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October 2, 2015

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)

2015 System Extension Application (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On June 30, 2015, FEI filed the Application referenced above. In accordance with Commission Order G-143-15 setting out the Amended Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact Brent Graham at 604-592-7857.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents

Page No.

A. COMMISSION CONCERNS

1.0 Reference: FORECASTING ACCURACY

Exhibit B-1, Application, Section 5.4.1, pp. 74, 75; Appendix C, L-34-14, p. 3

Main extension cost estimates

On page 3 of letter L-34-14, the British Columbia Utilities Commission (Commission) lists forecasting accuracy as an area of concern. The Commission explains:

> Forecasting accuracy refers to the accuracy of the inputs used in the forecast PI calculations. Inputs include, but are not limited to, main extension costs, number of attachments, timing of attachments, use per customer, and application of efficiency credits. Forecasting lower costs, a greater number of attachments, earlier attachments, and/or a higher use per customer than actual may result in a main extension meeting the main extension test with less (or no) contribution from the customer(s) than what the customer(s) should have contributed.

On page 74 of its Application, FortisBC Energy Inc. (FEI) includes a table providing the MX forecast and actual costs and the variances between the two.

1.1 Please complete the following table twice, once for FEI and once for FortisBC Energy Vancouver Island Inc. (FEVI) (in MX Year $):

1. MX Year	2.Total Forecast MX Cost Estimates used in Original MX Tests	3. Total Actual Cumulative MX Spend to Date	4. Estimated Remaining MX Costs	5. Variance (in MX Year $) 2 – (3+4)	6. Variance (in %) [2 – (3+4)]/2	7. Total Expected MX Costs (3+4)
2008						
2009						
2010						
2011						
2012						
2013						
2014						
Sum	8. Sum(2)	9. Sum(3)	10. Sum(4)	11. Variance 7 - (8+9)	12. Variance [7 – (8+9)]/7	Total (9+10)

Response:

In the course of responding to this information request, FEI has identified an error in Table 5-1 of the Application, which was caused by a Microsoft Excel Linking issue. A revised Table 5-1 is provided below.

Revised Table 5-1

	Forecast Cost	Actual Cost	Variance	Variance (%)	Comments
2008 FEI	$ 891,766	$ 970,334	$ 78,568	8.8%	MX reporting complete
2008 FEVI	$ 546,720	$ 640,757	$ 94,037	17.2%	
2009 FEI	$ 2,093,186	$ 2,496,469	$ 403,283	19.3%	Year 5 of cost reporting
2009 FEVI	$ 1,336,265	$ 1,614,962	$ 278,697	20.9%	
2010 FEI	$ 883,607	$ 1,022,728	$ 139,121	15.7%	Year 4 of cost reporting
2010 FEVI	$ 829,198	$ 821,133	$ (8,065)	-1.0%	
2011 FEI	$ 1,475,371	$ 1,614,217	$ 138,846	9.4%	Year 3 of cost reporting
2011 FEVI	$ 859,365	$ 873,305	$ 13,940	1.6%	
2012 FEI	$ 1,166,451	$ 1,683,334	$ 516,883	44.3%	Year 2 of cost reporting
2012 FEVI	$ 568,885	$ 558,529	$ (10,356)	-1.8%	
2013 FEI	$ 1,131,636	$ 1,314,614	$ 182,978	16.2%	Year 1 of cost reporting
2013 FEVI	$ 614,218	$ 570,460	$ (43,758)	-7.1%	
			Average Variance	**12.0%**	

The tables that have been requested in this information request are provided below.

The Company notes that the formulas used to aggregate the variance data (column 5 & 6) in the "Sum" rows appear to be incorrect. The requested formulas are adding all the forecast costs together with all the actual costs which results in an error in the variance percentage. The Company has included a second set of tables based on what it believes the Commission intended to see in the tables.

The Company also notes that the annual MX Report requires the data for mains and service lines to be presented combined whereas this response shows only data for mains and the response to BCUC IR 1.1.3 shows only data for service lines. Due to this and other reasons which are further discussed in response to BCUC IR 1.1.2, the results provided differ from those provided in revised Table 5-1 above.

poitive/negative appear reversed

FEI

Table Includes Forecast to Actual Main Extension Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative MX Spend to Date	4. Estimated Remaining MX Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 352,046	$ 467,819	$ -	$ (115,773)	-32.9%	$ 467,819
2009	$ 873,525	$ 944,648	$ -	$ (71,123)	-8.1%	$ 944,648
2010	$ 458,129	$ 453,092	$ -	$ 5,037	1.1%	$ 453,092
2011	$ 634,248	$ 728,259	$ -	$ (94,011)	-14.8%	$ 728,259
2012	$ 585,584	$ 713,526	$ -	$ (127,942)	-21.8%	$ 713,526
2013	$ 513,372	$ 768,151	$ -	$ (254,779)	-49.6%	$ 768,151
2014	$ 465,830	$ 451,639	$ 14,191	$ -	0.0%	$ 465,830
Sum	$ 3,882,734	$ 4,527,134	$ 14,191	$ (3,868,543)	-85%	$ 4,541,325
	8	9	10	11	12	7
	Sum of Column	Sum of Column	Sum of Column	7-(8+9)	[7-(8+9)]/7	

deviates from formula in column header

actuals over forecast now show as postive

FEI - Includes assumed result

Table Includes Forecast to Actual Main Extension Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative MX Spend to Date	4. Estimated Remaining MX Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 352,046	$ 437,819	$ -	$ (85,773)	24.4%	$ 437,819
2009	$ 873,525	$ 944,648	$ -	$ (71,123)	8.1%	$ 944,648
2010	$ 458,129	$ 453,092	$ -	$ 5,037	-1.1%	$ 453,092
2011	$ 634,248	$ 728,259	$ -	$ (94,011)	14.8%	$ 728,259
2012	$ 585,584	$ 713,526	$ -	$ (127,942)	21.8%	$ 713,526
2013	$ 498,166	$ 768,151	$ -	$ (269,985)	54.2%	$ 768,151
2014	$ 465,830	$ 451,639	$ 14,191	$ -	0.0%	$ 465,830
Sum	**$ 3,867,528**	**$ 4,497,134**	**$ 14,191**	**$ (643,797)**	**17%**	**$ 4,511,325**
	Sum of Column	Sum of Column	Sum of Column	2-(3+4)	[2-(3+4)]/2	

consistent with formula in column header

FEVI

Table Includes Forecast to Actual Main Extension Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative MX Spend to Date	4. Estimated Remaining MX Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 264,194	$ 298,877	$ -	$ (34,683)	-13.1%	$ 298,877
2009	$ 796,757	$ 937,423	$ -	$ (140,666)	-17.7%	$ 937,423
2010	$ 467,152	$ 482,629	$ -	$ (15,477)	-3.3%	$ 482,629
2011	$ 513,670	$ 558,939	$ -	$ (45,269)	-8.8%	$ 558,939
2012	$ 367,763	$ 366,389	$ -	$ 1,374	0.4%	$ 366,389
2013	$ 366,502	$ 352,995	$ -	$ 13,507	3.7%	$ 352,995
2014	$ 1,356,549	$ 1,032,878	$ 323,671	$ -	0.0%	$ 1,356,549
Sum	$ 4,132,587	$ 4,030,130	$ 323,671	$ (3,808,916)	-87%	$ 4,353,801

FEVI - Includes assumed result

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative MX Spend to Date	4. Estimated Remaining MX Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 264,194	$ 298,877	$ -	$ (34,683)	13.1%	$ 298,877
2009	$ 796,757	$ 951,042	$ -	$ (154,285)	19.4%	$ 951,042
2010	$ 467,152	$ 482,629	$ -	$ (15,477)	3.3%	$ 482,629
2011	$ 513,670	$ 558,939	$ -	$ (45,269)	8.8%	$ 558,939
2012	$ 367,763	$ 366,389	$ -	$ 1,374	-0.4%	$ 366,389
2013	$ 366,502	$ 352,995	$ -	$ 13,507	-3.7%	$ 352,995
2014	$ 1,356,549	$ 1,032,878	$ 323,671	$ -	0.0%	$ 1,356,549
Sum	**$ 4,132,587**	**$ 4,043,749**	**$ 323,671**	**$ (234,833)**	**6%**	**$ 4,367,420**

1

As indicated in the tables provided above, the main extension cost variance is 17% and 6% for FEI and FEVI respectively. This degree of accuracy is within an acceptable range for a Class 3 estimate, which is +30% to -15%, which FEI considers to be reasonable. However, FEI believes that forecasting accuracy is important and will continue to work to improve the results. While there are cost items that are out of the control of the Company, FEI has also taken steps to manage and reduce costs associated with system extensions.

1.2 Please explain the variances, if any, between the variances FEI submitted in Table 5-1 and the variances FEI reports in the table above.

Response:

The reasons for the variances between revised Table 5-1 provided in response to BCUC IR 1.1.1 and the Tables provided in response to BCUC IRs 1.1.1 and 1.1.3 are as follows:

- Revised Table 5-1 presents aggregate total costs for mains and service lines in accordance with the current reporting methodology required by the Commission. In BCUC IR 1.1.1, the Commission requested one table for mains and in BCUC IR 1.1.3, the Commission requested a separate table for service lines. The variance calculations will be different since the average variances for mains and service lines together are different than when treated separately.

- The table provided in response to BCUC IR 1.1.3 compares forecast costs to a sum of actual costs and re-forecast costs for service lines. Table 5-1 in the Application calculates the variance based on a comparison of forecast to actual costs only. This difference results in different variance calculations.

- The tables in BCUC IR 1.1.1 and 1.1.3 ask for 2014 values to be included while Table 5-1 in the application includes values up to 2013 only.

- Revised Table 5-1 contains costs extracted from the 2014 MX Report which was submitted earlier this year. There have been changes to the 2011 actual values since then due to adjustments and settlements against the work orders associated with the main extensions. These changes are to be expected given the thousands of work orders undertaken in a year and the nature of the process of invoicing, accounting and the reconciliation of work orders. These two changes are summarized in the table below.

		2014 MX Report (costs as of January 2014)	BCUC IR Response (costs as of June 2015)	Change
FEI	2011 Mains Actual	$727,525	$728,259	$734
FEVI	2011 Mains Actual	$557,216	$558,939	$7,723

1.3 Please complete the same table as above but for service line costs.

Response:

The tables for FEI and FEVI as requested are included below along with a second set of tables where the Company calculates what it believes the Commission intended for columns 5 and 6. (Please see response to BCUC IR 1.1.1 for a description of the formula error implicit in the question.) A description of the formulas is below each table for FEI. The FEVI tables are structured in the same manner as the FEI tables.

As can be seen in those tables, the total service line forecast versus actual cost variance for FEI and FEVI are 32% and 31% respectively, but the variance in more recent years has decreased. As the earlier years were impacted by the financial crisis, the attachments have taken longer to be realized than was forecast. This has resulted in higher costs due to inflationary pressures.

poitive/negative appear reversed

FEI

Table Includes Forecast to Actual Service Line Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative Service Line Spend to Date	4. Estimated Remaining Service Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 539,720	$ 532,515	$ 154,000	$ (146,795)	-27.2%	$ 686,515
2009	$ 1,219,661	$ 1,551,821	$ 167,000	$ (499,160)	-40.9%	$ 1,718,821
2010	$ 425,478	$ 569,636	$ 58,000	$ (202,158)	-47.5%	$ 627,636
2011	$ 841,123	$ 885,958	$ 147,000	$ (191,835)	-22.8%	$ 1,032,958
2012	$ 580,867	$ 969,808	$ 10,000	$ (398,941)	-68.7%	$ 979,808
2013	$ 633,469	$ 546,463	$ 149,000	$ (61,994)	-9.8%	$ 695,463
2014	$ 468,872	Not available	$ 468,872	$ -	0.0%	$ 468,872
Sum	$ 4,709,190	$ 5,056,201	$ 1,153,872	$ (3,555,318)	-57%	$ 6,210,073

**estimated service line cost based on assuming service line cost of $1,000 times the number of expected attachments*

**acutal service line cost based on actual attachments times annual average service line cost*

8	9	10	11	12	7
Sum of Column	Sum of Column	Sum of Column	7-(8+9)	[7-(8+9)]/7	

deviates from formula in column header

actuals over forecast now show as postive

FEI

Table Includes Forecast to Actual Service Line Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative Service Line Spend to Date	4. Estimated Remaining Service Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 539,720	$ 532,515	$ 154,000	$ (146,795)	27.2%	$ 686,515
2009	$ 1,219,661	$ 1,551,821	$ 167,000	$ (499,160)	40.9%	$ 1,718,821
2010	$ 425,478	$ 569,636	$ 58,000	$ (202,158)	47.5%	$ 627,636
2011	$ 841,123	$ 885,958	$ 147,000	$ (191,835)	22.8%	$ 1,032,958
2012	$ 580,867	$ 969,808	$ 10,000	$ (398,941)	68.7%	$ 979,808
2013	$ 633,470	$ 546,463	$ 149,000	$ (61,993)	9.8%	$ 695,463
2014	$ 468,872		$ 468,872	$ -	0.0%	$ 468,872
Sum	$ 4,709,191	$ 5,056,201	$ 1,153,872	$ (1,500,882)	32%	$ 6,210,073

**estimated service line cost based on assuming service line cost of $1,000 times the number of expected attachments*

**acutal service line cost based on actual attachments times annual average service line cost*

Sum of Column	Sum of Column	Sum of Column	2-(3+4)	[2-(3+4)]/2

consistent with formula in column header

FEVI

Table Includes Forecast to Actual Service Line Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative Service Line Spend to Date	4. Estimated Remaining Service Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 282,526	$ 341,880	$ 34,000	$ (93,354)	-33.0%	$ 375,880
2009	$ 539,508	$ 663,920	$ 268,000	$ (392,412)	-72.7%	$ 931,920
2010	$ 362,046	$ 338,504	$ 140,000	$ (116,458)	-32.2%	$ 478,504
2011	$ 345,695	$ 314,366	$ 77,000	$ (45,671)	-13.2%	$ 391,366
2012	$ 201,122	$ 192,140	$ 36,000	$ (27,018)	-13.4%	$ 228,140
2013	$ 247,716	$ 217,465	$ 77,000	$ (46,749)	-18.9%	$ 294,465
2014	$ 379,988	Not available	$ 379,988	$ -	0.0%	$ 379,988
Sum	$ 2,358,601	$ 2,068,275	$ 1,011,988	$ (1,346,613)	-44%	$ 3,080,263

**estimated service line cost based on assuming service line cost of $1,000 times the number of expected attachments*

**acutal service line cost based on actual attachments times annual average service line cost*

FEVI

Table Includes Forecast to Actual Service Line Costs included in MX Reporting Years 2008 to 2014

1. MX Year	2. Total Forecast MX Cost Estimates Used in Original MX Tests	3. Total Actual Cumulative Service Line Spend to Date	4. Estimated Remaining Service Costs	5. Variance (in MX Year $) 2- (3+4)	6. Variance (in %) [2-(3+4)]/2	7. Total Expected MX Costs (3+4)
2008	$ 282,526	$ 341,880	$ 34,000	$ (93,354)	33.0%	$ 375,880
2009	$ 539,508	$ 663,920	$ 268,000	$ (392,412)	72.7%	$ 931,920
2010	$ 362,046	$ 338,504	$ 140,000	$ (116,458)	32.2%	$ 478,504
2011	$ 345,695	$ 314,366	$ 77,000	$ (45,671)	13.2%	$ 391,366
2012	$ 201,122	$ 192,140	$ 36,000	$ (27,018)	13.4%	$ 228,140
2013	$ 247,716	$ 217,465	$ 77,000	$ (46,749)	18.9%	$ 294,465
2014	$ 379,988	Not available	$ 379,988	$ -	0.0%	$ 379,988
Sum	$ 2,358,601	$ 2,068,275	$ 1,011,988	$ (721,662)	31%	$ 3,080,263

**estimated service line cost based on assuming service line cost of $1,000 times the number of expected attachments*

**acutal service line cost based on actual attachments times annual average service line cost*

1.4 Please provide a breakdown of MX actual costs showing the highest, lowest and average of the actual cost of main extensions. Please use the following template.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
Row 1		Cost of Main Extensions (Actual) ($)					
Row 2		FEI			FEVI		
Row 3	Year	Lowest	Average	Highest	Lowest	Average	Highest
Row 4	2008						
Row 5	2009						
Row 9	...						
Row 10	2014						
Row 11	Total						

Response:

The Company has provided the requested table below. As the preamble to this set of IRs is in regards to the MX reporting, the information provided is based on main cost data from samples reported in the 2008 to 2014 MX report. The Company has also provided an alternate table where it assumes the Commission intended the "Total" (Row 11) for the "Averages" (Column 3 and Column 6) to calculate the average of the averages and not the total of the averages. Both versions of the table are provided.

Table 1: Breakdown of MX Actual Costs

	FEI			FEVI		
Year	Lowest	Average	Highest	Lowest	Average	Highest
2008	$ 2,621	$ 11,833	$ 52,674	$ 761	$ 12,995	$ 32,349
2009	$ 1,518	$ 15,486	$ 103,212	$ 415	$ 17,044	$ 235,869
2010	$ 700	$ 7,428	$ 29,552	$ 1,196	$ 10,969	$ 95,955
2011	$ 179	$ 11,034	$ 69,740	$ 846	$ 11,407	$ 101,509
2012	$ 1,462	$ 14,675	$ 87,366	$ 991	$ 11,564	$ 128,245
2013	$ 1,787	$ 17,625	$ 122,983	$ 728	$ 11,507	$ 55,541
2014	$ 478	$ 10,172	$ 80,741	$ 493	$ 29,126	$ 538,312
Total	$ 8,744	$ 88,253	$ 546,267	$ 5,429	$ 104,611	$ 1,187,780

Table 2: Breakdown of MX Actual Costs (Alternate)

	FEI			FEVI		
Year	Lowest	Average	Highest	Lowest	Average	Highest
2008	$ 2,621	$ 11,833	$ 52,674	$ 761	$ 12,995	$ 32,349
2009	$ 1,518	$ 15,486	$ 103,212	$ 415	$ 17,044	$ 235,869
2010	$ 700	$ 7,428	$ 29,552	$ 1,196	$ 10,969	$ 95,955
2011	$ 179	$ 11,034	$ 69,740	$ 846	$ 11,407	$ 101,509
2012	$ 1,462	$ 14,675	$ 87,366	$ 991	$ 11,564	$ 128,245
2013	$ 1,787	$ 17,625	$ 122,983	$ 728	$ 11,507	$ 55,541
2014	$ 478	$ 10,172	$ 80,741	$ 493	$ 29,126	$ 538,312
Total	$ 8,744	$ 12,608	$ 546,267	$ 5,429	$ 14,944	$ 1,187,780

Average of the Averages

It should be noted that the average values for both FEI and FEVI shown in the table above are not indicative of the actual average cost for all main extensions completed for a given year. The data in the table above is based on the samples used in the annual MX Reports with FEI and FEVI listed separately. The averages for a given year in the table above are thus based on the samples FEI is required to provide for the annual MX Report. In the Application, the Company calculated $11,600 as the average cost for a main extension based on all main extensions completed for both FEI and FEVI from 2008 to 2014.

1.5 Please explain Earned Value Reporting.

Response:

The Company did not propose an Earned Value Reporting methodology for MX reporting in this Application, has not obtained an expert to analyze the appropriateness of such a reporting method in the context of the MX Test, and is not an authority on Earned Value Reporting. However, for the purposes of answering this question, FEI has attempted to provide an explanation of Earned Value Reporting as it understands it based on a review of various websites[1].

[1] References:
http://blog.aresprism.com/10-benefits-of-implementing-earned-value-management
http://www.dau.mil/pubscats/pubscats/AR%20Journal/arq98/chrisevm.pdf

Earned Value Reporting

Earned value (EV) reporting is a method of performance management reporting for a small number of large scale projects with a multitude of clearly defined tasks. In general, an EV reporting system is a resource intensive exercise that requires a project management team to track various facets of a project such as cost, scheduling and scope for each task in real time and re-forecast the results throughout the life of the project[2]. There are three primary elements of an EV Report, which are:

- The Planned Value – The planned expenditure for each task and when it is expected to occur.
- The Actual Costs – The actual expenditure for each task and when it actually occurred.
- The Earned Value – The planned expenditure for each task and when the task was actually completed.

The earned value can be calculated by multiplying the budgeted amount for a task against the percentage of the task that is actually completed in the same time period. For example, if a task was expected to cost $100 and be completed by week 1, and only 50% of the task was completed, then the Earned Value for week 1 would be $50. If by week 2, the task was now 100% completed then the full earned value of $100 would be achieved.

Based on FEI's understanding of the EV reporting, the Company does not believe such reporting would be appropriate for MX Reporting, for the following reasons:

- EV Reporting is designed for tracking a number of large projects with complex tasks. In contrast, FEI has installed and completed thousands of main extension projects since 2008, averaging 800 per year, most of the mains are relatively small in scale, with an average cost of $11,600 and with a cost of $50,000 capturing 97% of mains; the construction consists of a few individual tasks such as digging a trench, installing the pipe and gasifying the system. Thus, it does not seem efficient and practical to apply the level of detail and rigor required for the primary elements of the EV report for each of the main extension projects the Company builds.
- EV Reporting will likely involve significant costs, which is inefficient given the size and amount of main extensions constructed every year;

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http://www.ehow.com/info_8584095_disadvantages-earned-value-project.html
http://www.humphreys-assoc.com/evms/basic-concepts-earned-value-management-evm-ta-a-74.html
http://www.icoste.org/LukasPaper.pdf.

[2] http://smallbusiness.chron.com/advantages-using-earned-value-management-23231.html.

- EV Reporting appears to require re-forecasting to project final results. The MX Test and the SLCA are tools used at the time of installation. They are not designed to be re-forecast and re-examined in hindsight; and

- A final earned value is measured at the end of a project. However, for a main extension, the earned value could not be measured at the completion of the project, but at the end of the useful life of the main as customers can continue to attach throughout the useful life.

1.6 Please discuss the pros and cons of using Earned Value Reporting to compare forecast and actual main extension cost and schedule performance, on an individual extension basis, and on a yearly aggregate basis.

Response:

Please refer to the response to BCUC IR 1.1.5.

Table 5-2 on page 75 provides pipe sizes for when FEI uses manual estimates and when FEI uses Geo-Code pricing. In footnote 69 on page 75, FEI explains: "Geo Code prices are derived by running regression analysis on historical data to derive average dollar per meter estimates."

1.7 Please provide and explain the regression analysis used to derive the average dollar per meter estimates in Table 5-2 and confirm that FEI plans to continue updating the Geo-Codes annually.

Response:

The Company updates its Geo-Prices using a linear regression analysis to determine an average cost per meter of a main extension based on geo-graphic zones. The geo-prices are updated yearly as explained below and are provided to the Commission as part of the annual MX report in accordance with Order G-152-07. The Company confirms that it will continue to employ the geo-pricing methodology for main extensions and to provide the Commission with annual updates.

The methodology for updating geo-pricing is as follows:

1. Actual cost and length data are gathered for all completed main extensions in the previous two years. The Company uses recent main extensions to ensure geo-prices are a reflection of current costs. A minimum of two years is necessary to ensure enough data points to perform a regression.

2. The information is then grouped by geographic zone and filtered to exclude main extensions that fall under the Company's manual estimate criteria, such as steel mains or transmission pressure mains.

3. A linear regression analysis is performed to determine the relationship of the actual cost of main extension to its length for each zone.

4. The resulting output from the regression analysis provides a cost per meter of main extension for each geo-graphic zone.

5. The Company then implements the updated geo-prices as of January 1 along with other updated parameters to be used in the MX Test.

Linear regression follows a standardized approach that examines a relationship between two variables[3]. Essentially it determines an equation that represents a line of best fit. In the context of a main extension, the line of best fit measures the relationship of the length of a main extension and cost. The regression results produce a table which identifies the cost per meter of main extension assuming a starting point of zero. An output of the regression for the South of Fraser River zone is provided below as an example. The "X variable 1" coefficient is $42.77 so a cost of $43/m was used in the 2015 Geo price table.

[3] https://www.easycalculation.com/statistics/learn-regression.php.

South of Fraser River Regression Output

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.879693678
R Square	0.773860968
Adjusted R Square	0.768625366
Standard Error	5973.088746
Observations	192

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	23319472104	23319472104	653.6131485	2.06406E-63
Residual	191	6814457730	35677789.16		
Total	192	30133929834			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
X Variable 1	42.77213433	1.673017686	25.56585904	1.44122E-63	39.47217054	46.07209813	39.47217054	46.07209813

2015 Geo Price Table

	Geo Code & Manual Pricing ($/metre)						
		PE Pipe ($/m)			Steel Pipe ($/m)		
	Zone	Up to 60 mm	88 - 114 mm	168 mm	Up to 60 mm	88 - 114 mm	168 mm
2015	Vancouver & Richmond	$61	Manual Estimates Only				
	North Shore & Squamish	$75					
	North of Fraser River	$52					
	South of Fraser River	$43					
	Interior North	$40					
	Interior South	$36					
	Vancouver Island	$52					

On page 75 of the Application, FEI states: "Another check and balance implemented is graduated senior management oversight. As main forecast costs increase, additional approvals from more senior staff are required."

1.8 Please provide the thresholds where approval from more senior staff are required and confirm that FEI plans to continue following the same policy in the future.

Response:

This answer responds to BCUC IR 1.1.8 and 1.2.2.

The total forecasted cost of a project determines the level of managerial approval required. FEI's internal main extension approval process provides progressively higher levels of senior management approval prior to construction. The managerial review includes all aspects of the main extension test before approving, such as the forecast customer attachments, consumption, costs, CIAC, PI and security if required.

The table below summarizes the level of approval required relative to the forecast capital cost of the main extension.

Forecast Main Extension Capital Cost	Managerial Approval
$0-$50,000	Manager
$50,000-$250,000	Senior Manager
$250,000-$500,000	Director
$500,000-$1,000,000	Executive
$1,000,000 and greater	President & CEO

The Company confirms that it will continue to adhere to the same approval policy in the future for all Main Extension Tests.

1.9 Please discuss the pros and cons of requiring independent reviews of the cost estimates of the higher forecast cost main extensions.

Response:

This answer responds to BCUC IRs 1.1.9 and 1.2.3.

The Company does not believe that independent reviews of the Company's cost estimates and customer attachment forecasts for higher forecast cost main extension are necessary.

There are a number of drawbacks to the review proposal, including:

- An independent review will not be cost-effective and it will add administrative burden. An independent review, even without knowing all the details as contemplated by the Commission, will likely cost more. The associated incremental costs for the independent review will have to be borne by customers. Further, it will add time to a customer's schedule as the Company would have to work with the independent party to review the estimate.

- While in theory one might conclude that having a third party conduct the review instead of FEI adds credibility, there is no indication that performing an independent review would increase the accuracy of the estimate. The third party would face similar data limitations to FEI. FEI installs more main extensions annually than any other party in the province and therefore has a better understanding of costs than a third party would.

- As explained in section 5.4 of the Application, the variances for main extension costs and customers attachments are reasonable, and the Company is committed to taking steps to increase the accuracy of its forecast.

As the only benefit that FEI has identified is providing additional reporting comfort, and there are significant practical limitations, FEI would not support the review suggested in the question.

2.0 Reference: FORECASTING ACCURACY

Exhibit B-1, Section 2.2.1, pp. 18, 19; Section 4.1.2.1, p. 55; Section 5.4.2, pp. 76–78;

Number and timing of attachments

On page 76 of the Application, FEI provides Table 5-3 showing the forecast and actual attachments, as well as variances.

2.1 Separately, once for FEI, once for FEVI, and once combined, please fill in the table in Appendix BCUC IR 1.2.1. Please explain any differences between the variances in Table 5-3 and the variance in response to this question.

Response:

The Company is unable to provide the information requested the table in Appendix BCUC IR 1.2.1 for two main reasons:

1) The relevant data prior to 2008 is not accessible; and

2) Completing the request for 2008 to 2014 data would take approximately 4-5 months (an extra 1-2 months beyond the 3 months that it currently takes to complete the MX Report).

Each issue is described further below.

Relevant Data Not Accessible Pre-2008:

The Company is not able to provide accurate and detailed information relating to all main extension tests conducted prior to 2008 because such data is not accessible.

Prior to 2006, all MX test data was held in a Microsoft access database that did not have any specialized reporting functions, and information on each main had to be accessed on an individual basis. This database is no longer in use and has since been retired by FEI.

In 2006, the Company's CAFÉ (Customer Attraction Front End) system was implemented. CAFÉ was designed as a front end user interface to the Company's SAP system. SAP in turn is used to hold details on work orders and schedules for the work crews. CAFÉ also holds MX test information and the parameters of the test as approved by the Commission. However, at the time of CAFÉ's design, the MX reporting requirements were not defined.

In December 2007, the Commission issued Order G-152-07 which outlined the Company's initial reporting requirements. In response, the Company undertook reporting upgrades to the CAFÉ software in order to meet the reporting requirements. The first upgrades were undertaken immediately after the order was issued in 2007. The upgrades captured the main extension activity on a go-forward-basis to satisfy the reporting requirements of Order G-152-07.

However, not all historic main extension test information was verified or migrated into the reporting system since it was not part of the requirements of Order G-152-07.

The CAFÉ system currently houses all main extension test information from part way through 2006[4] on-ward and the MX Test information that is available for reporting is reflective of the 2008 calendar year, consistent with the timing of Order G-152-07.

Request Exceeding Current MX Reporting Requirements:

The information requested is similar in nature to the information provided in the annual MX Report except on a larger scale. The MX Report is a manual and resource intensive effort and uses a sample of main extensions, whereas the information requested involves all main extensions for a given year.

The process that would be required to complete this response is manually intensive and the information required is found in four different systems within the Company's IT infrastructure namely CAFÉ (MX Test data), SAP (actual costs and installation dates), GIS (mapping software used for matching services with mains), and finally forecasting (used to extract rate class and consumption information). The following provides a high level description of the process:

- Extract all historic MX tests completed since 2008 from CAFE;
- Match the completed MX Tests to actual installed main extensions using GIS based mapping software;
- Group the completed MX tests by year and by main extension and extract forecast attachment profile for each MX test;
- Cross reference all the installed main extensions against approximately 75,000 new services that have connected since 2008;
- Extract the number of meters connected to those services and segment the resulting customer group by rate class and installation year;
- Align customers to specific main extensions and compare the forecast profile to actual in order to formulate a re-forecast; and
- Aggregate the forecasts and re-forecast attachment profile and compile the information in the Commission's table.

Extracting and compiling information related to forecasted MX test inputs and results along with actual capital costs is the least resource intensive.

[4] 2006 information is only based on a partial year of data.

Matching specific line item costs, services, customers and consumption values with specific individual main extension tests remains a resource intensive effort. Each main extension must be manually matched and verified against the actual values. Moreover, since the information required currently spans four different systems within the Company's IT infrastructure, producing the data requested for the 2008 to 2014 period would take approximately 4-5 months (i.e., 1 or 2 months beyond the three months currently required to complete the MX Reporting as currently requested by the Commission).

FEI states on page 77 of the Application:

> In recent years the Company has also changed the approval process for customer attachments such as a graduated approval is required based on the size of the project. Specifically, for smaller main extensions, a sales manager would sign off on all customer attachments and consumption while the Planner would sign off on the forecast cost. Together, both Sales and Planning/Operations must approve the MX Test results before the project can proceed, including the forecast PI, any CIAC as well as any steps being taken to collect security such as a take or pay agreement. For larger projects, approvals progress from the manager level to more senior management levels depending on the size of the project. This senior management oversight provides an additional opportunity to critically assess the information obtained from developers.

2.2 Please provide the thresholds where approvals progress from the manager level to more senior management levels and confirm, otherwise explain, that FEI plans to continue following the same policy in the future. Is this the same policy as used for MX costs (see IR 1.8)?

Response:

Please refer to the response to BCUC IR 1.1.8.

2.3 Please discuss the pros and cons of requiring independent reviews of customer attachment forecasts for higher forecast cost main extensions.

Response:

Pease refer to the response to BCUC IR 1.1.9.

In section 4.1.2.1 of the Application, FEI explains that it will utilize the following types of data to determine if a planning horizon period greater than 5 years is appropriate for use in the MX Test of a given project:

- Municipal Official Community Plans;
- Zoning plans;
- Discussions with municipal city planners;
- Evidence of commercial commitments having been made with developers; and
- The various options available to the Company to install a main(s) to serve the area.

FEI's Application on page 18 states: "The number of customers for a proposed main extension is estimated through discussions between the customer and FEI."

FEI's Application on page 19 states "The individual appliances to be used by the customer are determined through conversations between FEI and its customers."

On page 77 of the Application, FEI states: "The Company forecasts attachments based upon discussions with developers and its own knowledge of the marketplace and history with the developer."

On page 78 of the Application, FEI explains: "The Company will continue to forecast customer attachments based on plans submitted by the builder/developer or homeowner and build and design main extensions accordingly."

2.4 Please confirm, otherwise explain, that FEI's current policy for forecasting the number and timing of attachments, and the appliances to be used includes comparing its discussions with the potential customers to municipal official community plans, zoning plans, discussions with municipal city planners, and evidence of commercial commitments made with developers.

Response:

The following response describes FEI's current customer attachment and appliance forecast practices, focusing on residential customers.

There are two types of residential main extension projects:

- New home (and business) construction
- Conversion of existing neighborhoods

New Home Construction

New construction refers to a main extension projects where a new building or buildings in a subdivision requires a main extension to connect to FEI's system. For these projects, the customer seeking the main extension is often the builder who is managing the subdivision project and would be paying a CIAC (if required based on the MX Test).

The most important source of information the Company uses to establish a forecast under this circumstance is interaction with the builder. The Company has a long history of working with builders through decades of building relationships in the BC new home marketplace. Depending on the complexity and scale of the project, FEI's engagement with a builder could be over the span of years and involve multiple different parties from FEI and the builder's organization before new end users actually begin taking service from FEI. The Company works closely with the builder's business development staff, architects and engineers through all stages of the construction process to promote the use of natural gas.

In developing an attachment forecast, the Company confirms with the builder the plans being submitted to the municipality. At times, the Company uses both published municipal information such as Official Community Plans (OCP) and information gathered from discussions with municipal staff in planning and permitting departments and City Council to confirm the builder's commercial plans.

For larger projects, the Company is often involved in the discussions with the builder's vendors regarding the type and number of appliances to be installed.

The Company may also utilize third party market data, such as those produced by Construction Market Data,[5] Yellow Sheet Construction Data Limited[6] and Landcor Data Corporation,[7] to learn whether a project is in the land acquisition, planning, or bidding stage of the pre-construction process and to develop leads for potential projects that could ultimately lead to a customer incorporating natural gas into a project.

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5 http://www.cmdgroup.com/.
6 https://www.yellowsheet.ca/.
7 https://www.landcor.com/.

Conversion of Existing Neighborhoods

A main extension to an existing neighborhood is often referred to a conversion main as the customers are converting to natural gas from another fuel. For existing neighborhoods, FEI first assesses the level of interest from home owners to connect to the Company's natural gas distribution system through customer surveys, town hall meetings and/or door to door canvassing. If there is adequate interest, then the Company would typically run preliminary MX Tests under different customer attachment and appliance installation scenarios to educate customers on what the potential CIAC would be. For example, the scenarios might depict different number of homes connecting to the main. The Company would then follow up with each customer to determine attachment plans before proceeding with the project. The Company factors in the individual appliances in each home.

2.4.1 If confirmed, please elaborate on this policy and explain which of the plans, discussions and evidence of commitments are more important than the other and why.

Response:

The Company believes that all of its activities in forecasting the customer attachments and appliance uses as discussed in the response to BCUC IR 1.2.4 are important.

2.4.2 Please confirm, otherwise explain, that FEI plans to compare its discussions with the potential customers to municipal official community plans, zoning plans, discussions with municipal city planners, and evidence of commercial commitments made with developers for all of its future main extensions and use the importance explained in the answer to the previous question, whether it be for 5 year or 10 year planning horizons.

