7	**BVA Rider by Rate class - (Non - Bypass)**			
8				
9	**Residential**			
10	Rate Schedule 1		$ 2,144.8	81,227.4
11	**Commercial**			
12	Rate Schedule 2		$ 800.0	30,296.5
13	Rate Schedule 3		$ 530.5	20,091.1
14	Rate Schedule 23		$ 272.4	10,315.4
15	**Industrial**			
16	Rate Schedule 4		$ 3.9	146.9
17	Rate Schedule 5		$ 70.6	2,674.6
18	Rate Schedule 6		$ 0.7	28.0
19	Rate Schedule 7		$ 6.5	246.0
20	Rate Schedule 22- Firm Service		$ 297.4	11,263.5
21	Rate Schedule 22- Interruptible Service		$ 487.0	18,445.3
22	Rate Schedule 25		$ 370.1	14,017.0
23	Rate Schedule 27		$ 191.9	7,269.1
24				
25	**Total BVA Rider (Non-Bypass)**		**$ 5,175.8**	**196,020.8**
26				
27	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.026**	
28	(Line 4 divided by Line 25 TJ) $5,175.8 /196,020.8 TJ = $0.026 GJ			

In the 2016 Biomethane Decision, FEI was directed to provide a continuity of forecast, actual and variance (actual - forecast) biomethane (BERC) revenues and volumes sold by rate schedule, and type of contract.

The following table breaks down the BERC revenues and volumes by rate schedule and by short-term and long-term contracts. In 2017 the projected recoveries are $2.322 million attributable to sales volumes of 219.9 TJ from 8,812 Biomethane customers. At the time of filing this Application, FEI is in the process of negotiating a long-term contract and will file it separately as a Tariff Supplement with the Commission. The expected sales volume from this long-term contract is included in the 2017 projected volume and revenue in Table 10-9.

Table 10-9: BERC Revenue and Volume

Line No	Volume and Revenue	2017 Projected
1	**Volume (TJ)**	
2	**Short-term**	
3	Rate 1B	84.9
4	Rate 2B	10.9
5	Rate 3B	8.1
6	Rate 5B	-
7	Rate 11B	80.6
8	Rate 30	-
9	Sub-total	184.4
10		
11	**Long Term** [(a)]	
12	Rate 11B	35.5
13	Sub-total	35.5
14		
15	**Total Sales Volume (TJ)**	219.9
16		
17	**Recoveries ($000s)**	
18	**Short-term**	
19	Rate 1B	$ 894.5
20	Rate 2B	114.7
21	Rate 3B	85.2
22	Rate 5B	-
23	Rate 11B	849.6
24	Rate 30	3.5
25	Sub-total	1,947.6
26		
27	**Long Term** [(a)]	
28	Rate 11B	374.1
29	Sub-total	374.1
30		
31	**Total Sales**	$ 2,321.7

Note : *(a) The 2017 Projected assumes a Long Term contract with a start date of September 1, 2017.*

In the 2016 Biomethane Decision, FEI was also directed to provide the number of customers by rate class. The following table sets out the 2017 Projected number of renewable natural gas customers by rate class.

Table 10-10: RNG Customers by Rate Schedule

2017 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short-term	
Rate Schedule 1B	8,605
Rate Schedule 2B	183
Rate Schedule 3B	15
Rate Schedule 11B	8
Rate Schedule 5B	0
Rate Schedule 30 Off System	0
Long-term	
Rate Schedule 11B	1
Total	8,812

In summary, the 2018 BVA Rate Rider attributable to the cumulative December 31, 2017 transfers from the BVA is $0.026 cents per GJ recoverable from all non-bypass customers.

10.2.2 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 2017 is a credit of $8.5 million. The calculation of the 2018 RSAM riders is shown in Table 10-11.

Table 10-11: 2018 RSAM Riders

2017 RSAM + Interest Closing Balance ($000)	(8,525)
Amortization Period (years)	2
2018 Amortization post-tax ($000)	(4,262)
Tax Rate	26%
2018 Amortization pre-tax ($000)	(5,760)

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization ($000)	2018 Volume (TJ)	Rider ($/GJ)
Rate 1/1B/1U/1X		81,227.4	(0.041)
Rate 2/2B/2U/2X		30,296.5	(0.041)
Rate 3/3B/3U/3X		20,091.1	(0.041)
Rate 23		10,315.4	(0.041)
	(5,760)	141,930.4	(0.041)

The differences that result from the actual 2017 ending RSAM balance varying from the projection, and the actual 2018 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2019 RSAM Rate Riders and, in this way, refunded to or collected from customers.

10.2.3 Deferral Accounts Related to the Transition to Common Rates

There are three deferral accounts that are projected to have a residual balance at the end of 2017 that are related to the transition to common rates for the Mainland, Vancouver Island and Whistler service areas – the Rate Stabilization Deferral Account (the RSDA), the Phase-In-Rider Balancing Account, and the Amalgamation Regulatory Account. These accounts had rate riders attached to them that were designed to distribute the ending 2014 balances to customers by the end of 2017.

In the Annual Review for 2017 Rates, FEI calculated the 2017 rate riders for these accounts based on the forecast demand for the Mainland service area of 169,539.6 TJs[60] and for the Vancouver Island and Whistler services areas of 13,345 TJs[61]. The current projection for 2017 demand for the Mainland service area is 176.367.6 TJs and for the Vancouver Island and Whistler services areas is 14,512.8 TJs. Because of the differences in the original forecast and projected 2017 demand, the 2017 projected ending balance in the accounts differs from what was projected in FEI's 2017 Annual Review. Based on this updated demand forecast, FEI projects a 2017 after-tax ending debit balance in the three accounts of $0.748 million, which is

[60] FEI Annual Review for 2017 Rates, Section 10, Table 10-9.
[61] FEI Annual Review for 2017 Rates, Section 10, Table 10-8.

composed of an RSDA after-tax credit balance of $0.611 million, a Phase-In Rider Balancing Account after-tax debit balance of $1.233 million and an Amalgamation Regulatory Account after-tax debit balance of $0.126 million.

Tables 10-12 through 10-14 below show the projected continuity of the three accounts through 2017.

Table 10-12: 2017 RSDA Balance ($000s)

Rate Stabilization Deferral Account (RSDA)		2017 P	Notes/ Reference
Opening Balance (after-tax)		$ (16,776)	
Projected Disposition through Rider	$ 21,853		1
Tax on Rider	(5,682)	16,171	
Net		$ (605)	
Projected Interest		(6)	2
Projected Closing Balance		$ (611)	
Total Amount to be disbursed through Amortization		$ (611)	3

Table Notes:

1. $21,853 is based on 2017 Approved Riders by Rate Schedule multiplied by the latest 2017 Projected Volume by Rate Schedule
2. Interest Rate for 2017 equals 1.90%
3. The 2017 Projected closing balance will be amortizaed into all non-bypass customer's rates

Table 10-13: 2017 Phase-In Rider Balancing Account ($000s)

Phase-In Rider Balancing Account		2017 P	Notes/ Reference
Opening Balance (after-tax)		$ (2,289)	
Projected collections from Vancouver Island & Whistler	$ (11,439)		1
Tax on Rider	2,974	(8,465)	
Projected disbursements to Mainland	$ 16,199		1
Tax on Rider	(4,212)	11,987	
Projected Closing Balance		$ 1,233	
Total Amount to be disbursed through Amortization		$ 1,233	2

Table Notes:

1. Based on 2017 Approved Riders by Rate Schedule multiplied by the latest 2017 Projected Volume by Rate Schedule
2. The 2017 Projected closing balance will be amortizaed into all non-bypass customer's rates

Table 10-14: 2017 Amalgamation Regulatory Account ($000s)

Amalgamation Regulatory Account				2017 P	Notes/ Reference
Opening Balance (after-tax)			$	758	
2017 Projected Recovery	$	(856)			1
Tax on Rider		223		(633)	
Net					
Projected Interest				1	2
Projected Closing Balance			$	126	
Total Amount to be disbursed through Amortization			$	126	3

Table Notes:

1. Based on 2017 Approved Riders by Rate Schedule multiplied by the latest 2017 Projected Volume by Rate Schedule
2. Interest Rate for 2017 equals 1.90%
3. The 2017 Projected closing balance will be amortized into all non-bypass customer's rates

As 2017 is the last year that the rate riders related to the three deferral accounts are applicable, FEI is seeking approval to transfer the actual 2017 closing balance in the three deferral accounts, which will include any variances between the actual and projected 2017 additions, to the existing rate base Residual Delivery Rate Riders deferral account. Additionally, any residual rate rider recoveries collected in 2018 will be recorded directly to the Residual Delivery Rate Riders deferral account and amortized in the following year. The Residual Delivery Rate Riders deferral account has an approved amortization period of one-year.

10.3 *SUMMARY*

FEI has calculated the amount of earnings sharing to be returned to customers in 2018 in compliance with the approved mechanism, including an estimate for 2017 which includes an adjustment for capital exceeding the dead band, a true-up for 2016, and an adjustment for the impact of actual customer additions on growth capital. In addition, FEI has updated all of the 2018 delivery rate riders for 2017 projected ending balances and 2018 forecast volumes.

11. FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2018
($millions)

Line No.	Particulars	2018 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (47.318)		
3	Change in Other Revenue	(3.090)	(50.408)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	5.176		
7	Capitalized Overhead Change	(0.641)	4.535	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		21.276	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	0.162		
14	Deferrals	5.214	5.376	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	(2.671)		
18	Financing Ratio Changes	(5.780)		
19	Rate Base Growth	42.725	34.274	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	(0.293)		
23	Other Income Taxes Changes	13.428	13.135	
24				
25	**2017 REVENUE SURPLUS**		(32.012)	
26	**2018 REVENUE SURPLUS**		3.824	
27				
28	Revenue Deficiency (Surplus)		$ -	Schedule 16, Line 11, Column 4
29				
30	Margin @ Existing Rates		822.033	Schedule 16, Line 15, Column 3
31	Rate Change		0.00%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 5,666,380	$ 6,291,604	$ 625,224	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	7,460	27,640	20,180	Schedule 6.2, Line 35, Column 4
3	Net Additions	148,052	318,349	170,297	Schedule 6.2, Line 35, Column 5+6+7
4	Plant in Service, Ending	5,821,892	6,637,593	815,701	
5					
6	Accumulated Depreciation Beginning	$ (1,808,620)	$ (1,931,842)	$ (123,222)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	(133)	-	133	Schedule 7.2, Line 35, Column 6
8	Net Additions	(122,609)	(134,075)	(11,466)	Schedule 7.2, Line 35, Column 7+8
9	Accumulated Depreciation Ending	(1,931,362)	(2,065,917)	(134,555)	
10					
11	CIAC, Beginning	$ (424,231)	$ (427,702)	$ (3,471)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	(270)	(1,167)	(897)	
13	Net Additions	(2,662)	(5,665)	(3,003)	Schedule 9, Line 6, Column 5+6
14	CIAC, Ending	(427,163)	(434,534)	(7,371)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 147,462	$ 153,822	$ 6,360	Schedule 9, Line 13, Column 2
17	Net Additions	6,071	8,828	2,757	Schedule 9, Line 13, Column 5+6
18	Accumulated Amortization Ending - CIAC	153,533	162,650	9,117	
19					
20	Net Plant in Service, Mid-Year	$ 3,602,474	$ 4,206,074	$ 603,600	
21					
22	Adjustment for timing of Capital additions	$ -	$ 84,874	$ 84,874	
23	Capital Work in Progress, No AFUDC	30,435	34,392	3,957	
24	Unamortized Deferred Charges	23,395	(16,002)	(39,397)	Schedule 11.1, Line 24, Column 10
25	Working Capital	48,842	52,205	3,363	Schedule 13, Line 14, Column 3
26	Deferred Income Taxes Regulatory Asset	407,048	435,216	28,168	Schedule 15, Line 6, Column 3
27	Deferred Income Taxes Regulatory Liability	(407,048)	(435,216)	(28,168)	Schedule 15, Line 6, Column 3
28	LILO Benefit	(485)	(328)	157	
29					
30	Mid-Year Utility Rate Base	$ 3,704,661	$ 4,361,215	$ 656,554	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Reference	2014	2015	2016	2017	2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		0.473%	0.879%	0.980%	1.627%	1.979%	
3	AWE		2.277%	1.646%	2.050%	1.250%	1.433%	
4	Labour Split							
5	Non Labour		45.000%	45.000%	45.000%	45.000%	45.000%	
6	Labour		55.000%	55.000%	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%	1.420%	1.679%	
8	Productivity Factor		-1.100%	-1.100%	-1.100%	-1.100%	-1.100%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.360%	0.201%	0.469%	0.320%	0.579%	
10								
11	Customer Growth Factor		0.260%	0.614%	0.567%	0.675%	0.715%	
12	Inflation Factor for Base Capital	(1 + Line 9) x (1 + Line 11)	100.621%	100.816%	101.039%	100.997%	101.298%	
13								
14	Service Line Additions Factor		-0.688%	-5.615%	16.249%	0.324%	11.302%	
15	Inflation Factor for Growth Capital	(1 + Line 9) x (1 + Line 14)	99.669%	94.575%	116.794%	100.645%	111.946%	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

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			
17	Less: Fort Nelson Intangible Plant	-	(66)			
18	Total	33,262	111,987			
19	**2017**					
20	Net Inflation Factor	100.645%	100.997%			Schedule 3, Line 12 & 15, Column 6
21	Formula Capex	$ 33,477	$ 113,104			
22	**2018**					
23	Net Inflation Factor	111.946%	101.298%			Schedule 3, Line 12 & 15, Column 7
24	Formula Capex	$ 37,476	$ 114,572		$ 152,048	
25						
26	**Capital Tracked Outside of Formula**					
27	Pension & OPEB (Capital Portion)			$ 3,128		
28	Biomethane Interconnect			840		
29	NGT Assets			7,690		
30	Total			$ 11,658	11,658	
31						
32	**Total Capital Expenditures Net of CIAC**				$ 163,706	
33						
34	Contributions in Aid of Construction				5,665	
35	System Extension Fund				1,000	
36						
37	**Total Additions to Plant**				$ 170,371	
38						
39	Notes					
40	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
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars		2018 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2				
3	Growth Capital Expenditures	$	37,476	Schedule 4, Line 24, Column 2
4	Sustainment Capital Expenditures		114,572	Schedule 4, Line 24, Column 3
5	Forecast Capital Expenditures		11,658	Schedule 4, Line 30, Column 4
6	CIAC (Net of System Extension Fund)		6,665	Schedule 4, Lines 34 + 35, Column 5
7	Total Capital Expenditures	$	170,371	
8				
9	**Special Projects and CPCN's**			
10				
11	LMIPSU	$	164,618	
12	CTS		1,261	
13	Tilbury Expansion		25,000	
14	Total Capital Expenditures	$	190,879	
15				
16	**Total Capital Expenditures**	$	361,250	
17				
18				
19	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
20				
21	Regular Capital Expenditures	$	170,371	Line 7
22	Add - Capitalized Overheads		32,954	Schedule 20, Line 38, Column 4
23	Add - AFUDC		2,399	
24	Gross Capital Expenditures		205,724	
25	Change in Work in Progress		-	
26	**Total Regular Additions to Plant**	$	205,724	
27				
28	Special Projects and CPCN's Capital Expenditures	$	190,879	Line 14
29	Add - AFUDC		10,561	
30	Gross Capital Expenditures		201,440	
31	Change in Work in Progress		(31,693)	
32	**Total Special Projects and CPCN Additions to Plant**	$	169,747	
33				
34	**Grand Total Additions to Plant**	$	375,471	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	12/31/2017	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	175-00	Unamortized Conversion Expense - Squamish	777	-	-	-	-	777	
4	178-00	Organization Expense	728	-	-	-	-	728	
5	401-01	Franchise and Consents	297	-	-	-	-	297	
6	402-11	Utility Plant Acquisition Adjustment	62	-	-	-	-	62	
7	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
8	440-02	Water/Land Rights Tilbury	4,296	-	-	-	-	4,296	
9	461-01	Transmission Land Rights	54,515	84	832	502	-	55,933	
10	461-02	Transmission Land Rights - Mt. Hayes	610	-	-	-	-	610	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	87	-	-	-	-	87	
13	471-01	Distribution Land Rights	3,079	-	-	-	-	3,079	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	109,937	1,232	-	7,268	(7,157)	111,280	
16	402-02	Application Software - 20%	28,541	1,087	-	6,263	(3,098)	32,793	
17			$ 204,962	$ 2,403	$ 832	$ 14,033	$ (10,255)	$ 211,975	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	998	-	-	-	-	998	
22	433-00	Manufact'd Gas - Equipment	1,818	45	-	356	-	2,219	
23	434-00	Manufact'd Gas - Gas Holders	2,940	-	-	-	-	2,940	
24	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	-	-	-	-	875	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	100,704	-	-	-	-	100,704	
28	443-00	Gas Holders - Storage (Tilbury)	84,888	-	-	-	-	84,888	
29	448-11	Piping (Tilbury)	59,270	-	-	-	-	59,270	
30	448-21	Pre-treatment (Tilbury)	45,593	-	-	-	-	45,593	
31	448-31	Liquefaction Equipment (Tilbury)	123,100	-	-	-	-	123,100	
32	449-00	Local Storage Equipment (Tilbury)	34,874	328	-	2,537	(21)	37,718	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	17,310	-	-	-	-	17,310	
35	443-05	Gas Holders - Storage (Mount Hayes)	60,112	-	-	-	-	60,112	
36	448-41	Send out Equipment(Tilbury)	4,559	-	-	-	-	4,559	
37	448-51	Sub-station and Electric (Tilbury)	41,033	-	-	-	-	41,033	
38	448-61	Control Room (Tilbury)	13,678	-	-	-	-	13,678	
39	448-10	Piping (Mount Hayes)	11,488	-	-	-	-	11,488	
40	448-20	Pre-treatment (Mount Hayes)	28,714	-	-	-	-	28,714	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,714	-	-	-	-	28,714	
42	448-40	Send out Equipment (Mount Hayes)	22,960	-	-	-	-	22,960	
43	448-50	Sub-station and Electric (Mount Hayes)	21,644	-	-	-	-	21,644	
44	448-60	Control Room (Mount Hayes)	5,900	-	-	-	-	5,900	
45	449-01	Local Storage Equipment (Mount Hayes)	6,363	-	-	-	-	6,363	
46			$ 734,180	$ 373	$ -	$ 2,893	$ (21)	$ 737,425	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	12/31/2017	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,627	$ -	$ -	$ -	$ -	$ 10,627	
3	461-00	Transmission Land Rights	1	-	-	-	-	1	
4	462-00	Compressor Structures	29,484	-	-	-	-	29,484	
5	463-00	Measuring Structures	14,018	-	-	-	-	14,018	
6	464-00	Other Structures & Improvements	6,485	-	-	-	-	6,485	
7	465-00	Mains	1,196,622	1,954	166,776	15,202	(1,364)	1,379,190	
8	465-20	Mains - INSPECTION	19,557	339	-	2,679	(790)	21,785	
9	465-11	IP Transmission Pipeline - Whistler	42,288	-	-	-	-	42,288	
10	465-30	Mt Hayes - Mains	6,299	-	-	-	-	6,299	
11	465-10	Mains - Byron Creek	974	-	-	-	-	974	
12	466-00	Compressor Equipment	183,375	372	-	2,943	(733)	185,957	
13	466-10	Compressor Equipment - OVERHAUL	3,856	-	-	-	(180)	3,676	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,342	-	-	-	-	5,342	
15	467-10	Measuring & Regulating Equipment	59,318	-	-	-	-	59,318	
16	467-20	Telemetering	14,580	47	-	353	(7)	14,973	
17	467-31	IP Intermediate Pressure Whistler	313	-	-	-	-	313	
18	467-30	Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	39	
19	468-00	Communication Structures & Equipment	3,795	-	-	-	-	3,795	
20			$ 1,596,973	$ 2,712	$ 166,776	$ 21,177	$ (3,074)	$ 1,784,564	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 4,207	$ -	$ -	$ -	$ -	$ 4,207	
24	472-00	Structures & Improvements	21,577	-	-	-	-	21,577	
25	472-10	Structures & Improvements - Byron Creek	107	-	-	-	-	107	
26	473-00	Services	1,148,921	6,077	-	48,826	(4,025)	1,199,799	
27	474-00	House Regulators & Meter Installations	188,227	-	-	-	(14,006)	174,221	
28	474-02	Meters/Regulators Installations	155,047	3,651	-	27,532	-	186,230	
29	475-00	Mains	1,395,701	4,017	-	31,222	(1,864)	1,429,076	
30	476-00	Compressor Equipment	1,110	-	-	-	-	1,110	
31	477-10	Measuring & Regulating Equipment	140,183	1,225	-	9,683	(556)	150,535	
32	477-20	Telemetering	12,560	137	-	1,071	(62)	13,706	
33	477-30	Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	163	
34	478-10	Meters	251,650	2,460	-	14,195	(6,888)	261,417	
35	478-20	Instruments	11,944	-	-	-	-	11,944	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 3,331,397	$ 17,567	$ -	$ 132,529	$ (27,401)	$ 3,454,092	
38									
39		**BIO GAS**							
40	472-00	Bio Gas Struct. & Improvements	$ 745	$ -	$ -	$ 87	$ -	$ 832	
41	475-10	Bio Gas Mains – Municipal Land	1,684	-	-	289	-	1,973	
42	475-20	Bio Gas Mains – Private Land	55	-	-	-	-	55	
43	418-10	Bio Gas Purification Overhaul	20	-	-	-	-	20	
44	418-20	Bio Gas Purification Upgrader	9,109	-	-	-	-	9,109	
45	477-40	Bio Gas Reg & Meter Equipment	2,802	-	-	474	-	3,276	
46	478-30	Bio Gas Meters	45	-	-	7	-	52	
47	474-10	Bio Gas Reg & Meter Installations	226	-	-	-	-	226	
48	483-25	RNG Comp S/W	138	-	-	-	-	138	
49			$ 14,824	$ -	$ -	$ 857	$ -	$ 15,681	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	12/31/2017	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 12,310	$ -	$ -	$ 6,110	$ -	$ 18,420	
3	476-20	NG Transportation LNG Dispensing Equipment	12,578	-	-	1,730	-	14,308	
4	476-30	NG Transportation CNG Foundations	1,950	-	-	-	-	1,950	
5	476-40	NG Transportation LNG Foundations	1,313	-	-	-	-	1,313	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,497	-	-	-	-	1,497	
7	476-60	NG Transportation CNG Dehydrator	473	-	-	-	-	473	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 30,121	$ -	$ -	$ 7,840	$ -	$ 37,961	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 30,877	$ 68	$ 1,952	$ 392	$ -	$ 33,289	
13	482-10	Frame Buildings	16,822	-	187	-	-	17,009	
14	482-20	Masonry Buildings	130,778	1,060	-	6,082	(155)	137,765	
15	482-30	Leasehold Improvement	4,961	35	-	201	(35)	5,162	
16	483-30	GP Office Equipment	5,068	102	-	587	(425)	5,332	
17	483-40	GP Furniture	22,812	344	-	1,967	(898)	24,225	
18	483-10	GP Computer Hardware	49,256	1,675	-	9,682	(10,749)	49,864	
19	483-20	GP Computer Software	3,787	-	-	-	-	3,787	
20	484-00	Vehicles	17,492	476	-	2,726	-	20,694	
21	484-10	Vehicles - Leased	24,713	-	-	-	(1,458)	23,255	
22	485-10	Heavy Work Equipment	858	-	-	-	-	858	
23	485-20	Heavy Mobile Equipment	5,857	-	-	-	-	5,857	
24	486-00	Small Tools & Equipment	51,736	608	-	3,482	(1,529)	54,297	
25	487-20	Equipment on Customer's Premises	12	-	-	-	-	12	
26	488-10	Telephone	3,356	-	-	-	(451)	2,905	
27	488-20	Radio	10,762	217	-	1,276	(671)	11,584	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 379,147	$ 4,585	$ 2,139	$ 26,395	$ (16,371)	$ 395,895	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 6,291,604	$ 27,640	$ 169,747	$ 205,724	$ (57,122)	$ 6,637,593	
36									
37		Cross Reference			Schedule 5, Line 32, Column 2	Schedule 5, Line 26, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2017	1/1/2018 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 60	$ -	$ 1	$ -	$ -	$ -	$ 61	
3	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	778	-	-	-	-	-	778	
4	178-00	Organization Expense	728	1.00%	428	-	7	-	-	-	435	
5	401-01	Franchise and Consents	297	5.39%	205	-	11	-	-	-	216	
6	402-11	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	-	62	
7	402-03	Other Intangible Plant	1,907	2.01%	1,069	-	38	-	-	-	1,107	
8	440-02	Water/Land Rights Tilbury	4,296	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	55,431	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	610	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	87	0.00%	10	-	-	-	-	-	10	
13	471-01	Distribution Land Rights	3,079	0.00%	238	-	-	-	-	-	238	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	111,169	12.50%	65,816	-	13,896	(7,157)	-	-	72,555	
16	402-02	Application Software - 20%	29,628	20.00%	11,801	-	5,925	(3,098)	-	-	14,628	
17			$ 208,197		$ 82,253	$ -	$ 19,878	$ (10,255)	$ -	$ -	$ 91,876	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	998	2.82%	315	-	28	-	-	-	343	
22	433-00	Manufact'd Gas - Equipment	1,863	4.66%	338	-	85	-	-	-	423	
23	434-00	Manufact'd Gas - Gas Holders	2,940	2.45%	584	-	72	-	-	-	656	
24	436-00	Manufact'd Gas - Compressor Equipment	367	3.68%	126	-	13	-	-	-	139	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	2.34%	927	-	20	-	-	-	947	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	100,704	3.03%	3,647	-	3,051	-	-	-	6,698	
28	443-00	Gas Holders - Storage (Tilbury)	84,888	1.88%	12,305	-	1,597	-	-	-	13,902	
29	448-11	Piping (Tilbury)	59,270	2.46%	-	-	1,458	-	-	-	1,458	
30	448-21	Pre-treatment (Tilbury)	45,593	3.88%	-	-	1,769	-	-	-	1,769	
31	448-31	Liquefaction Equipment (Tilbury)	123,100	2.46%	-	-	3,028	-	-	-	3,028	
32	449-00	Local Storage Equipment (Tilbury)	35,202	3.83%	16,643	-	1,336	(21)	-	-	17,958	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	17,310	3.88%	4,531	-	672	-	-	-	5,203	
35	443-05	Gas Holders - Storage (Mount Hayes)	60,112	1.65%	6,595	-	992	-	-	-	7,587	
36	448-41	Send out Equipment(Tilbury)	4,559	2.44%	-	-	111	-	-	-	111	
37	448-51	Sub-station and Electric (Tilbury)	41,033	2.44%	-	-	1,001	-	-	-	1,001	
38	448-61	Control Room (Tilbury)	13,678	6.30%	-	-	862	-	-	-	862	
39	448-10	Piping (Mount Hayes)	11,488	2.46%	1,886	-	283	-	-	-	2,169	
40	448-20	Pre-treatment (Mount Hayes)	28,714	3.88%	7,525	-	1,114	-	-	-	8,639	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,714	2.46%	4,713	-	706	-	-	-	5,419	
42	448-40	Send out Equipment (Mount Hayes)	22,960	2.44%	3,764	-	560	-	-	-	4,324	
43	448-50	Sub-station and Electric (Mount Hayes)	21,644	2.44%	3,548	-	528	-	-	-	4,076	
44	448-60	Control Room (Mount Hayes)	5,900	6.30%	2,570	-	371	-	-	-	2,941	
45	449-01	Local Storage Equipment (Mount Hayes)	6,363	2.86%	381	-	182	-	-	-	563	
46			$ 734,553		$ 70,399	$ -	$ 19,839	$ (21)	$ -	$ -	$ 90,217	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2017	1/1/2018 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,627	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	1	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	29,484	3.51%	16,646	-	1,035	-	-	-	17,681	
5	463-00	Measuring Structures	14,018	2.29%	7,092	-	321	-	-	-	7,413	
6	464-00	Other Structures & Improvements	6,485	3.66%	2,883	-	237	-	-	-	3,120	
7	465-00	Mains	1,365,352	1.47%	393,611	-	20,042	(1,364)	-	-	412,289	
8	465-20	Mains - INSPECTION	19,896	15.20%	9,738	-	2,972	(790)	-	-	11,920	
9	465-11	IP Transmission Pipeline - Whistler	42,288	1.53%	5,134	-	647	-	-	-	5,781	
10	465-30	Mt Hayes - Mains	6,299	1.51%	693	-	95	-	-	-	788	
11	465-10	Mains - Byron Creek	974	5.03%	1,231	-	49	-	-	-	1,280	
12	466-00	Compressor Equipment	183,747	2.89%	87,230	-	5,300	(733)	-	-	91,797	
13	466-10	Compressor Equipment - OVERHAUL	3,856	10.19%	3,056	-	393	(180)	-	-	3,269	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,342	2.58%	1,314	-	138	-	-	-	1,452	
15	467-10	Measuring & Regulating Equipment	59,318	2.41%	25,037	-	1,430	-	-	-	26,467	
16	467-20	Telemetering	14,627	9.75%	8,013	-	1,422	(7)	-	-	9,428	
17	467-31	IP Intermediate Pressure Whistler	313	2.55%	97	-	8	-	-	-	105	
18	467-30	Measuring & Regulating Equipment - Byron Creek	39	2.41%	11	-	1	-	-	-	12	
19	468-00	Communication Structures & Equipment	3,795	0.56%	4,381	-	21	-	-	-	4,402	
20			$ 1,766,461		$ 566,670	$ -	$ 34,111	$ (3,074)	$ -	$ -	$ 597,707	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 4,207	0.00%	$ (9)	$ -	$ -	$ -	$ -	$ -	$ (9)	
24	472-00	Structures & Improvements	21,577	2.41%	9,206	-	520	-	-	-	9,726	
25	472-10	Structures & Improvements - Byron Creek	107	4.67%	58	-	5	-	-	-	63	
26	473-00	Services	1,154,998	2.45%	290,023	-	28,148	(4,025)	-	-	314,146	
27	474-00	House Regulators & Meter Installations	188,227	5.99%	82,326	-	11,275	(14,006)	-	-	79,595	
28	474-02	Meters/Regulators Installations	158,698	4.55%	17,295	-	7,056	-	-	-	24,351	
29	475-00	Mains	1,399,718	1.54%	474,498	-	21,493	(1,864)	-	-	494,127	
30	476-00	Compressor Equipment	1,110	0.00%	687	-	-	-	-	-	687	
31	477-10	Measuring & Regulating Equipment	141,408	3.05%	51,720	-	4,276	(556)	-	-	55,440	
32	477-20	Telemetering	12,697	2.82%	6,335	-	354	(62)	-	-	6,627	
33	477-30	Measuring & Regulating Equipment - Byron Creek	163	0.00%	216	-	-	-	-	-	216	
34	478-10	Meters	254,110	7.09%	134,996	-	17,842	(6,888)	-	-	145,950	
35	478-20	Instruments	11,944	2.99%	3,160	-	357	-	-	-	3,517	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 3,348,964		$ 1,070,511	$ -	$ 91,326	$ (27,401)	$ -	$ -	$ 1,134,436	
38												
39		**BIO GAS**										
40	472-00	Bio Gas Struct. & Improvements	$ 745	2.72%	$ 72	$ -	$ 19	$ -	$ -	$ -	$ 91	
41	475-10	Bio Gas Mains – Municipal Land	1,684	1.55%	69	-	25	-	-	-	94	
42	475-20	Bio Gas Mains – Private Land	55	1.55%	6	-	1	-	-	-	7	
43	418-10	Bio Gas Purification Overhaul	20	5.00%	4	-	1	-	-	-	5	
44	418-20	Bio Gas Purification Upgrader	9,109	4.89%	1,381	-	445	-	-	-	1,826	
45	477-40	Bio Gas Reg & Meter Equipment	2,802	3.24%	289	-	91	-	-	-	380	
46	478-30	Bio Gas Meters	45	5.02%	9	-	2	-	-	-	11	
47	474-10	Bio Gas Reg & Meter Installations	226	5.24%	29	-	12	-	-	-	41	
48	483-25	RNG Comp S/W	138	20.00%	28	-	28	-	-	-	56	
49			$ 14,824		$ 1,887	$ -	$ 624	$ -	$ -	$ -	$ 2,511	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2017	1/1/2018 Opening Adjt	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Natural Gas for Transportation**										
2	476-10	NG Transportation CNG Dispensing Equipment	12,310	5.00%	$ 1,835	-	615	-	-	-	$ 2,450	
3	476-20	NG Transportation LNG Dispensing Equipment	12,578	5.00%	1,661	-	629	-	-	-	2,290	
4	476-30	NG Transportation CNG Foundations	1,950	5.00%	280	-	99	-	-	-	379	
5	476-40	NG Transportation LNG Foundations	1,313	5.00%	231	-	66	-	-	-	297	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to L	1,497	10.00%	319	-	150	-	-	-	469	
7	476-60	NG Transportation CNG Dehydrator	473	5.00%	77	-	24	-	-	-	101	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 30,121		$ 4,403	$ -	$ 1,583	$ -	$ -	$ -	$ 5,986	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 32,897	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	17,009	6.04%	8,765	-	1,016	-	-	-	9,781	
14	482-20	Masonry Buildings	131,838	1.95%	27,931	-	2,571	(155)	-	-	30,347	
15	482-30	Leasehold Improvement	4,996	9.49%	2,467	-	474	(35)	-	-	2,906	
16	483-30	GP Office Equipment	5,170	6.67%	3,720	-	345	(425)	-	-	3,640	
17	483-40	GP Furniture	23,156	5.00%	7,945	-	1,158	(898)	-	-	8,205	
18	483-10	GP Computer Hardware	50,931	20.00%	22,273	-	10,186	(10,749)	-	-	21,710	
19	483-20	GP Computer Software	3,787	12.50%	2,707	-	473	-	-	-	3,180	
20	484-00	Vehicles	17,968	10.55%	8,283	-	1,896	-	-	-	10,179	
21	484-10	Vehicles - Leased	24,713	9.44%	21,440	-	1,511	(1,458)	-	-	21,493	
22	485-10	Heavy Work Equipment	858	6.38%	563	-	55	-	-	-	618	
23	485-20	Heavy Mobile Equipment	5,857	9.85%	3,042	-	577	-	-	-	3,619	
24	486-00	Small Tools & Equipment	52,344	5.00%	21,508	-	2,617	(1,529)	-	-	22,596	
25	487-20	Equipment on Customer's Premises	12	6.67%	9	-	1	-	-	-	10	
26	488-10	Telephone	3,356	6.67%	2,012	-	224	(451)	-	-	1,785	
27	488-20	Radio	10,979	6.67%	3,037	-	732	(671)	-	-	3,098	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 385,871		$ 135,719	$ -	$ 23,836	$ (16,371)	$ -	$ -	$ 143,184	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 6,488,991		$ 1,931,842	$ -	$ 191,197	$ (57,122)	$ -	$ -	$ 2,065,917	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(471)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(1,260)					
38		**Net Depreciation Expense**					$ 189,466					
39												
40		Cross Reference	Schedule 6.2, Line 35, Column 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars			12/31/2017	1/1/2018 Opening Adjt	CPCN's	Additions	Retirements	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Non-Regulated Plant**									
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	-	176,594	
4									-	
5	**Total**			$ 177,648	$ -	$ -	$ -	$ -	$ 177,648	
6										
7										
8										

9 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
10 **FOR THE YEAR ENDING DECEMBER 31, 2018**
11 **($000s)**
12
13

