September 25, 2017

VIA EMAIL

Patrick Wruck - Commission Secretary
B.C. Utilities Commission
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Vancouver, BC Canada V6Z 2N3

BCPIAC
Public Interest Advocacy Centre

Reply to: Leigha Worth
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Dear Mr. Wruck:

Re: FortisBC Energy Inc. 2016 Rate Design Application
Cost of Service Application (COSA) and Revenue to Cost (R:C) Ratios

Please be advised that we make the following final submissions in regards to the COSA and R:C Ratios from FEI's 2016 Rate Design Application on behalf of the ratepayer group known in this regulatory process as BCOAPO or BCOAPO et al. The member groups of BCOAPO et al. represent the interests of low and fixed income residential energy consumers before the BC Utilities Commission (Commission or BCUC) and, more specifically in this process, the interests of Fortis's low and fixed income residential natural gas ratepayers. As such, all of BCOAPO's member organizations have a direct and material interest in the outcome of this 2016 RDA.

This Streamlined Review Process was limited to two questions:

- Whether the COSA Studies for FEI and the Fort Nelson service area are in general and in detail reasonable representation of the cost causation; and
- Whether the revenue to cost (R:C) ratio; the margin to cost (M:C) ratio; or a combination of both R:C and M:C ratios should be used to guide rate design and the corresponding range(s) of reasonableness of the selected ratio(s) (together revenue to cost ratios)

While it is tempting to discount altogether the science behind the COSA and R:C Ratios FEI brought before the Commission in this application, BCOAPO agrees with the Utility that although cost allocation has a number of discretionary decisions, these decisions are not "art" but rather the serious weighing of alternatives based on a number of principles.

- Consistency - the results of cost allocation studies should not result in highly variable outcomes when run and changes to current practice should be accompanied by supporting evidence
- Industry standards – cost allocation and rate design is well understood and practiced among North American utilities – a cost allocation should adhere to well

established ("the Bonbright") principles and departures should be accompanied by reasoned evidence;

- The resulting revenue-to-cost ratios should be set to reasonably recover 100% of the study costs – recognizing that the results of such studies will vary over time a range of reasonableness for these ratios should be established so as to maintain the rate principle of stability.

COST OF SERVICE ALLOCATION STUDIES (COSA)

In comparison with the last 2012 study, the new COSA is modestly favourable to the residential class.

Rate Schedule	COSA results filed in Rate Amalgamation Application		COSA filed in 2016 Design	
	($000s)	Percentage of total	($000s)	Percentage of total
1	509,718	69.9%	510,654	65.2%
2	109,009	15.0%	129,861	16.6%
3/23	80,250	11.0%	95,247	12.2%
4	51	0.0%	51	0.0%
5/25	27,442	3.8%	35,111	4.5%
6	212	0.0%	151	0.0%
7/27	1,311	0.2%	1,540	0.2%
22	967	0.1%	806	0.1%
22A	n/a	n/a	6,824	0.9%
22B	n/a	n/a	2,602	0.3%
Total	**728,961**	**100%**	**782,847**	**100%**

The methodologies used for the functionalization, classification and allocation industry standards. FEI has followed conventional cost allocation methods. Below are changes since the last COSA (2012):

Table 6-7: Summary of Changes to COSA Methodologies from 2012

Application Section	Methodology Description	2012 COSA Method	2016 COSA Method	Comments
6.3.4	Functionalization	Eight Functional Categories: Gas Supply, Tilbury Storage, Mt. Hayes Storage, SCP, Distribution, Transmission, Customer Accounting and Marketing.	Seven Functional Categories. Eliminated SCP as a separate function and functionalized with Transmission.	Assets from the insourcing of the Customer Care function and costs embedded in General and Intangible plant are functionalized as Customer Accounting.
6.3.5	Classification	Three Cost Classifiers; Demand, Customer, Energy.	No change from 2012	
6.3.6	Allocations	Customer-related costs allocated based on average and weighted customers. Demand-related costs allocated to rate schedules based on coincident peak demand. Energy-related costs allocated based on sales volume.	No change from 2012 except that RSAM is classified as Energy- related and allocated it based on sales volume to rate schedules that it relates to (RS 1, RS 2, RS3)	The RSAM is in place for RS 1, RS 2 and RS 3 to mitigate revenue instability to both customers and the Utility from non-normal weather.
6.3.5.4	Distribution System Mains Classification	MSS was performed using 60 mm mains.	No change from 2012	