Response:

The Company plans to continue its current practices as discussed in the response to BCUC IR 1.2.4 even for those main extensions that have a 10 year planning horizon.

2.5 Please confirm, otherwise explain, that FEI's current policy includes a step where FEI verifies that the number and type of appliances that FEI used in its forecast are actually installed by the customer.

Response:

FEI does not have a formal appliance verification process to determine if a developer installs the proposed appliances and FEI does not feel that such a process is required or warranted. For the majority of main extension projects, the Company relies on the drawings provided by the builder to verify the number and type of appliance connections. Sales staff also regularly visit developers' construction sites as FEI assets are installed and are therefore able to see the installation of appliances (see also BCUC IR 1.11.1).

FEI does not have evidence to suggest that developers are not installing the proposed appliances, and as such, adding in a verification process would add costs and process with little tangible benefit.

FEI notes that it would not be in the best interest of the developer to misstate the number of appliances it expects to install. If thorough on-going discussions and site visits it comes to the attention of FEI that a developer did not install the appliances as expected, FEI would reduce the expected load from future projects by the developer; thus making it more costly for the developer in future projects. This alignment of interests helps to ensure that appliances are installed as expected.

2.5.1 Please confirm, otherwise explain, FEI plans to include this step in for all its future main extensions.

Response:

Please refer to the response to BCUC IR 1.2.5.

3.0 Reference: HISTORICAL DATA

Exhibit B-1, Section 5.4.2, p. 76

Number of attachments

3.1 Please confirm, otherwise explain, that the majority of customer attachments occur in the first two years of a main extension's life and very few occur in the subsequent years.

Response:

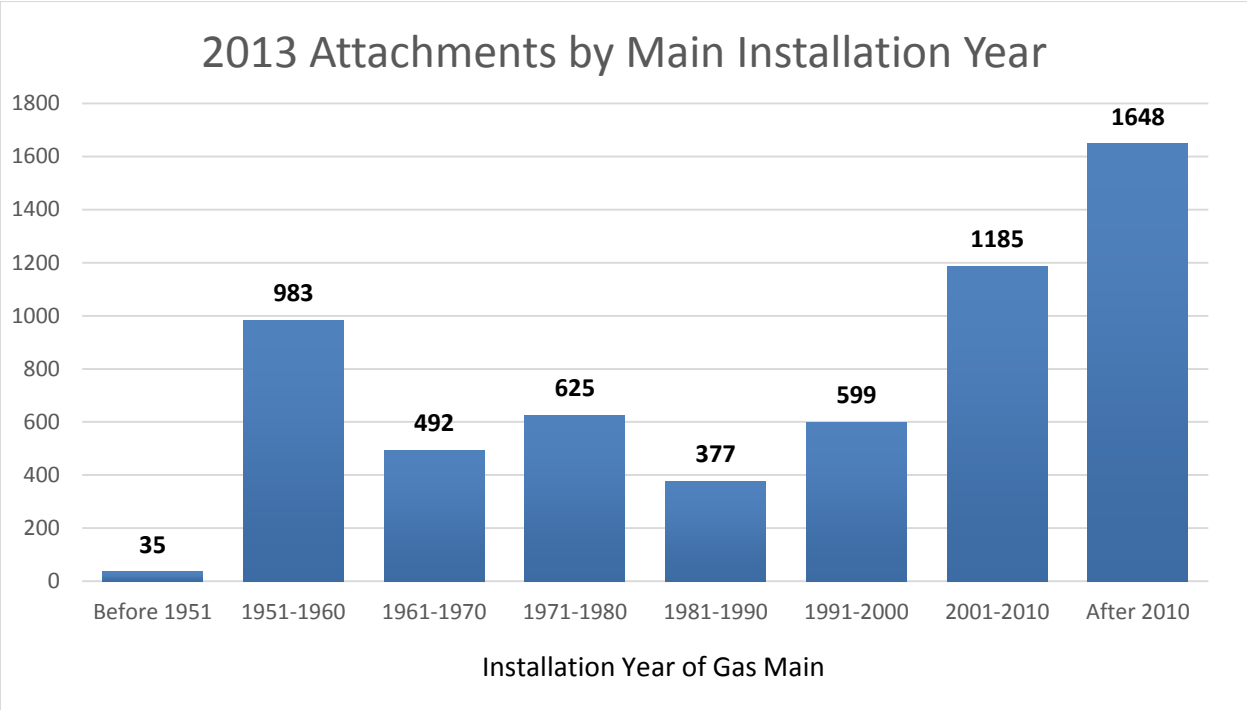
Not confirmed.

The number and timing of attachments to a main is dependent upon the specific main and the customers it is intended to serve. For example if a main is installed to only serve one new development in a cul-de-sac, and there is no possibility that the main will serve other customers beyond the cul-de-sac in the future, the attachments will generally occur over the timeframe contemplated in the MX test. It could be that the majority of attachments occur in the first two years, but it may be that the majority of attachments do not occur until year five with additional attachments occurring after the five year period. It is not possible to draw the conclusion that the majority of attachments occur in the first two years even in a most restrictive view of a "closed" main such a cul-de-sac.

Given the above, FEI conducted an analysis to determine how and when customers attach to a main. The results, explained below, show that customers attach to a main over the entire life of the main.

The graph below shows a profile of all single service line connections (connecting a customer to a main via a service line)[8] for the 2013 calendar year, grouped by the year the main extension was originally installed. For example, in 2013 there were 5,944 single service lines installed; of that total, 983 single service lines attached to main extensions that were originally installed sometime between 1951 to 1960. That is, these new service lines/customers attached to mains that were between 53 to 62 years old.

[8] Conversions and Multi-family attachments were excluded from the analysis given the resources required to extract the data. The Company expects a similar profile for other attachment types as well.



3.2 Please provide a customer addition profile line graph showing the actual number of attachments on the y-axis and each of the years on the x-axis for each of the following (please include data points showing figures representing the number of attachments):

a. 2009 FEI Sample Main Extensions for years 1 through 5;

b. 2009 FEVI Sample Main Extensions for years 1 through 5;

c. 2010 FEI Sample Main Extensions for years 1 through 4;

d. 2010 FEVI Sample Main Extensions for years 1 through 4;

e. 2009 FEI - 2nd Avenue Main Extensions for years 1 through 5;

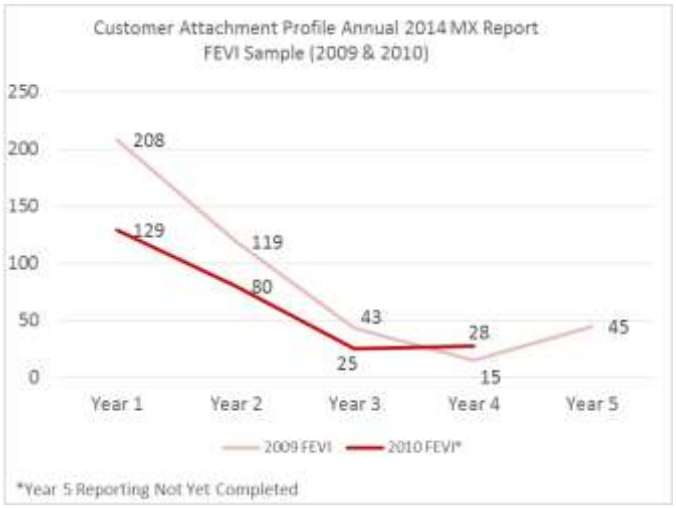
f. 2009 FEVI - Shawnigan Lake Road Main Extensions for years 1 through 5;

Response:

This answer also responds to BCUC IR 1.3.3.

The requested graphs provided below suggest that the majority of forecast attachments on a main extension occur within the first five years of construction (as FEI only forecasts attachments for the first five years). This result should not be confused with the actual total attachments over the life of the asset since, as indicated in the response to BCUC IR 1.3.1, the majority of customer attachments to main extension are infill customers that materialize over the life of the asset.

The Company has provided the graphs below using data extracted from the 2014 MX Report.



The Company notes that in some cases, such as large developments or subdivisions, there may be delays in construction or a slow-down in the housing market over the first five year period. These occurrences would move the actual attachment profile on a main extension out of sync with the forecast; however, this does not indicate there is a problem with forecasting, nor does it suggest potential undue harm to existing customers. It simply indicates that attachments

considered over five years is a relatively short period compared to the life of the asset and this time period may have failed to adequately capture the true benefit of a main extension. The Company has identified the issue of timing with the 2008 main extensions included in the 2014 MX Report. Due to the global financial crisis, many projects faced delays as the BC housing market was negatively impacted The Company has been seeing these attachments materializing since the marketplace recovered. This is illustrated in the 2014 MX Report included as appendix D in the Application, where the 2008 mains have added customers outside of the 5 year attachment window.[9]

3.3 Please identify and explain any general trends, or anomalies, in the customer addition profile graphs provided in response to the previous question.

Response:

Please refer to the response to BCUC IR 1.3.2.

3.4 Please provide the number of main extensions for FEI and FEVI, respectively, by year, for 2008 through 2014.

Response:

The table below provides the number of main extensions completed from 2008 to 2014 by FEI and FEVI respectfully.

FEI notes that this table will not match the totals included in the various MX Reports provided to the Commission. In the MX Report, the Company is required to base the random sampling on the number of main extensions completed for that year at the time of reporting. For instance, the Company conducts random sampling in January based on mains completed for the previous year. However, not all main extensions started in the previous year would be completed by January. The majority of main extensions will take several months to a year to complete. This is an important distinction as the results in the MX Report will always be less than the total actual number of mains completed.

The table below provides the number of main extensions completed in the years 2008 to 2014 regardless of when the construction of the mains started. All the mains in the table below were included in the Rate Impact analysis.

[9] Appendix D 2014 MX Report Page 10 (table 2-2).

	Total Main Extensions for FEI	Total Main Extensions For FEVI
2008	837	435
2009	505	248
2010	462	245
2011	545	221
2012	486	173
2013	433	203
2014	459	240
Total	3,727	1,765

1

4.0 Reference: FORECASTING ACCURACY

Exhibit B-1, Section 5.4.3, p. 78

Use per customer - consumption credits

In the Application, FEI explains:

> Consumption credits in the MX Test are determined by assigning a consumption value in GJs per year for each appliance the customer installs. The annual consumption per appliance is taken from the Residential End Use Study (REUS). The MX Test has been updated with REUS values in 2002, 2008 and 2012; this methodology was acknowledged in BCUC Order G-152-07.

4.1 Please confirm when FEI is committing to perform and submit the next REUS and for what MX year the REUS results will be incorporated into the MX test and the Service Line Cost Allowance (SLCA) calculation.

Response:

FEI is planning to undertake a Residential End Use Study in 2016, either separately or in conjunction with BC Hydro, with final results anticipated in early 2017. As such, the REUS results will be expected to be incorporated into the MX Test and SLCA calculations in 2018.

4.2 Please discuss the pros and cons of requiring more frequent REUS, and subsequently more frequent updating of the related inputs to the MX test and SLCA calculation.

Response:

The REUS is a comprehensive study that provides a snap shot of the residential customer base at a given time. It is designed to reflect the characteristics of approximately 875,000 dwellings and to capture information about building type, the building envelope, space and water heating appliances, and other appliances such as cooktops, fireplaces and barbecues, and to look at how residents use energy in the dwelling and their attitudes towards energy use. As part of the REUS, FEI undertakes a Conditional Demand Analysis (CDA), which is a multi-variable regression analysis that presents a disaggregation of the overall natural gas consumption of those included in the survey, broken down by appliance type.

The REUS is a mail out survey that takes approximately one year from initial design to the delivery of the final report and costs approximately $300 thousand. FEI's return rate from customers responding to the mail out surveys is approximately 17%.

Currently, the REUS is produced every four years. The Company does not believe more frequent REUS is required because more frequent REUS would not likely provide better information. More specifically:

- Less than five percent (5%[10]) of the housing stock changes every two years on average. Even if renovation activity is taken into account, it is not likely that the bulk of the housing stock would change materially enough to affect REUS results;
- Only dwellings with 24 months of continuous billing with the same customer are included in the survey; thus, the most up-to-date dwelling types will not be included; and
- Updating REUS requires resources and costs. As mentioned above, it takes approximately one year from initial design to the delivery of the final report and costs about approximately $300 thousand.

4.3 Please confirm, otherwise explain, that the REUS has the capability to determine new customer average consumption per appliance.

Response:

The REUS does not have the capability to determine the new customer average consumption per appliance, but provides a reasonable indication of consumption for individual appliances based on the average consumption of existing customers. FEI believes that the REUS is an appropriate method from which to derive consumption patterns of customers and appliances for use in the MX test. FEI also notes that other utilities simply use an average annual consumption of existing rate payers (as FEI used to do) in their system extension tests. Increasing the granularity of data to segregate new customers will not result in a better balance of new and existing customer interests but will add costs that must be borne by customers.

Moreover, collecting new customer data would present practical challenges and would require considerable changes to FEI's current practice with respect to the REUS, which likely means additional costs over and above the current cost to produce the REUS. For instance, to obtain the desired information as part of the REUS, the Company would need to identify and reach a statistically significant sample representing the new customers via mail-out surveys. The facts that the Company adds approximately 10,000 to 15,000 new customers per year, that the REUS requires two years of consecutive consumption with the same customer and that the mail out response rate is typically 17% together present a challenge of identifying a suitable sample.

[10] Calculated as: Number of dwellings / change in housing stock.

Surveys with customer site visits are another potential alternative, as opposed to the mail-out option, that would offer a varying degree of accuracy of determining new customer consumption per appliance; however, this would come at an even greater cost than the existing methodology

Sub-metering would provide the most accurate information; however, this would be the most expensive and intrusive option, as it would require the installation of an additional meter at the premise of new customers and customer participation.

Even if the alternatives above could be achieved, adding additional cost and effort in an attempt to obtain information regarding the new customer consumption per appliance will not necessarily result in increased accuracy about consumption per customer due to the inherent variability of survey results and the inherent variability in actual customer usage. Each and every customer uses their appliances differently and FEI does not compel customer to use a certain amount of fuel per appliance.

FEI believes that using the REUS is the most appropriate tool for determining residential consumption as it balances the needs of new and existing customers while providing a representative value in a cost effective manner.

4.3.1 If confirmed, please provide the new customer annual consumption per appliance.

Response:

This was not confirmed and therefore the information is not provided.

4.3.2 If not confirmed, please discuss why not and how FEI could obtain this information, whether it be in the REUS or some other manner.

Response:

Please refer to the response to BCUC IR 1.4.3.

4.4 Please discuss the pros and cons of knowing the new customer annual consumption per appliance.

Response:

Please refer to the response to BCUC IR 1.4.3.

4.5 Please compare the top five forecasted main extension PIs for both FEI and FEVI from the 2014 MX year, which uses consumption credits, to forecasted PIs for each of those same main extensions using what FEI actually expects for new customer consumption per appliance to be, and provide the quantum of difference:

1. Main Extension	2. Forecast PI using credits	3. Forecast PI using actual expected consumption	4. Difference (2 -3)
FEI Top 5 – 1			
FEI Top 5 – 2			
FEI Top 5 – 3			
FEI Top 5 – 4			
FEI Top 5 – 5			
FEVI Top 5 – 1			
FEVI Top 5 – 2			
FEVI Top 5 – 3			
FEVI Top 5 – 4			
FEVI Top 5 – 5			

Response:

As described in the response to BCUC IR 1.4.2, there are practical and financial limitations that prohibit the Company from providing an appliance based consumption forecast for new customers and therefore that data is currently not available. However, in an attempt to provide the Commission with some comparative information, FEI compares the forecast PI values using different vintages of REUS data. Specifically, the Company has provided below the PI values derived from using the 2008 REUS values, compared to the 2012 REUS values.

	1. Main Extension	2. Forecast PI Using 2008 REUS	3. Forecast PI Using 2012 REUS	Difference (2-3)
FEI	Maclure Road - 5550003872 - LML	1.98	1.78	0.20
	244 Avenue - 5550006721 - LML	1.00	0.95	0.05
	Predator Ridge Drive - 5550007707 - COL	0.80	0.67	0.13
	Highland Drive - 5550008051 - LML	1.07	0.88	0.19
	Plateau Drive - 5550008847 - LML	0.84	0.87	-0.03
FEVI	Stamp Way - 5550007879 - VI	0.80	0.70	0.10
	Westwood Road - 5550008861 - VI	0.91	0.77	0.14
	East Saanich Road - 5550008872 - VI	0.88	0.72	0.16
	Road A - 5550009123 - VI	0.87	0.61	0.26
	Howard Avenue - 5550009619 - VI	1.59	1.55	0.04

As seen in the table above, the PI values have decreased by 12%[11] by using the 2012 versus the 2008 REUS, illustrating how the more current REUS results reflect a decrease in use per customer over time.

4.6 Please provide a list of other BC utilities that use consumption credits, rather than actual expected consumption in their main extension policies.

Response:

This answer also responds to BCUC IRs 1.4.6.1 and 1.4.6.2 .

FEI uses a consumption credit for the purposes of determining consumption per customer based on a consumption value in GJs per year that has been assigned to each appliance a customer will be installing, as determined by the REUS. In BC, there are no other utilities that use a consumption credit per appliance in their main extension policies. As a result, no other utilities in BC compare forecast consumption in their test (because consumption is not used on a test by test basis) to actual consumption.

PNG uses the expected consumption based on the average consumption of existing customers. That is, expected revenues from new customers are determined based on the average consumption of existing customers in PNG's MX Test, irrespective of the appliances to be installed (note that this is the approach that FEI used prior to adopting the use of consumption credits based upon the REUS in 2011).

[11] 12% is the average PI variance for FEI and FEVI combined. For example, the Maclure Road PI difference of .20 represents a 10% variance. Where .02(PI Difference) ÷ 1.98 (Original PI) = 10%. This calculation methodology was performed on all main extensions in the table and the variances were averaged to arrive at 12%.

BC Hydro (BCH) and FortisBC (FBC) do not factor expected consumption in their main extension policies. Both utilities provide a maximum flat contribution towards an extension that is deducted from the expected cost for the connection, regardless of the customer's expected consumption, number of appliances in the home, or use per appliance.

For BCH, this flat contribution is derived from a 20-year PV calculation based on the distribution related capital costs assigned to residential customers in the cost of service study. The allocation of these costs is predominately based on the residential class's aggregate load profile relative to other rate classes.

For FBC, the flat contribution is determined by calculating the average amount of investment in distribution poles, conductors, and transformers, per existing customer that is covered in the applicable retail rate to ensure the addition of a new customer does not have a negative impact on embedded customers. The allowance will therefore vary by customer class.

4.6.1 Please elaborate on how those utilities determine their consumption credits.

Response:

Please refer to the response to BCUC IR 1.4.6.

4.6.2 Please provide the difference between those other utilities' consumption credit values and their actual expected consumptions.

Response:

Please refer to the response to BCUC IR 1.4.6.

4.6.3 Please discuss compare the difference between these other utilities' credits and actuals to the difference between FEI's credits and actuals.

Response:

FEI is the only utility in BC that uses consumption credits in its MX Test. As such, other utilities do not undertake any comparison between forecast consumption in a test with actual consumption of the customer.

5.0 Reference: FORECASTING ACCURACY

Exhibit B-1, Section 5.4.3, p. 79;

FEI 2014-2018 Revenue Requirement Application (RRA), p. 98

Use per customer - rate impact and Rate Stabilization Adjustment Mechanism (RSAM)

On page 79 of the Application, FEI states: "FEI has seen an overall reduction in use per customer for new customers compared to existing customers."

On page 98 of the FEI 2014-2018 RRA, FEI states:

> The RSAM stabilizes delivery margin received from residential and commercial customer classes on a UPC basis. If UPC rates vary from the forecast levels used to set the rates, whether due to weather variances or other causes, FEI records the delivery charge differences in the RSAM deferral account for refunding or recovering through a rate rider to the RSAM rate classes.

5.1 Please complete the table below to show the estimated impact on the RSAM of new customers having a lower use per customer than existing customers.

Estimated RSAM Impact of Residential Customer Additions

Year	Main Extension Customer Additions	New Customer Average UPC (GJ)	Existing Customer Average UPC (GJ)	Usage Variance per Customer (GJ)	Total Usage Variance (GJ)	Delivery Rate ($/GJ)	Total Delivery Variance ($)
	A	B	C	B- C=D	A X D = E	F	E x F = G
2010							
2011							
2012							
2013							
2014							

Response:

To the extent that the new customer was included in the customer additions forecast, there is a net impact of zero to the RSAM when all customers are considered and as such, FEI believes that the table would not provide meaningful information. To the extent that a new customer was not included in the forecast customer additions, there is no impact to the RSAM because the RSAM account does not capture the impact of variances in customer additions.

The RSAM captures variances in actual use per customer as compared to forecast use per customer and the forecast use per customer reflects the weighted average of the use rates of all customers in the RSAM rate class. The forecast use rate already incorporates trends and expectations about the impact on use rates of adding new customers. In this way, to the extent that newer customers may have a lower use rate than the average use rate for the rate class, other customers in the RSAM rate class would be expected to offset this impact because they would have a higher use rate than average.

6.0 Reference: FORECASTING ACCURACY

Exhibit B-1, Section 5.5, p. 80

Application of energy efficiency credits

In section 5.5 of the Application, FEI explains:

> The Company has applied the energy efficiency credits as approved by the Commission in Order G-152-07. In Section 4, the Company indicated that six percent of main extensions completed from 2008-2014 used the 10 percent credit and less than 1 percent used the 15 percent credit. The Company has proposed to remove the efficiency credits from the Test going forward to make the implementation of the Test simpler and easier to implement. The Company now has a robust Energy Efficiency and Conservation program that encourages customers to use gas more efficiently. As such the Company believes that it does not need to include these credits in the MX Test, in conjunction with the other proposed amendments to the MX Test.

6.1 Please provide the percent of main extension applications that received the 10% credit in each year from 2008 to 2014, and the percent that received the 15% credit in each year from 2008 to 2014. Please also provide a forecast of the number of customers who would be expected to receive each of these credits in 2015 to 2020 under the existing MX test.

	10% Credit	15% Credit
2008		
2009		
2010		
2011		
2012		
2013		
2014		
2015 (Forecast)		
2016 (Forecast)		
2017 (Forecast)		
2018 (Forecast)		
2019 (Forecast)		
2020 (Forecast)		

Response:

The requested table is provided below. It includes the proportion of main extensions that received the 10% and 15% energy efficiency credits from 2008 to 2014. Between 1% and 17% of main extensions qualified for the 10% credit while less than 1% qualified for the 15% credit.

The Company has forecast that 104 customers would receive the 10% credit in each of the years 2015 to 2020 if it was still available, which is based on the average of main extensions using the 10% energy efficiency credit for the previous years (2008 to 2014). However, the Company notes that it is difficult to provide a robust forecast on the future use of credits as the credit use will depend on circumstances beyond the Company's control, such as how many customers will choose to install both high efficiency heaters and hot water tanks, how LEED certification will evolve and how many customers will achieve that certification. Therefore, a historic average was used to forecast future years.

Proportion of Main Extension Applications
Receiving Energy Efficiency Credits

	10% Credit	15% Credit
2008	1%	
2009	4%	
2010	8%	0.09%
2011	10%	
2012	12%	0.25%
2013	17%	
2014	11%	
2015 (Forecast)	104	0
2016 (Forecast)	104	0
2017 (Forecast)	104	0
2018 (Forecast)	104	0
2019 (Forecast)	104	0
2020 (Forecast)	104	0

6.2 Please explain how each of: 1) the minimum energy performance standard for gas fired furnaces in annual fuel utilization efficiency (AFUE); 2) the minimum AFUE required for a gas fired furnaces to be EnergyStar rated; 3) the minimum efficiency rating for water heaters; and 4) the requirements for LEED General Certification, are taken into account in FEI's policy for applying energy efficiency credits.

Response:

In Order G-152-07, the Commission approved the following energy efficiency credits:

- For customers with high efficiency gas-fired space heating and water heating, a consumption credit of +10% of the volume otherwise used for both appliances; and
- For customers who have both high efficiency gas-fired space and water heating appliances as defined above, and who attain a minimum of LEED General Certification: a consumption credit of +15%.

FEI determines an energy efficiency credit for "high efficiency gas-fired space heating and water heating" based on both appliances being classified as "high efficiency". In Canada, a high efficiency hot water tank or furnace will display the energy star symbol if the model qualifies as high efficiency.

When the energy efficiency credits were first introduced in 2007, the minimum AFUE for a furnace was 78 percent. At that time, customers had a choice between a high-efficiency (90% AFUE) and medium efficiency (78% AFUE) furnace and the energy efficiency credits were designed to send an appropriate market signal.

As of January 1, 2010, the minimum AFUE for a gas furnace was changed to 90 percent[12] and the minimum AFUE for a high efficiency furnace was also increased to 95%.

For gas water heaters, the minimum EF (Efficiency Factor) to qualify as high efficiency is .67 while tankless water heaters are set at.82[13]. A water heater will display the ENERGY STAR symbol[14] if it qualifies as high efficiency. Currently, not all gas water heaters sold in Canada are high efficiency. Therefore, customers have a choice as to whether to install a high efficiency or mid-efficiency hot water heating system.

Since the Company applies energy efficiency credits to customers that choose to install both a high efficiency hot water tank or tankless water heater and a high efficiency gas furnace, changes to the efficiency requirements have not impacted the Company's ability to apply them.

The LEED credit of 15% is granted for those customers that achieve LEED[15] certification on their homes and install a high efficiency space and water heater system. The Company does not track individual LEED criteria on a building, but looks for LEED certification. Any changes to

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12 http://www.nrcan.gc.ca/energy/regulations-codes-standards/products/6879.

13 http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M144-243-2012-eng.pdf.

14 http://www.nrcan.gc.ca/energy/products/categories/water-heaters/14508.

15 http://www.cagbc.org/CAGBC/LEED/CommercGreenBuild/RatingSystems/CAGBC/Programs/LEED/CommercialInstitutional/RatingsSystems/LEED_Canada_Rating_S.aspx?hkey=5490b62b-b10f-45b7-9c41-2b5a299655b8

the requirements of a LEED certified home over time would be reflected in the certification and therefore would have no impact on the Company's ability to apply a LEED credit.

The table included below provides a summary of the changes in AFUE for water heaters and furnaces since 2007.[16]

		2007 (Introduction of Energy Efficiency Credits)			2015 (MX Application)			Change in HE AFUE
		Minimum Standard[5]	High Efficiency[6]	Energy Star[6]	Minimum Standard[4]	High Efficiency[6]	Energy Star[6]	Impact on Applying Energy Efficiency Credits in MX Test
Gas Furnace	AFUE - Annual Fuel Utilization Efficiency	0.78	0.90	0.90	0.92	0.95	0.95	+5% - No Impact
Gas Hot Water Tank[2]	EF - Energy Factor	n/a	0.62	0.62	0.62	0.67	0.67	+5% - No Impact
Gas Tankless Hot Water[3]	EF - Energy Factor	n/a	0.82	0.82	0.8	0.82	0.82	No Impact
LEED Certification Requiments					LEED Certicate[1]			None

[1]Individual LEED criteria not tracked by Company. Any changes over time would be reflected in certification

[2]US 40 Gallon Tank

[3]Less than 250,000 BTU

[4]2014 Addedum to 2012 BC Building Code

[5]NRCAN, The Company could find no evidence of mandated minimums for gas hot water heating in 2007

[6]As per NRCAN, Hot Water Tank and Furnace will display the Energy Star symbol if the model qualifies as high efficiency

6.2.1 Please discuss the changes in 1) through 4) from 2007 to today.

Response:

Please refer to the response to BCUC IR 1.6.2.

[16] http://www.nrcan.gc.ca/sites/oee.nrcan.gc.ca/files/files/pdf/equipment/WaterHeaterGuide_e.pdf
http://www.nrcan.gc.ca/energy/products/categories/heating/furnaces/15774
http://www.nrcan.gc.ca/energy/products/categories/water-heaters/14541
http://www.nrcan.gc.ca/energy/products/categories/water-heaters/14508
https://www.energystar.gov/ia/partners/prod_development/revisions/downloads/Furnace_Draft1_%20ProgReq_V2.pdf?442a-1e83
https://www.energystar.gov/ia/partners/prod_development/new_specs/downloads/water_heaters/WaterHeaterAnalysis_Final.pdf
https://www.energystar.gov/ia/partners/prod_development/new_specs/downloads/water_heaters/WaterHeaterAnalysis_Final.pdf
https://en.wikipedia.org/wiki/Water_heating

6.2.1.1 Do these changes affect FEI's ability to apply energy efficiency credits? Please explain.

Response:

No. Please refer to the response to BCUC IR 1.6.2.

7.0 Reference: VARIANCES BETWEEN FORECAST AND ACTUAL PROFITABILITY INDEX

Exhibit B-1, Appendix D, pp. 111–126; Table 10-3, p. 112; Table 10-6, p. 114;

Table 10-21, p. 122; Table 10-28, p. 126

2009 FEI and FEVI aggregate main extensions sample results

FEI state that the results for the 2009 main extensions "are based on a small sample of the actual main installations in 2008" and "up to this point in time, only consider attachments in the first 5 years of the life of the mains…"[17]

The following table was compiled using the data in sections 10.1 and 10.2 of Appendix D.

	2009 Aggregate Main Extensions (Sample)								
	Attachments			Use per Customer			Profitability Index		
	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)
FEI	1,228	1,061	-14%	107	38	-64%	**1.44**	**0.51**	**-65%**
FEVI	698	430	-38%	67	12	-82%	**1.63**	**0.15**	**-91%**

7.1 Please provide an explanation for the variances in the profitability index in each of FEI and FEVI. Please include a discussion of the costs, the attachments and the use per customer.

Response:

The PI variances illustrated in the table above relate to the attachment, use per customer and capital cost variance in 2009. Each variance is further described below.

Customer Attachments

The attachment variance reflects the timing delay related to the 2008/09 global financial crisis that negatively impacted the BC new construction housing market. The Company believes that the delayed attachments will materialize, albeit at a later time frame than forecast. Please refer to Table 5-3, which shows that the variance for customer attachments of the 2008 to 2013 main extensions was -7.2 percent. Please refer to the response to BCUC IR 1.3.1 for a discussion of how customers continue to attach to a main extension throughout the life of the asset.

[17] Exhibit B-1, Appendix D, p. 111.

Use per Customer

The variance in use per customer relates to the Commission required comparison between the consumption credits used in the MX Test to actual consumption. As discussed in the Application in section 5.4.3, consumption credits are based on the consumption of existing customers and do not represent a forecast of the consumption of new customers, which will result in a variance, all else equal, and have resulted in a variance in 2009.

Capital Cost

The capital cost variance for the 2009 main extension samples is attributable to unexpected factors which will always exist such as rocky conditions, weather and other elements. As discussed in section 5.4.1 of the Application, the Company has made improvements to our cost forecasting practices including the use of both manual estimates and geo code pricing. As a result, FEI's cost variance has been steadily improving since 2010.

7.2 Please explain how FEI proposes to reduce the risk, or resulting effect, of actual P.I.s being lower than forecasted.

Response:

FEI has not provided "Actual PI's" to the Commission. FEI has provided a snapshot, retroactive re-running of the MX test with different parameters (as requested by Commission staff) that results in the output of a PI. However this is not an "Actual PI". FEI assumes that when the Commission uses the words "Actual PI" they are referring to the outcome achieved by using "actual" (as opposed to forecast) inputs in the MX Test. If so, this re-running of the MX Test using actuals could only occur at the end of the useful life of the main (which in the case of a 2009 main would be in 2073). Further, using a PI or "Actual PI" as derived from a re-running of the MX Test is not the appropriate tool to determine the economic performance of a main. Please see section 3.4.2 for a discussion of the issues with the current MX assessment approach..

Please see BCUC IR 1.7.1, and 1.13.5 for an explanation of the steps that the company has taken to reduce the risk.

The following table was compiled using the data in Tables 10-21 and 10-28 of Appendix D.[18]

2009 Main Extensions - FEVI - West Coast Road								
Attachments			Use per Customer			Profitability Index		
Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)
201	2	-99%	70	18	-75%	1.56	0.00	-100%

7.3 Please provide the total number of 2009 main extensions for FEI and FEVI that have an attachment variance -90% or worse and the total number of 2009 main extensions for FEI and FEVI that have a use per customer variance of -90% or worse. For each one noted, please provide the information using the above table format.

Response:

The data is provided in the requested table format below.

[18] Ibid., pp. 112, 114.

		All Main Information Taken from 2014 MX Report (2009 Sample Dataset)									
			Attachments			Use Per Customer			Profitability Index		
		Main Project #	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)
Attachment Variance of 90% or worse	FEVI	5550000027	201	2	-99%	70	18	-74%	1.56	0.00	100%
		5550001661	1	0	-100%	1825	0	-100%	2.20	0.00	100%
		5550002581	1	0	-100%	109	0	-100%	1.37	0.00	100%
	FEI	5550001435	39	1	-97%	77	0	-100%	0.80	0.00	100%
		5550001712	98	1	-99%	62	13	-79%	0.97	0.00	100%

		All Main Information Taken from 2014 MX Report (2009 Sample Dataset)									
			Attachments			Use Per Customer			Profitability Index		
		Main Project #	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)	Original Forecast	Actual	Variance (%)
Consumption Variance of 90% or worse	FEVI	4110005369	36	23	-36%	116	10	-91%	1.64	0.12	-93%
		5550000978	32	24	-25%	36	3	-93%	3.09	0.33	-89%
		5550001196	27	54	100%	101	7	-93%	1.38	0.38	-73%
		5550002056	3	4	33%	28	1	-97%	1.09	0.04	-97%
		5550002112	2	1	-50%	62	0	-100%	0.75	0.00	-100%
		5550002317	19	2	-89%	41	2	-95%	1.58	0.11	-93%
		5550002359	2	1	-50%	86	8	-90%	0.70	0.00	-100%
		5550002488	2	1	-50%	43	2	-95%	0.81	0.00	-100%
		5550002581	1	0	-100%	109	0	-100%	1.37	0.00	-100%
		5550003306	1	1	0%	104	2	-98%	0.68	0.10	-85%
	FEI	4110014667	18	3	-83%	128	12	-91%	1.65	0.00	-100%

FEI recognizes that there have been main extensions that have not performed as expected over the limited five year MX reporting time-frame due to unforeseen factors such as the 2008 global financial crisis that negatively impacted the BC new home marketplace. The results provided above simply indicate that the attachments have not yet occurred in the reporting timeframe considered, which is not to say that they will never occur. As discussed in the response to BCUC IR 1.3.1, the majority of customer attachments are infill customers and do not materialize in early years of the life of the main. Moreover, despite what is indicated in the table, the Rate Impact analysis indicated that between 2008 and 2014 customer rates have gone down as a result of capital growth, including the 2009 FEI and FEVI main extensions.

With respect to the use per customer variance comparison, the Company notes that the Company's MX Test is based on the average use of all existing customers and the comparison between the use of an existing customer and that of a new customer is not part of the MX Test.

8.0 Reference: REPORTING METHODOLOGY

Exhibit B-1, Appendix D, 2014 Main Extension Report, Section 8, pp. 83–96

Projections in reporting

FEI's reporting on 2011 main extensions includes actual customer attachments, and use per customer for years 1 through 3 and re-forecast customer attachments and use per customer for years 4 and 5.[19] Tables 8-16 and 8-27 show the variance between the original and re-calculated PIs for the 2011 top 5 main extensions for FEI and FEVI.[20]

8.1 Please state whether the values for (i) the Use per Customer; and (ii) Customer Attachments for years 4 and 5 are re-forecasted using the same values that were used in the original MX test or based on the actuals observed in years 1 through 3 in the re-calculation of the PI for each main extension presented.

Response:

This answer responds to BCUC IRs 1.8.1, 1.8.1.1 and 1.8.1.2.