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2017	1/1/2018 Opening Adjt	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2018	Cross Reference
16	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
17										
18	**Non-Regulated Plant Depreciation**									
19	NRB Depreciation @ 0%	$ 1,054	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	NRB Depreciation @ 2.4%	176,594	2.40%	121,461	-	4,238	-	-	125,699	
21									-	
22	**Total**	$ 177,648		$ 121,461	$ -	$ 4,238	$ -	$ -	$ 125,699	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/2017	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 280,339	$ 1,085	$ -	$ 5,196	$ -	$ 286,620	
3	Transmission Contributions	146,075	82	-	469	-	146,626	
4	Others	722	-	-	-	-	722	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 427,702	$ 1,167	$ -	$ 5,665	$ -	$ 434,534	
7								
8	**Amortization**							
9	Distribution Contributions	$ (102,757)	$ -	$ -	$ (6,529)	$ -	$ (109,286)	
10	Transmission Contributions	(50,188)	-	-	(2,163)	-	(52,351)	
11	Others	(716)	-	-	(108)	-	(824)	
12	Biomethane	(161)	-	-	(28)	-	(189)	
13	**Total**	$ (153,822)	$ -	$ -	$ (8,828)	$ -	$ (162,650)	
14								
15	**Net CIAC**	$ 273,880	$ 1,167	$ -	$ (3,163)	$ -	$ 271,884	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (8,828)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,800)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2017	Net Salv Provision	Retirement Costs / 12/31/2018	12/31/2018	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**MANUFACTURED GAS / LOCAL STORAGE**							
2	442-00	Structures & Improvements (Tilbury)	$ 100,704	0.36%	$ 107	$ 363	$ -	$ 470	
3	443-00	Gas Holders - Storage (Tilbury)	84,888	0.45%	404	382	-	786	
4	448-11	Piping (Tilbury)	59,270	0.27%	-	160	-	160	
5	448-21	Pre-treatment (Tilbury)	45,593	0.46%	-	210	-	210	
6	448-31	Liquefaction Equipment (Tilbury)	123,100	0.54%	-	665	-	665	
7	449-00	Local Storage Equipment (Tilbury)	35,202	0.39%	610	136	-	746	
8	442-01	Structures & Improvements (Mount Hayes)	17,310	0.45%	78	78	-	156	
9	443-05	Gas Holders - Storage (Mount Hayes)	60,112	0.35%	210	210	-	420	
10	448-41	Send out Equipment(Tilbury)	4,559	0.27%	-	12	-	12	
11	448-51	Sub-station and Electric (Tilbury)	41,033	0.54%	-	222	-	222	
12	448-10	Piping (Mount Hayes)	11,488	0.27%	31	31	-	62	
13	448-20	Pre-treatment (Mount Hayes)	28,714	0.46%	132	132	-	264	
14	448-30	Liquefaction Equipment (Mount Hayes)	28,714	0.54%	155	155	-	310	
15	448-40	Send out Equipment (Mount Hayes)	22,960	0.27%	62	62	-	124	
16	448-50	Sub-station and Electric (Mount Hayes)	21,644	0.54%	117	117	-	234	
17	449-01	Local Storage Equipment (Mount Hayes)	6,363	0.28%	18	18	-	36	
18			$ 691,654		$ 1,924	$ 2,953	$ -	$ 4,877	
19									
20		**TRANSMISSION PLANT**							
21	462-00	Compressor Structures	$ 29,484	-0.02%	$ 460	$ (6)	$ -	$ 454	
22	463-00	Measuring Structures	14,018	0.57%	221	80	-	301	
23	464-00	Other Structures & Improvements	6,485	0.22%	44	14	-	58	
24	465-00	Mains	1,365,352	0.37%	13,680	5,045	-	18,725	
25	465-11	IP Transmission Pipeline - Whistler	42,288	0.34%	144	144	-	288	
26	465-30	Mt Hayes - Mains	6,299	0.32%	20	20	-	40	
27	466-00	Compressor Equipment	183,747	-0.12%	2,698	(221)	-	2,477	
28	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,342	0.21%	196	11	-	207	
29	467-10	Measuring & Regulating Equipment	59,318	0.22%	333	131	-	464	
30	467-31	IP Intermediate Pressure Whistler	313	0.22%	1	1	-	2	
31	468-00	Communication Structures & Equipment	3,795	-0.38%	430	(15)	-	415	
32			$ 1,716,441		$ 18,227	$ 5,204	$ -	$ 23,431	
33									
34		**DISTRIBUTION PLANT**							
35	472-00	Structures & Improvements	$ 21,577	0.32%	$ 256	$ 69	$ -	$ 325	
36	473-00	Services	1,154,998	1.61%	17,656	18,497	(9,823)	26,330	
37	474-00	House Regulators & Meter Installations	188,227	1.77%	(5,193)	3,331	(3,565)	(5,427)	
38	474-02	Meters/Regulators Installations	158,698	0.00%	1,594	-	-	1,594	
39	475-00	Mains	1,399,718	0.43%	24,434	6,002	(549)	29,887	
40	476-00	Compressor Equipment	1,110	0.00%	711	-	-	711	
41	477-10	Measuring & Regulating Equipment	141,408	0.46%	3,030	645	-	3,675	
42	477-20	Telemetering	12,697	0.42%	36	53	-	89	
43	478-10	Meters	254,110	-0.26%	3,808	(654)	-	3,154	
44			$ 3,332,543		$ 46,332	$ 27,943	$ (13,937)	$ 60,338	
45									
46		**BIO GAS**							
47	472-00	Bio Gas Struct. & Improvements	$ 745	0.29%	$ 2	$ 2	$ -	$ 4	
48	475-10	Bio Gas Mains – Municipal Land	1,684	0.39%	17	7	-	24	
49	475-20	Bio Gas Mains – Private Land	55	0.39%	1	-	-	1	
50	418-20	Bio Gas Purification Upgrader	9,109	0.26%	23	24	-	47	
51	478-30	Bio Gas Meters	45	-0.21%	-	-	-	-	
52	474-10	Bio Gas Reg & Meter Installations	226	1.35%	3	3	-	6	
53			$ 11,864		$ 46	$ 36	$ -	$ 82	
54									
55									
56		**Natural Gas for Transportation**							
57	476-10	NG Transportation CNG Dispensing Equipment	$ 12,310	0.00%	$ (1)	$ -	$ -	$ (1)	
58			$ 12,310		$ (1)	$ -	$ -	$ (1)	
59									
60		**GENERAL PLANT & EQUIPMENT**							
61	482-10	Frame Buildings	$ 17,009	0.00%	$ (12)	$ -	$ -	$ (12)	
62	482-20	Masonry Buildings	131,838	0.25%	311	330	-	641	
63	484-00	Vehicles	17,968	-1.00%	(148)	(180)	-	(328)	
64	485-10	Heavy Work Equipment	858	-0.68%	(6)	(6)	-	(12)	
65	485-20	Heavy Mobile Equipment	5,857	-2.89%	(169)	(169)	-	(338)	
66			$ 173,530		$ (24)	$ (25)	$ -	$ (49)	
67									
68		**Total**	$ 5,938,342		$ 66,504	$ 36,111	$ (13,937)	$ 88,678	
69		Less: Depreciation & Amortization Transferred to Biomethane BVA				(24)			
70		**Net Salvage Depreciation Expense**				$ 36,087			
71		Cross Reference	Schedule 6-6.2, Column 3+4+5						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/2017	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2018	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (11,644)	$ -	$ -	$ -	$ -	$ 7,867	$ (2,045)	$ (5,822)	$ (8,733)	
3	Commodity Cost Reconciliation Account (CCRA)	(15,507)	-	20,956	(5,449)	-	-	-	-	(7,754)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(8,476)	-	-	-	-	5,727	(1,489)	(4,238)	(6,357)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,995)	-	2,378	(618)	149	33	(8)	(3,061)	(4,028)	
6	Revelstoke Propane Cost Deferral Account	(51)	-	69	(18)	-	-	-	-	(26)	
7	SCP Mitigation Revenues Variance Account	330	-	-	-	(132)	-	-	198	264	
8	Pension & OPEB Variance	(3,289)	-	-	-	1,433	-	-	(1,856)	(2,573)	
9	BCUC Levies Variance	(739)	-	-	-	739	-	-	-	(370)	
10	Customer Service Variance Account	(3,458)	-	-	-	3,458	-	-	-	(1,729)	
11	TESDA Overhead Allocation Variance	612	-	-	-	(612)	-	-	-	306	
12		$ (47,217)	$ -	$ 23,403	$ (6,085)	$ 5,035	$ 13,627	$ (3,542)	$ (14,779)	$ (31,000)	
13	**2. Rate Smoothing Accounts**										
14											
15	**3. Benefits Matching Accounts**										
16	Energy Efficiency & Conservation (EEC)	$ 88,558	$ 12,822	$ 15,000	$ (3,900)	$ (11,599)	$ -	$ -	$ 100,881	$ 101,131	
17	NGV Conversion Grants	53	-	13	(3)	(14)	-	-	49	51	
18	Emissions Regulations	(1,442)	-	-	-	360	-	-	(1,082)	(1,262)	
19	On-Bill Financing Pilot Program	8	-	(1)	-	-	-	-	7	8	
20	Greenhouse Gas Reduction Regulation Incentives	26,615	-	12,275	(3,192)	(3,378)	-	-	32,320	29,468	
21	CNG and LNG Recoveries	(105)	-	-	-	105	-	-	-	(53)	
22	2014-2019 PBR	489	-	-	-	(244)	-	-	245	367	
23	AES Inquiry Cost	47	-	-	-	(47)	-	-	-	24	
24	2016 Cost of Capital Application	1,256	-	-	-	(419)	-	-	837	1,047	
25	2015-2019 Annual Review Costs	89	-	100	(26)	(89)	-	-	74	82	
26	2017 Rate Design Application	1,192	-	400	(104)	-	-	-	1,488	1,340	
27	2017 Long Term Resource Plan Application	443	-	432	(112)	-	-	-	763	603	
28	LMIPSU Application Costs	119	-	-	-	(119)	-	-	-	60	
29	2015 System Extension Application	(2)	-	-	-	2	-	-	-	(1)	
30	BERC Rate Methodology Application	19	-	-	-	(19)	-	-	-	10	
31	All-Inclusive Code of Conduct/Transfer Pricing Policy Application	(65)	-	-	-	65	-	-	-	(33)	
32		$ 117,274	$ 12,822	$ 28,219	$ (7,337)	$ (15,396)	$ -	$ -	$ 135,582	$ 132,842	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/2017	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2018	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 8,668	$ -	$ -	$ -	$ (739)	$ -	$ -	$ 7,929	$ 8,299	
3	2010-2011 Customer Service O&M and COS	8,057	-	-	-	(3,251)	-	-	4,806	6,432	
4	Gas Asset Records Project	2,018	-	762	(198)	(302)	-	-	2,280	2,149	
5	BC OneCall Project	514	-	88	(23)	(74)	-	-	505	510	
6	Gains and Losses on Asset Disposition	24,429	-	-	-	(3,985)	-	-	20,444	22,437	
7	Net Salvage Provision/Cost	(65,334)	-	13,937	-	(36,111)	-	-	(87,508)	(76,421)	
8	PCEC Start Up Costs	788	-	-	-	(44)	-	-	744	766	
9	Huntingdon CPCN Pre-Feasibility Costs	122	-	-	-	(122)	-	-	-	61	
10	LMIPSU Development Costs	781	-	-	-	(781)	-	-	-	391	
11	2020 Revenue Requirement Proceeding	22	-	70	(18)	-	-	-	74	48	
12	City of Surrey Operating Terms Application Costs	148	-	40	(10)	(50)	-	-	128	138	
13		$ (19,787)	$ -	$ 14,897	$ (249)	$ (45,459)	$ -	$ -	$ (50,598)	$ (35,190)	
14	**4. Retroactive Expense Accounts**										
15											
16	**5.Other Accounts**										
17	Pension & OPEB Funding	$ (181,874)	$ -	$ -	$ -	$ -	$ -	$ -	$ (181,874)	$ (181,874)	
18	US GAAP Pension & OPEB Funded Status	97,373	-	-	-	-	-	-	97,373	97,373	
19	BFI Costs and Recoveries	(442)	-	-	-	-	-	-	(442)	(442)	
20	Residual Delivery Rate Riders	-	748	-	-	(748)	-	-	-	374	
21	BVA Balance Transfer	3,830	-	-	-	-	(5,176)	1,346	-	1,915	
22		$ (81,113)	$ 748	$ -	$ -	$ (748)	$ (5,176)	$ 1,346	$ (84,943)	$ (82,654)	
23											
24	**Total**	$ (30,843)	$ 13,570	$ 66,519	$ (13,671)	$ (56,568)	$ 8,451	$ (2,196)	$ (14,738)	$ (16,002)	
25	Less: Net Salvage Amortization Transferred to Biomethane BVA					24					
26	**Net Rate Base Deferred Amortization Expense**					$ (56,544)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	12/31/2017	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2018	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ 13	
3	Flow-Through Account	(8,238)	-	(232)	-	8,470	-	-	-	(4,119)	
4	Marketer Cost Variance	17	-	(23)	6	-	-	-	-	9	
5		$ (8,208)	$ -	$ (255)	$ 6	$ 8,470	$ -	$ -	$ 13	$ (4,097)	
6	**2. Rate Smoothing Accounts**										
7	Phase-In-Rider Balancing Account	$ 1,233	$ (1,233)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8	Rate Stabilization Deferral Account (RSDA)	(611)	611	-	-	-	-	-	-	-	
9	2017 & 2018 Revenue Surplus	(20,637)	-	(5,134)	994	-	-	-	(24,777)	(22,707)	
10		$ (20,015)	$ (622)	$ (5,134)	$ 994	$ -	$ -	$ -	$ (24,777)	$ (22,707)	
11	**3. Benefits Matching Accounts**										
12	EEC-Incentives	$ 12,822	$ (12,822)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	Amalgamation Regulatory Account	126	(126)	-	-	-	-	-	-	-	
14	PEC Pipeline Development Costs and Commitment Fees	6,266	-	-	-	-	-	-	6,266	6,266	
15		$ 19,214	$ (12,948)	$ -	$ -	$ -	$ -	$ -	$ 6,266	$ 6,266	
16	**4. Retroactive Expense Accounts**										
17											
18	**5.Other Accounts**										
19	Mark to Market - Hedging Transactions	$ 13,724	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,724	$ 13,724	
20	2014-2019 Earning Sharing Account	(2,491)	-	(71)	-	2,562	-	-	-	(1,246)	
21		$ 11,233	$ -	$ (71)	$ -	$ 2,562	$ -	$ -	$ 13,724	$ 12,478	
22											
23											
24	**Total Non Rate Base Deferral Accounts**	$ 2,224	$ (13,570)	$ (5,460)	$ 1,000	$ 11,032	$ -	$ -	$ (4,774)	$ (8,060)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 14,290	$ 14,345	$ 55	Schedule 14, Line 29, Column 5
3					
4	Less: Funds Available				
5	Reserve for bad debts	(4,947)	(5,162)	(215)	
6	Employee Withholdings	(5,326)	(5,432)	(106)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	1,537	1,827	290	
10	Gas In Storage	42,032	45,346	3,314	
11	Inventory - Materials and Supplied	1,567	1,598	31	
12	Refundable Contributions	(311)	(317)	(6)	
13					
14	Total	$ 48,842	$ 52,205	$ 3,363	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2018 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	$ 1,130,706	38.3	$ 43,335,909		
4	Industrial Tariff Revenue	84,680	45.1	3,820,536		
5	Bypass and Special Rates	30,922	44.2	1,365,565		
6						
7	**Other Revenue**					
8	Late Payment Charges	2,688	38.3	102,950		
9	Connection Charges	3,148	38.3	120,568		
10	Other Utility Income	40,212	38.3	1,540,120		
11						
12	Total	$ 1,292,356		$ 50,285,648	38.9	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 424,275	(40.2)	$ (17,055,855)		
16	Operating and Maintenance	240,585	(25.5)	(6,134,918)		
17	Property Taxes	67,157	(2.0)	(134,314)		
18	Franchise Fees	8,150	(420.3)	(3,425,392)		
19	Carbon Tax	202,347	(29.1)	(5,888,298)		
20	GST	10,830	(38.8)	(420,204)		
21	PST	4,456	(37.1)	(165,318)		
22	Income Tax	49,079	(15.2)	(746,001)		
23						
24	Total	$ 1,006,879		$ (33,970,300)	(33.7)	
25						
26	Net Lag (Lead) Days				5.2	
27	Total Expenses				$ 1,006,879	
28						
29	Cash Working Capital				$ 14,345	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 APPROVED	2018 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (305,906)	$ (327,194)	$ (21,288)	
2	Tax Gross Up	(107,481)	(114,960)	(7,479)	
3	DIT Liability/Asset - End of Year	$ (413,387)	$ (442,154)	$ (28,767)	
4	DIT Liability/Asset - Opening Balance	(400,709)	(428,277)	(27,568)	
5					
6	DIT Liability/Asset - Mid Year	$ (407,048)	$ (435,216)	$ (28,168)	

Schedule 16

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 FORECAST at Existing Rates	Revised Revenue	at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	125,119	135,822		135,822	10,703	
3	Transportation Volume (TJ)	89,522	92,366		92,366	2,844	
4		214,641	228,188	-	228,188	13,547	Schedule 17, Line 25, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 949,086	$ 1,121,022	$ -	$ 1,121,022	$ 171,936	
8	Deficiency (Surplus)	-	-	-	-	-	
9	Transportation	121,032	125,286	-	125,286	4,254	
10	Deficiency (Surplus)	-	-	-	-	-	
11	Total	1,070,118	1,246,308	-	1,246,308	176,190	Schedule 19, Line 31, Column 8
12				-			
13	**COST OF ENERGY**	295,403	424,275	-	424,275	128,872	Schedule 18, Line 25, Column 3
14							
15	**MARGIN**	774,715	822,033	-	822,033	47,318	
16							
17	**EXPENSES**						
18	O&M Expense (net)	236,050	240,585	-	240,585	4,535	Schedule 20, Line 39, Column 4
19	Depreciation & Amortization	199,526	226,178	-	226,178	26,652	Schedule 21, Line 15, Column 3
20	Property Taxes	67,450	67,157	-	67,157	(293)	Schedule 22, Line 8, Column 3
21	Other Revenue	(42,958)	(46,048)	-	(46,048)	(3,090)	Schedule 23, Line 12, Column 3
22	2017 & 2018 Revenue Surplus	32,012	3,824	-	3,824	(28,188)	Schedule 1, Line 26, Column 3
23	Utility Income Before Income Taxes	282,635	330,337	-	330,337	47,702	
24							
25	Income Taxes	35,651	49,079	-	49,079	13,428	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 246,984	$ 281,258	$ -	$ 281,258	$ 34,274	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 3,704,661	$ 4,361,215		$ 4,361,215	$ 656,554	Schedule 2, Line 30, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.67%	6.45%		6.45%	-0.22%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	74,272.9	81,227.4	6,954.5	
4	Commercial				
5	Rate Schedule 2	28,527.0	30,296.5	1,769.5	
6	Rate Schedule 3	18,680.6	20,091.1	1,410.5	
7	Rate Schedule 23	9,175.6	10,315.4	1,139.8	
8	Industrial				
9	Rate Schedule 4	148.2	146.9	(1.3)	
10	Rate Schedule 5	2,189.0	2,674.6	485.6	
11	Rate Schedule 6	54.2	28.0	(26.2)	
12	Rate Schedule 7	148.8	246.0	97.2	
13	Rate Schedule 22 - Firm Service	11,193.8	11,263.5	69.7	
14	Rate Schedule 22 - Interruptible Service	18,486.9	18,445.3	(41.6)	
15	Rate Schedule 25	13,650.5	14,017.0	366.5	
16	Rate Schedule 27	6,414.5	7,269.1	854.6	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	8,298.0	8,582.0	284.0	
19	Rate Schedule 25	884.8	1,072.9	188.1	
20	Rate Schedule 46	1,098.2	1,111.2	13.0	
21	Byron Creek	247.6	230.8	(16.8)	
22	Burrard Thermal	-	-	-	
23	BC Hydro IG	16,425.0	16,425.0	-	
24	VIGJV	4,745.0	4,745.0	-	
25	Total	214,640.6	228,187.7	13,547.1	
26					
27	**REVENUE AT EXISTING RATES**				
28	Residential				
29	Rate Schedule 1	$ 629,064	$ 739,420	$ 110,356	
30	Commercial				
31	Rate Schedule 2	194,598	228,598	34,000	
32	Rate Schedule 3	104,808	127,547	22,739	
33	Rate Schedule 23	31,404	35,141	3,737	
34	Industrial				
35	Rate Schedule 4	558	678	120	
36	Rate Schedule 5	10,202	14,352	4,150	
37	Rate Schedule 6	331	197	(134)	
38	Rate Schedule 7	525	1,056	531	
39	Rate Schedule 22 - Firm Service	6,834	6,539	(295)	
40	Rate Schedule 22 - Interruptible Service	19,666	19,286	(380)	
41	Rate Schedule 25	31,423	31,484	61	
42	Rate Schedule 27	9,909	11,088	1,179	
43	Bypass and Special Rates				
44	Rate Schedule 22 - Firm Service	1,038	788	(250)	
45	Rate Schedule 25	315	482	167	
46	Rate Schedule 46	9,000	9,174	174	
47	Byron Creek	122	106	(16)	
48	Burrard Thermal	-	-	-	
49	BC Hydro IG	15,735	15,735	-	
50	VIGJV	4,586	4,637	51	
51	Total	$ 1,070,118	$ 1,246,308	$ 176,190	

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 176,278	$ 255,047	$ 78,769	
4	Commercial				
5	Rate Schedule 2	68,277	95,759	27,482	
6	Rate Schedule 3	41,394	60,192	18,798	
7	Rate Schedule 23	136	176	40	
8	Industrial				
9	Rate Schedule 4	270	394	124	
10	Rate Schedule 5	3,988	7,157	3,169	
11	Rate Schedule 6	80	66	(14)	
12	Rate Schedule 7	271	659	388	
13	Rate Schedule 22 - Firm Service	241	279	38	
14	Rate Schedule 22 - Interruptible Service	199	227	28	
15	Rate Schedule 25	191	227	36	
16	Rate Schedule 27	95	124	29	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	123	146	23	
19	Rate Schedule 25	13	18	5	
20	Rate Schedule 46	3,847	3,804	(43)	
21	Byron Creek	-	-	-	
22	Burrard Thermal	-	-	-	
23	BC Hydro IG	-	-	-	
24	VIGJV	-	-	-	
25	Total	$ 295,403	$ 424,275	$ 128,872	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved Margin	2018 FORECAST Margin at Existing Rates	2018 FORECAST Effective Increase	2018 FORECAST Margin at Revised Rates	2018 FORECAST Revenue at Existing Rates	2018 FORECAST Effective Increase	2018 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										
3	Rate Schedule 1	$ 452,786	$ 484,373	$ -	$ 484,373	$ 739,420	$ -	$ 739,420	911,429	81,227.4	
4	Commercial										
5	Rate Schedule 2	126,321	132,839	-	132,839	228,598	-	228,598	87,636	30,296.5	
6	Rate Schedule 3	63,414	67,355	-	67,355	127,547	-	127,547	5,225	20,091.1	
7	Rate Schedule 23	31,268	34,965	-	34,965	35,141	-	35,141	1,911	10,315.4	
8	Industrial										
9	Rate Schedule 4	288	284	-	284	678	-	678	18	146.9	
10	Rate Schedule 5	6,214	7,195	-	7,195	14,352	-	14,352	253	2,674.6	
11	Rate Schedule 6	251	131	-	131	197	-	197	6	28.0	
12	Rate Schedule 7	254	397	-	397	1,056	-	1,056	6	246.0	
13	Rate Schedule 22 - Firm Service	6,593	6,260	-	6,260	6,539	-	6,539	14	11,263.5	
14	Rate Schedule 22 - Interruptible Service	19,467	19,059	-	19,059	19,286	-	19,286	27	18,445.3	
15	Rate Schedule 25	31,232	31,257	-	31,257	31,484	-	31,484	550	14,017.0	
16	Rate Schedule 27	9,814	10,964	-	10,964	11,088	-	11,088	109	7,269.1	
17	Total Non-Bypass	$ 747,902	$ 795,079	$ -	$ 795,079	$ 1,215,386	$ -	$ 1,215,386	1,007,184	196,020.8	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 915	$ 642		$ 642	$ 788		$ 788	6	8,582.0	
22	Rate Schedule 25	302	464		464	482		482	4	1,072.9	
23	Rate Schedule 46	5,153	5,370		5,370	9,174		9,174	30	1,111.2	
24	Byron Creek	122	106		106	106		106	1	230.8	
25	Burrard Thermal	-	-		-	-		-	-	-	
26	BC Hydro IG	15,735	15,735		15,735	15,735		15,735	1	16,425.0	
27	VIGJV	4,586	4,637		4,637	4,637		4,637	1	4,745.0	
28	Total Bypass & Special	$ 26,813	$ 26,954	$ -	$ 26,954	$ 30,922	$ -	$ 30,922	43	32,166.9	
29											
30											
31	Total	$ 774,715	$ 822,033	$ -	$ 822,033	$ 1,246,308	$ -	$ 1,246,308	1,007,227	228,187.7	
32											
33	**Effective Increase**			0.00%			0.00%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 20

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			
19	Less: Fort Nelson Line Heater and Communications Cost	(30)			
20	Formula O&M	238,038			
21	**2017**				
22	Net Inflation Factor	100.997%			Schedule 3, Line 12, Column 6
23	Formula O&M	$ 240,412			
24	**2018**				
25	Net Inflation Factor	101.298%			Schedule 3, Line 12, Column 7
26	Formula O&M	$ 243,533		$ 243,533	
27					
28	**O&M Tracked Outside of Formula**				
29	Pension & OPEB (O&M Portion)		$ 17,077		
30	Insurance		5,360		
31	Biomethane O&M		1,121		
32	NGT Stations O&M		1,838		
33	LNG O&M		5,684		
34	Total		$ 31,080	31,080	
35					
36	**Total Gross O&M**			$ 274,613	
37	O&M Transferred to Biomethane BVA			(1,074)	
38	Capitalized Overhead			(32,954)	
39	**Net O&M Expense**			$ 240,585	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Schedule 21

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 169,923	$ 191,197	$ 21,274	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(399)	(471)	(72)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,334)	(1,260)	74	Schedule 7.2, Line 37, Column 7
5		168,190	189,466	21,276	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 49,265	$ 56,568	$ 7,303	Schedule 11.1, Line 24, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(22)	(24)	(2)	Schedule 11.1, Line 25, Column 6
10	Non-Rate Base Deferrals	(8,945)	(11,032)	(2,087)	Schedule 12, Line 24, Column 6
11	CIAC	(8,989)	(8,828)	161	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	27	28	1	Schedule 9, Line 19, Column 5
13		31,336	36,712	5,376	
14					
15	Total	$ 199,526	$ 226,178	$ 26,652	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 APPROVED	2018 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 54,832	$ 56,296	$ 1,464	
2	1% In-Lieu of Municipal Taxes	12,629	10,880	(1,749)	
3					
4	Total	$ 67,461	$ 67,176	$ (285)	
5					
6	Total Property Tax Expense per Line 4	$ 67,461	$ 67,176		
7	Less: Property Tax Transferred to Biomethane BVA	(11)	(19)		
8	**Net Property Tax Expense**	$ 67,450	$ 67,157		

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,180	$ 2,688	$ 508	
2	Connection Charge	3,118	3,148	30	
3	NSF Returned Cheque Charges	76	80	4	
4	Other Recoveries	243	288	45	
5	SCP Third Party Revenue	14,347	16,976	2,629	
6	NGT Tanker Rental Revenue	448	583	135	
7	NGT Overhead and Marketing Recovery	332	320	(12)	
8	Biomethane Other Revenue	448	532	84	
9	LNG Mitigation Revenue from FEI	18,039	18,039	-	
10	CNG & LNG Service Revenues	3,727	3,394	(333)	
11					
12	Total	$ 42,958	$ 46,048	$ 3,090	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 Approved	2018 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 246,984	$ 281,258	$ 34,274	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(122,183)	(134,340)	(12,157)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(23,333)	(7,233)	16,100	Schedule 24, Line 37
4	Accounting Income After Tax	$ 101,468	$ 139,685	$ 38,217	
5					
6	1 - Current Income Tax Rate	74.00%	74.00%	0.00%	
7	Taxable Income	$ 137,119	$ 188,764	$ 51,645	
8					
9	Current Income Tax Rate	26.00%	26.00%	0.00%	
10	Income Tax - Current	$ 35,651	$ 49,079	$ 13,428	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 35,651	$ 49,079	$ 13,428	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,000	$ 1,300	$ 300	
19	Depreciation	168,190	189,466	21,276	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	40,298	45,512	5,214	Schedule 21, Line 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	881	1,020	139	
22	Vehicles: Interest & Capitalized Depreciation	1,543	1,352	(191)	
23	Pension Expense	12,044	11,933	(111)	
24	OPEB Expense	7,500	10,128	2,628	
25					
26	Deductions:				
27	Capital Cost Allowance	(196,055)	(213,531)	(17,476)	Schedule 25, Line 26, Column 6
28	CIAC Amortization	(8,962)	(8,800)	162	Schedule 21, Line 11+12, Column 3
29	Cumulative Eligible Capital Allowance	(1,577)	-	1,577	
30	Debt Issue Costs	(1,202)	(1,379)	(177)	
31	Vehicle Lease Payment	(2,259)	(1,603)	656	
32	Pension Contributions	(15,496)	(13,659)	1,837	
33	OPEB Contributions	(3,324)	(2,112)	1,212	
34	Overheads Capitalized Expensed for Tax Purposes	(10,772)	(10,984)	(212)	
35	Removal Costs	(13,233)	(13,937)	(704)	Schedule 11.1, Line 7, Column 4
36	Major Inspection Costs	(1,909)	(1,939)	(30)	
37	Total	$ (23,333)	$ (7,233)	$ 16,100	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Class	CCA Rate	12/31/2017 UCC Balance	Adjustments	2018 Additions	2018 CCA	12/31/2018 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,092,511	$ -	$ 9,312	$ (43,887)	$ 1,057,936
2	1 (LNG Plant - post Feb 2015)	4%	14,164	-	-	(567)	13,597
3	1(b)	6%	74,883	-	7,207	(4,709)	77,381
4	2	6%	104,593	-	-	(6,276)	98,317
5	3	5%	1,970	-	-	(99)	1,871
6	6	10%	91	-	-	(9)	82
7	7	15%	21,168	-	2,496	(3,362)	20,302
8	8	20%	25,881	-	7,277	(5,904)	27,254
9	10	30%	10,686	-	2,726	(3,615)	9,797
10	10.1	30%	78	-	-	(23)	55
11	12	100%	6,536	-	13,276	(13,174)	6,638
12	13	manual	3,585	-	199	(487)	3,297
13	14	manual	125	-	-	(25)	100
14	14.1 (pre 2017)	7%	20,133	-	-	(1,409)	18,724
15	14.1 (post 2016)	5%	460	-	479	(35)	904
16	17	8%	1,343	-	-	(107)	1,236
17	38	30%	312	-	-	(94)	218
18	43.2	50%	1,992	-	-	(996)	996
19	45	45%	11	-	-	(5)	6
20	47	8%	211,204	-	-	(16,897)	194,307
21	47 (LNG Plant - post Feb 2015)	8%	227,019	-	6,512	(18,423)	215,108
22	49	8%	309,180	-	249,481	(34,714)	523,947
23	50	55%	10,620	-	9,590	(8,478)	11,732
24	51	6%	776,060	-	122,402	(50,236)	848,226
25							
26	Total		$ 2,914,605	$ -	$ 430,957	$ (213,531)	$ 3,132,031

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 APPROVED Earned Return	2018 Amount	2018 Ratio	2018 Average Embedded Cost	2018 Cost Component	2018 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 121,630	$ 2,465,118	56.52%	5.26%	2.98%	$ 129,782	$ 8,152	Schedule 27, Line 29&31, Column 5&6&7
2	Short Term Debt	553	217,029	4.98%	2.10%	0.10%	4,558	4,005	
3	Common Equity	124,801	1,679,068	38.50%	8.75%	3.37%	146,918	22,117	
4									
5	Total	$ 246,984	$ 4,361,215	100.00%		6.45%	$ 281,258	$ 34,274	
6									
7	Cross Reference		Schedule 2, Line 30, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2018
($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	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	$ 147,710	$ 150,000	7.073%	$ 10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	119,908	120,749	2.644%	3,193	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,751	150,000	3.827%	5,741	
13	2017 Medium Term Debt Issue	November 1, 2017	November 1, 2047	148,500	150,000	3.655%	5,483	
14	2018 Medium Term Debt Issue	July 1, 2018	July 1, 2048	148,500	75,616	4.058%	3,068	
15								
16	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
17	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
18								
19	LILO Obligations - Kelowna				17,248	6.563%	1,132	
20	LILO Obligations - Nelson				2,834	8.539%	242	
21	LILO Obligations - Vernon				8,323	9.912%	825	
22	LILO Obligations - Prince George				21,942	8.750%	1,920	
23	LILO Obligations - Creston				2,106	7.835%	165	
24								
25	Vehicle Lease Obligation				2,515	3.658%	92	
26								
27	Sub-Total				$ 2,471,333		$ 130,117	
28	Less: Fort Nelson Division Portion of Long Term Debt				(6,215)		(335)	
29	Total				$ 2,465,118		$ 129,782	
30								
31	Average Embedded Cost					5.26%		
32								
33	* 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 2018), emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI requests approval of the amendment of one existing deferral account and reports on the calculation of the balance in the Flow-through deferral account.

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 2018, FEI has not identified any items that merit exogenous factor treatment.

12.3 *ACCOUNTING MATTERS*

In the following section, FEI provides information on emerging accounting guidance.

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 three US GAAP accounting standards with the impacts set out below:

- ASU 2014-09 ASC Topic 606 Revenue Recognition - not expected to affect future rates but is still being assessed;
- ASU 2017-07 ASC Topic 715 Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost - results in a small decrease to 2018 rates; and
- For ASU 2016-02 ASC Topic 842 Leases - the assessment will conclude in 2018.

12.3.1.1 Revenue Recognition

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, and the amendments in this update created Accounting Standard Codification (ASC) Topic 606 *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 that can be applied consistently across various transactions, industries and capital markets. In 2016, a number of additional ASUs were issued that clarify implementation guidance in ASC Topic 606. This standard, and all related ASUs, is effective for annual and interim periods beginning after December 15, 2017.

The majority of FEI's revenue is generated from natural gas sales to customers based on published tariff rates, as approved by the Commission, and is considered to be in scope of ASU No. 2014-09. FEI does not expect that the adoption of this standard, and all related ASUs, will have a material impact on the recognition of revenue generated from natural gas sales to customers, or on its remaining material revenue streams.

However, FEI's conclusions on the recognition of its revenue under the new standard are still subject to final review by the Company's external auditors and could be affected by certain industry specific interpretative issues which remain outstanding. If conclusions reached either by the industry or external auditors are different than current practice or preliminary conclusions reached by FEI, it could impact the Company's consolidated financial statements and related disclosures beginning January 1, 2018.

Should the final conclusions ultimately result in a difference between how FEI recognizes revenue for rate-setting purposes and how it is required to recognize that same revenue for external accounting purposes, FEI will apply to capture that difference in a deferral account. The request for such a deferral account would provide greater certainty around the existence of a deferred charge asset or liability for external reporting purposes. Any such difference would be expected to affect the revenue recognized for external financial reporting purposes, with the offset recognized in a deferral account and as such would not be expected to affect revenue requirements.

12.3.1.2 Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, FASB issued ASU No. 2017-07, Compensation-Retirement Benefit (Topic 715) - *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*.

Current US GAAP does not contain explicit guidance on where the amount of pension and OPEB expense, also referred to as net benefit cost, should be presented in the income statement and does not require an employer to disclose the amount of net benefit costs included in each line item in the income statement or capitalized in assets. The amendments in ASU 2017-07 are intended to provide greater transparency around presentation of defined benefit cost in financial statements. The amendments in this update require that companies disaggregate the service cost component from the other components of pension and other post-retirement benefits (OPEB) expenses in the income statement and allow only the service cost component of pension and OPEB expenses to be eligible for capitalization. The amendments will be effective for annual and interim periods beginning on or after December 15, 2017, which is January 1, 2018 for FEI.

In prior applications, FEI treated all components of pension and OPEB expenses as eligible to be allocated between O&M and capital. For 2017, this allocation resulted in $15.826 million of pension and OPEB expense residing in O&M and the remaining balance of $3.718 million allocated to capital expenditures.

For this Application, FEI's 2018 Forecast is prepared consistent with ASU 2017-07 under which only the service cost of pension & OPEB expense as eligible for capitalization. The remaining non-service cost components (including interest cost, expected return on assets and amortization of net actuarial loss and prior service credit) will remain in the income statement as they are not eligible for capitalization. For the 2018 Forecast, $17.077 million or approximately 80 percent of pension & OPEB expense is recognized in O&M and $4.320 million or approximately 20 percent of pension & OPEB expense has been recognized in capital expenditures.

To assist with understanding the effects of this new guidance, the following table shows the 2017 Approved as compared to the 2018 Forecast pension and OPEB expenses disaggregated into the various components.

Table 12-1: Components of Pension and OPEB Expense

Line No.	Description	Approved 2017	Forecast 2018	Variance
1	Service cost	$ 22.701	$ 22.631	$ (0.070)
2	Interest cost	27.339	28.860	1.521
3	Expected return on assets	(31.416)	(32.379)	(0.963)
4	Amortization:			
5	Net actuarial (gain) loss	4.230	3.778	(0.452)
6	Prior service cost (credit)	(3.310)	(1.493)	1.817
7	Total Pension & OPEB Expense	$ 19.544	$ 21.397	$ 1.853

Table 12-2 below represents the allocation to capital and O&M of FEI's pension and OPEB expenses for 2017 Approved, 2018 Forecast using the past practice (existing guidance) and 2018 Forecast using the new guidance. As shown in Table 12-2, the new guidance results in an increase of $0.235 million in the pension and OPEB costs allocated to capital and a net decrease of $0.235 million in the net benefit costs recognized in O&M. An alternative comparison is that under past practice, approximately 81 percent of total pension and OPEB expense was recognized in O&M and the remaining 19 percent allocated to capital, as compared to the new guidance which would require 80 percent of total pension and OPEB expense to be recognized in O&M and the remaining 20 per cent allocated to capital.