Application Section	Methodology Description	2012 COSA Method	2016 COSA Method	Comments
6.3.5.4	Peak Load Carrying Capacity	Based on capacity determination of a distribution system using 60 mm mains as the minimum.	No change from 2012	
6.3.1.5	Revenues Associated with Bypass and Contract Rates	Revenues treated as a credit to Cost of Service and allocated to all other rate schedules	No change from 2012 (**COSA**)	**Final COSA** results include rate design proposals which have BCH ICP and JV included with other industrials in an industrial rate schedule
6.3.1.3	Revenues Associated with Industrial Customers (RS 22A & RS 22B)	Revenues treated as a credit to Cost of Service and allocated to all other rate schedules	R:C ratios are calculated and included in COSA schedules	Workshop feedback suggested that these rate schedules should be shown within the COSA.

Source: Table 6-7 Exhibit B-1, section 6.3.3, page 6-12

FUNCTIONALIZATION

One change has been proposed in the functionalization. As noted at Table 6-7, FEI proposes to remove the functional category of SCP. The elimination of SCP as a separate function has no impact on the costs allocated to the residential class. As we understand it Southern Crossing Pipeline costs are included in transmission rate bases based on peak day demand (SRP TR pg.461).

Table 6-16: Delivery Cost of Service Allocation to Rate Schedules

Rate Schedul	($000s)	Percentage of
1	510,65	65.2
2	129,86	16.6
3/23	95,24	12.2
4	51	0.0%

5/25	35,111	4.5%
6	151	0.0%
7/27	1,540	0.2%
22	806	0.1%
22A	6,824	0.9%
22B	2,602	0.3%
Total	**782,84**	**100.0**

Mt. Hayes LNG Storage

The major differences in comparison to other similar gas utility cost allocations are in the Mt. Hayes LNG Storage which is, in FEI's case, classified as a transmission function. The Elenchus review accepts FEI's explanation for this classification based on the fact that the asset is used for downstream gas distribution.

FEI considered two options for the LNG storage functionalization. Option A (the chosen methodology) is to continue to separate Mt. Hayes into its storage and transmission components. Option B is consistent with the Tilbury cost allocation, whereby all Mt. Hayes costs are allocated to delivery. Using Option A, the residential class is allocated $15,143,000 of Mt. Hayes costs, $3,990,000 within the COSA model and $11,154,000 through the midstream cost allocation model (which is reset annually). Under Option B, the residential class is allocated $13,494,000 within the COSA model.[1] The difference between the two functionalization models results in a difference of $1,649,000.

BCOAPO has no objection to FEI's proposals in regards to Mt. Hayes LNG Storage.

Classification

System Demand - Minimum System

The Minimum System methodology utilized by FEI is within accepted practice. FEI has used the PLCC adjustment rather than using the zero intercept method to differentiate customer and demand costs. We agree with Elenchus' conclusion that the methodology FEI has used in this application is appropriate and in line with industry practice.

One issue raised is whether 60mm or 42 mm pipe best represents FEI's minimum system infrastructure. It goes without saying that this is an issue because if FEI were to change to use 42mm pipe in this calculation this would cause an additional $14 million in costs to be allocated to the residential class[2]. In the course of this process, FEI has explained that it has been using 60mm pipe to as its minimum system infrastructure since 2003 and

[1] Exhibit B-8, BCOAPO IR 6.3.
[2] Exhibit B-5, BCUC IR 7.3.

furthermore, about 70% of mains installed in the past two years have been 60mm as compared to 5% at 42mm[3].

In BCOAPO's submission, FEI's approach passes both a relevance and consistency test.

We note FEI has amended its application to a specific Peak Load Carrying Capacity (PLCC) for Fort Nelson. BCOAPO supports this change as a Fort Nelson-specific PLCC is the more correct way to adjust the specific Fort Nelson Minimum System study[4].

Allocation

Customer Weightings

Table 6-15: Customer Weighting Factor Study and Customer Administration Factor Results

Rate Schedule	Customer Weighting Factor	Customer Admin & Billing Factor
1	1.0	1.0
2	1.7	1.0
3	7.0	1.2
4	13.6	0.9
5	11.1	43.0
6	13.3	43.0
7	132.5	43.0
22	49.9	75.0
22A	399.2	75.0
22B	562.6	75.0
23	10.3	75.0
25	17.6	75.0
27	46.2	75.0

Source: Application, Exhibit B-1, pg. 6-25

Customer weightings are amongst the more discretionary parts of a cost allocation study. In any evaluation of an application such as this one, the customary practice is one that looks for consistency with past practice as changes over time in this category are unusual for the larger customer classes.

Customer Weighting Factor for Service Lines and Meters

[3] Streamlined Review Process Transcript, page 407.
[4] Exhibit B-1-1-1.

Rate Schedule	2016 Customer Weighting Factor	2012 Customer Weighting Factor
1	1.0	1.0
2	1.7	1.7
3	7.0	6.8
4	13.6	13.2
5	11.1	11.8
6	13.3	14.2
7	132.5	37.2
22	49.9	38.6
22A	399.2	N / A
22B	562.6	N / A
23	10.3	10.0
25	17.6	16.5
27	46.2	31.7

Source: Exhibit B-8, BCOAPO IR 6.6.

FEI proposes some significant changes in customer weightings for the large class customer base and only minor adjustment for the small commercial class (Rate 3). The 2012 study did not include the large industrial customers in Rate Schedules 22A and 22B. The number of customers served under RS 7 is small and FEI states that the weighting factor changed dramatically due to the change in the number of customers served in 2012 relative to those in the 2016 study.

While it is difficult to determine the prudency of these changes it does follow that large class customers would have more variability in incurred costs due both to their unique characterization and their small numbers (relative to Rates 1 and 2). Meter costs and customer numbers largely affect customer weighting explaining the relative stability in the rate classes with larger number of customers.

> "*The Customer Weighting Factors for Administration and Billing were developed in 2011 and were included in FEI's 2012 Common Rates, Amalgamation and Rate Design Application. The process used to develop the factors did not involve any empirical analysis or calculations, but was through conversations with customer managers using their insight and experience, along with input from EES Consulting. For FEI's 2016 Rate Design Application, the factors developed in 2011 were again reviewed with customer service managers to determine whether they were still reasonable. FEI determined that the factors from 2011 were still reasonable and subsequently used them in the COSA that supports FEI's 2016 Rate Design Application.*"[5]

[5] Exhibit B-15, BCUC IR2 3.0.

It is clear from the responses to BCUC IR2 3.0-3.3 that the method for determining customer weights for Administration and Billing is one of the least rigorous parts of its COSA. As a result, BCOAPO recommends that the Commission order FEI to conduct a review of best practice in this area and report or apply its findings in its next COSA.

<u>NCP vs CP demand allocators</u>

Elenchus stated that the more usual practice is to use non coincident peak (NCP) to allocate distribution demand related assets and expenses by electric utilities. However, FEI noted that it has used a coincident peak allocator since 2001[6]. Furthermore, they stated that there would be very little difference in using NCP.

It is not clear to that FEI is correct in stating that using NCP as opposed to CP makes little difference. The table below shows the R:C ratios using the different methods and in BCOAPO's view it shows that using CP generally underestimates (or lowers) the R:C ratio for the residential class.

Particulars	Residential	Small Commercial	Large Commercial	Seasonal	General Firm	NGV / VRA	Interruptible Small Industrial	Large Industrial T-Service RS 22	Large Industrial T-Service RS 22A	Large Industrial T-Service RS 22B
1993 Post Phase B Decision M:C										
Coincident Peak	90%	95%	100%	127%	117%	82%	780%	754%	123%	90%
Non-Coincident Peak	96%	104%	113%	87%	124%	83%	140%	80%	85%	84%
Average & Excess	97%	107%	112%	79%	114%	79%	126%	76%	82%	81%
1996 Rate Design Application M:C										
Coincident Peak	87.1%	95.0%	117.0%	181.1%	186.1%	67.8%	875.4%	1827.8%	111.2%	115.5%
Non-Coincident Peak	90.8%	101.0%	127.6%	158.2%	203.7%	68.4%	171.4%	164.9%	89.4%	126.4%
Average & Excess	91.6%	103.1%	128.3%	137.5%	184.0%	66.9%	155.8%	144.9%	83.7%	121.7%
1996 Rate Design Settlement M:C										
Coincident Peak	91.4%	96.1%	103.9%		137.5%	67.3%			108.8%	111.3%
1996 Rate Design Settlement R:C										
Coincident Peak	95.3%	98.2%	101.6%			74.3%				
2001 Rate Design Application M:C										
Coincident Peak	92.0%	104.2%	118.2%	288.1%	123.3%	102.1%			93.4%	110.0%
2001 Rate Design Application R:C										
Coincident Peak	96.5%	101.5%	105.1%	119.8%	102.1%	101.0%				
2012 Common Rates, Amalgamation & Rate Design R:C [1)]										
Coincident Peak	93.4%	104.6%	107.9%		110.4%	112.7%				
2016 Rate Design Application M:C	Initial COSA									
Coincident Peak	93.1%	102.5%	103.3%	550.9%	112.2%	159.1%	712.3%	1864.4%	109.8%	99.7%
2016 Rate Design Application R:C										
Coincident Peak	95.6%	101.3%	101.6%	147.4%	104.9%	131.2%	139.6%	1425.5%	109.5%	99.7%
2016 Rate Design Application M:C	COSA after Rate Design Proposals									
Coincident Peak	94.4%	104.1%	107.6%	578.3%	116.0%	160.4%	713.6%	100.0%	113.4%	103.1%
2016 Rate Design Application R:C										
Coincident Peak	96.4%	102.2%	103.6%	150.2%	106.3%	131.7%	139.3%	100.0%	113.0%	103.1%

[6] Streamlined Review Process Transcript, page 416.

BCOAPO agrees with FEI's addendum to this interrogatory response where the utility noted that `*caution needs to be exercised when trying to compare the results from COSA study to another done at a different time*." This is even more the case given the structural changes that took place during FEI's amalgamation. It is also, in our view, indicative of why a wider range of reasonableness makes for a prudent R:C policy at this time.

Load Studies

In its load studies, FEI divides its service territory into heat zone areas (Lower Mainland, Inland, Whistler etc.) and then it uses a three year average to derive peak day demand.

BCOAPO agrees that use of the NCP is sufficient at this time. However, in our view, the Commission should direct FEI to investigate use on longer periods to derive its peak day demand average. Periods of 5 or even 10 years would be more representative and, in our view, eliminate immediate weather cycles from the data, with higher quality results.

Adjustments to the 2016 Revenue Requirement

FEI's COSA model is a based on the 2016 revenue requirement. It has made some adjustments for projects expected to be in-service after January 1, 2018. These are:

- the Lower Mainland Intermediate Pressure System Upgrade Project ("LMIPSU"),
- the Coastal Transmission System Project ("CTS"), and
- the Tilbury Expansion Project.

Tilbury Expansion

In response to CEC IR1, 12, FEI explained that "[*T]he primary purpose for current Tilbury LNG is to serve as a needle peaking gas supply resource for firm core service customers. Beyond that, it is important to differentiate Tilbury LNG as a gas supply resource and Tilbury LNG as a system capacity resource, as send out from Tilbury can be called for either gas supply or operational capacity reasons*."

The Tilbury Expansion project is estimated to cost $400 million plus development costs and AFUDC and it is being developed to serve the LNG market[7]. In this application, FEI has asserted that the Tilbury Expansion Project is unique amongst the three projects listed above as it will have incremental volumes and revenues associated with it. As a result, the Utility has elected to, instead of using a forecast of costs as of 2018 and the first year revenues, use a 10-year levelized forecast of the costs and revenues in the COSA to represent the medium term impact that the Tilbury Expansion Project will have on its customers.

[7] Streamlined Review Process Transcript, page 402.

Elenchus has stated that the 10 year horizon used by FEI in its COSA study to reflect the impact of the Tilbury Expansion project is not consistent with standard practice. Utilities undertake new investments on an ongoing basis and, as a result, the revenue requirement in any year includes costs for older assets that have a diminished impact on the total revenue requirement as well as new assets that have a high initial impact. "*Except in extraordinary cases, it would be inconsistent to levelize the costs of a single project while not levelizing the costs associated with other investments. Elenchus is not aware of any unique aspects of the Tilbury Expansion Project that make its impact on customers generally, or any class of customers, that justify exceptional treatment of this project in the form of levelizing its costs for purposes of the COSA*".

The difference between costs and revenues for the Tilbury Expansion Project is allocated to all non-bypass customers, including the residential rate schedule (RS 1). The amount allocated to RS 1 equals $3.8 million and translates to an annual bill increase of approximately 0.5% for 'the average residential customer'.[8]

The biggest change to the COSA resulting from the use of the 2018 Tilbury Expansion forecast costs and revenues as proposed is that the known and measurable changes are increased by $15,383,000. This increase is mainly due to the difference between the forecast revenues in 2018 compared to the ten-year levelized forecast revenues.[9]

In BCUC IR 9.2, the following rationale was provided along with the table below showing estimated costs and revenues associated with this project.

> *The Tilbury Expansion Project, which has both incremental volumes (revenues) and costs, is unlike the Lower Mainland Intermediate Pressure System Upgrade Projects and the Coastal Transmission System Project, which have costs but do not have incremental volumes associated with them. For the Tilbury Expansion Project, the incremental volumes are not all realized at the time that the full costs of the Tilbury Expansion Project are included in rate base. Reflecting only the first year of incremental revenues would not be representative of the longer term impact that the Tilbury Expansion Project will have on the revenue requirement. As such, and as described in Section 6.3.2.3, FEI used a 10-year levelized approach for inclusion of costs and revenues for the Tilbury Expansion Project.*

$000	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7			
O&M	3,570	3,928	4,331	4,823	5,722	7,072	7,213	7,357	7,504	7,654
Depreciation										
Structures & Improvements	3,096	3,130	3,161	3,188	3,211	3,341	3,360	3,409	3,429	3,450
Gas Holders - Storage	2,211	2,236	2,258	2,277	2,294	2,387	2,400	2,435	2,450	2,464
Compressor Equipment	9,434	9,540	9,634	9,717	9,787	10,183	10,241	10,391	10,451	10,513

[8] Exhibit B-5, BCUC IR 9.0.
[9] Exhibit B-5, BCUC IR 9.3.

Negative Salvage Provision	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423
Income Tax	(751)	(174)	438	929	1,396	1,761	1,116	521	(131)	(750)
LNG Tax Credit	(425)	(842)	(962)	(1,342)	(1,494)	(2,252)	(2,350)	(2,421)	(2,465)	(2,510)
LNG Tax	0	39	63	165	186	380	393	406	419	432
Earned Return	28,425	27,682	26,895	26,062	25,268	24,432	23,514	22,590	21,636	20,798
Total Cost of Service (i)	**46,984**	**46,963**	**47,241**	**47,241**	**47,793**	**48,727**	**47,311**	**46,112**	**44,716**	**43,474**
RS46 Delivery Revenue (ii)	**11,220**	**21,463**	**23,770**	**32,204**	**34,893**	**51,278**	**52,300**	**53,343**	**54,406**	**55,490**

Source: Exhibit B-5, IR 1 BCUC 9.2

FEI has also stated that "[*As] the LNG market grows and RS 46 revenues become greater than Tilbury Expansion costs, all non-bypass customers will benefit from the revenue greater than costs, so it is fair to allocate these same customers the net difference in the revenues and costs within the COSA model. Allocation to all non-bypass customers is also the treatment prescribed by Direction No. 5 for both RS 46 revenues and Tilbury Expansion costs*." (CEC IR 1 #13)

These forecasts appear to be dependent upon the coming into force of the enacted LNG Tac and Tax credit. In our view there is some risk that both the cost and revenue forecasts of FEI will vary significantly. This risk should, in BCOAPO's submission, be considered by the Commission in its deliberation of whether to include the Tilbury Expansion in the COSA on the proposed levelized basis.

Had FEI instead used the 2018 forecast costs in the COSA there wold be a $15.383M increase over that provide on the ten-year levelized approach as shown below.

Table 6-16 (Adjusted): Delivery Cost of Service Allocation to Rate Schedules

Rate Schedule	$ thousands	Percentage of total
1	519,186	65.0%
2	133,067	16.7%
3/23	97,838	12.3%
4	51	0.0%
5/25	36,138	4.5%
6	152	0.0%
7/27	1,542	0.2%
22	808	0.1%
22A	6,840	0.9%
22B	2,608	0.3%

Total	**798,230**	**100.0%**

Source (Exhibit B-5, BCUC 9.3.1 pg. 39)

The difference to the residential class is allocations of $519,186 as compared to the proposed 510,654. The resulting change to the proposed revenue-to-cost ratios are shown below:

Rate Schedule	Change in R:C
RS 1	+0.2%
RS 2	-0.2%
RS 3/23	-0.3%
RS 5/25	-0.3%
RS 6/6P	+0.9%
RS 22A	+2.0%
RS 22B	+1.8%
RS 22	0.0%
RS 4	+1.1%
RS 7/27	+0.9%

(Source: Exhibit B-5, BCUC 1.9.3.1)

On page 7 of its Final Submission, FEI relied on the Elenchus comment that, "*Cost allocation is more art than science. There is not going to be one right answer and a wrong answer. But, it should reflect their own utility circumstances".* On page 8, they also rely on the fact that FEI expects Tilbury to cause a new revenue stream not from existing customers. However, it is not clear why, on a principled basis, this change is being made. One might also argue that because both the costs and revenues are untested at this time that it would be imprudent to use the FEI levelized approach. It is also not clear why LNG facility costs should be allocated on an embedded costs basis as opposed to an incremental cost. If the LNG facility has specific new revenues associated with it then it might follow that it has directly assignable costs as well.

We agree with the Elenchus conclusion that the Tilbury Project should be included on the standard rolled in methodology[10]. In BCOAPO's submission, the Commission should revisit the issue of inclusion of the Tilbury Expansion project when it is fully or substantially completed (in-service).

RATE SPECIFIC ISSUES

Rate 22A and 22B

[10] Exhibit B-11, CEC IR 16.1.1.

Rate 5 Gas Cost Allocation

The only change in the gas cost allocation is in the derivation of the load factor for Rate Schedule 5 (General Firm Service) customers. FEI currently allocates midstream costs to Rate Schedule 5 using a deemed 50 percent load factor. This value was established as part of a negotiation with parties in the 1996 Rate Design Application.

FEI states that it contracts for its midstream resources based on a peak day demand and that this should be used for deriving the load factor for Rate Schedule 5. In FEI's view this would better allocate costs in the way in which they were caused.

FEI is proposing to utilize the same approach for allocating midstream costs to Rate Schedule 5 as it does for Rate Schedules 1, 2, and 3 by using a three-year rolling average load factor. Under the new approach, the load factor used to allocate midstream costs to Rate Schedule 5 would be approximately 45 percent.

The approach proposed by FEI appears reasonable. BCOAPO's only comment is with respect to the use of the 3 year rolling average which is used generally by FEI to determine load factors. Again, in our view, it is worth investigating the use of longer period averages to eliminate short term weather variations.

Utilities generally rely, at least in part, on estimated load profiles for some or all of their customer classes. In Elenchus' experience, the estimated load profiles are typically based on load research which involves detailed consumption data rooted in detailed metering of a statistically significant sample of customers or reliance on data from comparable utilities. These load research methods are considered to be the most cost-effective way to derive suitable load profiles for use in both systems planning and cost allocation."[11]

We note from the Utility's response to Exhibit B-15, BCUC IR 5.1 that the implementation of larger number of demand meters, presumably in the larger industrial class, has given FEI a better understanding of its peak customer demands. In a future COSA, BCOAPO suggests it might be beneficial for FEI to be required to undertake load studies based on sample demand meters within its other classes.

	1996	2001	2016
Residential Peak Demand (GJ)	687,83	696,57	635,52
Small Commercial Peak Demand (GJ)	213,87	232,65	247,04
Large Commercial			
No. of Customers	6,107	6,412	6,709
Total Peak Demand (GJ)	229,76	200,82	200,51
No. of Customers with Demand Meters	92	325	1,681

[11] Exhibit A2-11, Elenchus Response to BCUC IR 2 on Elenchus Report; Streamlined Review Transcript, page 524.

Total Peak Demand from Customers with Demand	Unknow	Unknow	66,56
Industrial			
No. of Customers	250	690	796
Total Peak Demand (GJ)	38,679	72,36	79,74
No. of Customers with Demand Meters	153	614	796
Total Peak Demand from Customers with Demand	Unknow	Unknow	79,74
Total Peak Demand on FEI System (GJ)	**1,378,13**		**1,206,19**

Source: Exhibit B15 BCUC 5.1

REVENUE TO COST RATIOS

Two issues need to be considered with respect to revenue to cost ratios

<u>R:C vs M:C ratios</u>

> "*The margin to cost ratio is calculated by excluding gas and storage and transport costs from both the numerator and denominator of the R:C ratio. The definition of R:C and M:C ratios implies that the calculated R:C ratio range would always be less than the calculated M:C ratio range. Since there is a consistent relationship between R:C and M:C ratios, it is essentially no difference in using either of the ratios as the benchmark. However, to compare FEI with other gas utilities, it is better to use a ratio that is adopted by others*."
> (Exhibit A2-2, Elenchus COSA Report, pg. 28)

However, at the SRP Mr. Todd clarified:

> *Our bias is, you've got to -- you have to have one as a primary reference. The M:C ratio excludes things that are pass-throughs. Therefore, it makes sense to use the M:C ratio. And I note that in other jurisdictions where they've got something they call the revenue-to-cost ratio, they do the revenues and costs for the distribution function and exclude the pass-throughs. So others have done it in the same way as FEI's margin to cost ratio. The advantage of that, as pointed out in the report, is one, the margin -- the pass-throughs vary across different classes. So using an MC ratio for all the classes as the primary measure, in a sense, makes more sense when you're comparing classes.*[12]

On page 28 of its Final Argument, FEI argued that R:C ratios are preferable to M:C ratio primarily on the basis that it is current practice.

While there might be some arguable merit in using an M:C ratio because it eliminates pass-through costs, the end results for either measure is the same, the only difference is

[12] Streamlined Review Process Transcript, page 436.

the range of reasonableness that might be attached to either ratio. Given the vicissitude of cost allocation as a whole, it is essential to ensure rate stability within the meaningful principle of cost causality. In BCOAPO's view, the proposed R:C ranges of FEI achieve this goal and it avoids the difficulty of using M:C ratios: the narrower band of reasonableness with more potential rate instability due to specious outcome changes in the cost allocation exercise.

The Range of Reasonableness

R:C ratios are assessed based on whether or not they fall within an established "range of reasonableness". FEI believes that the appropriate range of reasonableness for evaluating its R:C ratios is 90 per cent to 110%.

Commission Order G-130-07 in BC Hydro's 2007 Rate Design Application determined that a "range of reasonableness of 95 per cent to 105 per cent was proper. FEI argues that natural gas utilities have less certain system demand data compared to that available to electric utilities.

Table 6-18: R:C and M:C Ratio Results before Rate Design 1 Proposals or Rebalancing

Rate Schedule	R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%
Rate Schedule 2 *Small Commercial Service*	101.3%	102.5%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	101.6%	103.3%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.9%	112.2%
Rate Schedule 6 *Natural Gas Vehicle Service*	131.2%	159.1%
Rate Schedule 22A *Transportation Service (Closed) Inland Service*	109.5%	109.8%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	99.7%	99.7%

FEI excluded RS 4, RS 22, and RS 7/RS 27 from Table 6-17 on the basis that Rate Schedule 4 is a seasonal service (firm in the summer and interruptible in the winter), RS 22 is predominantly interruptible and RS 7/RS 27 is fully interruptible and as such these rate classes do not drive system capacity additions.

FEI has noted the following precedents with respect to the range of reasonableness.

Utility	Range of Reasonableness
AltaGas[61]	95% to 105%
ATCO[62]	95% to 105%
Union Gas[63]	Close to unity[64]
Enbridge[65]	Close to unity
Centra Gas[66]	100%
SaskEnergy[67]	95% to 105%

Source Table 4 – Elenchus Report

In BCOAPO's submission, the FEI range proposal to maintain the current band is reasonable. Attempts to use tighter ranges implies accuracy that simply does not exist. Cost of service studies, by their nature, contain many points of ambiguity for which judgement is required. For example, it is misguided to, as some have suggested, consider that the residential class is `subsidised` by some other classes based on R:C ratios. The fact is that the entire distribution system of FEI would not exist without the infrastructure which services and is paid for by the residential and small commercial classes. In this sense at least the large number of small volume customers subsidize the small number of large volume customers.

We agree with Elenchus and FEI who have noted that consistency and symmetrical treatment are important factors in using revenue-to-cost ratios whether one is considering the type of metric or its range of reasonableness.

R:C Ratios after Rate Design

The R:C ratios are adjusted for rate design changes. Note that the residential class R:C ratio increases by 90 basis points (nearly 1%) after this exercise.

Table 12-2: COSA R:C and M:1 C Results after Rate Design Proposals

Rate Schedule	COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after all Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%	848.1	0.1%	96.4%	94.4%

Rate Schedule 2 *Small Commercial Service*	101.3%	102.5%	(1,174.1)	-0.5%	102.2%	104.1%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	101.6%	103.3%	1,174.1	0.6%	103.6%	107.6%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.9%	112.2%	45.2	0.0%	106.3%	116.0%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.2%	159.1%	(61.7)	-16.5%	110.0%	119.0%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	109.5%	109.8%			113.0%	113.4%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	99.7%	99.7%			103.1%	103.1%
Rate Schedule 22 *Large Volume Transportation Service*	1425.5%	1864.4 %	(754.2)	-3.4%	100.0%	100.0%

Rate Schedule *(rates not set using allocated costs)*	COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after all Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	147.4%	550.9%	13.3	1.9%	150.2%	578.3%

Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.6%	712.3%	(90.7)	-0.3%	139.3%	713.6%

The reasons for the increase are:

1. Increase the Basic Charge per Day by $0.0195 from $0.3890 to $0.4085 to increase the proportion of fixed costs recovered by the Basic Charge; and
2. Decrease the Delivery Charge per GJ by $0.086 to maintain revenue neutrality.

The range used by FEI has been used historically and has strong roots in acceptable industry standards and there is nothing persuasive on the record to indicate another approach is necessary.

All of which is respectfully submitted.

Sincerely,
BC Public Interest Advocacy Centre

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