All tables in the 2014 MX Report are derived using the methodology designed by the Commission. The methodology requires the Company to annually re-forecast attachment and consumption values and re-run the MX Test. The current MX reporting practices as required by the Commission relating to use per customer and customer attachments are described below.

Attachment Re-forecasting

If an attachment is completed at the time of reporting, re-forecasting will be using actual values. For example, if in a given year, 10 out of 25 forecasted attachments occur, only 10 attachments will be used for the re-calculation. The methodology assumes the other 15 attachments do not materialize and therefore are not included in the MX Test for re-calculation.

For future years, the original forecast is used. For example, if a particular main is in Year 2 (out of 5) then actual values would be used for Year 1 and Year 2. The original forecast values are used for Years 3 to 5 since they haven't happened yet. As each additional year passes, actual values are used.

For example, if FEI had forecast 20 attachments in years 1 and 2 and 5 attachments in years 3, 4 and 5, and by the end of year 2 only 10 attachments had occurred, the MX Reporting methodology requires FEI to include the 10 attachments that had occurred in years 1 and 2 and the forecast of 5 attachments for the remaining three years, even if it is expected that the attachments in those three years will be higher.

[19] Exhibit B-1, pp. 83-96.
[20] Ibid., pp. 91, 96.

Consumption Re-forecasting

Consumption re-forecasting is treated the same as that described above. For years that have passed, the actual use per customer is used. For future years, the Company is required to leave the use per customer provided in the original MX test unchanged. As each additional year passes, actual values are used. Similar to the discussion on re-forecasting of mains, the values used for consumption in the original test are based upon appliance system averages and it is not expected that new customers will use exactly the same consumption as the appliance system averages.

8.1.1 If not, please state which values were used and explain why this value was chosen.

Response:

Please refer to the response to BCUC IR 1.8.1.

8.1.2 If not, please explain why.

Response:

Please refer to the response to BCUC IR 1.8.1.

9.0 Reference: SECURITY AND EXISTING RATEPAYER PROTECTION

Exhibit B-1, Appendix C, L-34-14, p. 3; Appendix C, FEI Response to L-34-14, p. 8; Section 3.4.2.2, p. 46; Section 5.6.2, p. 81;

Security policies

On page 3 of letter L-34-14, the Commission lists security and existing ratepayer protection as an area of concern. The Commission explains:

> It is possible, had the Companies obtained sufficient contributions in aid of construction or other securities for main extensions where the actual costs were higher, attachments were fewer or later, and/or customer consumption was lower than forecasted, the potential exposure to existing ratepayers of an undue cost burden as a result of the expansion of the distribution system to attach new customers would have been mitigated.

FEI's Application on page 81 states:

> Security is used in instances where the Company believes that there is a risk that the customer (typically a builder or developer) may not attach to the system in the timeframe expected, the number of appliances will not materialize or, in the case of commercial and industrial customers, when there is risk of the customer leaving the system. The Company adheres to section 12.10 of its tariff that stipulates, 'In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.'

Section 3.4.2.2 of FEI's Application states: "…builders and developers will continue to pursue attachments and, although delayed, [attachments] will usually materialize."

In its July 9, 2015 response to Commission letter L-34-14, FEI explains: "In most cases, unrealized attachments are simply delayed, and when considered beyond their respective forecast year, the majority of forecasted attachments will materialize."

9.1 Please provide and discuss the specific criteria FEI uses to determine when security is required and in what amount. If FEI does not use specific criteria, please explain why not.

Response:

As cited in the preamble, security is required where "the financial viability of a Main Extension is uncertain." Thus, the criterion for security requirement is whether the expectation is that a main extension will be financially viable. Examples of the types of circumstances that cause FEI to have additional concern regarding the viability of an extension and a desire to obtain additional security are provided in the response to BCUC IR 1.9.3.

The determination of the financial viability of a main extension is mainly based on the Company's internal project approval process, drawing upon the experience of the Company's internal resources with respect to main extension development and the Company's past dealings with the particular customer (such as the developer/builder involved in a specific instance). No specific thresholds are used given the large number of main extensions constructed per year.

In FEI's experience, security for main development is necessary only in a rare number of instances and there is no indication that changes are warranted to the Company's practices, for the following reasons.

First, the MX Test is a test based on forecast information. As explained in the response to BCUC IR 1.2.4, the Company works with the builders/developers to develop forecasts (in new constructions) and confirms with the municipal resources when appropriate.

Second, security is a means to mitigate potential risks to the Company and its ratepayers over and above the operation of an extension test, and the Company has required security from projects that may potentially pose a higher risk for the Company and its ratepayers than typical extensions undertaken under the extension test. Please refer to the response to BCUC IR 1.9.2 and 1.9.3 for examples and explanations where security was required by the Company for main extension developments. However, the financial risk from most main extension development is relatively low. Not only will the majority of forecasted attachments materialize even with some initial delays, the costs for the main extensions are relatively low compared to the Company's rate base, annual revenue requirement and growth capital expenditures.

Third, requiring security in circumstances where it is not warranted may create a significant disincentive to install natural gas due to the opportunity cost of tying up capital. Deterring extensions that should be proceeding through excessive risk mitigation tools is detrimental to ratepayers in the long run. Undeveloped main extensions mean that existing customers would not receive benefits from the system.

9.2 Please provide the number of times security was required and the total amount of security obtained in each of 2008, 2009, 2010, 2011, 2012, 2013 and 2014.

	Total number of extensions	Total number of extensions requiring security	Percent of extensions requiring security	Total amount of security required
2008				
2009				
2010				
2011				
2012				
2013				
2014				

Response:

The requested information is provided in the table below. The percentage of extensions requiring security is low.

.

Total Number of Main Extensions at Time of MX Report	Total Number of Extensions Requiring Security	Total Amount of Security Required
1,272	2	$897,000
753	1	$178,000
707	1	$1,400,000
766	0	-
659	0	-
636	0	-
699	0	-

9.3 Please list the two highest amounts of security required in each year and compare to the forecast cost of those extensions.

		Total forecast cost of extension	Total amount of security required	Amount of security / total forecast cost of extension

2008	Extension 1			
	Extension 2			
2009	Extension 1			
	Extension 2			
2010	Extension 1			
	Extension 2			
2011	Extension 1			
	Extension 2			
2012	Extension 1			
	Extension 2			
2013	Extension 1			
	Extension 2			
2014	Extension 1			
	Extension 2			

Response:

The Company has required security in some larger main extension projects where the financial viability of the projects was uncertain. FEI has required security on four main extensions from 2008 to 2014, one of which did not proceed.

		Total Forecast Cost of Extension	Total Amount of Security Required	Amount of Security/Total Forecast Cost of Extension
2008	Quest University – Squamish, BC	$309,000	$309,000	100%
	Silver Creek – Mission, BC	$699,000	$588,000	84%
2009	Eagles Landing – Chilliwack, BC	$429,000	$178,000	41%
2010	Sweet Water – Fernie, BC	$4,000,000	$1,400,000	35%

Each case is discussed further below.

Quest University

This main extension was planned and installed in annual phases beginning in 2006-2008. The total amount security required for Quest University was 100% of the cost of the project because there was a high level of uncertainty around the consumption requirements and the type of equipment that was to be installed. Based on the actual consumption over the refund period, Quest University has been refunded $150,000 of their original security.

Silver Creek

At the time of the Silver Creek main extension, the developer, Solterra, was unable to provide a reasonable attachment forecast because there was uncertainty with the timing of the development. Solterra has been refunded $120,000 after attaching 21 residential customers.

Eagles Landing

In the case of Eagle's Landing in Chilliwack, the customer, who in this case was the City of Chilliwack, had firm commitments and signed leases from a number of larger commercial customers such as Home Depot. However, they did not have a reasonable expectation as to the timing and consumption requirements of some of the small commercial customers expected to attach. As a greater number of attachments than forecast have materialized, the City received a full refund for their security deposit. There is currently a mix of approximately 60 large and small commercial customers attached to the Eagle's Landing main extension.

Sweet Water

The Sweet Water main extension was intended to serve a large proposed subdivision of homes near Fernie, BC. The main extension did not proceed.

10.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, Section 2.2.1, p. 17; Section 3.3.2, pp. 40–41; Section 5.6.2 p. 81

Security and Contribution in Aid of Construction (CIAC)

Figure 2-1 provides the current MX Test formula:

Figure 2-1: Current MX Test Formula

$$P.I. = \frac{\text{Net Present Value of Net Cash Inflows (20 Year DCF Term)}}{\text{Net Present Value of Capital Costs (5 years of Attachments)}}$$

$$\frac{\text{(Delivery Margin + Application Fees-O\&M-System Improvement –Municipal Tax-Property Tax-Income Tax)}}{\text{(Mains, Services \& Meter Costs + Overhead + Working Capital)}}$$

In the Application, FEI states:

> The Company currently recovers a CIAC from a customer based on the results of an MX Test. In the event that the project is a contributory main, the customer paying a CIAC is entitled to a pro-rata refund if a future customer connects within a five year window. The Company currently doesn't provide alternatives for recovering CIACs associated with system extensions.[21]
>
> Ten percent, or 551, of the 5,492 mains installed between 2008 and 2014 required a CIAC, totalling $3.9 million. By increasing the DCF from 20 to 40 years, the CIAC would have decreased by approximately $2.0 million in total and 4.8% of customers would have paid a CIAC, as shown below. The number of customers paying a CIAC would consequently go down from 551 to 261 by switching from the current 20 year DCF term to a 40 year DCF term.[22]
>
> The Company proposes to use a 10 year horizon for customer attachments in certain circumstances when it can be reasonably demonstrated by the customer or municipality that there is a longer term municipality-accepted plan for growth exceeding five years.[23]
>
> Security can provide a further level of ratepayer protection in the event a builder or developer did not deliver on their commitments… It should be noted that security is seen by developers and customers as a punitive measure. Rather than increasing existing rate payer protection because security is acquired, developers may choose not to attach, reducing the potential benefit from the

[21] Exhibit B-1, p. 40.
[22] Ibid., p. 53.
[23] Ibid., p. 53.

addition of new customers to the system. As such, the use of security must be used judiciously.[24]

10.1 Is the CIAC considered a negative capital cost (denominator) in the PI formula?

Response:

No, the CIAC amount is treated as an additional source of cash in year 0 of the main extension's life and is included in the numerator of the PI formula.

The CIAC requirement is determined from the MX Test. If an individual MX Test produces a PI below 0.8, a CIAC is required to bring the result of the MX Test up to the 0.8 PI. A simplified formula is provided below:

$$\frac{\text{NPV of Cash Inflows} + \text{CIAC Amount}}{\text{NPV of Capital Costs}} = \text{PI of 0.8}$$

10.2 In tabular format by year since 2008, please state the amount of CIAC that FEI collected.

Response:

This answer responds to BCUC IRs 1.10.2 and 1.10.3.

The table below presents the total CIAC amounts for all main extensions installed between 2008 and 2014 by FEI and FEVI respectfully.

[24] Ibid., p. 81.

MX Year	Total Contributions Received	FEI Contributions Received	FEVI Contributions Received
2008	$ 539,951	$ 436,727	$ 103,224
2009	$ 479,393	$ 368,955	$ 110,437
2010	$ 394,528	$ 292,231	$ 102,297
2011	$ 629,518	$ 523,062	$ 106,456
2012	$ 639,581	$ 446,312	$ 193,270
2013	$ 525,679	$ 432,673	$ 93,006
2014	$ 686,714	$ 623,689	$ 63,025
Total	$ 3,895,364	$ 3,123,649	$ 771,715

10.2.1 Please compare these amounts to the System Extension Fund (SEF) and discuss if the proposed $1 million amount is appropriate to help fund the CIAC.

Response:

The size of the SEF of $1.0 million is not directly related to the actual CIAC collected for a given year. The CIAC is required and collected from those customers whose main did not meet the 0.8 PI threshold and who decided to continue with the main and pay the CIAC. FEI does not have data on those customers who, after being made aware of a required CIAC, decided to not attach to the system. Thus, the actual CIAC amounts collected by the Companies since 2008 as provided in the response to BCUC IR 1.10.2 are reflective of those customers that were able to afford the up-front contribution and proceeded with the main extension. The SEF fund is intended to assist eligible customers who potentially have a larger CIAC and may not be able to afford the required contribution.

As explained in the Application (section 4.3.2), the customer would pay 50% of the CIAC of the project, subject to a cap of $10,000 per customer. Given that the average contribution for refundable mains over the past few years has been approximately $5,000, a $10,000 limit per customer should allow for a fair consideration of outliers.

For customers applying for the SEF fund, it is likely they would receive some level of funding, provided that they meet the eligible criteria indicated in the Application and that there is still sufficient amount in the SEF remaining. The Company does not know how many customers would apply to the SEF, so it cannot speculate on whether all customers who apply would receive some level of funding.

10.2.2 FEI collected an average of $0.65 million CIAC per year between 2008 and 2014[25]. If the Commission approves the Discounted Cash Flow (DCF) time horizon to 40 years, then the average CIAC would amount to be $0.33 million per year. Based on the criteria set out in the proposed SEF (i.e. $1 million per year, maximum $10,000 per customer, unused funds rolling over to second deadline, etc.) would it be fair to say that there will be a very high likelihood that all SEF applicants will receive some level of funding? Please explain.

Response:

Please refer to the response to BCUC IR 1.10.2.1.

10.3 Please provide the amount of CIAC received by year, 2008 to 2014 for FEI and for FEVI.

Response:

Please refer to the response to BCUC IR 1.10.2.

10.4 Please describe how the CIAC refund mechanism works in the existing Tariff based on a five year horizon. What impact, if any, would a ten year horizon have on the CIAC refund mechanism?

Response:

Section 12.7 of the FortisBC Energy Inc. Tariff states:

> "FortisBC Energy will collect contributions from all Customers connecting during the first five years after a Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who have previously made contributions."

[25] $3.9 million divided by 6 years.

The following provides a description of a contributory main and the Company's refund practices, followed by a discussion of the impact of a 10 year MX test time horizon would have on the CIAC refund mechanism.

A Contributory Main

A main is characterized as a "contributory" main where the required CIAC collected from customers is subject to refund. Thus, it is important to note that where a CIAC is required from a builder in order for a main to proceed, the main is not a "contributory" main because such CIAC will not be subject to refund due to the fact the builder will sell the residences attached to the main extension. Refund is applicable only if the contribution to a main was made by residential homeowners.

The Company will track a "contributory main" (once the construction of the main is completed). The purpose of the tracking is to ensure that new customers who will connect to a "contributory main" will be advised in advance of the applicable charges. Currently, contributory mains and the associated customers are tracked by FEI for a period of five years according to the Tariff. The main will retain its status as a "contributory" main until the end of the 5 year window regardless of whether new customers are connected or refunds are issued.

Each new customer that connects to a contributory main within the first five year window will be required to pay a proportional share of the original CIAC. This portion is collected by the Company and refunded back to the original/earlier customer(s).

The refund process is as follows:

- When a new customer attaches to a contributory main, he/she must pay a proportional share of the original contribution.
- The Company then takes the amount received from the new customer(s) and gives it back to the original/earlier customer(s) via a cheque. Section 12.8 of FEI's General Terms and Conditions describes how the determination and payment of the refund work.
- The new customer is then identified as a contributor to the main and is also eligible for future refunds along with all existing customers on the main.
- This process continues as each new customer attaches to the main.

According to the Tariff, by the end of the fifth year, all customers will have paid an equal contribution to the main after reconciliation and refunds. Contributions will also no longer be required from future customers once the main has reached 5 years in age.

Impact of 10 Year Time Horizon on CIAC Refund Mechanism:

The 10 year time horizon would apply to the MX tests for new main extensions for municipalities and developers or conversion main extensions in existing neighborhoods.

For municipalities or developers that qualify for the 10 year attachment window in the main extension test, and that test results in a contribution, their contribution amount would be "non-refundable" as discussed above. As such, there will be no impact of a 10 year time horizon on the Company's CIAC refund mechanism as described in the Tariff and as applied.

For a single homeowner or group of homeowners that use a 10 year attachment window in the main extension test for a conversion main and the MX test results in a contribution requirement, the main will be a contributory main, subject to refund. As such, the Company would track activity on the main extension and issue refunds over a period of 10 years rather than 5 years, using the same refund process described above.

10.4.1 Please explain how the proposed Tariff changes reflect the ten year horizon case.

Response:

The proposed 10-year horizon window impacts sections 12.4, 12.7 and 12.9 of the Company's General Terms and Conditions. In the proposed changes included as Appendix E of the Application, Section 12.4 has been proposed to be amended to the following:

> 12.4 Only those customers expected to connect to the Main Extension with 5 years of its completion, **or within 10 Years of its completion for a Main Extension with a planning horizon longer than 5 years as determined by FortisBC Energy,** will be considered. **(emphasis added)**

Please refer to Attachment 10.4.1 for the proposed changes to sections 12.7 and 12.9.

10.5 Please clarify if FEI is referring to developers or home owners (or both) when it states that "security is seen by developers and customers as a punitive measure."

Response:

FEI believes that both developers and homeowners may view security as a punitive measure.

11.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, section 5.6.2 p. 81

Security and Contribution in Aid of Construction

On page 81 of its Application, FEI states:

> Security can provide a further level of ratepayer protection in the event a builder or developer did not deliver on their commitments… Where the builder or developer has provided reasonable forecasts of appliances and end use customers, it would then be inappropriate to require security due to ultimate usage not materializing as that is beyond their ultimate control. To do so would be a disincentive to consider natural gas in their building plans.
>
> The Company believes that it is applying security appropriately and in a manner that considers the risk of new customer attachments without creating a punitive signal to the market. Applying more stringent steps would likely result in fewer attachments and therefore less benefit to potential and existing customers.

11.1 It would appear that builders and developers may have incentives to over-forecast attachments and consumption to avoid paying a security as they consider security as a punitive measure. Please explain how FEI ensures forecast accuracy and how the builder/developer could be held accountable without a security?

Response:

This answer responds to BCUC IRs 1.11.1 and 1.11.2.

Based on FEI's experience of dealing with customers, FEI does not believe, and has not seen, that builders/developers intentionally overstate attachments and consumption to avoid providing security or paying a CIAC.

FEI works closely with builders/developers to develop forecasts and has also used municipal resources to confirm commercial plans as available, and has a process to determine the necessity of security. Please refer to the response to BCUC IRs 1.9.1 to 1.9.3, which demonstrate that the Company has used security as a means to mitigate potential uncertainty about the financial viability of some proposed main extensions that would expose FEI to greater risk than what is typically associated with main extensions.

FEI collects CIAC in accordance with its tariff. Table 4-3 of the Application shows that FEI collected $3.9 million in CIAC on 10% or 551 of the total main extensions installed between 2008 and 2014. The vast majority of CIAC was collected from builders and developers. The response to BCUC IR 1.10.2 shows the CIAC collected by year for FEI and FEVI.

Moreover, as shown in Table 5-3 of the Application, FEI's customers, including builders and developers, deliver on their commitments. Between 2008 and 2013, the customer attachment variance is within seven percent of forecast.

11.2 Similarly, it would appear that builders and developers may have incentives to over-forecast attachments and consumption to avoid paying a CIAC. Please explain how FEI ensures forecast accuracy and how the builder/developer could be held accountable for its forecasts?

Response:

Please refer to the response to BCUC IR 1.11.1.

12.0 Reference: SECURITY AND CONTRIBUTIONS IN AID OF CONSTRUCTION

Exhibit A2-3, EB-2006-0243, Decision regarding an Application by Natural Resource Gas Ltd. to construct a natural gas pipeline and ancillary services, pp. 2–3

Other jurisdictions – Ontario Energy Board (OEB)

The section on page 2 of the decision titled "Economics of the Proposed Facilities" outlines that "To protect the ratepayers of NRG, a capital contribution of approximately $3.8 million is required from IGPC [Integrated Grain Processors Co-operative] to achieve a profitability index of 1.0." This is an increase from the PI of the proposed facilities stated earlier to be "0.55."

On page 3, the decision states that the:

> PCRA [Pipeline Cost Recovery Agreement] requires IGPC to provide an irrevocable delivery letter of credit in the amount of $5.3 million, which IGPC must maintain as long as it continues to receive service. This letter of credit will be reduced annually to an amount equal to the net book value of the assets of this project. This … will ensure that NRG can draw on this letter of credit in the event of either a default by IGPC or its ceasing operation prior to the assets are fully depreciated, thereby avoiding the potential for stranded assets. This protects NRG and its ratepayers.

12.1 Please discuss FEI's views on the use and magnitude of the CIAC required to achieve the profitability index of 1.0 as described in the preamble. Also discuss how the magnitude of this CIAC compares to CIACs collected by FEI in the 2008 to 2014 period.

Response:

The Company has to assume that NRG followed the terms of its tariff or other requirements (if any) when requiring the CIAC and therefore the use and magnitude of the CIAC are appropriate in NRG's circumstance. The Company does not have enough detail to provide any additional discussion regarding the appropriateness of the use and magnitude of the CIAC required in the referenced instance.

FEI notes however that the circumstances referred to in Exhibit A2-3, EB-2006-0243 are not comparable to those of the Company's during the 2008 to 2014 time period. NRG is a small utility with only 7,500 customers and at the time of application to the Ontario Energy Board (OEB) in 2007, NRG's Rate Base was $9.7 million. Additionally, the NRG application that was subject to the referenced OEB decision was for a major natural gas pipeline expansion to serve one potential industrial customer with a net present value project cost of $8.5 million. Even after

the CIAC of $3.8 million, the main extension in this case represented 55% of NRG's rate base. For comparative purposes, 55% of FEI's rate base amounts to approximately $2 billion.

12.2 Please discuss FEI's view on the use of the letter of credit and the process through which it is reduced over time.

Response:

Given the risk profile of the proposed project for NRG as FEI understands it, the use of a letter of credit by NRG appears to be appropriate since despite the $3.8 million CIAC, NRG would still be increasing its rate base by approximately 55% as a result of the project.

For FEI, the average cost of a main extension is $11,600, which would have an insignificant impact on FEI's rate base individually. Thus, a letter of credit or other form of security in most instances will not likely be required. If FEI had been approached by a customer seeking a main extension in the range of that noted for NRG ($5.3 million) during the time period from 2008-2014, a CPCN application would have been required and there would not have been an MX Test. However, regardless of whether or not a CPCN application was or is required, a customer seeking a main extension with a potential cost of more than $5 million and where the assets could only serve that one customer, FEI would likely seek security from the customer. The Eagle Mountain-Woodfibre Gas Pipeline Project (EGP) project is a recent example. The EGP Project is a large project that serves one potential customer. FEI has required the potential customer to provide security for the development work FEI is undertaking. In this case, Pacific Energy Corporation has agreed to provide FEI with performance security in the form of a letter of credit for FEI's costs incurred to support the development of the EGP Project. Although this project is not a main extension, it is an illustration of how the Company manages financial uncertainty associated with larger projects.

12.2.1 Is there an alternative that provides a similar level of protection for the utility and its ratepayers that FEI could incorporate into its Main Extension policies? If yes, please explain.

Response:

The Company believes that its current approach to security and CIAC as outlined in its tariff and approved by the Commission provides the appropriate level of protection to the utility and its

1 ratepayers. FEI does not have evidence to suggest that greater security provisions are required
2 and thus does not see the necessity to explore another alternative.

3 Please also refer to the response to BCUC IR 1.9.1 for a discussion of FEI's view on security
4 requirements.

5

B. CONSISTENCY WITH BCUC GUIDELINES

13.0 Reference: CONSISTENCY WITH OTHER BC UTILITIES

BCUC Utility System Extension Guidelines; Exhibit B-1, Appendix A, Paper 2, p. 43.

DCF term, customer addition term and cost allowances

On page 1 of the BCUC Utility System Extension Guidelines (Guidelines) it reads:

> The purpose of the system extension hearing was to look broadly at the system extension policies of the Utilities to determine if opportunities existed to improve the fairness and efficiency of these policies and to make them more consistent with one another.

FEI submitted a paper in Appendix A of its Application titled "Line Extensions for Natural Gas: Regulatory Considerations." In the author's recommendation, the author explains: "A good extension policy should feature certain objectives…A second objective is to create a level playing field among the different energy sources."

13.1 Does FEI agree with the objective in the paper FEI submitted? Why, or why not?

Response:

This answer responds to BCUC IRs 1.13.1 and 1.13.2.

FEI agrees with the objective of creating a level playing field among the different energy sources as articulated in the paper cited in the preamble. FEI interprets "creating a level playing field" to mean facilitating choice among different energy sources.

FEI's proposed changes to the MX Test (summarized in a table on page 50 of the Application) help meet this objective. The proposals, except the discontinuance of the energy efficiency credits, would have the effect of lowering the CIAC. This has the effect of making natural gas more readily available as an energy choice for customers while still protecting existing customers.

13.2 Do each of FEI's proposed changes meet this objective? Please explain.

Response:

Please refer to the response to BCUC IR 1.31.1.

13.3 Does FEI consider it fair to the other utilities to make FEI's proposed changes in isolation (i.e. without the other utilities making their own comparable adjustments)? Why, or why not?

Response:

Yes. FEI does not believe that the proposed changes to FEI's own MX Test will be unfair to other utilities or their customers. Each utility in BC operates in distinct service areas and serves different customers under its own rates, structures and operating circumstances, to which its system extensions must apply. And, it is likely that system extension policies for different utilities serving customers using different energy sources would need to be different to account for the advantages and disadvantages specific to each energy form. The changes to the system extension policy proposed in this Application were developed to address the particular circumstances of the Company and are related to the specific parameters of FEI's existing Commission approved MX test. A change in the Company's policies does not necessarily mean that a change is also warranted for other utilities. Should other utilities in BC wish to revisit their own system extension approach, presumably they will do so in consideration of their own individual circumstances and also in consideration of the policies in place in other utilities at the time, just like FEI did in this Application.

This is consistent with the BCUC System Extension Guidelines (issued September 5, 1996), where the Commission noted (at page 9):

> *[C]onsistency within and among Utilities in the analysis of system extension is desirable in that it reduces the potential for discrimination among current and prospective customers with regard to the availability of and charges for energy service. Nevertheless, the Commission recognizes that neither the values used as inputs into the analysis of proposed system extensions, nor the detailed calculation method, will necessarily be the same for each utility. In evaluating Utilities' system extensions, the Commission will endeavor to apply as much consistency as it considers reasonable given the individual circumstances of each utility.* [Emphasis added.]

13.4 Please provide and compare FEI's proposed cash flow term, customer addition terms, and cost allowances to British Columbia Hydro and Power Authority (BC Hydro), FortisBC Inc. (FBC) and Pacific Northern Gas Ltd.'s (PNG) discount cash flow terms, customer addition terms and cost allowances.

Utility	Cash Flow Term	Customer Addition Term	Cost Allowance
FEI	40 years	5 (or 10) years	$2,150 / $4,300
FBC			
BC Hydro			
PNG			

Response:

The following table compares FEI's proposed cash flow term, customer addition and cost allowances with that of BC Hydro (electric), FortisBC Inc. (electric) and Pacific Northern Gas.

Utility	Cash Flow Term	Customer Addition Term	Cost Allowance (residential service)
FEI	40 years	5 (or 10) years	$2,150 single family dwellings / $4,300 duplexes
FBC	N/A	N/A	$1,741
BC Hydro*	20 years	5 years	$1,475
PNG	20 years	5 years	None

* As indicated in the response to BCUC IR 1.4.6, BC Hydro's (BCH) distribution extension policies differ markedly from that of the Company's, where BCH calculates a flat contribution for residential customers to be applied as an offset to the cost of the required extension. That is, required CIACs from BCH customers are determined solely based on the difference between the flat cost allowance and the cost of the extension.

13.4.1 Based on the information in the above table, please explain how changing FEI's DCF term to 40 years, customer addition term to 10 years and increasing the cost allowances each support making the utility policies more consistent with one another.

Response:

As shown in the responses to BCUC IR 1.4.6 and 1.13.4, some degree of differences in extension policies already exists and has to exist among utilities. The Company does not

believe that such variations should be regarded as departing from the Guidelines or creating unfairness among utilities. Please refer to the response to BCUC IR 1.13.3.

13.4.2 Please discuss how the expected lives of FEI's main and service assets compare to expected lives of the same or similar assets of these other utilities.

Response:

The table below provides the expected lives of FEI's main and service assets and FortisBC Inc.'s (FBC) system extension service assets. Although FEI does not have the information on the asset lives of PNG or BC Hydro, the Company believes that it is reasonable to assume that the expected lives of FEI's main and service assets would be similar to those of PNG's, and that the expected lives of FBC's distribution assets would be comparable to those of BC Hydro.

Variations in the expected lives for mains, service lines, and meters between FEI and PNG could exist due to differences in the type of mains installed and the maintenance program employed by each utility, but the Company expects these variations to be immaterial. A more precise comparison would require insight into PNG's operations and deprecation studies, which the Company does not have access to.

As indicated in the table below, FEI's main and service assets are not comparable to similar assets of FBC and BC Hydro, since they are electric utilities. However, it is clear from the table provided that the expected life of distribution service lines for FBC is 75 years, which is longer than the 65 year expected life of a natural gas distribution main.

	Expected Average Service Life[26]
FortisBC Energy Inc.	
Mains	64 years
Service Lines	45 years
Meters	18 years
FortisBC Inc.	
Distribution Services	75 years
Line transformers	45 years
Poles, Towers and Fixtures	50 years

[26] Expected life for assets are derived from the Company's most recent 2014 Depreciation Study conducted Gannett Fleming filed as Appendix D1 to FEI's Annual Review for 2016 Rates and Appendix C to FBC's Annual Review for 2016 Rates.

13.4.3 Please discuss the infrastructure that these other utilities would require to construct a main extension and service line to serve a customer.

Response:

For BC Hydro and FortisBC Inc., the infrastructure required to connect an electric customer would generally involve:

- Installation of a new single-phase transformer on a concrete pad;
- Distribution service (high and low voltage service lines); and,
- Electric meter.

Costs for infrastructure for these utilities will not be comparable to FEI's cost for installing mains and services assets, since BC Hydro and FortisBC Inc. are electric utilities.

For FEI and Pacific Northern Gas (PNG), the infrastructure required to connect a gas customer would generally involve:

- Distribution Main;
- Service Line; and
- Meter.

The Company expects the capital costs to serve a new customer to be comparable to that of PNG, since the assets being installed are the same. However, differences in costs to connect a new customer between PNG and FEI are inevitable given geographical location differences, which affect construction costs, and differences in wages, which affect labor costs. A more precise comparison of the Company's cost to connect and PNG's cost to connect would require more detailed insight in the operations of PNG, which the Company does not have access to.

13.4.3.1 How would FEI's capital costs to serve a new customer compare to the costs these other utilities may encounter? Please explain.

Response:

Please refer to the response to BCUC IR 1.13.4.3.

13.4.4 Please discuss the uncertainties and risks that FEI encounters when planning a main extension 5 years out and when FEI plans extensions 10 years out.

Response:

For clarity, the Company is proposing a 10 year forecast period for customer addition estimates to be used in MX test where there is sufficient indication of a longer term build out horizon. A 5-year customer addition forecast horizon is still applicable in MX tests for the majority of main extensions.

One potential uncertainty when planning a main extension over a longer period is the extent to which customers actually connect. However, this could only be considered as an uncertainty if the benefits and costs of a main extension is only evaluated over a limited timeframe that is not representative of the life of the asset. As shown in the response to BCUC IR 1.3.1, the majority of customer attachments are infill customers over the life of the main, suggesting that in the long term, the uncertainties and risks that the attachments will not occur are very likely indistinguishable between a 5 year and a 10 year forecast. A 10 year forecast would be more reflective of the benefits of those customers waiting to connect to the main extension.

13.4.4.1 Would these other utilities expect to encounter similar uncertainties for their 5 year extensions and for their 10 year extensions? Please elaborate.

Response:

As shown in the response to BCUC IR 1.13.4, BC Hydro and PNG have a five-year customer addition term, while this does not apply to FBC. FEI is not aware whether other utilities are expecting changes to their system extension policies to reflect their operating circumstances and thus cannot provide further comments.

The Guidelines item 4 reads:

> The Commission expects the Utilities to ensure that estimates are as accurate as possible without adding substantially to the administrative workload associated with estimating system extension costs. The Commission will rely on prudency reviews to examine the accuracy of system extension estimates.

13.5 Please explain how the criteria FEI proposes it will report to the Commission could be used by the Commission to determine whether or not to initiate a prudency review to examine the accuracy of system extension estimates.

Response:

First, it is important to note that a prudence review would ultimately be focused on whether the costs of an extension were prudently incurred, and not "the accuracy of system extension estimates". In practical terms, the questions would be: (a) whether the decision to build the extension was prudent, and/or (b) whether an otherwise reasonable decision to proceed with an extension was executed in a manner that resulted in imprudently incurred (e.g. construction) costs.

Under the well-established two-stage prudence analysis, the only legal relevance of "the accuracy of system extension estimates" (i.e., in hindsight) to the prudence analysis is at stage 1 of the analysis. That is, a significant variance might provide a basis to rebut the presumption of prudence in the utility's decision and shift the burden of proof to the utility to demonstrate prudence (stage 2 of the prudence test).

At stage 2 of the analysis, the variance is irrelevant because hindsight is not permitted. Rather, at stage 2, the inquiry is whether FEI's decision to construct or the project execution was reasonable based on what was known, or ought to have been known, at the time. More specifically, in the stage 2 prudence assessment that examines a decision to build an extension, two factors may be relevant to what ought to have been known at the time:

- First, whether or not the estimating methodology employed by FEI was reasonable, or whether it reasonably should have been more robust; and
- Second, whether appropriate available data was used when applying the methodology.

As stated in section 5.4 of this Application, the Company believes that its forecast methodology is reasonable, as reflected by the historic average cost variance at 12% (updated in response to BCUC IR 1.1.1) and the historical variances in number and timing of attachments at 7.2%.

These variances are reasonable given the potential unforeseen conditions during construction and the unexpected market condition changes. Additionally, the Company has implemented measures to further refine its forecasts, including using manually intensive estimates (versus pricing average) for larger or more complex main extensions, in conjunction with Geo Code pricing and improving the internal approval process for customer attachments in congruence with the size of the main extensions. The Commission will be able to comment on these measures in this proceeding. If, going forward, FEI applies the methodology accepted by the Commission in this proceeding, then the only question that could legitimately be assessed in a prudence review of a decision to build an extension is whether FEI has used reasonable data in applying the methodology.

FEI's proposed reporting consists of two elements: annual reporting, and a periodic report informed by the Rate Impact analysis. These reporting mechanisms provide the Commission with appropriate oversight, as explained in the response to BCUC IR 1.32.1 and 1.32.7.1.

The Rate Impact analysis may be used as a source of information in assessing whether the test itself is serving its purpose or needs to change. For instance, if rates with capital growth equal rates without capital growth, it indicates a balance of new and existing customer interests having been met. If the rates are not equal, this may indicate that the methodology or data used by the Company for its decision to build extensions may need further review or revision. For example, the analysis provided in the Application indicates that existing customer rates have decreased as a result of capital growth from 2008 to 2014 suggesting that the associated benefit needs to shift from existing to new customers. The Company's proposals in the Application are designed to accomplish this objective.

14.0 Reference: CONSISTENCY

Exhibit B-1, Section 5.4.3, p. 78; Appendix A, p. 14

Existing and new customers, risks and uncertainties

On page 78 of the Application, FEI argues: [Using average volumes in the MX test] is intended to credit the new customers with an amount of consumption equal to the average consumption of other existing customers on a per appliance basis in order to treat the two groups comparably.

14.1 Please discuss how each of 1) changing the DCF term from 20 years to 40 years; 2) allowing 10 year customer addition terms; 3) changing to an overhead sliding scale; 4) allowing an System Extension Fund; and 5) removing the energy efficiency credits would each support treating the two groups comparably.

Response:

The Company interprets the "two groups" referred to in the question to mean new and existing customers.