This change in methodology to align with the new guidance has minimal impact, resulting in a 0.03 percent decrease to 2018 delivery rates. While fewer components of pension and OPEB expense are eligible to be capitalized under ASU 2017-07, there is a slight increase in capitalization primarily due to the expected return on assets component, which is a credit to pension expense, now recognized in O&M.

Table 12-2: Allocation of Pension Expense under New Guidance

Line No.	Description	Approved 2017	2018 Forecast per Existing Guidance	2018 Forecast per New Guidance	2018 Variance the Existing Guidance vs New Guidance
1	O&M	15.826	17.312	17.077	(0.235)
2	Capital				
3	Capital Expenditure	2.663	2.894	3.129	0.235
4	Retirement Costs	0.809	0.913	0.913	-
5	CMAE	0.246	0.278	0.278	-
6	Total Capital	3.718	4.085	4.320	0.235
7					
8	Total Pension & OPEB Expense	$ 19.544	$ 21.397	$ 21.397	$ -

12.3.1.3 Leases

In February 2016, FASB issued ASU No. 2016-02, *Leases (Topic 842*) which supersedes lease requirements in ASC Topic 840, *Leases*. This standard increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. This standard is effective for FEI for annual and interim periods beginning on January 1, 2019. The main provision of Topic 842 is the recognition of lease assets and lease liabilities on the balance sheet by lessees for those leases that were previously classified as operating leases. For operating leases, a lessee is required to do the following: (i) recognize a right-of-use asset and a lease liability, initially measured at the present value of the lease payments, on the balance sheet; (ii) recognize a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis; and (iii) classify all cash payments within operating activities in the statement of cash flows. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current US GAAP.

The new guidance will result in operating leases being recognized as assets and liabilities on the balance sheet. The new standard either classifies lease costs as interest and depreciation or as a rent expense, depending on the type of classification under this new lease standard. FEI will be assessing its arrangements that qualify as leases which could potentially be recorded as assets and liabilities on the balance sheet for external financial reporting purposes. Final assessments on the impact of this standard on FEI's external financial statements and revenue requirements, if any, will not be determined until 2018. Any updates will be incorporated into the Annual Review for 2019 Rates.

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, Schedule 12).

FEI maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base 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 requests approval of an amendment to one approved deferral account. FEI also provides additional information for the Flow-through deferral account. 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 Existing Deferral Accounts

12.4.1.1 2017 Revenue Surplus

As part of the Annual Review of 2017 Rates, FEI received approval through Order G-182-16 to establish the 2017 Revenue Surplus deferral account to capture the 2017 revenue surplus resulting from maintaining 2017 rates at existing 2016 levels. The forecasted 2017 revenue surplus amount to be recorded in this account is $32.012 million[62]. The account is approved to attract a weighted average cost of capital return. As directed in Order G-182-16, "FEI is directed to propose an amortization period for the 2017 Revenue Surplus deferral account as part of its annual review for 2018 delivery rates application."

As discussed in Section 7.2.2.1, FEI's proposal to include the Tilbury Expansion Project in rate base for a portion of 2017 requires FEI to recover a rate base equity return on the project for that period of time, in lieu of collecting AFUDC. FEI believes the simplest way to recover the equity return is through a reduction to the credit recorded in the existing 2017 Revenue Surplus account. The example below is a calculation of FEI's required 2017 equity return for the Tilbury Expansion Project, using a September 1, 2017 in-service date for rate base purposes and $461 million in total capital transferred to rate base:

$461 million x 38.5% equity x 8.75% ROE x 4/12 = $5.177 million

While the $5.177 million amount assumes a September 1, 2017 in-service date, the actual addition to the 2017 Revenue Surplus account could vary if the project's in-service date is delayed to a future month in 2017.

Additionally, given FEI is forecasting a 2018 revenue surplus of $3.824 million as shown in the financial schedules,[63] FEI is now seeking approval to also add the forecast 2018 revenue surplus to the 2017 Revenue Surplus account and to re-name the account to the 2017-2018 Revenue Surplus account.

In summary, the following amounts are forecast to be added to the deferral account in 2017 and 2018.

Table 12-3: 2017-2018 Revenue Surplus Account Additions

($ millions)	**Additions**
2017 forecast revenue surplus (G-182-16)	$ 32.012
Tilbury Expansion 2017 equity return	(5.177)
2018 forecast revenue surplus	3.824
Total Revenue Surplus to be returned in future years (excluding WACC Return)	**$ 30.659**

62 Line 28, Schedule 1 of Appendix A Financial Schedules attached to the Annual Review for 2017 Rates Order G-182-16 Compliance Filing.

63 Section 11, Schedule 1, Line 26

Given the forecasted revenue surplus in 2018, FEI will propose an amortization period for this account in a future application.

12.4.1.2 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 2017 projected Flow-through amount of $2.724 million debit is shown in Table 12-5 below. To calculate the amount distributed to customers, FEI also included the following adjustments:

- The $10.431 million credit difference between the projected ending 2016 Flow-through deferral account balance embedded in 2017 delivery rates of a $5.022 million[64] credit and the actual ending 2016 deferral account balance of a $15.453 million credit, and the associated financing adjustment of a $0.531 million credit for 2017. The main contributor to the variance of $10.431 million was approximately $8.0 million in additional 2016 actual delivery margin revenue compared to the 2016 projection in Table 12-2 of the Annual Review of 2017 Rates Application.
- 2018 forecast financing of a $0.232 million credit[65]

Therefore, the total amount to return to customers through amortization in 2018 is $8.470 million credit as shown in the non-rate base deferral section of the financial schedules in Section 11, Schedule 12.

[64] Annual Review of 2017 Rates Compliance Filing financial schedules, Schedule 12, Line 9, Column 2.
[65] Section 11, Schedule 12, Line 3, Column 4.

Table 12-5: 2017 Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	Reference	2017 Approved	2017 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)	(5)
1	Delivery Margin				
2	Residential (Rate 1)		$ (452.786)	$ (452.833)	$ (0.047)
3	Commercial (Rate 2, 3, 23)		(221.003)	(220.652)	0.351
4	Industrial (All Others)		(100.926)	(104.773)	(3.847)
5	Total Delivery Margin		(774.715)	(778.258)	(3.543)
6					
7	O&M Tracked outside of Formula				
8	Insurance		5.529	5.300	(0.229)
9	Bio-Methane		0.976	1.044	0.068
10	Bio-Methane O&M transferred to BVA		(0.912)	(1.001)	(0.089)
11	NGT O&M		1.557	1.365	(0.192)
12	LNG Production O&M		4.975	4.880	(0.095)
13					
14	Property and Sundry Taxes		67.450	65.210	(2.240)
15					
16	Depreciation and Amortization		199.526	200.141	0.615
17					
18	Other Operating Revenue		(42.958)	(42.555)	0.403
19					
20	Interest Expense		122.183	125.028	2.845
21					
22	Income Taxes		35.651	40.832	5.181
23					
24	2017 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)				2.724
25					
26	2016 Ending Deferral Account Balance True-up				(10.431)
27	2017 Financing True-up				(0.531)
28	2018 Financing Addition to Deferral Account				(0.232)
29					
30	2018 After-Tax Amortization				(8.470)

The variances in delivery margin are due to favourable industrial margin as a result of higher volumes than forecast and interruptible volumes for the Vancouver Island Joint Venture. Variances in 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 and higher depreciation as a result of a higher depreciable asset base. Variances in Other Revenue are shown in Section 5. The variance in interest expense is due to both higher long-term debt than forecast and higher short-term debt as a result of using a projected September 1, 2017 date for the inclusion of the Tilbury project in rate base. Finally, the variance in income taxes is due to the income tax impacts of each of the aforementioned items, including the impact of the Tilbury project discussed above, the tax related to the O&M formula variances after-sharing, and the variance between the projected and approved tax timing differences.

An adjustment to include the difference between the projected and final actual amounts for 2017 subject to flow-through will be recorded in the deferral account in 2018 and amortized in 2019 rates.

12.5 *SUMMARY*

FEI does not have any exogenous factors that are affecting delivery rates in 2018 but has provided an update on certain accounting related matters, requested approval of an amendment to one approved non-rate base deferral account, and included information on the Flow-through deferral account.

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 2016, the Commission issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The Commission determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The Commission stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

FEI agrees with the approach set out in this directive and believes the rationale applies equally to the review of its service quality under PBR. FEI has therefore added a review of its most recent year's (i.e. 2016) service quality to this section.

In the subsections below, FEI reports on its 2016 and June 2017 year-to-date performance as measured against the SQI benchmarks and thresholds. Both 2016 and June 2017 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2016, for the nine SQIs with benchmarks, seven performed at or better than the approved benchmarks with two, Emergency Response Time and All Injury Frequency Rate (AIFR), performing better than the threshold and within the performance range. For the four

SQIs that are informational only, performance generally remains at a level consistent with prior years.

June 2017 year-to-date performance is similar to 2016 with eight SQIs with benchmarks now performing at or better than the approved benchmarks.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's 2016 and June year-to-date performance for 2017 to the Commission-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation and that were approved by the Commission. Actual 2016 and June year-to-date results for 2017 are also provided for the four informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2016 Results	2017 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	97.7%	96.2%	97.4%	97.7%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	92.8%	98.5%	97.6%
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	2.13	2.26
Public Contacts with Pipelines	3 year average of number of line damages per 1,000 BC One calls received	16	16	9	8
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	74%	81%	80%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.57	0.63
Meter Reading Accuracy	Number of scheduled meters that were read	95%	92%	96.9%	95.5%
Telephone Service Factor (Non- Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	93.8%	96.9%	97.1%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.8	8.3
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.2%	2.0%
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	3	2

Performance Measure	Description	Benchmark	Threshold	2016 Results	2017 June YTD Results
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0047	0.0023

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2016 and 2017. 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:

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

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 2016 result was 97.4 percent which was within the performance range, with the benchmark at 97.7 percent and the threshold at 96.2 percent. The June 2017 year-to-date performance is 97.7 percent which meets the benchmark.

The Company's 2009 to 2016 annual and 2017 year-to-date emergency response time results are provided below. The improved response time since 2014 in all operating zones is a reflection of a combination of factors including a decrease in the number emergency events 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.

Table 13-2: Historical Emergency Response Time

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Results	97.7%	97.7%	97.9%	97.4%	97.4%	96.7%	97.3%	97.4%	97.7%
Benchmark	n/a	n/a	n/a	n/a	n/a	97.7%	97.7%	97.7%	97.7%
Threshold	n/a	n/a	n/a	n/a	n/a	96.2%	96.2%	96.2%	96.2%

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 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 2016 result was 98.5 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2017 year-to-date performance is 97.6 percent which is also better than the benchmark.

The Company's TSF (Emergency) results for 2009 to 2016 annual and 2017 year-to-date are provided below:

Table 13-3: Historical TSF (Emergency) Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Results	98.3%	99.2%	96.5%	96.5%	95.6%	95.8%	97.6%	98.5%	97.6%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	92.8%	92.8%	92.8%	92.8%

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, the measurement of performance is based on the three year rolling average of the annual results.

The 2016 (three-year rolling average) result was 2.13 which was within the performance range, with the benchmark at 2.08 and the threshold at 2.95. The 2016 annual AIFR was 2.13 as a result of 12 Medical Treatment and 18 Lost Time Injuries.

The three-year rolling average of the annual results including 2017 June year-to-date results is 2.26 which is also between the threshold and the benchmark. The 2017 June year-to-date annual AIFR is 2.13 as a result of 7 Medical Treatment and 9 Lost Time injuries.

Safety continues to be a core value for FEI and prevention of injury remains a key focus. FEI continues to focus on and reinforce the fundamentals of safety through effective safe work planning identifying hazards and mitigating risks, detailed work observations and thorough event analysis capturing learnings and identifying opportunities for continued improvement.

Target Zero is the continual improvement program which was launched in January 2016. This program focuses on a number of key elements designed to enhance the existing safety management system and engage employees at all levels in safety as well as promote an interdependent safety environment. The Company believes this program has contributed to the positive safety trend experienced.

The Company's 2009 to 2016 and 2017 year-to-date AIFR results are provided below.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	2.49	2.66	1.66	1.91	3.02	1.73	2.52	2.13	2.13
Three year rolling average	2.55	2.26	2.27	2.08	2.20	2.22	2.42	2.13	2.26
Benchmark	n/a	n/a	n/a	n/a	n/a	2.08	2.08	2.08	2.08
Threshold	n/a	n/a	n/a	n/a	n/a	2.95	2.95	2.95	2.95

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.

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 number of line damages and number of calls to BC One Call is provided in Table 13-5 below.

The 2016 (three-year rolling average) result was 9, which is better than the benchmark of 16. The three-year rolling average of the June 2017 year-to-date results is 8, also below and better than the benchmark.

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.

The Company's 2009 to 2016 annual and 2017 year-to-date results along with the three year rolling averages 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 13-5: Historical Public Contact with Pipelines Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	20	19	16	13	10	9	8	8	7
Three year rolling average	26	22	18	16	13	11	9	9	8
Benchmark	n/a	n/a	n/a	n/a	n/a	16	16	16	16
Threshold	n/a	n/a	n/a	n/a	n/a	16	16	16	16
Calls to BC One Call	72,691	78,734	82,396	86,828	92,002	107,509	122,627	129,645	75,052
Line Damages	1,435	1,457	1,329	1,094	955	954	1,035	1,086	535

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 FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2016 result was 81 percent which was better than the benchmark of 78 percent approved by the Commission. The June 2017 year-to-date performance is 80 percent and better than the benchmark.

The Company's 2009 to 2016 annual and 2017 year-to-date 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 13-6: Historical First Contact Resolution Levels

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	72%	77%	75%	78%	81%	80%	81%	81%	80%
Benchmark	n/a	n/a	n/a	n/a	n/a	78%	78%	78%	78%
Threshold	n/a	n/a	n/a	n/a	n/a	74%	74%	74%	74%

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 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.

The 2016 result was 0.57 which was better than the benchmark of 5.0. The June 2017 year-to-date performance is 0.63 which is also better than the benchmark. No significant billing issues have arisen in 2016 or so far in 2017.

The 2016 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2016 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	99.98%	If (PA≥99.9%,5000*(1 - PA),1.05-PA))	0	0
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	99.15%	(100%-PA)*100	0	0.85
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	97.62%	(100%-PA)*100	1.7	2.38
Billing Service Quality Indicator; Target < 5.0		(Accuracy PA+Timeliness PA+Completion PA)/3	0.57	0.57

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below. The results were higher in 2012 as that was the year when the Company transitioned its billing functions in-house from its previous third party provider; a process that included all new systems and employees during 2012.

Table 13-8: Historical Billing Index Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	3.75	2.4	0.24	3.01	1.43	0.89	1.06	0.57	0.63
Benchmark	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0
Threshold	n/a	n/a	n/a	n/a	n/a	5.0	5.0	5.0	5.0

Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

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

Factors influencing this SQI's performance include the resources available, system issues impacting the Company's billing or reading collections systems, weather conditions including road and highway conditions and traffic related issues.

The 2016 result was 96.9 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2017 year-to-date performance is 95.5 percent and is also better than the benchmark.

The Company's 2009 to 2016 annual and 2017 year-to-date 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.

While the 2017 year-to-date results are above the benchmark, meter reading accuracy results were lower than previous years during the first several months due to challenging winter weather conditions.

Table 13-9: Historical Meter Reading Accuracy Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	n/a	n/a	n/a	n/a	92.5%	97.0%	97.5%	96.9%	95.5%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	92.0%	92.0%	92.0%	92.0%

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:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

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. The 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 expected call volume 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 and the complexity of the calls.

The 2016 result was 71 percent which was better than the benchmark of 70 percent. The June 2017 year-to-date performance is 70 percent which meets the benchmark. Although the benchmark has been achieved year to date, call volumes related to higher bills during the winter months have been greater than recent years and this has contributed to challenges meeting this benchmark in the first half of the year.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below. As indicated in the following table, the Company's TSF (Non-Emergency) results were consistent with a benchmark of 75 percent from 2009 to 2014. The 2014 result was achieved with the Company targeting 75 percent as the benchmark. The Commission approved the revised target of 70 percent in mid-September 2014. In 2015 and subsequent years, actual results are expected to be reflective of the revised target of 70 percent.

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

	2009	2010	2011	2012	2013	2014		2015	2016	June 2017 YTD
	77%	77%	75%	76%	73%	75%		71%	71%	70%
						Jan-Aug	Sept-Dec			
Benchmark	>=75%	>=75%	>=75%	>=75%	>=75%	>=75%	>=70%	70%	70%	70%
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	68%	68%	68%	68%

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:

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

Factors influencing results include process improvements, number of emergencies, weather and traffic conditions. The process improvements initiated in recent years 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 2016 result was 96.9 percent which was better than the benchmark of 95 percent approved by the Commission. The June 2017 year-to-date performance is 97.1 percent and also better than the benchmark. The June 2017 year-to-date result continues to improve on the performance observed in recent years.

The Company's 2009 to 2016 annual and 2017 year-to-date results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	94.7%	94.2%	96.5%	96.5%	97.0%	95.5%	96.6%	96.9%	97.1%
Benchmark	n/a	n/a	n/a	n/a	n/a	95.0%	95.0%	95.0%	95.0%
Threshold	n/a	n/a	n/a	n/a	n/a	93.8%	93.8%	93.8%	93.8%

Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that 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 survey is conducted quarterly and results are presented as a score out of ten.

The 2016 result was 8.8, higher than the 8.6 score in 2015. The June 2017 year-to-date average index score is 8.3, lower than the 8.7 score for the same period last year. Of the five measures that make up the overall score, year-to-date results were lower in all categories. Year-to date decreases from June 2016 to June 2017 were observed. The score for overall satisfaction and accuracy of meter reading decreased from 8.5 to 8.3 and 8.4 to 8.1, respectively. The energy conservation information, contact centre and field services metrics decreased from 7.7 to 7.5, 8.9 to 8.2 and 9.4 to 8.9 respectively from June 2016 year-to-date to June 2017 year-to-date. Although not conclusive, customer comments and statistical analysis suggest that the lower 2017 year-to-date result may be associated with lower customer satisfaction with the cost of natural gas following commodity cost increases in October 2016, followed by a colder, wetter winter.

The Company's 2009 to 2016 annual and 2017 year-to-date results, in the previous and current formats, are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results – current format	n/a	n/a	8.3	8.3	8.3	8.5	8.6	8.8	8.3
Annual Results – prior format	80.1%	80.0%	79.3%	78.9%	n/a	n/a	n/a	n/a	n/a
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	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 biannual 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 percent and 8.3 in 2011 and 78.9 percent and 8.3 in 2012.

Telephone Abandon Rate

The Telephone Abandon Rate is an informational indicator that 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 2016 result was 2.2 percent and consistent with the prior years' results. The June 2017 year-to-date result of 2.0 percent is consistent with the Company's prior and full years' results.

The Company's 2012 to 2015 results, which are reflective of performance since the repatriation of outsourced Customer Service functions, are provided below. Telephone Abandon Rates prior to 2012 were not reported from our third party Customer Service provider.

Table 13-13: Historical Telephone Abandon Rates

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results	n/a	n/a	n/a	2.2%	2.1%	1.8%	2.0%	2.2%	2.0%
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

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.

Prior to the third quarter of 2014, the practice was to report only on the higher pressure transmission events designated as serious. However, the OGC put in place new reporting criteria effective October 1, 2014, which required 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 limits 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 2015, 2016, and for June 2017 year-to-date by severity level.

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents in 2015	Reportable Incidents in 2016	Reportable Incidents to June 30, 2017
Level 1 (moderate)	3	3	2
Level 2 (major)	0	0	0
Level 3 (serious)	0	0	0

As indicated in the above table, the 2016 result was three Level 1 reported incidents.

- The first Level 1 incident occurred in March 2016 when a leak was detected and repaired in Burnaby on a section of pipeline that is being replaced as part of the Lower Mainland Intermediate Pressure System Upgrade project.
- The second Level 1 incident occurred in July 2016 when a contractor for the City of Surrey directionally drilled through a steel IP service. Repairs were completed by the next day.
- The third Level 1 incident occurred when a homeowner working in his yard pulled an Intermediate Pressure (IP) branch service off the tee in September 2016. The line was repaired and re-gasified the same day.

As also indicated in the table above, from January 1, 2017 to June 30, 2017, there have been two Level 1 reportable incidents. The first Level 1 incident occurred on February 1, 2017 and involved an apparent attempt to siphon gas from a farm tap in Chemainus. The second Level 1 incident occurred on June 11, 2017 with a third party hit on an IP pipeline, which was repaired without public impact.

The Company's 2009 to 2016 historical annual and 2017 year-to-date 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

Description	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Annual Results – Level 1	n/a	n/a	n/a	n/a	n/a	1	3	3	2
Annual Results – Level 2	n/a	n/a	n/a	n/a	n/a	1	0	0	0
Annual Results – Level 3	n/a	n/a	n/a	n/a	n/a	0	0	0	0
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator approved by the Commission that measures the number of leaks on the distribution system per KM of distribution system mains. The metric is intended to be an indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system is surveyed for leaks, with the number of leaks varying from year to year, depending on the condition of the pipe surveyed.

Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system as some sections of the pipeline system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline. As the distribution system ages, the expected number of leaks may increase depending on the Company's pipeline renewal/replacement activities. Increases in leak survey activity levels will generally also result in a higher number of leaks detected.

In 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 2017 year-to-date five-year rolling average result of 0.0057 calculated using data from July 2012 to June 2017.

Table 13-16: June 2016 Year-to-Date Five Year Rolling Average

Period	Metric
July – December 2012 (6 months)	0.0037
January – December 2013	0.0075

Period	Metric
January – December 2014	0.0059
January – December 2015	0.0045
January – December 2016	0.0047
January – June 2017 (6 months)	0.0023
Five Year Rolling Average	0.0057

The Company's 2009 to 2016 annual results are provided below. The five-year average for each year shown is calculated by taking the average of the results of the stated year and the four years prior (e.g. the 2016 five-year average is calculated using 2012 to 2016 annual data). The 2016 result was 0.0047 which is based on 107 leaks as compared to 102 in 2015 and 114 in 2014. The June 2017 year-to-date result is 0.0023 which is based on 53 leaks detected year-to-date as compared to 58 in 2016 and 59 in 2015 for a similar time period.

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

Leaks per KM of Distribution System Mains	2009	2010	2011	2012	2013	2014	2015	2016	June 2017 YTD
Leaks	122	140	166	169	143	114	102	107	53
Total km	18,760	18,895	18,974	19,040	19,098	19,172	22,602	22,813	22,951
Leaks per km	0.0065	0.0074	0.0087	0.0089	0.0075	0.0059	0.0045	0.0047	0.0023
5 year average	0.0062	0.0064	0.0067	0.0075	0.0078	0.0077	0.0071	0.0063	0.0057

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 May 31, 2017, FEI reported to the BC Ministry of Environment its 2016 GHG emissions of 124,077 tCO2e. The 2015 reported value was 120,997 tCO2e.

13.4 SUMMARY

In summary, FEI's 2016 results and June 2017 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2016, for those SQIs with benchmarks, seven performed at or 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 remains at a level consistent with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: CANSIM Table 326-0020

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Home > CANSIM

Table 326-0020 [2, 9]

Consumer Price Index

monthly (2002=100)

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

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 = British Columbia

Products and product groups [18]	All-items	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
2015 July	120.8	134.8	113.9	115.3	99.6	128.4	182.1	113.7	119.9	137.3
2015 August	121.0	134.6	114.1	115.1	102.2	127.8	178.9	113.8	120.6	137.9
2015 September	121.0	135.6	114.0	115.4	108.0	125.2	162.1	114.4	119.6	139.5
2015 October	120.6	135.2	114.4	114.9	108.2	125.6	160.0	114.0	116.4	137.6
2015 November	120.8	136.2	114.5	113.7	106.5	127.2	167.4	114.7	115.3	139.0
2015 December	120.4	137.0	114.6	114.1	101.8	126.6	162.5	113.9	115.1	137.8
2016 January	120.7	139.5	114.4	114.7	101.4	125.9	148.0	114.6	114.6	140.1
2016 February	120.8	137.9	114.4	115.8	103.4	125.0	140.3	115.1	116.0	140.2
2016 March	121.8	138.1	114.7	117.1	106.0	126.9	150.8	114.9	117.8	141.1
2016 April	121.8	137.3	115.0	117.2	105.3	127.7	153.8	115.9	116.7	141.2
2016 May	122.7	137.7	115.3	117.3	105.3	130.3	161.4	115.5	119.6	140.9
2016 June	123.1	137.0	115.8	117.3	103.6	131.7	166.9	116.4	120.9	141.1
2016 July	123.3	137.8	115.7	116.9	103.2	131.1	166.4	115.9	123.5	141.8
2016 August	123.4	137.5	116.0	117.9	103.7	130.0	162.4	116.7	123.5	141.7
2016 September	123.2	135.4	115.9	117.0	106.9	130.5	167.9	115.9	123.0	141.9
2016 October	123.1	134.1	116.8	117.5	107.3	131.3	171.5	116.7	120.0	142.4
2016 November	122.7	135.0	117.1	117.3	106.1	129.3	160.9	116.3	118.4	142.7
2016 December	122.7	135.7	117.1	116.8	104.3	130.2	162.9	116.1	118.2	141.7
2017 January	123.5	136.1	117.1	117.1	102.2	133.3	174.6	117.4	119.3	143.2
2017 February	123.6	136.6	117.0	117.1	103.7	132.6	168.0	116.2	120.6	143.9
2017 March	124.2	136.6	117.2	116.9	106.5	133.4	176.6	116.5	123.0	144.3
2017 April	124.4	137.1	117.7	117.8	105.1	134.1	183.1	117.8	120.7	144.1
2017 May	125.0	138.1	117.8	118.4	105.9	133.6	177.8	118.2	123.5	144.5
2017 June	125.2	138.5	118.3	118.7	103.9	133.5	172.7	118.3	123.9	144.9

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 overt employees by North American Industry Classification System (NAICS), seasonally adjusted

monthly

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

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] [3, 5]	Goods producing industries [11-33N] [5]	Forestry, logging and support [11N] [5]	Mining, quarrying, and oil and gas extraction [21]	Utilities [22]	Construction [23]	Manufacturing [31-33]	Servic produci industr [41-91 [5]
2015 July	914.85[A]	1,154.64[A]	1,173.48[A]	1,715.72[A]	1,653.21[A]	1,143.70[A]	1,032.94[A]	869.28[A]
2015 August	907.74[A]	1,130.30[A]	1,204.64[A]	1,725.43[A]	1,700.13[A]	1,127.50[A]	1,014.75[A]	863.98[A]
2015 September	912.59[A]	1,145.27[A]	1,239.12[A]	1,701.82[A]	1,577.58[A]	1,129.88[A]	1,041.00[A]	866.89[A]
2015 October	915.24[A]	1,154.93[A]	1,286.28[A]	1,751.60[A]	1,614.48[A]	1,113.44[A]	1,077.46[A]	868.22[A]
2015 November	910.21[A]	1,156.57[A]	1,287.80[A]	1,803.49[A]	1,605.43[A]	1,115.07[A]	1,057.17[A]	862.10[A]
2015 December	918.18[A]	1,158.77[A]	1,315.59[A]	1,768.22[A]	1,567.11[A]	1,109.84[A]	1,055.00[A]	879.28[A]
2016 January	906.99[A]	1,147.60[A]	1,283.82[A]	1,871.30[A]	1,694.18[A]	1,118.98[A]	1,050.69[A]	859.40[A]
2016 February	913.20[A]	1,145.25[A]	1,320.52[A]	1,831.69[A]	1,645.40[A]	1,111.67[A]	1,046.51[A]	869.82[A]
2016 March	915.42[A]	1,152.16[A]	1,248.83[A]	1,879.29[A]	1,822.15[A]	1,115.96[A]	1,044.59[A]	869.44[A]
2016 April	920.95[A]	1,157.69[A]	1,278.97[A]	1,757.12[A]	1,860.00[A]	1,126.00[A]	1,093.66[A]	874.58[A]
2016 May	917.48[A]	1,145.12[A]	1,236.77[A]	1,717.18[A]	1,781.26[A]	1,116.80[A]	1,049.74[A]	872.66[A]
2016 June	927.60[A]	1,158.69[A]	1,135.29[A]	1,715.00[A]	1,707.11[B]	1,147.66[A]	1,042.45[A]	884.26[A]
2016 July	911.54[A]	1,147.71[A]	1,217.51[A]	1,759.44[B]	1,605.27[A]	1,121.33[A]	1,054.20[A]	868.16[A]
2016 August	920.30[A]	1,164.08[A]	1,266.57[A]	1,791.15[A]	1,730.02[A]	1,142.26[A]	1,062.10[A]	872.73[A]
2016 September	919.84[A]	1,161.59[A]	1,276.31[A]	1,838.00[A]	1,658.94[A]	1,102.77[A]	1,072.55[A]	873.40[A]
2016 October	917.50[A]	1,148.26[A]	1,199.22[A]	1,749.57[A]	1,727.95[A]	1,123.73[A]	1,061.91[A]	872.88[A]
2016 November	927.86[A]	1,169.90[A]	1,111.49[A]	1,789.40[A]	1,794.96[A]	1,143.97[A]	1,082.22[A]	880.20[A]
2016 December	931.43[A]	1,191.28[A]	1,268.40[A]	1,840.48[A]	1,804.00[A]	1,154.03[A]	1,080.56[A]	890.24[A]
2017 January	931.06[A]	1,185.70[A]	1,205.23[A]	1,840.33[A]	1,726.37[A]	1,148.97[A]	1,097.60[A]	879.56[A]
2017 February	928.94[A]	1,193.15[A]	1,229.89[A]	1,747.09[A]	1,975.76[A]	1,151.79[A]	1,114.58[A]	878.00[A]
2017 March	934.30[A]	1,193.89[A]	1,271.42[A]	1,896.04[A]	1,721.37[A]	1,147.06[A]	1,115.54[A]	884.07[A]
2017 April	935.01[A]	1,160.82[A]	1,253.20[A]	1,792.34[A]	1,662.37[A]	1,121.94[A]	1,093.56[A]	889.97[A]
2017 May	939.99[A]	1,176.34[A]	1,186.44[B]	1,859.52[A]	1,778.63[A]	1,127.34[A]	1,091.63[A]	894.20[A]

1 **Table A1-3: CBOC BC Housing Starts Embedded in Forecast as Filed**

November 10, 2016
Provincial Medium Term
Forecast: 20163 Run: 17
Table: 156 and 157

BRITISH COLUMBIA	2015	2016	2017	2018
Forecasted Single-Family Housing Starts (Units)	10,152	12,676	10,689	9,963
Forecast Percent Change	6.1	24.9	-15.7	-6.8
Forecasted Mult-Family Housing Starts (Units)	21,294	29,466	25,865	25,001
Forecast Percent Change	13.3	38.4	(12.2)	(3.3)
Forecast Housing Starts Total	31,446	42,143	36,554	34,964

2

Appendix A-2

Historical Forecast and Consolidated Tables

Table of Contents

List of Appendices

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historic and Forecast Data
    a. 2007-2016 actual data
    b. 2017 seed year data
    c. 2018 forecast data
2. Percent Error
    a. 2007-2016 forecast, actual and percent error

2. HISTORIC AND FORECAST DATA TABLES

Table A2-1: FEI Customer Counts, Customer Additions, Use per Customer, and Energy[1]

FEI Customer Counts

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
RS 1	825,262	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169	897,528	907,224	916,365
RS 2	83,289	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076	86,074	87,284	88,494
RS 3	5,290	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301	5,189	5,205	5,223
RS 23	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724	1,803	1,868	1,934
Industrial	1,197	1,145	1,113	1,017	951	954	981	977	976	955	954	954
NGT	0	0	0	0	2	5	10	18	31	42	55	58
Total	916,341	929,114	937,261	946,574	953,943	942,872	953,295	964,971	979,277	991,591	1,002,589	1,013,027

FEI Customer Additions

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
RS 1	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359	9,696	9,141
RS 2	1,198	1,330	446	128	511	577	1,329	1,173	1,450	998	1,210	1,210
RS 3	-71	171	-31	37	-16	-104	-86	35	132	-112	16	19
RS 23	97	3	42	58	27	88	9	-7	202	79	65	66
Total	17,018	12,825	8,179	9,409	7,433	6,932	10,391	11,673	14,293	12,324	10,986	10,435

FEI Normalized Use Per Customer (Gjs)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
RS 1	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5	88.3	89.1
RS 2	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1	342.1	345.2
RS 3	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721	3,781	3,842
RS 23	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279	5,353	5,399

FEI Energy (Pjs)(1)

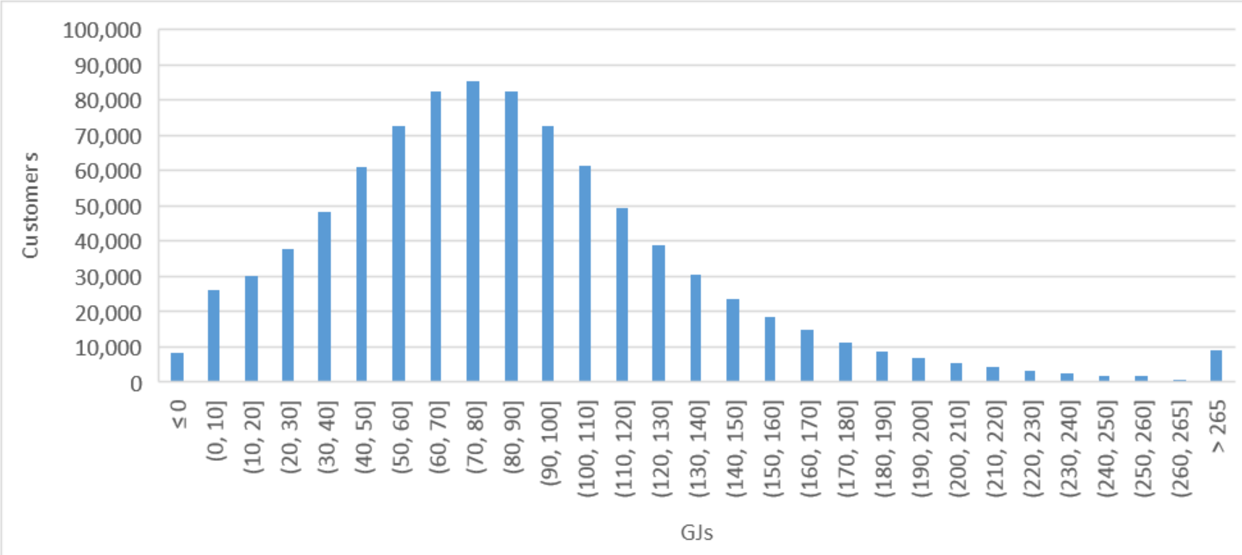
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017S	2018F
RS 1	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	77.9	79.7	81.2
RS 2	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0	29.0	29.6	30.3
RS 3	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.1
RS 23	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6	9.3	9.9	10.3
Industrial	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7	87.7	84.3
Sub-Total	208.7	202.1	199.2	201.9	206.6	209.7	206.3	205.7	209.5	219.3	226.5	226.2
NGT	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.8	1.1	1.3	1.6	2.0
Total	208.7	202.1	199.2	201.9	206.7	209.9	206.6	206.5	210.6	220.6	228.0	228.2

Table A2-2: FEI 2017 Industrial Forecast Demand by Region[2]

Industrial	2018 Forecast Demand By Region
Mainland	61.8
Vancouver Island	22.4
Whistler	0.1
Total	**84.3**

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

1 **Figure A2-1: FEI Residential Customers Normalized UPC in 2016**



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3. PERCENT ERROR DATA TABLES

In the data tables presented below, FEI provides 10 years of historical actual demand, forecast demand and percent error for each customer class and service area and on a 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.

Percent error is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

$$PE_t = \left(\frac{Y_t - F_t}{Y_t}\right) \times 100$$

Where F_t is the forecast at time t and Y_t is the actual value at time t.

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.

3.1 AMALGAMATED NET CUSTOMERS

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	828,303	842,919	846,375	849,539	857,592	870,980	880,331	866,852	883,371	892,830
Actual	825,262	836,583	844,306	853,492	860,403	854,050	863,189	873,661	886,169	897,528
Error = (ACT-FCST)	-3,041	-6,336	-2,069	3,953	2,811	-16,930	-17,142	6,809	2,798	4,698
Percent Error = (Error/ACT)	-0.4%	-0.8%	-0.2%	0.5%	0.3%	-2.0%	-2.0%	0.8%	0.3%	0.5%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	82,591	83,957	84,667	86,383	87,262	85,482	85,627	81,923	84,651	85,667
Actual	83,289	84,619	85,065	85,193	85,704	81,123	82,452	83,625	85,076	86,074
Error = (ACT-FCST)	698	662	398	-1,190	-1,558	-4,359	-3,175	1,702	425	407
Percent Error = (Error/ACT)	0.8%	0.8%	0.5%	-1.4%	-1.8%	-5.4%	-3.9%	2.0%	0.5%	0.5%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	4,942	5,116	5,316	5,671	5,785	5,553	5,597	5,147	5,117	5,035
Actual	5,290	5,460	5,429	5,466	5,451	5,220	5,134	5,169	5,301	5,189
Error = (ACT-FCST)	348	344	113	-205	-334	-333	-463	22	184	154
Percent Error = (Error/ACT)	6.6%	6.3%	2.1%	-3.8%	-6.1%	-6.4%	-9.0%	0.4%	3.5%	3.0%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast	1,313	1,423	1,426	1,319	1,328	1,526	1,586	1,634	1,552	1,670
Actual	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,724	1,803
Error = (ACT-FCST)	-10	-117	-78	87	105	-6	-57	-112	172	133
Percent Error = (Error/ACT)	-0.8%	-9.0%	-5.8%	6.2%	7.3%	-0.4%	-3.7%	-7.4%	10.0%	7.4%

3.2 AMALGAMATED NET CUSTOMER ADDITIONS

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	16,267	14,603	9,827	7,012	7,724	8,984	9,352	6,647	9,710	9,461
Actual	15,794	11,321	7,723	9,186	6,911	6,371	9,139	10,472	12,508	11,359
Error = (ACT-FCST)	-473	-3,282	-2,104	2,174	-813	-2,613	-213	3,825	2,798	1,898
Percent Error = (Error/ACT)	-3.0%	-29.0%	-27.2%	23.7%	-11.8%	-41.0%	-2.3%	36.5%	22.4%	16.7%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	588	796	618	830	877	145	145	411	1,026	1,026
Actual	1,198	1,330	446	128	511	577	1,329	1,173	1,450	998
Error = (ACT-FCST)	610	534	-172	-702	-366	432	1,184	762	424	-28
Percent Error = (Error/ACT)	50.9%	40.2%	-38.6%	-548.4%	-71.6%	74.9%	89.1%	65.0%	29.2%	-2.8%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	-284	14	14	105	114	44	44	4	-52	-51
Actual	-71	171	-31	37	-16	-104	-86	35	132	-112
Error = (ACT-FCST)	213	157	-45	-68	-130	-148	-130	31	184	-61
Percent Error = (Error/ACT)	-300.0%	91.8%	145.2%	-183.8%	812.5%	142.3%	151.2%	88.6%	139.4%	54.5%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast	147	70	53	9	9	60	60	57	30	30
Actual	97	3	42	58	27	88	9	-7	202	79
Error = (ACT-FCST)	-50	-67	-11	49	18	28	-51	-64	172	49
Percent Error = (Error/ACT)	-51.5%	-2233.3%	-26.2%	84.5%	66.7%	31.8%	-566.7%	914.3%	85.1%	62.0%

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	95.7	92.4	87.7	87.9	86.5	86.3	85.2	86.0	83.1	81.6
Actual	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4	87.5
Error = (ACT-FCST)	(3.5)	(3.6)	1.4	0.5	(0.2)	1.3	(0.5)	(1.8)	1.3	5.9
Percent Error = (Error/ACT)	-3.8%	-4.1%	1.6%	0.6%	-0.2%	1.5%	-0.6%	-2.1%	1.5%	6.7%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	318.7	325.4	309.0	320.5	320.2	315.0	314.5	340.0	333.7	329.5
Actual	322.1	318.2	325.1	316.2	317.7	341.2	331.6	330.6	332.6	339.1
Error = (ACT-FCST)	3.4	(7.2)	16.1	(4.3)	(2.5)	26.2	17.1	(9.4)	(1.1)	9.6
Percent Error = (Error/ACT)	1.1%	-2.3%	5.0%	-1.4%	-0.8%	7.7%	5.2%	-2.8%	-0.3%	2.8%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	3,527	3,573	3,164	3,496	3,487	3,450	3,435	3,872	3,754	3,593
Actual	3,565	3,539	3,480	3,485	3,588	3,684	3,610	3,573	3,587	3,721
Error = (ACT-FCST)	38	(34)	316	(11)	101	234	175	(299)	(167)	128
Percent Error = (Error/ACT)	1.1%	-1.0%	9.1%	-0.3%	2.8%	6.4%	4.8%	-8.4%	-4.7%	3.4%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast	4,796	4,850	4,391	4,680	4,680	4,901	4,927	5,546	5,309	5,382
Actual	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,174	5,279
Error = (ACT-FCST)	(18)	(152)	495	170	458	337	222	(286)	(135)	(103)
Percent Error = (Error/ACT)	-0.4%	-3.2%	10.1%	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.6%	-2.0%

3.4 AMALGAMATED DEMAND

Normalized Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	78.4	77.2	73.8	74.3	73.8	74.7	74.6	74.2	73.1	72.5
Actual	75.4	73.7	74.8	75.0	73.9	74.5	72.7	73.2	74.1	77.9
Error = (ACT-FCST)	(3.0)	(3.5)	1.0	0.7	0.1	(0.2)	(1.9)	(1.0)	1.0	5.4
Percent Error = (Error/ACT)	-4.0%	-4.7%	1.3%	0.9%	0.1%	-0.3%	-2.6%	-1.4%	1.3%	6.9%
Abs. Percent Error	4.0%	4.7%	1.3%	0.9%	0.1%	0.3%	2.6%	1.4%	1.3%	6.9%

Normalized Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	26.2	27.1	26.1	27.5	27.7	26.9	26.9	27.7	28.1	28.0
Actual	26.7	26.6	27.5	26.9	27.1	27.6	27.0	27.5	28.0	29.0
Error = (ACT-FCST)	0.5	(0.5)	1.4	(0.6)	(0.6)	0.7	0.1	(0.2)	(0.1)	1.0
Percent Error = (Error/ACT)	1.9%	-1.9%	5.1%	-2.2%	-2.2%	2.5%	0.4%	-0.7%	-0.4%	3.4%

Normalized Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	18.3	18.2	16.8	19.6	19.9	19.1	19.1	19.9	19.2	18.1
Actual	18.8	18.9	19.0	19.0	19.5	19.3	18.7	18.5	19.2	19.4
Error = (ACT-FCST)	0.5	0.7	2.2	(0.6)	(0.4)	0.2	(0.4)	(1.4)	(0.0)	1.3
Percent Error = (Error/ACT)	2.7%	3.7%	11.6%	-3.2%	-2.1%	1.0%	-2.1%	-7.6%	-0.2%	6.7%

Normalized Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast	5.7	6.6	6.1	6.1	6.2	7.2	7.5	8.7	8.3	9.0
Actual	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.6	9.3
Error = (ACT-FCST)	0.2	(0.4)	0.4	0.5	1.2	0.6	0.4	(0.7)	0.3	0.3
Percent Error = (Error/ACT)	3.4%	-6.5%	6.2%	7.6%	16.2%	7.7%	5.1%	-8.7%	3.5%	3.2%

Normalized Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Commercial										
Forecast	50.2	51.9	49.0	53.2	53.8	53.2	53.5	56.3	55.6	55.1
Actual	51.4	51.7	53.0	52.5	54.0	54.7	53.6	54.0	55.8	57.7
Error = (ACT-FCST)	1.2	(0.2)	4.0	(0.7)	0.2	1.5	0.1	(2.3)	0.2	2.6
Percent Error = (Error/ACT)	2.3%	-0.4%	7.5%	-1.3%	0.4%	2.7%	0.2%	-4.3%	0.3%	4.5%
Abs. Percent Error	2.3%	0.4%	7.5%	1.3%	0.4%	2.7%	0.2%	4.3%	0.3%	4.5%

Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Industrial*										
Forecast	82.3	75.1	71.9	73.2	71.3	72.1	72.1	86.2	76.4	78.1
Actual	81.8	76.6	71.4	74.4	78.8	80.6	80.1	78.6	79.6	83.7
Error = (ACT-FCST)	(0.5)	1.5	(0.5)	1.2	7.5	8.5	8.0	(7.6)	3.2	5.6
Percent Error = (Error/ACT)	-0.6%	2.0%	-0.7%	1.6%	9.5%	10.5%	10.0%	-9.7%	4.0%	6.7%

Demand,PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
FEI										
Forecast	210.9	204.2	194.7	200.7	198.9	200.0	200.2	216.7	205.2	205.7
Actual	208.6	202.0	199.2	201.9	206.7	209.8	206.4	205.8	209.5	219.3
Error = (ACT-FCST)	(2.3)	(2.2)	4.5	1.2	7.8	9.8	6.2	(10.9)	4.3	13.6
Percent Error = (Error/ACT)	-1.1%	-1.1%	2.3%	0.6%	3.8%	4.7%	3.0%	-5.3%	2.1%	6.2%

* Does not include NGT and Burrard Thermal

3.5 *MAINLAND NET CUSTOMERS*

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	744,400	755,539	755,803	757,161	762,460	773,231	780,005	768,622	780,972	787,836
Actual	740,954	748,913	753,735	760,559	765,553	759,712	766,668	774,083	782,914	790,562
Error = (ACT-FCST)	(3,446)	(6,626)	(2,068)	3,398	3,093	(13,519)	(13,337)	5,461	1,942	2,726
Percent Error = (Error/ACT)	-0.5%	-0.9%	-0.3%	0.4%	0.4%	-1.8%	-1.7%	0.7%	0.2%	0.3%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	74,019	75,037	75,685	77,204	77,954	76,126	76,175	72,922	75,315	76,166
Actual	74,579	75,701	75,986	76,028	76,437	72,235	73,480	74,464	75,451	76,326
Error = (ACT-FCST)	560	664	301	(1,176)	(1,517)	(3,891)	(2,695)	1,542	136	160
Percent Error = (Error/ACT)	0.8%	0.9%	0.4%	-1.5%	-2.0%	-5.4%	-3.7%	2.1%	0.2%	0.2%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	4,332	4,514	4,715	5,083	5,191	4,962	5,002	4,577	4,560	4,497
Actual	4,700	4,869	4,841	4,882	4,863	4,675	4,598	4,625	4,671	4,605
Error = (ACT-FCST)	368	355	126	(201)	(328)	(287)	(404)	48	111	108
Percent Error = (Error/ACT)	7.8%	7.3%	2.6%	-4.1%	-6.7%	-6.1%	-8.8%	1.0%	2.4%	2.3%

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast	1,313	1,423	1,426	1,319	1,328	1,526	1,586	1,634	1,552	1,582
Actual	1,303	1,306	1,348	1,406	1,433	1,520	1,529	1,522	1,573	1,614
Error = (ACT-FCST)	(10)	(117)	(78)	87	105	(6)	(57)	(112)	21	32
Percent Error = (Error/ACT)	-0.8%	-9.0%	-5.8%	6.2%	7.3%	-0.4%	-3.7%	-7.4%	1.3%	2.0%

3.6 MAINLAND NET CUSTOMER ADDITIONS

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	12,764	11,094	6,410	4,777	4,983	6,507	6,774	4,594	6,889	6,863
Actual	12,003	7,959	4,822	6,824	4,994	4,475	6,956	7,415	8,831	7,648
Error = (ACT-FCST)	(761)	(3,135)	(1,588)	2,047	11	(2,032)	182	2,821	1,942	785
Percent Error = (Error/ACT)	-6.3%	-39.4%	-32.9%	30.0%	0.2%	-45.4%	2.6%	38.0%	22.0%	10.3%

											ETS
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016
Rate Schedule 2											
Forecast	523	626	480	713	750	49	49	331	851	851	830
Actual	1,064	1,122	285	42	409	325	1,245	984	987	875	875
Error = (ACT-FCST)	541	496	(195)	(671)	(341)	276	1,196	653	136	24	45
Percent Error = (Error/ACT)	50.8%	44.2%	-68.4%	-1597.6%	-83.4%	84.9%	96.1%	66.4%	13.7%	2.7%	5.1%

											ETS
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016
Rate Schedule 3											
Forecast	(288)	8	7	101	108	40	40	-	(65)	(64)	35
Actual	(69)	169	(28)	41	(19)	(144)	(77)	27	46	(66)	(66)
Error = (ACT-FCST)	219	161	(35)	(60)	(127)	(184)	(117)	27	111	(2)	(101)
Percent Error = (Error/ACT)	-317.4%	95.3%	125.0%	-146.3%	668.4%	127.8%	151.9%	100.0%	241.3%	3.0%	153.0%

											ETS
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016
Rate Schedule 23											
Forecast	147	70	53	9	9	60	60	57	30	30	(12)
Actual	97	3	42	58	27	88	9	(7)	51	41	41
Error = (ACT-FCST)	(50)	(67)	(11)	49	18	28	(51)	(64)	21	11	53
Percent Error = (Error/ACT)	-51.5%	-2233.3%	-26.2%	84.5%	66.7%	31.8%	-566.7%	914.3%	41.2%	26.8%	129.3%

3.7 MAINLAND NORMALIZED USE PER CUSTOMER

	Existing Method											ETS
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016
Rate Schedule 1												
Forecast	100.6	99.8	96.1	91.1	91.7	90.3	90.8	89.9	90.7	88.1	86.3	85.7
Actual	96.8	96.0	92.5	93.3	92.6	90.4	92.2	89.3	88.8	88.7	92.0	92.0
Error = (ACT-FCST)	(3.8)	(3.8)	(3.6)	2.2	0.9	0.1	1.4	(0.6)	(1.9)	0.6	5.7	6.3
Percent Error = (Error/ACT)	-3.9%	-4.0%	-3.9%	2.4%	1.0%	0.1%	1.5%	-0.7%	-2.1%	0.7%	6.2%	6.9%

	Existing Method											ETS
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016 ETS
Rate Schedule 2												
Forecast	307	314	322	303	318	318	308	306	334	329	329	332
Actual	314	317	312	321	311	314	338	330	330	330	338	338
Error = (ACT-FCST)	7	2	(10)	17	(7)	(4)	30	23	(3)	1	10	6
Percent Error = (Error/ACT)	2.3%	0.7%	-3.1%	5.4%	-2.1%	-1.3%	8.8%	7.0%	-1.0%	0.2%	2.8%	1.7%

	Existing Method											ETS
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016 ETS
Rate Schedule 3												
Forecast	3,391	3,394	3,429	2,976	3,346	3,347	3,334	3,316	3,769	3,599	3,537	3,498
Actual	3,314	3,426	3,420	3,372	3,370	3,484	3,566	3,517	3,529	3,524	3,658	3,658
Error = (ACT-FCST)	(77)	32	(9)	396	24	137	232	201	(240)	(75)	121	160
Percent Error = (Error/ACT)	-2.3%	0.9%	-0.3%	11.7%	0.7%	3.9%	6.5%	5.7%	-6.8%	-2.1%	3.3%	4.4%

	Existing Method											ETS
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2016 ETS
Rate Schedule 23												
Forecast	4,979	4,796	4,850	4,391	4,680	4,680	4,901	4,927	5,546	5,309	5,348	5,233
Actual	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,149	5,260	5,157	5,304	5,304
Error = (ACT-FCST)	(293)	(18)	(152)	495	170	458	337	222	(286)	(152)	(44)	71
Percent Error = (Error/ACT)	-6.3%	-0.4%	-3.2%	10.1%	3.5%	8.9%	6.4%	4.3%	-5.4%	-2.9%	-0.8%	1.3%

3.8 MAINLAND NORMALIZED DEMAND

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	73.6	72.0	68.5	69.2	68.6	69.9	69.8	69.5	68.5	67.7
Actual	70.6	68.8	70.0	70.0	68.9	69.8	68.1	68.5	68.9	72.3
Error = (ACT-FCST)	(2.9)	(3.2)	1.5	0.9	0.4	(0.1)	(1.7)	(1.0)	0.4	4.6
Percent Error = (Error/ACT)	-4.1%	-4.6%	2.1%	1.2%	0.5%	-0.2%	-2.5%	-1.5%	0.5%	6.4%
ABS	4.1%	4.6%	2.1%	1.2%	0.5%	0.2%	2.5%	1.5%	0.5%	6.4%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	23.1	24.0	22.9	24.4	24.6	23.4	23.3	24.2	24.7	24.9
Actual	23.5	23.4	24.3	23.6	23.9	24.3	23.9	24.5	24.6	25.6
Error = (ACT-FCST)	0.4	(0.6)	1.4	(0.8)	(0.7)	0.9	0.6	0.2	(0.0)	0.7
Percent Error = (Error/ACT)	1.6%	-2.7%	5.7%	-3.2%	-3.0%	3.6%	2.5%	0.9%	-0.2%	2.7%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	15.5	15.5	14.0	16.8	17.2	16.5	16.5	17.3	16.4	16.0
Actual	16.1	16.3	16.5	16.4	16.9	16.7	16.3	16.3	16.5	16.8
Error = (ACT-FCST)	0.6	0.8	2.5	(0.4)	(0.3)	0.2	(0.2)	(1.0)	0.0	0.8
Percent Error = (Error/ACT)	3.7%	4.9%	15.2%	-2.4%	-1.8%	1.2%	-1.2%	-6.1%	0.3%	5.0%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast	5.7	6.6	6.1	6.1	6.2	7.2	7.5	8.7	8.3	8.4
Actual	5.9	6.2	6.5	6.6	7.4	7.8	7.9	8.0	8.0	8.4
Error = (ACT-FCST)	0.2	(0.4)	0.4	0.5	1.2	0.6	0.4	(0.7)	(0.3)	-
Percent Error = (Error/ACT)	3.4%	-6.5%	6.2%	7.6%	16.2%	7.7%	5.1%	-8.7%	-3.3%	0.0%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Commercial										
Forecast	44.3	46.1	43.0	47.3	48.0	47.1	47.3	50.2	49.3	49.3
Actual	45.5	45.9	47.3	46.6	48.2	48.8	48.1	48.8	49.1	50.8
Error = (ACT-FCST)	1.2	(0.2)	4.3	(0.7)	0.2	1.7	0.8	(1.5)	(0.3)	1.5
Percent Error = (Error/ACT)	2.6%	-0.5%	9.1%	-1.4%	0.4%	3.4%	1.6%	-3.0%	-0.5%	3.0%

3.9 VANCOUVER ISLAND AND WHISTLER AMALGAMATED DATA

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. Tables in Sections 3.10 through 3.17 use this mapped data for historical calculations.

3.10 *VANCOUVER ISLAND NET CUSTOMERS*

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	81,732	85,256	88,394	90,106	92,811	95,460	98,023	95,858	99,921	102,458
Actual	82,210	85,536	88,321	90,671	92,554	92,067	94,173	97,162	100,747	104,358
Error = (ACT-FCST)	478	280	(73)	565	(257)	(3,393)	(3,850)	1,304	826	1,900
Percent Error = (Error/ACT)	0.6%	0.3%	-0.1%	0.6%	-0.3%	-3.7%	-4.1%	1.3%	0.8%	1.8%

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	8,304	8,666	8,718	8,917	9,042	9,081	9,172	8,710	9,047	9,209
Actual	8,461	8,658	8,815	8,900	8,981	8,613	8,691	8,875	9,330	9,459
Error = (ACT-FCST)	157	(8)	97	(17)	(61)	(468)	(481)	165	283	250
Percent Error = (Error/ACT)	1.9%	-0.1%	1.1%	-0.2%	-0.7%	-5.4%	-5.5%	1.9%	3.0%	2.6%

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	548	545	539	527	532	532	536	509	497	479
Actual	531	533	527	525	527	484	476	484	582	531
Error = (ACT-FCST)	(17)	(12)	(12)	(2)	(5)	(48)	(60)	(25)	85	52
Percent Error = (Error/ACT)	-3.2%	-2.3%	-2.3%	-0.4%	-0.9%	-9.9%	-12.6%	-5.2%	14.6%	9.8%

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										83
Actual									141	175
Error = (ACT-FCST)									141	92
Percent Error = (Error/ACT)										52.6%

3.11 *VANCOUVER ISLAND NET CUSTOMER ADDITIONS*

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	3,428	3,479	3,367	2,200	2,705	2,463	2,564	2,001	2,759	2,537
Actual	3,757	3,326	2,785	2,350	1,883	1,845	2,106	2,989	3,583	3,611
Error = (ACT-FCST)	329	(153)	(582)	150	(822)	(618)	(458)	988	824	1074
Percent Error = (Error/ACT)	8.8%	-4.6%	-20.9%	6.4%	-43.7%	-33.5%	-21.7%	33.1%	23.0%	29.8%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	53	165	128	116	125	91	91	71	171	171
Actual	129	197	157	85	81	251	78	184	453	129
Error = (ACT-FCST)	76	32	29	(31)	(44)	160	(13)	113	282	(42)
Percent Error = (Error/ACT)	58.6%	16.3%	18.3%	-36.4%	-54.1%	63.8%	-16.4%	61.1%	62.2%	-32.6%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	3	6	4	4	5	4	4	4	13	13
Actual	(4)	2	(6)	(2)	2	39	(8)	8	98	(51)
Error = (ACT-FCST)	(7)	(4)	(10)	(6)	(3)	35	(12)	4	85	(64)
Percent Error = (Error/ACT)	175.0%	-200.0%	166.7%	300.0%	-150.0%	89.7%	150.0%	50.0%	86.6%	125.5%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										-
Actual									141	(58)
Error = (ACT-FCST)									141	34
Percent Error = (Error/ACT)										-58.6%

3.12 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	57.7	59.3	58.6	55.0	54.9	48.6	46.9	45.0	44.0	45.1
Actual	57.0	56.1	53.5	52.5	51.8	49.5	47.3	47.1	50.5	52.6
Error = (ACT-FCST)	(0.7)	(3.2)	(5.1)	(2.5)	(3.1)	0.9	0.4	2.1	6.5	7.5
Percent Error = (Error/ACT)	-1.2%	-5.7%	-9.5%	-4.8%	-6.0%	1.8%	0.8%	4.5%	12.9%	14.3%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	356.0	353.0	354.0	340.0	337.0	365.0	372.0	390.0	372.0	334.0
Actual	366.0	365.0	361.0	351.0	345.0	369.0	344.0	328.0	346.0	343.0
Error = (ACT-FCST)	10.0	12.0	7.0	11.0	8.0	4.0	(28.0)	(62.0)	(26.0)	9.0
Percent Error = (Error/ACT)	2.7%	3.3%	1.9%	3.1%	2.3%	1.1%	-8.1%	-18.9%	-7.5%	2.6%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	6,512.0	6,499.0	6,454.0	6,295.0	6,349.0	6,351.0	6,398.0	5,896.0	5,896.0	4,030.8
Actual	4,631.0	4,488.0	4,421.0	4,435.0	4,460.0	4,820.0	4,431.0	3,901.0	3,894.0	4,060.0
Error = (ACT-FCST)	(1881.0)	(2011.0)	(2033.0)	(1860.0)	(1889.0)	(1531.0)	(1967.0)	(1995.0)	(2002.0)	29.2
Percent Error = (Error/ACT)	-40.6%	-44.8%	-46.0%	-41.9%	-42.4%	-31.8%	-44.4%	-51.1%	-51.4%	0.7%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										5,996.2
Actual									5,636.0	5,052.0
Error = (ACT-FCST)										(944.2)
Percent Error = (Error/ACT)										-18.7%

3.13 *VANCOUVER ISLAND NORMALIZED DEMAND*

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	4.6	4.9	5.1	4.9	5.0	4.6	4.5	4.3	4.3	4.6
Actual	4.6	4.7	4.6	4.7	4.7	4.5	4.4	4.5	5.0	5.4
Error = (ACT-FCST)	-	(0.2)	(0.5)	(0.2)	(0.3)	(0.1)	(0.1)	0.2	0.6	0.8
Percent Error = (Error/ACT)	0.0%	-4.3%	-10.9%	-4.3%	-6.4%	-2.2%	-2.3%	4.4%	12.9%	15.6%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	2.9	3.0	3.1	3.0	3.0	3.3	3.4	3.3	3.3	3.0
Actual	3.1	3.1	3.2	3.1	3.1	3.1	3.0	2.9	3.2	3.2
Error = (ACT-FCST)	0.2	0.1	0.1	0.1	0.1	(0.2)	(0.4)	(0.5)	(0.2)	0.2
Percent Error = (Error/ACT)	5.2%	3.2%	2.5%	3.2%	1.6%	-5.1%	-14.9%	-16.0%	-4.7%	6.3%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	2.4	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.5	1.9
Actual	2.5	2.4	2.4	2.3	2.3	2.3	2.1	1.9	2.4	2.2
Error = (ACT-FCST)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.1)	(0.3)	(0.5)	(0.1)	0.3
Percent Error = (Error/ACT)	1.6%	-4.2%	-5.1%	-6.8%	-8.1%	-2.6%	-13.7%	-28.3%	-5.0%	13.6%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										0.5
Actual									0.5	0.8
Error = (ACT-FCST)									(0.5)	(0.3)
Percent Error = (Error/ACT)										-37.5%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Commercial										
Forecast	5.3	5.5	5.5	5.5	5.6	5.7	5.8	5.7	5.9	5.4
Actual	5.5	5.5	5.5	5.5	5.4	5.5	5.1	4.8	6.2	6.2
Error = (ACT-FCST)	0.2	-	(0.0)	(0.1)	(0.1)	(0.2)	(0.7)	(1.0)	0.3	0.8
Percent Error = (Error/ACT)	3.6%	0.0%	-0.7%	-1.1%	-2.6%	-4.0%	-14.4%	-20.8%	4.4%	12.9%

3.14 WHISTLER NET CUSTOMERS

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	2,171	2,124	2,178	2,272	2,321	2,289	2,303	2,372	2,478	2,536
Actual	2,098	2,134	2,250	2,262	2,296	2,271	2,348	2,416	2,508	2,608
Error = (ACT-FCST)	-73	10	72	-10	-25	-18	45	44	30	72
Percent Error = (Error/ACT)	-3.5%	0.5%	3.2%	-0.4%	-1.1%	-0.8%	1.9%	1.8%	1.2%	2.8%

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	268	254	264	263	267	275	280	291	289	292
Actual	249	260	263	265	286	274	281	285	295	289
Error = (ACT-FCST)	-19	6	-1	2	19	-1	1	-6	6	-3
Percent Error = (Error/ACT)	-7.6%	2.3%	-0.4%	0.8%	6.6%	-0.4%	0.4%	-2.1%	2.0%	-1.0%

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	62	57	62	61	62	59	59	61	60	59
Actual	59	58	61	59	61	61	60	60	48	53
Error = (ACT-FCST)	-3	1	-1	-2	-1	2	1	-1	-12	-6
Percent Error = (Error/ACT)	-5.1%	1.7%	-1.6%	-3.4%	-1.6%	3.3%	1.7%	-1.7%	-25.0%	-11.3%

Customers	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										5
Actual									10	14
Error = (ACT-FCST)									10	9
Percent Error = (Error/ACT)										64.3%

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	75	30	50	35	36	14	14	52	62	61
Actual	34	36	116	12	34	51	77	68	92	100
Error = (ACT-FCST)	(41)	6	66	(23)	(2)	37	63	16	30	39
Percent Error = (Error/ACT)	-120.6%	16.7%	56.9%	-191.7%	-5.9%	72.5%	81.8%	23.5%	32.6%	39.0%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	12	5	10	1	2	5	5	9	4	4
Actual	5	11	3	2	21	-	7	5	10	(6)
Error = (ACT-FCST)	(7)	6	(7)	1	19	(5)	2	(4)	6	(10)
Percent Error = (Error/ACT)	-144.9%	54.5%	-233.3%	50.0%	90.5%		28.6%	-80.0%	60.0%	166.7%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	1		3		1				-	-
Actual	2	(1)	3		2	(0)	(1)	(0)	(12)	11
Error = (ACT-FCST)	1		(0)		1				(12)	5
Percent Error = (Error/ACT)	52.8%		-2.3%		41.1%					45.5%

Customer Additions	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										-
Actual									10	4
Error = (ACT-FCST)									10	4
Percent Error = (Error/ACT)										100.0%

3.16 *WHISTLER NORMALIZED USE PER CUSTOMER*

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	89.9	88.2	90.1	92.1	82.3	104.0	106.3	90.6	79.7	85.1
Actual	95.7	89.9	82.6	99.5	94.7	89.4	87.3	87.6	91.3	97.7
Error = (ACT-FCST)	6	2	-8	7	12	-15	-19	-3	12	13
Percent Error = (Error/ACT)	6.1%	1.9%	-9.1%	7.4%	13.1%	-16.3%	-21.8%	-3.4%	12.7%	12.9%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	414.0	431.0	456.0	464.0	430.0	610.0	637.0	464.0	408.0	465.0
Actual	489.0	502.0	427.0	563.0	506.0	429.0	465.0	471.0	660.0	520.2
Error = (ACT-FCST)	75	71	-29	99	76	-181	-172	7	252	55
Percent Error = (Error/ACT)	15.3%	14.1%	-6.8%	17.6%	15.0%	-42.2%	-37.0%	1.5%	38.2%	10.6%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	5,286.0	5,286.0	5,092.0	4,894.0	4,114.0	3,876.0	3,630.0	3,595.0	3,822.0	4,326.0
Actual	5,107.0	4,641.0	4,037.0	4,512.0	4,271.0	3,822.0	4,213.0	4,285.0	5,618.0	5,638.0
Error = (ACT-FCST)	-179	-645	-1,055	-382	157	-54	583	690	1,796	1,312
Percent Error = (Error/ACT)	-3.5%	-13.9%	-26.1%	-8.5%	3.7%	-1.4%	13.8%	16.1%	32.0%	23.3%

UPC, GJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										5,888.0
Actual									4,328.0	5,078.0
Error = (ACT-FCST)										-810
Percent Error = (Error/ACT)										-16.0%

3.17 *WHISTLER NORMALIZED DEMAND*

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 1										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Actual	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Error = (ACT-FCST)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0
Percent Error = (Error/ACT)	3.5%	2.0%	-7.5%	7.5%	12.0%	-14.2%	-21.5%	-1.4%	0.0%	14.6%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 2										
Forecast	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1
Actual	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2	0.2
Error = (ACT-FCST)	0.0	0.0	(0.0)	0.0	0.0	(0.0)	(0.0)	0.0	0.1	0.0
Percent Error = (Error/ACT)	8.3%	15.4%	-9.1%	20.0%	21.4%	-33.3%	-30.8%	0.0%	36.8%	10.0%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 3										
Forecast	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.3
Actual	0.3	0.3	0.2	0.3	0.3	0.2	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	(0.0)	(0.0)	(0.1)	(0.0)	0.0	0.0	0.0	0.0	0.1	0.0
Percent Error = (Error/ACT)	-10.3%	-11.1%	-29.2%	-11.1%	3.8%	0.0%	15.4%	15.4%	17.9%	13.3%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate Schedule 23										
Forecast										0.03
Actual									0.03	0.06
Error = (ACT-FCST)										0.03
Percent Error = (Error/ACT)										50.9%

Demand, PJs	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Commercial										
Forecast	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Actual	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
Error = (ACT-FCST)	(0.0)	(0.0)	(0.1)	0.0	0.0	(0.0)	0.0	0.0	0.2	0.1
Percent Error = (Error/ACT)	-4.9%	-2.5%	-22.9%	0.0%	10.0%	-11.4%	0.0%	10.3%	30.0%	16.8%

3.18 *HOLT'S EXPONENTIAL SMOOTHING (ETS) TEST FORECASTS*

3.18.1 Residential UPC Forecast Results Update

Consistent with the approach taken in Appendix A4 of the Annual Review for 2017 Rates, residential use rates were calculated using the ETS method for the Lower Mainland, Inland and Columbia regions. All other aspects of the forecast were unaltered. The resulting residential demand forecast is shown below.

The Mainland residential demand forecast for 2016 using the existing method was 67.7 PJs. The ETS forecast was almost identical at 67.8 PJs. As a result, the MAPE calculated from 2012 through 2016 remains almost identical for the two methods at just over 2 percent.

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2016 MAPE
Existing	2012	2010	69.9	69.8	0.1%	
	2013	2010	69.8	68.1	2.5%	
	2014	2012	69.5	68.5	1.5%	
	2015	2013	68.5	68.9	0.6%	
	2016	2014	67.7	72.3	6.4%	2.2%
ETS	2012	2010	68.4	69.8	2.1%	
	2013	2010	67.6	68.1	0.7%	
	2014	2012	68.9	68.5	0.6%	
	2015	2013	67.6	68.9	1.9%	
	2016	2014	67.8	72.3	6.2%	2.3%

3.18.2 Commercial UPC Forecast Results Update

Consistent with the approach taken in Appendix A4 of the Annual Review for 2017 Rates, separate commercial use rates were prepared for Rate Schedules 1, 2, 3 and 23 for the Lower Mainland, Inland and Columbia regions using the ETS method. All other aspects of the forecast were unaltered. The resulting commercial demand forecast is shown below.

The Mainland commercial demand forecast for 2016 using the existing method was 49.1 PJs. The ETS forecast was higher at 49.9 PJs and closer to the actual demand of 50.8 PJs. The 2016 error for the ETS method was 1.7 percent compared to 2.9 percent for the Existing method. As a result, the ETS MAPE calculated from 2012 through 2016 is 0.9 percent, while the MAPE for the existing method is 2.3 percent.

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2016 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	
	2016	2014	49.3	50.8	2.9%	2.3%
ETS	2012	2010	48.1	48.8	1.4%	
	2013	2010	48.5	48.1	0.8%	
	2014	2012	48.5	48.8	0.5%	
	2015	2013	49.1	49.1	0.0%	
	2016	2014	49.9	50.8	1.7%	0.9%

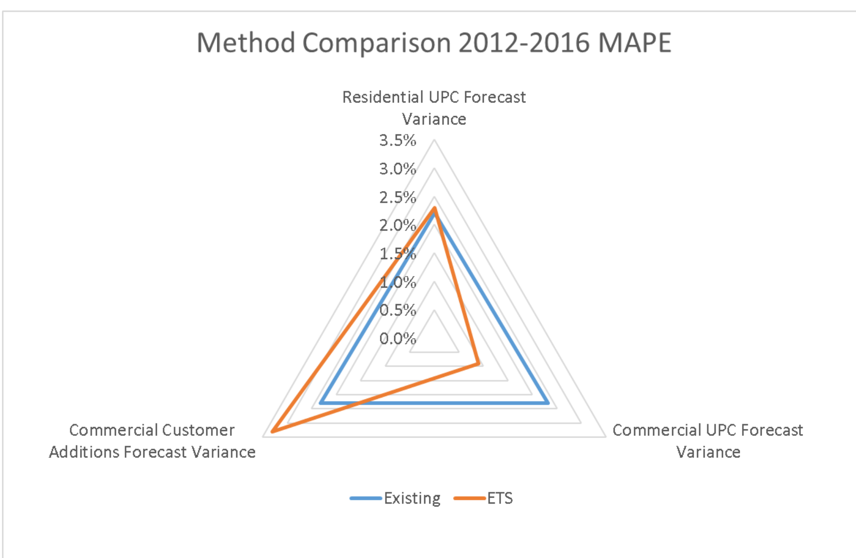
3.18.3 Commercial Customer Additions Forecast Update

Consistent with the approach taken in Appendix A4 of the Annual Review for 2017 Rates, separate commercial customer additions forecasts were prepared for Rate Schedules 1, 2, 3 and 23 for the Lower Mainland, Inland and Columbia regions using the ETS method. All other aspects of the forecast were unaltered. The resulting commercial demand forecast is shown below. The Mainland commercial demand forecast for 2016 using the existing method was 49.3 PJs. The ETS forecast was lower at 48.4 PJs. The 2016 error for ETS was 3.3 percent compared to 2.4 percent for the existing method. As a result, the ETS MAPE calculated from 2012 through 2016 is 3.3 percent, while the MAPE for the existing method is less at 2.3 percent.

	Year	Data Cutoff	Forecast Demand	Actual Demand (PJs)	APE	2012-2016 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	
	2016	2014	49.3	50.8	2.9%	2.3%
ETS	2012	2010	46.2	48.8	5.3%	
	2013	2010	46.7	48.1	3.0%	
	2014	2012	50.3	48.8	3.1%	
	2015	2013	48.8	49.1	0.5%	
	2016	2014	48.4	50.8	4.7%	3.3%

3.18.4 Evaluation

The following chart compares the performance of the ETS method with the existing method in the three areas under investigation.