FEI made the proposed changes in consideration of fair treatment of both customer groups: new customers are not unduly burdened with attachment costs and existing customers are not exposed to undue costs from the attachment of the new customers. For each proposed change, the Company discussed how the interests of the existing customers and new customers are affected. The details of the discussion are provided in section 4 of the Application. The following is a summary of how new and existing customers will be impacted under each proposal, which shows that the interests of both customer groups are considered and balanced.

Note that for each change below where there is a rate impact on existing customers, the rate increase described is actually a reduction in the rate benefit (decrease) provided to existing customers by the addition of new customers.

Changing the DCF Term from 20 Years to 40 Years

By extending the DCF term from 20 to 40 years, new customers receive a benefit more commensurate with the life of the main and consequently are less likely to pay a CIAC in order to gain access natural gas service. The rate impact on the existing customers would likely be an increase of rates of $0.002/GJ resulting from the cumulative $2.0 million decrease in CIAC over the seven year period, and assuming the 40 year term was in place in 2008.

Allowing 10 Year Customer Addition Terms

The effect for new customers of this change (where applicable) would be a lower CIAC in circumstances where there is sufficient indication of a build-out plan that exceeds 5 years. For

existing customers, although it is impractical to estimate what the impact of allowing 10-year customer addition terms would have, the Company does not expect a high number of these main extensions every year.

Changing to an Overhead Sliding Scale

The Company expects that this change will more fairly allocate the overhead costs without negatively impacting existing customers. In section 4.1.3.1 of the Application, the Company showed the difference in the total cumulative CIAC reduction in the amount of approximately $1.0 million resulting from the change based on the mains installed from 2008 and 2014. This means a rate impact on existing customers on rates of $0.001/GJ based on the Rate Impact analysis.

Allowing a System Extension Fund

For eligible new customers, the creation of and ability to access to the SEF will help with the upfront CIAC required in order to proceed with a main. For existing customers, the introduction of the SEF will have only a very modest impact, even under conservative assumptions. Using the Rate Impact analysis, the rate impact is conservatively forecast to be $0.001/GJ, assuming that the fund of $1 million is fully subscribed annually. Additionally, any resulting increased throughput on FEI's systems would result in rate reductions, all else being equal.

Removing the Energy Efficiency Credits

For new customers, discontinuing this credit may directionally increase the likelihood and/or amount of a CIAC. For existing customers, the impact of this proposal is not likely to be significant given the fact that only six percent of main extensions completed from 2008-2014 used the 10 percent credit and less than 1 percent used the 15 percent credit.

The Company notes that one of the differences between new and existing customers is the fact that new customers generally consume less energy than existing customers due to more energy efficient appliances. Hence, in the context of the MX Test, FEI is proposing to continue to use the consumption value derived from the REUS in order to treat new and existing customers fairly and not to penalize new customers for using more energy efficient appliances. Please refer to the response to BCUC IR 1.35.1 for further discussion.

In Appendix A of the EES Report, it explains:

> FEI is consistent in this practice as it uses the results of the REUS survey of usage per appliance which is based on all customers on the system. Because

the REUS is updated periodically, any trends in customer usage will be reflected in the calculations. It is also consistent with the practice of BC Hydro where the line extension credit is a flat amount based on the costs and benefits associated with a customer using a standard amount of electricity based on historic averages.

14.2 Please provide and compare BC Hydro's historic average use per customer that it uses to determine its line extension credit to its new customer use per customer.

Response:

Please refer to the response to BCUC IR 1.4.6 for a discussion on BC Hydro's approach which does not use a consumption estimate.

14.3 Please provide and compare the difference between FEI's average use per existing customer and FEI's expected average use per new customer to the difference between BC Hydro's historic average use per customer that is used to determine its line extension credit and its new customer use per customer.

Response:

Please refer to the response to BCUC IR 1.14.2.

15.0 Reference: INTRODUCTION AND OVERVIEW

Exhibit B-1, Section 1.1, p. 3

System extension fund – approvals sought

On page 3 of the Application, FEI is seeking the following approval, among others: "The establishment of the System Extension Fund of $1.0 Million, to be recovered through gas delivery rates and included in rate base each year as an offset to Contributions in aid of Construction."

15.1 Under what section of the Utilities Commission Act, or any other jurisdiction of the Commission, is FEI requesting Commission approval for the proposed System Extension Fund (SEF)?

Response:

The Company is applying for the updates to its system extension policies under sections 28-30 and 59-61 of the UCA, including the establishment of the SEF. These sections should be read together and therefore FEI believes that it is appropriate to refer to all these sections when considering what section of the UCA is applicable. FEI does not believe further precision is necessary, as FEI believes that the Commission has the authority under sections 59-61 of the UCA to approve the SEF. "Rate" is broadly defined under the UCA, which includes "a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate." This definition is broad enough to capture the SEF.

15.1.1 Please state the criteria that the Commission should consider when it assesses the merits of a SEF. Provide an analysis on how the SEF meets/does not meet such criteria.

Response:

This answer responds to BCUC IRs 1.15.1.1 and 1.15.2.

The success of the SEF is measured by how many potential eligible customers will apply for and receive funding and proceed with the main extension. As discussed in section 4.4.3 of the Application, the Company proposes to include the total number of approved requests to access the Fund and the total dollar value of the approved requests in its MX reporting. The Commission will thus be able to monitor the fund's activities.

FEI believes that no additional reporting requirements or evaluation criteria should be required for the SEF given the fund is limited to $1 million and has a very low impact on rates as discussed on page 66 of the Application.

15.1.2 Please provide any government policy and/or recommendation for FEI to implement a SEF.

Response:

There is no specific government policy or recommendation for FEI to implement a SEF, but there is an established precedent in BC for doing so.

15.2 How would FEI evaluate the success of the SEF program? How would FEI inform the Commission that the SEF is performing (or not performing) as intended?

Response:

Please refer to the response to BCUC IR 1.15.1.1.

15.3 What is the trigger mechanism to terminate, renew, or modify the SEF? When is the appropriate time to review the SEF?

Response:

If there are circumstances where the fund in not functioning as intended or is being under-utilized, either FEI or the Commission can bring forward modifications or termination of the SEF.

16.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.3.2, pp. 64–66; EES Report, p. 15

Terasen Gas (Whistler) Inc. Certificate of Public Convenience and Necessity for the Whistler Natural Gas Project and Terasen Gas (Vancouver Island) Inc. Certificate of Public Convenience and Necessity for the Squamish to Whistler Intermediate Pressure Pipeline, Exhibit B1-13, TGW Response to BC Hydro IR 2.0, p. 3

System extension fund recommendations

On page 64 of the Application, FEI states:

> FEI is proposing that the Fund be established for its natural gas customers at $1.0 million, equivalent to two thirds the size of BC Hydro's $1.5 million level, to reflect that FEI has a smaller service territory and a smaller number of new customer added annually…
>
> The Fund would be set up with comparable provisions to the BC Hydro fund; however, there would be natural differences due to the fact that it would apply to gas customers rather than electric customers. FEI is also proposing a simpler approach than the one in place at BC Hydro.

In the Terasen Gas (Whistler) Inc.[27] proceeding as noted above, it states:

> Tariff elements such as rates and connection policies are established to provide reasonable assurance that existing customers will not be negatively impacted by new core customers joining the system but there is not a long-term requirement that the new customers provide the same actual revenues they were forecast to provide when they joined the system. <u>There are some instances in B.C., such as with BC Hydro's Uneconomic Extension Fund, where it can be argued that existing utility customers are explicitly subsidizing new customers for reasons that were found acceptable by the Commission when the tariffs were approved.</u> In citing this TGVI is not implying that any special benefit should be conferred on TGW to attach to the system but neither should a stronger revenue recovery burden be imposed on TGW than on core market customers anywhere else on TGVI's system. [Emphasis added]

The EES Report, dated June 2015, states that "projects with a P.I. above 1.1 offset the added costs of those projects below 1.0, leading to an aggregated outcome that does results in holding existing customers harmless from the growth in customers."

[27] FortisBC Energy (Whistler) Inc. (FEW) was formerly known as Terasen Gas (Whistler) Inc. FEW amalgamated with FEI on December 31, 2014.

16.1 Please compare BC Hydro's 2015 rate base to FEI's 2015 rate base. What would the size of the extension fund be if it was sized in the exact same proportions?

Response:

According to Appendix C, Schedule 10.0 of BC Hydro's F2015-16 Revenue Requirements Filing, BC Hydro's mid-year distribution rate base for 2015 is approximately $4.37 billion. The size of BC Hydro's Uneconomic Extension Fund (UEA) is $1.5 million, which equals approximately 0.03% of its distribution rate base.

FEI's comparable distribution rate base is approximately $1.98 billion for 2015[28]. If using the exact portion (i.e. 0.03% of the distribution rate base), the size of the fund for FEI would be approximately $0.7 million. The Company's proposal for an SEF of $1.0 million is to ensure that the size of the fund is sufficient to meet the potential demands from customers, particularly from customers remotely located.

16.2 With respect to the underlined response by FEI, please confirm the proposed $1 million SEF that FEI is seeking is a subsidy from existing utility customers to new customers. If not confirmed, please explain.

Response:

The test in the UCA is whether there is "undue discrimination". Rates will almost always involve some degree of cross-subsidy or discrimination in the technical sense because the cost to serve individual customers will almost always differ. The question is whether the subsidy is "undue." FEI believes that the System Extension Fund is an appropriate rate mechanism. It is not unfair to existing customers, because:

- The SEF in aggregate is only for a short period of time until additional customers have attached to the distribution system. If this occurs to a main which is affected by the SEF, the main could then provide a net benefit to existing customers over the life of the main. In other words, the SEF is a deferral of the benefits that will be realized by existing customers; and

- The use of the SEF eases the access to natural gas. A higher throughput on FEI's distribution system means lower rates for existing customers, all else being equal.

[28] Per FEI's compliance filing in its Annual Review for 2015 Delivery Rates, this is equal to the mid-year value of distribution, biogas and NGT plant (cost less accumulated depreciation less net contributions less negative salvage provision).

16.3 Instead of providing up to $1 million each year by way of a SEF, are there any merits to lower the individual PI threshold in substitution of the SEF? For example, would FEI agree that this alternative may reach more beneficiaries, ensure non-discriminatory new customers treatment, and reduce the burden of administrating the SEF? Please provide a risk-benefit analysis between the proposed SEF and lowering the individual PI threshold.

Response:

Although a lower PI may have the benefits as outlined in the preamble, the Company believes the proposed SEF is a more appropriate solution because the SEF as it is structured and intended presents a lesser risk to, or has a lesser impact on, existing customers, while allowing new customers the ability to access natural gas distribution system, as further explained below.

Although the Fund will be applicable to all eligible owners of single-family residential home or townhomes irrespective of location, the intent of the Company is, and the reality will be, that owners in the lower density areas of the Company's service area will be more likely to be eligible for funding given the likelihood of a higher CIAC. Lowering the individual PIs in substitution of the fund would make it easier for *all* customers applying for a main extension, thereby undermining the intent of the SEF.

The SEF is capped at $1 million annually and does not accumulate. FEI has proposed to account for any allowance for customers from this fund as an offset to the CIAC additions that are included in rate base each year. The potential rate impact to the existing customers is insignificant, forecast to be a maximum of $0.001/GJ (using Rate Impact analysis). While FEI has no way of accurately forecast the rate impact from a hypothetical change to the individual PI, such change would likely put upward pressure on rates, all else being equal, because more customers with a PI less than 0.8 would be attaching to the system.

Moreover, as discussed in the Application (page 66), by simply having the SEF as an option, more residents will be likely to commit to a main project earlier, thereby lowering the CIACs and the need to access the SEF.

16.4 What would the equivalent individual PI threshold be, if CIACs were reduced by $1M annually?

Response:

To the extent that the question is asking what the equivalent individual PI threshold would be if CIAC were reduced by $1 million annually in relation to the proposed SEF, it is not possible to determine an individual PI threshold equivalent to a $1 million CIAC reduction because the Company cannot conduct an accurate ex-post analysis of individual PI thresholds for existing main extensions. More specifically:

1) the SEF was not available at the time and there is no way to determine which main extension customers would have accessed the fund;

2) it is not possible to determine the extent to which the SEF would have been used to reduce the CIAC in those main; and

3) there is no way to determine the number of main extensions that would have proceeded had the SEF been an option.

To the extent that the question is asking what the equivalent individual PI threshold would be if CIAC were reduced by $1 million annually (irrespective of the SEF), the Company is unable to produce a result that would be meaningful. The analysis would involve an ex post analysis of completed main extensions that required a CIAC over an arbitrary period, which would result in a PI equivalent to a $1 million reduction in CIACs collected *for that specific sample of main extensions*. It would not be reasonable to assume that the ex-post PI result would provide any assurance that the reduction in CIAC collected by the Company would be capped at $1 million in the preceeding year.

16.5 With respect to the EES Report, the gap between 0.8 PI and 1.0 PI could be viewed as one group of new customers subsidizing another group of new customers in the same cohort year. To the extent possible, please estimate the total annual CIAC that would be needed to bring all 0.8 PI main extensions up to 1.0 PI for each year since 2008. State the assumptions.

Response:

EES characterized FEI's use of an individual PI of 0.8 and an aggregate PI of 1.1 as appropriate and consistent with other the practices of other utilities. The relevant section of the EES Report is provided below for reference:

> *"FEI's use of a 0.8 target for the PI on an individual basis, along with a 1.1 overall target, is consistent with the practices of other utilities surveyed. While there are differences among the utilities, FEI is well within the range of options used…. FEI's practice of using a lower individual target and a higher aggregated target allows for recognition of the potential benefits in the future associated with new customers that are below 1.0 on their own, as well as the uncertainty in actual costs and benefits. Further, projects with a PI above 1.1 offset the added costs of those projects below 1.0, leading to an aggregated outcome that does results in holding existing customers harmless from the growth in customers".*[29]

The Company believes this is appropriate and should continue as it is preferable than having a lower aggregate PI of 1.0. Commission Order G-152-07 supports this assertion:

> *"The Commission Panel notes that one of Terasen's stated objectives for system extensions tests and policies is to promote fair and equitable treatment of customers and avoid undue discrimination, and notes that Terasen is effectively broadening the scope of the policy to ensure that the addition of a full year's cohort of customers does not adversely affect the customers in existence at the beginning of that year. The Commission Panel finds such a proposal to be in the public interest and to conform with its Guidelines and approves the proposal to establish a new threshold PI of 0.80 for individual main extensions, and to establish an aggregate PI of 1.10 as the threshold for all main extensions completed on an annual basis."*[30]

The Company is not able to estimate the "annual CIAC that would be needed to bring all 0.8 PI main extensions up to 1.0" as requested. The Company does not have the data or a defined methodology available to perform such an analysis.

[29] Appendix A, page 15.

[30] Page 30.

17.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.3, pp. 63–66;

BC Hydro 2004-2006 Revenue Requirements Application, Exhibit B1-8, Peace River Regional District IR 1.6.0, BC Hydro response dated March 29, 2004 (page 7382 of 8018 in the PDF);

A Generic Hearing into Extension Policies of Regulated Utilities, November 7, 1995

System extension fund

The uneconomic extension fund has an annual budget of $1.5 million. FEI states that it has been in place for roughly 30 years.

At the Generic Hearing into Extension Policies of Regulated Utilities, on November 7, 1995, BC Hydro indicated that any qualifying party who has applied for Uneconomic Extension Assistance (UEA) funding in the past has received it.[31]

Based on a BC Hydro response in 2004, it provides the total UEA funds spent and the number of numbers.

Details of the UEA program are provided below. Information prior to F1996 is not available. The total number of kilometres of distribution line constructed is also not readily available.

UNECONOMIC EXTENSION ASSISTANCE PROGRAM

Fiscal Year	Amount ($ 000's)	Number of Customers
1996	1,328.8	139
1997	605.1	92
1998	508.7	102
1999	584.5	73
2000	1,485.6	121
2001	362.9	47
2002	297.9	63
2003	290.1	23
2004 Forecast	845.6	56

On page 66 of the Application, FEI states:

> … the Company regards the $1.0 million as an annual maximum amount that does not accumulate. That is, unused fund amounts from previous years will not be carried over to future years. As such, FEI proposes to account for any allowance for customers from this fund as an offset to the CIAC additions that are included in rate base each year. As a result, these amounts will be recovered

31 http://search.allwestbc.com:8080/bcuclibrary/proceedings/other/1995extensionpoliciesreview/tr/19951107.pdf_T6: 954

through the delivery rates of all non-bypass customers via the amortization of contributions embedded in the revenue requirement. This approach is simple, and is consistent with BC Hydro. [Emphasis added]

17.1 For clarification purposes, please confirm that BC Hydro's Uneconomic Extension Fund, Uneconomic Extension Assistance (UEA), and UEA program all have the same meaning.

Response:

Confirmed.

17.2 Please describe BC Hydro's rate recovery mechanism of the UEA program. Compare and contrast BC Hydro's mechanism to the FEI proposal.

Response:

It is FEI's understanding that BC Hydro forecasts the UEA funds as part of its capital planning process.The forecast capital expenditures offset the contribution that would normally have been collected from UEA eligible customers and the result is a net reduction in contributions within rate base. The fund expenditure is recovered through the revenue requirement and rates charged to all customers. FEI's proposal with respect to rate recovery is consistent with the BC Hydro rate recovery mechanism.

17.3 BC Hydro's UEA actual funding ranges from $0.29 to $1.49 million from 1996 to 2003 and it appears that BC Hydro customers are likely going to receive funding if requested. Please forecast the actual SEF amount that will be granted and the number of customers that will receive the SEF for 2016 to 2020.

Response:

It is likely SEF eligible customers will receive funding if requested, similar to BC Hydro's funding situation. Using a simple comparative estimation and assuming that the SEF had similar initial usage as BC Hydro's UEA of 19% to 99% (from 1996 to 2003) of the total available funds, FEI estimates SEF funding of $0.19 million to $0.99 million per year from 2016 to 2020 as the program is introduced to customers. FEI notes that the UEA usage has gone down over time

and averaged $0.3 million (i.e. 20% of the UEA) from 2011 to 2015 (See response to CEC IR 1.45.7). Using similar comparative logic, FEI assumes that over the long term, the SEF usage will also go down over time.

Although FEI has customers that have decided against pursuing a main extension once they are faced with paying the CIAC, FEI is not able to accurately forecast how many future customers would change their decision to install natural gas from "no" to "yes" as a result of the introduction of the SEF. The program is new and the final decision whether to install a main is the customer's which may be influenced by other factors as well.

17.4 With respect to the underlined, is FEI proposing to use any remaining unused SEF to offset the CIAC each year? Please clarify.

Response:

No. Only the amount of the fund that is disbursed to customers will be included as an offset to the CIAC each year, to a maximum of $1 million per year.

18.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 1.1, p. 3; Section 4.3.2, pp. 64–66; Section 4.4.3, pp. 67–68; Appendix E, p. 12-5

System extension fund – proposed mechanism

On page 65 of the Application, FEI states:

> Customers applying for service failing to meet the required P.I. of 0.8, but at least a 0.2, for the requested main extension can apply for the Fund. Customers must complete all required forms and submit them to FEI on or before March 31st or June 30th of each year. Forms will be available on-line as well as through regional FEI sales staff.
>
> FEI will review all applications and will select projects to be funded. Project selection will consider the potential to connect future customers. Projects with a higher potential for future customer connections based on the number of lots between the customer and the beginning of the main extension will be given priority.

In the proposed Tariff changes on page 12-5 of Appendix E, FEI states: "The number of Customers eligible to receive the System Extension Fund will be limited and the determination of eligibility will be made by FortisBC Energy in its sole discretion, acting reasonably."

On page 3 of the Application, FEI explains that by way of an annual report, FEI proposes to report "The total number of approved requests to access the System Extension Fund, including the total dollar value of the approved requests."

18.1 Please provide the rationale that the PI must be at least 0.2 to be eligible for the SEF.

Response:

The Company believes that the P.I. requirement of 0.2 is a reasonable threshold. A PI requirement of 0.2 means that the customer's consumption and resulting revenue would at least cover 20% of the cost of the main extension, with the remaining 60% of cost (to get the PI to 0.8) to be shared between the customer through a CIAC, and the Company's ratepayers through the proposed SEF.

An eligible customer could receive up to 50% of the CIAC through the SEF. For example, to reach an individual 0.8 PI threshold, a customer with a PI of 0.2 would be required to pay a CIAC of 0.6 (i.e. 0.8 minus 0.2). In this example, 0.6 x 50% = 0.3. Therefore, the customer contributes a CIAC amount to reach a minimum PI of 0.5 (0.2 + 0.3). The Company believes a

PI of 0.5 represents a reasonable minimum CIAC, especially when the customer may have to forgo a potential refund from a contributory main.

18.2 Please file the required forms that FEI will be requesting customers to complete.

Response:

The development of the SEF proposal was focused on its overall design. The specific administrative elements of the SEF have not been developed absent knowing that the SEF proposal will be approved. Pending the Commission's approval of the establishment of the SEF, the Company will develop the procedures and elements required to administer the SEF.

18.3 Please provide the rationale why "Projects with a higher potential for future customer connections based on the number of lots between the customer and the beginning of the main extension will be given priority." Please elaborate and provide an example.

Response:

The Company proposed a "priority" as a means of managing SEF funding requests in the event funding requests exceed the $1.0 million cap. Should FEI have to decide between eligible customers' requests, the Company's preference would be to provide funding to the customer with the highest potential of benefiting the system with additional customer attachments at some point in the future. More attachments to the system mean more potential benefits to FEI's customers, all else being equal.

Two examples of potential SEF applicants are provided below.

The first type of main extension project is an SEF applicant who lives on a street and has no neighbors between the applicant's home and the main. Once the Company extends the main to this customer, there would be no potential for future benefit from additional customers attaching to the main.

The second type of main extension is a project that would serve a street with many neighbors. Some of the neighbors on this street have decided to get natural gas service as a part of the

main extension project while others have not. This project has potential for future benefit from additional customers to be added once the main is installed.

In the event that the Company would have to prioritize funding between these two SEF applicants, FEI would choose to fund the second applicant since it has a higher potential for future benefit due to potentially additional customer attachments.

18.4 Regarding the Tariff, please elaborate on the statement: "the determination of eligibility will be made by FortisBC Energy in its sole discretion, acting reasonably." Can the applicant customer file a dispute, reconsideration, or complaint? If yes, how would that process be handled? If not, why not?

Response:

The Company will be responsible for managing the Fund, including determination of eligibility, ranking and final approval of customer applications for the SEF, using reasonable judgement and acting in good faith.

If the SEF funding application for a particular customer were denied by the Company, the SEF applicant would be advised of the reasons, and have the option to request a review with the Company. There are a number of reasons why a customer's application for SEF may not be eligible, including not meeting the minimum 0.2 PI threshold requirements, having a lower ranking than other applicants, or the SEF for a particular period has been fully allocated. Customers are free to re-apply to the SEF in a future period. Customers also have the ability to file a complaint with the Commission.

18.5 How many times can a customer apply for the SEF? Is there a limit?

Response:

The number of SEF applications that a customer can apply for is limited by the number of main extension projects a customer is involved in. For example, if an eligible customer is involved in two main extensions requiring a CIAC, the customer would be eligible to apply for SEF funding up to two times.

18.6 Are there specific regions that FEI expects will use the SEF more so than others? For example, would new customers in certain areas of Vancouver Island be expected to benefit more than customers in the Lower Mainland, Fraser Valley or Interior from the SEF? Please explain.

Response:

The Company anticipates that all regions of the province will benefit from the SEF. Specifically, conversion customers (i.e. those switching from one fuel to another in a pre-existing home) are most likely to access the SEF, if eligibility is met. The greatest conversion potential is on Vancouver Island although opportunities exist throughout the rest of the province as well.

D. DISCOUNTED CASH FLOW TERM

19.0 Reference: RECOMMENDATIONS
Exhibit B-1, Section 4.1.1, p. 51;
Community Energy Association, http://communityenergy.bc.ca/
Analysis of DCF term

In its Application, FEI states: "The Company is recommending a 40 year DCF term. Although a longer DCF term may also be justified as it more closely aligns with the life of the main and captures more of the benefits, the Company is proposing to limit the DCF term to 40 years, as it covers the majority of useful life of the main."

19.1 FEI states that 40 years covers the majority of useful life of the main. Please discuss how climate action plans and community energy plans to reduce fossil fuel use and GHGs could reduce the economic life and revenue from a system extension to below 40 years.

Response:

Provincial and local government policies all can impact FEI's ability to attract new customers and/or retain existing ones. There are also some municipal policies such as mandatory connection to a district energy system, which could have the effect of reducing the natural gas throughput on particular extensions (although there is still the potential to have non-heating load).

The useful life of a main is actually 64 years on average based on current studies. FEI does not believe that it is appropriate to base the MX test on a parameter that is based on an assumption of an across-the-system useful life of mains below 40 years. In the event that the useful life shortened over time across the system, it would be reflected in the depreciation studies available to the Commission to consider in future changes to main extension parameters.

Increasing the economic life of mains in the MX test closer to their actual useful life can also make the transition from higher-emitting fuels to natural gas or RNG more financially feasible and as such support government policies.

20.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1.1.1, p. 51;

BCUC Gas Uniform System of Accounts, Account 473, p. 197

Analysis of DCF term

On page 51 of its Application, FEI states: "Between 2008 and 2014, 5,492 mains were installed by the Company. FEI conducted a CIAC analysis using a proxy version of the 2015 MX Test since it would be impractical to re-run thousands of individual MX tests to determine the impact on each CIAC by extending the DCF term."

Page 197 of the Gas Uniform System of Accounts for account 473 states: "Services which have been used, but have become inactive, shall be retired from plant in service immediately if there is no prospect for re-use, and, in any event, shall be retired by 'the end of the second year following that during which the service became inactive unless re-used in the interim."

20.1 Please provide the number of mains and services installed by FEI and FEVI from 2008-2014 by year, also provide the number of services installed by FEI and FEVI from 2008-2012 that became inactive.

Response:

The requested table is provided below. For the purposes of this analysis, the Company defines an "inactive service" as a service with customers that have had no consumption for at least the two most recent years[32] based on available consumption data (for the period of 2008 to 2014).

1,008 service lines have been classified as inactive using this analysis, representing approximately 1.8% of the total installed service lines from 2008 to 2012.

However, many of the services that are classified as inactive still have an account with the Company and continue to pay the basic charge on their monthly bill. As a result of removing these customers from the total, the remaining 692 customers or 1.3% have inactive services and do not have an active account with the Company.

It should be noted that many of these inactive services with no account have actually had consumption prior to the two most recent years (2013 and 2014). The Company believes since these services have been used in the past, it is reasonable to expect they will be used again. The difference, as identified in the last column of the table, of 327 customers represents services with no accounts and that have had no active consumption since 2008. This represents less than 1% of the total installed service lines from 2008 to 2012.

[32] 2013 & 2014.

The Company also notes that an update to the consumption figures for this analysis at any given time in the future will yield different results as customers continue to open and close accounts. While there is no gas flowing currently on some of these services, there are often prospects for re-use.

The Company has a policy in place to retire inactive services in the event that there is no prospect for re-use and two years has transpired since the service became inactive.

	Total Main Extensions	Total Number of Service Lines	Inactive Services* *(Service Lines with No Active Consumption for 2013 and 2014)*	Inactive Services* with no Account *(not receiving a bill)*	Inactive Services* with no Account That Have Had No Consumption from 2008 to 2013
2008	1,272	13,539	280	223	84
2009	753	9,278	211	162	74
2010	707	11,782	206	147	64
2011	766	10,213	164	99	61
2012	659	10,545	147	61	44
2013	636	9,495			
2014	699	10,728			
Total	5,492	75,580	1,008	692	327
	% of Services Installed from 2008 to 2012		1.8%	1.3%	0.6%

*Inactive services as at December 31, 2014

20.2 Please confirm that the "proxy version of the 2015 MX Test" has not been reviewed or approved by the Commission. Also provide the parameters used in the" proxy version of the 2015 MX Test."

Response:

The proxy version of the MX Test used to conduct the CIAC analysis is identical to the current MX Test approved by the Commission. The use of the term "proxy" refers to the sensitivity scenarios analyzed by the Company to illustrate the impact of changing the DCF term. In particular, the Company was assessing the impact of changing the MX Test from a 20 year to a 40 year DCF term. Since it is not feasible to individually re-create and re-calculate the

thousands of MX tests completed since 2008, the Company created a number of "proxy" scenarios using the MX Test and varied the DCF term to measure the impact on the revenue.

The Company annually updates the parameters used in the MX Test and includes these values to the Commission in the annual MX report. Below are the parameters that were used in the MX Test referenced above.

Economic Parameters FEI	2015
Overhead Rate	23.29%
CCA Class 1	6.00%
Discount Rate	4.90%
Working Capital Rate	0.50%
O&M per Customer	
Residential	$77.00
Commercial	$81.00
System Improvement (SI)	$0.24
Property Tax Rate	1.86%
Income Tax Rate	26.00%

	2015			
FEI Rate Class	Basic Charge ($/yr)	Delivery Charge ($/GJ)	In Lieu Rate (%)	New Service Fee ($)
Rate 1	$142.08	$4.22	1.88%	$25.00
Rate 2	$298.08	$3.41	2.21%	$25.00
Rate 3/23	$1,590.23	$2.85	2.03%	$25.00
Rate 4	$5,268.00	$1.94	3.54%	$25.00
Rate 5/25	$7,044.00	$19.74	1.39%	$25.00
Rate 6	$732.00	$4.40	1.90%	$25.00
Rate 7/27	$10,560.00	$1.32	1.02%	$25.00
Rate 22	$43,968.00	$0.96	1.01%	$25.00

21.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1.1.1, Table 4-2, p. 52

Analysis of DCF term

21.1 Please provide a fully functioning Excel spreadsheet showing the calculation of each of the results in Table 4-2 and provide the discount rates, inflation rates and all other assumptions used in the calculations.

Response:

Please refer to Attachment 21.1 for the requested fully functioning spreadsheet showing the calculation of each of the results in Table 4-2.

The purpose of the DCF analysis that resulted in Table 4-2 was to assess the extent to which a change in the DCF term can impact revenues and costs in the MX Test under different scenarios. In general, an increase in the DCF term results in a decrease in the required contribution amount because additional years of revenue are considered while the initial capital costs and PI threshold of 0.8 would remain constant.

The assumptions and MX Test parameters are stated below:

- The 2015 MX Test was used in the analysis to establish the relationship between the DCF term and the percentage increase in revenue. All parameters and rates were held constant. Please refer to BCUC IR 1.20.2 for a list of the parameters used in the 2015 MX Test.

- The discount rate of 4.9% included in the test is net of inflation (consistent with the approved methodology).

More specifically:

- As illustrated in the spreadsheet provided in Attachment 21.1, the Company created several scenarios to represent main extension projects with varying capital costs, rate classes and consumption amounts. (See cells N2 to AB11)

- The Company ran these scenarios through the 2015 MX Test to calculate the revenue for each scenario. All parameters in the 2015 MX Test were held constant including the approved discount rate of 4.9% (after inflation). The Company varied the DCF term of the MX test from 20 years to 30, 35, 40, 45 and 50 years and recorded the MX test revenue amounts for each scenario under each DCF term.

- The Company then calculated the percentage increase in revenue from the original 20 year DCF term for each scenario. (See cells J30 to AB59)

- The Company found that although the MX Test under different scenarios used different consumption, revenue and capital amounts, the percentage increase in revenue was similar for each scenario when the DCF term was changed.

- The results were averaged and then recorded in the spreadsheet (See cells B13 to L23) and included in Table 4-2 of the Application.

The outcome of the DCF analysis shows that the percentage change in revenue for each DCF term is relatively consistent across all main extensions as seen in Table 4-2 (assuming all else is remains constant).

21.2 Recalculate Table 4-2 using discount rates based on FEI's approved 2008-2014 weighted average cost of capital adjusted for inflation by year.

Response:

The weighted average cost of capital discount rates used in the main extension test for FEI from 2008 to 2014 are provided in the following table. All discount rates are adjusted for inflation.

	2014	2013	2012	2011	2010	2009	2008
Approved FEI Discount Rate Used in MX Test	4.5%	5.00%	5.00%	5.10%	5.10%	4.20%	4.00%
Total Capital Expenditures on Main Extensions	$ 8,114,041	$ 6,932,818	$ 8,055,730	$ 7,994,503	$ 6,947,390	$ 8,652,598	$ 18,854,976
Weighted FEI Discount Rate	0.56%	0.53%	0.61%	0.62%	0.54%	0.55%	1.15%
Weighted FEI Discount Rate 2008-2014	**4.57%**						

	2015
Approved FEI Discount Rate Used in Application (2015 MX Test)	4.9%

The Company has calculated a weighted average discount rate of 4.57%, weighted by the actual capital expenditures for main extensions each year.

The Company believes that using the actual approved weighted average cost of capital (WACC) of 4.9% for 2015 is the appropriate approach for evaluating a proposed change to the DCF term. Table 4-2 in the Application is used to assess the rate impact of a change in the DCF term within the MX test. Since a change in the DCF term will be implemented on a go-forward basis, the 2015 approved WACC is most reflective of what the discount rate may be in the future.

FEI has provided the requested table and notes that the variation in the weighted average discount rate and the 2015 discount rate is small and as such the values in the recalculated table below have no material differences compared to Table 4-2 in the application.

Re-calculation: 2015 FEU Residential and Commercial Mixed Use DCF Revenue Impact

Main Extension Capital Cost

DCF Life	$1,060 (Bottom 10%)	$11,600 (Average)	$50,000 (Captures 97%)	$500,000 (Large Project)
30	27.6%	27.5%	26.8%	30.7%
35	37.4%	37.1%	36.2%	41.2%
40	45.1%	44.8%	43.6%	49.4%
45	51.3%	50.9%	49.6%	55.8%
50	56.2%	55.8%	54.3%	60.9%

1

2

22.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1.1.1, pp. 52-53;

FEI Annual Review for 2015 Rates, Section 11, Schedule 25, p. 91

DCF term-meter life

On page 53 of its Application, FEI states: "Increasing the DCF term to 40 years will have no impact on the capital costs in the Test since the life of the main and the service line both exceed 40 years and the impact of an assumed meter and regulator replacement at 20 years will have an immaterial impact on the MX Test results."

22.1 Please provide each of the total residential meter costs and the total regulator costs included in the 2008-2014 MX tests, by year.

Response:

This response has been filed confidentially with the Commission as it contains information which is commercially sensitive to FEI and its vendors, and if disclosed publicly may cause harm to vendors and FEI's ability to negotiate in future.

Schedule 25 of the FEI Annual Review for 2015 Rates shows a depreciation rate of 7.36 percent (13.6 years) for account 474, house regulators and meter installations.

22.2 Please recalculate Table 4-2 assuming that meters and regulators are replaced every 14 years.

Response:

FEI notes that account 474 is for House Regulator and Meter Installations prior to 2012 and is no longer in use. The appropriate asset class for meters is 478-10 and for meter installations, 474-02. In addition, it is not appropriate to look at the depreciation rate that is developed for an asset class since the rate is influenced by existing over or under recovered depreciation at the time the depreciation study is undertaken. Rather, it is the asset life itself that is of relevance. As approved in Order G-44-12, the currently approved asset life for meters is 20 years and for meter installations it is 22 years based on the 2009 Depreciation Study[33].

Since the request was based on an incorrect assumption, FEI has not completed the calculations as requested in this Information Request.

[33] The 2014 Depreciation Study that was filed with FEI's Annual Review for 2016 Rates recommends a life of 18 years for meters and 22 years for meter installations.

23.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1.1, p. 51

DCF term-appliance life

23.1 Please provide the expect life of each of the appliances used in the 2014 system extension test parameters.

Response:

The expected life of appliances is not used in the MX Test parameters approved by the Commission. The NPV of cash inflow and outflows of the MX Test is discussed in detail in sections 2.2.1.1 and 2.2.1.2 of the Application.