The blue triangle represents the MAPE scores for the existing method for each of the three tests. The orange line represents the MAPE scores for ETS. Lines closer to the center of the plot are better. The chart shows that for residential UPC the scores for the two methods are very close. For commercial use rates, the ETS method performed better. For commercial customer additions, the existing method performed better.

Appendix A2-1

HISTORICAL FORECAST AND CONSOLIDATED TABLES

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix A3

Demand Forecast Methods

Table of Contents

List of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides a detailed description of its demand forecast method.

The following table shows the high level method 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 2018 demand forecast, in the following order:

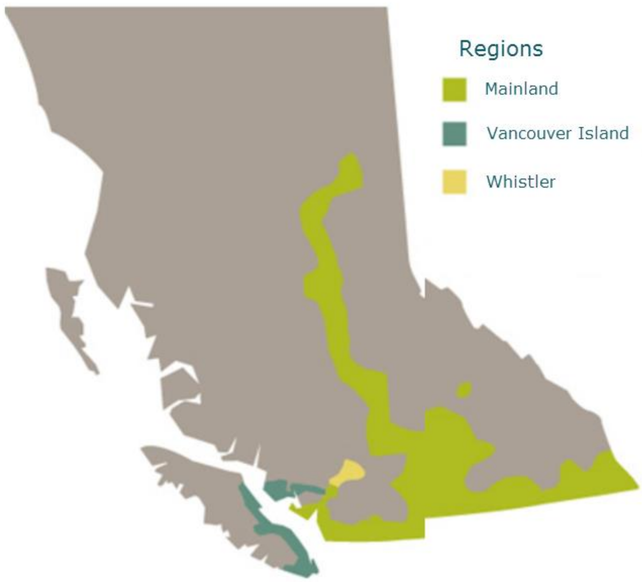
- Residential Customer Additions
- Commercial Customer Additions
- Residential Use Rate
- Commercial Use Rate
- Residential and Commercial Demand Forecast
- Industrial Demand Forecast

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.
- **Forecast Year(s)**: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or two or more years depending on the filing.
- **Seed Year:** The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing.

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.

Industrial	
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.

3. RESIDENTIAL CUSTOMER ADDITIONS

The residential net customer additions forecast was developed based on housing starts data from CBOC forecast of November 10, 2016 Provincial Medium Term Forecast: 20163 Run: 17, Table LTPF156 and LTPF157. The housing starts data was as follows:

Table A3-3: Housing Starts Data

Housing Type	2015	2016	2017S	2018F
SFD	10,152	12,676	10,689	9,963
MFD	21,294	29,466	25,865	25,001
Total	31,446	42,143	36,554	34,964

From the above housing starts forecast, the 2017S SFD growth rate is calculated as follows:

$$2017S\ SFD\ Growth\ Rate = \left(\frac{10{,}689}{12{,}676}\right) - 1 = -15.7\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

Table A3-4: Growth Rates

	2017S	2018F
SFD	-15.7%	-6.8%
MFD	-12.2%	-3.3%

The following table incorporates the FEI proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2016 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally the CBOC growth rates for 2017 are applied to the SFD and MFD proportions for 2017 in column F and G and for 2018 in column I and J.

Table A3-5: FEI Proportions of Actual Account Additions by SFD and MFD

	Internal Split		2016A			2017S			2018F		
Sub- Region	% SFD	% MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
	A	B	C	D	E	F	G	H	I	J	K
Mainland			7,648	4,582	3,066	3,864	2,691	6,555	3,601	2,601	6,203
Lower Mainland	45%	55%	4,412	1,994	2,418	1,682	2,122	3,804	1,567	2,051	3,619
Inland	80%	20%	2,999	2,398	601	2,022	528	2,550	1,885	510	2,395
Columbia	75%	25%	185	140	45	118	40	158	110	38	148
Revelstoke	97%	3%	52	50	2	42	2	44	40	1	41
Whistler	60%	40%	100	60	40	50	35	86	47	34	81
Vancouver Island	92%	8%	3,611	3,309	302	2,791	265	3,055	2,601	256	2,857
Total FEU			**11,359**	**7,951**	**3,408**	**6,705**	**2,991**	**9,696**	**6,250**	**2,891**	**9,141**

For example, the Lower Mainland 2018F SFD value of 1,567 (column I) is derived as follows:

- Lower Mainland 2016 Internal Split – SFD percentage = 45% (column A)
- Lower Mainland 2016 Actual additions = 4,412 (column C)

$$LML\ 2016A\ Actual\ SFD = 45\%\ \times 4{,}412 = 1{,}994\ (column\ D)$$

$$LML\ 2017S\ Forecast\ SFD =\ -15.7\% \times 1{,}994 = 1{,}682\ (column\ F)$$

$$LML\ 2018F\ Forecast\ SFD = -6.8\% \times 1{,}682 = 1{,}567\ (column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated as an average of the net customers additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland Rate Schedule 2.

Table A3-6: Customer Additions for Lower Mainland Rate Schedule 2

Year	Customers	Customer Additions	Average 2014-2016
2013	50,749		
2014	51,423	674	
2015	52,124	701	
2016	52,790	666	680
2017S	53,470		
2018F	54,150		

The three-year average additions was 680, so 680 net additions are forecast in each of 2017 and 2018.

$$2017S\ Customers = 2016\ Customer\ Additions + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2017S = 53{,}470 = 52{,}790 + 680$$

Identical calculations are completed for all regions and all commercial rate schedules.

5. RESIDENTIAL USE RATE

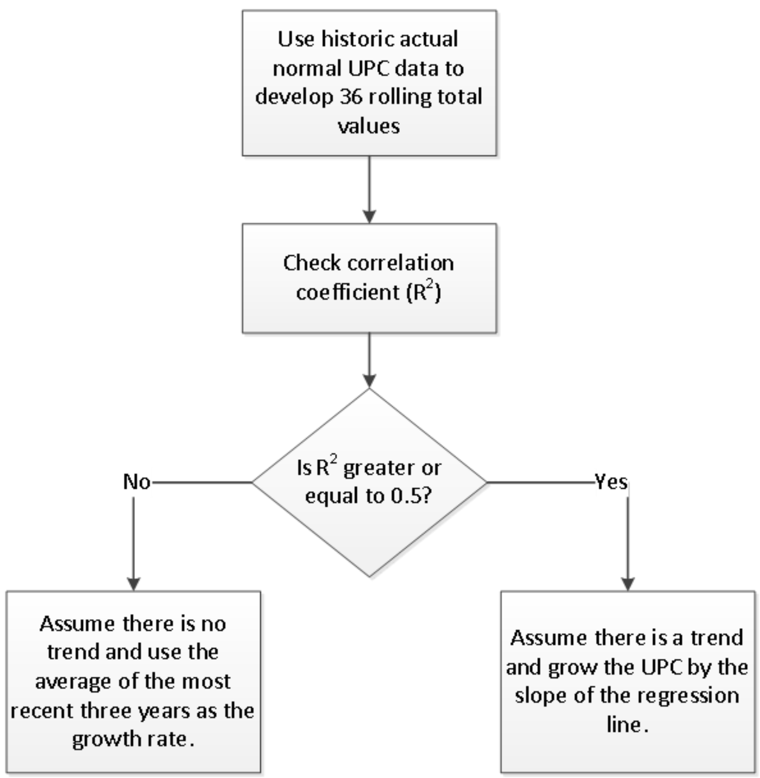
The Residential Demand Forecast is the product of the number of residential customers and the residential use rate. This section describes the method for forecasting the residential use rate.

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 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 A3-2: Residential Use Rate Forecast Method



The UPC method for Lower Mainland Rate Schedule 1 (residential) is demonstrated below. The Mainland UPC forecasts are developed from individual forecasts for the Lower Mainland, Inland and Columbia regions. Calculations for the Inland and Columbia regions are identical to the Lower Mainland so are not shown here.

(i) ***Lower Mainland Rate Schedule 1***

The rolling 12-month UPCs for Lower Mainland Rate Schedule 1 were calculated as follows:

Table A3-7: Rolling 12-month UPCs for Lower Mainland Schedule 1

LML RS 1	Monthly UPC	12 Month Rolling UPC	Period
Jan-2013	14.71		
Feb-2013	12.30		
Mar-2013	11.32		
Apr-2013	7.90		
May-2013	4.96		
Jun-2013	3.48		
Jul-2013	2.65		
Aug-2013	2.74		
Sep-2013	3.60		
Oct-2013	6.86		
Nov-2013	11.03		
Dec-2013	14.46		
Jan-2014	14.14	95.44	1
Feb-2014	11.53	94.67	2
Mar-2014	11.05	94.39	3
Apr-2014	8.14	94.63	4
May-2014	4.85	94.52	5
Jun-2014	3.14	94.19	6
Jul-2014	2.82	94.36	7
Aug-2014	2.86	94.49	8
Sep-2014	3.14	94.03	9
Oct-2014	7.31	94.48	10
Nov-2014	10.72	94.18	11
Dec-2014	14.98	94.70	12
Jan-2015	14.86	95.41	13
Feb-2015	11.74	95.63	14
Mar-2015	10.45	95.03	15
Apr-2015	7.56	94.45	16
May-2015	4.93	94.53	17
Jun-2015	3.82	95.20	18
Jul-2015	2.84	95.22	19
Aug-2015	2.39	94.75	20
Sep-2015	3.14	94.76	21
Oct-2015	6.32	93.76	22
Nov-2015	10.77	93.81	23
Dec-2015	15.33	94.15	24
Jan-2016	14.75	94.04	25
Feb-2016	13.47	95.77	26
Mar-2016	11.51	96.83	27
Apr-2016	7.49	96.77	28
May-2016	4.66	96.49	29
Jun-2016	3.38	96.05	30
Jul-2016	2.63	95.85	31
Aug-2016	2.56	96.01	32
Sep-2016	2.95	95.82	33
Oct-2016	7.50	96.99	34
Nov-2016	13.08	99.30	35
Dec-2016	14.22	98.19	36

The following summary is developed.

Table A3-8: UPC Calculation Summary

	A	B	C	D	E	F	G
1		2013	2014	2015	2016	2017S	2018F
2	UPC	96.01	94.70	94.15	98.19	98.96	99.73
3	Correlation	43%					
4	Result	Use 3 Yr Avg					
5	Growth		-1.36%	-0.58%	4.29%		
6	3 Yr avg	0.78%					
7	Slope	0.0768	0.92				

The R^2 (correlation) is 43 percent (row 3), so a three year average is used, as per the flow chart above.

The 2017 seed year forecast is developed by multiplying one plus the three-year average growth rate (0.78%, row 6) tby the 2016 actual UPC (98.19, in E2) as follows:

$$2017S\ UPC = 98.19\ \times (1 + 0.78\%) = 98.96\ GJs$$

The 2018 forecast is developed by multiplying one plus the three year average growth rate (0.78%) by the 2017 seed year forecast UPC (98.96) as follows:

$$2018F\ UPC = 98.96 \times (1 + 0.78\%) = 99.73\ GJs$$

6. COMMERCIAL USE RATE

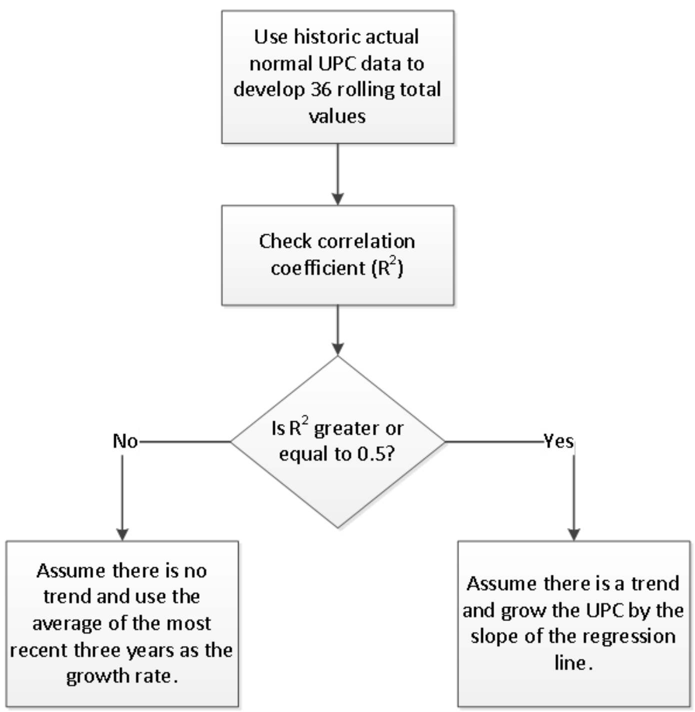
The following sections show how the use rate method works for the commercial forecast. The following method applies to all sub-regions and Rate Schedules 2, 3 and 23.

6.1 *MONTHLY WEATHER-NORMALIZED ACTUAL UPCS*

FEI develops its commercial 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 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 A3-3: Commercial Use Rate Forecast Method



The UPC method for Lower Mainland Rate Schedule 3 is demonstrated below. The Mainland UPC forecasts are developed from individual forecasts for the Lower Mainland, Inland and Columbia regions. Calculations for the Inland and Columbia regions are identical to the Lower Mainland so are not shown here.

(i) ***<u>Lower Mainland Rate Schedule 2</u>***

The rolling 12-month UPCs for Lower Mainland Rate Schedule 2 were calculated as follows:

Table A3-9: Rolling 12-month UPCs for Lower Mainland Rate Schedule 2

LML RS 2	Monthly UPC	12 Month Rolling UPC	Period
Jan-2013	53.86		
Feb-2013	44.85		
Mar-2013	40.93		
Apr-2013	28.26		
May-2013	18.32		
Jun-2013	12.96		
Jul-2013	9.82		
Aug-2013	10.38		
Sep-2013	13.29		
Oct-2013	24.07		
Nov-2013	38.36		
Dec-2013	53.69		
Jan-2014	52.76	347.69	1
Feb-2014	41.85	344.69	2
Mar-2014	40.20	343.96	3
Apr-2014	29.08	344.78	4
May-2014	18.03	344.49	5
Jun-2014	11.79	343.32	6
Jul-2014	10.76	344.26	7
Aug-2014	11.03	344.92	8
Sep-2014	12.14	343.76	9
Oct-2014	26.52	346.21	10
Nov-2014	37.54	345.39	11
Dec-2014	55.41	347.10	12
Jan-2015	56.17	350.52	13
Feb-2015	43.14	351.81	14
Mar-2015	37.62	349.24	15
Apr-2015	26.61	346.77	16
May-2015	18.30	347.03	17
Jun-2015	13.98	349.22	18
Jul-2015	10.90	349.36	19
Aug-2015	9.47	347.79	20
Sep-2015	11.99	347.64	21
Oct-2015	22.91	344.03	22
Nov-2015	37.37	343.86	23
Dec-2015	56.67	345.12	24
Jan-2016	56.00	344.95	25
Feb-2016	49.04	350.85	26
Mar-2016	41.40	354.63	27
Apr-2016	26.86	354.87	28
May-2016	16.91	353.48	29
Jun-2016	12.42	351.92	30
Jul-2016	10.01	351.03	31
Aug-2016	9.82	351.39	32
Sep-2016	11.04	350.44	33
Oct-2016	26.46	353.99	34
Nov-2016	45.44	362.07	35
Dec-2016	51.78	357.19	36

The following summary is developed.

Table A3-10: UPC Calculation Summary

	A	B	C	D	E	F	G
1		**2013**	**2014**	**2015**	**2016**	**2017S**	**2018F**
2	**UPC**	348.80	347.10	345.12	357.19	360.84	364.49
3	**Correlation**	53%					
4	**Result**	Use regression					
5	**Growth**		-0.5%	-0.6%	3.5%		
6	**3 Yr avg**	0.8%					
7	**Slope**	0.3042	3.65				

The R^2 (correlation) is 53 percent, so a regression is used, as per the flow chart above.

The 2017 seed year forecast is developed by adding the annual slope in C7 (3.65) to the 2016 year end value in E2 (357.19) as follows:

$$2017S\ UPC = 357.19 + 3.65 = 360.84\ GJs$$

The 2018F forecast is developed by adding the annual slope in C7 (3.65) to the 2017 seed forecast as follows:

$$2018F\ UPC = 360.84 + 3.65 = 364.49\ GJs$$

6.2 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. The amalgamated use rates are calculated using the following relationship:

$$Use\ Rate = \frac{\sum Volume}{\sum Accounts}$$

FIS calculates both the monthly volume and accounts by region and rate class. In an external spreadsheet the volumes and accounts are summed by month and by rate class for all regions.

7. UPC METHODS

The following table shows the use rate calculation method used for each region and rate class for the 2018 Forecast.

Table A3-11: Use Rate Calculation Method

Region	Rate Schedule	Method Applied for 2018F
LowerMainland	RS 1	3 Year Average Model
	RS 2	Regression Model
	RS 3	3 Year Average Model
	RS23	3 Year Average Model
Inland	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	Regression Model
	RS23	3 Year Average Model
Columbia	RS 1	3 Year Average Model
	RS 2	Regression Model
	RS 3	3 Year Average Model
	RS23	Regression Model
Revelstoke	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
Vancouver Island	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23*	Used Average due to lack of historic data points
Whistler	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	Regression Model
	RS 23*	Used Average due to lack of historic data points

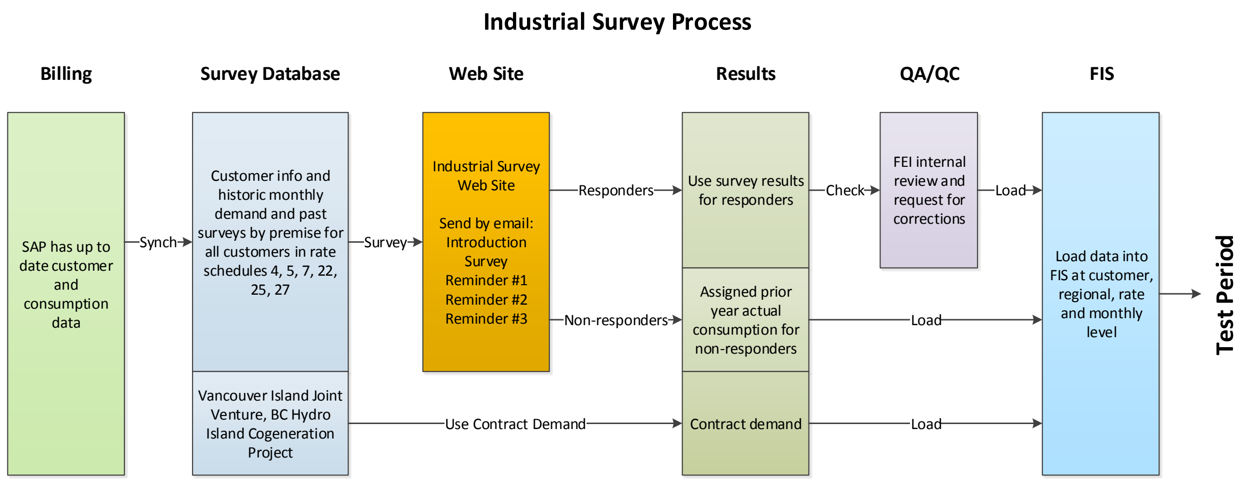
8. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast at the sub-regional level. The sub-regions, regions and months are then summed to arrive at the amalgamated demand forecast.

9. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure A3-4: 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.

9.1 *CREATE THE SURVEY*

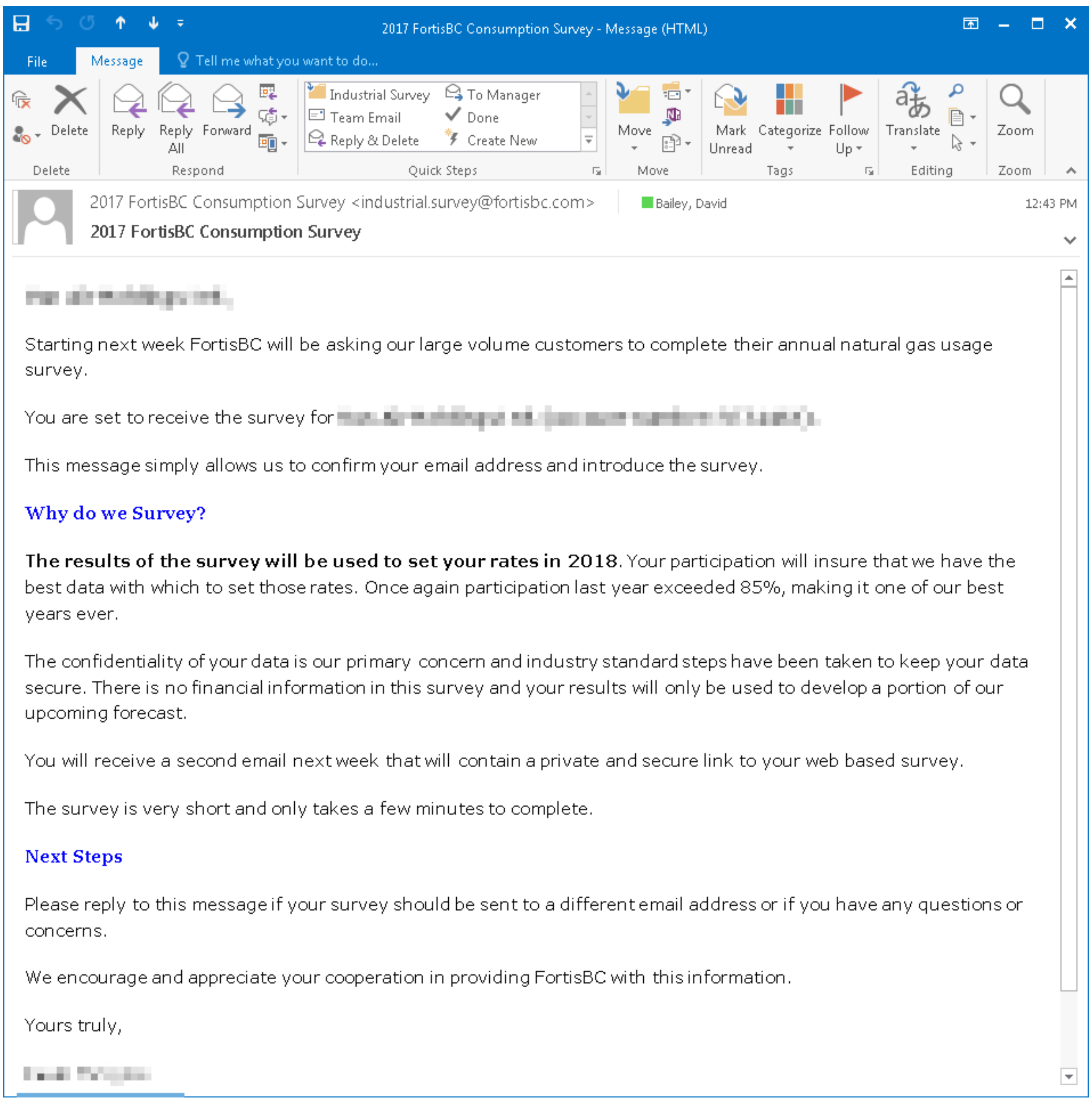
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

9.2 *SEND OUT THE INTRODUCTION EMAIL*

The customer is introduced to the survey several days before the actual surveys are sent out. This allows the customer time to update their contact information and possibly to assign the survey to a different employee if there have been staffing changes. FEI has found this to be an important step and contributes to the high success rate because a minimal number of surveys are sent to the wrong person.

The survey web site creates the form letters and manages the send out. The following is an example of the introductory email.

Figure A3-5: Survey Introductory Email Example



Starting next week FortisBC will be asking our large volume customers to complete their annual natural gas usage survey.

You are set to receive the survey for

This message simply allows us to confirm your email address and introduce the survey.

Why do we Survey?

The results of the survey will be used to set your rates in 2018. Your participation will insure that we have the best data with which to set those rates. Once again participation last year exceeded 85%, making it one of our best years ever.

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 next week that will contain a private and secure 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.

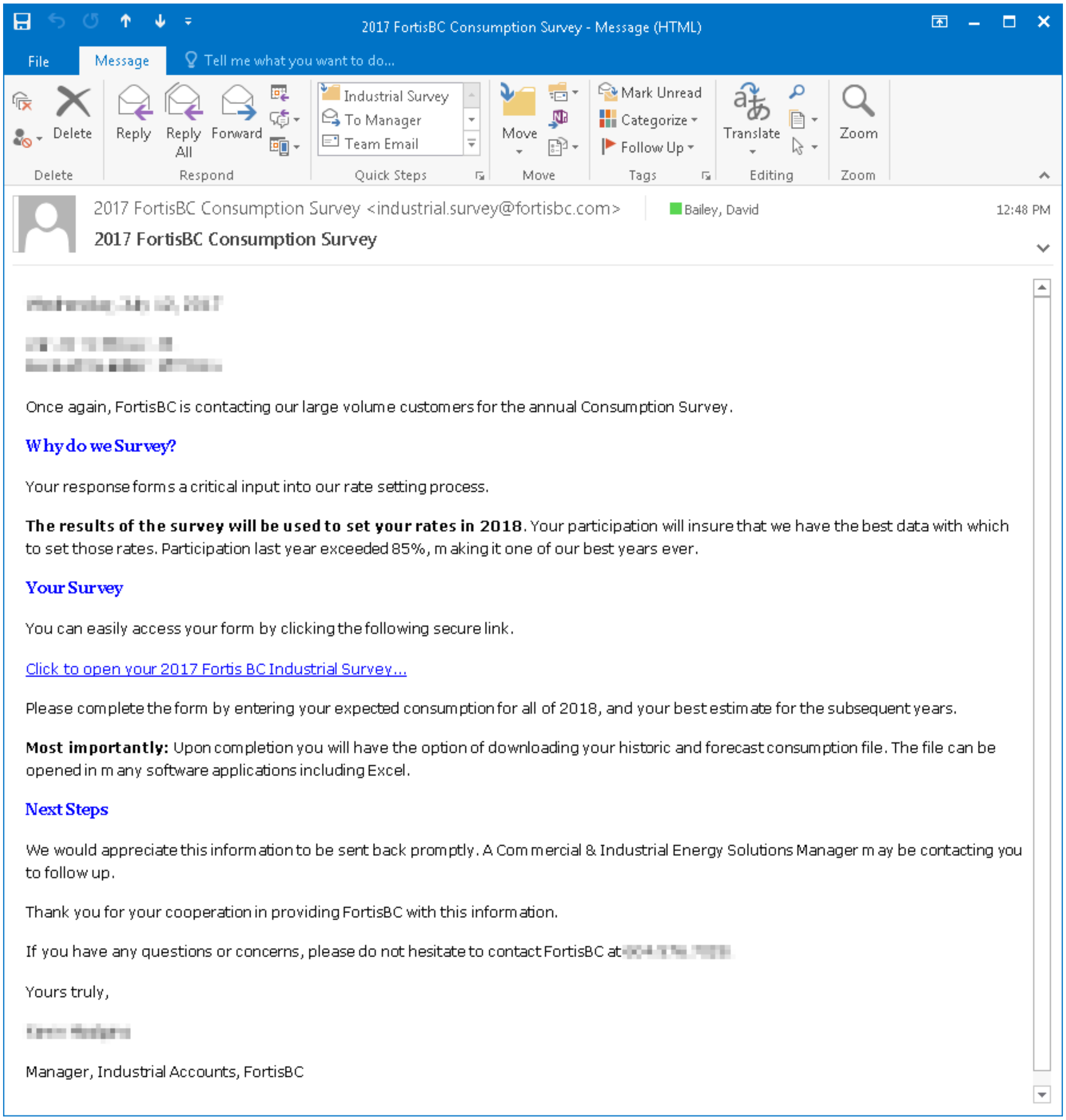
Yours truly,

Replies to these emails are used to update the contact and other information in the survey web site.

9.3 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 A3-6: Survey Email Example



2017 FortisBC Consumption Survey - Message (HTML)

File | Message | Tell me what you want to do...

Delete | Reply | Reply All | Forward | Industrial Survey | To Manager | Team Email | Move | Mark Unread | Categorize | Follow Up | Translate | Zoom

Delete | Respond | Quick Steps | Move | Tags | Editing | Zoom

2017 FortisBC Consumption Survey <industrial.survey@fortisbc.com> | Bailey, David | 12:48 PM

2017 FortisBC Consumption Survey

[illegible]

[illegible]
[illegible]

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 2018. Your participation will insure that we have the best data with which to set those rates. Participation last year exceeded 85%, making it one of our best years ever.

Your Survey

You can easily access your form by clicking the following secure link.

Click to open your 2017 Fortis BC Industrial Survey...

Please complete the form by entering your expected consumption for all of 2018, and your best estimate for the subsequent years.

Most importantly: Upon completion you will have the option of downloading your historic and forecast consumption file. The file can be opened in many software applications including Excel.

Next Steps

We would appreciate this information to be sent back promptly. A Commercial & Industrial Energy Solutions Manager may be contacting you to follow up.

Thank you for your cooperation in providing FortisBC with this information.

If you have any questions or concerns, please do not hesitate to contact FortisBC at [illegible]

Yours truly,

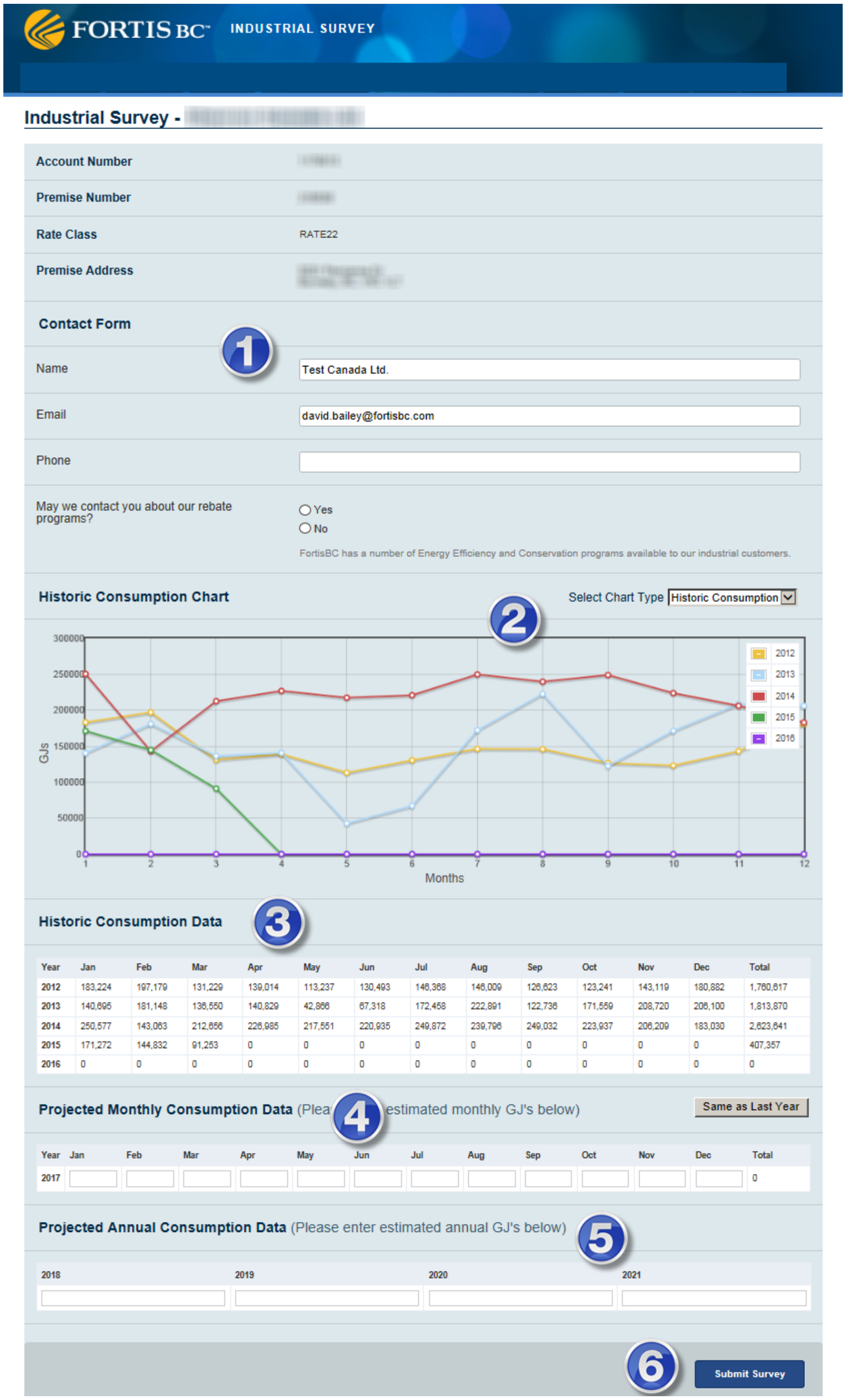
[illegible]

Manager, Industrial Accounts, FortisBC

9.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

1 **Figure A3-7: Survey (Web) Form Example**



FORTIS BC INDUSTRIAL SURVEY

Industrial Survey -

Account Number

Premise Number

Rate Class RATE22

Premise Address

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	1,780,617
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 customer's 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 shown for the prior five years. Zeroes are shown in this example because the survey database is not updated until the start of a real survey.

4) The customer is asked for monthly consumption for the coming year. The total at the right side is automatically updated to reduce typing errors. If the customer believes that its consumption is not changing they can use the "Same as last year" button as a fast alternative to typing in the same values.

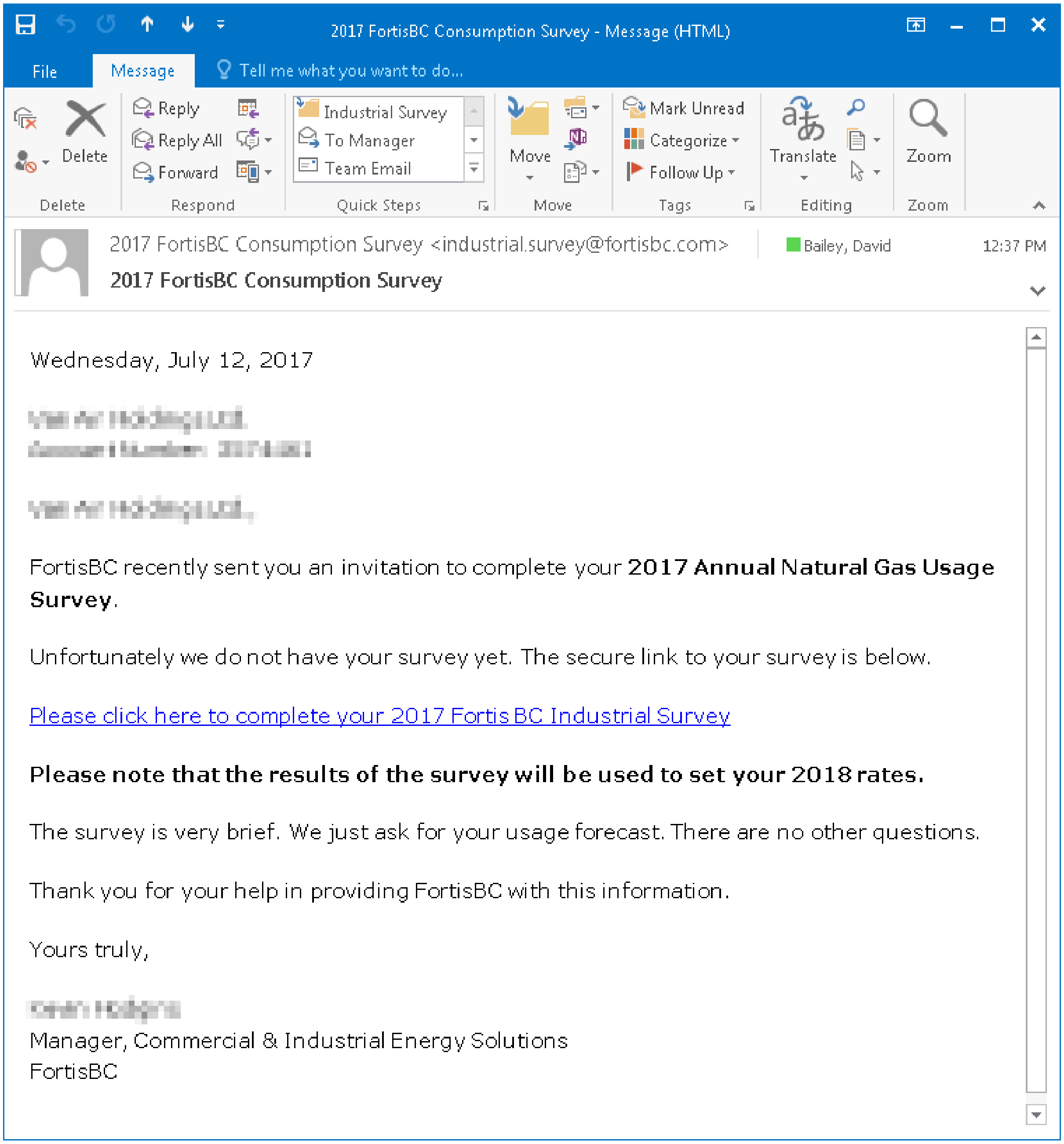
5) Annual forecasts are requested for the remaining 4 years of the survey.

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.

9.5 *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 A3-8: Example of Survey Reminder Email



Wednesday, July 12, 2017

FortisBC recently sent you an invitation to complete your **2017 Annual Natural Gas Usage Survey**.

Unfortunately we do not have your survey yet. The secure link to your survey is below.

Please click here to complete your 2017 Fortis BC Industrial Survey

Please note that the results of the survey will be used to set your 2018 rates.

The survey is very brief. We just ask for your usage forecast. There are no other questions.

Thank you for your help in providing FortisBC with this information.

Yours truly,

Manager, Commercial & Industrial Energy Solutions
FortisBC

9.6 *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.

Figure A3-9: Example of Survey Results Dashboard

9.7 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.

9.8 *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 year's consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

10. SUMMARY OF DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month, region and rate class to prepare the overall forecast of demand.

11. HOLTS LINEAR EXPONENTIAL SMOOTHING METHOD

The Holts Linear Exponential Smoothing method (ETS) is implemented as a “wizard” in Excel 2016 and, as a result, intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in its software. Therefore, to demonstrate the key elements of the method, a manual model is required. The model shown below uses accepted practices, but may differ from the optimization methods and strategies used by Microsoft in Excel 2016.

ETS is applied in the same manner to all data sets, including use rates and customers. Given that the illustration of ETS is quite technical (as shown below) and the same for all data sets, FEI has provided one illustration.

Below FEI illustrates how ETS can be used to develop the 2015 forecast UPC for the Lower Mainland. To do this, FEI first introduces the three equations used in ETS and sample Lower Mainland UPC data for purposes of the illustration. FEI then explains how the equations are used with the data to develop the 2015 forecast UPC for the Lower Mainland.

<u>ETS Equations and Sample Data</u>

The three equations used in ETS to develop level, trend and forecast data are shown below:

Table A3-12: ETS Equations

Reference Number	Description	Equation
1	Level forecast at time t	$L_t = \alpha Y_t + (1-\alpha)(L_{t-1} + b_{t-1})$
2	Trend forecast at time t	$b_t = \beta(L_t - L_{t-1}) + (1-\beta)b_{t-1}$
3	Aggregate forecast at time t	$F_{t+m} = L_t + b_t m$

Sample Lower Mainland UPC data (GJ) is provided below, including actual and forecast data from 2004 to 2013 and forecast data for 2014 and 2015. In the discussion below, the 2015 forecast value of 94.04 GJ in row 12, column 6 of the table below will be developed using the three ETS equations above.

Table A3-13: Sample Lower Mainland UPC ETS Calculation

	Alpha	**0.500**					
	Beta	**0.000**					
	1	2	3	4	5	6	7
	Date	**Actual, Y**	**Level, L**	**Trend, b**	**Period, m**	**Forecast, F**	**Error**
1	2004	107.81	107.81	(1.10)			
2	2005	103.92	105.32	(1.10)	1	106.71	(2.8)
3	2006	103.16	103.69	(1.10)	1	104.22	(1.1)
4	2007	102.62	102.60	(1.10)	1	102.59	0.0
5	2008	99.51	100.51	(1.10)	1	101.50	(2.0)
6	2009	100.18	99.79	(1.10)	1	99.41	0.8
7	2010	99.81	99.25	(1.10)	1	98.69	1.1
8	2011	97.10	97.63	(1.10)	1	98.15	(1.1)
9	2012	98.60	97.56	(1.10)	1	96.53	2.1
10	2013	96.01	96.24	(1.10)	1	96.46	(0.5)
11	2014				1	95.14	
12	2015				2	94.04	
						SSE	**20.33**

Establish Starting Values for the Level and Trend

From the ETS equations 1 and 2 above, the level and trend at time "t" rely on level and trend values from the previous time period (t-1).

In this model, FEI has set the starting level to be the same as the 2004 actual (107.81). There are a number of ways of setting the initial trend. Excel uses the SLOPE function over the entire set of actual data and therefore sets the initial trend at -1.1 as shown in the table above.

Once the initial values are set, equations can be entered into each remaining cell in columns 3, 4 and 6, as shown below.

Cell Formulas

The three equations shown above are next entered into columns 3, 4 and 6 of rows 2 through 12. The following view of the above model confirms the correct equations have been entered into the columns. Column 3 uses equation 1, Column 4 uses equation 2 and Column 6 uses equation 3.

Table A3-14: Cell Formulas

	Alpha	**0.5**					
	Beta	**0**					
	1	2	3	4	5	6	7
	Date	**Actual, Y**	**Level, L**	**Trend, b**	**Period, m**	**Forecast, F**	**Error**
1	2004	107.81	=C9	=SLOPE(C9:C18,B9:B18			
2	2005	103.92	=Alpha*C10+(1-Alpha)*(D9+E9)	=Beta*(D10-D9)+(1-Be	1	=D9+E9*F10	=C10-G10
3	2006	103.16	=Alpha*C11+(1-Alpha)*(D10+E10)	=Beta*(D11-D10)+(1-B	1	=D10+E10*F11	=C11-G11
4	2007	102.62	=Alpha*C12+(1-Alpha)*(D11+E11)	=Beta*(D12-D11)+(1-B	1	=D11+E11*F12	=C12-G12
5	2008	99.51	=Alpha*C13+(1-Alpha)*(D12+E12)	=Beta*(D13-D12)+(1-B	1	=D12+E12*F13	=C13-G13
6	2009	100.18	=Alpha*C14+(1-Alpha)*(D13+E13)	=Beta*(D14-D13)+(1-B	1	=D13+E13*F14	=C14-G14
7	2010	99.81	=Alpha*C15+(1-Alpha)*(D14+E14)	=Beta*(D15-D14)+(1-B	1	=D14+E14*F15	=C15-G15
8	2011	97.1	=Alpha*C16+(1-Alpha)*(D15+E15)	=Beta*(D16-D15)+(1-B	1	=D15+E15*F16	=C16-G16
9	2012	98.6	=Alpha*C17+(1-Alpha)*(D16+E16)	=Beta*(D17-D16)+(1-B	1	=D16+E16*F17	=C17-G17
10	2013	96.01	=Alpha*C18+(1-Alpha)*(D17+E17)	=Beta*(D18-D17)+(1-B	1	=D17+E17*F18	=C18-G18
11	2014				1	=$D$18+$E$18*F19	
12	2015				2	=$D$18+$E$18*F20	
						SSE	**=SUM(H10:H18^2)**

Application of Equations 1-3

The values for the level, trend and forecast in row 2 are determined as demonstrated below:

$$Equation\ 1{:}\ L_t = 0.50 \times 103.92 + (1 - 0.50)(107.81 - 1.10) = 105.32$$

$$Equation\ 2{:}\ b_t = 0.0(105.32 - 107.81) + (1 - 0.0)(-1.10) = -1.10$$

Equation 3 is then used to get the forecast value for 2006 in row 3:

$$Equation\ 3{:}\ F_{t+1} = 105.32 - (1.10 \times 1) = 104.22$$

Calculations for columns 3, 4 and 6 are repeated for all rows, through row 10.

Establish the Alpha and Beta Parameters

Once the equations have been entered into the model, values for the alpha and beta parameters can be established. Alpha and beta values must be selected before the forecasts in rows 11 and 12 can be computed. The purpose of the data in rows 1 through 10 is to establish the optimum values of alpha and beta. The data in rows 1 through 10 is referred to as the initialization set.

The process to establish the optimum values of alpha and beta is as follows:

1. Enter values for alpha and beta in the Alpha and Beta cells in the model. In the screen shot above, the values are 0.0 and 0.5, respectively.

2. Values in rows 1 through 10 will be updated using the new parameters.

3. The error calculation in column 7 is the difference between the forecasted value in column 6 and the actual value in column 2. The forecast value in column 6 is from equation 3.

4. Square each error to remove the positive/negative cancellation effect, and then sum the squared errors (SSE).

5. The optimum values for alpha and beta are the pair that result in the minimum SSE over the initialization set.

6. Alpha and beta can be established using values established by Excel, or by step wise trials. Both methods result in the same values, as shown below:

   a) In Excel 2016 the formula "=FORECAST.ETS.STAT" can be used to determine the values of alpha and beta selected by Excel. For the Lower Mainland Rate Schedule 1 data used in this example, the values chosen by Excel are Alpha = 0.05 and Beta = 0.

   b) Alternatively step wise trials can be used. The following chart or "heat map" shows the SSE results of step wise trials for every combination of alpha and beta at 0.05 intervals. Both alpha and beta must be between 0 and 1. The "heat map" shows the sensitivity of the model to the choices of alpha and beta. The chart is colored such that green cells represent lower SSE (better) values than yellow and orange or red cells. Each cell represents a complete model run. The optimum value (20.3) for Alpha=0.50 and Beta=0.0 is black.

Table A3-15: Alpha and Beta Parameters

		ALPHA																				
		0.0	0.05	0.10	0.15	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70	0.75	0.80	0.85	0.90	0.95	1.00
BETA	0.0	51.9	38.9	31.4	27.1	24.5	22.8	21.8	21.0	20.6	20.4	20.3	20.4	20.7	21.1	21.6	22.3	23.1	24.0	25.0	26.2	27.5
	0.05	51.9	37.4	30.0	26.2	24.1	22.8	22.0	21.5	21.1	20.9	20.9	21.0	21.3	21.8	22.3	23.1	23.9	24.9	26.1	27.4	28.8
	0.10	51.9	36.2	29.0	25.8	24.2	23.3	22.6	22.2	21.8	21.6	21.6	21.7	22.0	22.4	23.1	23.8	24.8	25.9	27.2	28.6	30.1
	0.15	51.9	35.0	28.4	25.8	24.7	24.0	23.5	23.0	22.6	22.3	22.2	22.3	22.6	23.1	23.8	24.6	25.6	26.9	28.3	29.8	31.6
	0.20	51.9	34.1	28.0	26.1	25.4	24.9	24.3	23.7	23.2	22.9	22.8	22.8	23.1	23.7	24.4	25.3	26.5	27.8	29.4	31.2	33.1
	0.25	51.9	33.3	27.9	26.7	26.3	25.8	25.1	24.4	23.8	23.3	23.2	23.3	23.6	24.2	25.0	26.1	27.3	28.9	30.6	32.6	34.7
	0.30	51.9	32.6	28.0	27.4	27.2	26.7	25.8	24.9	24.2	23.7	23.5	23.6	24.0	24.7	25.6	26.8	28.2	29.9	31.8	34.0	36.5
	0.35	51.9	32.0	28.3	28.3	28.2	27.4	26.3	25.3	24.5	23.9	23.8	23.9	24.4	25.2	26.2	27.5	29.1	31.0	33.2	35.6	38.3
	0.40	51.9	31.5	28.7	29.1	29.0	28.1	26.8	25.5	24.6	24.1	24.0	24.2	24.8	25.6	26.8	28.3	30.1	32.2	34.6	37.3	40.3
	0.45	51.9	31.2	29.2	30.0	29.8	28.6	27.0	25.7	24.8	24.3	24.2	24.5	25.2	26.1	27.5	29.1	31.1	33.4	36.1	39.1	42.4
	0.50	51.9	30.9	29.9	30.9	30.5	29.0	27.2	25.8	24.8	24.4	24.4	24.8	25.6	26.7	28.1	30.0	32.2	34.7	37.7	41.0	44.7
	0.55	51.9	30.7	30.6	31.8	31.1	29.2	27.3	25.8	24.9	24.5	24.6	25.1	26.0	27.2	28.9	30.9	33.3	36.2	39.4	43.1	47.2
	0.60	51.9	30.6	31.3	32.6	31.6	29.4	27.3	25.8	24.9	24.6	24.8	25.4	26.4	27.8	29.6	31.9	34.5	37.7	41.3	45.4	49.9
	0.65	51.9	30.6	32.1	33.3	31.9	29.5	27.3	25.8	25.0	24.8	25.0	25.7	26.9	28.4	30.4	32.9	35.9	39.3	43.3	47.8	52.7
	0.70	51.9	30.6	32.9	34.0	32.2	29.5	27.2	25.7	25.0	24.9	25.3	26.1	27.4	29.1	31.3	34.0	37.3	41.1	45.5	50.4	55.8
	0.75	51.9	30.7	33.6	34.6	32.3	29.4	27.1	25.7	25.1	25.1	25.5	26.5	27.9	29.8	32.2	35.2	38.8	43.0	47.8	53.2	59.2
	0.80	51.9	30.9	34.4	35.0	32.4	29.3	27.0	25.7	25.2	25.3	25.8	26.9	28.4	30.5	33.2	36.5	40.4	45.1	50.4	56.3	62.7
	0.85	51.9	31.1	35.2	35.4	32.4	29.1	26.9	25.7	25.3	25.5	26.1	27.3	29.0	31.3	34.2	37.9	42.2	47.3	53.1	59.6	66.6
	0.90	51.9	31.4	35.9	35.8	32.3	29.0	26.8	25.8	25.4	25.6	26.4	27.7	29.6	32.1	35.4	39.3	44.1	49.6	56.0	63.1	70.6
	0.95	51.9	31.7	36.6	36.0	32.2	28.8	26.8	25.8	25.6	25.9	26.7	28.1	30.2	33.0	36.6	40.9	46.1	52.2	59.2	66.9	75.0
	1.00	51.9	32.0	37.2	36.2	32.1	28.7	26.8	25.9	25.7	**26.1**	27.0	28.6	30.9	34.0	37.9	42.6	48.3	55.0	62.6	70.9	79.5

Calculation of the Forecast on Row 11 and 12

Once the optimum values of alpha and beta are established, they can be used to forecast the level and trend. Row 10 is the final year of actual values. The trend component established in row 10 will be used in the forecast years for 2014 seed and 2015 forecast (rows 11 and 12).

Using the data in row 10, the seed year forecast in row 11 for 2014 is developed using the ETS equations as follows:

$$Equation\ 1: L_t = 0.50 \times 96.01 + (1 - 0.50)(97.56 - 1.10) = 96.24$$

$$Equation\ 2: b_t = 0.0(96.24 - 97.56) + (1 - 0.0)(-1.10) = -1.10$$

$$Equation\ 3: F_{t+1} = 96.24 - 1.10 \times 1 = 95.14$$

The resulting value of 95.14 GJs is the 2014 seed year forecast value, shown on row 11, column 6 of the table above.

In row 12, "m" becomes 2 because we need to forecast two periods forward. L_t and b_t remain unchanged. For all subsequent forecast periods, the level is assumed to remain constant while the trend component changes linearly.

The forecast at any time (t+m) is calculated using equation 3 above. Thus, the forecast in row 12 for 2015 is calculated as follows:

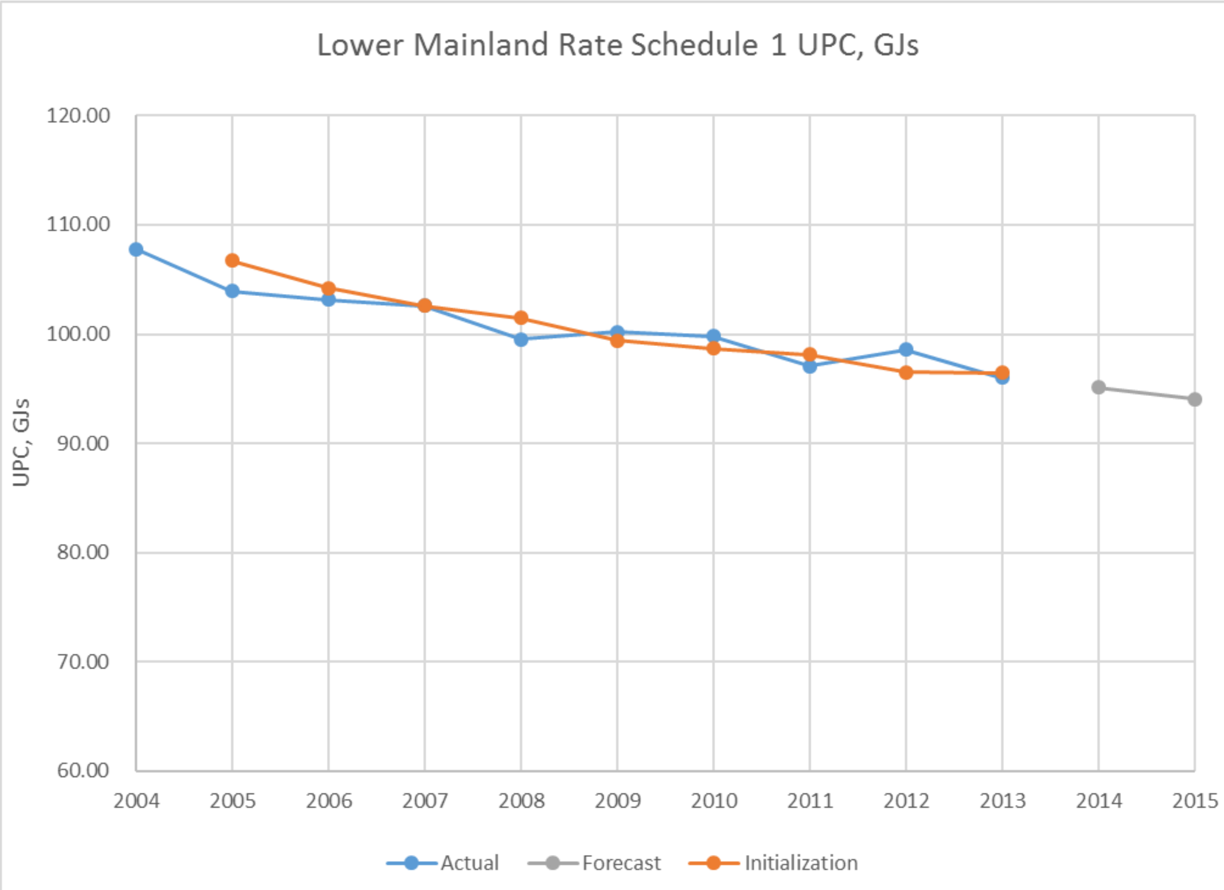
$$Equation\ 3: F_{t+1} = 96.24 - 1.10 \times 2 = 94.04$$

The resulting 94.04 GJs is the forecast value shown for 2015 on row 12, column 6.

Summary Plot

A plot of the actuals and forecast values demonstrates the reasonableness of the forecast:

Figure A3-10: Actuals and ETS Forecast Values



The above plot shows the initialization data (orange) developed with the optimized values of alpha and beta. If less optimal values are chosen, the orange line will deviate further from the actual line and result in a less accurate forecast.

Calculations for commercial use rates and customer additions are identical not reproduced here.

Appendix B

Natural Gas for Transportation and LNG Service

Table of Contents

1. INTRODUCTION

FEI continues to make significant progress in adding natural gas demand to the distribution system through increased adoption of natural gas as a transportation fuel. This increased adoption has resulted in FEI contracting with natural gas for transportation (NGT) customers for compressed natural gas (CNG) and liquefied natural gas (LNG) fueling station services at both existing fueling stations as well as constructing new fueling stations where appropriate. In addition to fueling station services, for most LNG customers, FEI supports these customers with LNG logistics and fuel delivery services through ownership and operation of LNG tanker assets. The LNG transportation and delivery service is offered as an optional service available to LNG customers under Rate Schedule 46.

The transportation aspects of LNG service include tanker transportation service available to LNG customers as well as capital expenditures at the Tilbury LNG facility to support the growth of LNG demand. LNG volumes reported herein also include demand from non-NGT activities, which is primarily LNG supply for non-transportation related markets such as power generation and other end-use applications.

FEI expects to continue to add natural gas demand to the distribution system by advancing both CNG and LNG transportation applications across a variety of transportation market segments. To continue to support and advance the natural gas demand, FEI issues financial incentives under the Greenhouse Gas Reduction (Clean Energy Act) Regulation (GGRR) for new market segments as well as supports continued growth in currently captured market segments. The GGRR is also expected to lead to an increased demand for CNG and LNG fueling stations as the requirement for fueling infrastructure continues to expand over the next number of years to provide fueling service to the growing number of natural gas vehicles.

This appendix provides details on FEI's 2018 revenue and cost forecasts for the NGT program, and transportation aspects of LNG service. The NGT program consists of the construction and maintenance of the CNG or LNG fueling stations, the incentives to convert eligible vehicles from diesel and gasoline to CNG or LNG, and support for maintenance facility upgrades and training and support for customers adopting natural gas as a fuel.

The following table provides a brief summary of how each component of the NGT program relates to the 2018 forecast revenue requirement in this Application:

1 **Table B-1: Connection between the NGT Program and the Revenue Requirement**

Program Component	Connection to Revenue Requirement	Background
Fleet[1] Conversion Incentives	Fleet 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 Schedules 3, 5, 23, 25, and 46, and as such, included in the overall utility revenue and delivery margin forecast for 2018 as set out in Section 3 of the Application.	The 2018 demand and revenue forecast for CNG and LNG is based on (i) existing demand and (ii) incremental demand for 2018 determined by utilizing the forecast fleet conversion incentives and fueling station additions as the inputs, as well as the addition of non-NGT demand that FEI expects to serve under Rate Schedule 46.
Fueling Stations	Expenditures associated with fueling stations are included in the 2018 capital and O&M forecasts (Sections 6 of the Application for O&M forecasts and Section 7 of the Application for capital expenditure forecasts). The forecast capital and O&M of fueling station services included in the delivery cost of service is offset by the revenue 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. 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 for a CNG or LNG customer under the GGRR, FEI will apply for a CPCN for the construction and operation of that fueling station for a customer. For 2018, 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 Commission. That is, a service that qualifies as a prescribed undertaking under the Regulation requires an application to and approval of the rates by the Commission.

[1] Order in Council 609/2016 repealed the definition of “eligible vehicle” and replaced it with “eligible vehicle or machine”. The term ‘Vehicle’ is used throughout this application to refer to both eligible vehicles or machines, and includes on-road trucks, buses, waste haulers, mine haul trucks, locomotives, marine vessels, asphalt pavers, fracture pump units, generators, boilers, burners and kilns.

[2] The setting of rates to recover the costs of prescribed undertakings is required under section 18 of the *Clean Energy Act*.

Program Component	Connection to Revenue Requirement	Background
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). The forecast capital and O&M associated with the tankers included in the delivery cost of service is offset by the revenue from 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 LNG tankers are a prescribed undertaking under section 2(3) of the GGRR.

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 - Vehicle Incentives: provides a forecast of the incentives that will be provided in 2018.
- Section 4 - CNG & LNG Demand and Revenue: provides a forecast of natural gas demand for NGT and non-NGT demand and a discussion of the corresponding revenue and margin forecasts for 2018.
- Section 5 - NGT Fueling Station Services: 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 2018.
- Section 6 - Enabling LNG Demand Fulfilment: discusses the forecast costs and recoveries associated with the tanker transportation service provided under Rate Schedule 46.
- 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 2018 forecast revenue requirement.

The organization of Sections 3 through 6 follows the progression of the business model for NGT. FEI provides incentives to customers for the purchase of CNG/LNG powered vehicles or the conversion of eligible vehicles (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 SECTION 12B)

On December 1, 2010, FEI filed an Application for Approval of General Terms and Conditions (GT&C) for Compression and Dispensing Service for CNG and Fuel Storage and Dispensing Service for LNG, (collectively CNG and LNG Service). The proposed Section 12B Vehicle Fueling Stations of FEI's GT&Cs (GT&C Section 12B) 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 Section 12B by 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 tankers and LNG fueling stations and infrastructure (Prescribed Undertaking 3).

The GGRR was initially set to expire on April 1, 2017. 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, 2 and 3.

[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 in Order G-67-13 (dated April 30, 2013) for the rate treatment of incentives of $5.573 million incurred in 2010-2011.[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 would be able to spend up to $56.427 million in additional funding under Prescribed Undertaking 1.

On November 27, 2013, the GGRR was amended to expand the list of vehicles eligible for financial incentives under Prescribed Undertaking 1 to include vehicles such as locomotives and mine haul trucks. Additionally, the expiration date of the GGRR was repealed and the definition of "expenditures" for the purposes of the GGRR was expanded to include binding commitments to incur expenditures in the future.

The GGRR was further amended on June 3, 2015. The 2015 amendments broadened the application of natural gas to more transportation sectors within the previously-established funding limits to promote continued development of the use of natural gas in certain transportation sectors. Important amendments included:

- extending the undertaking period to March 31, 2018;
- allowing a public utility to increase incentives by a defined amount for vehicles defined as an "early adopter vehicle"[5];
- providing an alternative for fueling station service agreements; and
- adding a prescribed undertaking that provides incentives for the conversion of a "specified vehicle"[6] to operate on natural gas and establishing an incentive cap for this incentive at $5 million (Prescribed Undertaking 3.1), to be recorded in the NGT Incentives Account, approved by Order G-161-12.

On August 19, 2016, the GGRR was further amended through Order in Council 609. The key 2016 amendments included:

- extending the undertaking period to March 31, 2022;
- broadening the definition of "eligible vehicle" to include "eligible vehicle or machine";
- clarifying the cost of service recovery rules of CNG and LNG fueling stations by striking out "energy provided at each station…" and substituting "the station's forecast total operating costs…";

[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] "Early adopter vehicle" as defined in the GGRR, Section 2 Prescribed Undertakings.

[6] A "specified vehicle" means a heavy-duty vehicle, medium-duty vehicle, school bus or transit bus, as defined in the GGRR, Section 1.

- increasing the allowable funds available under Prescribed Undertaking 1 from $62.0 million to $107.9 million;
    a. includes increasing the allowable expenditure on marketing, training, education and administration by $5.0 million from $3.1 million to $8.1 million; and
    b. increasing the amount of incentives available for eligible vehicles or machines under Prescribed Undertaking 1 by an incremental $40.9 million;
- creating a new Prescribed Undertaking to issue incentives of up to $6.1 million for remote industrial power generation applications such as generators, boilers, kilns, burners that use natural gas as a fuel source;
- clarifying that incentives issued under Prescribed Undertaking 1 to a “Shipping, passenger transportation or commercial services by marine vehicle that will use fuel purchased from a public utility” may be made to persons who are not in British Columbia but will be required to procure fuel from the utility; and
- creating a new Prescribed Undertaking for allowable investment in infrastructure pertaining to LNG distribution and storage infrastructure to not exceed $15 million during the undertaking period.

On March 21, 2017, the GGRR was further amended through Order in Council 161. The key 2017 amendments included:

- increasing the allowable incentives available under Prescribed Undertaking 1 from $107.9 million to $177.9 million for eligible vehicles or machines;
- adding a new subsection specifying that expenditures may exceed $177.9 million by a further $40 million if the $40 million is for expenditures in relation to eligible vehicles or machines operated on liquefied natural gas or compressed natural gas all of which is derived from biogas or biomass;
- increasing the allowable infrastructure investment under Prescribed Undertaking 3 by $20 million from $30.5 million to $50.5 million;
- creating a new prescribed undertaking for allowable infrastructure investments in LNG shore-side assets to not exceed $25 million over the undertaking period; and
- adding subsection 3.6 to allow a public utility, during the undertaking period, to make expenditures on feasibility and development costs in relation to shore-side assets that do not exceed $5 million.

FEI will file with the Commission a letter setting out the treatment of costs permitted under the OIC 161 GGRR amendments. This letter is expected to be filed in August 2017.

For all CNG and LNG fueling stations, the rates related to each new fueling station service agreement constructed under the GGRR will be submitted in separate applications to the Commission for review and approval.

2.3 LNG AND CNG SUPPLY

Under the NGT program, FEI is supplying LNG under Rate Schedule 46 to customers on both a firm (short and long term contract) and spot basis.

For CNG services, FEI has four Commission-approved CNG natural gas vehicle Tariffs: Rate Schedule 6 Natural Gas Vehicle Service, Rate Schedule 6A General Service Vehicle Refueling Service, Rate Schedule 6P Public Service and Rate Schedule 26 Natural Gas Vehicle Transportation Service.

In addition to the above Rate Schedules, FEI is also provides CNG distribution service using existing Rate Schedules 3, 5, 23 and 25.

2.3.1 CNG and LNG Fueling Station Service

In addition to FEI providing natural gas supply distribution under Commission approved FEI Rate Schedules, natural gas fueling services are available to customers with natural gas fueled vehicles. These customers would have entered into an agreement with FEI for FEI to own and operate fueling stations and to provide CNG or LNG fueling services.

The rates for fueling station services are not contained in the Rate Schedules referenced above, which are only for the distribution and delivery of the natural gas to the customer’s location. Rates for fueling station services are agreed upon individually with the NGT customers and these rates are approved on an agreement-by-agreement basis by the Commission.

3. VEHICLE INCENTIVES

As discussed in Section 2.2 above, the GGRR enables FEI to provide grants or zero-interest loans for the purchase of eligible natural gas vehicles operating in British Columbia or for related safety practices and maintenance facility upgrades up to $177.9 million in total (Prescribed Undertaking 1), plus a potential $40 million additional for those NGT customers that take either LNG or CNG wholly derived from biomass or biogas, plus an additional $6.1 million in grants or zero-interest loans for the purchase of generators, boilers, burners or kilns that use natural gas to produce electricity.

Applications for incentive funding are accepted every quarter and an independently appointed fairness advisor ensures that the evaluation process and the provision of funds are 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, with a focus on openness, competitiveness, transparency and compliance.

Table B-2 below provides a forecast of GGRR incentives under Prescribed Undertaking 1 and Prescribed Undertaking 3.2 projected to be paid out in 2017 and forecast to be paid out in 2018 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 will be recovered in the delivery rates of non-bypass customers over a period of ten years, which was also approved by Order G-161-12.

Table B-2: FEI Forecast GGRR (NGT) Incentive Deferral Additions ($millions)[7]

Incentive Forecast ($ millions)		2017A		2017P		2018F
Total Vehicle Incentives	$	4.000	$	3.983	$	3.375
Marine, Mining & Rail Incentives	$	8.250	$	10.000	$	6.000
Remote Power	$	-	$	-	$	1.200
Safety Practices and Maintenance Facilities Incentives	$	0.500	$	0.690	$	0.700
Admin, Education, Safety Training	$	0.798	$	0.800	$	1.000
Total	$	13.548	$	15.472	$	12.275

Typically there is a lag of up to two years (or more for certain marine customers) between the time an applicant applies for incentive funding and when the vehicles are in service and operational. For this reason FEI has a two-step process for providing incentives. A smaller amount (up to 25%) is paid at the time of approving the application for incentives and the remaining amount is paid to the customer once the vehicles are in service and fully operational.

[7] Throughout the tables in this appendix, "A" refers to Approved for 2017, (Order G-182-16 in relation to the FEI Annual Review for 2017 Application), "P" refers to Projected for 2017, and "F" refers to Forecast for 2018.

For the 2017 Projection, FEI anticipates issuing a total of $15.472 million in incentives. This includes incentives of $13.983 million for vehicle, marine and mining incentives. In addition, incentives of $0.800 million related to administration, education and safety training, and $0.690 million related to safety practices and maintenance facility upgrades are expected to be incurred.

Of the total amount of $13.983 million in incentives, $3.983 million is allocated for fleet conversion incentives (i.e. excluding marine, mining and rail related incentives). Of the $3.983 million for fleet conversion incentives, $2.616 million consists of incentives for CNG vehicles that have entered service in 2017 and incentives for a portion of the CNG vehicles expected to be in service in early 2018. The remaining $1.366 million is allocated for applicants interested in the diesel blending pilot application (Prescribed Undertaking 3.1) as authorized by OIC No. 297. This pilot was introduced to address the gap that existed in the availability of 15L Original Equipment Manufacturer (OEM) engines. Of the $1.366 million of incentives for the diesel blending pilot program, $1.229 million is for LNG diesel blending vehicles and $0.137 million is for CNG diesel blending vehicles.

Of the $10.000 million of incentives allocated for marine, mining and rail, $1.750 million is allocated for advancing 25 percent of the agreed incentive contribution amount of $7.000 million for two new marine vessels subject to BC Ferries procuring LNG from FEI. The remaining 75% for these two new marine vessels will be paid to the customer once these vessels are put into operation, which is expected to begin in Q3 2018 for the first vessel and early 2019 for the second vessel. The remaining $8.250 million is allocated for the outstanding 75% payment of the initial $11.000 million incentive provided to BC Ferries for its three vessels and to Seaspan for its two vessels which were put into service in 2017.

For 2018, FEI forecasts total expenditures of $12.275 million, which includes incentives for eligible vehicle purchases and remote power projects, implementation of safety practices and improvement of facilities for operating vehicles, and expenditures for administration, education and training. Of the $12.275 million total forecasted incentives for 2018, FEI forecasts $6.000 million for the marine, mining and rail category, $1.200 million for remote power generation projects, $3.375 million for CNG and LNG vehicle incentives, and $1.700 million for administration, education, safety training and safety practices.

4. CNG & LNG DEMAND AND REVENUE

4.1 FORECAST NGT & NON-NGT DEMAND

Table B-3 below provides a projection and forecast of total NGT and non-NGT demand in 2017 and 2018, respectively, based on the expected number of vehicles that will be added, in addition to existing vehicles that are in operation. Non-NGT volumes are mainly related to LNG demand from power generation and non-transportation customers. As directed in Order G-86-15, FEI has now included a forecast of spot purchases in the total NGT and non-NGT demand.

Table B-3: FEI Total Natural Gas Demand (GJ/Year) for NGT & Non-NGT

GJ	2017A	2017P	2018F
CNG	769,467	773,761	920,525
LNG	932,300	568,697	901,250
Total NGT Demand	**1,701,767**	**1,342,458**	**1,821,775**
Non-NGT Demand	165,866	210,000	210,000
Total NGT and Non-NGT Demand	**1,867,633**	**1,552,458**	**2,031,775**

The total forecasted natural gas demand for CNG and LNG applications for 2018 of 2,031,775 GJ includes forecasted spot volumes of 210,000 GJ. The spot volumes are related to non-NGT customers, mostly for power generation[8]. 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 these customers expect they would require for 2018.

The incremental increase in CNG & LNG demand between 2017 and 2018 is 479,317 GJ. The following table summarizes the demand that makes up this incremental load.

Table B-4: CNG/LNG 2018 Forecast Incremental Demand Additions by Fuel Type

	2018 Incremental Demand (GJ)
CNG	146,764
LNG	332,553
Total Incremental NGT Demand	**479,317**
Non-NGT CNG/LNG Incremental Demand	-

8 Spot Volumes for Cryopeak, NWT Energy Corp, Yukon Energy and Anahim Lake are non-NGT and are mainly for power generation.

The incremental demand of 479,317 GJ represents an annual growth rate in demand of about 31 percent over the projected 2017 natural gas volumes from CNG and LNG applications. This increase is mainly attributed to realizing full year demand from the five marine vessels that will be operated by BC Ferries and Seaspan.

4.2 FORECAST REVENUE, COST OF GAS AND DELIVERY MARGIN

Currently, FEI delivers CNG and LNG to all GGRR and non-GGRR fueling stations under Rate Schedules 3, 5, 23, 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 customers served under Rate Schedules 3, 5, 23, 25 and 46, which includes customers for which FEI does not construct the fueling station but delivers gas to the customer's location under approved FEI rate schedules. The LNG volume dispensed under Rate Schedule 46 also includes volumes provided to non-NGT customers.

The following two tables identify, for the rate schedules, the forecast of CNG and LNG volumes sold, associated delivery margin at 2017 rates[10], cost of gas[11], and revenue (delivery margin plus cost of gas). All forecasts are included in the financial schedules within this Application.

Table B-5: Rate Schedule 3, 23, 5, and 25 CNG Projection and Forecast

CNG - Volume, Revenue, Margin under RS 3, 5, 23, and 25	2017A	2017P	2018F
Demand (GJ)	769,467	773,761	920,525
Total Delivery Margin ($ millions)	$ 0.991	$ 1.453	$ 1.718
Total Cost of Gas ($ millions)	$ -	$ 0.524	$ 0.600
Total Revenue ($ millions)	$ 0.991	$ 1.977	$ 2.319

Table B-6: Rate Schedule 46 LNG Projection and Forecast[12]

LNG - Volume, Revenue, Margin under RS 46	2017A	2017P	2018F
Demand (GJ)	1,098,166	778,697	1,111,250
Total Delivery Margin ($ millions)	$ 5.153	$ 3.705	$ 5.368
Total Cost of Gas ($ millions)	$ 3.847	$ 2.907	$ 3.805
Total Revenue ($ millions)	$ 9.000	$ 6.611	$ 9.173

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.