It is not relevant to use the expected life of appliances when determining the DCF term. The purpose of the MX Test is to provide an economic assessment of *the infrastructure to be installed by the Company.* During the life of a main extension a customer will add or remove gas equipment and improve gas equipment but that equipment is not owned by FEI and does not impact FEI's costs. Attempting to forecast how a customer uses the equipment, when they will retire equipment or when the customer may add an appliance (for example a range, water heater etc.) would be extremely difficult and entirely unreliable. Further, once a customer is on the system, FEI does not require that the customer use an appliance for a certain time, keep the same appliances and/or use a certain amount of volume. In fact, the Company actually encourages customer to reduce consumption via DSM programs. Customers often replace appliances and add new appliances over the life of a building. As such the life of a given appliance is not relevant to the main extension test.

23.1.1 Should the expected life of appliances should be considered when determining the DCF term. Please explain why, or why not.

Response:

No. Please refer to the response to BCUC IR 1.23.1.

23.2 Please discuss the risks and uncertainties in forecasting each of the items in the revenues part of the MX test 40 years out.

Response:

The risks and uncertainties in forecasting each of the items in the revenues part of the MX Test using a 40 years DCF term is the same as using the current 20 DCF term. The MX Test is a tool that the Company uses to provide an assessment of the viability of adding customers to the system at the time of the installation, using the information available at the time. The MX Test is constructed such that the major components identified in Figure 2-1 of the Application are held constant, regardless of the DCF term. For example, the FEI basic and delivery charge, described on page 18 of the Application, is held constant throughout the DCF term, regardless of the length of the DCF term, even though those parameters change each year.

E. CUSTOMER ADDITION TERM

24.0 Reference: CUSTOMER FORECAST PERIOD

Exhibit B-1, Section 3.3.1.3, pp. 37–38; Section 4.1.2, pp. 54–55

Customer forecast period

On page 38 of the Application, FEI states "The EES [EES Consulting Ltd.] survey found that utilities in Saskatchewan and Ontario currently use a 10 year customer forecast window for all projects."

FEI proposes to "use a 10 year horizon for customer attachments in certain circumstances when it can be reasonably demonstrated by the customer or municipality that there is a longer term municipality-accepted plan for growth exceeding five years." FEI then lists five types of data to be used to determine if a planning horizon period greater than 5 years is appropriate for use in the MX Test of a given project. FEI further states that "it is impractical to estimate the rate impact of this recommendation."[34]

On page 54 of the Application, FEI states: "Based on feedback from customers and the Company's experience in the new construction marketplace, FEI estimates that there will be a relatively small number of these main extensions every year. These main extensions are expected to have a higher capital cost than the average main cost which is $11,600."

24.1 Please explain the reason for the difference in application of the 10 year customer forecast period used for all projects in Ontario and Saskatchewan and FEI's proposed approach to use a 10 year customer forecast window in certain circumstances, as outlined in section 4.1.2.1.

Response:

Based on discussions with other utilities, FEI believes that the Company's proposal is not very different from the approach used by other utilities. Union Gas, for example, reported that although they have the ability to use a 10 year customer attachment forecast for all main extensions, the majority of their attachments are forecast in the first few years of the 10 year period.

FEI's proposal is similar, except that the Company is seeking Commission approval to have the ability to use a 10 year forecast on a case-by-case basis in circumstances where there is sufficient indication of potential benefit to customers. FEI believes a 5-year forecast period continues to be appropriate for the majority of main extensions based on feedback from customers and the Company's experience in the new construction marketplace. However, the

[34] Exhibit B-1, Section 4.1.2, p. 55.

Company would not be opposed to applying the 10 year forecast to all main extensions if this solution was preferred by the Commission.

Please refer to the response to BCUC IR 1.2.4 for a description of the two types of main extension projects, new home construction and conversion of existing neighborhoods, and their respective forecasting methods.

24.1.1 Please list and describe the sources and types of data for the 10 year customer addition forecasts used by utilities in Ontario and Saskatchewan in their main extensions test.

Response:

Based on FEI's understanding through discussions with these utilities, there are no differences between the sources and types of data used by the utilities in Ontario and Saskatchewan and those FEI described in section 4.1.2.1 of the Application. Specifically, similar to FEI, the utilities in Ontario and Saskatchewan rely on discussions with their customers as the most important source of data gathering in establishing the customer addition forecast. These utilities also consult municipalities and third party data for sales leads and verification of market potential, as does FEI.

24.1.2 Please explain the differences, if any, between the sources and types of data provided in response to the previous question and those proposed by FEI in Section 4.1.2.1.

Response:

Please refer to the response to BCUC IR 1.24.1.1.

24.2 Please provide an analysis using figures and explanations to show:

(i) the number of mains extensions as a percentage of the total number of main extensions between 2003 and 2013 where a customer forecast period of 10 years would be required based on the circumstance outlined in section 4.1.2; and

(ii) the number of customer attachments as a percentage of the total customer attachments between 2003 and 2013 where a customer forecast period of 10 years would be required based on the circumstance outlined in section 4.1.2.

Response:

It would be impossible and impractical for the Company to assess in hindsight the circumstances of the main extensions completed between 2003 and 2013 to determine which could have qualified for the 10 year forecast and the resulting number of customer attachments for the following reasons.

For the reasons described in response to BCUC IR 1.2.1, it is not possible for the Company to provide accurate and detailed information relating to main extensions prior to 2008.

From 2008 to 2014, 5,492 main extensions were completed by the Company. To review each extension to make the required determination would be time and resource consuming. For example, the determination of whether or not a 10-year customer addition forecast period could apply would have been based on the available information at the time, such as municipal plans, zoning plans discussion with municipal city planners and evidence of commercial commitments having been made with developers. Therefore, to retroactively assess the extent to which a 10-year forecast could have been applied would involve a review of the relevant plans and conversations with developers and municipal planners at the time for each of the 5,492 main extensions completed between 2008 and 2013.

Notwithstanding the difficulties of performing hindsight analysis of historical main extensions, FEI estimates that a small percentage of the average of 785 main extensions installed each year would warrant the use of the 10 year forecast. This high level estimate is derived from past experience of the Company, including the experience of the personnel from the Operations group who design these projects and provide the cost estimates, and from the Marketing group, who are responsible for the customer attachment and load forecasts. The Company estimates a small percentage initially; however, it is uncertain what future usage will be as new customer opportunities may present themselves. i

24.3 Please list and explain the types of data currently used by FEI to forecast customer additions during a planning horizon of up to 5 years.

Response:

As discussed in the response to BCUC IR 1.2.4, the Company relies on discussions with customers and our expertise and knowledge in the regional housing markets to develop reasonable forecasts at the time of installation. The Company also consults other sources such as municipalities' plans and third party market data when making a forecast.

The Company will rely on the same type of information in forecasting customer additions to apply to a MX Test, whether the forecast period be 5 years or 10 years. In reviewing the information, the Company may decide that a 10-year forecast period should be applied because there is a reasonable indication of a planning horizon period that exceeds 5 years.

These practices are consistent with the practices of those utilities in Ontario and Saskatchewan with whom FEI had the opportunity to have a discussion.

24.3.1 Please explain how the data listed in response to the previous question differs from those FEI propose to use to determine if a planning horizon period greater than 5 years is appropriate.

Response:

Please refer to the response to BCUC IR 1.24.3.

24.4 Please discuss the possibility that Municipal Official Community Plans and Zoning plans are modified, updated or replaced during a 10 year period.

Response:

The Company believes it is unlikely that a change or update to a Municipal Official Community Plan (OCP) or Zoning plan would restrict the development of an area that was originally identified or qualified to be developed, particularly if the development process was already

underway. When a municipality identifies in an OCP that an area is going to be developed and re-zoned for residential and/or commercial purposes, the following typically occurs:

- The area is re-zoned by the municipality for residential and commercial purposes and new building permits are made available for that area;
- The owner of the land would receive the necessary building permits based on the zoning and begin development; and
- The Company installs a main extension at the request of the customer, should the customer decide to connect to the Company's main.

In absence of a permit, which would be based on the zoning and the OCP, the main extension could not be installed.

24.5 Is there a threshold or criteria that will be used for each type of the five types of data? For example, what type and how much commercial commitment will be required by the developer to support the decision to use a customer forecast period of greater than 5 years? Please address each of the 5 types of data, providing quantitative examples where applicable.

Response:

There is no proposed threshold or criteria that will be used for each type of data utilized in assessing whether or not a 10 year forecast period is appropriate. FEI is seeking the ability to use a 10 year forecast on a case by case basis. The determination will be a judgment made by considering the relevant information as listed in section 4.1.2.1 of the Application for each main extension to be installed. The decision will be based on all available data at the time the main extension is contemplated and no one threshold/criteria is determinative.

Additionally, the Company has proposed a reporting mechanism, which will allow the Commission to review how the 10-year horizon is applied.

24.6 Please explain if there are any additional risks to current ratepayers associated with extending the forecasting period for customer additions to 10 years.

Response:

The Company does not believe that extending the forecast period for customer additions to 10 years in some projects will create additional risks to the existing customers for two main reasons.

- The Company anticipates the vast majority of MX Tests will continue to use the 5 year planning horizon. The Company will be assessing projects on a case by case basis to establish whether a 10 year horizon is warranted.

- The majority of customer attachments are infill customers over the life of the main, which suggests that in the long run, the uncertainties and risks in terms of customer additions are likely indistinguishable between a 5 year and a 10 year forecast.

Please also refer to the response to BCUC IR 1.13.4.4.

24.6.1 If there are additional risks, please discuss the possibility of using a different P.I. threshold, for example no less than 1.0, for circumstances described in the preamble.

Response:

Please refer to the response to BCUC IR 1.24.6.

24.7 Please explain why the capital costs are expected to increase for projects using a 10 year customer addition forecast in the MX Test as opposed to a 5 year forecast. Is there a change in the length of the main extension pipe?

Response:

For clarification, the Company believes that it could be more cost effective to use a ten versus five year planning horizon to *reduce* capital costs for some projects, not to increase them as suggested in the information request.

In general, a longer customer addition forecast period would allow the Company to service multi-staged subdivision projects more cost effectively in instances where there is sufficient indication of a build out that will exceed 5 years. If sufficient indication exists, the Company

would install one longer main extension in the early stages of a new subdivision development instead of multiple, shorter main extensions over a 10 year period; thus, future road cuts and repairs may be avoided, which could result in a reduction of total capital costs for servicing that subdivision, all else being equal.

24.8 Please discuss how FEI would install a 10 year main. Would FEI install the pipe for the entire main extension all at once or in stages? When would the main go into rate base? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.24.7 for a description of how a main extension would be installed.

There would be no change to the current accounting treatment of an installed main extension, whether a five or ten year forecast period was used in the MX Test.

25.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1.2.1, p. 55

DCF term-meter life

FEI states in its Application: "The Company believes the revenue for these longer horizon system extensions will be more fairly represented using a 10 year horizon. Additionally, the Company expects improvements in the efficiency and cost to install these types of main extensions by taking a longer term view. However, it is impractical to estimate the rate impact of this recommendation."

25.1 Should the portion of the main extension for customers connecting in years 6-10 be treated as Gas Plant Held for Future Use, account 102, until a customer connects to this portion of the main extension? Please explain why, or why not.

Response:

There are alternative classifications which may be appropriate. Based on FEI's review of the BCUC USoA, it appears that continuing to record these amounts in 475 Mains is appropriate. Although the account description for 475 Mains is not as specific as that of 473 Services, which states that the account will include "the cost of stub services run in anticipation of future use, even if such services have never been used", FEI believes the same principles should be applied.

There are other alternatives, such as account 115 Gas Plant Under Construction, as well. Overall, there is little difference to the delivery rates as to where these amounts are recorded – the only impact would be whether they are recorded in a depreciable asset account such as 475 or in a temporary account with no depreciation such as 102 or 115. Overall, FEI does not expect the amounts related to "years 6 to 10" to be material enough to warrant the system changes that would be required to track and record the ins and outs to a separate account for this component, and that the costs of this would outweigh the benefits of any delayed depreciation that would result.

25.2 Please discuss how FEI would go about installing a 10 year main. Would FEI install the pipe for the entire main extension all at once or in stages? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.24.7 for a description of how a main extension would be installed.

25.3 Please explain how main and service lines sizes are determined. In most cases, would a 10 year main be expected to be bigger than a 5 year main? Please elaborate.

Response:

A service line is usually serving one premise. Thus, it is sized in accordance with the expected load of the premise to be served.

The size of a main will take into consideration the expected loads extending from the main over the life of the main. Thus, a new main is not sized just to serve the currently expected load, but also the potential loads served over the life of the main based on a reasonable forecast. Given the expected life of a main, a main with a 5-year or 10-year horizon for customer attachments may make little difference in terms of the size of the main. Further, in situations where a larger pipe size is required for future capacity requirements, this incremental cost is generally minimal as a percentage of the total project.

F. SLIDING SCALE OVERHEAD RATE

26.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, Section 3.3.1.4, Figure 3-3, p. 39

Sliding scale overhead calculation

26.1 Please provide the fully functional spreadsheet used to generate the graph in Figure 3-3.

Response:

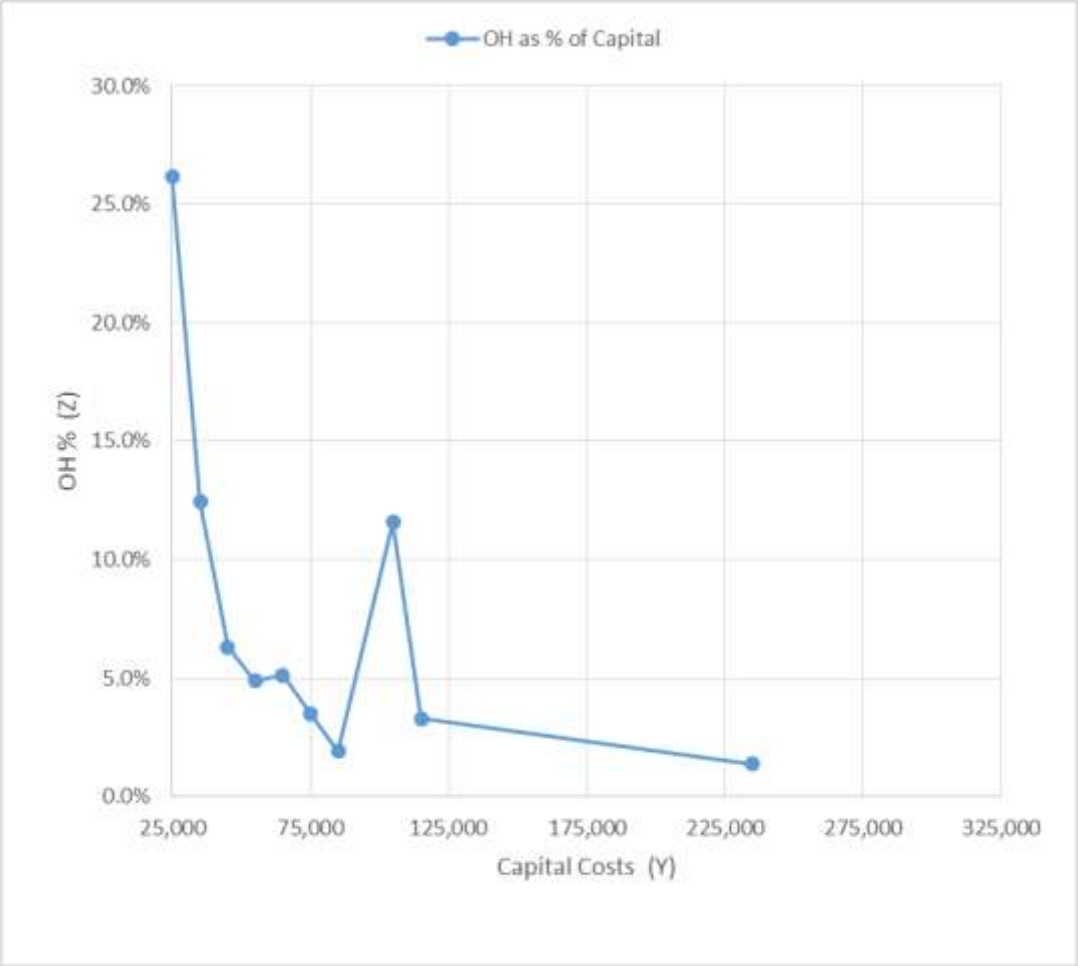
Please refer to Attachment 26.1 for the fully functional spreadsheet.

26.2 Please recalculate graph in Figure 3-3 for the period 2010-2014 by year. Also include a fully functional electronic spreadsheet showing the calculations.

Response:

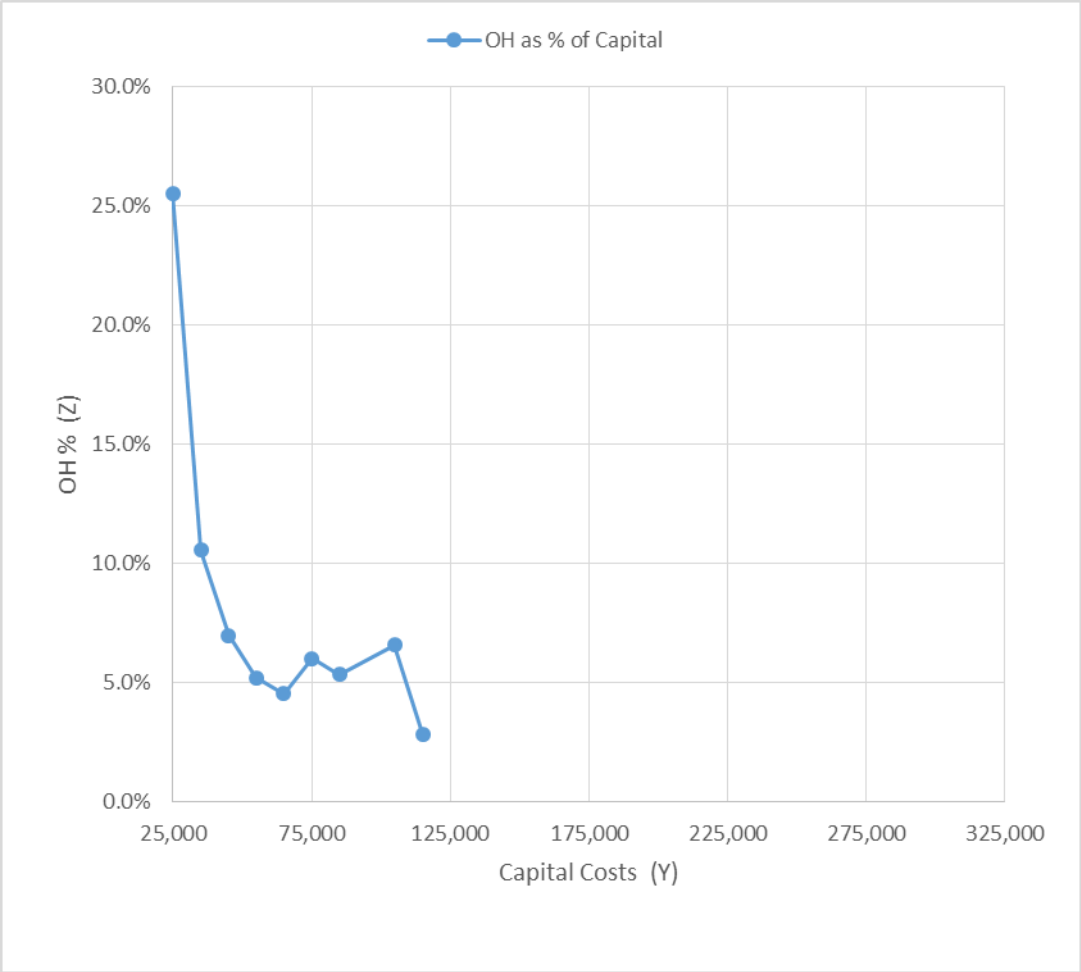
Figure 3-3 for the years 2010 – 2014 is provide below. Please refer to Attachment 26.2 for the fully functional spreadsheet.

1 ***2010***


OH as % of Capital
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
OH % (Z)
25,000
75,000
125,000
175,000
225,000
275,000
325,000
Capital Costs (Y)

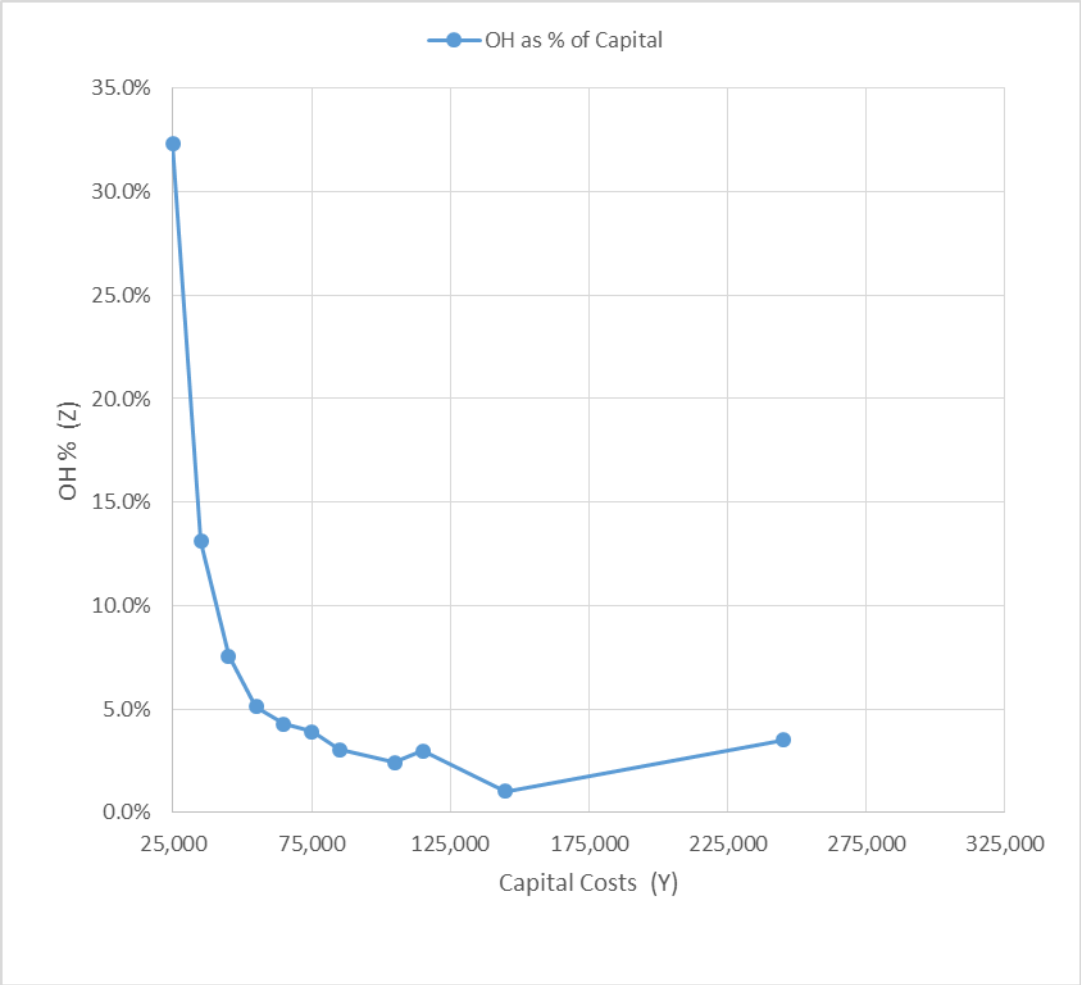
2

1 ***2011***


OH as % of Capital
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
OH % (Z)
25,000
75,000
125,000
175,000
225,000
275,000
325,000
Capital Costs (Y)

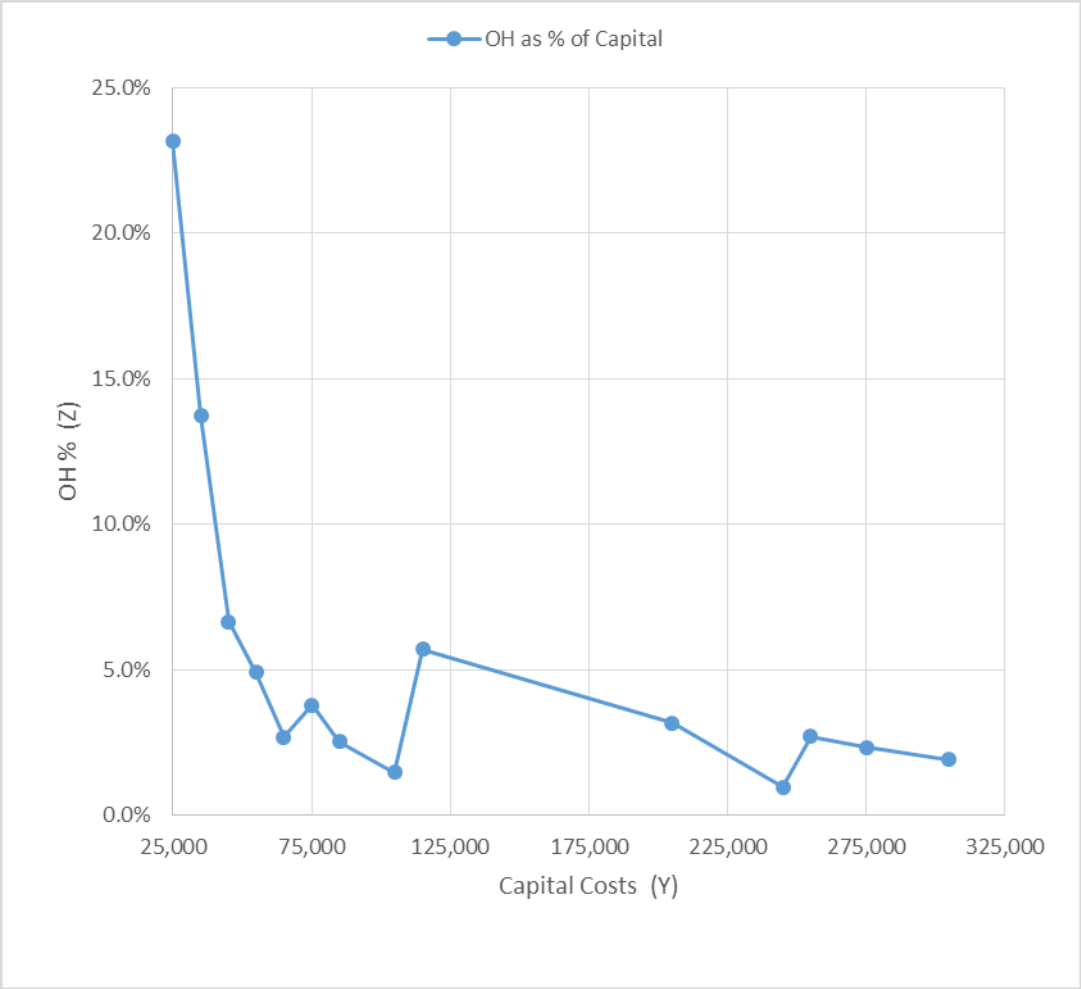
2

1 ***2012***


OH as % of Capital
35.0%
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
OH % (Z)
25,000
75,000
125,000
175,000
225,000
275,000
325,000
Capital Costs (Y)

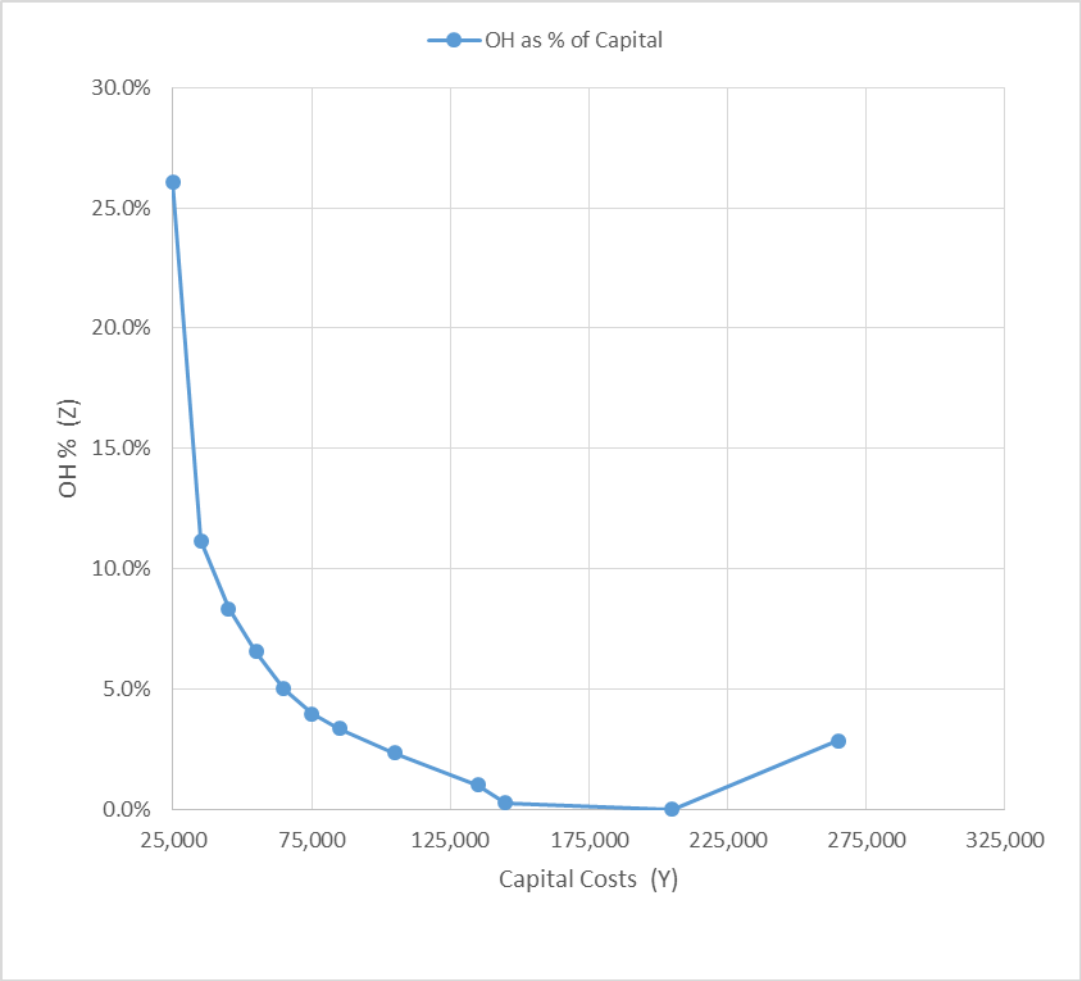
2

1 ***2013***


OH as % of Capital
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
OH % (Z)
25,000
75,000
125,000
175,000
225,000
275,000
325,000
Capital Costs (Y)

2

1 ***2014***


OH as % of Capital
30.0%
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
OH % (Z)
25,000
75,000
125,000
175,000
225,000
275,000
325,000
Capital Costs (Y)

2

3

27.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1-4.1.3.2, pp. 56–58

Sliding scale overhead calculation

27.1 Please explain the methodology used to determine the Sliding Scale Overhead formula and provide the standard error of the estimate.

Response:

FEI modeled linear, log10, natural log and exponential scales in an attempt to create a curve that best fit the data to determine the Sliding Scale Overhead formula. FEI found an exponentially declining curve with a minimum (floor) overhead rate and exponential slope of -0.963 to be the best fit to calculate an overhead rate that was slightly (conservatively) greater than the data suggests. The standard error of the estimate is 0.0349.

27.2 Please explain how FEI proposes to update the Sliding Scale Overhead formula on an annual basis.

Response:

FEI does not plan on updating the sliding scale formula on an annual basis. FEI will apply the formula as set out in section 4.1.3 of the Application.

27.3 Please complete the table below for mains (account 475), services (account (473) and meters (account 474) and provide the response as a fully functional electronic spreadsheet.

Capitalized Overhead - Mains

($000's)

Year	Actual Additions	Actual Overhead Capitalized	Cap O/H % of Additions	Forecast Additions per MX Test	Forecast MX Test Cap O/H	Forecast Cap O/H % of MX Additions
2008	14,567	6,412	44%	10,000	3,300	33%
2009						
2010						
2011						
2012						
2013						
2014						

Response:

FEI is unable to provide the requested information isolated to MX additions; however, the following tables provide the additions and allocated overhead to accounts 475 - Mains, 473 - Services and 474 - Meters in total for FEI for the years 2008 through 2014. Please refer to Attachment 27.3 for the fully functional electronic spreadsheet.

The capitalized overhead allocated to these asset classes is not comparable to the overhead applicable to the MX test, both because of the components of the overhead and because of the methodology. The percentage allocated in each year to each asset class will vary depending on the capitalized overhead rate, the level of O&M, and the capital additions to each asset class in the year. This process for allocating capitalized overhead to the various asset classes is explained in the response to BCUC IR 1.29.1.

FEI

Capitalized Overhead - Mains

($000's)

Year	Actual Additions	Allocated Overhead Capitalized	Cap O/H % of Additions
2008	18,609	7,571	41%
2009	19,977	9,109	46%
2010	13,260	7,374	56%
2011	14,567	6,412	44%
2012	14,813	5,843	39%
2013	21,590	7,604	35%
2014	20,599	6,632	32%
Total	123,415	50,545	41%

Capitalized Overhead - Services

($000's)

Year	Actual Additions	Allocated Overhead Capitalized	Cap O/H % of Additions
2008	21,585	11,669	54%
2009	16,440	8,356	51%
2010	17,475	8,859	51%
2011	21,513	7,898	37%
2012	24,302	10,142	42%
2013	25,994	9,013	35%
2014	26,924	8,671	32%
Total	154,233	64,608	42%

Capitalized Overhead - Meters

($000's)

Year	Actual Additions	Allocated Overhead Capitalized	Cap O/H % of Additions
2008	8,000	0	0%
2009	8,628	0	0%
2010	8,305	0	0%
2011	10,509	0	0%
2012	10,956	0	0%
2013	11,569	0	0%
2014	10,339	0	0%
Total	68,306	0	0%

Capitalized Overhead - Mains, Services & Meters

($000's)

Year	Actual Additions	Allocated Overhead Capitalized	Cap O/H % of Additions
2008	48,194	19,240	40%
2009	45,045	17,465	39%
2010	39,040	16,233	42%
2011	46,589	14,310	31%
2012	50,071	15,985	32%
2013	59,153	16,617	28%
2014	57,862	15,303	26%
Total	345,954	115,153	33%

1

2

28.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.1.3.1, Table 4-4, p. 58

Sliding scale overhead calculation

28.1 The difference between the fixed annual rate overhead rate and the sliding scale overhead calculation in Table 4-4 is $1.605 million. Please calculate the sliding scale overhead that would be required to eliminate the $1.605 million difference.

Response:

The $1.605 million difference should not be eliminated. As described in section 3.3.1.4 of the Application, the overhead cost currently embedded in the test for large projects is greater than the incremental overhead costs expected to be incurred. The proposed sliding scale methodology is expected to result in an overhead cost that is more reflective of the incremental overhead cost incurred.

Thus, the $1.605 million is better described as a retrospective look at the difference in the overheads that *would have* been allocated within the MX Test if the sliding scale had been in place comparing to the fixed overhead rate that was in place. Therefore, there is no sliding scale overhead rate that could eliminate the $1.605 million difference; only by re-applying the fixed overhead would the difference of $1.605 million be eliminated. Further, while manipulating either the capital threshold or the floor could result in varying overhead amounts and potentially reducing the $1.605 million, FEI believes that the proposed capital cost threshold of $25 thousand and the 5% floor result in overhead costs embedded in the test that are a better indication of the overhead costs expected to be incurred.

29.0 Reference: APPENDIX A
Exhibit B-1, Appendix A, Attachment 2, p. 12
Sliding scale overhead calculation

FEI states in Appendix A: "For consistency purposes, we believe it is appropriate for the amount of overheads added to the costs used in the MX test to be comparable to the overheads capitalized as part of the amount placed in rate base."