10 For this purpose, delivery rates exclude the delivery rate riders which are calculated separately.

11 The 2017 projected cost of gas is based on the GLJ Forecast Sumas Spot Price for April 1, 2017 for the year 2017 of $2.960 $US/MMBTU. The 2018 forecasted cost of gas is based on the GLJ Forecast Sumas Spot Price for April 1, 2017 for the year 2018 of $2.800 $US/MMBTU (exchange rate of 1 US$ = 1.29 CDN$, Conversion factor of 1.055056 GJ per 1 MMBtu is used to convert to GJ).

12 A break out of the total Rate Schedule 46 demand into NGT and non-NGT categories is provided in Section 4.1 of this Appendix and also shown in Figure 3-12 of the Application. The variance between 2017A and 2017P LNG demand is mainly due to the timing of the five marine vessels that were put into operation throughout 2017 as discussed in Section 3.5.4 of the Application.

5. NGT FUELING STATION SERVICES

Another component of FEI's NGT program consists of provisions to construct CNG or LNG fueling stations for the purpose of providing suitable fueling facilities for customers. FEI provides fueling station infrastructure under the two approved regulatory models, the FEI GT&C Section 12B Vehicle Fueling Stations, and the GGRR.

The Commission-approved GT&C Section 12B applicable fueling station agreements sets out the terms for FEI's ownership and operation of fueling stations. For CNG assets, GT&C Section 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 Section 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 model under which FEI can provide fueling infrastructure is under the provisions of the GGRR. As mentioned above, the GGRR enables public utilities to make expenditures of up to $12.000 million to own and operate CNG fueling stations and infrastructure and make expenditures of up to $50.500 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 2018 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 completed the construction of nine CNG fueling stations, and is in the process of completing one additional CNG station in 2017 for a total of ten CNG fueling stations. A fueling station is currently under construction for United Parcel Service (UPS) in Richmond. This station is expected to be operational by December 2017. FEI forecasts three additional CNG fueling stations will be constructed in 2018.

The table below summarizes all CNG fueling stations constructed or under construction, as well as the applicable regulatory model under which the construction of each station was undertaken to support CNG customers that have adopted natural gas. The Waste Management of Canada Corporation (Waste Management) agreement was developed based on previously proposed GT&Cs, and was accepted by the Commission "on an exception basis only"[14].

[13] $12.0 million and $50.5 million total investment per utility over the regulation period, which ends March 31, 2022, which was amended by OIC 161 in March 2017.

[14] Commission Order G-128-11; Appendix A, dated July 19, 2011, p. 31.

Table B-7: CNG Fueling Stations Constructed by FEI

Customer/Station	Applicable Order Numbers	Regulatory Model
Progressive Waste Solutions	C-6-12/G-78-13	GT&C Section 12B
Waste Management	G-128-11/G-229-13	GT&C Section 12B
Kelowna School District	G-158-13	GT&C Section 12B
Cold Star	G-187-13	GGRR
Smithrite	G-72-14	GGRR
For Less Disposal	G-128-14	GGRR
City of Vancouver	G-105-15	GGRR
Burnaby Operations (Canadian Linen and Disposal Queen)	G-91-16/G-96-16	GGRR
Mid Island (City of Nanaimo and Nanaimo Cold)	G-99-16/G-100-16/G-101-16	GGRR
United Parcel Service	To Be Filed	GGRR

FEI has constructed six LNG fueling stations for its customers. The table below summarizes the approvals granted for each of these customers. All of the LNG fueling stations, with the exception of the station on the premises of Vedder Transport Ltd., were constructed under the provision of the GGRR.

Table B-8: LNG Fueling Stations Constructed by FEI

Customer/Station	Applicable Order Numbers	Regulatory Model
Vedder	G-22-14	GT&C Section 12B
Arrow Transport	G-33-14	GGRR
Denwill	G-34-14	GGRR
Westcan Bulk Transport	G-35-14	GGRR
Teck Coal Ltd.	G-151-15	GGRR
Cool Creek (Vedder Resources)	G-83-16	GGRR

5.2 *FORECAST FUELING STATIONS AND CAPITAL EXPENDITURES*

FEI is not projecting constructing any new LNG fueling stations under the GGRR model or GT&C Section 12B, for the remainder of 2017 or for 2018. This is based on the vehicle incentive expenditures to date and the forecast volume of LNG demand for vehicles.

FEI is forecasting a total of 10 CNG fueling stations by the end of 2017 as discussed in Section 5.1 of this Appendix; one new CNG fueling station is expected to be completed in the remainder of 2017 and three new CNG fueling stations forecasted to be constructed in 2018. The following table provides the total projected and forecast number of FEI-owned stations as at December 31 for 2017 and 2018, respectively:

Table B-9: Forecast Total FEI Fueling Stations

	2017A	2017P	2018F
CNG Stations	10	10	13
LNG Stations	6	6	6
Total	16	16	19

The following table provides a summary of total capital expenditures projected in 2017 and forecast for 2018 related to fueling station additions.

Table B-10: NGT Fueling Station Capital Expenditures & Additions Forecast

$ millions		2017A		2017P		2018F
CNG Stations	$	2.125	$	2.260	$	6.000
LNG Stations		-		-		-
Total	**$**	**2.125**	**$**	**2.260**	**$**	**6.000**

The total capital expenditure projected for CNG stations in 2017 is approximately $2.260 million and no capital expenditure is forecasted for LNG stations. Of the $2.260 million of capital expenditure for CNG fueling stations projected for 2017, $2.000 million is estimated for the new UPS CNG fueling station which is expected to be constructed by the end of 2017. FEI will apply to the Commission before the end of 2017 for approval of rates to recover the cost of this new CNG station. The remaining $0.260 million projected for 2017 is for expansions at two existing CNG fueling stations. The $6.000 million capital expenditure forecasted in 2018 is the total of the three new CNG fueling stations estimated at $2.000 million each.

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 2017 and 2018, the expenditures occur the same year that the assets are placed into service. The 2018 capital additions for the CNG and LNG stations are embedded in the total found in Section 11, Schedule 4, Line 29, Column 4, under the NGT Assets heading.

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, Table B-11 below shows the forecast O&M expenses for existing fueling stations, the new CNG fueling station to be constructed in 2017 and the additional three new fueling stations that will be constructed in 2018.

Table B-11: Forecast Annual CNG and LNG Fueling Station O&M[15]

$ millions		2017A		2017P		2018F
CNG Stations	$	0.723	$	0.619	$	0.988
LNG Stations	$	0.566	$	0.415	$	0.417
Total	**$**	**1.289**	**$**	**1.034**	**$**	**1.405**

The O&M increase from 2017 Projected $0.619 million to 2018 Forecast $0.988 million is mainly due to the addition of three CNG stations forecasted to be constructed in 2018.

5.4 *FORECAST FUELING STATION RECOVERIES*

The 2018 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 station services. These two revenue items are described further below.

5.4.1 CNG and LNG Service Revenue Forecast

FEI forecasts the fueling station recoveries for 2018 to be $3.234 million, an increase from the 2017 projected recoveries of $2.896 million. The forecast is based on the approved rates of the 15 completed fueling stations already in-service as identified in Tables B-7 and B-8, the estimated rates for the one CNG fueling station expected to be in-service in 2017 as discussed in Section 5.1 of this appendix and the three new CNG fueling stations forecasted to be constructed in 2018 as discussed in Section 5.2 of this Appendix. Table B-12 provides a breakdown between CNG and LNG station recoveries. 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. Any variance in forecast CNG and LNG service revenue will be captured in the CNG and LNG Recoveries deferral account.

Table B-12: CNG and LNG Service Revenue Forecast ($millions)[16][17]

CNG/LNG Service Revenue		2017A		2017P		2018F
CNG		2.313		1.547		1.870
LNG		1.380		1.349		1.364
TOTAL CNG/LNG Service Revenue	**$**	**3.693**	**$**	**2.896**	**$**	**3.234**

[15] Excludes the O&M forecast of $0.050 million in 2018 for the short-term LNG fueling service as discussed in Section 5.5 of this Appendix, and the O&M forecasts of $0.383 million in 2018 for the LNG Tanker Rental Service as discussed in Section 6.1 of this Application. O&M expense discussed in Section 6.3.4 of the Application includes these O&M expense for a total of $1.838 million in 2018.

[16] Excludes compression revenue of $0.034 million from Surrey Operations CNG Pump as discussed in Section 4.2 of this Appendix and revenue of $0.126 million from the short term MRU fueling asset as discussed in Section 5.5 of this Appendix. Other Revenue discussed in Section 5 as well as shown in Section 11 of the Application, Financial Schedule 23, Line 10 includes these revenues for a total of $3.394 million in 2018.

[17] Where a Commission approved CNG agreement or LNG agreement outlines terms and conditions for use by other customers, more than one CNG or LNG customer may receive CNG or LNG fueling service at an NGT Fueling Station (as outlined in Tables B-8 and/or B-9), where applicable.

5.4.2 NGT Overhead and Marketing Recoveries Forecast

Pursuant to Order G-78-13, FEI has forecast for 2018 a recovery of overhead and marketing (OH&M) costs from NGT customers. Table B-13 below also provides a projection of recoveries of the OH&M costs from NGT customers.

On August 21, 2015, FEI filed with the Commission a letter in response to Directive 5(II) of Order G-105-15[18], wherein FEI calculated the OH&M rate based on updated cost and volume forecasts. FEI recommended that the OH&M rate remain unchanged at $0.52 per GJ. FEI further recommended that this OH&M rate continue to be applied to all fueling stations until it is reviewed as part of FEI's 2016 Rate Design Application. On September 30, 2015 the Commission's Performance Monitoring, Conduct and Compliance Division issued an acknowledgement letter indicating that no further action on this matter was required, effectively confirming the continuation of the OH&M rate of $0.52 per GJ as recommended by FEI until further order of the Commission.

On December 19, 2016, FEI filed the 2016 Rate Design Application. In that application, FEI provided an updated calculation of the OH&M charge using the forecast of 2016 and 2017 costs and NGT volumes. The updated calculation resulted in an OH&M charge of $0.57 per GJ. Given that the OH&M charge is dependent on forecast volumes, which are expected to increase, and because the term of the GGRR has been extended to 2022, FEI expects that the OH&M charge will decrease over time as volumes increase. FEI therefore recommended that the OH&M charge for CNG and LNG fueling station customers remain unchanged at $0.52 per GJ.[19]

As shown in Table B-13 below, the total projection of NGT OH&M revenue for 2017 is $0.304 million and the forecast NGT OH&M revenue for 2018 is $0.320 million. This revenue is calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[20] 2017 projected and 2018 forecast CNG and LNG sales volume (GJ), respectively.

Table B-13: NGT Overhead and Marketing Revenue Forecast

NGT Overhead and Marketing Revenue	2017A	2017P	2018F
Applicable Volume (GJ)	638,891	585,023	616,278
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.332**	**$ 0.304**	**$ 0.320**

[18] Order G-105-15, Directive 5(II): *Recalculate the Overhead and Marketing (OH&M) Charge, using the most recent cost and volume forecast, and the same methodology as Order G-78-13, to determine if the $0.52/GJ OH&M Charge continues to be appropriate.*, issued June 18, 2015.

[19] In response to the Commission's Rate Design Application IR 1.37.1, FEI re-calculated the OH&M charge over the GGRR period of 2012 to 2022. The average OH&M charge over this period was forecast to be $0.30 per GJ. FEI recommended that the OH&M charge remain unchanged at $0.52 per GJ while FEI reviewed the appropriate level for the OH&M charge.

[20] This volume is limited to CNG and LNG contract volume delivered through an FEI-owned CNG or LNG fueling stations for the host customer and for all volumes related to third parties fueling at host stations.

5.5 SHORT TERM LNG FUELING SERVICES

On June 21, 2016, FEI applied for approval from the Commission to transfer specific LNG assets comprised of the IMC 6000 and two Orca LNG units (the Specific LNG Assets), which were held outside of FEI's rate base at that time, to the general natural gas rate base, and to approve a rate to provide short-term LNG fueling service using these specifc LNG assets. These specified LNG assets are essentially mobile LNG refueling stations. The two Orcas are capable of being filled with LNG at either the Tilbury LNG Facility or the Mt. Hayes LNG Facility, transported to a location that is capable of staging the LNG Orca fueling units and providing LNG fueling services to LNG transportation customers. The IMC 6000 provides similar functionality as the Orca units except it is not capable of being transported over the road while filled with LNG. LNG supply for the IMC 6000 is transported via LNG tankers and dispensed on site from a tanker into the IMC 6000. The Commission approved the transfer of these assets to the general natural gas rate base, and approved a short-term fueling service rate on a permanent basis on March 23, 2017 by Order G-44-17.

5.5.1 Forecast Short Term LNG Fueling Recoveries

Order G-44-17 approved a rate of $10,500 per month per unit to be applied to LNG customers that use these assets for short term fueling services. The table below provides a summary of the 2017 Projected and 2018 Forecast amounts pertaining to the use of the these short term fueling assets.

Table B-14: Short Term LNG Fueling Revenue Projection and Forecast

LNG Short Term Fueling	2017A	2017P	2018F
No. of Specific LNG Assets Used	-	1	2
No. of Months Under Use	-	3	6
Rate ($/month/unit)	10,500	10,500	10,500
Total ($ millions)	$ -	$ 0.032	$ 0.126

These assets are considered fueling assets, and as such the revenue collected from the use of these assets is recorded under Other Revenue as "CNG & LNG Service Revenues" as discussed in Section 5.2.4 of the Application and also Section 11 Financial Schedules 23.

5.5.2 Forecast Short Term LNG Fueling Capital Expenditures

FEI is not projecting any capital expenditures for the Short Term LNG Fueling Service in 2017 and in 2018.

5.5.3 Forecast Short Term LNG Fueling Operations and Maintenance (O&M)

The forecast O&M expenses for the operation of the specific LNG assets under the Short Term LNG fueling service are embedded and recovered from the approved rate ($10,500 per month per unit) as discussed in Section 5.5.1 of this Appendix.

Based on the estimated use in 2017 and 2018, and an O&M rate of $0.050 million per year per unit (prorated to monthly), the 2017 Projected and 2018 forecast O&M expenses for the Short Term LNG Fueling Service is estimated to be $0.013 million and $0.050 million, respectively based on the usage of the Specific LNG Assets.

6. ENABLING LNG DEMAND FULFILMENT

FEI provides an optional tanker transportation service to LNG customers for the hauling of the LNG between LNG facilities and the customer's designated location. This optional service is interrelated with the NGT program and is part of Rate Schedule 46 (the LNG Transportation Service). Furthermore, the LNG tanker expenditures are a prescribed undertaking under the GGRR[21], for which cost recovery is provided in section 18 of the Clean Energy Act.

6.1 *LNG TRANSPORTATION SERVICE UNDER RATE SCHEDULE 46*

6.1.1 LNG Tanker Capital Expenditure Forecast

FEI is projecting approximately $1.227 million in capital expenditures in 2017 and forecasting $1.690 million in 2018. This includes the purchase of two marine equipped tridem LNG tankers, one at the end of 2017 for early 2018 delivery and one in 2018 for delivery in 2018, to serve the growing LNG demand with additional marine market customers expected to be in service throughout 2018[22]. The estimated capital cost for each of these marine equipped tridem tankers is approximately $0.990 million, which includes customized marine fittings and pumps necessary to serve marine customers. The costs of the marine equipped tridem tankers will be offset by the approved Rate Schedule 46 LNG applicable tanker charge.

In addition to the LNG tanker trailers mentioned above, the 2018 forecast capital expenditure of $1.690 million also includes two new standard tandem tankers or ISO containers at a cost of $0.250 million each to serve local market demand and approximately $0.200 million for supporting service equipment such as logistics monitoring equipment and nitrogen purging units in order to service the LNG tankers.

6.1.2 Tanker O&M Forecast

FEI is forecasting the 2018 O&M expenses to be $0.383 million, which comprise of $0.283 million for LNG tanker trailers and $0.100 million for Emergency Response and Preparedness (ERAP) coverage. LNG is sold under Rate Schedule 46 as free-on-board (FOB) at the LNG facility. As such, under Transport Canada Regulations, as the producer of a dangerous good as defined by Transport Canada, FEI is required to provide a registered ERAP plan for the LNG product while in transit. The plan lays 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.

[21] Prescribed Undertaking 2.
[22] BC Ferries currently has 3 marine vessels in operation and Seaspan has 2 marine vessels. The additional marine equipped tankers are required to serve 2 additional BC Ferries vessels that will be put into operation starting 2018 and early 2019.

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. On January 17, 2017, FEI applied to the Commission for the approval of 1.6 percent CPI rate increase to Rate Scehdule 46 Table of Charges in order to recover the cost of tankers from applicable customers. On February 2, 2017, The Commission issued Order G-15-17, approving the proposed ammendments effective January 1, 2017 and the table of charges were updated with the following rates: $269 per day or partial day for the standard tandem tanker, $323 per day or partial day, and the marine equipped tridem tanker charge at $454 per day or partial day.

FEI has forecast its 2018 tanker rental revenues as shown in Table B-15 below based on the 2017 projected tanker deliveries plus additional deliveries to account for incremental 2018 forecast LNG volumes. As described in Section 6.1.1 of this appendix, FEI is acquiring two new marine equipped tridem tankers for 2018 to service the increased forecast marine load. The table below summarizes the expected revenue per the currently approved Rate Schedule 46 rates as discussed above.

Table B-15: LNG Tanker Rental Revenue

Tanker Rental Revenue	**2017A**	**2017P**	**2018F**
Standard Tanker Rental Deliveries	768	753	840
Rate ($/Delivery)	$ 269	$ 269	$ 274
Sub Total ($ millions)	$ 0.207	$ 0.203	$ 0.230
Tridem Tanker Rental Deliveries	240	97	130
Rate ($/Delivery)	$ 323	$ 323	$ 329
Sub Total ($ millions)	$ 0.078	$ 0.031	$ 0.043
Marine Equipped Tridem Tanker Rental Deliveries	360	295	670
Rate ($/Delivery)	$ 454	$ 454	$ 463
Sub Total ($ millions)	$ 0.163	$ 0.134	$ 0.310
Total Tanker Rental Revenue ($millions)	**$ 0.448**	**$ 0.368**	**$ 0.583**

7. CONCLUSION

The following table provides a summary of the total O&M, capital and revenue forecast included in the 2018 forecast revenue requirement.

Table B-16: Summary of 2018 Forecast Revenues and Costs ($ millions)

Particular		2018	Reference
Incentives (deferral additions)	$	12.275	Section 11, Schedule 11, Line 20, Column 4
Capital Expenditures			
Fueling Stations		6.000	Section 11, Schedule 4, Line 29, Column 4
Tankers		1.690	Section 11, Schedule 4, Line 29, Column 4
Total Capital Expenditures	$	7.690	
Revenue			
Delivery Margin	$	7.087	Appendix B, Table B-5 and B-6
Fueling Station		3.394	Section 11, Schedule 23, Line 10, Column 3
Overhead & Marketing		0.320	Section 11, Schedule 23, Line 7, Column 3
Tanker Rental		0.583	Section 11, Schedule 23, Line 6, Column 3
Total Revenue	$	11.384	
O&M			
Fueling Stations	$	1.455	Appendix B, Table B-11 & Appendix B, Section 5.5
Tankers		0.283	Appendix B, Section 6.1.2
ERAP		0.100	Appendix B, Section 6.1.2
Total O&M	$	1.838	

Appendix C

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-138-14 – FEI MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
1.	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.	Consultation underway. Study will be filed in 2018.	N/A
2.	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					
3.	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
4.	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 (Public Contact with Pipelines) and 13.2.3 (Leaks per KM of Distribution System Mains)
5.	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
6.	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

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
7.	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
8.	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.	Ongoing during PBR period	Appendix C2
9.	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.	Ongoing during PBR period	Table 1-2 in Section 1.4.2
G-120-15 – FEI-FBC PBR CAPITAL EXCLUSION CRITERIA					
10.	17	4	***Capital ExpendituresExceeding the Deadband*** Should the dead-band for annual capital expenditures approved in the PBR Plans be exceeded FBC or FEI are directed to include in its next Annual Review filing, recommendations as to any adjustment to base capital (re-basing) for Commission approval.	Completed	Section 1.4.4
G-193-15 – FEI ANNUAL REVIEW FOR 2016 RATES					
11.	8	6a	***2017 LTRP Application Deferral Account*** FEI estimates the cost of third party consultants to assist with preparatory work for the 2017 LTRP Application to be $1.050 million (over two years). The Panel considers this amount to be a ceiling and directs FEI to submit any amount in excess of this to the Commission for approval prior to committing to expenditures	N/A – FEI confirms not over the ceiling.	N/A
12.	22	n/a	***Presentation of Historical SQI Results*** The Panel acknowledges FEI's statement that it will present the test year and historical SQI results in a single table in future annual review filings, as requested by BCSEA.	Ongoing during PBR period.	Sections 13.21, 13.2.2 and 13.2.3

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
13.	24	12a	***Costs Allocated to FBC for Call Handling*** If in the future the annual costs being allocated to FBC from FEI for the handling of calls exceeds $100,000 in any one year, FEI is directed to provide an analysis of various cost allocation methodologies and provide evidence as to which will provide the most appropriate results.	Confirmed costs do not exceed $100,000.	N/A
14.	25	n/a	***Revenue Deficiency Reconciliation*** The Panel is satisfied with FEI's reconciliation provided as Table 1 in its reply submission and notes FEI's agreement to provide a reconciliation between the contributors to the revenue deficiency and the financial schedules in its future annual review applications.	Ongoing during PBR period.	Section 1.5 revenue deficiency summary now agrees to Schedule 1 of Section 11
G-182-16 – FEI ANNUAL REVIEW FOR 2017 RATES					
15.	9	2	***Amortization of 2017 Revenue Surplus deferral account*** The Panel directs FEI to propose an amortization period for the 2017 Revenue Surplus deferral account as part of FEI's Annual Review for 2018 Delivery Rates Application.	Amortization period will be proposed in a future application.	Section 12.4.1

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
16.	12	6	***Cost of Capital Application deferral account*** FEI is directed to file the requested additional information as part of its annual review for 2018 delivery rates application. The Panel does not approve FEI's request for a three-year amortization period for the 2016 Cost of Capital Application deferral account at this time, and directs FEI to provide additional information and explanations for the amount of experts/consultants costs and external legal costs incurred in the 2016 Cost of Capital proceeding. This additional information, outlined below, must be filed as part of FEI's annual review for 2018 delivery rates application: • An explanation as to why there was such a broad range in the rate per hour charged by FEI's expert/consultant (i.e. $55-725 USD) in the 2016 Cost of Capital proceeding. • An explanation as to why the upper range of the hourly rate charged by FEI's expert/consultant was approximately $225 USD per hour higher than the upper range of the hourly rate charged by FEI's experts/consultants in the 2012 GCOC Stage 1 proceeding. • A breakdown of the hours charged by the expert/consultant in the 2016 Cost of Capital proceeding at each hourly rate and the supporting descriptions of the activities performed. • The total FEI proceeding costs for the FEI-FBC 2014-2019 PBR proceeding and the 2012 GCOC Stage 1 proceeding after allocations to other utilities. • A detailed explanation for why the external legal costs in the 2016 Cost of Capital proceeding were only approximately 15 percent lower than in the 2012 GCOC Stage 1 proceeding given the difference in Oral Hearing days, the number of IRs, and the length of the proceedings. This response should include a comparison of the number of hours billed and the number of legal counsel used in the 2016 Cost of Capital proceeding versus the 2012 GCOC Stage 1 proceeding.	Information provided.	Section 7.5.2.1

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
17.	17	7	***Capital Expenditures*** FEI is directed to provide additional information on its capital expenditures, as outlined in the Reasons for Decision attached as Appendix A to this order, as part of FEI's annual review for 2018 delivery rates application. Thhe Panel directs FEI to provide the following information in its annual review for 2018 delivery rates application: • The information contained in Table 1-3 of the Application updated for 2016 Actuals and Projected 2017 results; • A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Growth Capital, which separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any); • A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Sustainment/Other Capital, which separately quantifies the amount of the annual variances and cumulative variance attributable to: (i) the reduction to the Base Sustainment Capital for the Vancouver Island region; (ii) the growth factor for net customer additions; (iii) the Regionalization Initiative; (iv) the installation of Jomar valves; (v) increased in-line inspection activity; (vi) unanticipated system improvements and new stations to supply gas to large new customers; (vii) Burns Bog Stress Relief; and (viii) other contributing factors (if any); and • A description of how FEI is prioritizing its capital expenditures during the remainder of the PBR term, with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken during the PBR term. FEI must also provide a description of any projects which it had originally planned to complete during the PBR term but are now expected to be delayed until after the PBR term.	Information provided.	Appendix C4

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
18.	19	8	***Forecasting Directive*** FEI is directed to report the Holt's Exponential Smoothing (ETS) test forecasts and the aggregate Mean Average Percent Error (MAPE) results as part of its annual review for 2018 delivery rates application and in all remaining annual review applications. FEI is also directed, as part of its future annual review application materials, to extend the applicable tables in Section 3 of Appendix A2 of the Application to include variance information for the ETS method for the residential and commercial use per customer, and the commercial customer additions.	Results reported.	Appendix A2 Section 3.18
19.	23	9	***Headcount Information*** FEI is directed to provide the headcount and Full Time Equivalent information as outlined in the Reasons for Decision attached as Appendix A to this order in its annual review for 2018 delivery rates application and in all remaining annual review applications during the term ofthe Performance Based Ratemaking Plan.	Information provided.	Appendix C3
G-25-17 – FEI ALL INCLUSIVE CODE OF CONDUCT AND TRANSFER PRICING POLICY					
20.	24	4	***Shared Services*** FEI is directed to file a review of its shared services model as part of its 2018 Annual Review under its Performance Based Rate Plan or alternatively, as part of its next revenue requirement proceeding.	The shared services model will be filed at a later date.	N/A

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 requested by the Commission.

Table C2-1: Regionalization Initiative – Phase 1

	2014	2015+
Activities undertaken	• Operations Supervisor recruitment and training • Dispatcher relocation, recruitment and training • Planner relocations • Process review and modification • IT infrastructure and system 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

Table C2-2: Regionalization Initiative – Phase 2

	2016	2017+
Activities undertaken	• Regionalize pre-req, closing, and hazards functions closer to service areas • Process review and modification • IT infrastructure modifications • Facilities modifications	None
Organizational changes	• Operations support staff decreases • Operations support staff re-allocated to service areas	None
O&M expenditures incurred or expected to be incurred	**$0.8 million** This included costs for a number of activities including employee development/training, IT, facilities and communication	None
Capital expenditures incurred or expected to be incurred	**$0.7 million** This includes costs for IT and facilities and back office costs.	None
Anticipated savings - Labour	**$1.1 million** approximately. Similar to Phase 1, 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

Table C2-3: 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

1 **Table C2-4: 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. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. 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 permanent reduction in Compugen's costs to support FEI, the vendor and FEI share 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

2

Table C2-5: Online Service Application

	2015 / 2016	2017+
Activities undertaken	• Development of internet based application using .net technology. • Interfaces with existing enterprise applications such as SAP, GIS, ClickSchedule, Café using Web Services and BizTalk.	None
Organizational changes	• None	None
O&M expenditures incurred or expected to be incurred	**$0.05 million** This included costs for analysis, training and change management.	$0.01 million
Capital expenditures incurred or expected to be incurred	**$1.8 million** This includes the costs for developing the application.	$0.5 million
Anticipated savings	This application is designed to enhance the customer experience by offering customers another channel to request a service line in addition to the existing customer contact centre voice channel.	$0.05 million annual O&M savings

Table C2-6: SAP Integration

	2017 and 2018	2019+

Activities undertaken	• Blueprint / Technical Design Phase
	• Realization Phase
	• Testing
	    o Regression Test
	    o Data Migration Test
	    o Integration Test
	    o Security Test
	    o User Acceptance Test
	• Cutover Phase & Go Live
	• Stabilization Phase
		None

Organizational changes	• Displacement of contractors with internal resources	None
O&M expenditures incurred or expected to be incurred	$0.3 million This included costs for Change Management support.	None
Capital expenditures incurred or expected to be incurred	$4.2 million This includes costs for implementation including build, test and deliver.	None
Anticipated savings	None in 2017 and 2018. Project completion is expected in the third quarter of 2018.	$0.9 million ($0.6 m FEI; $0.3 m FBC)

On page 23 of Appendix A attached to Order G-182-16 approving FEI's Annual Review for 2017 Rate, the Commission provided the following directive:

> FEI is directed to provide the headcount and Full Time Equivalent information as outlined in the Reasons for Decision attached as Appendix A to this order in its annual review for 2018 delivery rates application and in all remaining annual review applications during the term of the Performance Based Ratemaking Plan.

As directed by the Commission, FEI provides below Table C3-1 with the headcount information and Table C3-2 with the FTE information by the various categories outlined by the Commission in Appendix A.

Table C3-1: Headcount

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Projected	2017 Projected
Total Annual Headcount	1,764	1,704	1,656	1,667	1,721	1,724
Change in Annual Headcount (year over year)	(1)	(60)	(48)	11	65	57
# of Positions Added Each Year (total) and broken down as follows:						
Regionalization Initiative - Phase 1 and 2	-	31	-	-	-	-
Project Blue Pencil	-	-	-	-	-	-
Other Major Initiatives	-	-	-	-	-	-
Outside of Base O&M	25	(4)	(5)	6	19	28
Inside Base O&M	(26)	(34)	(32)	23	46	28
Total Positions Added	(1)	(8)	(37)	30	65	57
# of Positions Eliminated Each Year (total) and broken down as follows:						
Regionalization Initiative - Phase 1 and 2	-	(52)	-	(19)	-	-
Project Blue Pencil	-	-	(10)	-	-	-
Other Major Initiatives	-	-	-	-	-	-
Outside of Base O&M	-	-	-	-	-	-
Inside Base O&M	-	-	-	-	-	-
Total Positions Eliminated	-	(52)	(10)	(19)	-	-
Net Change in Headcount (year over year)	(1)	(60)	(47)	11	65	57
# of Unfilled Vacancies						
# of Unfilled Vacancies for each year	n/a	n/a	n/a	n/a	n/a	n/a

Table C3-2: FTE

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Projected	2017 Projected
Total Annual FTEs	1,679	1,650	1,573	1,581	1,613	1,650
Change in Annual FTEs (year over year)	(3)	(29)	(77)	8	40	69
# of Positions Added Each Year (total) and broken down as follows:						
Regionalization Initiative - Phase 1 and 2		31				
Project Blue Pencil						
Other Major Initiatives						
Outside of Base O&M	25	(4)	(5)	6	10	28
Inside Base O&M	(28)	(3)	(62)	21	30	40
Total Positions Added	(3)	23	(67)	27	40	69
# of Positions Eliminated Each Year (total) and broken down as follows:						
Regionalization Initiative - Phase 1 and 2		(52)		(19)		
Project Blue Pencil			(10)			
Other Major Initiatives						
Outside of Base O&M	-	-	-	-	-	-
Inside Base O&M						
Total Positions Eliminated	-	(52)	(10)	(19)	-	-
Net Change in FTE - year over year	(3)	(29)	(77)	8	40	69
# of Unfilled Vacancies - included related to O&M, Capital, Other						
# of Unfilled Vacancies for each year	19	30	39	51	n/a	n/a

Overview of Approach to Preparing the Information Requested

The numbers provided in the tables above are FEI's approximation of the changes in headcount and FTE by the different classifications (Regionalization Initiative, Project Blue Pencil, Other Major Initiatives, Outside Base O&M, Inside Base O&M, etc.) as outlined in the format provided by the Commission in Appendix A to Order G-182-16.

FEI does not track and report headcount and FTEs in the classifications outlined by the Commission. FEI's Human Resources systems track employees and the positions that they occupy and which part of the organization they belong to. In addition, the systems track changes in the status of positions, positions added and removed. The position changes tracked in the systems include the transfers of positions from one department to another, even though the changes do not necessarily represent true net changes to the organizational overall.

Reporting on the classifications requested by headcount and FTEs is inherently difficult. An employee, depending upon their job responsibilities, may perform a number of activities that fall into the different classifications outlined. For example, an employee may spend 80% of their time performing O&M activities with the remaining 20% of their time on capital activities. On an FTE basis, 0.80 FTE would be reported as O&M and 0.20 FTE reported as Capital. However, a headcount cannot be split, so the headcount can be reported as either O&M or Capital, but not partly O&M and partly Capital. As a result, the headcount information provided in Table C3-1 above has been completed in a similar manner to that reported on an FTE basis in Table C3-2 (i.e. one FTE equals one headcount). Where there are differences between the headcount and

FTE information (which are typically caused by vacancies within a given period and the use of part-time and temporary employees), for the purpose of the information requested, the differences are reported as part of the Inside Base O&M classification, recognizing that the Inside Base O&M classification accounts for the majority of headcount and FTE at FEI.

With the limitations described, FEI's approach to generating the information requested by the Commission was to first approximate the changes in FTEs by the broad classifications (i.e. Inside Base O&M, Outside Base O&M). This was estimated using financial and costing data in FEI's SAP system. The financial data was then converted to FTEs using average annual wage/salary assumptions for different employee affiliations (i.e. M&E, IBEW, MoveUp). Reporting by specific initiatives (i.e. Regionalization, Project Blue Pencil) was based on additional headcount and FTE information available, as the headcount and FTE changes were tracked separately for some initiatives. Adjustments to the FTEs reported for the broad classifications (i.e. Inside Base O&M, Outside Base O&M) were made to avoid double-counting of the changes.

Separating the FTE changes into Additions and Deletions is not possible given the existing systems and information available. Changes in FTEs can occur for different reasons, including new positions, positions eliminated, turnover of staff (i.e. vacancies) and changes in the how much time is allocated between one activity versus another (O&M versus Capital). As a result, FEI was only able to separate Additions from Deletions for the Regionalization and Blue Pencil initiatives, as these were the only ones where the information was tracked separately. Therefore, other than for these two initiatives, the information requested is reported on a Net Change basis.

With regards to the "# Unfilled Vacancies" information requested, FEI understands "Unfilled Vacancies" to mean existing positons that become temporarily vacant due to turnover. For FEI, the proxy to measure this is by taking the number of job bulletins identified as for "replacement" in a given year and calculating how long the job bulletins are vacant for. The days vacant estimated are then converted to an FTE basis. However, FEI is unable to determine specifically for all the job vacancies in a given year, how many are related to the different classifications (i.e. O&M, Capital), or whether in the interim the vacancy was filled by use of a contractor or a consultant, or by additional overtime (unpaid or paid) by existing employees. Due to the difficulties described, FEI has not forecast Unfilled Vacancies (i.e. 2016 and 2017 Projected).

Given the above circumstances and assumptions, the headcount and FTE information provided are approximations only. The information is indicative of factors contributing to headcount and FTE changes, instead of having a direct and accurate correlation to costs incurred and savings realized.

1. INTRODUCTION

In Order G-182-16, at page 17, the Commission set out the following capital directives.

> The Panel directs FEI to provide the following information in its annual review for 2018 delivery rates application:
>
> - The information contained in Table 1-3 of the Application updated for 2016 Actuals and Projected 2017 results;
> - A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Growth Capital, which separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any);
> - A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Sustainment/Other Capital, which separately quantifies the amount of the annual variances and cumulative variance attributable to: (i) the reduction to the Base Sustainment Capital for the Vancouver Island region; (ii) the growth factor for net customer additions; (iii) the Regionalization Initiative; (iv) the installation of Jomar valves; (v) increased in-line inspection activity; (vi) unanticipated system improvements and new stations to supply gas to large new customers; (vii) Burns Bog Stress Relief; and (viii) other contributing factors (if any); and
> - A description of how FEI is prioritizing its capital expenditures during the remainder of the PBR term, with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken during the PBR term. FEI must also provide a description of any projects which it had originally planned to complete during the PBR term but are now expected to be delayed until after the PBR term.

FEI included an updated Table 1-4 in Section 1 of the Application. In this Appendix, FEI provides the requested information for each of the remaining three areas.

2. ANNUAL GROWTH CAPITAL VARIANCES

This section provides annual and cumulative variances between formula and actual/projected growth capital broken down into mains growth capital and service line additions growth capital. In its directive, the Commission requested information which includes a breakdown and explanation for both the annual variances and the cumulative variance between formula and actual/projected growth capital, and separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any). As shown in Table 1-4 of the Application, the cumulative growth capital variance for the 2014 to 2017 period is projected to be $48.8 million. The service line additions growth capital variance discussed in Section 2.1 below totals $37.8 million, and the mains growth capital variance discussed in Section 2.2 below totals $9.3 million. These two amounts sum to $47.1 million of the $48.8 million cumulative growth capital variance.