29.1 Is the sliding scale overhead methodology consistent with calculation of overheads capitalized as part of the amount placed in rate base (i.e. a lower overhead rate is applied to larger projects)? Please explain why, or why not.

Response:

Yes, the result of the sliding scale overhead methodology is generally consistent with the approach to capitalizing overhead to amounts placed in rate base.

The methodology for calculating and applying capitalized overhead was explained on page 286 and 287 of FEI's PBR Application as follows:

> *Capitalized overhead is calculated by applying the overhead capitalization rate of 14 percent to Gross Operations & Maintenance (O&M net of direct charges to capital and other non-O&M accounts). Capitalized overhead is then charged on a pro rata basis (based on capital additions in the period) to the appropriate asset account. CPCN projects do not attract capitalized overhead as any overhead required for the CPCN is directly charged to the project. Similarly some other asset accounts such as land, land rights, general plant assets and meters do not attract capitalized overhead.*

For FEI's regular capital expenditures, capitalized overhead is applied at the asset class level rather than at the project level, with the result that each asset class that is subject to overheads capitalized will be allocated a similar percent in any given year.[35] As noted above, FEI excludes from its overheads capitalized treatment CPCNs and other large capital projects and instead allocates overhead costs directly to these larger projects. This is to avoid skewing the amounts that are allocated to the regular capital expenditures, and because the fixed costs for these large projects are lower as a percentage of the total capital cost.

The capitalized overheads methodology for regular capital expenditures is a simplified approach that applies overhead at a class level rather than a project level; it is not applied at a granular enough level to reflect different percentages of overhead being applied to individual projects depending on their size. However, there is an implicit recognition that larger projects have a lower percentage of overheads in FEI's treatment of CPCNs and other large capital projects.

[35] The allocated percent may change depending on changes in the overall mix of assets over time

G. SERVICE LINE COST ALLOWANCE

30.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.2.2, p. 62

Service Line Cost Allowance (SLCA)

In section 4.2.2, FEI states: "...68.3 GJ is a scenario representing the normalized average annual consumption of residential customers that connected to FEI's system between 2008 and 2014."

30.1 Please explain why FEI is using the normalized average annual consumption of residential customers between 2008 and 2014 to calculate the SLCA, when the 1996 and 2007 analysis used the consumption for only the most recent year.

Response:

The 1996, 2007 and 2015 SLCA analyses all used the normalized average annual consumption of residential customers for the most recent year. The 2007 analysis also factored in theoretical sensitivity scenarios to address the decline in annual use. The 2015 analysis improved on the 2007 analysis by providing actual data to reflect the decline in annual use.

The Company has included an excerpt from the 2007 SLCA analysis and provides further clarification below.

> *"As in the 1996 test, this calculation of the maximum allowance was based on the average normalized consumption across TGI's residential customer base. Since 1996, however, TGI has experienced a decline in the average annual use rate which is expected to continue as customers upgrade to higher efficiency appliances and also as a result of a higher proportion of multi-family homes associated with new customer connections. In order to address the decline in annual use rates sensitivity scenarios were also run assuming annual consumption of 90 and 80 GJ's"*[36]

Scenarios of 66 and 61 GJs for TGVI customers were also provided to theoretically represent the decline in annual use. In Order G-152-07, the Commission determined the scenarios that corresponded to 80 GJ for TGI and 61 GJ for TGVI were most appropriate.

In the 2015 SLCA analysis, the Company used the actual (vs. theoretical) normalized average annual consumption for customers that attached from 2008 to 2014 to account for the decline in annual use. This methodology is consistent with the 2007 SLCA analysis approved by the Commission and more accurately characterizes the decline in annual use.

[36] Terasen Gas Inc. (TGI)-Terasen Gas (Vancouver Island) Inc. (TGVI) System Extension and Customer Connection Policy Changes – July 31, 2007 p14.

30.2 Please recalculate Table 4-7 using the normalized average annual consumption of residential customers that connected to FEI and FEVI in 2014.

Response:

For the SLCA analysis, the Company used the normalized average annual consumption for the 2008-2014 residential customer additions to ensure a representative average consumption value that reflects all FEI regions and residential building types.

The Company cannot recalculate Table 4-7 using the normalized average annual consumption of residential customers that connected to FEI and FEVI in 2014 because:

- The majority of 2014 customers do not yet have a full year's worth of consumption to calculate an average.[37]
- The remaining customers cannot be considered a representative sample since the full population 2014 customers is not available to choose from.

Furthermore, the majority (nearly half) of the 600 services with enough consumption happen to be multi-meter services installed in the Lower Mainland. This will present a skewed result since it would not contain a full mixture of the residential buildings connected with gas in the year.

30.3 In Table 4-6, the 2007 FEI Mainland consumption of 80 GJ results in a Maximum allowance of $1,535 and the 2014 consumption of 68.3 GJ results in a Maximum allowance of $2,150. Please explain why the lower 2014 consumption results in a higher service line Maximum allowance.

Response:

There is no direct correlation between customer consumption and the Service Line Cost Allowance (SLCA) amount as the question suggests. Rather, the SLCA amount is correlated to a "target average service line cost". The higher the target average service line cost, the bigger the SLCA amount. However, the increase of the SLCA results from the change of rates and the MX Test parameters, not from one single factor. This is further explained below.

[37] Approximately 11,400/12,000 did not have a full year's worth of consumption available at the time the data was pulled together for the Application. (Early 2015).

To determine what the SLCA amount should be, the Company calculates a ”target average service line cost” using the MX Test, which uses all of the same inputs (prevailing rates, property tax, etc.) used in the MX formula for the time period considered. In a typical MX test, the expected revenues and costs for mains, meters and service lines are input into the MX Test formula (along with the other MX test inputs) to calculate an expected PI result. In the calculation of the “target average service line cost”, the expected revenues and average costs for mains and meters are input into the MX test formula, but the average costs for service lines are left out. In this calculation, this PI result in the formula is also set to equal 1.0. In this way, the Company is able to isolate and determine what the average cost for service lines in the MX test formula needs to be in order to yield the 1.0 PI result. The resulting amount is the ‘target average service line cost’.

Since this “target average service line cost” is calculated to ensure a PI result of 1.0, it indicates what the maximum average cost of a service line connection can be for the Company before existing customers are impacted negatively. This figure is compared to the actual average cost the Company invested over the same period. A ‘target average service line cost’ that exceeds the actual average cost the Company invested over the same period indicates that the Company can contribute more to service line installations. That is, the Company is able to spend more on each service line connection, in order to raise the actual average cost of a service line to equal the “target average service line cost”.

In the most current SLCA analysis for the 2008 and 2014 period, the “target average service line cost” exceeded the actual average cost the Company incurred for a service line installation. The main MX Test inputs that impacted this are illustrated in the table below. Through the SLCA analysis, the Company was able to determine that it could spend $2,150 per service line connection in order to raise the actual average cost the Company incurred to equal the ‘target average service line cost.’

The MX test used in the 1996 and 2007 SLCA analyses was reflective of customer rates and economic test parameters at the time the analysis was conducted and was updated with the average main cost and consumption at that time. For this reasons, those results are unrelated to the analysis conducted for this Application.

The table below highlights some of the primary MX test parameters from 2007 to 2014 to explain the increases in the target average service line cost and the resulting SLCA amount.

		2007 MX Test	2015 MX Test	Change	
FEI Residential Rate 1	Fixed Charge	$ 131.28	$ 142.08	$ 10.80	increases MX test revenue
	Variable Charge	$ 2.74	$ 4.22	$ 1.48	increases MX test revenue
MX Test Parameters	Overhead Rate	32%	23.3%	-8.7%	decreases MX test cost
	Income Tax Rate	33%	26%	-7.0%	increases MX test revenue

The table above illustrates that both the fixed and variable charge for residential rates have increased since 2007. The increase in rates has more than offset the decline in average consumption for a residential customer since 2007.

H. ENERGY EFFICIENCY CREDITS

31.0 Reference: ENERGY EFFICIENCY CREDITS

Exhibit B-1, Section 4.1.4, pp. 58–59

FEI's demand side management program

On page 58 of the Application, FEI proposes to eliminate the use of energy efficiency credits reasoning that energy efficiency is now being driven by their demand side management (DSM) program.

31.1 Please outline the aspect of the DSM program which incentivizes new customer attachments (i) for using high efficiency gas-fired space heating and water heating appliances; and (ii) for attaining LEED General Certification.

Response:

While DSM programs are available for new construction projects, they are not specifically intended to incentivize new customer attachments. Rather, they incentivize the efficient use of natural gas.

A table of DSM programs relating to gas-fired space heating and water heating appliances is provided below.

Customer Class	Incentive Amount ($)	Qualifying DSM Measure	DSM Program Name
Space Heating			
Residential	300	EnerChoice® Fireplaces	New Home Program[1]
Commercial	Up to 45,000 per boiler	Eligible Boilers	Efficient Boiler Program[2] & Commercial Custom Design Program[3]
Whole Home			
Residential	250 to 2,000	Single Family Dwellings & Rowhomes built to ENERGY STAR® for New Homes	New Home Program[1]
	250	Laneway Homes rated at least EnerGuide® 82	New Home Program[1]
Water Heating			
Residential	200	0.67 EF Storage Tank	New Home Program[1]
	400	Non-Condensing Tankless	New Home Program[1]
	500	Condensing Tankless & Hybrid	New Home Program[1]
	1,000	Condensing Storage Tank	New Home Program[1]
Commercial	Up to 15,000 per water heater	Eligible Water Heaters	Efficient Commercial Water Heater Program[4]

In addition, the Switch and Shrink program provides an incentive of $1,000 to customers who replace an existing oil or propane heating system with a high efficiency natural gas system. More information on this program can be found here:

http://www.fortisbc.com/NaturalGas/Homes/Offers/SwitchNShrink/Pages/default.aspx.

There are no DSM incentives provided for attaining LEED General Certification.

[38] http://www.fortisbc.com/NaturalGas/Homes/Offers/NewHomeProgram/Pages/default.aspx.

[39] http://www.fortisbc.com/NaturalGas/Business/Offers/EfficientBoilerProgram/Pages/default.aspx.

[40] http://www.fortisbc.com/NaturalGas/BuildingProfessionsTrades/IncentivePrograms/CommercialCustomDesignProgramNewConstruction/Pages/default.aspx.

[41] http://www.fortisbc.com/NaturalGas/Business/Offers/Pages/EfficientCommercialWaterHeaterProgram.aspx.

I. REPORTING METHODOLOGY – ANNUAL REPORTING

32.0 Reference: APPROVALS SOUGHT

Exhibit B-1, Section 1.1, p. 3; Section 4.1.2, Figure 4-1, pp. 54, 55; Section 3.2.4.2, p. 32; Decision for TGVI TGI 2007 System Extension & Customer Connection Policies Review Proceeding (2007 Decision), p. 35

Reporting

On page 3 of the Application, FEI requests:

> 3. Effective with the reporting on 2015 main extensions:
>
> a. The discontinued use of the current MX reporting requirements.
>
> b. To provide a Report to the Commission at the end of the first quarter for the preceding year's main extensions that includes:
>
> i. The total number of main extensions completed, including the total actual costs for main extensions completed; the forecast PI for all main extensions in aggregate; the total number of customers providing a CIAC, including the total dollar value of CIAC. For main extensions using a 10-year customer addition forecast period, the number of main extensions, the actual costs and the total number and dollar value of CIAC will be provided separately from the total main extensions.
>
> ii. The total number of approved requests to access the System Extension Fund, including the total dollar value of the approved requests; and
>
> iii. Updated MX Test input parameters consistent with approved practices, for implementation January 1 of the following year.

On page 42 of the Application, FEI quotes the Core Review:

> The BCUC should make additional efforts to ensure all compliance reports are necessary and useful, and eliminate the reporting requirement for those that are not. The BCUC should place more responsibility on regulated entities to report, on an exception basis, deviations from forecasts that could affect costs and rates, instead of routine reporting.

32.1 Please provide a sample annual report in the form FEI proposes to submit to the Commission annually using 2013 MX results.

Response:

The objective of the MX reporting is to allow the Commission to review whether the Company has complied with the application of the MX Test and "to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1" (2007 Decision, at page 37).

Consistent with the spirit of the Core Review, the MX Reporting should allow the Commission to have sufficient oversight over the main extensions installed in a given year, but without an undue administrative burden to the reporting utility. In other words, the information requested for reporting should be useful for its intended purpose. As explained in section 3.4.2 of the Application, the main problem with the current reporting requirements is that the Commission is using the MX reporting information for a purpose for which it should not be used..

The Company has included a sample report as requested in Attachment 32.1 using 2013 data where possible. Below is a brief description of the major components of the proposed MX report and a discussion of how the components serve the purposes of MX reporting outlined above.

Forecast PI

The Company will report on the forecast aggregate PI for all main extensions (i.e., the entire population) for which a MX test was run in a given year.

Reporting on the forecast aggregate PI will allow the Commission to review whether the MX Test was applied as approved and to determine if the aggregate PI thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1.

Main Extension Test Parameter Update

The updated MX Test parameters will be provided to the Commission to demonstrate that the Company used the inputs to the MX Test, as approved by the Commission. For clarity, currently the parameters have been updated to the year for which the report relates. For instance, for the 2014 MX report that is filed in March 2015, the updated 2014 parameters are provided.

Main Extension Installation Activity

This section will include information on:

1. total number of main extensions completed in a given year;
2. total costs for those completed mains;
3. the number of customers providing a CIAC and the dollar value of the CIAC; and,

4. the number of main extensions using a 10 year customer addition forecast, and the actual cost and CIAC amounts (if any) associated with those main extensions.

This information will allow the Commission to have sufficient oversight over the Company's main extension activities in a given year, such as the total capital investments in main extensions completed by the Company.

System Extension Fund Activity

FEI will provide the total number and value of approved system extension requests to access the Fund for the reporting year. Given this is a new proposed program for the Company's system extension policies, the reported information will allow the Commission sufficient oversight to assess whether the Fund has been utilized and the extent of the Fund's utilization.

Service Line and Meter Installation Activity

The Company will provide the total number and costs for all new service line installations in a given year. By including the service line installations in addition to the mains installations, the Commission will have a fuller picture of capital expenditures and customer additions.

Timing of the MX Report

The Company proposes to continue to submit the annual report by the end of the first quarter of the following year. All mains, services and meter information in the report available at the time of the report will be included based on the field complete (FCMP) date. The FCMP date represents the actual date the infrastructure was installed.

The Company believes that the proposed MX annual report will allow the Commission to review whether a forecast PI of 1.1 has been achieved, whether FEI has been using Commission approved MX Test parameters, and whether the approved PI threshold is still appropriate on a going forward basis. The proposed report would also provide certain actual data pertaining to the main extensions installed in a given year on an aggregate basis, the system extension fund and the main extensions with 10 year customer addition forecast, which would allow the Commission to review the capital investments made by the Company and the usage of the two programs (SEF and 10 year forecast) following their introduction to customers.

Please refer to the response to BCUC IR 1.32.7.1 for a discussion of why reporting at a more granular level (e.g. on an extension by extension or service line by service line basis) will not be necessary or useful.

32.2 Please provide the number of hours spent preparing and the cost of preparing each MX Report from 2008 through 2014, including only preparation costs and

not extraneous activities such as the EES reports, the consultation activities for this application and these application costs.

Response:

Previously, MX Reports contained a small number of tables designed to provide the Commission with aggregate MX test information to determine if the Company was using the MX test appropriately. For instance, the 2008 MX report had 15 tables and took a small amount of resources to complete. The current annual MX reporting consists of 175 individual data tables and takes one highly specialized employee approximately 3 months to complete, assuming a 5 day work week and 100% of the workload is dedicated to the annual MX Report. In addition, the Company must draw upon internal resources across the organization to produce the current MX Report, including assistance from the Forecasting, GIS-Mapping, Information Systems, Operations, Sales, Marketing and Regulatory departments.

In total, the Company estimates the preparation of the current format of the MX Report, excluding extraneous activities as requested, requires approximately 500 labor hours, costing approximately $100,000 annually to produce. This is an estimation based on quantifying the annual resources required to produce the MX Report.

The table below provides an approximation of the requested data for the preparation of a MX Report.

Resource Required	Task	Estimated Labor Hours	Approximate Cost
Manager	1. Gathering and Confirming Annual MX Test information 2. Re-Forecast MX test inputs and PI's 3. Produce Report 4. Regulatory Review	380 Includes regulatory review	~$65,000 includes regulatory review
IT Specialist	5. Extracting all details for each MX Test from IT Systems	120	$5,000
SAP Analyst	6. Produce actual cost and mains information		$6,000
GIS Specialist	7. Matching forecasted mains to installed mains to installed attachments		$20,000
Forecasting Analyst	8. Producing annual average consumption by rate class for attachments on particular main extensions		$4,000
Total		**500**	**~$100,000**

32.3 Please provide the costs of this application and explain how FEI plans to account for these costs.

Response:

For the preparation, filing and review of the 2015 System Extension Application, the Company estimates it will incur approximately $325,000 in costs. These costs are associated with consulting and legal fees, intervener and participant funding costs, Commission costs and miscellaneous facilities, stationery and supplies.

In its Application for the Annual Review for 2016 Rates, the Company has requested to recover these costs through a rate base deferral account, the 2015 System Extension Application account, amortized over a two year period beginning in 2016.

32.4 Please estimate the number of hours and the costs FEI expects to spend preparing the proposed annual reports, and separately, the proposed Rate Impact Analysis reports.

Response:

In consideration of the data tables currently required for the MX Report, the Company expects to incur significant savings related to a reduction in the number of data tables and the amount of time spent on matching, re-forecasting and re-calculating individual MX tests. These savings will be in the form of reduced unpaid overtime, and an ability to focus the existing resources on other value added projects.

Annual Reports

Based on the items proposed to be reported in the annual MX Report, the Company estimates it will cost approximately $10,000 to prepare the report as set out in the following table.

Resource Required	Existing Task	Existing Estimated Labour Hours	Approximate Cost
Manager	1. Gathering and Confirming Annual MX Test information 2. Produce Report and Aggregate PI Calculation 3. Regulatory Review	25 (includes regulatory review)	$4,000 (includes regulatory review)
IT Specialist	4. Extracting all details for each MX Test from IT Systems	20	$2,500
SAP Analyst	5. Produce actual cost for all service, mains and meter installations		$3,500
Total		**45**	**$10,000**

Rate Impact analysis

Given that Rate Impact model has already been developed and the majority of the input data required for the rate impact analysis will have already been gathered through the annual MX Reporting, the Company estimates $15,000 to periodically produce this analysis. The table below provides an approximation of the number hours and costs required to conduct the Rate Impact Analysis.

Resource Required	Existing Task	Existing Estimated Labour Hours	Approximate Cost
Manager	1. Update Rate Impact model with cost, and attachment information 2. Regulatory Review	55	$10,000
SAP Analyst	3. Extract total number of customers attaching to mains and services included in Rate Impact analysis	20	$2,000
Forecasting Analyst	4. Produce the actual average use per customer based on new customer additions		$3,000
Total		**75**	**$15,000**

32.5 Please explain how the costs of FEI's proposed changes to the reporting regime would affect PBR.

Response:

FEI does not anticipate any incremental O&M savings as a result of the reporting changes being proposed. Savings will be in the form of reduced unpaid overtime, and an ability to focus the existing resources on other value added projects.

Under the PBR, the Company is encouraged to find efficiencies. If there were any O&M savings they would properly be the subject of earnings sharing under the PBR framework. As such, no changes to the PBR are required.

The 2007 Decision highlighted that Terasen [now FEI] stated the following in its Reply Argument:

> Due to the significant work that is involved in using the entire population of main extensions, the Companies propose to use only a sample of the main extensions completed to review in order to determine if the aggregate PI is above 1.1. … The Companies are in the planning stages to make modifications to the information systems will also enable the Companies to use the entire population of main extensions in a given year to determine the aggregate PI without significant manual involvement. However, at the present time, the Companies believe that a sample population will provide the best compromise between the costs associated with the administrative burden related to the amount of work involved and the accuracy of the result.[42]

32.6 Please confirm, otherwise explain, that FEI has completed the modifications referenced in the preamble.

Response:

Confirmed.

32.6.1 If confirmed, is population data currently available for MX performance reporting?

Response:

Yes.

32.7 Please confirm that FEI has the capability to and does track:

i. actual capital costs for each main extension;
ii. forecast capital costs for each main extension;
iii. actual costs for each service line;
iv. forecast costs for each service line;

[42] 2007 Decision, p. 35.

v. actual total costs for service line connections;

vi. forecast total costs for service line connections;

vii. forecast number of connections per main extension;

viii. actual number of connections per main extension;

ix. forecast PI for each main extension;

x. forecast use per customer (i.e. not the "credit" inputs to the PI test, but what FEI believes will actually be consumed), individually or in aggregate, for each main extension; and

xi. actual use per customer, individually of in aggregate, for each main extension.

Response:

FEI has the capability to, and does track items 'i' to 'ix'. These types of data are currently provided in the annual MX Reports.

FEI also forecasts use per customer and tracks actual use per customer. However, as discussed in the response to BCUC IR 1.4.2, the Company does not have the capability to develop and track the forecast or actual use per customer on a per appliance basis (currently the MX Test accounts for consumption on a per appliance basis using values from the REUS).

32.7.1 If any of these are confirmed please explain why FEI is not proposing to report on this information to the Commission.

Response:

Although the information requested in the above list may be generated by the Company in the MX Report, reporting at a more granular level (such as extension by extension reporting on variances between forecasts and actuals) than what is proposed by the Company is not appropriate for the reasons discussed below. Thus, the Company does not believe the information requested in the above list should be part of the annual MX reporting.

Inconsistency with the Core Review Recommendation

A more granular level of reporting is inconsistent with the recommendations of the Core Review. For convenience, the Core Review's specific recommendation with respect to the requirements for compliance reporting is cited below:

"The BCUC should make additional efforts to ensure all compliance reports are necessary and useful, and eliminate the reporting requirement for those that are not. The BCUC should place more responsibility on regulated entities to report, on an exception basis, deviations from forecasts that could affect costs and rates, instead of routine reporting."

The above recommendation made the following two points clear: First, unnecessary or low value information should not be part of the compliance reporting requirements. Second, deviations from forecasts are not part of the routine reporting; rather, they are done "on an exception basis."

The information requested by the Commission focuses on "actual" and "forecast" costs or numbers for each main, each service line, and each connection. The Company does not see how providing such reporting meets the language of "on an exception basis." Nor does FEI see how such information is useful, except the possibility that the information can be used to support a position that the forecasts and actuals are different on a very granular level (however, broadly speaking it would be expected that forecasts and actuals are always different).

To the extent that the requested information will be used for interpreting the Company's forecasting performance, the performance of main extensions and, more generally, the impact on existing customers, the information will lead to misleading results. Section 5.4.2.2 of the Application offers further explanation. In brief, the true economic performance of a main is not known until or near the end of the life of the main, given that customers continue to attach to the main throughout the main's life.

Efficiency and Cost Effectiveness

As suggested in the Core Review, efficiency and cost effectiveness are factors that should be weighed when the Commission sets reporting requirements. Efficiency would not be achieved if reporting on the information listed in BCUC IR 1.32.7 and other IRs (e.g. BCUC IR 1.32.9 to 1.32.13) will be required. As indicated in the responses to BCUC IR 1.32.2 and 1.32.4, granular level reporting requires much more resources and costs substantially more, comparing to the costs and resources required for providing the report as proposed by the Company in this Application. It goes well beyond the level of reporting that makes sense given the number and average size of the extensions. Between 2008 and 2014, 5,492 mains were installed by the Company, thus averaging 785 extensions per year. The average size and cost of these extensions is small, with the average main extension cost being $11,600 and 97% of all main extension costs below $50,000.

Despite the resources invested, the information generated will provide little useful information for reviewing the Company's forecasting performance, the performance of main extensions and, more generally, the impact on existing customer, as discussed above. Whereas as discussed in the response to BCUC IR 1.32.1, the Company's proposed approach to reporting achieves the

MX reporting purposes in a manner that provides the Commission with sufficient oversight and is not administratively burdensome.

Evaluation of Main Extension Activities

The Company understands the Commission has oversight over the Company's main extension activities and thus has proposed to report information such as the total number of main extensions completed and the total actual costs for all main extensions completed in a given year.

Coupled with the annual reporting, the Company has proposed a separate process, informed by the Rate Impact analysis. The Rate Impact analysis allows the Commission to review periodically the aggregate impact on customer rates from adding new customers over a period of time.

As a part of the Rate Impact analysis and periodic review, the Company will be tracking and providing to the Commission the following in aggregate for a given period:

1. Capital costs for each main extension, service line and meter;
2. Customer connections per main extension;
3. Customer usage by rate class; and
4. Estimated rate impact on customers.

With the annual reporting and periodic Rate Impact analysis together, the Company will be confirming that the MX Test has been applied as approved by the Commission, and assessing whether the test itself is balancing interests of new and existing customers over a longer time frame..

32.7.2 If any of these are not confirmed please explain why not.

Response:

Please refer to the response to BCUC IR 1.32.7.

32.8 Please discuss the pros and cons of reporting each of the above information to the Commission.

Response:

Please refer to the response to BCUC IR 1.32.7.1.

32.9 Please confirm, otherwise explain, that with the actual capital cost for each main extension and the forecast capital costs for each main extension, one could evaluate and trend FEI's cost estimate forecasting performance for main extensions, and identify deviations from forecasts that affect costs and rates.

Response:

This response also addresses BCUC IRs 1.32.10, 1.32.11, 1.32.12, and 1.32.13.

If viewed over a long enough period of time and the proper contextual considerations are factored in, the forecast to actual variance of the capital cost, service line and customer connections could provide indication of FEI's forecasting performance trend that may have an effect on costs and rates. However, the Company believes the Rate Impact analysis provides a more efficient, insightful means to assess the impact of capital growth on customer rates.

The Company does not consider the consumption used in the MX Test to be a forecast, instead it is a credit. Therefore, the Company does not believe a comparison of a consumption credit to actual consumption would provide any meaningful insights into forecasting performance. A more meaningful comparison would be to compare how the use per customer credit derived from the REUS has been going down over time.

Please also refer to the response to BCUC IR 1.32.7.1 for reasons why reporting deviations at the granular level does not provide useful information to assess the economic viability of main extensions.

32.10 Please confirm, otherwise explain, that with the actual service line cost for each connection and the forecast service line cost for each connection, one could evaluate and trend FEI's cost estimate forecasting performance for service lines, and identity deviations from forecasts that affect costs and rates.

Response:

Please refer to the response to BCUC IR 1.32.9.

32.11 Please confirm, otherwise explain, that with the actual number of connections and the forecast number of connections, one could evaluate and trend FEI's connection forecasting performance, and identify deviations from forecasts that affect costs and rates.

Response:

Please refer to the response to BCUC IR 1.32.9.

32.12 Please confirm, otherwise explain, that with the forecast total service line costs and the actual total service line costs, one could evaluate and trend FEI's forecasting performance on the average cost per service line in each year, and identify deviations from forecasts that affect costs and rates.

Response:

Please refer to the response to BCUC IR 1.32.9.

32.13 Please confirm, otherwise explain, that with the forecast use per customer, individually or in aggregate by main, and the actual consumption by main, one could evaluate and trend FEI's forecasting performance for consumption, and identify deviations from forecasts that affect costs and rates.

Response:

Please refer to the response to BCUC IR 1.32.9.

32.14 Please confirm, otherwise explain, that the forecast aggregate PI is the average of the individual PIs and not a weighted average aggregate PI.

Response:

The forecast aggregate PI is a weighted average of the main extensions for the sample being reported on. The aggregate PI is calculated by summing up the inputs from each of individual MX test that makes up the random sample for the MX Report. These 'summed up' inputs are then applied in a single MX test that recalculates the PI for the entire sample set in aggregate.

This approach provides a PI result that is the most accurate and reflective of all inputs used in the individual main extension tests that make up the random sample for reporting.

32.14.1 If confirmed, would FEI consider it more appropriate to use a weighted average aggregate PI for its MX test? Why or why not?

Response:

Please refer to the response to BCUC IR 1.32.14.

32.15 Please discuss the pros and cons of using an average versus a weighted average aggregate PI.

Response:

Please refer to the response to BCUC IR 1.32.14.

32.16 Please confirm, otherwise explain, that FEI would consider the five most costly main extensions, material extensions? If confirmed, why? If not confirmed, why not?

Response:

FEI does not consider the recent top five main extensions to be material in comparison to FEI's rate base and their impact on the annual revenue requirement. Please refer to the response to BCUC IR 1.32.17 for a table showing FEI's top 5 main extensions from 2008 to 2014.

32.17 Please provide the cost of the five most costly main extensions in 2008, 2009, 2010, 2011, 2012, 2013 and 2014.

Response:

The table below provides the cost of the five most costly main extensions by year for 2008 to 2014. The cost data in this table was taken from the actual cost data included in the Rate Impact analysis included as a part of the Application.

The Company clarifies a timing issue between the MX Reports and the data included in the table below. The top 5 annual costs in the table will not match the top 5 costs for main extensions in the MX Report.

The top 5 costs in the MX report are based on the highest cost mains available at the time of the report. For example, the final costs for a large main starting in December of 2012 would not have been available in January of 2013 when the 2013 MX Report was sampled and therefore would not be incorporated in the results.

Top 5 Installed Mains Cost by Year Taken from Rate Impact Study					
	1	2	3	4	5
2008	$ 1,862,680	$ 342,460	$ 294,388	$ 266,841	$ 210,421
2009	$ 232,703	$ 104,818	$ 103,212	$ 101,429	$ 96,276
2010	$ 110,083	$ 92,511	$ 85,907	$ 82,883	$ 72,910
2011	$ 250,121	$ 163,391	$ 157,638	$ 124,139	$ 77,867
2012	$ 289,737	$ 132,915	$ 91,846	$ 78,309	$ 68,206
2013	$ 274,142	$ 177,812	$ 149,733	$ 134,003	$ 132,797
2014	$ 564,483	$ 164,241	$ 108,314	$ 98,934	$ 82,774

32.18 Would FEI consider it helpful to the Commission to understand FEI's main extension performance by reporting each year on the five most costly main extensions? Why or why not? Please discuss.

Response:

FEI has been required to provide data on the five most costly main extensions in the annual MX report since 2008. The Company does not believe that continuing to provide this type of data would be helpful to the Commission. As discussed in the response to BCUC IR 1.32.16, these mains are not sufficiently material to warrant exception based reporting.

J. REPORTING METHODOLOGY – OTHER JURISDICTIONS

33.0 Reference: REPORTING METHODOLOGY

TGVI TGI 2007 System Extension & Customer Connection Policies Review Proceeding, Exhibit B-1, Sections 5.4 and 5.5, pp. 24–26;

Exhibit A2-2, OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, Section 3, pp. 5–7;

Exhibit B-1, Appendix D, 2014 Main Extension Report, pp. 26–27;

Other jurisdictions - Ontario Energy Board (OEB)

In the Application for the System Extension & Customer Connection Policies Application Review, dated August 13, 2007, FEI [then TGI] drew parallels with the practice of gas utilities in Ontario, referring to Enbridge Gas' Main Extension Policy when describing FEI's proposed Profitability Index.

Exhibit A2-2 contains the Ontario Energy Board (OEB) Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario. Section 3 of these guidelines provides details regarding the monitoring of portfolio performance and short-term rate impacts. Section 3.1 outlines the information regarding the test (forecast) year and the historic year that is to be submitted on a periodic basis. Section 3.2 outlines information to be submitted to the Board to allow for a review of the utilities distribution system expansion project portfolios including financial and environmental requirements.

33.1 Please highlight and discuss the similarities and differences regarding the monitoring and reporting of main extension performance and short-term rate impacts between FEI's reporting proposals and sections 3.1 and 3.2 in OEB's Guidelines referenced in the preamble. Please include discussion regarding OEB's requirement of historic reporting of the aggregate NPV, the total capital, and the portfolio P.I. for a rolling project portfolio at the end of each year; and each of section 3.2 (A), (a), and (b).

Response:

As indicated in the preamble, Section 3 of the OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario (OEB Guidelines) provides details for monitoring portfolio performance and short-term rate impacts. In Ontario, utilities are required to track system extension projects under two different portfolios: the Investment Portfolio and the Rolling Project Portfolio. For context and clarity, a review of both the Investment Portfolio and the Rolling Project Portfolio is provided below. This is followed by a review of Sections 3.1: Rate Case Filings and Sections 3.2: Ongoing Monitoring Information of the OEB Guidelines.

OEB Investment Portfolio

The OEB Investment Portfolio (IP) tracks the costs and revenues associated with all new distribution customers who are forecast to attach in a particular *test year*, including new customers attaching to existing mains (infill customers). The IP also includes a forecast of normalized system reinforcement costs[43] and is only reviewed during a utility's rate case. This portfolio takes a more expansive view of the utilization of utility's system for a given test year.

FEI does not follow the 'Investment Portfolio' approach.

OEB Rolling Project Portfolio

The OEB Rolling Project Portfolio (RP) tracks all forecast future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the portfolio over a rolling 12 month period but excludes those customers requiring only a service lateral from an existing main extension (infill customers). This is similar to the Company's practice

The RP is updated monthly, and is intended to be an ongoing management tool for the estimation of the future impacts of capital expenditures associated with distribution system expansion. The cumulative results of project specific DCF analysis from the past twelve months are to be calculated monthly.

Review of OEB Guidelines Section 3.1: Rate Case Filings

This section of the Guideline provides details on the reporting requirements that are to be filed in each rate case, which consists of reported information for the 'Test Year' and for the 'Historic Year'. Under the existing PBR in Ontario, this occurs every five years.

Test Year Reporting

The reporting requirement for the Test Year is specifically related to the IP and the information required is provided on a forecast basis. The purpose of the Test Year Reporting is to measure the propensity for short term rate impact resulting from the utility's test year system expansion plan and involves an estimate of the Test Year rate impacts. See Section 3.1 of the OEB Guidelines for more details.

Historic Year Reporting

The reporting requirements for the Historic Year involve reporting for both the IP and the RP. For the IP, the utility must provide the NPV, total capital in the portfolio and the IP portfolio PI[44]. The utility must also provide the rate impact of the Historic Year IP reflecting actual capital expenditures and customer related data.

[43] BCUC Exhibit A2-2, Section 1.

[44] Ibid., Section 3.1.

For the RP, the utility must provide an aggregate NPV, the total capital and the portfolio PI at the end of the historic year and a list of all completed projects with negative and positive NPVs.

Review of OEB Guidelines Section 3.2: Financial Monitoring

This section of the OEB Guidelines provides details on the financial monitoring of the RP. According to the OEB Guidelines, the utility must provide for a selected sample of projects in the RP:

- The cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs and the corresponding year 3 customer attachment forecasts; and,
- The associated revenues and costs for a sample of projects included in the RP.

In reviewing Section 3.2 of the OEB Guidelines, it does not appear to the Company that the financial monitoring for the RP involves the comparison of the 3rd year forecast and actual PIs.

FEI's Reporting Proposal

The Company's reporting proposal is different than that described above for the utilities in Ontario. The Company believes that the Ontario reporting requirements are not appropriate. Much of the reporting requirements specified are for the Rate Case Review of the Ontario utility's Investment Portfolio, which does not apply to the Company. While the reporting requirements for the Rolling Project Portfolio specified in Section 3.2 of the Guidelines would constitute an improvement over the Company's current reporting requirements, in that the requirement does not appear to involve a comparison of forecast to actual PIs, it still constitutes a form of variance reporting that is not necessary.

33.2 Please discuss the inclusion of the associated revenues along with the costs of the cumulative number of customers attached at the end of each year in the annual main extensions report.

Response:

Please refer to the response to BCUC IR 1.32.7.1 for reasons why a more granular level of reporting does not provide useful information for assessing economic viability of main extensions and to the response to BCUC IR 1.32.1 for a description of the Company's annual reporting proposal.

34.0 Reference: REPORTING METHODOLOGY

Exhibit A2-2, OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, Section 3.1, Historic Year, Subsection (c), p. 6

Projections in reporting

Subsection (c) under the title "Historic Year" outlines that "upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio."

34.1 Please discuss FEI's view of providing projected results of individual main extensions to the Commission.

Response:

Please refer to the response to BCUC IR 1.32.7.1 for reasons why a granular level of reporting does not provide useful information to assess the economic performance of main extensions.

35.0 Reference: USE PER CUSTOMER

Exhibit B-1, Section 5.4.3, pp. 78–79;

Exhibit A2-2, OEB Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, Section 2.1, p. 3

Use per new customer

FEI states in section 5.4.3 of its Application:

> FEI has seen an overall reduction in use per customer for new customers compared to existing customers. There are several factors which may contribute to the reduction in use per customer more generally, including successful energy efficiency and conservation efforts, marketplace shifts to high efficiency appliances, and a reluctance of customers to incur the high fixed costs associated with installing multiple gas appliances. … With respect to those customers that have installed high efficiency appliances, the Company does not feel it would be appropriate to encourage the customer to consume more gas simply to meet the volume averages of existing customers in order to create a more favourable MX Test result. Nor would it be fair to new customers to use a lower volume for a more efficient appliance as a credit in the test as this would lead to a lower PI forecast and encourage customers to use less efficient appliances in order to pass the MX Test. In addition, the Company does not have data on which to base a volume credit for gas usage in new more efficient appliances. … it remains appropriate to use the volume credit, as derived from existing customers in the REUS, as an input into the MX test. [Emphasis added]

The OEB states that the DCF calculation for a Portfolio will be based on a set of common elements including "an estimate of average use per added customer which reflects the mix of customers to be added."

35.1 Please discuss the benefits and disadvantages to existing ratepayers of accounting for the increased efficiency associated with the use of newer appliances in the MX test.

Response:

This answer responds to BCUC IR 1.35.1, 1.35.2 and 1.35.3.

Currently, the consumption value used in the MX test for the new customer is based on the average consumption of existing customers on a per appliance basis. The annual consumption per appliance is taken from the REUS. FEI acknowledges that there is merit in accounting for the increased efficiency associated with the use of new appliances in the MX Test and that the existing methodology using the REUS takes this into account. FEI believes that the current

method of determining consumption per customer is reasonable and thus should continue, and an adjustment as suggested in the question 1.35.3 is not necessary.

The determination of consumption for new customers must balance the interests of both new and existing customers: in other words the consumption values used should not unduly burden either group. Using the REUS accomplishes this desired outcome. Using the REUS does not significantly disadvantage a new customer for having a more efficient house or appliance (and associated lower consumption), as the MX Test used consumption values of existing customers. However, as each REUS is updated, and residential consumption declines, the consumption values used for new customers is adjusted. Existing customers attached to the system at a time when consumption was higher and costs were lower. Existing customers also have access to energy efficiency programs that encourage them to lower consumption through the use of more efficient appliances. This balance of needs between new and existing customers is an important consideration in determining the methodology of including consumption values in the MX Test.

The following also supports the continued use of the REUS for determining consumption values in the MX Test.

First, the REUS is not a “stale” study as it is updated periodically and the consumption values in the REUS do reflect the declining use per customer associated with energy efficiency. As shown in the response to BCUC IR 1.4.5, the average PI values for the top 5 main extensions in 2014 decreased 12% using the 2012 REUS, comparing to the resulting values if the 2008 REUS was used. This comparison demonstrates that the increased efficiency with the use of new appliances is being incorporated in the MX Test.

Second, the current method for determining consumption value per appliance does not unduly burden the new customers. Changing the method for determining consumption value, such as suggested in question 1.35.3, could have negative implications for new customers. For instance, if a lower consumption value were used without a corresponding lowering of the PI thresholds, the likelihood of a CIAC would be higher. That is, new customers would be penalized for using energy efficient appliances because of the increased likelihood of paying a CIAC.

Third, the Rate Impact analysis showed that using the actual consumption of new customers that attached from 2008 to 2014, existing customer rates decreased. This finding demonstrates that the existing customers have not been exposed to undue costs under the current method of determining consumption value. If new customers were facing a more prohibitive CIAC due to a lower consumption value as discussed above, they would be less likely to attach to FEI’s system. Reducing customer attachments to FEI’s system in this manner would have a detrimental effect on existing customer rates (all else being equal).

35.2 Please confirm, otherwise explain, that the increased efficiency associated with the use of newer appliances is not incorporated into FEI's main extension test. If confirmed, please explain why not.

Response:

Not confirmed. Please refer to the response to BCUC IR 1.35.1.

35.3 Please discuss FEIs view on the use of the Residential End-Use Survey to establish a base use per customer value followed by an adjustment to this base for changes in building code, increased appliance efficiency as a result of new technology and experience monitoring the recent variances between actual and forecast use per customer.

Response:

Using the REUS as a base and then adjusting to account for building code changes or efficiency standards is not a practical solution. The amount of information required, the time to arrive at values and the number of assumptions required would render any adjustment no better than a guess.

For example, to simply determine how to adjust for building code and appliance efficiency, a study would be needed to understand the effect of existing customer building codes on energy usage. Then a sample of buildings constructed under new buildings codes would need to be studied to arrive at the adjustment (this would involve sub-metering over a large enough sample size covering many years). This same process would be required to address efficiency. Lastly, the REUS would need to change to disaggregate the data so that new low consumption customers were not impacting the analysis of volume from studies suggested above.

As can be seen from this example, it would be impractical to use the REUS as a base and then adjust for other factors.

Please also refer to the response to BCUC IR 1.35.1.

35.4 Please discuss FEI's view on the section of the OEB Guidelines in the preamble.

Response:

This response addresses BCUC IRs 1.35.4, 1.35.4.1 and 1.35.4.2.

Based on a review of section 2.1 (c) of the OEB Guidelines, which is referenced in the preamble, the Company believes that the purpose of section 2.1 of the OEB Guidelines is to define the standard DCF test to be applied at both the project level[45] and aggregate portfolio level, and to recommend that utilities estimate the average use per added customer that reflects the mix of customers to be added for the DCF calculation.

In calculating the PI for the (aggregate) portfolio to reflect the mix of customers that were added to that portfolio, FEI understood from conversations with Union Gas employees that this estimation equaled the sum of all of the expected customer consumptions that were applied in each of the project specific DCF analyses that made up Union Gas' Portfolio over the reporting period. That is, the expected customer consumption values from each individual MX is aggregated and used as the estimate of the average use per added customer for the entire portfolio to determine the forecasted revenue for the portfolio. This is similar to the approach currently taken by the Company in calculating the aggregate PI for reporting, where the Company tallies up all of the consumption values used in each individual MX test that comprised the reporting sample for input into the aggregate MX Test. However, FEI believes that its approach is conservative in comparison in that FEI customers are allocated consumption on a per appliance basis in the MX Test whereas in Ontario, customers are allocated an average consumption amount (for the entire house/residence), regardless of the appliances expected to be consumed in the home.

In calculating the PI at the project level, the Company understood from conversations with Union Gas employees that the average consumption of existing customers was reduced by 10% in order to reflect the mix of customers that were added to the project. Union Gas indicated that a simple 10% reduction was applied to the average consumption of existing customers to recognize efficiently that new customer consumed less than existing customers, since there was no way to accurately determine what new customer consumption was. This methodology is different than that used by the Company for individual MX tests.

The Company did not receive a response from Enbridge Gas but Union Gas officials indicated that their methodologies were consistent.

[45] The term ''project level' refers to an individual main extension test.

35.4.1 Please explain how utilities in Ontario satisfy the section of the OEB Guidelines in the preamble.

Response:

Please refer to the response to BCUC IR 1.35.4.

35.4.2 Please discuss the feasibility of FEI utilizing a similar approach.

Response:

Please refer to the response to BCUC IR 1.35.4.

35.5 Please discuss the pros and cons of reporting to the Commission the number of each type of appliance forecast to be installed and the number and type of the appliances actually installed.

Response:

FEI collects forecast data on appliances as part of the MX Test process as appliances determine volume which determines revenue. In order to determine the number and type of appliances installed, FEI would require an audit and evaluation process that currently does not exist. The process would require individual visits to every single customer who attached and verification of each appliance. In many cases multiple visits to each building may be required if the customer is not home. This would be a costly process.

FEI does not have evidence that customers are not installing the appliances they forecast and therefore adding this process and cost would have little benefit. Further, while a customer may have an appliance, simply having an appliance does not result in the consumer using the appliance in the manner envisioned in the MX Test. The customer may use more or less volume in one appliance versus another appliance. Therefore while having the appliance is better than not having the appliance, there will always be variation from a forecast. FEI believes that adding in such a verification process would be costly and provide little benefit, therefore reporting on such activity is not feasible. Please refer to the response to BCUC IR 1.32.9 for a discussion of the limitations of reporting on consumption credits versus actual consumption.

36.0 Reference: VARIANCES BETWEEN FORECAST AND ACTUAL PROFITABILITY INDEX

Exhibit A2-1, OEB's E.B.O. 188 - Final Report of the Board, Para. 6.3.9, p. 32;

Exhibit A2-2, OEB's Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario, Section 3.3, p. 7

Other jurisdictions – Ontario Energy Board (OEB)

In Exhibit A2-1, the OEB concludes its report with: "The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers." Section 3.3 of Exhibit A2-2 discusses the risks of non-performance of a main extension.

36.1 Please discuss FEI's view of the section of paragraph 6.3.9 of OEB's decision quoted above.

Response:

This response addresses BCUC IRs 1.36.1 and 1.36.2.

Based on FEI's review, the noted quote in the question's preamble is taken from paragraph 6.3.9 of the referenced OEB decision (Exhibit A2-1) (the OEB Decision) and is related to the evaluation of the Investment Portfolio in Utility Rate Case Review. For clarity, paragraph 6.3.9 of the OEB Decision is provided in full:

> The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variation and the corrective action taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers. [Emphasis added]

The broader context of the above cited paragraph is the 'Rate Case Review' of the Investment Portfolio. Paragraphs 6.3.2 to 6.3.8 preceding the cited conclusion provide details on the reporting requirements for the Investment Portfolio in "Rate Cases" and the OEB's expectation regarding affordability and rate stability to ensure they are addressed in the utilities' plans under the portfolio approach. The underlined portion that was omitted from the quote in the preamble is in reference to the variances between the actual and forecast portfolio NPVs of the Investment Portfolio during Rate Case Reviews.

Section 3.3 of the OEB Guidelines, included as appendix B of the OEB Decision is also written in the context of the Investment Portfolio. For clarity, Section 3.3 of the Guideline is provided in full below:

OEB Guideline 3.3: Risk of Non-Performance

In the even the actual results of the Investment Portfolio do not produce a positive NPV or a PI of at least 1.0, the following will occur [Underline added]:

- The utility will be required to provide a complete variance explanation in its rate case and the Board will determine whether or not an acceptable explanation has been provided; and
- The implications of a negative NPV or PI less than 1.0 will be determined by the Board on a case by case basis.

The Company does not believe the cited conclusion in paragraph 6.3.9 of the OEB Decision or section 3.3 of the OEB Guidelines is relevant to the approach being proposed by the Company because it is pertinent to the Investment Portfolio, which is not comparable to the Company's aggregate portfolio of main extensions.

36.2 Please discuss FEIs views on section 3.3 of Exhibit A2-2.

Response:

Please refer to the response to BCUC IR 1.36.1.

K. REPORTING METHODOLOGY – RATE IMPACT ANALYSIS

37.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, Section 3.2.4.2, p. 32

EES Rate Impact analysis

On page 32 of its Application, FEI states: "To facilitate the understanding of the EES analysis, FEI forwarded a working model of the Rate Impact analysis to stakeholders along with a briefing on how it was constructed, and invited participants to meet individually with EES to review the assumptions in greater detail if required."

37.1 Please provide a fully functional copy of the most recent Rate Impact analysis model.

Response:

Please refer to the Excel spreadsheet provided in Attachment 37.1 for the Rate Impact analysis.

Please note a correction in the attached file as compared to the version provided on page 26 of Appendix A to the Application. The categorization of some costs has been corrected in the attached model. The corrections do not impact the total capital dollars and do not change the results of the rate impact study. Nevertheless, a table detailing the correction has been provided below for clarification

	MX Application Appendix A –p.26 2008-2014 Growth Amount	Attachment 37.1 Spreadsheet
2008-14 Meters/Regulators	*$16,026,762*	*$16,163,726*
2008-14 Services (Company Paid)	*$119,082,263*	*$115,724,553*
2008-14 Mains (Company Paid)	*$58,435,929*	*$61,656,929*
2008-2014 SJ and Internal Costs	$7,228,180	$7,228,180
Total	**$200,773,134**	**$200,773,134**

37.2 Has the methodology used in Rate Impact analysis model been approved and used in other jurisdictions? If yes, please provide the jurisdictions. If not, please explain why not.

Response:

The following response was provided by EES Consulting.

EES Consulting has not specifically done a search for such a model; however, FEI received a copy of a table measuring the rate impact associated with adding new customers from Gaz Metro. It is the experience of EES Consulting that utilities routinely look at the forecasts of rates over time and under different conditions. The Rate Impact analysis model is simply a tool for forecasting rates under different conditions. The model was developed using the standard parameters (revenue requirements, sales, etc.) that are used in setting rates for all utilities. The model is a straightforward forecast of the average cost per GJ with and without growth on the system.

38.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, Section 3.4.3.1, p. 47

EES Rate Impact analysis

FEI states in its Application: "The Rate Impact analysis does not determine if a main or aggregate of mains is economic, but it does provide a better "point in time" view on the impact that new customers have been having on existing customers, and can serve as a reasonable assessment of the functioning of the system extension policies and MX Test."

38.1 Given that the "Rate Impact analysis does not determine if a main or aggregate of mains is economic", please explain how it provides a "reasonable assessment of the functioning of the system extension policies and MX Test."

Response:

In order to accurately determine if a main or aggregate of mains is economic, the revenue and cost would need to be compared at the end of the life of the main. In FEI's case, this analysis would be greater than fifty years, which FEI recognizes is impractical. Thus, FEI has proposed a periodic analysis that, while not able to truly determine the economics of a main, is a more practical solution than using an analysis at the end of the life of a main. As also noted, the MX Test is not an ex post evaluative tool and cannot and should not be used to determine the economic performance of a main.

The Rate Impact analysis provides a point in time assessment of the system extension policies and MX Test because it considers the rate impact of system extensions on both new and existing customers. It considers attachments over a number of years and uses actual revenues and costs. As such it can determine at that point in time the impact of adding a set group of mains. As seen below, there are three general scenarios that could arise from the Rate Impact analysis with resulting implications:

Rate Impact Analysis Scenarios	System Extension Policy Implications
Rates unchanged	New and existing customer interests are balanced and the system extension policies and MX test are functioning as intended
Rates Increased or Decrease	Changes could be made to rebalance new and existing customer interests.

It is important to note that while the economics of a main can and will change over the life of the main, the Rate Impact Analysis does show how the mains are performing over the timeframe studied. However the Rate Impact analysis is not a forecast and should not be used to predict how a main will function in the future. For example, since the Rate Impact analysis has shown rates have gone down as a result of system extensions installed between 2008 and 2014, the

1 Company is recommending changes to its system extension policies that rebalance the benefit
2 towards new customers while at the same time ensuring that existing customers are not
3 harmed.

4

39.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, Appendix A, pp. 23–24;

EES Rate Impact analysis

On page 23 of Appendix A, FEI states:

> When more customers and sales are added to the system, those fixed costs are spread out among more customers and that benefits all ratepayers
>
> ..Because there are many factors that impact rates over time, the analysis is designed to isolate the impacts of customer additions while holding all other factors constant.

39.1 Please confirm that "fixed costs are spread out among more customers and that benefits all ratepayers" only when incremental revenue generated by the additional customers exceed their incremental costs.

Response:

Confirmed.

As measured by the MX Test, the proposed policies will continue to encourage additions where the forecast revenues exceed the forecast costs in aggregate, and therefore the additions lead to fixed costs being spread among a greater number of customers.

39.2 Would FEI agree that cost of providing service to new customer s using less than 5 GJ/year is likely to be more than the incremental revenue generated by these customers? Please explain why, or why not.

Response:

FEI agrees that unless the capital cost to connect the customer is very low, a customer using less than 5 GJ/year is likely to have a very low P.I. under the MX Test, given the low revenues associated with consuming 5 GJ/year. FEI has not proposed that the MX Test parameters be changed to allow this type of customer to connect to the system at no cost to the customer.

On page24 of Appendix A, FEI states: "In order to determine the added costs associated with new customers, we included the costs associated with meters/regulators, services and mains for new customers as well as costs associated with Standing job orders and internal costs."

39.3 Does omitting the impact of new customers on general plant (i.e. buildings, office equipment and vehicles) and incremental O&M overstate the benefits of adding new customers? Please explain why, or why not.

Response:

To the extent that new customers have an impact on general plant and O&M, excluding these costs would be overstating the benefits of adding new customers. However, FEI has not omitted these costs and therefore is not overstating the benefits in the Rate Impact analysis conducted. FEI reviewed the impact of new customers on general plant and determined that the incremental costs are zero at the present time. As described on page 25 of Appendix A, incremental O&M costs associated with new customers have been included in the analysis and are equal to $10.5 million, or an average of $122.68 per new customer.

39.4 Please provide the increase in general plant costs from 2008-2014.

Response:

General plant capital costs primarily include costs for office facilities, the land the facilities occupy and computer hardware and software, and as such, are not affected or determined by the customer additions each year. The December 31, 2014 ending gross plant in service balance of general plant was $337.2 million as compared to the December 31, 2007 ending gross plant in service balance of $310.7 million, representing a change of approximately $26.4 million over the 2008-2014 period. This change in total general plant is entirely attributable to general plant additions from CPCN projects such as the Customer Care Enhancement CPCN and the Victoria Regional Office CPCN totaling approximately $34 million.

Please also refer to the response to BCUC IR 1.39.3.

On page 24 of Appendix A, FEI states: "The 13.8% multiplier was determined by looking at the expense items associated with return, depreciation and taxes relative to the rate base of the utility for the meters, services and mains categories."

39.5 Please show the calculation of the 13.8 percent multiplier.

Response:

Please refer to the table below which provides the calculation of the 13.8 percent multiplier.

Line	Particular	2015	Reference and Notes
		$ Thousands	***All data sourced from Exhibit B-1-1, FEI Annual Review for 2015 Rates***
1	*Gross Plant*		
2	Open	2,568,838	Accounts 475-00, 473-00, 478-10, Section 11, Schedule 21
3	Additions	85,224	Accounts 475-00, 473-00, 478-10, Section 11, Schedule 21
4	Retirements	(11,756)	Accounts 475-00, 473-00, 478-10, Section 11, Schedule 21
5	Close	2,642,306	
6			
7	*Accumulated Depreciation*		
8	Open	(745,586)	Accounts 475-00, 473-00, 478-10, Section 11, Schedule 25
9	Depreciation	(62,139)	Accounts 475-00, 473-00, 478-10, Section 11, Schedule 25
10	Retirements	11,756	Accounts 475-00, 473-00, 478-10, Section 11, Schedule 25
11	Close	(795,969)	
12			
13	*Net CIAC - Distribution*		
14	Open	(180,865)	Distribution, Section 11, Schedule 28
15	Additions	(5,994)	Distribution, Section 11, Schedule 28
16	Amortization	4,958	Distribution, Section 11, Schedule 28
17	Close	(181,901)	
18			
19	Mid Year Rate Base	1,653,412	(Opening + Closing Balances)/2
20			
21	Cost of Service		
22	Depreciation	62,139	- Line 9
23	Amortization	(4,958)	- Line 16
24	Property Tax	27,591	Line 19 x 1.67% (forecast utility property tax/ total utility rate base)
25	Income Tax	27,995	Class 51 CCA
26	Earned Return	115,793	Line 19 x 7.0% Return on Rate Base (Section 11, Schedule 3)
27		228,560	Sum of Lines 22 through 26
28			
29	**Multiplier**	**13.8%**	Line 27 / Line 19

L. AMALGAMATION AND PBR IMPACTS

40.0 Reference: APPENDIX A

Exhibit B-1, Appendix A, pp. 7-8; 1996 System Extension Guidelines, p. 19

Amalgamation

On page 7 of Appendix A, FEI states: "The usage estimated for each new customer will also be based on common usage rates rather than regional levels. The usage will still be based on the expected appliances to be installed."

40.1 Please provide a schedule comparing the 2014 FEI and FEVI usage rates and the 2015 common usage rates by appliance.

Response:

A schedule comparing the 2014 FEI and FEVI usage rates and the 2015 common usage rates by appliance is provided below.

	2014 (GJ/yr)			2015 (GJ/yr)
Appliance	Lower Mainland	Interior	Vancouver Island	All Regions
Barbeque	3.1	3.1	3.1	3.1
Boiler	62.0	51.6	43.0	52.4
Clothes Dryer	4.2	3.6	3.4	3.9
Fireplace - Décor	18.3	15.9	16.1	17.7
Fireplace - Heating	21.4	19.8	19.7	14.6
Furnace (primary)	62.0	51.6	43.0	52.4
Furnace (secondary)	18.1	39.3	19.9	24.5
Hot Tub	19.5	19.5	19.5	21.3
Hot Water Tank	20.4	18.8	18.8	26.3
Pool	38.5	38.5	38.5	43.1
Range/Cooktop	5.6	5.1	4.7	12.5
Wall Heater	7.1	7.1	7.1	7.1

To complete the table above, the Company used the 2008 REUS values for 2014 and the 2012 REUS values for 2015. Following amalgamation, in 2015 the Company began using a single region where it had previously used the Lower Mainland, Interior and Vancouver Island regions.

On page 8 of Appendix A, FEI states: "Given the goals and practices associated with amalgamation, looking at each separate MX project as needing to be cost-effective on an individual basis may not be appropriate as it does not reflect the goal of treating customers the same regardless of their individual location and costs."

40.2 Is the "goal of treating customers the same regardless of their individual location and costs" consistent with the statement on page 19 of the 1996 System Extension that it is "appropriate to also require greater precision in the determination of the net revenue which offsets these costs"? Please explain why, or why not.

Response:

The goal of treating all customers the same regardless of their individual location is at odds with precision in cost allocation in that the utility does not charge each customer the cost to serve them on an individual or more granular basis. However, the lack of perceived "precision" in cost allocation does not make a rate or practice relating to a rate inappropriate. It has been established and approved that postage stamp rates or setting rates without regard to location is just, reasonable and not unduly discriminatory.

That is not to say that the MX test should not use precision in forecasting and calculating both revenues and costs. Revenues can be calculated by using the expected appliances that are to be installed and the cost of an extension can reflect the terrain that is specific to that extension; however, usage per appliance should not differ between regions or between old and new when forecasting the economic viability of a main.

41.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4, p. 50; Order G-120-15

FEI 2014-2019 Multi-Year Performance Based Ratemaking Plan (PBR)

41.1 If the Application is approved as filed, will changes to the MX test be treated as an exogenous factor in the PBR? Please explain why, or why not.

Response:

The criteria for exogenous factor treatment are:

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.

Based on these criteria, the changes to the MX test as proposed could not be treated as an exogenous factor under the approved PBR Plan. Based on the impact analysis performed in Section 4.1 of the Application, it is extremely unlikely that the changes would exceed the materiality threshold in any year.[46]

41.2 Please provide a schedule showing the differences between 2014 PBR growth capital and costs forecast in the2014 main extension test by account.

Response:

FEI understands the question to be asking for a reconciliation of the allowed growth capital spending for 2014 under the category of mains growth capital to the actual mains capital spending reported in the 2014 MX Report. FEI cannot provide this reconciliation. The PBR

[46] With the exception of the System Extension Fund, for which FEI has proposed a separate treatment.

formula provides for an overall growth capital spending envelope, and FEI does not have a PBR formula capital amount specific to mains.

41.3 If the Application is approved as filed, does FEI expect to construct any main extensions that will exceed FEI's PBR materiality thresholds of $15 million or its Certificate of Public Convenience and Necessity dollar threshold of $15 million during the term of the PBR?

Response:

The Company is not anticipating, nor is it aware of, any upcoming main extension that would exceed the established CPCN threshold of $15 million. In general, a main extension of such magnitude is extremely rare. As indicated in the Application, there were only three main extensions that had a cost greater than $500,000 between the 2008 – 2014 periods. Should a main extension arise that exceeds the $15 million threshold, it would be subject to a CPCN application and not the MX Test.

M. OTHER

42.0 Reference: CUMULATIVE IMPACT AND SUMMARY

Exhibit B-1, Section 4.1.5, pp. 59, 60; Section 3.2.4.1, Figure 3-1, pp. 29–31;

FEI 2007 System Extension Proceeding, Exhibit B-1, pp. 8, 9

Cumulative impacts

On page 59 and 60 of the Application, FEI explains:

> …the estimated annual cumulative rate impact of all of these changes is approximately $0.003 per GJ as follows:

Table 4-5: Approximate Delivery Rate Impact of Recommendations[65]

Recommendation	Approximate Rate Impact ($/GJ)
Extending DCF Term to 40 years	$0.002
Extending Customer Additions forecast to 10 years	-
Sliding Scale Overhead	$0.001
Discontinue Use of Energy Efficiency Credits	-
	$0.003

42.1 Please provide the approximate delivery rate impact assuming the proposed increase to the SLCA, and separately assuming the proposed System Extension Fund is approved.

Response:

If the new SLCA amounts had been in place for the 2008-2014 period, the reduction in contributions (CIAC) would have been $4.1 million in total for all the years. Including these additional costs as capital (foregone CIAC) in the rate impacts model results in an approximate rate impact of $0.003 per GJ.

Assuming the system extension fund is fully utilized each year for $1 million, including $7 million ($1 million x 7 years) additional costs as capital (foregone CIAC) in the rate impacts model results in an approximate rate impact of $0.006 per GJ.

Adding these two impacts to Table 4-5 results in a total of $0.012 per GJ[47] which is equal to an approximate $1 annual bill change for a residential[48] customer. Please note that these amounts

[47] $0.003 (SLCA) + $0.006 (SEF) + $0.002 (DCF) + $0.001 (OH).

[48] Using 90 GJ per year.

do not reflect any additional sales resulting from these programs and the resulting incremental customers. While additional sales are expected, they cannot be quantified at this time. Any additional sales resulting from the changes would lessen the rate impact as stated.

42.2 Please provide the approximate cumulative delivery rate impact assuming all of FEI's recommendations are approved.

Response:

The cumulative impact per GJ for all the changes would be $0.012 per GJ. This reflects a percentage increase of 0.3% of the average rate. Please note that the cumulative impact assumes that the entire $1 million per year SEF fund is fully subscribed over the 7 year period. If the full amount is not needed in each year, then the impacts would be less.

Again, as these amounts do not reflect any additional sales resulting from the proposed changes, the actual impacts are likely to be less than stated above. As demonstrated in the EES Report, this impact is an offset to the positive impact of adding new customers to FEI's distribution system. In other words, the $0.012 per GJ increase in rates reduces the positive impact of $0.060 per GJ on rates resulting from the addition of new customers over the 7-year period (all else being equal). As such, using the Rate Impact analysis, even if the SEF was fully subscribed over the 7-year period, it would not have resulted in an overall negative impact in rates.

42.3 Please fill in the table in the attached Excel spreadsheet and discuss the results.

Response:

There are too many variables and unknowns that could impact the "status quo forecast", therefore making it impractical and too speculative to provide an accurate or useful forecast for the individual proposals. The most challenging part that cannot be estimated with any reasonable accuracy relates to the question: 'How many customers that would likely decline a system extension in the future due to a prohibitive CIAC, or would change their decision because of the Company's individual proposals?'. For these reasons, FEI is unable to fill in the attached Excel spreadsheet.

As an alternative to the spreadsheet provided, the following table summarizes FEI's growth capital expenditures and gross customer additions as forecast in the Company's most recent PBR proceeding to provide some context for the discussion of the expected impacts of the proposals.[49] Although FEI is unable to quantify the impact on customer additions and CIAC of each proposal, FEI believes that when combined, the proposed changes provide for a better balance between new and existing customers and as such, the opportunity to increase customer additions over the status quo forecast.

Growth Capital and Gross Customer Additions as Forecast in the 2014-2018 PBR[50]

Mains, Services & Meters Capital ($Thousands)	2016 Forecast	2017 Forecast	2018 Forecast
New Customer Mains	5,561	5,664	5,798
New Customer Services	20,214	20,337	20,363
New Customer Meters	1,876	1,877	1,862
	27,651	27,818	28,022
Gross Customer Additions	9,505	9,382	9,189

In addition, based on anecdotal customer discussions, the Company expects that future conversion customers would be more likely to decide to proceed with natural gas service as a result of the proposals in the Application. Due to the potential economic benefit of switching to natural gas and lowering the CIAC barrier, these customers are most likely to change their behavior and overcome their consumer inertia.[51] As noted in the PBR proceeding, seven percent of historical service activity relates to conversion.[52] In the Table above, seven percent of growth capital expenditures equal $1.9 million. Between 2016 and 2020, the Company estimates an annual increase of up to five percent of the $1.9 million related to conversion. The Company does not segment gross additions by service type in the PBR so it cannot provide a baseline for comparison.

Further, associated with the challenges of predicting customer response to the proposals, the Company provided in the Application a retroactive analysis that showed what the CIAC and rate impact would have been had individual recommendations been in place from 2008 to 2014. The analysis provided the Commission with an insight into whether or not the interests of new and existing customers are being served. For example, in section 4.1.1 of the Application, the Company conducted an analysis of the mains installed from 2008-2014 showing the impact of

[49] 2014-2018 PBR Application, Exhibit B-1, June 10, 2013, Tables C4-11 and C4-13, pp.228-229.

[50] Ibid.

[51] In Appendix A EES Consulting included a report by the National Regulatory Research Institute (NRRI), *Line Extensions for Natural Gas: Regulatory Considerations.* On pages 13-14 NRRI discusses the barriers to fuel switching including a description of the challenge of overcoming consumer inertia.

[52] FEI PBR Revenue Requirements 2014-2018, Exhibit B-1, Figure C4-4, page 233. June 10, 2013.

extending the DCF term to 40 years on the revenue and costs in the MX Test, the percentage of MX Tests requiring a CIAC and customer rates. In this example, the Company showed that revenue would go up, CIAC would go down and existing customers would not have been materially impacted.

Finally, in the response to BCUC IR 1.46.1, the Company discusses the gap in provincial energy policy relating to the GHG emissions from imported electricity that make it prohibitive for the Company to provide informed, credible data related to GHG emissions associated with new natural gas customers.

42.4 Please explain why FEI has proposed adjustments to the inputs to the MX test but not to the individual PI threshold or the aggregate PI threshold.

Response:

There were two potential approaches FEI could have taken to update its system extension policies:

1. Reviewing the individual inputs into the MX Test and assuming the PI thresholds are constant; or

2. Lowering the individual or aggregate PI and assuming all MX Test inputs are held constant.

The Company believes both methods could be used. The Company used the first approach because:

- The individual and aggregate PI thresholds remain valid today. In Order G-152-07, the Commission approved the individual and aggregate PI thresholds based on FEI's proposal.[53] As stated in the 2007 Application, the individual PI threshold of 0.8 and the aggregate PI threshold of 1.0 sent the appropriate market signals to customers attaching to the system and were in line with other utilities considered at that time. The Company believes the existing thresholds continue to send the right market signals, and, as the EES Report indicates, the PI thresholds are still consistent with industry standards.[54] .

[53] 2007 Decision, Page 36.
[54] Page 16.

- The MX Test continues to serve its purpose and the basic construct of the Test continues to work. Thus, the changes as recommended by the Company are intended to better account for a reasonable time period over which to estimate the benefits of a main extension, to better capture customer additions of a main with a longer build out time frame, and to better reflect the operating reality of the Company, without a full overhaul of the MX Test.

- Third, in order to provide a baseline for comparative purposes, as summarized Table 4-5, the PI thresholds need to be constant. In absence of a constant PI, it would be impossible to examine the potential impact of the proposed changes on the CIAC and rates (if any).

42.5 Please fill in the following table and discuss:

1. 2014 Main Extensions	2. Forecast PI	3. Forecast PI assuming all approvals sought are approved	4. Difference (2 -3)
FEI Top 5 – 1			
FEI Top 5 – 2			
FEI Top 5 – 3			
FEI Top 5 – 4			
FEI Top 5 – 5			
FEVI Top 5 – 1			
FEVI Top 5 – 2			
FEVI Top 5 – 3			
FEVI Top 5 – 4			
FEVI Top 5 – 5			

Response:

The Company has provided the first table below as requested and notes that the Commission's formula for column 4 of the table indicates a decrease in PI's. The formula is incorrect and was

1 reversed to indicate an increase in forecast PI's as shown in the second table below, assuming
2 all approvals sought are approved.

3 For each of the top 5 mains, the Company re-ran the MX test assuming the following:

4 • A DCF term of 40 years

5 • A sliding scale overhead rate

6 • The removal of energy efficiency credits

	1. 2014 Main Extensions	2. Forecast PI	3. Forecast PI assuming all approvals sought are approved	4. Difference (2 -3)
FEI	Maclure Road	1.98	3.12	-1.14
	244 Avenue	1.00	1.59	-0.59
	Predator Ridge Drive*	0.80	1.23	-0.43
	Highland Drive	1.07	1.92	-0.85
	Plateau Drive*	0.84	1.36	-0.52
FEVI	Stamp Way	0.80	1.12	-0.32
	Westwood Road	0.91	1.48	-0.57
	East Saanich Road	0.88	1.40	-0.52
	Road A	0.87	1.37	-0.50
	Howard Avenue	1.59	2.36	-0.77

** Original MX Test contained EEC Credits which were removed from the recalculated PI*

7

	1. 2014 Main Extensions	2. Forecast PI	3. Forecast PI assuming all approvals sought are approved	4. Difference (3-2)
FEI	Maclure Road	1.98	3.12	1.14
	244 Avenue	1.00	1.59	0.59
	Predator Ridge Drive*	0.80	1.23	0.43
	Highland Drive	1.07	1.92	0.85
	Plateau Drive*	0.84	1.36	0.52
FEVI	Stamp Way	0.80	1.12	0.32
	Westwood Road	0.91	1.48	0.57
	East Saanich Road	0.88	1.40	0.52

	Road A	0.87	1.37	0.50
	Howard Avenue	1.59	2.36	0.77

** Original MX Test contained EEC Credits which were removed from the recalculated PI*

As seen in the table above, the PI increases in all cases, consistent with the objective of more accurately reflecting the impact of the benefits and costs over the life of the asset.

On pages 29, 30 and 31 of the Application, FEI explains and shows in Figure 3-1, that natural gas prices have decreased since 2007, are below those observed in 2007 and are currently more competitive than heating oil, propane and electricity on an operating basis for heating and hot water.

On pages 8 and 9 of FEI's 2007 System Extension application, FEI justified "a reduction in the upfront connection costs partly on the basis that '…the price differential between gas and electricity has narrowed and has eroded much of the traditional operating cost advantage of natural gas' and as such it '…is the belief of the Companies that…a reduction in the upfront connection costs is appropriate and should be made at this time.'"

42.6 Considering gas commodity prices are lower now than they were in 2007, please discuss how FEI proposes the Commission take into account the effects the 2007 changes had on the upfront connection costs.

Response:

The Company interprets the question to be asking whether the current, lower commodity price affects the Company's justification for a reduction of the upfront connection costs, and explains below. To the extent that the question asks the Company to re-justify its position in 2007 based on the current operating environment, FEI does not believe it to be appropriate.

In FEI's 2007 System Extension Application, FEI justified a reduction in the upfront connection costs on several grounds[55]:

1. The increased natural gas commodity prices vis a vis Heritage-related electricity rates that created a misconception amongst many consumers and builders that natural gas

[55] TGI-TGVI 2007 System Extension and Customer Connection Policy Application, p. 8-9.

space and water heating systems were more expensive to operate than their electric equivalent;

2. The technological changes that require the installation of more expensive high efficiency natural gas furnaces, in addition to the more costly venting requirements associated with those furnaces, in new buildings;

3. The energy decisions of developers that are profit driven, whose preference may gravitate towards the less expensive option of installing electric space and water heating infrastructure over natural gas; and

4. The market shift to multi-family and condominium apartments that are built with electric baseboard heating systems as a result of the low relative up-front capital costs at the expense of residences who are faced with the higher operational cost of electricity for heating.

Although the operational cost advantage of natural gas has improved today with lower gas commodity prices, the other factors mentioned above for lower upfront connection charges continue to provide valid justifications for a reduction of the upfront connection costs. For instance, upfront capital costs for the installation of a high-efficiency natural gas furnace, along with the required venting, remains more expensive than its electric equivalent, and developers continue to opt for the low cost option. As explained in the Application (section 3.2.4.1), upfront cost of installing natural gas infrastructure, including any potential CIAC related to system extensions, presented a main barrier to getting access to natural gas service for new customers. Thus, the Company continues to believe a reduction of the upfront connection is necessary.

43.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, section 3.2.4.1, pp. 29–31

Provide an energy choice

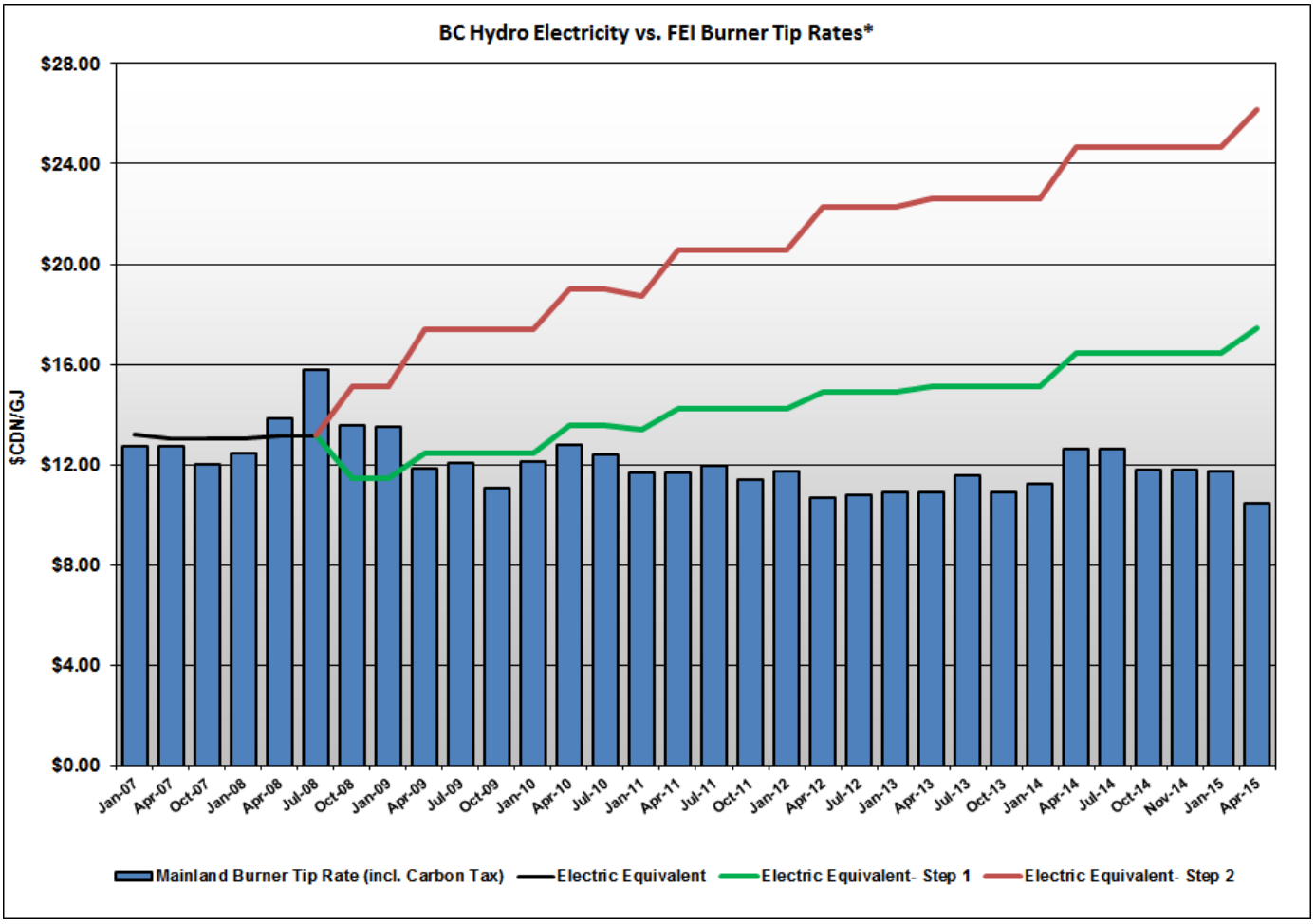
On page 30, Figure 3.2 shows the BC Hydro electricity vs. FEI Mainland burner tip rates.

On page 31, FEI states: "Customers want access to natural gas to save money on their total utility bills since heat and hot water are the biggest energy requirements in homes, and natural gas is less expensive to operate compared to heating oil, propane and electricity."

43.1 Please expand Figure 3.2 to show 2007 through 2015.

Response:

Please refer to the chart below which expands Figure 3.2 to include the years 2007 through 2015.



Assumptions:

The Mainland (FEI) burner tip rate presented in the chart includes the commodity charge, storage and transport charge, fixed basic and delivery charges and the carbon tax to provide a comparison against the electric equivalent, based on an average annual use of 90 GJ.

The Electric Equivalent rates (including Step 1 and Step 2 rates) have been adjusted using a 75% efficiency to represent the average efficiency level of all existing space heating customers. It is important to note that the rate that BC Hydro customers ultimately pay is dependent on their actual consumption (Step 1 and Step 2). This can impact the rate comparisons of natural gas against electricity depending on the customer's consumption levels for electricity. For example, water heating load may be better compared to Step 1 electricity rates because it generally has a flat yearly profile versus space heating which would have a winter profile (Step 2).

43.2 If upfront costs for appliances or a potential CIAC is included, would natural gas still have a competitive advantage over electricity? If not, please estimate the time horizon that it will take for natural gas customer savings to break even compared to electricity. State the assumptions.

Response:

Yes, natural gas is still competitive when looked at over this horizon. However, many customers do not look at lifecycle costs for comparative purposes and as noted initial upfront capital costs and/or a CIAC are significant bariers to customer attachment.

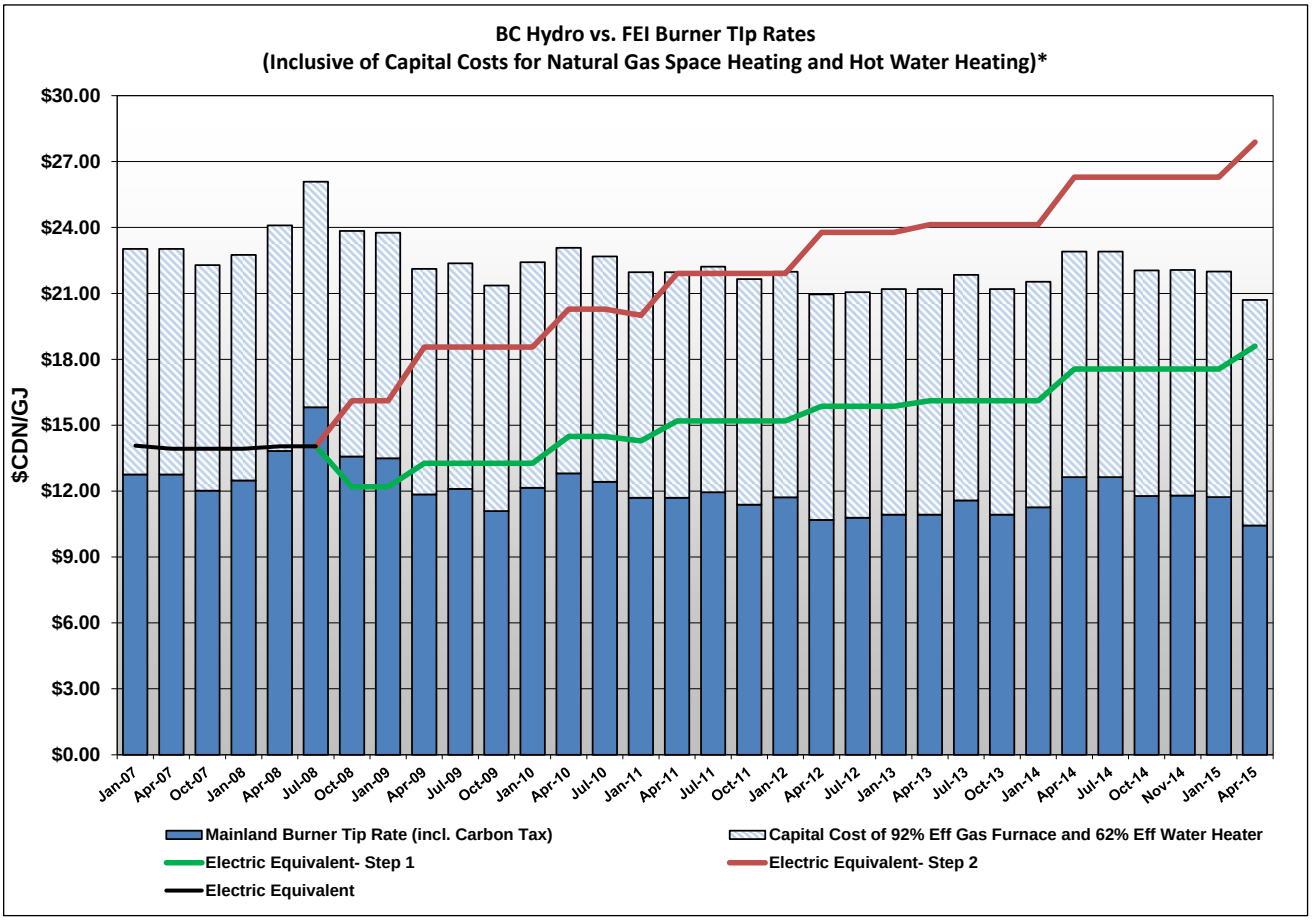
Please refer to the chart below which expands Figure 3.2 to include the years 2007 through 2015 and includes the estimated difference in upfront capital costs between natural gas and electricity for space heating and hot water heating, over the measureable life of a natural gas furnace, assumed to be 18 years.[56]

The difference in upfront capital costs between natural gas and electricity means that over the measureable life of the natural gas furnace, the operating cost advantage between natural gas and electricity would have to be at least $10.27/GJ for space heating and hot water heating, for the installation of the natural gas rather the electric equipment to be economic for the customer. In other words, natural gas rates would have to be below electric rates by $10.27/GJ for 18 years in order to "break even" in comparison to electricity.

As shown in the chart below which includes the upfront capital costs, based on April 1, 2015 rates, FEI's residential rate inclusive of the upfront costs is higher than BC Hydro's Step 1 residential rate and lower than BC Hydro's Step 2 residential rate. Therefore depending on customers' actual consumption and load profile, current natural gas rates may be considered

[56] The measureable life of a natural gas furnace was used for the analysis as it is assumed to be 18 years versus 13 years for a new natural gas hot water tank.

more or less competitive compared to electricity prices (the calculations do not include any CIACs).



Assumptions:

- FEI's Mainland burner tip rate presented in the chart includes the commodity charge, storage and transport charge, fixed basic and delivery charges, upfront capital costs, and carbon tax to provide a comparison against the electric equivalent, based on an average annual use of 90 GJ.

- The upfront capital cost calculations are based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at approximately 3,000 square feet), an interest rate of 6% and the measurable life of 18 years for a natural gas space heating furnace. The annual payments to recover the difference in upfront capital costs is calculated based on the present value of an annuity formula where PV of an annuity = annuity * [(1-(1+r) ^-n)/r], (r is interest rate and n is the measurable life of the equipment).

- The Electric Equivalent rates (including Step 1 and Step 2 rates) have been adjusted using an 80% efficiency to represent the weighted average efficiency level of a new gas-fired electric furnace and a new natural gas hot water tank.

43.3 Suppose natural gas becomes relatively more expensive compared to heating oil and propane, would it be fair to say that FEI is exposed to uneconomic customers and possibly stranded assets where these customers will substitute to other fuel?

Response:

Heating oil and propane prices have been consistently higher than natural gas commodity prices and it is unlikely for heating oil and propane to become more expensive than natural gas in the near future.

Once FEI customers are connected to the natural gas system and have invested in the upfront capital costs of natural gas appliances and potentially a CIAC, it would be highly unlikely for them to switch to other fuel types in the short or medium term unless the price gap is significant and persists for a long period of time. Further, given that oil and propane have a higher carbon content, there could be environmental considerations by the customer to remain on the natural gas system.

It is even more unlikely that all customers that utilize a main would switch to other fuels; there would continue to be utilization of the main and the gas system as a whole.

44.0 Reference: RECOMMENDATIONS

Exhibit B-1, Section 4.6.4, p. 69

Recognizing First Nations

In section 4.6.4, FEI states: "… one of the stakeholders in the Review, Seabird Island Band, will have much greater opportunity to access service as a result of the changes put forward by the Company."

44.1 Please demonstrate the Seabird Island Band case with the proposed changes. Compare with the existing MX Test.

Response:

The Company does not have the necessary data to do the requested comparison.

The Company referenced the Seabird Island Band for the purposes of demonstrating that the proposals would meet the Guiding Principle of "Recognizing First Nations". During the stakeholder workshops Chief Clem told the group that the Band was struggling during the winter time to pay their heating bills. He expressed that access to natural gas would help alleviate this problem. All of the Company's proposals, except for the removal of the energy efficiency credit, will help increase the ability to access natural gas service.

45.0 Reference: SYSTEM EXTENSION POLICY REVIEW

Exhibit B-1, Section 3.3.3, p. 41

Service to off system communities

On page 41, FEI states:

> In BC, similar government policy promoting the expansion of natural gas to off system communities does not yet exist as it does in Ontario, Quebec and parts of the US. The Company notes that having a supportive government policy is critical to the successful development of a program to serve these types of customers. FEI intends to continue to pursue the need to provide natural gas service to off system communities with the provincial government. Consequently, FEI does not make any related recommendations in this Application.

The Ministry of Energy and Mines and Responsible for Core Review states[57]:

> There are close to 70 remote communities in B.C. that are not connected to the major natural gas or electricity grid. These communities have challenges and opportunities in their energy systems that are very different than grid connected communities. The Ministry's community energy solutions support in these communities is tailored to these unique situations.
>
> The Remote Communities Regulation was issued in conjunction with Special Direction 10 to support the 2007 Energy Plan Policy Action #27 that allows BC Hydro to offer electric utility service to interested and eligible remote communities.

45.1 Please define on and off system communities. What criterion is used to determine whether or not a community is on system or off system?

Response:

For the purposes of the Application, a community such as Sicamous in BC is defined by the Company as an off-system community due to the following criteria:

1. Appearance on the 2011 Statistics Canada Census as a BC community;
2. Natural gas is not currently available anywhere within the community; and
3. The community lies within the service area of FEI or Spectra Energy (PNG was excluded from the study).

[57] http://www.empr.gov.bc.ca/RET/COMMUNITYENERGYSOLUTIONS/RCCEP/Pages/default.aspx.

45.2 Please explain how the 200m threshold noted in Section 28 and 29 of the Utilities Commission Act apply to FEI's current test and how it relates to the Fund, if at all.

Response:

Sections 28 and 29 of the Utilities Commission Act describe a public utility's obligation to serve when a customer requests service.

FEI employs an MX Test to ensure that customers added to its delivery system or to be serviced by a "supply line" are forecast to be economically beneficial to the system. In other words, the MX Test is a tool approved by the Commission and used by FEI to mitigate against the risk of new customers that are added to FEI's system unduly burdening the existing customers.

Although there is no stated distance threshold/parameters expressed in the MX Test, as explained in the Application (section 4.3.1), the farther away a premise wishing to be connected to FEI's system is from the existing system, the more costly is it for a potential customer as a larger CIAC will be required. The SEF will provide financial assistance to some extent to these customers.

45.3 On page 33 of the Application, FEI states that there are 180 off-system communities throughout BC that do not have access to natural gas service. However, the Ministry of Energy and Mines indicates that close to 70 remote communities in BC are not connected to the major natural gas or electricity grid. Please clarify the statistics regarding the number of off-system communities.

Response:

As stated in the response to BCUC IR 1.45.1, the Company considers an off-system community as one where there is no natural gas service currently available. However, some of those communities are connected to the electricity grid. The nearly 70 remote communities identified by the BC Ministry of Energy and Mines are those communities not connected to either the major natural gas or electricity grid.

45.3.1 Of the 180 off system communities, how many of them actually have a community energy plan that they wish to receive natural gas service and pay for the infrastructure?

Response:

Currently, the Company is not able to provide an accurate estimate. If the B.C. provincial government were to develop a program to promote access to natural gas for off system communities, similar to the programs in Ontario, the Company would engage relevant stakeholders to explore questions like the one asked and other related questions regarding the program.

45.4 FEI submits that it does not make any recommendations regarding off system communities in this Application. Please confirm that the proposed $1 million SEF will not have any impact in servicing off system communities. If not confirmed, please clarify.

Response:

Confirmed.

45.5 Please provide the status of FEI's efforts to pursue providing natural gas service to off system communities with the government. To expand natural gas service to off system communities, would FEI require government support similar to the BC Hydro's Remote Community Regulation?[58]

[58] http://www.bclaws.ca/civix/document/id/complete/statreg/240_2007.

Response:

The Company has engaged in periodic, high level discussions with the Ministry of Energy and Mines about the need to expand natural gas service to off system communities. However, there are no substantive or concrete outcomes of these discussions to report at this time.

FEI believes that government policy support is required to facilitate expansion of natural gas service to off system communities. Regulation similar to BC Hydro's Remote Community Regulation (BCHRCR) is one option. For instance, the regulations would need to specify and clarify the recovery mechanisms for serving off system communities.

Another approach is that taken in Ontario[59]. In Ontario, the provincial government produced a plan and a budget to facilitate natural gas service to off system communities. Below is an excerpt from the Ontario provincial government plan to expand natural gas to more communities:

> *"Increased natural gas access, through the $200 million Natural Gas Access Loan and $30 million Natural Gas Economic Development Grant, will attract new industry, make commercial transportation and agriculture more affordable, help to create jobs, provide more energy choices and will lower electricity prices for businesses and consumers across Ontario."*[60]

As seen in the attachment to this IR, in concurrence with the provincial government announcements, the Ontario Energy Board invited parties with the appropriate financial and technical expertise to propose plans for natural gas expansion. The relevant sections from page 2 of the OEB invitation are summarized below, while the full invitation is attached as Attachment 45.5.

> *"While minimizing cross-subsidization either within a portfolio of projects, or between a portfolio and the rest of Ontario customers remains an important goal, the Board is cognizant that the specific requirements of EBO 188 [EBO 188 Report on Natural gas Distribution Expansion]* may require some flexibility *to expand access to natural gas for communities that are not currently served.*
>
> *To the extent that the economics of a proposed project may not be accommodated within the current regulatory construct, the Board invites proponents to identify, within their applications, any options to address such regulatory issues."* (Emphasis added)

Union Gas has since submitted a related application and the Company understands that Enbridge Gas Distribution plans to submit an application as well.

[59] https://www.ontario.ca/page/infrastructure-funding-small-communities#!/.
[60] Ibid.

46.0 Reference: SUPPORT GOVERNMENT OBJECTIVES

Exhibit B-1, Section 3.2.4.3, p. 33; Section 3.2.4.1, p. 30

Low cost energy: BC Hydro electricity versus FEI natural gas rates

On page 33 of the Application, FEI states that the expansion of access to natural gas services supports the following government objective: "Assisting in meeting the legislated greenhouse gas (GHG) emissions targets and related energy objectives set forth in the Clean Energy Act (CEA)."

46.1 Please complete the following table, providing the GHG emissions in CO2e. Please insert a new row for each type of attachment that would otherwise be categorized as "Other."

	Column 1	Column 2	Column 3	Column 4	Column 5
Row 1	Type of Attachment	New Customer Attachments from 2008 through to 2014			
Row 2		Number	% of Total	GHG Emissions**	% of Total GHG Emissions
Row 3	New*				
Row 4					
Row 5	Fuel Switch from:				
Row 6	Electricity				
Row 7	Wood				
Row 8	Heating Oil				
Row 9	Propane				
Row 10	Other				
Row 11	**Total**				

* - New refers to customers of new developments who are not fuel-switching

** - GHG Emissions refers to GHG Emissions from using FEI's Natural Gas system

Response:

The Company cannot provide a full table as requested because the Company only has data relating to customers converting from certain higher carbon fuels to natural gas and because there is a lack of data and provincial policy regarding electricity import emission factors for new customers.

Converting from Certain Higher Carbon Fuels to Natural Gas

The statement quoted in the preamble is relevant to fuel switching from heating oil and propane to natural gas in terms of GHG emission reductions. When fuel switch customers connect to the FEI system, they do not indicate their pre-existing fuel type. Consequently, FEI can only speak to the actual fuel switching data it has available from the Company's Switch 'n' Shrink DSM rebate program.

In 2014, for example, slightly less than half of FEI's total number of fuel switch customers converted from heating oil to natural gas.[61] In situations where natural gas displaces heating oil,

[61] These fuel switch customers accessed a Switch 'n' Shrink rebate and indicated they were previously using heating oil.

it will result in reduction of 1.6 tonnes of CO2e relative to these customers continuing to use heating oil for heating purposes.[62] The GHG savings would be larger if those fueling switching customers used renewable natural gas (RNG).

Approximately 13% of new residential customer additions from 2008-2014 were fuel switching customers, with the remaining 87% being new customers. The table below summarizes the potential GHG emission reduction assuming all 10,000 customers switched from heating oil to natural gas for heating purposes:

Type of Attachment	New Customer Attachments from 2008 to 2014			
Fuel Switch From	**Number**	**% Total**	**GHG Emissions (tonnes of CO_2e)**	**% of Total GHG Emissions**
Light Fuel Oil	10,041	13%	(16,066)[63]	N/A

Electricity Imports Emission Factors

In order to complete the table as requested for new customers, FEI needs to know the source of the fuel that natural gas is displacing. (This source energy requirement also exists for those fuel switch customers that may have switched from electricity to natural gas). For example, if natural gas were to displace electricity, the Company would have to identify the generation source of the electricity and the related emission factors to provide a meaningful comparison. The Commission in its October 26, 2007 Decisions on BC Hydro's 2007 Rate Design – Phase 1 acknowledged this:

> *"Commission Panel commends Terasen for its initiative in leading evidence both concerning the use of electricity for space and water heating in BC Hydro's service area, and concerning the potential growth in demand for electric space and water heat that BC Hydro is forecasting. The implications of the growth in demand were among the reasons that led the Commission Panel to encourage and guide BC Hydro to implement an inclining block residential rate, so that customers receive the correct pricing signal in this regard. The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest".*[64]

The relevant natural gas and electricity emission factors in British Columbia are listed below:

---

[62] The Company is using the terms heating oil and light fuel oil synonymously.

[63] 10,041 customers x 1.6 tonnes of CO_2e avoided per year for heating purposes as indicated on p.33 of the Application.

[64] BCUC Decision in the Matter of British Columbia Hydro and Power Authority 2007 Rate Design Application – Phase 1, October 26, 2007, p. 191.

Type of Fuel	Emission Factor kg/GJ of CO_2e[65]
Alberta purchased electricity for stationary purposes	225
Average Northwest Power Pool[66]	102
Natural gas for stationary fuel combustion	49.75
BC Hydro purchased electricity for stationary sources	2.8
Renewable natural gas for stationary fuel combustion	0.29

However, the emission factors are only meaningful for the requested comparison if the source of the BC electricity import is known. The Company is able to provide general data on BC Hydro's electricity imports. As shown below, from 2008 to 2014, BC Hydro's international imports ranged from 8 to 12 gigawatt hours per year and 0.04 to 0.4 gigawatt hours per year inter provincially.[67]

Year	Inter-national Exports	Inter-national Imports*	Inter-national Trade Balance	Inter-provincial Exports	Inter-provincial Imports	Inter-provincial Trade Balance	Overall Trade Balance
2008	8,081,432	11,514,053	-3,432,621	1,554,501	361,462	1,193,039	-2,239,582
2009	6,223,905	10,801,679	-4,577,774	1,281,419	298,627	982,792	-3,594,982
2010	5,259,016	10,124,777	-4,865,761	1,757,915	117,608	1,640,307	-3,225,454
2011	9,661,014	9,998,739	-337,725	3,151,673	41,463	3,110,210	2,772,485
2012	10,838,849	8,017,073	2,821,776	3,087,769	61,639	3,026,130	5,847,906
2013	6,921,917	8,472,898	-1,550,981	1,817,988	223,850	1,594,138	43,157
2014	7,395,149	9,699,509	-2,304,360	1,310,548	384,161	926,387	-1,377,973

However, the Company is not able to report on the relevant emission factors for electricity imports since there is a gap in the data provided by BC Hydro relating to purchased electricity as reported by the Ministry of Environment:

[65] 2014 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. Ministry of Environment. Tables 1 & 3, pages 12 and 14. November 2014.

[66] http://www.bpa.gov/news/pubs/FactSheets/fs-201303-Measuring-the-carbon-ontent.pdf. Refer to page 2. 819.21 lbs of CO2e per MWh is equivalent to 102 kg per GJ of CO2e assuming a conversion factor of 1 MWh = 3.6 GJ.

[67] http://www.bcstats.gov.bc.ca/statisticsbysubject/ExportsImports/Data/ElectricityTrade.aspx.

> *"BC Hydro reports on its website the GHG intensity of electricity generated by BC Hydro and independent power producers in BC. The emissions associated with electricity imports are not included. This exclusion will be evaluated as more information becomes available and as policy evolves in regard to imported electricity."*

The document goes on to comment on BC Hydro's requirement to report GHG emissions from gross imported electricity:

> *"Since 2011, BC Hydro's wholly-owned subsidiary Powerex has reported GHG emissions associated with gross imported electricity, as required under B.C.'s Reporting Regulation."*[68]

Unfortunately the Company was not able to locate Powerex's GHG emissions associated with imported electricity.

The gap in government policy and data regarding electricity imports emission factors makes an informed, credible GHG comparison for new customers impossible. For example, if the Company assumed electricity imports were from Alberta or the Northwest Power Pool, displacement of electricity by natural gas in this instance could reflect a GHG reduction given the high GHG emissions factor of these electricity imports.

[68] 2014 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions. Table 1, p. 14. November 2014.

Attachment 10.4.1

12.7 **Contributions Paid by Connecting Customers**

The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years, or during the first 10 Years (if applicable) after the Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who had previously made contributions, except those Customers who have received funding under Section 12.11 (System Extension Fund). At the end of the fifth Year or tenth Year (if applicable), all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 **Refund of Contributions**

A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due:

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

For clarity, no refunds will be due to Customers who receive funding under Section 12.11 (System Extension Fund).

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12.9 **Extensions to Contributory Extensions**

When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension or within the ten-Year contributory period for the existing extension (if applicable), the new extension will be evaluated using the Main Extension Test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension, subject to Section 12.11 (System Extension Fund). The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 **Security**

In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

12.11 **System Extension Fund**

FortisBC Energy will budget funds annually to its System Extension Fund which is intended to provide limited assistance to eligible new Customers who are required to pay a contribution in aid of construction of a Main Extension.

Customers must apply for funding from the System Extension Fund, and the applications will be received by FortisBC Energy on or before March 31 or June 30 of each year.

The Customer applying for the System Extension Fund must meet the following requirements:

(a) The Customer must be within FortisBC Energy's Mainland, Vancouver Island, and Whistler Service Areas;

(b) The Customer must be the lawful owner of a separately metered single family , residence, evidenced by a copy of the Land Title Certificate;

(i) If the copy of the Land Title Certificate is not available, the Customer must give consent to FortisBC Energy to conduct a search of the Land Title Office to verify ownership;

(c) The residence must be used as the principal residence for the Customer; and

(d) The result of the economic test for the Main Extension must indicate a Profitability Index of greater than 0.2 and less than 0.8, and a contribution in aid of construction must be paid by the Customer.

The number of Customers eligible to receive the System Extension Fund will be limited and the determination of eligibility will be made by FortisBC Energy in its sole discretion, acting reasonably. The maximum System Extension Fund available to a Customer is 50 percent of the required contribution in aid of construction from the Customer, up to a maximum of $10,000 per Customer per residence.

A Main Extension may not proceed until funding has been approved and payment of the contribution is paid. A Main Extension must commence construction within nine calendar Months of the date FortisBC Energy approves the application for the System Extension Fund. Customers who provide a contribution in aid of construction for a Main Extension and who receive funding from the System Extension Fund will not be eligible for a refund as set forth in Section 12.8 (Refund of Contribution).

Attachment 21.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 26.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 26.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 27.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 32.1

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

Attachment 37.1

REFER TO LIVE SPREADSHEET MODEL

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Attachment 45.5

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Ontario

BY E-MAIL

BY: EMAIL AND WEB POSTING

February 18, 2015

To: All Applicants and Potential Applicants for Expansion of Natural Gas Distribution

Re: Expansion of Natural Gas Distribution

The Provincial Government has set out a goal of ensuring that Ontario consumers in communities that currently do not have access to natural gas are able to share in affordable supplies of natural gas. In an effort to facilitate enhanced access to natural gas for rural and remote communities and businesses in the province, the Ontario Energy Board (the "Board") is inviting parties with the appropriate financial and technical expertise to propose one or more plans for natural gas expansion.

In this context and depending on the nature and scope of any proposals made, the Board is aware that regulatory flexibility may be required. The Board will hear requests for regulatory flexibility or appropriate exemptions in the context of an application made for approvals pertaining to expansion portfolios and specific projects.

Background

In the Long Term Energy Plan the Ontario Government signaled that it would look at opportunities to expand natural gas service within the Province to areas that are not currently served. In support of this objective, the Government, through the Minister of Economic Development, Employment and Infrastructure, will be making available;

- $200 million in Natural Gas Access Loans over two years to help communities partner with utilities to extend access to natural gas, and
- $30 million in "Natural Gas Economic Development Grants" to accelerate projects with clear economic development potential.

In 1998, the Board established guidelines for the expansion of natural gas service in its *EBO 188 Report on Natural Gas Distribution System Expansion* (EBO 188). The intent of EBO 188 is to facilitate the expansion of natural gas service while holding other customers harmless from the cost of new connections.

EBO 188 adopts a portfolio approach for gas expansion/connections, which requires distributors to design a portfolio of projects that will achieve an overall profitability index (PI) of 1. This means that over the life of the projects within the portfolio, connected customers will pay the entire costs (through rates and a capital contribution if required). EBO 188 also specifies that any one individual expansion project within a portfolio or otherwise must meet a PI of 0.8. This requirement is intended to minimize cross-subsidization across customers within a portfolio.

While minimizing cross-subsidization either within a portfolio of projects, or between a portfolio and the rest of Ontario customers remains an important goal, the Board is cognizant that the specific requirements of EBO 188 may require some flexibility to expand access to natural gas for communities that are not currently served.

The Board's Approach

To the extent that the economics of a proposed project may not be accommodated within the current regulatory construct, the Board invites proponents to identify, within their applications, any options to address such regulatory issues. The Board will consider any such options as part of its adjudicative process. For instance, the Board may consider specific and supportable proposals that address;

- Whether the Board should allow existing natural gas distributors to establish surcharges to improve the feasibility of potential expansion projects by minimizing the level of required capital contribution.
- Whether the Board should allow for recovery of the revenue requirement associated with expansion costs in rates prior to the end of any incentive regulation plan term once the assets are used and useful.
- Whether projects that have a portfolio PI less than 1.0 and individual projects within a portfolio that have a PI lower than 0.8 should be considered.

Applicants should take the following into consideration when filing their application:

- Where no certificate of public convenience and necessity has been previously granted in a particular area, applications will be considered from all proponents with the requisite financial and technical expertise and experience.

- Proponents should develop proposals that, while ensuring safety and reliability, are cost effective and incorporate flexibility with respect to cost recovery (e.g. ROE, depreciation period, recovery of capital contribution, etc.).

- Proponents should develop proposals that include measures that foster predictability and cost certainty from a consumer perspective.

- Proponents should develop proposals that minimize impacts on existing natural gas ratepayers as a result of new expansion projects.

The Board is considering the need and manner in which to provide clarity for municipalities and potential new service providers on the processes needed to be taken to expand access to natural gas and will communicate further on this.

Invitation to Submit Application

The Board encourages parties interested in distributing natural gas to unserved rural and remote communities to submit an application seeking one or more required approvals (e.g. certificate of public convenience and necessity, franchise agreement, leave to construct) for the Board's consideration.

Subsequent to any Board approval of the above applications, a company would be required to apply to the Board for an order approving just and reasonable rates for the sale of gas and provisions of gas distribution services.

A summary of the requisite approvals is found under Appendix A of this letter.

Any questions relating to this letter should be directed to **Jason Craig** at **jason.craig@ontarioenergyboard.ca** **at** 416-440-8139. The Board’s toll-free number is 1-888-632-6273.

Yours truly,

Original Signed By

Peter Fraser
Vice President, Industry Operation Performance

Appendix – A
Description of Approvals

Certificate of Public Convenience and Necessity

In order to provide natural gas distribution services to consumers in Ontario, a company must apply to the Board for a certificate of public convenience and necessity for the service territory that is to be served.

The certificate of public convenience and necessity grants the gas distributor the right to construct infrastructure for the purposes of supplying gas to consumers in the service territory specified.

Numerous examples of certificate of public convenience and necessity applications can be found on the Board's website.

Franchise Agreement

In order to provide natural gas distribution services to consumers in Ontario, a company must also enter into a municipal franchise agreement with a municipality. The municipal franchise agreement is signed by both the municipality that is agreeing to be served and the distribution company.

The Board has the authority to approve the municipal franchise agreement. The municipal franchise agreement sets out the right for a natural gas distributor to operate works and add to works for the distribution of gas within the boundaries of a municipality.

In 2000, a Model Franchise Agreement ("MFA") was developed for use across the province.

The MFA sets out the obligations of the gas distributor in regard to the technical, construction, safety, and operational aspects of the natural gas distribution system within the municipality. The terms of the MFA ensure coordination between the municipality and the utility with regards to construction, operation and maintenance of the system. The standard term of the MFA is 20 years.

The model franchise agreement and examples of franchise agreement applications can be found on the Board's website.

Leave to Construct

Any company planning to build a distribution system in Ontario must apply to the Board for leave to construct if the proposed pipeline:

a) is greater than 20 kilometres in length;
b) is estimated to cost more than the amount prescribed by certain regulations (currently $2 million); or
c) uses pipe that has a nominal pipe size of 12 inches or more and has an operating pressure of 2,000 kilopascals or more.

Application may also be made to the Board to expropriate the land rights necessary to build the pipeline (and related infrastructure) once leave to construct is granted.

Leave to construct applications typically provide: a project summary, information regarding the need for the proposed project, facility planning information, the projected costs of the project and other economic, engineering, and environmental information (including detailed environmental reports), and the land requirements for the project (including plans for informing and negotiating with impacted landowners).

The Board's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* provides detailed information regarding the planning requirements for locating new facilities, the mitigation measures required for pipeline (and related facility) construction and the process for review and approval of environmental reports. These guidelines can be found on the Board's website: http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Enviro_Guidelines_HydrocarbonPipelines_2011.pdf.

Numerous examples of leave to construct applications and the associated Board decisions on those applications can be found on the Board's website.