The growth capital variances are attributable to two main factors: (1) an increase in the volume of service and main installations, and (2) a higher per installation cost than was utilized in calculating the approved formula growth capital amounts. FEI's Base Capital costs for the PBR period were based on the 2013 Approved (for FEI) and 2014 Approved (for Vancouver Island and Whistler) growth capital costs, which were in turn based on 2010 actual costs for FEI and 2012 actual costs for Vancouver Island and Whistler. Since that time, FEI has seen a substantial increase in the number of services and mains installed to meet customer demand, and an increase in installation costs. As a result, overall growth capital expenditures are higher than what the PBR formula allows

It is important to note that, for growth capital, each customer must pass an extension test in order to attach to the system. This test is either a service line cost allowance test or a main extension test. If the customer passes this test, or elects to pay a contribution if they do not pass the test, FEI is obligated to provide service to the customer[1]. These tests do not consider restrictions on capital spending, whether through a PBR formula or otherwise. Further, in the case of particularly large mains, costs may be high, but offsetting revenues may be high as well. Thus, higher capital expenditures may be offset by higher revenue. As noted in the regulatory proceeding to review FEI's system extension policies, the addition of customers from 2008-2014 has had a positive effect on rates, since new customers pay more than their cost to serve.

Variances attributed to service line addition growth capital and mains growth capital are further explained below.

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[1] Section 28 (1) of the Utilities Commission Act: On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose.

2.1 *SERVICE LINE ADDITIONS GROWTH CAPITAL VARIANCE*

To determine the annual and cumulative variance from service lines additions FEI first had to determine the approved capital amount for service line additions embedded in growth capital. The following table shows the break out of approved growth capital split by Mains, Meters and Service Line Additions (SLAs). As shown in Table C4-1, the cumulative approved formulaic capital for SLAs is $71.4 million.

Table C4-1: Components of Approved Growth Capital ($000s)

Line No.	Year	Approved Growth Capital	Growth Capital for Mains	Growth Capital for Meters	Growth Capital for SLAs
1	2014 A	$ 21,479	$ 6,490	$ 2,102	$ 12,886
2	2015 A	28,480	8,672	2,312	17,495
3	2016 A	33,262	10,129	2,700	20,432
4	2017 P	33,477	10,194	2,718	20,565
5	**Cumulative**	**$ 116,697**	**$ 35,485**	**$ 9,832**	**$ 71,380**

The following Table C4-2 shows the total capital variance and then splits the total variance into activity and cost components.

Table C4-2: Service Line Addition and Capital Variances ($000s unless otherwise noted)

Line No.	Year	*Approved* SLAs	*Approved* $/SLA	*Approved* Capital	*Actual / Projected* SLAs	*Actual / Projected* $/SLA	*Actual / Projected* Capital	*Variance* SLAs	*Variance* Capital
1	2014 A	7,934	$ 1,624	$ 12,886	8,473	$ 2,096	$ 17,762	539	$ 4,876
2	2015 A	9,586	$ 1,825	$ 17,495	12,392	$ 2,430	$ 30,110	2,806	$ 12,615
3	2016 A	11,143	$ 1,834	$ 20,433	12,288	$ 2,546	$ 31,291	1,145	$ 10,858
4	2017 P	11,180	$ 1,840	$ 20,565	14,753	$ 2,032	$ 29,979	3,573	$ 9,414
5	**Cumulative**	**39,843**	**$ 1,792**	**$ 71,381**	**47,906**	**$ 2,278**	**$ 109,143**	**8,063**	**$ 37,762**
6									
7									

8		*Activity Variance*			*Cost Variance*			*Variance*
9	Year	SLAs Variance	Approved $/SLA	Capital Variance from # SLAs	Actual SLAs	$/SLA Variance	Capital Variance from Cost per SLA	Capital
10	2014 A	539	$ 1,624	$ 875	8,473	$ 472	$ 4,001	$ 4,876
11	2015 A	2,806	$ 1,825	$ 5,122	12,392	$ 605	$ 7,493	$ 12,615
12	2016 A	1,145	$ 1,834	$ 2,099	12,288	$ 713	$ 8,759	$ 10,858
13	2017 P	3,573	$ 1,840	$ 6,574	14,753	$ 193	$ 2,840	$ 9,414
14	**Cumulative**	**8,063**		**$ 14,669**	**47,906**		**$ 23,093**	**$ 37,762**

2.1.1 Growth Factor for Service Line Additions

The variance in approved versus actual, for both SLAs and overall capital, is impacted by the PBR formula which uses a historical growth factor to determine the future years approved capital expenditures, in addition to the growth formula accounting for only one half of growth[2]. As a result, the PBR formula does not accurately account for the actual number of service line additions. Line 14 from Table C4-2 shows that FEI has installed 8,063[3] more service lines than the formula contemplated, which accounts for $14.7 million of the total variance.

2.1.2 Other Factors Contributing to the Variance for Service Line Additions

As shown in line 14 of Table C4-2, overall service line attachments were higher than the formula allowed. Line 5 also shows that the actual average cost per SLA is $486 per SLA higher than the formula approved amount ($2,278 - $1,792). The primary factors that have changed since the base capital per SLA amounts were developed, and that are contributing to the cost per service line variance include:

- An increase in customer attachments per service line, which results in a higher cost per service line addition;
- An increase in SLA activity on Vancouver Island (where costs are higher), compared to the SLA activity in the growth capital formula;
- An unfavourable USD exchange rate that has resulted in an increased cost of equipment and supplies purchased from the United States due to; and
- Local government requirements.

These contributing factors are described in more detail below.

2.1.2.1 Increase in Customer Attachments per Service Line Addition

Due to the changing housing market from single detached homes to multi-family developments, FEI is seeing an increase in the number of customer attachments per SLA. In the case of a single detached home, there is generally one customer attachment per SLA. In the case of a multi-family development, there can be upwards of 10 to 40 customers attaching to a single service line. For example, in 2012 there were approximately 1.2 customers per SLA, whereas in 2016 there were approximately 1.4 customers per SLA. To serve a single detached home requires smaller pipe, fewer fittings, and a smaller riser resulting in a lower cost per service line attachment compared to the cost to serve a multi-family development, which requires a service

[2] FEI has calculated the impact on Total Capital of the growth factors for SLAs and net customer additions being reduced by half in Section 1.4.4.1. In addition, FEI is compensated for the use of an historical growth level instead of actual through the earnings sharing mechanism, but the capital formula itself is not adjusted for the lag. The adjustment to the earnings sharing mechanism is described in Section 10.1.2.

[3] 2014 – 2016 Actual plus 2017 Projection

line attachment with larger pipe, additional fittings and a larger riser contributing to a higher SLA cost.

2.1.2.2 SLA Activity on Vancouver Island and the Cost per Service Line Addition

The cost variance is due in part to the increase in SLA activity on Vancouver Island compared to the SLA activity in the growth capital formula. When the Vancouver Island and Whistler service areas were amalgamated with FEI, the 2014 growth capital base was adjusted for both the number of SLAs and the cost per SLA for Vancouver Island (and Whistler). At that time, the Vancouver Island SLA adjustment added 2,167 SLAs, which represented 21 percent of the total 2014 SLAs of 10,156. In 2015, 2016 and projected for 2017, FEI is experiencing increased SLAs on Vancouver Island compared to those in the base (26 percent, 29 percent and 29 percent of total SLAs in 2015, 2016 and 2017, respectively). The increase in this activity on Vancouver Island at a higher cost per SLA than the Mainland is a contributing factor to the cost variances attributed to SLAs.

2.1.2.3 USD Exchange Rates

The Canada-United States exchange rate forecast, on which FEI based its capital cost assumptions for the PBR term, was higher than the exchange rates that have been realized during the PBR term. FEI's Base Capital for the PBR plan was set at FEI's 2013 Approved levels, with additions for Vancouver Island and Whistler based on 2014 Approved expenditures, following the amalgamation of the companies. FEI's 2013 Approved capital expenditures were based on a CAD/USD exchange rate forecast of $0.9723 and Vancouver Island (and Whistler) Approved capital expenditures in 2014 were based on a CAD/USD exchange rate of $0.99. Thus, FEI's Base Capital was set based on an expectation that the exchange rate would be close to par, whereas capital expenditures during the PBR term have been incurred at an exchange rate closer to 0.811[4]. This causes capital cost pressure on FEI's formula-driven expenditures under the PBR plan.

2.1.2.4 Evolving Local Government Requirements

Local governments have implemented regulations that place increased requirements on utilities. FEI is continuing to work with local governments and regulators to meet evolving municipal regulations. Additional permitting requirements, working arrangements and restricted working hours have added additional cost pressures to growth capital.

[4] Average 2014 through 2017 Bank of Canada indicative CAD/USD exchange rate (2014: 0.905, 2015: 0.782, 2016: 0.755, 2017: 0.800)

2.2 *MAINS GROWTH CAPITAL VARIANCE*

As noted in the preamble to the discussion on growth capital, FEI is experiencing strong customer growth in both service lines and in mains with more residential developments which require main extensions, but also a number of larger mains required for commercial/industrial customers.

The annual and cumulative variances between formula and actual/projected capital is provided for total New Customer Mains as shown in Table C4-3 below. FEI is currently projecting mains expenditures in 2017 to be similar to those of 2016.

Table C4-3: New Customer Mains ($ thousands)

New Customer Mains (000's)	Actual/ Projected	Allowed	Variance	Var%
2014	5,399	6,649	(1,250)	-19%
2015	14,082	9,007	5,075	56%
2016	13,103	10,444	2,659	25%
2017	13,190	10,400	2,790	27%
Cumulative	45,774	36,500	9,274	25%

The variance in costs for customer mains is driven partly by the growth in large industrial mains, and a number of other factors.

2.2.1 Growth in Larger Industrial Main Additions

FEI does not have a capital formula specific to larger industrial mains so is not able to directly quantify the amount of the variance due to this factor. Instead, FEI provides the following discussion of larger mains.

The average cost per metre of main in FEI's 2013 Base was $62 per metre. The actual cost per metre of main was $87 in 2014, $121 in 2015 and $121 in 2016, with 2017 expected to be similar to 2016. The 2014 through 2017 costs have been influenced upward by a number of larger cost mains. The 20 mains with the highest cost per metre that FEI has installed since 2014 had an average cost per metre of $347, which has contributed approximately $4.6 million to date to the capital cost pressure when compared to the average cost that was embedded in the PBR formula.

In 2010, the year that was used to develop the 2013 Base for the PBR formula, there was one new main with a cost greater than $100 thousand. This compares to 15 and 11 new mains greater than $100 thousand in 2015 and 2016, respectively. The number of larger new mains (greater than $50 thousand) has more than doubled in 2015 and 2016 compared to that of 2014.

FEI mains expenditures are driven by customer growth and the type of customer impacts the timing, size and cost of the mains. The decision by large industrial customers to connect to

FEI's system, their load profile and the location they wish to connect to are largely driven by factors outside the control of FEI. Larger diameter and more costly mains to serve customer load requirements, in addition to a significantly larger number of main installations compared to previous years, have contributed to variances in growth capital.

2.2.2 Other Factors Contributing to the Variance for Mains

Some of the cost pressures contributing to the SLA growth capital variance also contribute to the Mains growth capital variance. An increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate and local government requirements are contributing to the mains growth capital cost variance.

3. ANNUAL SUSTAINMENT/OTHER CAPITAL VARIANCES

In Table C4-4 below, FEI provides a breakdown and itemization of variances attributable to the items identified by the Commission.

Table C4-4: Annual Sustainment/Other Capital Variances ($ millions)

Line No.	Description	2014	2015	2016	2017	Cumulative
1	PBR Decision reduction to base sustainment capital for Vancouver Island pressure	-	6.351	6.417	6.484	19.253
2	PBR Decision growth factor for net customer additions pressure	0.259	0.939	1.586	2.250	5.035
3	Regionalization Initiative	1.300	0.100	0.600	-	2.000
4	Installation of bypass (Jomar) valves	-	0.050	2.070	2.600	4.720
5	Increased in-line inspection activity	1.730	1.200	3.287	3.000	9.217
6	Unanticipated system improvements and new stations to supply gas to large new customers	0.600	2.700	1.764	2.498	7.562
7	Burns Bog stress relief	1.000	1.400	0.987	2.913	6.300
8	Other contributing factors:	1.000	2.330	-	2.275	5.605
9	PBR formula pressures resulting from increase in PIF (1.1% vs. 0.5%)	0.597	0.664	0.669	0.676	2.606
10	Prince George #1 lateral erosion	0.150	0.030	0.040	0.670	0.890
12	Ministry of Transportation and Infrastructure IP relocation		0.050	0.700		0.750
13	Mission IP seismic upgrade		1.200			1.200
14	Cyber security				0.375	0.375
15	**TOTAL Sustainment / Other Pressures**	6.636	17.015	18.121	23.741	65.513
16	**Actual annual and cumulative Sustainment / Other capital expenditures variance compared to formula**	1.825	(3.098)	2.587	26.671	27.985

Table C4-4 shows that the pressures experienced in years 2014 through 2016 are greater than FEI's annual sustainment and other capital expenditures over formula in those years. As explained elsewhere, in order to manage pressures experienced during years 2014 to 2016 of the PBR term, some projects that were assessed as being less critical to the system, or that were temporarily less time-sensitive, were reprioritized to future years to accommodate the required projects listed in the table. In 2017, FEI has prioritized additional capital expenditures to start to catch-up on an accumulation of work that had been re-prioritized from previous years of the PBR term into 2017. For this reason, FEI's cumulative sustainment and other capital expenditure compared to formula is higher than the total of the items shown in Table C4-4.

FEI provides below a further discussion of each of the items in the table above, other than the formula-related items which are self-explanatory.

3.1 *REGIONALIZATION INITIATIVE*

The Regionalization Initiative is described further in Section 1.4.3 of the Application and Appendix C-2.

3.2 *INSTALLATION OF BYPASS (JOMAR) VALVES*

The installation of bypass valves (Jomar Valves[5]) on residential meter sets within the FEI service area began with a trial in 2015 in order to improve customer satisfaction, improve employee safety, improve maintenance flexibility and reduce costs associated with the Residential Meter Exchange Program. Currently, exchanging a residential gas meter set results in a supply outage to the customer when the old meter is disconnected and the new unit installed. This has a negative impact on customers as they must be present for the FEI technician to enter their premises and relight appliances. The Residential Meter Exchange Program is an approximately $15 million annual expenditure and involves the replacement of approximately 75 to 85 thousand meters per year – with the same number of scheduled customer outages. The program is undertaken by FEI to ensure its meters are accurate and is necessary to remain compliant with Measurement Canada Regulations. The Company expects that the installation of bypass valves will reduce annual Residential Meter Exchange Program costs by reducing the time to complete a meter exchange and associated relights, increase operational efficiencies through better scheduling and use of office and field resources, and increase customer satisfaction by reducing customer disruption.

Based on operational efficiencies to the Company and societal benefits to customers by not requiring them to take time away from work to be present for the meter exchange, the installation of bypass valves will result in cost savings and customer benefits over the approximate life of the bypass valves and the service line.

Given the expected cost savings combined with the elimination of residential customer disruption associated with meter exchanges, FEI concluded that it was appropriate to begin installation of the bypass valves in 2015.

3.3 *INCREASED IN-LINE INSPECTION ACTIVITY*

FEI needs to continue to enhance its Integrity Management Program to manage aging infrastructure, meet the CSA Z662-15 standard, and adopt industry practices deemed appropriate to FEI's system. Enhancements to FEI's in-line inspection activities include the adoption of the circumferential magnetic flux leakage technology with a run frequency of approximately 7 years, and an increased number of transmission lines subject to in-line inspection.

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[5] The bypass valve currently being deployed by FEI is manufactured by the Jomar Group of companies. The terminology "bypass valve" and "Jomar valve" are sometimes used interchangeably within FEI.

3.4 UNANTICIPATED SYSTEM IMPROVEMENTS AND NEW STATIONS TO SUPPLY GAS TO LARGE NEW CUSTOMERS

The addition of large new customers has resulted in the need for system improvements or new stations to support the added load described in section 2.

3.5 BURNS BOG STRESS RELIEF

Through the analysis of soil monitors, and subsequent in-line inspection and physical pipeline probing, FEI determined that the transmission pipelines in Burns Bog had been exposed to excessive stress due to soil loading and required mitigation on a planned, non-emergent basis. FEI scheduled and carried out mitigative action on the NPS 24 line in 2015 and 2016 and is conducting additional stress relief work on the NPS 36 line in 2017.

3.6 OTHER CONTRIBUTING FACTORS

In addition to the PBR formula pressures discussed in Section 1.4 of the Application, FEI has identified the following other contributing factors.

3.6.1 Prince George #1 Lateral Erosion

Changes in surface water drainage across FEI's Prince George #1 Lateral transmission pipeline have threatened the stability of the pipeline right of way and the integrity of the pipeline. FEI is working to stabilize the ground around the pipeline.

3.6.2 Ministry of Transportation and Infrastructure IP Relocation

This project was driven by the widening of Highway 16 East between Gauthier Road to Blackwater Road in Prince George and the Ministry of Transportation and Infrastructure direction that the FEI IP pipeline be relocated outside of the new road structure.

3.6.3 Mission IP Seismic Upgrade

FEI replaced approximately 1.2 kilometres of IP pipeline within Mission with a longer IP pipeline in a more seismically stable location.

3.6.4 Cyber Security

In 2017, FEI is implementing cyber security measures to protect networks, computers and data from attack, theft, damage or unauthorized access. This initiative is described in more detail in Section 1.4.1.

3.6.5 CAD-USD Exchange Rates

This item was discussed above in Section 2.1.2.3. An increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate is contributing to the sustainment / other capital cost variance.

3.6.1 Evolving Local Government Requirements

This item was discussed above in Section 2.1.2.4. An estimate of the pressures attributable to this item was not included in Table C4-4 as it is difficult to quantify.

4. CAPITAL PRIORITIZATION

In this section, FEI provides a discussion of how capital expenditures will be prioritized during the remainder of the PBR term, with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken during the PBR term. This includes a description of any projects which were originally planned to be completed during the PBR term but are now expected to be delayed until after the PBR term.

Prioritization of capital expenditures has been an evolving process and FEI has taken a number of steps over the years to improve its internal capital prioritization processes.

As an example of this evolution, FEI developed its Long Term Sustainment Plan (LTSP), as described in the 2014-2018 PBR Application,[6] which strove to develop a long-term planning approach to manage the growing need for investment in an aging system. The LTSP was undertaken over two years and achieved a number of outcomes including:

- the development of the mains renewal prioritization program which leverages off the GE Smallworld GeoSpatial Analysis (GSA) tool;
- an initial relative risk framework which could be manually applied to assess projects driven by asset condition; and
- a listing of other long-term system upgrade projects identified during the LTSP development.

One of the learnings following the development of the LTSP was an understanding that a manual process was not sustainable and could not be applied to all asset categories, nor did it adequately consider other investment drivers such as regulatory requirements, technology advancement and operational efficiency. It became clear that further development and automation of the methodology would be required.

As the gas delivery infrastructure continues to age, the need to invest in sustaining the system continues to increase. These investment needs must in turn compete with other investments to:

- maintain or increase system reliability and resilience;
- improve employee and public safety;
- add new customers;
- meet changing regulatory requirements and industry practice; or
- leverage new technologies.

[6] PBR Application, Appendix C3.

FEI recognizes the need for continual improvement in prioritizing investments and for more transparency in ensuring that all investments create value for the customer. As such, FEI continues to align processes across the organization in its capital planning to help achieve the highest level of benefit for the available funds and resources. FEI provides below a description of its current capital expenditure prioritization processes and the planned improvements to those processes over the remainder of the PBR term.

4.1 CURRENT CAPITAL PRIORITIZATION PROCESS

As described in Section 1.4.4.1 and shown in Table 1-4 of this Application, higher expenditures for customer growth capital during the PBR term have led to capital expenditure pressures in other areas of the organization. This growth capital pressure has been partially offset by FEI reprioritizing some sustainment work that is flexible in timing. However, as a public utility, FEI is required to provide service, and as such, FEI considers the capital expenditures associated with customer requests for attachments, including service line installations and main extensions that pass the MX Test, to be non-discretionary in nature.

FEI manages its capital investment plan to maintain a safe and reliable gas delivery system and an acceptable risk profile for the system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan is built to contain a mix of projects, some of which are time-sensitive and others that have some flexibility in timing. This is done with the understanding that conditions change and the plan must be capable of adapting. This plan flexibility allows FEI to manage and execute normal levels of unforeseen urgent work that come up throughout the year within the resource and budget constraints of the capital plan.

To date during the current PBR term, capital expenditures (other than non-discretionary growth capital) have been prioritized through the following steps:

Step 1: Within the various planning groups of gas system assets sustainment and general plant (e.g. Information Systems (IS), Fleet and Facilities), capital investments are prioritized through established asset-specific means. For example, gas main renewals are prioritized based on the risk algorithm developed through the LTSP project; station projects are prioritized according to relevant criteria such as asset condition, number of customers, location, etc.; IS projects are prioritized through the Project Portfolio Management process that quantifies the benefit of the proposed projects[7].

Step 2: In addition to this asset specific prioritization, during the development of the 2016 capital plan, FEI began assigning each project to one of the following three classifications:

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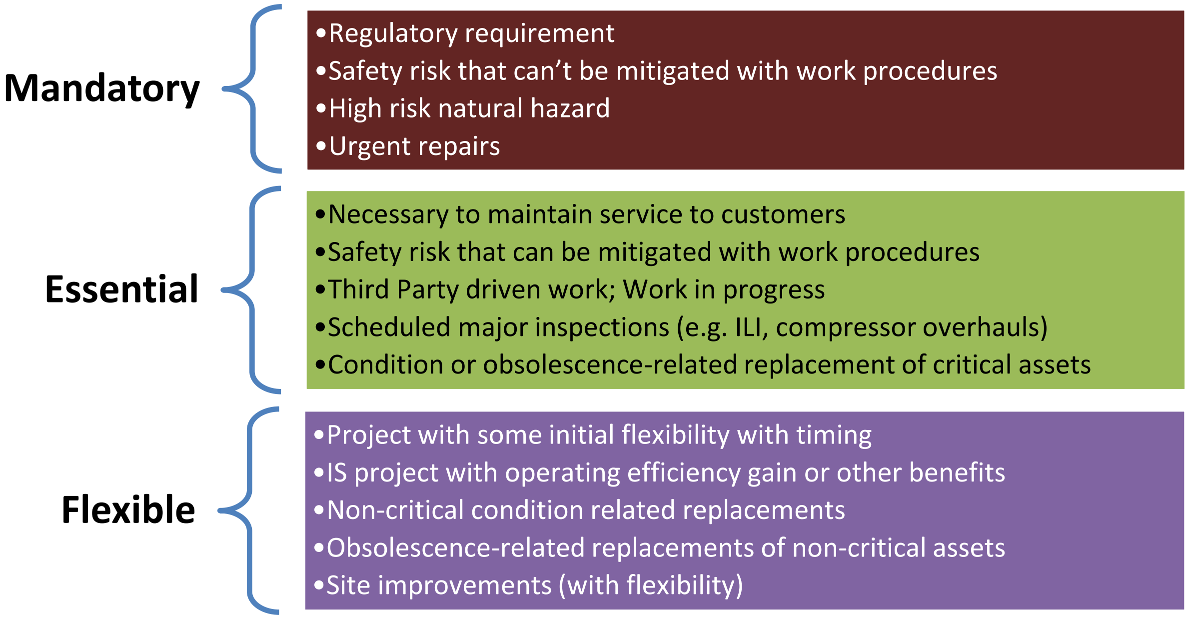
[7] IS Capital Prioritization using Project Portfolio Management and Benefits Management Practice is described in Appendix C-4 response to 2012-2013 RRA Decision BCUC Directive No. 42.

Figure C4-1: Sustainment/Other Capital Priority Classification



Step 3: Based on the three classifications set out in Figure C4-1, available funds and resources were allocated towards mandatory and essential work first. As funds were anticipated to be insufficient to cover the proposed scope of flexible work, further analysis was completed as described in Step 4.

Step 4: Projects that were classified as Flexible in the subject year were subject to further analysis to determine which ones would proceed in that year and which ones would be rescheduled to future years. This analysis included an evaluation of risk mitigation, financial performance, customer growth, customer service, and employee engagement. An example of Flexible work that was prioritized is the installation of bypass valves described above in Section 3.2. This work was prioritized due to the customer service benefits and future cost savings it offered. The benefits of bypass valve installation cannot be achieved until a substantial population of the customer meter sets are retrofitted with the bypass valves. Consequently, delaying the installations delays the onset of the benefits. Additionally, any delay in these installations means a delay to the next meter exchange cycle which is 15 to 20 years from now. Therefore, to achieve the greatest customer benefit and future cost savings, the bypass valve installations began in 2015.

In any given year, projects that have been rescheduled to future years are re-assessed for risk or business value and may change in classification. Projects that were considered Flexible in one year may be considered Essential or Mandatory the following year. Examples of this would be equipment replacement projects driven by obsolescence; once vendor support and spare parts are no longer available, projects that were previously considered Flexible become more urgent and hence considered Essential or Mandatory.

Step 5: Once the year's plan is approved and released, plan execution is monitored and adjustments are made as required. For example, in 2014 through 2016, growth expenditures were significantly higher than anticipated which caused other work to be reprioritized to later years. Likewise, unanticipated urgent work such as the Burns Bog Stress Relief project may be added to the plan and cause other work to be reprioritized to future years.

4.2 *PLANNED IMPROVEMENTS TO THE CAPITAL PRIORITIZATION PROCESS*

In recognition of the importance of consistently valuing and prioritizing its investments, and in light of recent capital pressures that are expected to continue, FEI is pursuing opportunities to build on and enhance its capital planning process to further align capital investment decision-making across the Company and leverage the tools, processes and systems implemented to date.

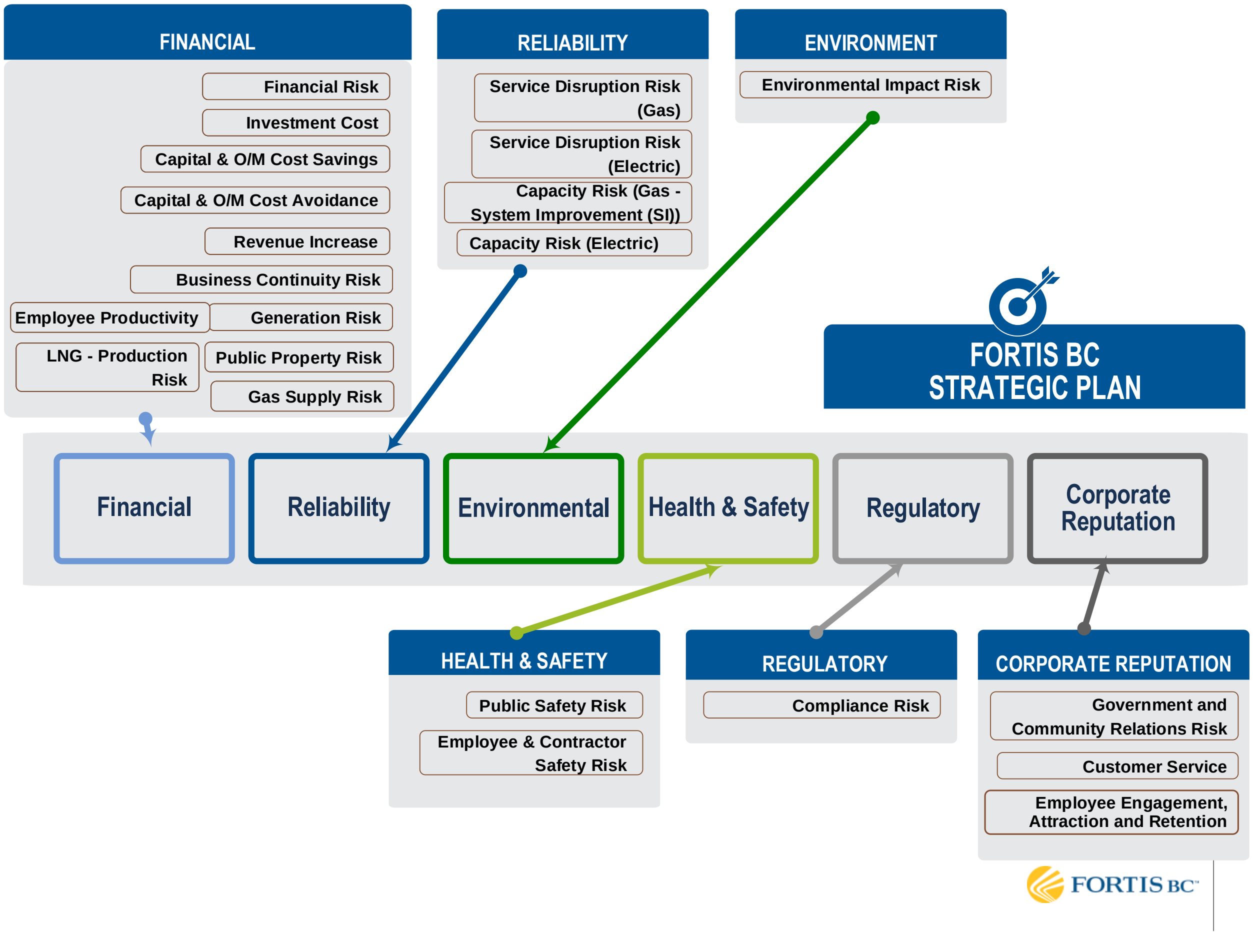
To this end, in 2017 FEI is implementing the first phase of an Asset Investment Planning (AIP) tool[8]. Over time, the AIP will allow the consistent quantification of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

The foundation of the AIP tool is the value framework that is used to quantify the value of potential investments. The value framework is made up of six overarching values that were derived from FEI's strategic objectives and core values. They are: financial, reliability, environmental, health & safety, regulatory, and corporate reputation. Under each value, there are measures which contribute and impact each value. These measures, and which value they impact, are shown below in Figure C4-2.

Each project is evaluated against one or more of the measures that will be impacted by undertaking the project. The measures can be calculated automatically using asset and investment data or through user responses to predefined questions or a combination of both.

[8] Phase 1 applies to Gas asset management and to information systems. General plant and Electric asset management will be part of future phases.

Figure C4-2: Preliminary Value Measures for Asset Investment Planning Tool



Once projects are evaluated using the value framework, the tool provides the ability to conduct an automated optimization of the capital planning portfolio for a given period of time to achieve the greatest benefit within a set of user-defined financial and/or resource constraints. Multiple scenarios can be generated using differing constraints to evaluate alternate execution strategies. The tool also supports approval workflows at the project and portfolio levels to ensure appropriate levels of senior management review. Once an overall optimal portfolio is selected and approved, it becomes the locked-down version which can be used to compare in-year plan changes.

Once fully implemented, the AIP tool will provide the following benefits:

- Increased ability to make risk-informed decisions in capital planning by valuing investments through a common value framework;
- Ability to show consistent methodology across asset classes in valuing capital projects;
- Increased transparency and ability to communicate the value being achieved through execution of the capital plan; and

- Improved ability to optimize the portfolio over multiple years and to consider alternative constraint scenarios.

4.3 PROJECTS PLANNED TO BE UNDERTAKEN OUTSIDE OF PBR TERM

The management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints. FEI reprioritizes capital spending as part of its routine management of the capital portfolio and has done so in prior years to accommodate unforeseen events and work, and to mitigate in part some of the pressures seen in the past years of PBR term. However, FEI will not defer significant amounts of capital spending that would result in increased risk exposure.

FEI continuously manages its capital investment plan to:

- Ensure a safe and reliable gas delivery system;
- Maintain an acceptable risk profile for the system;
- Optimize resources and spending; and
- Achieve efficiencies and cost savings.

In order to achieve these goals, some projects that are assessed to be less critical to the system, or that are less time-sensitive, may be reprioritized to future years in favour of more urgent projects. Likewise, if additional capital is made available through project delays or cost savings, projects may be brought forward based on their assessed priority and their ability to be successfully executed.

The base capital amount and annual formula adjustments were not derived from a list of future capital projects FEI planned to undertake each year during PBR. Rather, they were based on 2013 forecasts derived from historical capital expenditures. As such, FEI is unable to provide a comprehensive listing of projects that have been delayed, rescheduled, cancelled or added today against what was anticipated when the formula was developed. However, the following is a list of the larger projects that FEI had identified for execution in the 2014-2018 PBR Application and has delayed beyond the PBR term.

Table C4-5: Projects Delayed to Beyond the PBR Term

Description	Estimated Timing	Current Status
Class Location Upgrade: 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston	2016	Planned for 2022
Class Location Upgrade: 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk	2017	Planned for 2022

Description	Estimated Timing	Current Status
Class Location Upgrade: 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks	2018	Planned for 2022
Tilbury LNG Plant Buildings	2018	Planned for 2020. Delayed to assess business requirements.
Distribution Main, Service Renewals and Alterations: Penticton Second Supply – Penticton	2015	Planned for 2020. Reprioritized due to capital constraints and to allow routing and siting review with the City of Penticton.
The addition of pipe storage to the Burnaby Operations building	2014	Delayed due to further review of requirements for space strategy and capital constraints.

As described in the PBR Application[9], FEI developed a forecast of Information Systems expenditures for the PBR period to allow for the implementation of projects to improve employee and public safety, address potential shortcomings in customer service levels and to drive O&M cost reductions. Information Systems expenditures are categorized under five main areas of focus including infrastructure sustainment, desktop infrastructure sustainment, application sustainment, business technology transformation and business technology enhancements. The annual portfolio under each category is continually evolving and individual projects are added or removed from the portfolio as required by the business. Each year is considered to be a new portfolio and projects are re-evaluated. FEI does not have any IS projects that have been deferred to outside the PBR term.

4.4 SUMMARY

FEI has taken a number of steps over the years to enhance and strengthen its internal capital prioritization processes. FEI is implementing an AIP tool. The AIP tool will allow the consistent quantification and evaluation of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

The management of the capital plan is a dynamic and ongoing process. Changing conditions make it essential to routinely assess and re-optimize the capital planning portfolio in order to achieve the greatest benefit within a set of user-defined financial and/or resource constraints.

As FEI implements the AIP tool over the remaining term of the PBR plan, FEI anticipates an improved ability to optimize the portfolio in a transparent way over multiple years and to communicate the value being achieved through execution of the capital plan.

[9] Table C4-22, Section 4.6.4 of the PBR Application.

Appendix D

DRAFT ORDER

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Annual Review of 2018 Delivery Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On September 15, 2014, the British Columbia Utilities Commission (Commission) issued its Decision and Order G-138-14 approving for FortisBC Energy Inc. (FEI) a Multi-Year Performance Based Ratemaking (PBR) Plan for 2014 through 2019 (the PBR Decision). In accordance with the PBR Decision, FEI is to conduct an Annual Review process to set rates for each year;

B. By letter dated July 24, 2017, FEI proposed a regulatory timetable for its annual review of 2018 delivery rates;

C. By Order G-115-17 dated July 27, 2017, the Commission established the regulatory timetable for the annual review of 2018 delivery rates which included the anticipated date for FEI to file its annual review materials, the deadline for intervener registration, one round of information requests, a workshop, FEI's response to undertakings requested at the workshop, and written final and reply arguments;

D. On August 4, 2017, FEI submitted its Annual Review for 2018 Rates Application materials (Application);

E. The Commission has reviewed the Application and evidence filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, the Commission orders as follows:

1. FortisBC Energy Inc. is approved to maintain 2018 delivery rates at the approved 2017 levels, before consideration of rate riders, effective January 1, 2018.

2. The following deferral account requests are approved:

    a. Creation of a rate base deferral account for the 2020 Revenue Requirement regulatory proceeding with an amortization period to be proposed when that application is filed;

    b. Creation of a rate base deferral account for the Surrey Operating Agreement regulatory proceeding with a three-year amortization period;

    c. A three-year amortization period for the existing 2016 Cost of Capital Application deferral account, commencing in 2018;

    d. A name change of the 2017 Revenue Surplus account to the 2017-2018 Revenue Surplus account, the inclusion of a $5.177 million reduction to the deferral account balance in 2017 and an addition of the 2018 surplus of $3.824 million to the 2017-2018 Revenue Surplus account; and

    e. The transfer of the ending 2017 balances in the Rate Stabilization Deferral Account Phase-in Rider Balancing Account and Amalgamation Regulatory Account to the Residual Delivery Rate Riders deferral account.

3. The following rate rider requests are approved:

    a. A Biomethane Variance Account Rate Rider for 2018 in the amount of $0.026 per gigajoule; and

    b. Revenue Stabilization Adjustment Mechanism riders for 2018 in the amounts set out in Table 10-9 of the Application.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner