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June 1, 2012

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("FEFN" or "Fort Nelson"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW") Common Rates, Amalgamation and Rate Design Application (the Application)

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

In accordance with Commission Order No. G-46-12 setting out the Regulatory Timetable for the review of the Application, the FEU respectfully submit the attached response to BCUC IR No. 1.

If there are any questions regarding the attached, please contact Paul Craig at 604-592-7459.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Requested Approvals

Exhibit B-3, Section 2.1.2, p. 11

1.1 Please file the current Corporate Services Agreement between FortisBC Holdings Inc. and each of FEVI and FEW.

Response:

The current Corporate Services Agreements executed between FortisBC Holdings Inc. ("FHI") and each of FEI, FEVI and FEW are all effective January 1, 2010, each with an executed Amending Agreement, effective January 1, 2012, reflecting the corporate name changes. Attachment 1.1 contains the current Corporate Services Agreements in effect between FHI and each of FEVI and FEW.

1.2 Please file a black-lined version of the amended agreement with FEI, the clean version of which is included in Appendix F.

Response:

Attachment 1.2 contains a black-lined version of the proposed Corporate Services Agreement as provided in Appendix F of the Application. The black-lined version compares the Corporate Services Agreement currently in effect between FEI and FHI effective January 1, 2010 to the proposed Corporate Services Agreement for the Amalgamated Entity.

1.3 Please file the FEI Transfer Pricing Policy and Code of Conduct and the similar policy or any similar document that FEU is proposing to replace with the FEI Transfer Pricing Policy for any of the other companies.

Response:

Attachment 1.3 contains the FEI Transfer Pricing Policy ("TPP") and Code of Conduct ("COC") currently in effect and utilized by FEI today (there is no separate policy for FEVI or FEW).

The TPP and COC were reviewed during the FEI 2010-2011 RRA which determined that the policies were working as intended and that the current TPP and model used to charge NRBs by the utilities was reasonable and complete. The FEU, therefore, believe that for the Amalgamated Entity (retaining the name FortisBC Energy Inc.), the TPP and COC remain suitable and appropriate to govern utility interaction with NRBs.

1.4 Please specify the adjustment of conditions to Commission Order G-49-07 that are necessary to reflect the amalgamation of the FEU.

Response:

Commission Order No. G-49-07 re-affirmed the provisions regarding ring-fencing, governance and location of data. The FEU do not believe the principles outlined in the conditions to Commission Order No. G-49-07 need to be adjusted to reflect amalgamation, even though the named utilities will no longer exist but will continue as one after amalgamation. The principles would apply to the new amalgamated entity. If the Commission were to re-issue the conditions to reflect the amalgamation of gas utilities and to be applicable to FEI post-amalgamation, the FEU would propose the adjustments as laid out in the following table.

Conditions in Order G-49-07	Adjustments
Ring-Fencing	
"(1) Each Terasen Utility shall maintain, on a basis consistent with BCUC orders and accounting practices, a percentage of common equity to total capital that is at least as much as that determined by the Commission from time to time for ratemaking purposes.	(1) Change "Each Terasen Utility" to "FortisBC Energy Inc."
(2) No Terasen Utility will pay a common dividend without prior Commission approval if the result would reasonably be expected to violate the restriction in (1) above.	(2) Change "No Terasen Utility will" to "FortisBC Energy Inc. will not".
(3) (a) No Terasen Utility will lend to, guarantee or financially support any affiliates of the Terasen Utilities, other than between TGI and TGS, or as otherwise accepted by the Commission.	(3)(a) Change "No Terasen Utility will" to "FortisBC Energy Inc. will not"; remove "of the Terasen Utilities, other than between TGI and TGS"; change "or as otherwise" to "unless".
(b) TGI and TGS shall together maintain separate banking and cash management arrangements from other affiliates. TGVI shall establish separate banking and cash management arrangements from other affiliates once it has completed its proposed refinancing.	(3)(b) Remove.
(c) No Terasen Utility will enter into a tax sharing agreement with any affiliate of the Terasen Utility, unless the agreement has been approved by the Commission.	(3)(c) Change "No Terasen Utility will" to "FortisBC Energy Inc. will not" and remove "of the Terasen Utility".
4) No Terasen Utility will enter into transactions with affiliates that are not in compliance with Commission guidelines, policies or directives regarding affiliate transactions, and no Terasen Utility will enter into transactions with affiliates on terms less favourable to the Terasen Utility than those available from third parties on an arms-length basis, unless otherwise approved by the Commission.	(4) Change "No Terasen Utility will" to "FortisBC Energy Inc. will not" in two instances; remove "to the Terasen Utility".
5) No Terasen Utility will engage in, provide financial support to or guarantee non-regulated businesses, unless otherwise approved by the Commission.	(5) Change "No Terasen Utility will" to "FortisBC Energy Inc. will not".
Governance	
The Commission Panel finds that the Terasen Utilities should be required to maintain existing governance policies and that any changes in these policies should be approved by the Commission. In particular, the Commission Panel concludes that the continued independence of Directors, as required in existing governance policies, will provide a further assurance that the Terasen Utilities will comply with the ring-fencing conditions.	Change "the Terasen Utilities" to "FortisBC Energy Inc." in two instances.

Conditions in Order G-49-07	Adjustments
Location of Functions and Data	
The location of data and servers providing service to the Terasen Utilities is to be restricted to Canada and that any proposal to locate data and servers providing services to the Terasen Utilities (including data and servers providing back-up services) outside Canada will require the Commission's approval".	Change "the Terasen Utilities" to "FortisBC Energy Inc." in two instances.

2.0 Reference: Requested Approvals

Exhibit B-3, Section 1, p. 1; Exhibit B-5, Slide 7, *Utilities Commission Act*, s. 53(5)

Amalgamation and Postage Stamp Rates

On page 1 of the Application, the FEU request approval "to amalgamate FEI, FEVI and FEW, as well as Terasen Gas Holdings (THI)." On page 10 of the Application the FEU state "The rationale for amalgamation is entirely dependent on the adoption of postage stamp rates for the Amalgamated Entity for delivery, midstream and commodity rates."

Amalgamation of the FEU

- Legal Amalgamation of Natural Gas Utilities (FEI, FEVI, FEW & THI)
- Combined Cost of Service
- Maintenance of existing Capital Structure - 40% equity / 60% debt
- Weighted Average ROE
- Combined Gas Portfolio
- Common Tariffs/Terms & Conditions based on FEI

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Common Rates

- Common Commodity, Midstream and Interim Delivery rates effective Jan 1, 2014
- Rate Mitigation Approaches using RSDA to:
  - Phase-in Fort Nelson common rates over 15 years
  - Offset impact to FEI non-bypass customers – RSDA amortized over a three year timeframe

53(5) On conclusion of its inquiry, the commission must,

(a) if it is of the opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, submit its report and findings to the Lieutenant Governor in Council, or

(b) dismiss the application.

2.1 Please confirm that the FEU are not seeking a decision on amalgamation if the Commission does not approve common rates.

<u>Response:</u>

The following response addresses BCUC IR 1.2.1 and 1.2.2.

The principal approval sought within the Application is the request for common rates, which is sought on the basis of fairness and primarily to address the rate disparity across the service areas served by the FEU. In order to implement common rates, legal amalgamation of the FEU is necessary. The FEU believe that extension of the current common rate structure currently realized by FEI's 850,000 customers to the other service areas served by the FEU most appropriately achieves this objective. As discussed in this Application, there are other rate structures that the FEU have considered that could move toward this objective. However, it is the FEU's view that amalgamation without a change in rate structure does not provide material benefits beyond what the companies have already been able to achieve through its common management structure.

As discussed in the Application, Section 3, page 51, the companies have operated under a common management and operating structure since the early 2000s, as such, benefits normally associated with an amalgamation have largely been achieved. Section 6 outlines several operational benefits that would be achieved via the implementation of common rates and amalgamation.

Under the scenario where only amalgamation is approved, the majority of those benefits cannot be realized. Specifically, if only amalgamation is approved, the legal (Section 6.6.2) and some of the other financial (Section 6.6.4) efficiencies could be realized. With respect to the potential savings on the cost of debt (Section 6.6.3), that would also be achievable assuming that legal amalgamation resulted in FEI Amalco maintaining its current ratings.

Please refer to BCUC IR 1.2.3 for a discussion on scenarios that may address the FEU's objectives in addition to the proposed common rates design and amalgamation. Please refer to the response to BCUC IR 1.5.12 for further explanation.

2.2 Please explain why the FEU state they will not proceed with amalgamation in the absence of common rates. Please specifically state if the FEU consider that there are no other significant benefits to amalgamation beyond the ability to postage stamp rates.

Response:

Please refer to BCUC IR 1.2.1.

2.3 If common rates were approved for most service areas but one or more regional rates were preserved, would the FEU proceed with amalgamation?

Response:

The following response is for BCUC IR 1.2.3 and 1.2.4.

The FEU would proceed with amalgamation if an alternative rate design to the common rates proposal included in the Application were approved that sufficiently addressed the rate discrepancies that currently exist across the FEU. The acceptable rate designs under which the FEU would proceed with include two of the options identified in Section 5.7 of the Application that were assessed against the common rates proposal. These two options are:

- Implementing common rates for FEI (Mainland), FEVI and FEW.
- Implementing common rates for all services areas, while maintaining regional midstream rates.

While other rate designs may also similarly meet the FEU's objectives, the rate designs noted above are those the FEU have considered as an alternative to the preferred approach of common rates.

The FEU would also proceed with amalgamation if there were an approval of common rates that proposed different 'phase-in' options for all service areas. For example, a phase-in approach could be implemented whereby FEW and FEVI's rates are decreased over a defined period rather than moving immediately to common rates in 2014, which would result in a longer phase-in period for the rate increases within FEI (Mainland).

2.4 Please specify all scenarios under which the FEU would proceed with amalgamation.

Response:

Please refer to BCUC IR 1.2.3.

2.5 Given that s.53(5) of the *Utilities Commission Act* provides the Commission with jurisdiction to report to the LGIC the following: a) that the application for amalgamation as filed with the Commission is in the public interest; b) that the application for amalgamation would be more beneficial in the public interest if *x* or *y* were to occur; or c) to dismiss the application, what would be the FEU's response to a Commission report that finds amalgamation beneficial in the public interest but does not recommend common rates, combined cost of service, maintenance of existing capital structure, weighted average ROE, Combined gas portfolio?

Response:

Please refer to the response to BCUC IR 1.2.1.

2.6 Do FEU consider it fair that they recover the regulatory costs related to the amalgamation request from its customers if, despite receiving Commission approval for amalgamation, they do not pursue it? Please explain.

Response:

The regulatory costs related to this Application are reasonable and should be recovered in rates. The FEU have put forward a reasonable application which represents the next logical step in the common management and operations of the Companies. If the Commission approves amalgamation on terms different than requested such that, after review, the FEU determines that that they will not pursue amalgamation, the result in terms of cost recovery should be the same. That is, these circumstances would not change the fact that the FEU have acted reasonably and prudently in bringing the Application forward and that it is fair that the regulatory costs be recovered from customers.

3.0 Reference: Legal Requirements to Amalgamate

Exhibit B-3, Section 7.2.2, p. 131

Requirements under the Business Corporations Act

3.1 Please confirm that the FEU are proposing to effect amalgamation under section 269 of the *Business Corporations Act*.

Response:

Section 269 of the Business Corporations Act allows the amalgamation of a company with one or more other companies and continue as one company. Sections 270, 273, and 274 describe how amalgamation can be effected. The FEU currently intend to use the "ordinary amalgamation" procedures outlined under section 270 to effect the amalgamation.

3.2 If so, please confirm whether the FEU intend to receive shareholder approval under s. 271(1) or 271(6) of the *BCA*?

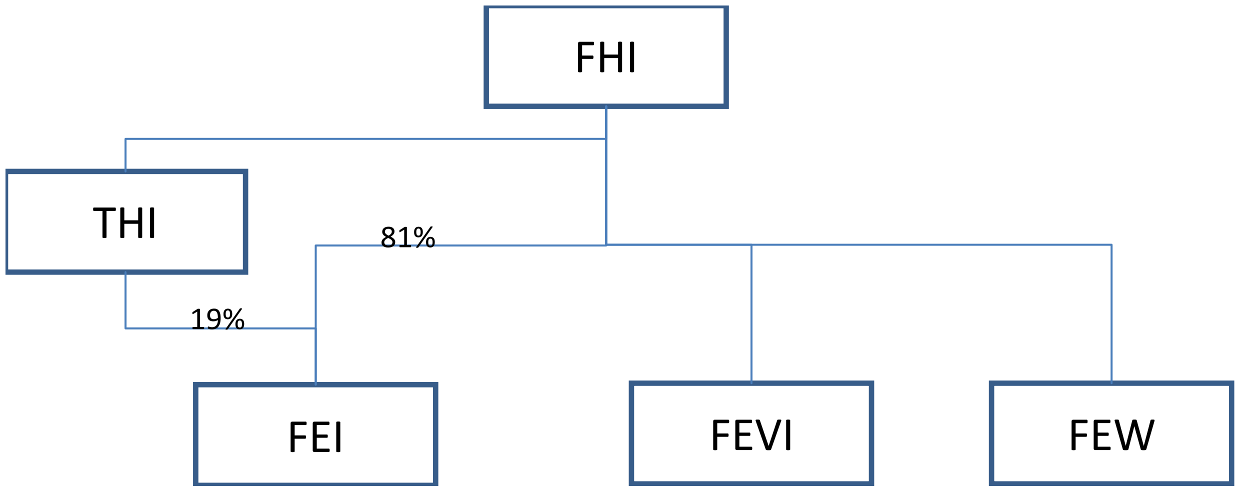
Response:

The FEU currently intend to effect the amalgamation under section 271(1)(a) by a unanimous resolution.

3.3 Please confirm that the sole shareholder of the separate legal entities is FortisBC Holdings Inc.

Response:

The current corporate structure as it relates to the FortisBC gas utilities is set out below. All share ownerships are 100% unless otherwise indicated.



3.4 What specific steps must the FEU take to obtain shareholder approval for amalgamation?

Response:

The Board of FortisBC Holdings Inc. and FEI will consider and approve the overall transactions. Once that is approved, the amalgamation entities will execute an amalgamation agreement, which will be adopted by a resolution by the shareholders of each amalgamating company.

4.0 Reference: Request for Legal Amalgamation

Exhibit B-3, Section 7.4

Operational Effects of Amalgamation

4.1 Could FEU clarify how the accounting processes, accounting systems and financial statement processes will be altered by the proposed amalgamation?

Response:

The existing accounting processes, accounting systems and financial statement preparation processes are currently similar for each legal entity. The existence of three legal entities requires the processes to be undertaken simultaneously for each entity.

The FEU have responded to this question assuming two different scenarios – the first where both amalgamation and postage stamping are approved, and the second where only amalgamation is approved. The table below responds to this IR under each of the two scenarios.

	Amalgamation with Postage Stamp Rates	**Amalgamation without Postage Stamp Rates**
Accounting Processes	No change to process itself but a reduction in the number of times the accounting process is undertaken simultaneously for each legal entity (company code in SAP)	The simultaneous processes that take place for each separate legal entity will instead take place within one legal entity (i.e. since separation of rate base and cost of service would continue to be required, entries that previously were posted to separate company codes would be created within one company code but using internal orders and cost centres and additional allocation entries) effectively reducing any potential savings that would be created by amalgamation.
Financial Statement Processes	One set of financial statements prepared instead of three; consolidation process will be simplified.	One set of financial statements prepared instead of three; consolidation process will be simplified. Disclosure in the financial statements will be increased to describe the various rates and rate setting constructs for the different service areas.
Accounting Systems	The SAP accounting system and associated modules, interfaces and uploads will need to be modified to reflect only one company code, one set of bank accounts, one set of accounts receivable and payable, etc. One time journal entries will be required to transfer opening balances from FEVI and FEW to the FEI company code.	The SAP accounting system and associated interfaces and uploads will need to be modified to reflect only one company code, one set of bank accounts, one set of accounts receivable and payable, etc. One time journal entries will be required to transfer opening balances from FEVI and FEW to the FEI company code. Also, additional cost centres and orders will be required to implement segregation of the entries within the company code to separate required costs and revenues of the service areas for regulatory purposes.

4.2 Have FEU prepared any documents explaining how internal operations will change, such as department or job flow charts or internal controls documentation of the various accounting systems? If so, could the FEU provide such documents?

Response:

The FEU have not prepared documents explaining how internal operations will change upon amalgamation and the implementation of common rates. The FEU believe that undertaking this effort prior to an approval is premature and would result in sunk costs for ratepayers and the companies should the work be undertaken and the Application subsequently denied.

Since the FEU have been operating under a common management team and shared services agreement for a number of years, significant changes to internal operations are not expected due to amalgamation and postage stamp rates. Changes to internal controls and accounting systems due to amalgamation and postage stamp rates will result in a simplification, but are not expected to result in material changes in process.

4.3 Do the FEU propose to maintain separate accounting records for the operations of what is currently FEVI, FEW, FEI (FN) and FEI which could ultimately be consolidated into a single reporting entity?

Response:

No. If amalgamation and postage stamping are approved, the FEU propose to amalgamate the accounting records into one reporting entity so that separate accounting records would not be maintained for each of FEVI, FEW, FEI(FN) and FEI.

The FEU note that, even under its proposal to amalgamate accounting records, revenues and delivery margin could continue to be tracked by service area, as is the current practice for the existing Lower Mainland, Inland, Columbia and Fort Nelson regions. In addition, with some allocations of common plant and SAP reporting modifications, property plant and equipment could also be assigned to a service area.

4.4 If amalgamation was approved, would FEU be willing to maintain standalone records for each of the current operating entities that were ultimately consolidated into a single reporting entity?

Response:

As indicated in the response to BCUC IR 1.4.3, the FEU do not propose to maintain standalone records for each of the current operating entities. If amalgamation and the adoption of common rates is approved but the FEU are directed to maintain standalone records for the current entities, the FTE savings discussed in response to BCUC IR 1.4.5 would be minimized.

4.5 What would be the savings associated with the FEU becoming a single reporting unit compared to maintaining multiple reporting units for each of the various current legal entities?

Response:

Please refer to the response to BCOAPO IR 1.9.1 and Section 6.6 of the Application.

4.6 Is it fair to conclude that the FEU will require less internal accounting personal, audit, tax and board oversight as a result of the amalgamation. If not please explain.

Response:

Please refer to the response BCOAPO IR 1.9.1 and Section 6.6 of the Application.

5.0 Reference: Request for Legal Amalgamation

***UCA* Section 53 (1); Exhibit A2-1, Reasons for Decision for Order G-63-92, pp. 16, 17; Reasons for Decision for Order G-116-05, pp. 18-22; Reasons for Decision for Order**

G-52-06, p. 6

Evaluation Framework – Key Evaluation Criteria

Section 53 (1) of the *Utilities Commission Act* (*UCA*) states:

> **Consolidation, amalgamation and merger**
>
> 53 (1) A public utility must not consolidate, amalgamate or merge with another person
>
> (a) unless the Lieutenant Governor in Council
>
> (i) has first received from the commission a report under this section including an opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, and
>
> (ii) has, by order, consented to the consolidation, amalgamation or merger, and
>
> (b) except in accordance with an order made under paragraph (a).

The Commission, in its August 5, 1992 BC Gas Inc. Revenue Requirement Application Reasons for Decision (G-63-92) stated on page 16 and 17 (Exhibit A2-1):

> "In considering requests for the approval of a merger, acquisition, amalgamation or consolidation, the Commission has historically applied as set of criteria:
>
> > 'One, the utility's ability to finance future capital requirements; two, the continuation of existing covenants that would preserve the customer's interest; three, the utility's ability to maintain the required level of service into the future; four, the preservation of the public interest; and five, compliance with pertinent legislation and regulations.'

The Commission in its November 10, 2005 Kinder Morgan (KMI) 2005 Terasen Inc. Acquisition Reasons for Decision attached to Order G-116-05 (KMI Decision)[1] accepted criteria proposed by KMI and outlined in earlier decisions as appropriate for reviewing the Application. These criteria from earlier decisions were recounted in that decision at pages 19-22, as follows:

1 http://www.bcuc.com/Documents/Proceedings/2005/DOC_9223_KMI-Terasen%20Decision_FINAL2.pdf

> "The Commission interprets the provisions of Section 61 [now Section 54] of the Act as requiring that the proposed acquisition not detract from [the utility's] ability to provide ongoing service of the quality that its customers have the right to expect and at rates which are fair to those customers and to the utility itself. The Commission concludes that it is the intent of these sections, regardless of ownership, to preserve the authority of the Commission to regulate [the utility] effectively and in the public interest.' (Cited from Order No. G-31-87, June 30, 1987 Decision regarding the acquisition of West Kootenay Power and Light Company by Utilicorp United Ltd.)."
>
> "…the Commission also identified specific criteria to assist in determining whether the public utility and the users of the services of the public utility will be detrimentally affected by a proposed acquisition. The criteria are that:
>
> (a) the utility's current and future ability to raise equity and debt financing not be reduced or impaired;
>
> (b) there be no violation of existing covenants that will be detrimental to the customers;
>
> (c) the conduct of the utility's business, including the level of service, either now or in the future, will be maintained or enhanced;
>
> (d) the application is in compliance with appropriate enactments and/or regulations;
>
> (e) the structural integrity of the assets will be maintained in such a manner as to not impair utility service; and
>
> (f) the public interest will be preserved. ..." (Cited from Order No. G-39-04 Decision regarding the Fortis Pacific Holdings Inc. acquisition of Aquila Networks Canada (British Columbia) Ltd. [previously West Kootenay Power] dated April 30, 2004)

At page 19 of the Commission's KMI Decision, it states:

> "Terasen ... submits that these criteria are generally consistent with those applied by the Commission in reviews of other applications under Section 54 of the *UCA* including Terasen's acquisition of Centra Gas (2002), Duke Energy's acquisition of Westcoast Energy and (indirectly) Pacific Northern Gas (2001), Pacific Northern Gas' acquisition of Northland Utilities (1993), Utilicorp's

> acquisition of West Kootenay Power (1987), and Fort Nelson Gas' acquisition of the Fort Nelson gas distribution utility (1985). ..."

Later in the KMI Decision, the Commission states on pages 21 to 22:

> "In determining the issues to be considered in this Proceeding, the Commission Panel has applied the following principles: First, the public interest must be considered with respect to the Utilities over which the Commission has jurisdiction. ... Second, the public interest must be viewed in the context of the scope of the approval that is being requested. For example, the Application does not request any change in the rates charged by the Terasen Utilities and does not propose any change in the jurisdiction of the Commission to regulate rates and services in the public interest. Third, the Commission Panel concludes that the public interest criterion used in this Proceeding should not extend beyond issues normally considered by this Commission for the general regulation of public utilities in the public interest. ... Finally, the Commission Panel concludes that it is appropriate to exclude issues that are more appropriately dealt with by, or that are more properly within the jurisdiction of, other agencies or levels of government."

The Commission, in its 2006 Reasons for Decision on an Application by 0745848 B.C. Ltd. for approval for the acquisition of the common shares of Terasen Utility Services Inc. (G-52-06)[2], also used the specific criteria identified in the KMI Decision (a) through (f) above as the approval criteria. (p. 6)

5.1 While the evaluation criteria quoted in the KMI 2005 Decision (G-116-05) related to an acquisition, the criteria used in that decision is consistent with the evaluation criteria used by the Commission in the 1992 BC Gas Inc. Decision (G-63-92) which related to a consolidation. In evaluating FEU's legal amalgamation proposal under Section 53 of the *UCA*, do the FEU support using the six evaluation criteria (a) through (f) from page 19 the 2005 KMI Decision as the evaluation framework? If no, please explain why.

Response:

The 2005 KMI Decision referenced in the IR response involved an application for the acquisition of shares under section 54 of the UCA. Section 54(9) of the UCA states that the Commission "must not give its approval under this section unless it considers that the public utility and the users of the service of the public utility will not be detrimentally affected." Thus, as stated by

[2] http://www.bcuc.com/Documents/Proceedings/2006/DOC_11707_G-52-06%20TUS_TMUS%20Acquisition%20Order%20and%20Reasons.pdf

the Commission in the paragraph quoted above that introduces the evaluation criteria: "…the Commission also identified specific criteria to assist in determining whether the public utility and the users of the service of the public utility will be detrimentally affected by a proposed acquisition."

The test in section 53 of the UCA is different than that found in section 54 as it requires the Commission to form an opinion that the amalgamation is "beneficial in the public interest." In considering an amalgamation under section 53, it is relevant for the Commission to consider whether the amalgamation would result in a detrimental effect when determining if, overall, the proposal is beneficial in the public interest. Thus, as noted in the preamble to this IR, similar criteria to those referred to in the 2005 KMI Decision are cited by the Commission in the 1992 BC Gas Inc. Decision as being historically applied to both amalgamations and acquisitions.

The FEU agree that the six evaluation criteria (a) through (f) from page 19 of the 2005 KMI Decision are relevant factors for the Commission to consider when evaluating a proposal to amalgamate. However, the criteria of "preservation of the public interest" should include a consideration of the benefits of amalgamation and any other relevant factors to determine overall if the proposed amalgamation is beneficial in the public interest. For example, in the 1992 BC Gas Inc. Decision, the Commission considered the benefits of the proposed consolidation (see pages 17-20 of Exhibit A2-1), such as the savings due to efficiencies.

The FEU submit that when taking into account the benefits of amalgamation as the FEU have described in its Application, including the facilitation of postage stamp rates, the proposed amalgamation is beneficial in the public interest.

5.2 Do FEU consider that, in order to comply with section 53 of the *UCA*, the FEU should be required to demonstrate that the amalgamation provides a "net public benefit" rather than meeting a lower threshold of "not resulting in a 'disbenefit'"? Please explain why or why not.

Response:

Under section 53 of the UCA, a public utility may not amalgamate unless the LGIC receives a report from the Commission including an opinion that the amalgamation is "beneficial in the public interest." The reference to "beneficial" suggests that the FEU is required to demonstrate that the amalgamation provides a net benefit in the public interest.

Section 54 of the UCA, which is not engaged by the Application, would appear to be closer to the threshold referred to in the IR of "not resulting in a 'disbenefit'". Where there is an application pursuant to Section 54 of the UCA, such as an application to acquire the shares of a utility, the Commission must consider whether "the public utility and the users of the service of the public utility will not be detrimentally affected."

5.3 Do FEU consider that, in evaluating if legal amalgamation is in the public interest, the Commission should evaluate legal amalgamation on its own, or legal amalgamation plus postage stamp rates? Please explain why or why not.

Response:

The FEU's application is for common rates and amalgamation and the Commission should evaluate the Application on that basis. As the FEU have already realized the majority of efficiencies normally associated with amalgamation, the primary benefit of amalgamation is that it facilitates implementation of rate structures that only an amalgamated entity can adopt, such as postage stamp rates. Therefore, in evaluating if legal amalgamation is beneficial in the public interest, the Commission should evaluate amalgamation plus rates that would address the objectives of the FEU, as discussed in response to BCUC IR 1.2.1

5.4 In determining issues to be considered in this proceeding, does FEU support using the four principles outlined on page 21 to 22 of the 2005 KMI Decision above? If no, please explain why.

Response:

The four principles in the 2005 KMI Decision were set out in the context of an acquisition of a utility pursuant to section 54 of the UCA. As indicated in the FEU's response to BCUC IR 1.5.3, the test under section 54 of the UCA is different than the test under section 53. Further, the acquisition of shares of a company raises different concerns than an amalgamation of utilities such as the FEU, which are already regulated by the Commission and already under common ownership.

Therefore, while the FEU do not object to the use of the four principles outlined on pages 21 to 22 of the 2005 KMI Decision, the FEU do not believe that the four principles help determine issues to be considered in this proceeding. Each principle is discussed briefly below.

1. "First, the public interest must be considered with respect to the Utilities over which the Commission has jurisdiction." This principle is more relevant in the context of the acquisition of public utility over which the Commission has jurisdiction by a utility over which the Commission does not have jurisdiction. In this proceeding, the Commission has jurisdiction over each of the FEU (FEI, FEVI and FEW), so this principle is not particularly helpful.

2. "Second, the public interest must be viewed in the context of the scope of the approval that is being requested." Applying this principle to this Application, the public interest should be viewed within the scope of approval requested by the FEU, including both amalgamation and postage stamp rates. As the FEU have stated elsewhere, the FEU consider that the primary benefit of amalgamation of the FEU is the different rate designs it permits; therefore, the issue of the benefits of amalgamation and rate design should not be separated.

3. "Third, the Commission Panel concludes that the public interest criterion used in this Proceeding should not extend beyond issues normally considered by this Commission for the general regulation of public utilities in the public interest." The FEU's basis for seeking amalgamation and postage rates only engage public interest criterion that are within issues normally considered by the Commission for the general regulation of public utilities in the public interest.

4. "Finally, the Commission Panel concludes that it is appropriate to exclude issues that are more appropriately dealt with by, or that are more properly within the jurisdiction of, other agencies or levels of government." The FEU's request for approval of amalgamation and postage stamp rates is within the core of the Commission's ratemaking jurisdiction under sections 53 and 59 to 61 of the UCA.

5.5 Would approval of legal amalgamation reduce or impair FEU's current and future ability to raise capital and debt financing? Please explain why or why not.

Response:

Assuming any approval does not have a material impact on the amalgamated entity's allowed ROE or capital structure, or credit ratings, the FEU anticipate that amalgamation would not reduce or impair the amalgamated entity's ability to raise financing. Under this scenario, the FEU would also anticipate that there would be no violation of existing covenants.

5.6 Would approval of legal amalgamation result in a violation of any existing covenants that may be detrimental to customers? Please explain why or why not.

Response:

No.

Please refer to the response to BCUC IR 1.5.5.

5.7 Would approval of legal amalgamation negatively affect the conduct of the utility's business, including the level of service, either now or in the future? Please explain why or why not.

Response:

The approval of legal amalgamation would not negatively affect the conduct of the utility's business, including the level of service, either now or in the future.

As discussed in Section 3, page 51, the FEU have been operating under a common management structure for a number of years, and therefore operate the business as one entity today.

The effect of legal amalgamation is one of simplification of the corporate structure of the FEU as opposed to an operational amalgamation. Therefore, the day-to-day operations of the business will not be affected by the legal amalgamation.

5.8 Would approval of legal amalgamation result in non-compliance with appropriate enactments and/or regulations? Please explain why or why not.

Response:

Approval of legal amalgamation would not result in non-compliance with appropriate enactments and/or regulations. The FEU are seeking approval to amalgamate in accordance with section 53 of the UCA. If approval is granted, the FEU will implement amalgamation in accordance with the provisions of the *Business Corporations Act* and will comply with all appropriate enactments and regulations.

5.9 Would approval of legal amalgamation result in a reduction in structural integrity of the assets to be maintained in such a manner as to impair utility service? Please explain why or why not.

Response:

The approval of legal amalgamation will not result in a reduction in the structural integrity of the assets in such a manner as to impair utility service.

The FEU's assets are maintained in a consistent manner across the service areas, and legal amalgamation will not negatively impact asset integrity activities or reduce the structural integrity of the assets. Asset integrity activity is primarily code and compliance driven by regulatory bodies that are independent of a legal amalgamation of the FEU.

5.10 Please outline what FEU consider are the key public interest considerations under the following scenarios. In your response, please explain how inclusion of these benefits is consistent with the four principles outlined on pages 21 to 22 of the 2005 KMI Decision:

i. The Commission evaluates legal amalgamation under Section 53 of the *UCA* without consideration of postage stamp rates; and

ii. The Commission evaluates legal amalgamation under Section 53 of the *UCA* and includes consideration of postage stamp rates.

For each public interest consideration identified, please state to what extent the benefit can (in whole or in part) be obtained without legal amalgamation? Please explain.

Response:

If the Commission were to evaluate legal amalgamation under Section 53 of the *UCA* alone (i.e. without consideration of postage stamp rates or other rate designs as discussed in FEU's response to BCUC IR 1.2.3), then the key public interest considerations would be whether there are any benefits as a result of amalgamation, such as any cost savings or efficiencies. The benefits of amalgamation alone are discussed in the response to BCUC IR 1.2.1. Consideration of amalgamation without consideration of postage stamp rates would be inconsistent with the second principle identified in the 2005 KMI Decision.

If the Commission were to evaluate legal amalgamation under section 53 of the *UCA* with consideration of postage stamp rates, then the key public interest considerations are the benefits described in section 6 of the Application. These benefits require amalgamation. (As discussed in section 6, while common service offerings can be offered without amalgamation, a benefit of amalgamation and postage stamp rates is that it facilitates the expansion of all services in a more efficient manner.) These benefits are consistent with the four principles outlined on pages 21 to 22 of the 2005 KMI Decision. Please refer to the response to BCUC IR 1.5.4.

5.11 FEU have included in the Application information on the financial costs and benefits associated with legal amalgamation. Please provide a net present value cost benefit analysis of the impact on FEU customers of FEU legal amalgamation. Please exclude from this analysis any costs or benefits associated with postage stamp rates. Please explain all assumptions used in the calculation.

Response:

The following net present value cost benefit analysis should be regarded with caution as there are several assumptions, particularly with respect to future interest savings that are difficult to ascertain. For details of the analysis see the table below.

Expected Savings/Benefits

In the Application on page 149 FEU has identified long term annual cost savings associated with Depreciation and Amortization related to Whistler Pipeline, Income Tax savings due to net changes on amalgamation of the Rate Base, and reduced Earned Return related to lower cost of short term debt. The total of these items from Table 8-1, Page 147 of the Application is $1.988 million ($28,000 + $92,000 + $1,868,000). FEU has also forecast the potential and ongoing ancillary savings associated with the reporting and operational efficiencies as discussed in Section 6.6; approximately $700 per year in legal savings, approximately $18,000 per year in audit savings and approximately $100,000 per year in rate agency fee savings Any net savings from amalgamation, on a forecast basis, would be flowed through in reduced rates to customers.

Although forecast at approximately $2 million, the short term interest savings are a function of the 2013 forecast cost of service. That is, the savings represent the forecast 2013 interest rates, the forecast 2013 interest rate differential amongst the legal utilities, and the balance of rate base financed by short term debt in 2013 for each utility. In effect, the savings reflects the assumption that the short term debt balance of FEVI, in an amalgamation scenario, would be funded by FEI Amalco, which is assumed to maintain the current, higher, credit ratings of FEI pre-amalgamation. All three of these variables will change over time. Therefore, although the amalgamated entity is expected to experience ongoing interest savings because of the higher credit rating of the amalgamated entity, it is very difficult to extrapolate interest savings over time with a high degree of certainty. Thus, for purposes of the net present value analysis below, FEU has provided a range of benefits based on the current average unfunded interest rate differential of 1.25% (FEI relative to FEVI) and has assumed average short term debt affected by this differential of $25 million and $50 million (an estimate of the average short term debt that would be applicable to FEVI service area, which would be financed at the lower short term debt rate of FEI Amalco).

One other savings that has not been calculated is the potential savings with respect to long term debt. Over a reasonable horizon, FEVI would expect to issue long term debt. Post amalgamation, that debt will be issued within FEI Amalco. As with short term debt, the assumed interest rate for FEI Amalco will be lower relative to FEVI. Currently, the indicative spread differential between FEI (which is the proxy for the FEI Amalco borrowing rate) and FEVI on a long-term debenture is in the range of 20 basis points. Applied to an assumed $100 million debt issue, that would be approximately $200 thousand in pre-tax savings per annum, which would result in lower cost of service.

Expected Costs

The cost to amalgamate is forecast to be $2 million as described on page 154 of Section 8.2.1.2; this includes the legal and transactional costs as we as operational costs of implementation. In addition, the cost of the application itself is forecast at $1.5 million as described on page 155 of Section 8.2.1.2. The related tax shield is included in the analysis as a benefit.

Cost Benefit Analysis

Based on the forecast in the Application, including forecast short term debt balances and the interest differentials, FEU estimates that it will take approximately less than two years for the savings to exceed the one time amalgamation costs (($2.0 + $1.5) / $1.988 = 1.7 years). Actual savings realized in this timeframe may vary depending on the variables affecting short term interest expense as described above.

Please see the table below which provides an expected range of the discounted net amalgamation benefit over a ten year period, taking into consideration the savings and costs described above. The discount rate applied reflects the 2013 weighted average cost of capital of the amalgamated entity as derived from Schedule 3 of Appendix J-1.

Approximate NPV of Amalgamation Costs & Benefits, 10 Years ($ Thousands)

	$25 Million Short Term Debt	**$50 Million Short Term Debt**	
Discount Rate	6.69%	6.69%	After Tax WACC of amalgamated entity
Present Value of Benefit of Amalgamation			
Depreciation and Amortization extended	402	402	Net difference in Whistler Pipeline Dep & Amort - ~ 50 years
Income Tax recovery	243	243	Mainly related to various deferrals - assumed 3 year benefit
Short-Term Interest Differential	2,227	4,453	Based on a 1.25% unfunded debt rate differential as at May 28, 2012
Legal, Audit and Rate Agency Savings	846	846	Approximately $700/yr legal, $18,000/yr audit and $100,000/yr rating
Tax Shield on Amalgamation Costs	733	733	
Total of Present Value of Benefits	4,451	6,678	
Present Value of Cost of Amalgamation			
Total Cost of Amalgamation	(3,550)	(3,550)	Legal, transactional, operational and application costs
Total Present Value of Cost	(3,550)	(3,550)	
Net Present Value of Benefits	$ 901	$ 3,128	

5.12 With reference to the efficiencies and savings discussed in Sections 6.6.1 to 6.6.4 of the Application, can most of these be realized without also adopting a common rate structure? In other words, could most of these efficiencies be realized by just effecting a legal amalgamation? Please provide a full discussion.

Response:

No, most of the efficiencies discussed in Sections 6.6.1 to 6.6.4 of the Application cannot be achieved by just effecting a legal amalgamation. Each item is discussed below:

- Section 6.6.1 Regulatory Efficiencies – these efficiencies could not be achieved with approval of legal amalgamation only. Regulatory efficiencies can only occur with regulatory consolidation. In absence of regulatory consolidation, each regulatory division would have to file its own Applications and reports to the Commission and maintain its own tariffs, i.e. there would not be any reduction in the number of tariffs and customer classifications and associated cost savings. Further, if new services were to be offered that entailed new customer classes the number of new tariffs could be 4 instead of 1.

- Section 6.6.2 Legal Efficiencies - Legal efficiencies could occur in a situation where legal amalgamation is approved. As discussed in the Application, the amalgamated entity would need to have only one set of company records as opposed to individual records for each entity, as well as lower labour and legal costs to administer each legal corporation. However, from a regulatory perspective, if the four rate bases and six service areas are maintained, there would be no legal savings in regulatory proceedings for the same reasons as there are no regulatory efficiencies under an amalgamation only scenario.

- Section 6.6.3 Interest Savings – Interest savings would be achievable by effecting legal amalgamation assuming that the legal amalgamation resulted in the amalgamated entity maintaining the current credit rating of FEI. Please refer to the responses to BCUC IR 1.62.1 and 1.62.1.1. In addition to being affected by the credit rating of the amalgamated entity, potential interest savings achieved would be affected by market conditions and actual borrowing rates, and the balance of debt financed by short term credit facilities which will vary over time.

- Section 6.6.4 Other Financial Efficiencies - Other financial efficiencies would be limited in the situation where only legal amalgamation is approved. This is because the requirement to maintain the accounting records to support the identification of each division's Rate Base and Cost of Service would require the same level of audit requirements as is in place today; however, it is likely that some external audit fees could be saved and the rating agencies savings could occur as only one entity would exist.

6.0 Reference: Request for Common Rates

Exhibit A2-7, Ofgem October 2010 paper "RIIO: A new way to regulate energy markets," p. 38

Common Rates Evaluation Framework

Ofgem (Great Britain Office of Gas and Electricity Markets) states in its October 2010 Final Decision paper "RIIO: A new way to regulate energy networks" (Exhibit A2-7)[3] on page 38:

> "Our principal objective is to protect the interests of existing and future consumers. In carrying out its functions in accordance with the principal objective, the Authority must also have regard to the need to secure that licence holders are able to finance the activities which are the subject of obligations on them. This means that efficient network companies should be able to secure financing in a timely way and at a reasonable cost in order to facilitate the delivery of their regulatory obligations. This is also in the interests of consumers. However, it is important that the regulatory framework does not provide excessive returns, reward inefficiency or 'bail-out' a company that has encountered financial distress as a result of its own behaviour."

6.1 Do FEU agree that the framework used to evaluate FEU's postage stamp rate proposal should include (consistent with Ofgem's principle objective described above) determining if postage stamp rates results in improved regulation by enabling efficient utilities to secure financing in a timely way and at a reasonable cost, while not providing excessive returns, rewarding inefficiency or 'bailing-out' a utility that has encountered financial distress as a result of its own behaviour. If no, please explain why not.

Response:

No, the FEU do not agree. Ofgem is in a different jurisdiction, has a different statutory regime than the BCUC and regulates different utilities in a different context. It is not appropriate to take a general statement from Ofgem and apply it to this proceeding in the BC context. The UCA provides the statutory regime under which the BCUC is to review the Application and make its decisions.

Regardless, the "framework" referenced in the IR does not offer a helpful way to evaluate the FEU's postage stamp rate proposal. Postage stamp rates would not negatively change the FEU's ability to secure financing in a timely way and at a reasonable cost. Postage stamp rates are cost-based rates and would not provide any utility with "excessive returns" or result in

[3] http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/Decision%20doc.pdf

"rewarding inefficiency". There is no relevance to the reference to "'bailing-out' a utility that has encountered financial distress as a result of its own behaviour". None of the FEU are in financial distress.

7.0 Reference: Request for Common Rates

Exhibit B-3, Section 5, p. 80, Section 10, p. 240; Exhibit A2-3, Inquiry Report for Order G-100-96, pp. 1-18; Reasons for Decision for Order G-45-11, p. 5 Reasons for Decision for Order G-171-07, p. 33

Common Rates Evaluation Framework - Criteria

The FEU state on page 80 of the Application: the FEU determined that "its objectives are to achieve the following:

- Minimize the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW;
- Implement a long-term solution for FEVI customers to the loss of the government subsidies and associated rate impacts; ..."

The FEU state on page 240 of the Application: "Some businesses believe that this proposal will negatively impact their operations and is unfair for businesses that have set up on the Mainland. One customer stated that they 'disagree with making the cost of gas cheaper in areas where the actual cost is higher. This seems to me to be an incentive for people and companies to set up in areas where the actual economics don't make sense and penalizes those people that are located in areas that make more economic sense.'"

The Commission, on page 5 of the Reasons for Decision for Order G-45-11 on BC Hydro's Residential Inclining Block Rate Re-Pricing Application (dated March 14, 2011)[4] stated that " ... the Commission is guided by the eight "Bonbright Principles" which can be described as follows:

"Principle 1: Recovery of the revenue requirement;

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);

Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);

Principle 4: Customer understanding and acceptance;

4 http://www.bcuc.com/Documents/Proceedings/2011/DOC_27176_G-45-11_BCH-RIB-Re-Pricing-Reasons.pdf

Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);

Principle 6: Rate stability (customer rate impact should be managed);

Principle 7: Revenue stability; and

Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

(Source: James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 1961)"

On October 10, 1996, the Commission issued Order G-100-96 which included at Appendix A an Inquiry Report into BC Gas Utility Ltd. and Propane Price Increases in the City of Revelstoke. (Exhibit A2-3) This Inquiry Report related to an application by BC Gas for approval to pass-through an increase in the cost of propane which would have represented an average increase to residential customers of approximately 24% and 32% to commercial customers. (p. 1)

In that inquiry, several witnesses proposed that the increase should instead be spread across the entire client base of BC Gas, including its natural gas customers, on the basis that the service that BC Gas delivers is comfort and the costs for a Vancouver customer should be the same or similar for a Revelstoke customer. One witness (Mr. Jack Heavenor, General Manager of Downie Timber Ltd.) accused BC Gas of aggressively selling him on piped propane kiln-drying, without even suggesting that there might be a major change in propane rates. (pp. 9-13)

The Commission rejected the proposal to roll in the acquisition costs of propane with that of natural gas, instead deciding in favour of a two-year phase in of the required rate increase. (p. 18)

The Commission, on page 33 of its Reasons for Decision on BC Hydro's 2007 Rate Design Application Phases II and III (G-171-07) stated "Discrimination, when applied to rates for utility service, can only be of an 'intra-utility' nature and not 'inter-utility'."[5]

7.1 Do FEU consider that a "distinct and special area" under section 60 (2) to (4) of the *UCA* is equivalent to a utility service area for the purpose of rate design? If no, please explain why not.

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5 http://www.bcuc.com/Documents/Proceedings/2007/DOC_17589_12-21_BCH_2007RDA-Decision-Phases_2&3_Final.pdf

Response:

The FEU consider that a "distinct and special area" can be a service area for the purpose of rate design, but that all service areas are not necessarily a "distinct and special area."

7.2 Please provide legal or regulatory precedent for FEU's objective in the Application to "Minimize the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW."

Response:

The following response addresses both BCUC IR 1.7.2 and BCUC IR 1.7.3.

The effect or benefit of an amalgamation is often the harmonization of rates among different regions that used to be served by different service providers, which, in turn, can result in lower rates for some customers and higher rates for others.

For instance, in a 2005 decision by Ontario Energy Board in the matter of an application by PowerStream Inc. and Aurora Hydro Connections Limited under section 86 of the Ontario Energy Board Act, seeking leave for PowerStream Inc. to acquire all outstanding shares in and subsequently to amalgamate with Aurora Hydro Connections Limited (AHCL) (EB 2005-0254 included in Attachment 7.2), the Board approved the proposed transactions based on several effects or benefits resulting from the proposed transactions. As indicated in the Decision at page 12, the applicant submitted that the transaction would:

- provide opportunities for efficiencies and economies of scale, which could mitigate the impact of increased upward pressure on distribution rates for electricity consumers currently served by AHCL";
- based on an analysis of current rates, [to] result in lower rates for electricity consumers currently served by AHCL than would be the case were AHCL to remain a stand-alone company;

At page 13 of the Decision, the Board noted that PowerStream Inc. committed "to provide AHCL's current customers with a benefit from the harmonization of rates of at least $10,000,000 over a ten-year period relative to what they would otherwise be as compared to AHCL remaining a stand-alone company."

When approving a subsequent application by PowerStream to harmonize four sets of rates for each area served by it, the OEB noted that "when rates are harmonized, some customers will experience an increase and others a decrease." In that case, the largest increase for a typical residential customer was 2.5% while the largest decrease 8.2%. For services for street lighting, the increase was 17% in one area. The OEB found the changes to be reasonable. (EB-2007-0074, also included in Attachment 7.2).

Similarly, in 2009 the OEB allowed a post-amalgamation rate harmonization for Greater Sudbury Hydro Inc. which was expected to lead to a bill impact of nearly 30% for some customers with the implementation of harmonized rates (EB-2008-0230, at pp. 39-39, also included in Attachment 7.2).

Similarly, in NSUARB-W-EHAN-R-09/2010 NSUARB 46 (also included in Attachment 7.2), the Nova Scotia Utility and Review Board approved an application to amalgamate two existing water utilities. As stated in the decision on p. 8, paragraph. 15:

> *"The application is based upon the need to adjust and standardize the rates as a result of increasing operating costs; capital improvements to the fire protection system and infrastructure; and recognizing reduced water consumption."*

In that Application, the amalgamation and standardizing of rates took place because one of the existing utilities was not able to continue on its own. As indicated on page 21, paragraph 55 of the decision: "The Board noted that this situation is not unique and that other municipalities have proposed amalgamations to solve similar problems."

7.2.1 Can this objective also be summarized as "same price for same service, regardless of costs?" If no, please explain why not.

Response:

No, the Companies do not believe that the "same price for same service regardless of costs" is a precise characterization of the objective to minimize the regional rate differences that are in effect today. As explained in section 3 of the Application, the cost differences in place today between FEI, FEVI, FEW and Fort Nelson reflect the historic costs attributed to those areas. With the proposed amalgamation, what the Companies are trying to achieve is a common rate structure that allows the pooling of all costs for the benefit of all customers, no matter where they happen to reside within the service territories of the FEU. Additionally, as detailed in section 8 of the Application, the rates proposed are based on the 2013 cost of service. Thus, it would be imprecise to say that the common rate structure is without regard to cost.

7.2.2 Does this objective also provide benefits to the FEU shareholder? Please explain why or why not.

Response:

No, the FEU's common rates proposal is revenue neutral to the Companies. The objective to "minimize the regional rate differences that are in effect today", is intended to have no impact on the FEU's shareholder.

7.2.3 Please link this objective to the Bonbright rate design principles as described in the Commissions Reasons for Decision for Order G-45-11.

Response:

The objective of minimizing the regional rate differences that are in effect today is consistent with or supported by all of the Bonbright rate design principles. Section 9.5 of the Application explains how the FEU have applied rate design principles based on those identified by Dr. Bonbright in his widely accepted work, "*Principles of Public Utility Rates.*" In the following discussion, we will rephrase these principles as articulated in the preamble.

Principle 1: Recovery of the revenue requirement. The FEU are seeking approval of delivery rates for the Amalgamated Entity using the 2013 cost of service to be implemented on January 1, 2014 on an interim basis. That is, the proposed interim rates for 2014 are based on the consolidated proposed revenue requirements for 2013 for the FEU, and also include any necessary adjustments to the cost of service to account for amalgamation.

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates). For rate design, fairness implies the recovery of costs based on cost causation. The proposed rate structures require similar customers to pay similar delivery margins. The proposed rate design for the Amalgamated Entity ensures that the revenues to be recovered from each rate class are closely aligned with the cost to serve them, and rewards those who utilize the system more efficiently through lower rates for customer classes with higher load factors. Load factors are a relative measure of how efficiently a customer class uses the system.

Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy). This is related to competitiveness in rate design and refers to designing rates in consideration of other fuel alternatives. The rates proposed in this Application for the Amalgamated Entity will have minimal impact on competitiveness of natural gas for the vast majority of customers currently served by FEI. On the other hand, the rates for FEVI and FEW will become more economic compared with the alternative fuels and become aligned with that experienced by FEI customers. In addition, the FEU are proposing to use the FEI flat rate structures for the amalgamated entity. The Commission has also approved FEI applying its revenue requirement increases only to the delivery charge while leaving the basic charge as is. This approach improves energy conservation pricing signals by increasing the energy-related component of the rates which over time will encourage customers to conserve. The flat postage stamp rate structure applied to Fort Nelson will eliminate the existing declining block rate structures currently in place and will provide energy conservation pricing signals for those customers.

Principle 4: The principle of ease of understandability, administration and rate continuity refers to rates that are both easily understood by customers and easily administered by the Company. As explained in the Application, changes should be gradually implemented where possible, ensuring consistency and continuity in application so as to minimize customer confusion, and to promote customer fairness and equity. By capturing all utility customers under one common rate regardless of region, the principle of ease of understandability, administration and rate continuity is advanced. By amalgamating the rate schedules for FEVI, FEW and Fort Nelson with the FEI structure, the Companies will reduce the total number of rate schedules by 18.

Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives). The details of the Application demonstrate that postage stamp rates are practical and cost effective to implement. Postage stamp rates are sustainable and meet long-term rate stability objectives.

Principle 6: Rate stability (customer rate impact should be managed). The principle of stability refers to the stability of rates themselves, with minimum unexpected rate increases that are seriously adverse to existing customers. The longer-term rate stability in the smaller FEVI, FEW and Fort Nelson service areas is one of the objectives of this Application which is achieved through postage stamp rates. The proposed common rates across a combined entity will provide rate stability for the smaller service areas of FEVI, FEW and Fort Nelson (as discussed earlier in Section 6.3.2) by allowing a broader customer base to absorb any significant capital expenditures, customer or volume losses and declining use per customer without generating significant spikes in rates for any one service area. The rate increases due to implementing postage stamp rates themselves are proposed to be phased in.

Principle 7: Revenue stability. The proposed postage stamp rates will adopt the FEI rate structures and thus generate reasonably stable revenue based on the portion of revenue derived from the fixed basic charges relative to the revenue variable with consumption derived from delivery charges.

Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained). The proposed postage stamp rates are based on the FEI rate classes and preserve the interclass equity established for FEI and eliminates the differences in rates across the existing entities for the same services. In addition, the amalgamated entity COSA shows that the revenue to cost ratios are reasonable for each of the proposed postage stamp rate classes.

7.2.4 If this objective is accepted by the Commission, do FEU plan to request postage stamp rates for Revelstoke customers? Please explain why or why not.

Response:

The objective of removing rate discrepancies is not novel as it is reflected in all postage stamp rate designs. Accepting this objective would therefore be consistent with existing postage stamp rate designs in the province and would not set a new precedent.

Revelstoke currently has postage stamped delivery rates. The propane commodity cost is flowed through to Revelstoke customers, just as the natural gas commodity cost is flowed through to FEI's natural gas customers. The FEU have no current plans to postage stamp the commodity or midstream costs for Revelstoke as propane is a different fuel type than the natural gas delivered to the Companies' other customers.

7.2.5 Do FEU consider that moving away from a cost causation principle would result in an increase in the number of extensions where delivery revenues received from the new customer would be lower than the extension cost? Please explain why or why not.

Response:

The FEU disagree with the statement that they are moving away from cost causation principles. The FEU's postage stamp rates are consistent with cost causation principles as discussed in Section 9.5.2.

Further, the FEU's postage stamp rate proposal will not increase the number of extensions where delivery revenues received from a new customer would be lower than the extension costs. As explained in Section 7.4.2.3, the Company will continue the established Profitability Index ("PI") test, but use one set of PI formula inputs reflecting the amalgamated entity as a whole. Thus, the recovery of costs for main extensions continues to reflect cost causation principles.

Please also refer to the responses to BCUC IRs 1.10.2 and 1.10.3.

7.3 Please provide legal or regulatory precedent for FEU's objective in the Application to "Implement a long-term solution for FEVI customers to the loss of the government subsidies and associated rate impacts."

Response:

Please refer to the response to BCUC IR 1.7.2.

7.3.1 Does this objective also provide benefits to the FEU shareholder? Please explain why or why not.

Response:

No, as explained in the response to BCUC IR 1.7.2.1, the FEU's common rates proposal is revenue neutral to the Company; thus, the objective to "Implement a long term solution for FEVI customers to the loss of the government subsidies and associated rate impacts" is not intended nor being pursued to have an impact on the FEU's shareholder.

7.3.2 Please link this objective to the Bonbright rate design principles as described in the Commissions Reasons for Decision for Order G-45-11.

Response:

Please refer to the response to BCUC IR 1.7.2.3.

7.4 Do FEU agree with Commission Order G-171-07 that discrimination, when applied to rates for utility service, can only be of an "intra-utility" nature and not "inter-utility." If no, please explain why not.

Response:

Yes. The FEU are not claiming that the current rates for any of the FEU entities are "discriminatory". The FEU believe, however, that postage stamp rates across all of the service areas of the FEU are preferable to the current rates in place.

8.0 Reference: Request for Common Rates

Exhibit A2-4, Alberta EUB Decision U96055, p. 27

Common Rates Evaluation Framework - Net Benefit

Alberta Energy and Utilities Board (EUB) June 12, 1996 Nova Gas Transmission Ltd. (NGTL) Decision on a 1995 General Rate Application – Phase II (Decision U96055) stated on page 27 with regard to postage stamp versus distance sensitive gas transmission rates:[6]

> "Before making a change in toll design, the Board would need to be satisfied, on the basis of clear and convincing evidence, that greater efficiencies or cost savings would accrue to the benefit of shippers overall. The Board would also need to be satisfied that the magnitude of the changes to affected parties are acceptable and that benefits in the broad public interest would result. The Board would also look for transitional measures designed to manage such changes. Absent such considerations, the Board is concerned that a decision to change NGTL's rate design could have negative effects on investor confidence in NGTL, the province's natural gas industry and on the industry's overall well-being."

8.1 Do FEU agree with the Alberta EUB that, before addressing a "distinct or special area" for the purposes of ratemaking, the Commission should be satisfied, on the basis of clear and convincing evidence, that greater efficiencies or cost savings would accrue to customers overall, that the magnitude of the changes to affected parties are acceptable, and that benefits in the broad public interest would result. Please explain why or why not.

Response:

The potential for efficiencies and cost savings, the magnitude of the rate changes, and the benefits in the public interest are all relevant considerations when determining whether to recognize a "distinct or special area". However, the statements made by the Alberta EUB in the referenced case were made in the context of a particular factual matrix in which the Alberta EUB was taking into account the particular consequences of determining a regional rate for the utility in question at that time. Notably, the EUB was considering a transmission toll design, rather than a gas distribution rate design, so the situation is not directly analogous to the circumstances of the FEU. In each case, the unique circumstances of the utility in question should be taken into account and in each case there may be other factors than those

[6] http://www.auc.ab.ca/applications/decisions/Decisions/1996/U96055.pdf

specifically mentioned by the EUB which are relevant or determinative. Therefore, the FEU would not adopt the criteria used by the Alberta EUB as a general rule.

8.2 Do FEU agree that demonstrable efficiency or cost impacts resulting from addressing a "distinct or special area" for the purposes of ratemaking could include the following items? In each of the three cases below please explain why or why not.

i. Efficiency benefits/losses arising from the ability of regional rates to allow for customized rate design where there are regional differences in incremental cost to serve, customer price responsiveness and price/reliability trade-offs;

ii. Increased/reduced administration/regulatory costs; and

iii. Increased/reduced data available to ensure efficient regulation by the Commission.

Response:

When determining whether to recognize a "distinct and special area" the Commission should consider all relevant factors in the public interest and must determine a rate that is just and reasonable. The relevant factors include all of the rate design principles described in section 9.5 of the Application. Postage stamp rates are the most common rate design and it is appropriate to socialize the costs of public utility services so that all customer classes have access to the same service at the same cost. There should be a compelling reason to recognize a "distinct and special area" that would justify moving away from a postage stamp rate.

The FEU address each of the three suggested items below separately.

Taking into account a "distinct or special area" could result in efficiency benefits or losses arising from customized rate design. Efficiency benefits are taken into account in Bonbright's Economic Efficiency rate design principle (see section 9.5 of the Application). There are not any efficiency losses resulting from the postage stamp rate design proposed by the FEU. The Amalgamated Entity will continue FEI's current rate structures, which include a greater number of customer classes to accommodate a larger number of different customer types than those of FEVI, FEW and FEFN and therefore more likely to result in an efficient rate for each customer.

The FEI's rate structure also includes a fixed and variable component to encourage efficient use.

Taking into account a "distinct or special area" generally increases complexity and the administrative and regulatory burden and therefore would likely result in increased administration and regulatory costs. This item is generally included in Bonbright's rate design principle of Ease of Understandability, Administration and Rate Continuity. A benefit of the FEU's postage stamp rate proposal is that it increases ease of understandability and reduces administrative burden. These benefits are discussed in section 6 of the Application.

It is not clear how taking into account a "distinct or special area" would result in increased or reduced data available to ensure efficient regulation by the Commission. The data required in order to ensure efficient regulation would seem to be independent of what rate design is in place. In addition, moving to postage stamp rates based on the FEI rate design will provide the requisite data required to ensure efficient regulation.

9.0 Reference: Request for Common Rates

Exhibit A2-1, Reasons for Decision for Order G-63-92, p. 20; Exhibit A2-2, Reasons for Decision for Order G-101-93, pp. 6, 7; Order G-34-95, p. 1; Reasons for Decision for Order G-156-10, p. 14

Common Rates Evaluation Framework - Customer Preferences

The Commission, in its August 5, 1992 BC Gas Inc. Reasons for Decision G-63-92 (Exhibit A2-1) stated on page 20: "The Commission recognizes that a financial benefit would accrue to the utility customers as a result of consolidation. While this saving is material, the canvassing of the full impact on all customers is more important."

The Commission's October 25, 1993 Reasons for Decision on BC Gas Utility Ltd's Phase B Rate Design Application G-101-93 (Exhibit A2-2) stated on pages 6 to 7:

> "BCGUL received general support for consolidation from its interior customers and from the municipalities which it serves. .. The Commission approved consolidation with certain conditions."

Commission Order G-34-95 on an Application by Centra Gas BC Inc. for Approval of 1995/96 Revenue Requirements – Whistler and Port Alice Districts stated: [7] "Centra Gas also applied to consolidate its Whistler and Port Alice Districts for rate-making purposes. ... On February 23, 1995, at the ADR meeting in Whistler, B.C., Centra Gas officially withdrew its proposal to consolidate the two Districts ... ."

The Commission, in its October 19, 2010 Reasons for Decision on FortisBC Inc. 2009 Rate Design and Cost of Service Analysis[8] (G-156-10) stated:

> "BCMEU [British Columbia Municipal Electric Utilities] argues in support of the continued use of a common class for municipal customers, stating that ... each of the BCMEU members support retaining one customer class ... no other customer class is harmed by a consolidation approach and it is revenue neutral to FortisBC ..." (p. 14)

9.1 Do FEU agree that previous Commission decisions indicate that customer preferences in remaining or becoming a "distinct or special area" should be one of the key evaluation criteria in evaluating FEU's proposal to move to postage stamp rates? If no, please explain why not.

Response:

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7 http://www.bcuc.com/Documents/Proceedings/2006/DOC_11625_A2-1_Orders-re-Interim-Rates.pdf

8 http://www.bcuc.com/Documents/Proceedings/2010/DOC_26325_FortisBC-2009-RDA_WEB.pdf

No, customer preferences to stay as a distinct or special area should not be one of the key evaluation criteria in evaluating the move to postage stamp rates. The pre-amble to this IR cites specifically the need to consult and solicit input from interveners and customers on amalgamation and postage stamping. The Companies have done so, soliciting affected customer input on its amalgamation and postage stamp proposals. In addition, a distinct or special area does not necessarily constitute separate rates and its own rate design.

9.2 Please explain why Centra Gas withdrew its proposal to consolidate its Whistler and Port Alice Districts for rate-making purposes in 1995. In your response, please specifically address if lack of customer support for this proposal was a significant factor in Centra Gas' withdrawal of its postage stamp rate proposal.

<u>Response:</u>

The FEU are not aware of the reasons that Centra Gas withdrew its proposal to consolidate its Whistler and Port Alice Districts for rate making purposes in 1995. The FEU are aware that there was an NSP process to review the proposal by Centra Gas that was attended by stakeholders, and that after the NSP, Centra Gas withdrew the application to combine Whistler and Port Alice for rate making purposes.

10.0 Reference: Request for Common Rates

Exhibit A2-2, Reasons for Decision for Order G-101-93, pp. 6, 7; Exhibit A2-5, Alberta EUB Decision 2000-6, pp. 50, 51; Exhibit A2-6, BC Gas 2001 Rate Design Application, Tab 4, p. 10; BC Hydro 2007 Rate Design Application, Exhibit C7-4, p. 11, Testimony of EES Consulting, p. 3, 5; Reasons for Decision for Order G-87-07, pp. 5-16; Reasons for Decision for Order G-156-10, pp. 14, 18

Distinct or Special Area – Cost Based Rates

The Commission's October 25, 1993 Reasons for Decision on BC Gas Utility Ltd's Phase B Rate Design Application G-101-93 (Exhibit A2-2) stated on pages 6 to 7:

> "The Company also suggested that the results of the Fully Distributed Cost Studies prepared by BCGUL indicated that the costs of serving residential customers in the three Divisions were comparable and therefore the Utility should move toward consolidation and postage stamp rates. ...The Commission approved consolidation with certain conditions. ... internal divisional accounts must be maintained so that rate base and cost of service can be determined in future rate design applications. ... BCGUL will be required to demonstrate each time that any rate change will preserve or enhance the revenue to cost ratio for each divisional rate class as determined in this Decision."

In its December 2000 Decision on NGTL 1999 Products and Pricing (Decision 2000-6), the Alberta EUB approved a move to distance based transmission rates (Exhibit A2-5),[9] and stated on page 50 and 51 of the decision:

> "In summary, the Board believes that the receipt point specific tolling as proposed by NGTL represents a reasonable balance of acceptable attributes of sound rate making and will be in the public interest. The new rate design is directionally positive in that it is more reflective of the cost of providing service."

BC Gas stated in its 2001 Rate Design Application (Exhibit A2-6)[10] (Tab 4, p. 10)

> "The primary arguments in support of postage stamp rates are that postage stamp rates are seen to be a fair and equitable way to recover costs of delivery service from all customers, as well as easy to administer and understand. Arguments in favor of regionally differentiated rates are based primarily on

9 http://www.auc.ab.ca/applications/decisions/Decisions/2000/2000-06.pdf

10 http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/2001_RateDesign_App.pdf

differences in the cost of service across different regions. Thus a decision to depart from postage stamp rates requires an assessment of the degree to which costs vary across regions versus the benefits realized through the use of postage stamp rates."

Terasen Utilities, in Exhibit C7-4 to BC Hydro's 2007 Rate Design Application submitted the following Testimony of EES Consulting on behalf of Terasen Utilities (page 3 and 5 of the Testimony):[11]

> "Cost causation should be the foundation of the COS [Cost of Service] and rate setting for BC Hydro."
>
> "The COS study is based on the principle that service should be provided at cost. The determination of cost of service requires a study is driven by the principles of cost causation (i.e., costs are allocated to those who cause the cost to be incurred)."

Terasen Utilities, in Exhibit C7-4 to BC Hydro's 2007 Rate Design Application,[12] page 11, stated:

> "In its application BC Hydro did not provide any rigorous analysis of the cost causal nature of its distribution system to be used to classify distribution costs, rather it based its classification on "experience and the practices of other distribution utilities." ... As this Rate Design Application and the inherent cost allocations form the foundation for future rate design initiatives, it is important that this foundation be based on generally accepted rate design principles, including cost-causation."

The Commission in its August 7, 2007 Reasons for Decision on An Application by FortisBC Inc. for a Rate Design on the Big White Supply Project (G-87-07)[13] states on pages 5 to 16:

> "The Application also discusses certain implementation and policy issues which, in FortisBC's view, should be addressed prior to any decision to impose a line extension charge, rate surcharge or zonal rates on Big White customers. ... The EES Report submits that "The pertinent technical question is whether or not the revenues and allocated costs from/to the Big White area are

11 http://www.bcuc.com/Documents/Proceedings/2007/DOC_15516_C7-4_Terasen-Utilities-Evidence.pdf (page 18, 19 of pdf)
12 http://www.bcuc.com/Documents/Proceedings/2007/DOC_15516_C7-4_Terasen-Utilities-Evidence.pdf
13 http://www.bcuc.com/Documents/Proceedings/2007/DOC_16326_G-87-07_FBC_Big-White-RD-Reasons-for-Decision.pdf

> significantly different from those revenues and allocated costs collected from/to other areas within the FortisBC service territory to warrant special and unique retail rate treatment for the Big White area." (p. 5)
>
> "The COS analysis demonstrates that ... with the Project costs assigned directly to the Big White area, the revenue to cost ratio is approximately 84 percent after load growth has occurred. The Commission Panel agrees with FortisBC that all of these results fall within the range of revenue to cost ratios of the other communities in the FortisBC area that were analyzed and notes that the EES Report ... suggests that the entire FortisBC service area would face a similar variability between areas and towns. ...
>
> The Commission Panel, therefore, agrees with FortisBC that an analysis of the revenues and allocated costs indicates that Big White is not sufficiently different from other areas in FortisBC's service territory to warrant special and unique retail rate treatment." (pp. 15-16)

The Commission, in its October 19, 2010 Reasons for Decision on FortisBC Inc. 2009 Rate Design and Cost of Service Analysis (COSA)[14] (G-156-10) stated:

> "BCMEU [British Columbia Municipal Electric Utilities] argues in support of the continued use of a common class for municipal customers, stating that .... the BCMEU members have similar revenue to cost ratios under standard COSA principles, although not under FortisBC's proposed COSA approach [and] no other customer class is harmed by a consolidation approach and it is revenue neutral to FortisBC ... ." (p. 14)
>
> "The Commission Panel agrees with each of BCMEU's arguments in favour of a single class and determines that the Wholesale customers (other than Nelson which will remain its separate class) can be considered to be a single class for COSA purposes. The Commission Panel directs FortisBC to re-run the COSA on this basis." (p. 18)

10.1 Previous regulatory decisions appear to support an approach of only moving to postage stamp rates where costs in the different regions are similar (i.e. where postage stamp rates are more, rather than less, cost reflective compared to the existing rate). Doe FEU agree with this conclusion? If no, please explain why.

[14] http://www.bcuc.com/Documents/Proceedings/2010/DOC_26325_FortisBC-2009-RDA_WEB.pdf

Response:

No, the citations in the preamble to this IR weigh the particular merits of the rate design applicable to the particular utility at that time and do not make statements about when it is appropriate to move to postage stamp rates generally. Further, many of the items cited in the preamble to this IR do not support the conclusion posed that moving to postage stamp rates is only appropriate where costs in the different regions are similar. For example:

1. The 2001 BC Gas Rate Design Application citation above states that costs must be weighed against the various benefits of postage stamping across the regions of the utility. In other words, the costs considered have to be weighed against the various benefits of the postage stamp rate design that was already in place for BC Gas at the time.
2. The 2007 BC Hydro Rate Design proceeding citation states that the classification of distribution costs should be based on cost causation. This citation deals specifically with the cost causation associated with the postage stamp rate design in place for the last approximately 45 years at BC Hydro, not whether BC Hydro should move to postage stamp rates.
3. While the 2007 FortisBC Inc. Rate Design on the Big White Ski Project Decision states that the cost of service of the area relative to other areas is an important consideration, the decision cites other considerations for postage stamping the rates of the Big White Ski Project in with the rest of FortisBC such as the nature of extension, government policy and other utility practice. In this case, the citation deals with the appropriateness of applying the postage stamp rates already in place at FortisBC to the Big White Ski Area extension.
4. The 2009 FortisBC Inc Rate Design Decision citation is with regard to the appropriateness of maintaining a single rate class for municipal customers, not whether it is appropriate to move to postage stamp rates across entities. The full quote from the FortisBC Decision includes a number of considerations, as follows: "(i) they each have a customer mix which is primarily residential; (ii) the BCMEU members have similar revenue to cost ratios under standard COSA principles, although not under FortisBC's proposed COSA approach; (iii) each of the BCMEU members support retaining one customer class; and (iv) no other customer class is harmed by a consolidation approach and it is revenue neutral to FortisBC."

Moreover, postage stamp rates are the most commonly accepted rate design, the premise of which is to have the same rate regardless of location. Every example of postage stamp rates represents a regulatory decision in which different regional costs were shared amongst all customers. Please also refer to the responses to BCUC IRs 1.7.2 and 1.13.1.

As EES stated on page 6 of its report in Appendix D-1 of the Application:

> *"In comparing postage stamp pricing to regional pricing, it is important to consider standard utility practice as well as equity among customers, accuracy of the data involved, and practical considerations. Regional pricing can provide a greater reflection of actual costs but requires a greater administrative burden and relies on being able to accurately split out costs for shared facilities. However, postage stamp pricing simplifies the process, treats all customers in the same manner, and reflects the shared nature of many facilities."*

> *"Postage stamp pricing better reflects the fact that utility systems have a high level of interconnection, and facilities are most often shared among large groups of customers. Facilities closer to the customer, like distribution facilities, are more closely tied to local groups of customers, while facilities upstream from the customer, like transmission, are generally used by all customers on the system. When the FEU service areas had separate ownership they were operated as stand-alone entities and needed to rely on their own facilities to deliver gas to customers. Each separate utility had postage stamp rates within their service areas. The acquisition of the different utilities led to operational efficiencies and resulting cost savings. This includes greater integration of existing facilities and installation of new facilities that benefit the entire utility. As the systems become more and more integrated, the application of postage stamp pricing across all regions becomes more appropriate."*

10.2 Do FEU agree that cost causation should be the foundation of rate setting? If no, please explain why not.

Response:

The FEU agree that cost causation should be a foundation of rate setting, and cost causation is a foundation of the Companies' proposed postage stamp rates. The cost causation principle is also adhered to in the current postage stamp rate design existing within FEI (excluding FEFN) and this principle is being extended across the FEU. The recovery of the costs in FEI is the basis for the postage stamp rates within FEI and the Companies are proposing a similar approach that incorporates all of the service areas of the FEU.

Cost causation must also be balanced with other rate setting principles for the unique circumstances in each proceeding. In many of the proceedings cited in the preamble to the IR, the postage stamp context was with regard to overall rate rebalancing of the utility rates amongst its various existing postage stamped rate classes. The FEU submit that the circumstances are significantly different in this proceeding, and that the FEI (including FEFN), FEVI and FEW costs combined in the amalgamated COSA are appropriate to be used as a foundation for postage stamp rate setting in this proceeding.

10.3 Do FEU agree that alignment with cost causation principles/avoidance of cross-subsidies should be a key evaluation criteria in evaluating FEU's proposal to move to postage stamp rates? If no, please explain why not.

Response:

The FEU agree that alignment with cost causation principles is one evaluation criteria in evaluating the Companies' postage stamp rate proposals. Cost causation must be balanced with the other rate design principles and used as a guide to the appropriate rate for each customer class. The FEU believe that the revenue to cost ratios as stated in Table 9-10 on page 220 of the Application reflect a reasonable basis for the rates for each class considered and that no rebalancing is required. The Companies also believe that as stated in the response to BCUC IR 1.10.1 that costs can vary significantly within a postage stamped area (as they do today within each existing service area), and that this should not preclude the combination of the costs and setting postage stamp rates for the benefit and fairness to all customers in the amalgamated service area.

11.0 Reference: Request for Common Rates

***UCA*, Section 60 (2) to (4); Exhibit B-3, Exhibit B-3-1, Appendix H-5-9**

Distinct or Special Area – Section 60 (2) to (4)

Section 60(2) to (4) of the *Utilities Commission Act* states:

> (2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.
>
> (3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.
>
> (4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

11.1 If the Commission takes a distinct or special area into account for ratemaking purposes, would a COSA Study prepared consistently with those in Appendix H-5 to H-9 (using embedded costs) need to show a total revenue: cost ratio of close to 100 percent in order to demonstrate that an area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area? Please explain why or why not.

Response:

If an area was determined to be a distinct or special area for ratemaking purposes, and a separate COSA could be established for that area with clearly defined assets and costs attributed to the area, then the revenue to cost ratio would be expected to be 100% for the assigned revenue requirements for the area as a whole (but not for each customer class) to ensure that a fair and reasonable return was provided for the distinct area. This would only be the case if the Commission determined that the area must be treated as a stand-alone utility in terms of costs and that the revenue requirements must be totally separated from the remaining portion of the utility costs.

A rate could be determined for a distinct or special area that was based on a relationship between the distinct area and the remaining area of the utility that would not require a separate COSA for the area. In this case, the COSA for the entire utility area would expect to yield a

100% revenue to cost ratio for the total revenue requirements to ensure a fair and reasonable return. However, there would not be a revenue to cost ratio calculated for the distinct area.

11.1.1 What do FEU interpret "appraised value of the plant or system" to mean?

Response:

The FEU interpret the appraised value of the plant or system to mean the rate base value (usually historical costs less accumulated depreciation) of the FEU's plant or system. To the FEU's knowledge, this interpretation reflects the consistent practice of the Commission and other similar regulatory tribunals.

11.1.2 Does the cost included in FEU's Fully Distributed COSA Studies include any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession? If yes, please identify the amounts included.

Response:

The FEU Fully Distributed COSA study includes $55 thousand of annual depreciation expense related to Account 401-00, Franchise and Consents. Further, although not directly included in the cost of service, the lead lag days used in the determination of the cash working capital component of rate base account for the collection and remittance of franchise fees in applicable municipalities.

To clarify, although there is a small balance in plant and consideration of the working capital impact in rate base, the Fully Distributed COSA studies do not include the franchise, licence or permit fees collected from customers on behalf of the municipalities where such fees may apply.

Please refer to Appendix J-1, Schedule 16, Line 7 and Schedule 18, Line 7 for details on Account 401-00.

11.1.3 Assuming customers in the "unique and special area" did not provide a significant contribution to the original extension and additional benefits were minimal, what do FEU consider would be an acceptable range that the total revenue: cost ratio for each distinct and special area could vary from 100 percent and yet still be considered reasonable. Please explain.

Response:

In this case, the acceptable revenue to cost ratio would be 100 percent for each area, with the same qualifications as provided in the response to BCUC IR 1.11.1.

11.1.4 Do FEU consider that the acceptable range would change if customers in the "unique and special area" contributed significantly to the costs of the original extension to the area? If yes, please explain how.

Response:

The acceptable range would not change because the revenue requirement would already take into account any contributions made to the original extension to the area, which in turn would be accounted for in the revenue to cost ratio.

11.1.5 Do FEU consider that the acceptable rate would change if there were other widespread benefits to customers outside of the "unique and special area" from a move to postage stamp rates? If yes, please explain how.

Response:

If there were widespread benefits to customers outside of the "unique and special area", the FEU do not believe that the area in question would meet the conditions necessary to treat it as a stand-alone utility in terms of developing a separate revenue requirements and COSA.

11.2 Please describe the "distinctive characteristic" considerations that FEU consider should be considered in an evaluation of postage stamp rates. Please explain in your response if these characteristics should include (and if so, to what extent) economic development, sparsely settled regions, environmental and social considerations.

Response:

The FEU has not found any areas within the FEU service areas that it considers to have the "distinctive characteristics" required in the Act. Distinctive characteristic considerations of unique and special areas might include economic development, sparsely settled regions, environmental and social considerations. It would also require that the area could be operated on a stand-alone basis and would not be part of a system that is planned for and operated on an integrated basis.

12.0 Reference: Request for Common Rates

Exhibit B-3, Section 6, pp. 107, 108; Reasons for Decision for Order G-17-06, pp. 7, 10; Exhibit A2-4, Alberta EUB Decision U96055, p. 27

Dinstinct and Special Area - District of Chetwynd

The FEU state on page 107 and 108 of the Application "EES Consulting states:.'In 2004 the District of Chetwynd, which is within the FEI service area, filed a complaint challenging the postage stamp rates and requesting separate rates for the District. The Commission rejected the request in Letter No. L-24-04 and upheld the continuation of postage stamp rates.'"

In the Reasons for Decision to Order G-17-06 (Application by Terasen Gas Inc. for Approval of Operating Terms for the Supply and Distribution of Natural Gas Service within the district of Chetwynd) dated February 2, 2006 the Commission states on page 7 and 10:[15]

> "Terasen noted that the District of Chetwynd has proposed fees of approximately 11 percent but also suggested that these fees should not be charged back to the residents of Chetwynd. Terasen objected to this suggestion as it would have the effect of Terasen either not recovering its cost of service or having to recover this cost from all customers served by Terasen. ...
>
> The Commission continues to hold the view .. that franchise/operating agreements and gas rates for customer are issues that largely need to be resolved separately and, therefore, finds no compelling reason for a new short-term Operating Agreement given that rate matters are determined and set by the Commission from time to time in the duration of any operating agreement."

Alberta Energy and Utilities Board (EUB) June 12, 1996 Nova Gas Transmission Ltd. (NGTL) Decision on a 1995 General Rate Application – Phase II (Decision U96055) stated on page 27 (Exhibit A2-4) with regard to postage stamp versus distance sensitive gas transmission rates:[16]

> "Before making a change in toll design, the Board would need to be satisfied, on the basis of clear and convincing evidence, that greater efficiencies or cost savings would accrue to the benefit of shippers overall."

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[15] http://www.bcuc.com/Documents/Orders/2006/DOC_10725_G-017-06_TGI_%20Chetwynd%20OpAgrmnt%20Reasons.pdf

[16] http://www.auc.ab.ca/applications/decisions/Decisions/1996/U96055.pdf

12.1 Have FEU consulted with the District of Chetwynd on the Application? If yes, please document the results of that consultation. If no, please explain why not.

Response:

The FEU consulted with the FEI Inland service area, which includes the District of Chetwynd. In addition to canvassing Inland customers through market research[17] and public information sessions, Inland stakeholders, including the District of Chetwynd, received stakeholder letters.[18] On receipt of a second letter, the District of Chetwynd requested that the FEU provide further information on the projected impacts to Chetwynd as a result of common rates.[19] The District of Chetwynd was provided with the approximate rate impacts for the region and was also informed that the FEU were examining approaches to phase-in the increase so as to mitigate the rate increase in the short-term. Once the rate impacts had been provided, no further correspondence was received from the District of Chetwynd.

12.2 Do FEU agree that, in considering if the district of Chetwynd should be added as a ‘‘distinct or special area," the Commission should be satisfied, on the basis of clear and convincing evidence, that greater efficiencies or cost savings would accrue to customers overall; that the magnitude of the changes to affected parties are acceptable; and that benefits in the broad public interest would result? If no, please document the criteria that FEU consider should be used in evaluating this option.

Response:

The FEU have not applied for Chetwynd, or any other area, to be considered as a distinct or special area. Please refer to the response to BCUC IR 1.8.1.

17 Market Research results by region can be found in Appendices E-5 and E-6 of the FEU Common Rates, Amalgamation and Rate Design Application. Please note that Inland customers are classified as Interior customers within the market research.

18 Refer to the FEU's response to BCUC IR 1.107.1 for the November letter and Appendix E-9 of the Application for the January letter.

19 Refer to the FEU's response to BCUC IR 1.107.2 for District of Chetwynd letters.

13.0 Reference: Request for Common Rates

Exhibit B-3, Section 4, p. 71, Section 10, p. 232; Reasons for Decision for Order

G-171-07, pp. 7, 33

BC Hydro – Postage Stamp History

The FEU, on page 71 of the Application, state: "The postage stamping of rates within the FEU's largest service areas reflects the most widely accepted practice in the utility industry and the rate design approved by the Commission for most utilities in BC. In particular, postage stamp rates are consistent with the rates approved for the electrical utilities in the Province, namely, BC Hydro and FBC."

The Commission, on page 7 and 33 of its Reasons for Decision on BC Hydro's 2007 Rate Design Application Phases II and III (Order G-171-07 dated December 21, 2007)[20] stated:

> "BC Hydro states that upon its formation in 1962, it assumed responsibility for the supply of electricity to the majority of B.C. residents from its predecessor companies, the B.C. Power Commission and B.C. Electric and that, in 1962, the residential rate was established on a "postage stamp" basis throughout the province with the government agreeing to provide a subsidy of $150,000 towards the losses incurred in districts served by diesel generation.
>
> BC Hydro states that in 1966 the provincial government established the policy that it was not prepared to subsidize electric space heating from diesel generated electricity in the Atlin district, and that two separate tariff or rate zones were to be created, following which BC Hydro applied the same principle to all districts served by diesel generation. BC Hydro states that Zone II has been a separate rate zone on BC Hydro's rate map since January 1967 ... "

The FEU state on page 232 of the Application: "there is a very high seasonal occupancy rate for properties in Whistler (during the conversion project from propane to natural gas FEW found that approximately 70% of the residential dwellings in Whistler were not occupied year-round), ... many property owners live outside of British Columbia."

The FEU state on page 66 of the Application: "In 2008, 91% of the FEU's residential customer base used natural gas as the main space heating fuel. Regionally, Table 4-4

20 http://www.bcuc.com/Documents/Proceedings/2007/DOC_17589_12-21_BCH_2007RDA-Decision-Phases_2&3_Final.pdf

below indicates the lowest proportion of homes using natural gas as the main space heating fuel is within FEVI and FEW."

13.1 Commission Order G-171-07 appears to indicate that BC Hydro put postage stamp rates in effect initially at the request of the provincial government. Has the provincial government requested that FEU introduce postage stamp rates? If yes, please provide supporting evidence.

Response:

No, the provincial government has not requested that postage stamp rates be applied to the FEU's service areas. However, provincial government policy has been in favour of postage stamp rates. The following provides evidence of the support for postage stamp rates in BC:

1. In the BC Hydro 2007 Rate Design Application (RDA), BC Hydro filed a 2003 letter from the Minister of Energy to the President of the Union of BC Municipalities that made direct commitment to the continuance of the postage stamp rate design in the context of the Heritage Contract Inquiry (BC Hydro 2007 RDA, Exhibit B-47, included as Attachment 13.1).

2. In response to an information request in the BC Hydro 2007 RDA BC Hydro stated its support for postage stamp rates as follows:

   "BC Hydro considers postage stamp rates to be a fundamental rate design objective….The application of postage stamp rates has been in place for many decades and continues to remain a cornerstone of rate design for BC Hydro. Absent any policy direction from the provincial government it is unlikely that BC Hydro would move away from this fundamental rate design objective. The 2007 Energy Plan does not contain any policy actions specifically encouraging or requiring a move away from postage stamp rates.

   BC Hydro notes that the concept of postage stamp rates is practiced by most distribution utilities, as a matter of public policy, and in some jurisdictions is also mandated through legislation."

   The FEU agree with BC Hydro that the concept of postage stamp rates is common among distribution utilities, and in some jurisdictions it is also mandated through legislation.

3. Changes to the BC Hydro System Extension Test (SET) coming out of the BC Hydro 2007 RDA place new customers on an equitable footing with existing customers in terms of connecting to the system, particularly with respect to the cost of electricity. The SET no

longer includes the marginal cost of electricity in the analysis so that the test is no longer skewed in favour of existing customers relative to new customers. In effect, it recognizes a pooling of electricity supply costs (Heritage power and new IPP supply resources) resulting in the test being more compatible with BC Hydro's position on postage stamp rates and recognizes a fair approach to customer attachments. Since the required contributions from new customers do not incorporate the marginal cost of power the revised SET sustains the BC Hydro postage stamp rate structure by granting new customers similar access to Heritage Resources as existing customers.

4. In the FortisBC Inc. 2009 Rate Design and Cost of Service Analysis Decision, dated October 19, 2010, the Commission stated (at p. 69) that the postage stamp principle followed by FortisBC is supported by government policy. The Commission Panel also noted (at p. 69) that "the current policy, supporting same rates to all members of a class regardless of their location in the Province, can also be interpreted to support the idea that the FortisBC residential customer rate structure should more closely resemble the BC Hydro residential rate structure." (At the request of the Commission Panel the letter in Attachment 13.1 was also filed in the FortisBC Inc. 2009 RDA as Exhibit A2-1.)

5. In the case of the amalgamation of Terasen Gas (Squamish) Inc. into FEI (see section 3.2.1.3 of the Application, pages 25 and 26) the provincial government supported the postage stamp rate principle in place for FEI by requiring in Special Direction No. 3 (dated Nov. 2, 2006) that "(i)n regulating and fixing rates for amalgamated TGI, the commission must apply the Terasen Gas Inc. Tariff and must not apply the Terasen Gas (Squamish) Inc. Gas Tariff."

6. The provincial government supported the retention of BC Hydro's postage stamp rate structure in the establishment of the Remote Communities Regulation (O.I.C. 509 dated June 25, 2007) and Special Direction No. 10 (O.I.C. 508 dated June 25, 2007). In combination, these require the Commission to allow BC Hydro to recover the costs of the projects undertaken in the specified remote communities in its revenue requirements and that the customers in those communities be charged the existing postage stamp rates (whether Zone 1 or Zone 2 rates).

7. The Commission has historically recommended or supported the postage stamp principle. An example is a large system upgrade of the electricity service by FortisBC to the ski resort at Big White (refer to page 108 of the current Application). A significant issue in the hearing pertained to whether the service to Big White should attract an incremental toll after the project was completed since the system upgrade would only (or primarily) benefit customers

at Big White. In BCUC Order G-87-07, the Commission determined that the extension to Big White should not be subject to an incremental toll and should be rolled into FortisBC electrical rates, thereby sustaining the postage stamp principle that was in existence across the FortisBC service territory. Another example, is Letter No. L-24-4 in response to the complaint from the District of Chetwynd, as discussed on page 115 of the Application.

13.2 Do FEU consider it is reasonable to assume that a key driver for BC Hydro's postage stamp approach is to mitigate potentially high electricity costs in remote communities? Please explain why or why not.

Response:

The FEU do not believe that mitigating potentially high electricity costs in remote communities was a key driver in BC Hydro's postage stamp approach since the BC Hydro service territory is divided into only two zones, Zone 1 for integrated areas and Zone 2 for non-integrated areas. There are many methods BC Hydro could have adopted if the objective was simply to mitigate high electrical costs in remote communities; however by implementing an "integration approach" BC Hydro was able to support the postage stamp objective to keep rates the same in each area. Therefore it is reasonable to assume that the key driver was to have the same rates across the province for grid-connected customers (i.e. Zone 1 customers) in the same rate classes, which comprised the great majority of electric customers of the combined entity. The postage stamp rates were applied to non-integrated areas as well.

13.2.1 Do FEU consider that FEVI and FEW customers also fit the criteria of remote communities who require financial assistance to meet their basic needs? If yes, please explain why.

Response:

No, the FEU do not consider that FEVI and FEW fit the criteria of remote communities.

The FEU do not believe there is anything in the Remote Communities Regulation that states or otherwise implies that the residents of remote communities need financial assistance to meet their basic needs. The FEU believe that the intent of the provincial government in establishing the Remote Communities Regulation and Special Direction No. 10 was to express its view to the Commission that the benefits of BC Hydro's postage stamp rate structure (in either Zone 1 or Zone 2) should be extended to communities that otherwise may not have access to these benefits.

13.2.2 Do FEU consider that provision of delivered gas to vacation homes, and where customers only have low gas use appliances such as ornamental fireplaces, stoves and BBQs, are consistent in terms of the overall benefits to BC as electricity provided to remote communities? If yes, please explain how.

Response:

The FEU do not accept the characterization in the question of customers with very low energy use as being representative of the customers of FEVI and FEW. Customers with low gas use overall would be more likely to be subject to a contribution when they connect to the natural gas system. However, the energy uses mentioned in the question represent very efficient and valuable uses of energy.

The FEU are not in a position to judge whether the provision of natural gas to the important communities of Vancouver Island and Whistler is more or less beneficial to B.C. than electric service to remote communities. However, the provincial and federal governments have consistently supported the provision of natural gas service to Vancouver Island; the Whistler Pipeline and Conversion Projects were supported by the RMOW and granted CPCNs by the Commission. The FEU provide a significant amount of energy to these communities, which is relied on for a variety of uses.

BC Hydro's postage stamp rates, as referred to in the preamble of this IR, extend to the communities of Vancouver Island and Whistler.

14.0 Reference: Request for Common Rates

Reasons for Decision for Order C-4-09, p. 3; Reasons for Decision for Order

G-58-10, pp. 6, 10;

BC Hydro –Remote Community Electrification

The Commission, on page 3 of its September 15, 2009 Reasons for Decision on an Application by BC Hydro for a CPCN for the Toad River Remote Community Electrification project (C-4-09) stated:[21]

> "By Order in Council No. 508 dated June 25, 2007 the Provincial Government issued Special Direction No. 10 to the BCUC, section 5 of which provides that , in setting rates for BC Hydro, the Commission must ensure BC Hydro's "rates and classes of service available to customers in the non-integrated area [defined as Anahim Lake, Atlin, Bella Bella, Bella Coola, Dease Lake, Eddontenajon, Queen Charlotte Islands and Telegraph Creek District], ...are available to customers who receive electricity service under section 2 of the Remote Communities Regulation." It further provides that, in setting rates for BC Hydro, the Commission must ensure that the rates are sufficient to allow BC Hydro to, amongst other things, recover the costs related to the provision of such service."

The Commission, on page 6 and 10 of its March 26, 2010 Reasons for Decision on an Application by BC Hydro on the Southern St'at'imc Electrification Project Application (G-58-10) stated:[22]

> "The Commission recognizes the benefits of grid connection and accepts that the added $9 million costs of grid connection (over the minimum costs of providing service by way of diesel generation) is off-set by a customer contribution in aid of construction which renders the grid connection alternative revenue neutral to ratepayers. The Commission supports the recommendation of BC Hydro to connect the Southern St'at'imc Communities to the grid. ...
>
> "The Commission determines that the Southern St'at'imc Communities are eligible to receive ectricity service from BC Hydro as Rate Zone 1 customers as defined and specified in BC Hydro's Electric Tariff once they are connected to the BCTC integrated electrical grid."

21 http://www.bcuc.com/Documents/Proceedings/2009/DOC_22853_C-4-09_BCH%20Toad%20River%20Electrification%20Project.pdf

22 http://www.bcuc.com/Documents/Proceedings/2010/DOC_25181_G-58-10_BCH_St'at'imc-Electrification-Project-Reasons.pdf

14.1 Would FEU be supportive of FEVI and FEW customers being treated consistently with electric customers under BC Hydro's Remote Communities Regulation, which requires that the Commission ensure that the rates are sufficient to allow BC Hydro to, amongst other things, recover the costs related to the provision of service to those areas? Please explain why or why not.

Response:

No, it is not necessary to invoke the principles from Special Direction No. 10 pertaining to electric customers in remote communities for FEVI and FEW in the context of this Application. The customers of FEVI and FEW are not in remote communities and the principles of recovering costs and a reasonable return on investment are fundamental principles in establishing utility revenue requirements. These principles are equally valid for separate utilities individually or amalgamated utilities taken together.

Special Direction No. 10 does provide an example of government support for rolling in the costs of projects in remote communities into the overall revenue requirements of BC Hydro. In that sense Special Direction No. 10 is supportive of and sustains the postage stamp rate structure in effect for BC Hydro.

15.0 Reference: Request for Common Rates

Exhibit B-3, Section 6, pp. 107, 108

Practice of Other Utilities

The FEU state on page 107 of the Application:

> "Postage stamp rates are the accepted regulatory approach approved by the Commission for most other utilities in BC and are more widely accepted than regional rates in the utility industry generally. EES Consulting states: 'Both regional rates and postage stamp pricing are seen for natural gas rates. Pacific Northern Gas, ATCO Gas and Union Gas maintain regional rates for natural gas. However, postage stamp pricing is the more widely accepted practice in the utility industry ... Postage stamp rates also apply for AltaGas, Centra Gas Manitoba, Heritage Gas, Gaz Metro and SaskEnergy, as well as the majority of gas utilities in the U.S. ... ' "

The FEU state on page 108 of the Application:

> "EES Consulting sums up the attributes of postage stamp rates as follows: ... The current regional differences in delivery rates are a result of the past ownership structure and do not necessarily reflect the same regional separation that would occur based on operating and cost differences alone."

15.1 Recognizing that postage stamp and regional rates can be the result of past ownership structures, has the general trend in the gas delivery industry over the last 20 years been to move from postage stamp to regional rates, or regional rates to postage stamp rates? Please support your response with examples.

<u>Response:</u>

The FEU has not completed an extensive review of trends in gas delivery rates over the past 20 years that would allow it to conclude if a trend exists. EES Consulting provides examples that include both postage stamp and regional rates and concludes that postage stamp rates are more common. The approval of postage stamp vs. regional rates depends on the unique circumstances of the utility in question.

15.1.1 For any examples provided, please state the key reasons accepted by the regulator for the rate design change.

Response:

The FEU did not provide any examples in the response to BCUC IR 1.15.1.

15.2 Please confirm that Union Gas customers are subject to postage stamp fixed and variable delivery charges, but that commodity, storage and transportation charges differ by delivery area.

Response:

The FEU understand that the delivery rates are postage stamped within the Northern and Eastern rates but that delivery charges are different for the Southern rates. Commodity, storage and transportation rates do differ by region.

15.2.1 Why, in the FEU’s opinion, would Union Gas have implemented postage stamp delivery charges and regional commodity, storage and transportation charges?

Response:

The FEU understand that Union Gas’s regional commodity, storage and transportation charges are a result of mergers prior to 1993. The FEU are not aware of why Union Gas has not proposed to postage stamp these rates.

15.3 Please confirm that ATCO Gas customers on the Northern system pay different fixed, variable and midstream (transmission) charges than those on the Southern system.

Response:

Confirmed.

15.4 What, in the FEU's opinion, is the justification for ATCO's implementation of a two-region rate structure?

Response:

The FEU understand that ATCO's two-region rate structure stems from a merger or acquisition in 1999. The FEU is not aware of any justification for the continuation of this structure.

15.4.1 Do customers receiving gas in Pacific Northern Gas' Fort St. John service area pay Spectra's T-South transportation charge as part of their rate?

Response:

The FEU understand that customers receiving gas in Pacific Northern Gas' Fort St. John service area do not pay Spectra's T-South transportation charge as part of their delivery rate, however, they have some T-North Short-Haul tolls included in their gas supply cost.

15.5 Can the circumstances of Union Gas, ATCO and PNG provide a case for the implementation of regional midstream rates in the FEU's service areas?

Response:

No. The FEU have submitted its goals and reasons associated with proposing postage stamped midstream rates. While the FEU may proceed with amalgamation if regional midstream rates were determined by the Commission, the Companies do not believe that regional midstream rates are the best and most appropriate method at this time. Each utility must look at its own unique circumstances in determining rates.

15.6 Can the circumstances of ATCO and PNG provide a case for the implementation of regional delivery rates in the FEU's service areas?

Response:

No. The FEU have submitted its objectives and described the benefits associated with proposing postage stamped delivery rates and does not believe that regional delivery rates are the appropriate rate structure for FEI Amalco. Each utility must look at its own unique circumstances in determining its preferred rate structure. The circumstances at ATCO and PNG may support a different approach for those utilities, but the circumstances of ATCO and PNG and their decisions to maintain regional delivery rates are not relevant factors in setting the FEU rate structure.

16.0 Reference: Request for Common Rates

***UCA*, Section 59 (1) and (2); Exhibit B-3-1, Appendix G-4, p. 39; Exhibit B-3, Section 9, p. 189; Reasons for Decision for Order G-45-11, p. 5**

Evaluation Framework

Section 59 (1) and (2) of the *UCA* states:

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

Policy Action No. 4 of the 2009 BC Energy Plan (p. 39), filed at Appendix G-4 of the Application, states:

> "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation."

The FEU, on page 189 of the Application state:

> "In considering the appropriate rate design, the FEU applied seven rate design principles based on those identified by Dr. Bonbright in his widely accepted work, "Principles of Public Utility Rates." The seven principles adopted by the FEU for the rate design, in no particular order, are:
>
> - Customer Impact;
> - Fairness;
> - Economic Efficiency;
> - Stability;
> - Ease of Understandability;
> - Competitiveness; and
> - Recovering the Cost of Service."

The Commission, on page 5 of the Reasons for Decision for Order G-45-11 on BC Hydro's Residential Inclining Block Rate Re-Pricing Application (dated March 14, 2011)[23] stated that " ... the Commission is guided by the eight "Bonbright Principles" which can be described as follows:

"Principle 1: Recovery of the revenue requirement;

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);

Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);

Principle 4: Customer understanding and acceptance;

Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);

Principle 6: Rate stability (customer rate impact should be managed);

Principle 7: Revenue stability; and

Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

(Source: James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 1961)"

16.1 Why did FEU adopt the seven principles it did for rate design rather than adopting the eight Bonbright principles listed above?

Response:

The decision to adopt the seven Rate Design Principles as filed in the FEU Common Rates and Amalgamation application was based on past precedents to maintain regulatory consistency in methodology with past FEU Rate Designs. Like the principles used by the Commission as set out in the Reasons for Decision for Order G-45-11, the principles adopted by the FEU for this Rate Design are based on those identified by James Bonbright. Table 1 below illustrates the Commission approved rate design principles as filed in previous FEU Rate Design applications, from which the current Rate Design principles in question were derived, and compares them to those principles used by the BCUC in Order G-45-11.

[23] http://www.bcuc.com/Documents/Proceedings/2011/DOC_27176_G-45-11_BCH-RIB-Re-Pricing-Reasons.pdf

Table 1: Rate Design Principles Comparison - FEU Past Rate Design Applications & those used by the BCUC in Order G-45-11

1993 BC Gas Rate Design Application	1996 BC Gas Rate Design Application	2001 BC Gas Rate Design Application	2010-2011 TGVI Revenue Requirement and Rate Design Application	2012 FEU Common Rates and Amalgamation Application	Principles used by the BCUC as per Decision for Order G-45-11	
-	Recovering the Cost of Service	Recovering the Cost of Service	Recovering the Cost of Service	Recovering the Cost of Service	P1	Recovery of Revenue Requirements
Fairness	Fairness	Fairness	Fairness	Fairness	P2 P8	Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates) Avoidance of undue discrimination (interclass equity must be enhanced and maintained)
Economic Efficiency	Economic Efficiency	Economic Efficiency	-	Economic Efficiency	P3	Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy)
-	Ease of Understandability & Administration	Ease of Understandability & Administration	Ease of Understandability & Administration	Ease of Understandability & Administration	P4 P5	Customer Understanding and acceptance Practical and cost-effective to implement (sustainable and meet long-term objectives)
Gradualism (Customer Impact)	Customer Impact	Customer Impact	Customer Impact	Customer Impact	P6	Rate Stability (Customer Rate Impact should be Managed)
Stability	Stability	Stability	Stability	Stability	P6 P7	Rate Stability Revenue Stability
Conservation		Competitiveness	Competitiveness	Competitiveness	P3	Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy)
-	-	-	Maintain the Safety and Reliability of the Utility System	-	-	-

As Table 1 indicates, the eight guiding principles used by the Commission, as set out in the Reasons for Decision for Order No. G-45-11, are embodied in the seven Rate Design principles adopted by the FEU for this Application. As such, the Commission's use of the eight 'Bonbright Principles' as a guide to evaluating the FEU's postage stamp rate proposal is consistent with using those adopted by the FEU for the Common Rates and Amalgamation Application, with the clarification around the use of "Competitiveness" discussed below.

With respect to "Competitiveness", the FEU do not propose "Competitiveness" to be a rate design criteria, but rather a guiding principle to be considered in conjunction with the remaining principles. Ratemaking does not involve treating each principle as a necessary criterion that must be met, but rather it involves managing the necessary trade-offs with regard to these guidelines to achieve the most appropriate balance, while carrying out the objective of the rate design.

In this Application, the principle of Competitiveness means the consideration of other fuel alternatives and the changing market conditions in designing a rate. "Competitiveness" can be considered a sub-component of economic efficiency insofar as it is consistent with Bonbright's characterization of efficiency, where efficiency in any new rates should:[24]

1) Decrease the delay and distortion of market signals;
2) Accommodate changes in market conditions;
3) Maintain cost control for all commodities and services delivered; and,
4) Enhance open access of the gas transportation network.

16.2 Do FEU agree with the Commission being guided by the eight "Bonbright Principles" above in evaluating, for any "distinct or special" area identified by the Commission, FEU's postage stamp rate proposal under section 59 to 61 of the *UCA*.

Response:

Please refer to the response to BCUC IR 1.16.1.

[24] James C. Bonbright, Principles of Public Utility Rates 2nd Edition, Columbia University Press, 1988, Chapter 22, p.51

16.3 Do FEU agree that "Competitiveness" as a rate design criteria as proposed by FEU in the Application is a sub-component of "economic efficiency", in that rates which results in uneconomic bypass of the utility would not be economically efficient? If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.16.1.

17.0 Reference: Overview of the FortisBC Energy Utilities

Exhibit B-3, Section 3.2.1.2, p. 23-6

Maintenance of Lower Mainland, Inland and Columbia Service Areas

"A new company, BC Gas Inc., was created in 1989 to amalgamate [Emphasis added] the divisions of Lower Mainland Gas, Inland, Columbia, and Fort Nelson."

"In its 1992 Revenue Requirements Application, BC Gas Utility Ltd. (now FEI) sought consolidation of its four gas divisions, including Fort Nelson."

"The Commission approved postage stamp delivery charges for the Inland and Lower Mainland residential, commercial and general firm service customers. Although the Commission declined to include the Columbia region in the postage stamp delivery charges approved for the Mainland and Inland, they did allow the Company to set the same delivery rate for Columbia customers."

"Since that time, the Lower Mainland, Inland and Columbia commodity rates have been postage-stamped, while the midstream rates have maintained slight differences between these regions."

17.1 Please provide additional detailed background information regarding the consolidation of the three gas divisions. What was the genesis for this consolidation proposal? What were the main arguments for and against? What were the major costs and benefits?

Response:

The predecessor companies to BC Gas Inc., B.C. Gas Inc. (Lower Mainland Division), Inland Natural Gas Co. Ltd., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd. were permitted to legally amalgamate by the Lieutenant Governor in Council (LGIC) by Order-in-Council 681/89. Each of the predecessor companies then became divisions of BC Gas Inc.; each division maintained its own rate base, cost of service, and rates (which were frozen during a period of approximately three years while the entities were under the regulation of the LGIC). Approval for regulatory consolidation was sought from the BCUC in BC Gas Inc.'s 1992 test year revenue requirements application ("1992 RRA"). The Commission deferred making a decision on regulatory consolidation until it could be considered as part of the utility's Rate Design Application in 1993 ("1993 RDA"). Commission Order G-63-92, regarding BCG's 1992 RRA, stated the following on Page 20 of the decision:

"The Commission recognizes that a financial benefit would accrue to the utility customers as a result of consolidation. While this saving is material, the canvassing of the full impact on all customers is more important. The Commission believes that the

Phase B Rate Design hearing will provide an appropriate forum for resolution of the consolidation issue. Therefore, the Commission directs BC Gas to file its cost of service studies on a divisional basis for that hearing. In the interim period, the company is to maintain divisional rates."

In the 1993 RDA, BC Gas Utility Ltd. proposed consolidation and postage-stamp margins on the delivery component of its rates to residential and commercial customers in the Lower Mainland, Inland and Columbia divisions. Fort Nelson was excluded from the consolidation proposal. The Commission considered consolidation and postage-stamp rates to be separate issues, and determined they would be dealt with independently.

Subsequently, the Commission approved the consolidation of the Lower Mainland, Inland and Columbia regions for regulatory purposes, through Order G-68-93. The matter of postage-stamped delivery rates was examined in the 1993 RDA hearing. In the Commission's Decision dated October 25, 1993 by Order G-101-93, the Lower Mainland and Inland Divisions were approved for postage-stamped rates. Although, the Columbia Division was not included for postage stamping the Basic, Demand and Delivery Charges for residential, Commercial, NGV and General Service, the approved rates were the same as for Lower Mainland and Inland.

There were a number of reasons that were given as benefits of consolidation: seeking to simplify utility regulatory requirements with respect to accounting, applications, reporting to the Commission, legal concerns regarding not having unduly discriminatory rates, and the opportunity to avoid associated duplicative costs. Dr. Waters, a consultant hired by the Commission for the 1992 RRA estimated the savings from consolidation would be $500,000 per year; Mr. Butler, a consultant hired by BC Gas Inc., estimated the savings would be $600,000 per year.

The following table lists the advantages (benefits) and disadvantages from consolidation that were given in the 1992 RRA and repeated in the 1993 Phase B Rate Design, and those identified in the current Common Rates, Amalgamation and Rate Design Application that would still be applicable.

Advantage / Disadvantage of Consolidation	1992 Revenue Requirement / 1993 Phase B Rate Design	2012 Common Rates, Amalgamation & Rate Design
ADVANTAGES		
Similar system design standards	√	√
Similar main extension policies	√	√
Similar policy re ownership of services & connections	√	√
Similar costs for each of the entities	√	
The same regulator (BCUC)	√	√
Service areas all within British Columbia	√	√
Operational & administrative management from one single management group	√	√
Similar Cost of Capital	√	√
Similar Capital Structure	√	√
Same accounting methodologies	√	√
Similar depreciation rates	√	√
Same test year	√	√
Natural gas service originated at about the same time	√	
Similar long run incremental costs	√	√[25]
Economies of scale	√	√
Similar load characteristics of residential & commercial customers	√	√[26]

[25] For the 2001 and 2012 rate design applications, no LRIC studies were done by FEU. However, the single most important item in an LRIC for FEU would be the long run incremental cost of gas which would be similar across FEI, FEVI, and FEW. Currently, there is approximately $1 / GJ difference between FEVI and FEI due to hedging in FEVI and the treatment of UAF gas costs and company use gas costs. The commodity and midstream cost of gas is reviewed quarterly by the Commission.

Advantage / Disadvantage of Consolidation	1992 Revenue Requirement / 1993 Phase B Rate Design	2012 Common Rates, Amalgamation & Rate Design
Difficulty in allocating operational & administrative costs & related capital overheads by division / company & common costs	√	√
Postage-stamp margins meet criterion of providing just & reasonable rates that are not unduly discriminatory	√	√
Simplify regulatory oversight through eliminating duplicative reports, revenue requirements, resource plans – savings to BCUC, Intervenors & Company	√	√
Standardized GT&C's and rate schedules reduces the number of tariffs & rate schedules	√	√
Greater rate / revenue stability	√	√
Elimination of complexity & administration of projects that cross divisional / corporate boundaries	√	√
Lower costs to finance future capital requirements	√	√
Elimination of the need to maintain accounts on a divisional basis will allow more flexibility in displacing gas from one area to another to meet operating requirements	√	√
Ease of extending service offerings		√
Functional Integration	√	√
DISADVANTAGES		
Postage-stamp rates would result in some customer rates increasing, phasing of increases could mitigate rate shock	√	√
Potential for utility to experience 'diseconomies of scale'	√	

[26] For similar types of customers, the load factor percentage is similar between FEVI and FEI. The use per customer for similar types of customers in FEVI and FEI varies, as FEVI use per customer is lower than FEI's.

The FEU did not identify any major costs associated with consolidation when reviewing the Commission decisions, BCGUL Application, and the expert witness evidence of Mr. Butler. The Commission's Phase B Decision did note BCGUL's evidence that customers were favourable to consolidation.

17.2 Was the consolidation of the divisions of Lower Mainland Gas, Inland, Columbia, and Fort Nelson similar to the proposed option by the FEU in the current application? If not, please discuss the differences and the reasons therefore.

Response:

The 1993 Phase B Rate Design Application ("1993 RDA") is similar to the current Application in that both applications requested approval for a single revenue requirement (consolidation) for the purposes of setting rates and rate design, a common set of rate schedules and a common set of tariff general terms and conditions (GT&C's). However, the 1993 RDA excluded the Fort Nelson Division in its Consolidation proposal and did not seek approval for amalgamation. The BC Gas predecessor utilities had already been amalgamated by the LGIC in 1989 by OIC 681/89. In the current Application, the FEU is seeking Commission approval for the amalgamation of FEI, FEVI and FEW. The Application seeks to build on the 1993 consolidation, by amalgamating the three utilities and consolidating the three smaller service areas of FEVI, FEW and FEFN into the already consolidated Lower Mainland, Columbia and Inland service areas.

Also refer to the response to BCUC IR 1.17.1.

17.3 Please clarify what is meant by "consolidation" of the four gas divisions. Does it differ from amalgamation? If yes, please elaborate.

Response:

The terms "consolidation" and "amalgamation" are generally considered to be synonymous, and are often used to describe the same concept. Although these two terms are often used interchangeably, in the context of the 1992 Revenue Requirements Application and the 1993 Phase B Rate Design Application ("1993 RDA"), amalgamation and consolidation of the Lower

Mainland, Inland, Columbia and Fort Nelson divisions were assigned distinct definitions. The following is an excerpt from Appendix C of the 1993 RDA:

> *"It is recognized that there can be some confusion with respect to the use of the words "integration", "amalgamation" and "consolidation". For purposes of this Report;*
>
> ***Integration*** *will refer to a centralising or merging of certain operations of the utility, such as purchasing, engineering or planning, so that one department can provide services to other regions or divisions,*
>
> ***Amalgamation*** *refers to the legal combination of two or more companies into one corporate entity, and*
>
> ***Consolidation*** *refers to the consolidation of the budgets, forecasts or projections and other data obtained from a number of regions or divisions."*

In terms of the current application before the Commission, the six service areas of the FEU (Lower Mainland, Inland, Columbia, Fort Nelson, Vancouver Island and Whistler), already operate under a common management structure. Therefore many of the benefits of "integration" (as defined above) have already been achieved. Amalgamation as referred to in this proceeding, includes both "amalgamation" and "consolidation" as defined above. This Application proposes to merge the three legal entities into one legal entity (amalgamate), as well as combine the revenue requirements for the six service areas, to facilitate the establishment of postage-stamped rates (consolidate).

17.4 Please provide additional detailed background information regarding the basis for the approval of postage stamp delivery charges for the Inland and Lower Mainland residential, commercial and general firm service customers.

Response:

In its 1993 Phase B Rate Design Application, BCGUL requested postage-stamp margins for its residential, commercial and general firm service customers across the Lower Mainland, Inland and Columbia divisions. In Order G-101-93, the Commission approved postage stamp delivery charges for the Inland and Lower Mainland residential, commercial, seasonal, general firm service customers and NGV, while for the Columbia division allowed the same delivery rates to be adopted for these customer classes but did not approve postage stamp rates per se.

The following four points were noted by the Commission as the evidence from the company supporting postage-stamping rates:

- Fairness, equity and the spreading of risk were major reasons,
- Less significant factors were simplicity and economic neutrality,
- Customers perceive their rates to be fair and equitable if they pay the same rates for similar services in all different parts of the province, and
- The Utility's Fully Distributed Cost studies demonstrated that the revenue to cost ratios of residential and commercial customers, based on its proposal would be similar and within the +/- 10 percent band of reasonableness.

Order No. G-101-93 provided the following explanation in its decision to approve postage stamp delivery charges for the Inland and Lower Mainland residential, commercial and general firm service customers:

> *"The Commission is of the view that, on balance, where the revenue to cost ratios and other conditions are similar, the perceived fairness and simplicity of postage-stamping outweighs the other considerations. However, where the nature of the rate base, the customer makeup, the gas supply administration, the operational characteristics and the overall cost structures between Divisions have historically differed, and there is no anticipation of early closer alignment, postage-stamping may not be appropriate.*
>
> *In BCGUL's case, both the Lower Mainland and Inland Divisions are facing rapid customer growth. The resulting growth in rate base is not shared by the Columbia Division. Also, because of its grid system design and location, the Columbia Division experiences different operating and maintenance costs. On a broader basis, BCGUL has recognized, and the Commission has confirmed, gas supply cost differences exist between Divisions.*
>
> *Although consolidation was widely publicized and was generally supported by the interior communities, postage-stamping did not appear to be as well-understood or to be fully supported (T. 151). In fact, the witness for Line Creek Resources Ltd. spoke against postage-stamp rates due to the uniqueness of the Columbia system (T. 208)."*

Based on the Commission's conclusion that the Columbia region was sufficiently different from the Inland and Lower Mainland divisions, postage stamping was only approved for the Inland and Lower Mainland's residential, commercial and general firm service customers.

The Lower Mainland, Inland and Columbia service areas' delivery rates have remained the same in these rate classes since January 1, 1994. In addition, while the structure of commodity and mid-stream charges has evolved over time, since the introduction of commodity unbundling (Customer Choice), the commodity charges for the three regions have been postage stamped, while slight differences in the midstream rates have remained in effect.

17.5 Why were postage stamp delivery charges not applicable to all customer classes of Inland and Lower Mainland?

Response:

In its 1993 RDA Phase B Rate Design Application, BCGUL requested postage-stamp margins for the residential, commercial and general service firm customers. The postage-stamp margin proposal did not apply to large industrial customers, and customers with negotiated bypass rates. In his testimony on July 6, 1993, Patrick Lloyd of BCGUL explained that the BCGUL proposed that the existing large industrial interior customers be grandfathered into Rate Schedule 22A (Inland Division) and 22B (Columbia Division), and that these Rate Schedules (22A and 22B) be closed. Any new large industrial customers would negotiate their rates on a customer-by-customer basis under Rate Schedule 22. The reason at that time in 1993 for not postage stamping the large industrials was that the service between the Lower Mainland large industrials and the Interior industrials was viewed as being significantly different. The Lower Mainland customers were receiving almost exclusively only interruptible service, whereas, the Interior customers transported most of their gas volumes under firm service, and typically used smaller quantities under interruptible service. At the time of the Phase B hearing the Columbia industrial customers also had a "uniquely linked rate design".

Regarding new firm large industrial customers, the Commission, in its Decision (Pages 45 and 46) encouraged flexibility around rates and rate structures. The rate(s) "must consider long-run incremental costs, but otherwise BCGUL is encouraged to be flexible as to the tariff structure so long as the time value of money is considered". However, negotiated rates for new industrial customers would be subject to BCUC approval.

17.6 Please provide additional background information regarding the reasons for declining to include the Columbia region in the postage stamp delivery charges.

Response:

In BCUC Order No. G-101-93, the Commission declined to approve the postage stamping of delivery charges for the Columbia region with those of the Lower Mainland and Inland Service Areas. Please refer to the response to BCUC IR 1.17.4 for the relevant excerpts from the Reasons for Decision for Order No. G-101-93.

At that time, the Commission concluded that the Columbia Division was sufficiently different from the Inland and Lower Mainland divisions, and therefore should not be "linked" to the postage stamp rates that were approved for the Inland and Lower Mainland Divisions' residential, commercial and general firm service customers. While the Commission did not approve postage stamping in principle BCGUL was allowed to set the delivery charges for the Columbia Service Area at the same rates as those in the Lower Mainland and Inland Service Areas.

The delivery charges for residential, commercial and general firm service in the Columbia Service Area have remained the same as those in the Lower Mainland and Inland Service Areas since January 1, 1994. Over time other aspects of commonality and postage stamping have been extended to the Columbia Service Area. For instance at the time of the 1993 RDA historical gas supply arrangements were still in effect for the Columbia Service Area. When these gas supply contracts came to an end the replacement gas supply arrangements were merged with the gas supply portfolio of the Lower Mainland and Inland Service Areas and the 1991 RDA Phase A gas cost allocation principles began to be applied to all three service areas. During the development and implementation of the Customer Choice program, in which the gas supply portfolios were separated into commodity and midstream components, the commodity rates in all three service areas were postage stamped.

17.7 Please provide additional detailed background information regarding the reasons why commodity rates were postage-stamped and midstream rates remained differentiated (regionalized?)

Response:

The 1991 Phase A Rate Design proceeding established the principles for allocating gas supply costs, which at the time included all commodity costs and midstream costs. Consistent with the gas cost allocation methodology established in the 1991 Phase A, some costs related to third party pipeline transportation and service area UAF are streamed to the different regions. For example, a portion of the Westcoast Pipeline charges are streamed to the Lower Mainland Division. Further, and also consistent with the 1991 Phase A, the underlying principles for allocating costs remain, as variable costs are allocated on a volumetric basis, and fixed costs are allocated to the sales customer classes on a load factor adjusted basis.

The January 16, 2004 Commodity Unbundling and Customer Choice Phase 1 Cost Allocation Application (the "January 16 Application") dealt with the separation of the GCRA into the new CCRA and the MCRA deferral accounts, and the commodity and midstream rate setting mechanisms. The January 16 Application proposed that the gas cost allocation methodology currently in place for the GCRA remain unchanged and be consistently applied to the various gas cost components whether reassigned to the CCRA or the MCRA. The gas cost deferral account and rate setting proposals within the January 16 Application were approved pursuant to Commission Order No. G-25-04 and the accompanying Reasons for Decision attached as Appendix A to the Order.

The CCRA was comprised of baseload commodity costs, including related hedging, plus the CCRA allocation of the Core Market Administration Expenses ("CMAE"). The majority of the CCRA costs have always been variable however, prior to late 2006 the CCRA included some 70/30 netback supply contracts where the costs were split out between the variable and the fixed components for allocations to rates. The last remaining 70/30 netback contracts expired at October 31, 2006. Today the CCRA costs are all treated as variable and are allocated to sales customers on a volumetric basis resulting in a postage-stamped rate.

The MCRA costs are predominantly fixed costs for third party pipeline and storage charges. The regional differences in the midstream cost allocations today are minor and are a result of the gas cost allocation methodology remaining unchanged from that established in the 1991 Phase A proceeding.

17.8 Please provide the COSA Model for the Inland and Columbia regions as directed by the Commission in its October 25, 1992 BC Gas Utility Ltd. Decision.

Response:

A PDF copy of the Fully Distributed Cost Studies as filed in the 1993 FEI (formerly BC Gas Inc.) Rate Design Application is provided in Attachment 17.8 (showing each of Lower Mainland, Inland and Columbia areas). The October 25, 1993 Decision did not direct any particular COSA

Model. The Commission's findings regarding the Cost and Pricing Studies in the 1993 Decision at page 15, are as follows:

> *"3.3 Commission Decision*
>
> *The FDC studies and the LRIC study were essentially used by BCGUL to determine inter-class cost causation and thereby to guide inter-class rate design. Issues of intra-class rate design are discussed in the sections of this Decision devoted to individual customer classes.*
>
> *The Commission accepts the results of the FDC study showing that cost causation by customer class supports a shift of revenue responsibility from industrial customers to residential and commercial customers. While the LRIC study was found to have shortcomings as noted in Section 3.1.2, it does directionally support the rate shifts indicated by the FDC study. Therefore, the Commission accepts the specific BCGUL proposal which shifts some of the revenue responsibility from industrial customers to residential and commercial customers. However, as noted in Section 4, measures will be undertaken by the Utility to offset the impacts of this general inter-class rate shift."*

18.0 Reference: Overview of the FortisBC Energy Utilities

Exhibit B-3, Section 3.2.1.3, p. 25 & 26

Amalgamation of Squamish and FEI

"As part of the Annual Review, FEI recommended amalgamation [emphasis added] between what was then TGI and TGS. The amalgamation was requested to address TGS' increasing financial obligation to the Province of British Columbia."

"In 2006 the Province agreed on a process to resolve the financial obligations between TGS and the Province. As part of the resolution of the financial obligations, TGI was to amalgamate with TGS, effective January 1, 2007."

"TGS adopted the rate design and general terms and conditions of TGI, as approved by Order No. G-160-06."

18.1 Please provide additional detailed background information on the financial obligations that existed between TGS and the Province, the process employed to resolve these, and the final result from the process.

Response:

Prior to 1989, TGS was a piped propane utility serving customers in Squamish. With the arrival of the Terasen Gas Vancouver Island Inc. ("TGVI") High Pressure Transportation System ("HPTS"), TGS customers moved from piped propane service to natural gas. When the pipeline was connected, TGS became party to a number of agreements which determined the operation of the utility. To encourage customers to switch from propane to natural gas and to encourage customer growth, the Province became a financial supporter of the utility providing funding via the Rate Stabilization Facility ("RSF") to record shortfalls and surpluses of the utility. TGS received funding for the RSF under the Rate Stabilization Agreement ("RSA") dated July 9, 1992 between the Province of B.C. and Squamish Gas Co. Ltd.

The rates that TGS charged customers were based upon the direction as laid out in the RSA. TGS rates were set at a discount to the retail price of oil or the BC Hydro electricity trailing block, whichever was lower. As these rates were not based upon cost of service, TGS either under or over collected revenues. Under and over collection of revenues were netted out via the RSF.

Both TGS and the Province had obligations under the RSA. After many years of stability, the commodity cost of natural gas began to rise; in addition, TGS added to its capital base by beginning construction of the Garibaldi Brackendale MX. The combined effect of these two changes resulted in a draw position that was in excess of $1 million.

On October 5, 2006, TGS, TGVI, TGI and the Province signed the Squamish Gas Arrangements Termination Agreement (the "Agreement"). The Agreement provided for the Termination of the RSA and the Rate Stabilization Facility Contribution Agreement and for the amendment of the Transportation Services Agreement. The Agreement provided for the payment from TGS to the Province of $1.75 million. The Agreement also contained three Orders-in-Council:

1. Order-in-Council 768, which contained Special Direction No. 3 to the BCUC;
2. Order-in-Council 767, which amended the Special Direction 1510; and
3. Order-in-Council 766, which exempted TGI and TGS from Section 53 of the Utilities Commission Act for the purpose of amalgamation of those two entities.

The effect of the Agreement enabled TGI and TGS to amalgamate and to extinguish the obligations of both the Province and TGS under the RSA. On December 14, 2006 the BCUC issued Order No. G-160-06 which accepted that TGI did not have to apply to the Commission for approval of an amalgamation of itself and TGS. In addition, the Commission approved the revenue requirements of TGI for 2007. On January 1, 2007 the Registrar of Companies of the Province of BC issued a Certificate of Amalgamation that certified the amalgamation of TGS and TGI under the name Terasen Gas Inc.

18.2 Was there any impact on the shareholder of TGS as a result of resolving the financial obligations? If yes, please discuss.

Response:

Yes. Although the ROE and capital structure of the amalgamated TGI was a weighted average of the ROE and capital structure of TGI (pre amalgamation) and TGS, the shareholder was responsible for paying the Province $1.75 million as part of the TGS Termination Agreement.

18.3 Was the amalgamation of Squamish (TGS) and the subsequent adoption of the rate design and general terms and conditions of FEI (TGI) similar to the proposed option by the FEU in the current application? If not, please discuss the differences and the reasons therefore.

Response:

Yes. The amalgamation of TGS into FEI (TGI at the time) was similar to the amalgamation proposed in this Application. TGS became part of TGI and the GT&C of TGI applied to amalgamated TGI. Customer rate classes in TGS were mapped to the then existing TGI rate classes following the same logic as the FEU have proposed in this Application. The rate base of both TGS and TGI were amalgamated and the capital structure and ROE reflected the weighted average of the two companies.

19.0 Reference: Overview of the FortisBC Energy Utilities

Exhibit A2-1, Reasons for Decision for Order G-63-92, pp. 16-20; Exhibit A2-2, Reasons for Decision for Order G-101-93, p. 6; Exhibit B-3, Section 3.2.1.2, p. 27

Legal/Regulatory Considerations - Fort Nelson

The Commission, in its August 5, 1992 BC Gas Inc. Reasons for Decision G-63-92 (Exhibit A2-1) stated on page 16 to 20:

> "When Inland purchased the Columbia and Fort Nelson Divisions in 1979 and 1985 respectively ... Inland entered into a series of agreements with the Province. Item I of the original Resale Restriction Agreement states:
>
> > "Inland intends that the customers of each of the Company, Inland, Columbia and Fort Nelson will, after the reorganization, continue to be charged separate natural gas rates; ..."
>
> The amalgamation of the four gas Divisions took effect on July 1, 1989. OIC 953, dated June 29, 1989 ... required among its conditions that:
>
> > "2. (1) BC Gas shall, from July 1, 1989 until the end of September, 1991, establish and maintain its rate base on a divisional basis, with a separate rate base for each of the Lower Mainland Division, the Inland Division, the Columbia Division, and the Fort Nelson Division."
>
> The Order also required the Divisions to maintain separate accounts on a divisional basis, and separate schedules of divisional rates. ...
>
> The evidence indicated that consolidation would achieve savings and efficiency. Consolidation would not impede BC Gas' ability to finance future capital requirement, to continue the existing covenants, or to maintain service at the required levels. There was some concern, however, as to whether the consolidation proposal is in tune with the intent of the Agreement and OIC 953/89. ...
>
> Although Mr. Butler [consultant retained by BC Gas] did not know why there were the requirements for separate rate base and divisional accounts in OIC 953, he agreed with Commission counsel that "...if a cost of service study was performed for each of the Divisions, that the customers within those Divisions would be in a better position to determine the true cost of service and identify

any real benefits that there might be of consolidation before the consolidation took place." ...

The Commission is concerned with the preservation of the public interest. ... Mayor F. Parker and Mr. Griffith, Administrator for Fort Nelson-Liard Regional District, appeared before the Commission to oppose the BC Gas Application for consolidation of rates. Their submission ... stated in part:

> ... We believe that the Fort Nelson Gas division can operate as a going concern on an independent basis and would continue to provide an adequate return to BC Gas with rates being established on a completely separate and individual basis from the rest of their divisions. We also believe that Fort Nelson Gas should be able to pay for its share of capital costs and face certain economic fluctuations on an independent basis.
>
> It is our intention to oppose, on principle, any increase that is tied into the concept of consolidated or postage-stamp rates for BC Gas."

While the residents of Fort Nelson and the intervenors suspected that consolidation was the first step towards postage-stamp rates, the Applicant was not able to confirm or deny the suspicion. ...

The Commission recognizes that a financial benefit would accrue to the utility customers as a result of consolidation. While this saving is material, the canvassing of the full impact on all customers is more important. ... Therefore, the Commission directs BC Gas to file its cost of service studies on a divisional basis for that hearing. In the interim period, the Company is to maintain divisional rates."

The Commission's October 25, 1993 Reasons for Decision on BC Gas Utility Ltd's Phase B Rate Design Application G-101-93 (Exhibit A2-2) stated on page 6 "Fort Nelson was excluded from the consolidation application as BCGUL explained that the municipality wished to remain independent and unconsolidated."

"FEI decided to exclude Fort Nelson from the 1993 Phase B consolidation and postage stamp proposal." (p. 27)

19.1 Please provide a copy of the Resale Restriction Agreement related to the purchase of Fort Nelson Divisions by Inland.

Response:

Please refer to Attachment 19.1.

19.2 Please provide a copy of OIC 953, dated June 29, 1989.

Response:

Please refer to Attachment 19.2.

19.3 Do FEU agree that the Resale Restriction Agreement and OIC 953 create a presumption that Fort Nelson rates should not be postage stamped if Fort Nelson customers are opposed to it? If no, please explain why not.

Response:

No, the FEU do not agree that the Resale Restriction Agreement and OIC 953 create a presumption that Fort Nelson rates should not be postage stamped if Fort Nelson customers are opposed to it. The FEU have reviewed both the Resale Restriction Agreement and OIC 953, and no wording in these two documents can be interpreted to give rise to the presumption stated in the question.

The Resale Restriction Agreement, entered into September 29, 1988, contains no restriction on the form of rates after the end of September 1991. Particularly, section 2.0 of this Agreement states:

> *Inland will not, nor will it permit B.C. Gas to, apply under the Utilities Commission Act or the Privatization Act to have the natural gas rates of Inland, the Company, Columbia or Fort Nelson increased or altered in form until October I, 1991, except in the manner provided in the Orders in Councilor the Rate Agreement, and for the application of certain tariff filings for Inland, Columbia and Fort Nelson pursuant to orders granted prior to the date hereof by the British Columbia Utilities Commission under the Utilities Commission Act.*

The Rate Agreement, referred in the quoted paragraph and also entered into on September 29, 1988, contains the similar limitation on rates:

"5.0 LIMITATION ON RATES

5.01 During the period until the end of September, 1991, no changes in the presently existing rates of Inland, Columbia or Fort Nelson Gas other than those described in sections 4.01 and 4.02 shall be made."

The parties clarified in a letter, dated November 17, 1988, that:

"The word "rates" in Section 5.01 is a reference only to the prices contained in the tariffs and schedules of Inland, Columbia and Fort Nelson Gas and it is not and was not the intention of the parties to the Agreement that the work "rates" should encompass tariff wording other than price. Furthermore, it is not and was not the intention of the parties to the Agreement to preclude the filing by Inland, Columbia and Fort Nelson Gas of new tariffs that may be determined to be in the public interest and were not contemplated by Section 5.01 of the Agreement."

Another relevant agreement is the agreement entered between BC Gas (the entity after consolidation of various divisions) and the provincial government on July 1, 1989. It also indicates that "the BC Gas will not apply under the utilities Commission Act or the Privatization Act to have the natural gas rates in the areas served by the Divisions increased or altered in form until October 1, 1991, except in the manner provided in the Order in Council."

The Resale Restriction Agreement, the Rate Agreement, and the post-consolidation agreement between BC Gas and the government, all included in Attachment 19.1 to the response to BCUC IR 1.19.1, contain a similar complete agreement clause. For instance, section 6 of the Resale Restriction Agreement states:

"This Agreement and the schedules attached hereto contain the complete agreement between the parties hereto with respect to the transaction contemplated hereby and supersede all prior agreements and understandings among the parties with respect to such transactions. There are no restrictions, promises, representations, warranties, covenants, indemnities, or undertakings by the parties other than those expressly set forth in this Agreement and the Schedules. This Agreement may be amended, modified or terminated only by written instrument signed by all parties hereto and subject to the requirements of the Privatization Act."

Moreover, the wording of OIC 953, effective July 1, 1989, indicates that it imposes no restriction on then existing rates after the end of September 1991. Please refer to the response to BCUC IR 1.19.2.

Therefore, there is no basis to read into the agreement or the OIC any restriction on or presumption against postage stamp rates on or after October 1, 1991.

19.4 Please provide additional detailed background information regarding the decision to exclude Fort Nelson from the 1993 Phase B consolidation and postage stamp proposal.

Response:

Based on record of the 1993 Phase B proceeding, the decision to exclude Fort Nelson was made "in recognition of the position of the officials of Fort Nelson municipality as stated at the Company's revenue requirement hearings in 1992." (BCUC IR No. 1, Part B, Volume 1, Tab 5, Question 3(a).).

The FEU have been unable to locate further additional background information regarding the decision to exclude Fort Nelson from the consolidation proposal in the 1993 Rate Design Application.

20.0 Reference: Overview of FortisBC Energy Utilities

Exhibit B-3-1, Appendix D-12, p. 1, Section 3, pp. 39, 40; TGVI 2010 2011 Revenue Requirements, Rates Application, Exhibit B-1, p. 44;

Fortis Energy Vancouver Island

The FEU include a November 4, 1989 newspaper article in Appendix D-12 of the Application titled 'Financing pact signed for Vancouver Island gas line' which states "The federal government has committed $150 million to the project; a 100-million grant and a $50-million repayable loan. The B.C. government will provide a $75-million repayable loan."

FEU state on page 39 and 40 of the Application:

> "Sections 2.8 and 2.10(j) of the [*Vancouver Island Natural Gas Pipeline Act*] Special Direction instructed that beginning January 1, 2003, rates were to be set at a level that would recover the cost of service and also include an amount sufficient to eliminate the RDDA [Revenue Deficiency Deferral Account] balance in the "shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates. ...
>
> At the present time, with the RDDA reduced to zero and the cessation of the Royalty Revenues, the Special Direction has essentially run its course. The Special Direction states that it shall cease to have any application after the latest of three conditions occurring: (a) the time when the balance of the RDDA has been reduced to zero; (b) the expiration/termination of the Joint Venture Transportation Service Agreement ("JV TSA"), but no later than January 1, 2011; or (c) the date of the termination of the Squamish Gas TSA. As the RDDA has been reduced to zero and condition (b) expired on January 1, 2011, the remaining condition to be met to bring the Special Direction to an end is the termination of the Squamish Gas TSA. Upon amalgamation, the Squamish Gas TSA would terminate and the Special Direction would cease to have any application."

Terasen Gas (Vancouver Island) Inc (TGVI), on page 44 of Exhibit B-1 to its 2010 and 2011 Revenue Requirements and Rates Application stated:[27]

> "Section 3.1(b) of the Special Direction imposes on TGVI a $1.867 million annual reduction in return on equity, imposed as part of the broader

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27 http://www.bcuc.com/Documents/Proceedings/2009/DOC_22335_B-1_TGVI_Application_2010-2011_RRA_RDA-part1.pdf

restructuring that took place at the time of the Special Direction. The reduction cannot be recovered from customers, and thus customers have benefitted from this provision as an offset to TGVI's revenue requirement. The continuation of the Special Direction means that customers will benefit by an additional $1.867 million annually."

20.1 Please document the legal/regulatory background information regarding the gas extension to Vancouver Island, including any commitments made by Centra and the government (for example, around sharing of costs and risks), CPCN approval, other legal and regulatory requirements, and any changes made to these commitments over time.

Response:

In 1989 the Government of Canada ("Canada") and the Province of British Columbia ("Province") and PCEC entered into an agreement called the Binding Agreement to construct the transmission gas line from the Mainland to Vancouver Island and the Sunshine Coast.

Under the Binding Agreement:

- Both Canada and the Province made financial contributions (refer to the response to BCUC IR 1.21.1).
- The Province agreed to provide an open-ended support mechanism called the Rate Stabilization Facility, to finance operating deficits incurred by PCEC during a market development period of up to 20 years.
- Centra had also entered into a separate agreement with the Province (the Rate Stabilization Agreement) regarding rates charged to residential and commercial customers which were set at a discount to heating oil rather than at a traditional regulated cost of service basis.
- The Rate Stabilization Agreement also provided for the payment of penalties by Centra to the Province if certain volume and cost targets were not achieved. Significant penalties were being incurred by Centra as a result.

In 1995, the Province, PCEC and Centra entered into a financial re-structuring known as the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA"). Under the VINGPA:

- The distribution assets of Centra were transferred into PCEC, and PCEC was re-named as Centra ("New Centra").

- The Province issued a Special Direction to the BCUC that set customer rates and provided a mechanism to fund and recover revenue deficiencies incurred by New Centra.
- Wetscoast Energy (the parent of New Centra) agreed to fund revenue deficiencies incurred by New Centra from 1996 – 2011 inclusive, to a specified maximum amount.
- The Province agreed to make payments to New Centra from 1996 to 2011 inclusive, based on provincial royalties associated with a specific volume of gas for each year.
- The obligations of New Centra to repay the contributions made by Canada and the Province in the Binding Agreement were deferred and restructured.

As of now, with the exception of the government refundable contributions, the obligations and risks of each party that were set out in the 1995 restructuring are now fully discharged.

The current regulatory and legal framework includes the Utilities Commission Act and the VINGPA. The VINGPA includes the Special Direction from the Province to the British Columbia Utilities Commission ("Special Direction"), the Pacific Coast Energy Pipeline Agreement ("PCEPA"), the Squamish Gas Transportation Service Agreement and the Vancouver Island Gas Joint Venture Transportation Service Agreement. Please see Appendix D-11 and D-16 of the Application.

Currently, under the VINGPA, there are four parties involved and their remaining interest and obligations are as follows:

1. **BCUC**

   a. *Special Direction*. The Special Direction remains in effect until the termination of the Squamish Gas Transportation Service Agreement. At this time in 2012, the Special Direction provides instructions relevant to:

      i. *1996 Opening Rate Base.* The Rate Base Value of FEVI in 1996 to resolve any prudency issues prior to 1996 and for ongoing continuity purposes,

      ii. *Competitive Business Environment*. Setting of customer rates to be competitive with alternative energy sources,

      iii. *Reasonability of Rates*. Setting of customer rates to be reasonable,

      iv. *Cost of Service Recovery*. Setting of customer rates to enable FEVI to recover its cost of service in accordance with regulatory principles that are generally applied to gas distribution utilities operating within British Columbia from time to time,

v. *Service Contracts*. Setting Squamish Gas Transportation and Vancouver Island Gas Joint Venture rates according to their respective Transportation Service Agreements.

b. *Utilities Commission Act*. The Utilities Commission Act provides authority to the BCUC to regulate the service levels and rates of FEVI except where the Special Direction provisions are not consistent with the Utilities Commission Act.

2. Government

a. *Canada Repayable Contribution*. As per PCEPA, Canada provided a $50 million contribution to reduce the rate base until the service is financially sustainable. FEVI forecasts that the Canada repayable contribution will be fully repaid by the end of 2013.

b. *British Columbia Repayable Contribution*. As per PCEPA, the Province provided a $25 million contribution to reduce the rate base until the service is financially sustainable. FEVI anticipates that it will begin repaying the British Columbia Repayable Contribution in amounts of $10,000,000 per year for two years and a final payment of $5,000,000 once the Canada Repayable Contribution has been fully repaid at the end of 2013. Once the British Columbia Repayable Contribution has been fully repaid, the PCEPA will terminate.

c. *Royalty Revenue Payments.* Under VINGPA, the Province made Royalty Revenue Payments each year from 1996 through 2011. This payment reduced the cost of gas for core customers of FEVI during those years.

d. *Lump Sum Payment.* As per VINGPA, in 1996, the Province made a payment of $120,000,000 conditional upon combining PCEC with the Centra Companies, to reduce the rate base of the transmission pipeline assets of FEVI as of January 1, 1996 forward.

e. *Squamish Gas Rate Stabilization Facility*. The Province has had no obligations with respect to the Squamish Rate Stabilization Facility since Squamish Gas amalgamated with FEI in 2007.

3. **FEVI**

    a. *Adjustment to Cost of Service.* As per VINGPA, during 1996 through 2011, FEVI was required to reduce the allowed return by $1,867,000 compared to what otherwise would have been approved by the BCUC.

    b. *Revenue Deficiency Deferral Account.* FEVI is no longer at risk for the balance of the Revenue Deficiency Deferral Account because it was reduced to zero and eliminated in 2009. As per the VINGPA, FEVI shareholders were at risk for up to $120,000,000 of cumulative revenue deficiencies.

4. **Ratepayers**

    a. *Core customers*. Today, core distribution customers pay rates that recover the cost of service, including the RSDA, are competitive with alternatives and are reasonable as determined by the BCUC from time to time.

    b. *Squamish customers.* Today, Squamish customers pay the same rates as lower mainland customers.

    c. *Vancouver Island Gas Joint Venture.* Today, the VIGJV pays rates set according to their Transportation Service Agreement.

    d. *Transportation customers.* All transportation customers other than the VIGJV and Squamish have rates set according to contracts that have been negotiated and approved since 1996 by the BCUC.

20.2 Were FEU aware of the upward pressure on rates in Vancouver Island when they purchased the FEVI business franchise?

Response:

The following response includes a response to BCUC IR 1.20.2.1.

The FEU were aware of the business risk profile of FEVI when it was acquired and have managed the business risk over time as the utility has been maturing. This is demonstrated by items such as the elimination of the RDDA; the ongoing cost savings achieved as a result of a move to a common management structure; and the negotiation and agreement of long term contracts with key customers, e.g., BC Hydro and VIGJV. In addition, the RSDA has been introduced.

The FEU disagree that there is a transfer of risk from the shareholder under the common rates proposal. The regulatory compact that has been in place remains the same post-amalgamation.

20.2.1 If yes, was there any expectation at the time of the purchase of the Vancouver Island franchise that FEU may be able to transfer these business risks from the shareholder to FEI ratepayers by applying to the Commission for postage stamp rates? Please explain.

Response:

Please refer to the response to BCUC IR 1.20.2.

20.3 Please describe the key components of the Squamish Gas TSA, including the conditions which must be met for it to be terminated.

Response:

The Squamish Gas TSA, dated April 1, 1990 has been amended by Section 2.4 of the Squamish Gas Arrangements Termination Agreement, dated January 1, 2007. Both agreements are included in Appendix D-16 of the Application.

Under the Squamish Gas TSA, transportation service is provided to specified delivery points in the District of Squamish at a unit toll of $1.04 per gigajoule. As described in sections 4 and 5, the transportation service includes service on a non-interruptible basis up to the shipper's contract demand and also includes interruptible service. Section 10.1 states that statements and payments will be provided in accordance with section 8 of FEVI's Transmission Transportation Service Tariff. Other terms of the agreement address matters such as receipt and delivery pressure (Section 11), gas quality specifications (Section 12), measurement (Section 13), possession and control of gas and liability (Section 14), and force majeure (Section 15).

Section 6.0 addresses the term and renewal of the contract. It states:

"6.01 The term of this Agreement shall commence on the date that Gas is taken by Shipper at any one or more of the Delivery Points and shall continue until the later of (i) the date upon which the balance of the Revenue Deficiency Deferral Account of TGVI has been reduced to zero, and (ii) the date upon which the Commission establishes a new rate for the transportation of Gas to Shipper.

6.02 The term of this Agreement shall be automatically renewed from year to year after expiry of the initial term provided in section 6.01 unless terminated by the Shipper providing Pacific Coast with one year's notice of termination."

20.3.1 If the Commission does not approve amalgamation and postage stamp rates, would the Squamish Gas TSA expire? Please explain why or why not.

Response:

No, it would continue in accordance with its terms. Please refer to the response to BCUC IR 1.20.3.

20.3.2 If the Commission approves amalgamation but not postage stamp rates, would the Squamish Gas TSA expire? Please explain why or why not.

Response:

Yes, the Squamish Gas TSA would expire upon amalgamation because the parties to the agreement would become one amalgamated entity.

20.4 If the Special Direction ceases to have any application to FEVI, does this mean that FEVI customers will no longer benefit from an additional $1.867 million annually related to a reduction in return on equity? Please explain why or why not.

Response:

FEVI customers no longer benefit from the reduction whether or not the Special Direction ceases to have any application to FEVI. The $1.867 million annual reduction in return on equity expired on December 31, 2011 in accordance with clause 3.1(b) of the Special Direction, which says:

> *"For each year from January 1, 1996 to December 31, 2011, the return on equity component of PCEC's rate base that would have been otherwise approved by the BCUC shall be reduced by the amount of $1,867,000. Such reduction shall not be recovered in whole or in part, directly or indirectly, through rates or tolls in any manner whatsoever."*

21.0 Reference: Overview of FortisBC Energy Utilities

Exhibit B-3, Section 3, pp. 38; Exhibit B-3-1, Appendix D-12, p. 1,

Government/Franchise Agreement Requirements

FEU include a November 4, 1989 newspaper article in Appendix D-12 of the Application titled 'Financing pact signed for Vancouver Island gas line' which states "The federal government has committed $150 million to the project; a 100-million grant and a $50-million repayable loan. The B.C. government will provide a $75-million repayable loan."

FEU state on page 38 of the Application with regard to FEVI:

> "Construction began in 1989 and was completed in 1991. Both the pipeline and distribution facilities received initial financial assistance from the Federal and Provincial Governments, with the Vancouver Island Gas Joint Venture ("VIGJV") customers being eligible for conversion grants. ... The Province provided a guarantee that absorbed the shortfall between revenues from customers and the costs of the transmission and distribution facilities.
>
> By the mid-1990s a financial restructuring of the pipeline and distribution facilities was needed to achieve financial viability. ... As part of the restructuring, the Province made a $120 million lump sum payment as a contribution to capital costs with a corresponding reduction in Centra Gas" rate base as set out in the Special Direction. The Federal and Provincial Governments had previously provided $75 million to PCEC to assist in the construction of the pipeline from Vancouver Island to the Sunshine Coast. Under the Pacific Coast Energy Pipeline Agreement, FEVI's predecessor, as part of the restructuring, agreed to repay the Canada Repayable Contribution ($50 million) and the British Columbia Repayable Contribution ($25 million).
>
> The VINGPA [Vancouver Island Natural Gas Pipeline Act] and Special Direction also contemplated the payment by the Provincial Government of gas royalty revenues ("Royalty Revenues") to FEVI through to 2011, which are based on the wellhead price of gas. These Royalty Revenues have mitigated fluctuations in the cost of gas to the benefit of FEVI's core market customers."

21.1 For the initial Vancouver Island gas line extension, please provide a breakdown of total government (federal and provincial) contributions towards the extension, and customer contributions towards the extension.

Response:

Pursuant to the Binding Agreement dated November 1989, the Federal Government provided a $100 million non-repayable contribution and a $50 million repayable contribution, while the Provincial Government provided a $25 million repayable contribution. These amounts were all paid to PCEC in respect of the initial Vancouver Island transmission gas line extension. There were no customer contributions towards the Vancouver Island gas line extension.

Subsequently, pursuant to the VINGPA dated December 1995, as part of the financial re-structuring, the Provincial Government provided a $120 million non-repayable contribution. In accordance with the Special Direction of the VINGPA, $90 million of the contribution was applied against the rate base of Centra (distribution assets) and $30 million against the rate base of PCEC (transmission assets).

21.2 For the initial Whistler gas line extension, please provide government (federal and provincial) contributions towards the extension, and customer contributions towards the extension.

Response:

The contribution for the Whistler pipeline was provided by FEW, and was $17.034 million for the construction of the Whistler pipeline from Squamish to Whistler. This amount is being recovered in rates from FEW customers over time. There were no other contributions for the Whistler Pipeline.

21.3 Did FEVI, FEW or any of their predecessor companies receive any government guarantees if the anticipated load failed to materialize? If yes, please describe.

Response:

No, not to the knowledge of the FEU.

21.4 Were FEVI, FEW or any of their predecessor companies, compelled by their franchise agreement to make investments that they otherwise would not have, the result of which is an increase in asset impairment risk?

Response:

The FEU understand the question to be in relation to franchise or operating agreements with individual municipalities. On this basis, the response to the question is 'no', not to the knowledge of the FEU.

There is little difference between the FEU's obligations to serve and extend its system where it has a franchise agreement that compels it to do so and where it does not. As a public utility, the FEU have a duty to serve and maintain safe and reliable service. Its operations are overseen by the Commission, scrutinized by interveners and regulated by other bodies to ensure its assets are in compliance with codes and regulations. The FEU are also compelled by the UCA to extend its system in some circumstances and could be subject to complaints from customers if it were to refuse to serve and can be compelled by the Commission to extend its system. For this reason, there is no relevant distinction between investments that are compelled by a franchise agreement and those that are not.

21.4.1 If yes, please describe and state if FEU considers that any additional risk arising from these directions were previously recognized and included in FEU's allowed return on equity.

Response:

Please refer to the response to BCUC IR 1.21.4.

22.0 Reference: Request for Common Rates

***UCA*, Section 59 (1); Reasons for Decision for Order G-130-07, p. 70**

Legal/Regulatory Considerations – Other

Section 59 (1) of the *UCA* states:

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

The Commission, on page 70 of its December 17, 2007 Reasons for Decision on BC Hydro's 2007 Rate Design Application - Phase 1 (G-130-07), stated:[28]

"In response to a question by the CEC, whether past R/C ratios should be a consideration in rebalancing of rates, BC Hydro submits that rates approved by the Commission are by law just, reasonable and not unduly discriminatory."

22.1 Please discuss any legal reasons related to FEU's proposal to postage stamp the rates of some customers but not others in light of section 59(1) of the *UCA*.

Response:

As discussed in the response to BCUC IR 1.22.1.1, the FEU are proposing to postage stamp all rates that are capable of such treatment. The proposal not to postage stamp rates that cannot be postage stamped is just and reasonable, not unduly preferential and otherwise consistent with section 59(1) of the *UCA*.

22.1.1 Please identify any customers/customer classes whose rates could be postage stamped, but FEU is not proposing to do so. For these customers, please explain why FEU is not proposing to postage stamp these rates.

[28] http://www.bcuc.com/Documents/Proceedings/2007/DOC_17004_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf

Response:

There are no customers/customer classes whose rates could be postage stamped, that the FEU are not proposing to do so. As discussed on page 178 of the Application, the FEU have requested an approval for common rates for all customers/customer classes whose rates could be postage stamped.

The customers/customer classes that cannot be included in the common rates proposal include:

- The FEVI special contract and large industrial transportation customers BC Hydro and VIGJV. These customers have unique long term contracts in place and the Company is working with these customers on extensions and updates to their contracts appropriate for service with the Amalgamated Entity.
- The FEI bypass contract customers who each have unique contracts in place based on the alternative cost of service to by-pass the system.
- The FEI grandfathered large industrial customers on the closed Rate Schedules 22A and 22B. These grandfathered rate schedules have unique terms and conditions specific to transportation service off the Westcoast and TransCanada pipeline systems respectively. These rate schedules have been closed to new customers since 1993.

These large industrial and special contract customers have specific rate structures and operating conditions. As stated in FEI's General Terms and Conditions, such contracts are entered into when:

(a) a minimum rate or revenue stream is required by FortisBC Energy to ensure that service to the Customer is economic; or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep the Customer on-system.

Because of these factors, the special contracts are unique and cannot be postage stamped. Please also refer to the response to BCUC IR 1.17.5.

22.2 Do FEU agree that rates that are approved by the Commission are by law just, reasonable and not unduly discriminatory? If no, please explain.

Response:

Yes.

23.0 Reference: Financial Overview of FEI (Including Fort Nelson Service Area)

Exhibit B-3, Section 3, p. 32

Mapping Rate Schedules

Within Section 3 of the Application the FEU provide short descriptions of the each of the rate classes currently available in each of the four utility rate bases. What is not evident is the comparison between like/similar schedules between the service areas and what the fundamental changes would be for each rate class.

23.1 Please provide a table that shows the FEI Amalco proposed rate class (as shown in Appendix B-1) and map the rate schedules of the FEVI, FEW and FEFN to show where each of those utilities rate classes would flow into the proposed rate schedules of FEI Amalco.

Response:

The requested table is provided below. Please also see Tables 9-2, 9-3 and 9-4 of the Application.

FEU Amalco Rate Class	FEVI Rate Class	FEW Rate Class	FEFN Rate Class
Rate Schedule 1	RGS	SGS Res	Res
Rate Schedule 2	AGS, SCS1,SCS2, LCS1	SGS Com, LGS 1	GSR 2.1, 2.2
Rate Schedule 3	AGS, LCS2, LCS3, HLF, ILF	LGS2, LGS 3	GSR 2.1, 2.2, R25

23.2 Please provide a short narrative indicating the fundamental changes in each rate class characteristics in a similar table to that shown below. If the table is not appropriate, please provide an appropriate presentation that shows the information.

FEU Amalco Rate Class	FEVI Rate Class	Narrative on Significant changes FEVI	FEW Rate Class	Narrative on Significant Changes FEW	FEFN Rate Class	Narrative on Significant Changes FEFN
Rate Schedule 1	RGS		SGS Res		RS 1	
Rate Schedule 2	Etc..........					

Response:

The requested table is provided below.

FEU Amalco Rate Class	FEVI Rate Class	Narrative On Significant Changes FEVI
Rate Schedule 1	RGS	No significant change to rate structure as FEVI currently has basic charge and variable component that includes delivery and commodity costs
Rate Schedule 2	AGS, SCS1,SCS2, LCS1	No significant change to rate structure as FEVI currently has basic charge and variable component that includes delivery and commodity costs
Rate Schedule 3	AGS, LCS2, LCS3, HLF, ILF	No significant change to rate structure for AGS, LCS2 and LCS3 as FEVI currently has basic charge and variable component that includes delivery and commodity costs. HLF customers would move from a demand based rate structure with a basic charge, demand charge and variable component to a rate that is only comprised of a basic charge and variable charges for delivery and commodity.. These customers would likely move to demand based Rate Schedule 5 or 25 after the implementation of postage stamp rates. ILF customers are seasonal and currently have a similar rate structure that has a basic charge and variable component that includes delivery and commodity costs. ILF customers are currently limited in the amount of gas they can consume in the winter whereas Rate Schedule 3 does not include a seasonal limit. These customers would likely move to seasonal Rate Schedule 4, or interruptible Rate Schedules 7 or 27 after the implementation of postage stamp rates due to the seasonality in their businesses. All the customers mapped to Rate Schedule 3 will have numerous FEI rate options available to them, to which they may move subsequent to the implementation of postage stamp rates.

FEU Amalco Rate Class	FEW Rate Class	Narrative On Significant Changes FEW
Rate Schedule 1	SGS Res	No significant change to rate structures as FEW currently has basic charge and variable charges for delivery and commodity costs separated out in the tariff. The most significant change is that FEW currently has only one rate schedule for all customers and now customers would be grouped into rate schedules that are more closely aligned to the type of customer and their annual consumption. In addition, the FEW customers mapped to Rate Schedule 3 will have numerous rate options available to them.
Rate Schedule 2	SGS Com, LGS1	
Rate Schedule 3	LGS2, LGS3	

FEU Amalco Rate Class	FEFN Rate Class	Narrative On Significant Changes FEFN
Rate Schedule 1	Res	Basic Charge does not include the first 2 GJ and there is no declining step variable charge based upon meeting consumption thresholds
Rate Schedule 2	GSR 2.1, 2.2	Basic Charge does not include the first 2 GJ and there is no declining step variable charge based upon meeting consumption thresholds
Rate Schedule 3	R25	No declining step variable delivery charge based upon meeting consumption thresholds and no minimum delivery charge per month. The customers mapped to Rate Schedule 3 will have numerous rate options available to them.

24.0 Reference: Review of Options

Exhibit B-3, Section 5.3, p. 82

Alternatives to Common Rates

24.1 Please model two scenarios where amalgamation and common rates are not approved and the RSDA balance is used to mitigate (phase-in) the rate increase to FEVI over multiple years. Please provide 2 versions of this table as follows:

i. Using the current RSDA balance;

ii. Using the current RSDA balance less the loan repayment.

Response:

The following table provides the two scenarios as requested. This analysis is based on the same assumptions used in Figure 6-1 on page 111 of the Application. In the second scenario it is assumed that the RSDA balance is used to repay the outstanding $25 million government loan at the beginning of 2014.

FEVI Rate Analysis
Approximate Annual Rate Change

	2014	2015	2016	2017	2018
FEVI with RSDA	0%	0%	0%	11%	13%
FEVI with RSDA, Early Loan Repayment	0%	0%	3%	18%	4%

24.2 Please model all scenarios where common rates are accepted but where FEVI and FEW customers, in all classes, do not see a decrease in rates. One example would be where FEVI and FEW rates are held frozen while, over a number of years, FEI and FEFN rates increase.

Response:

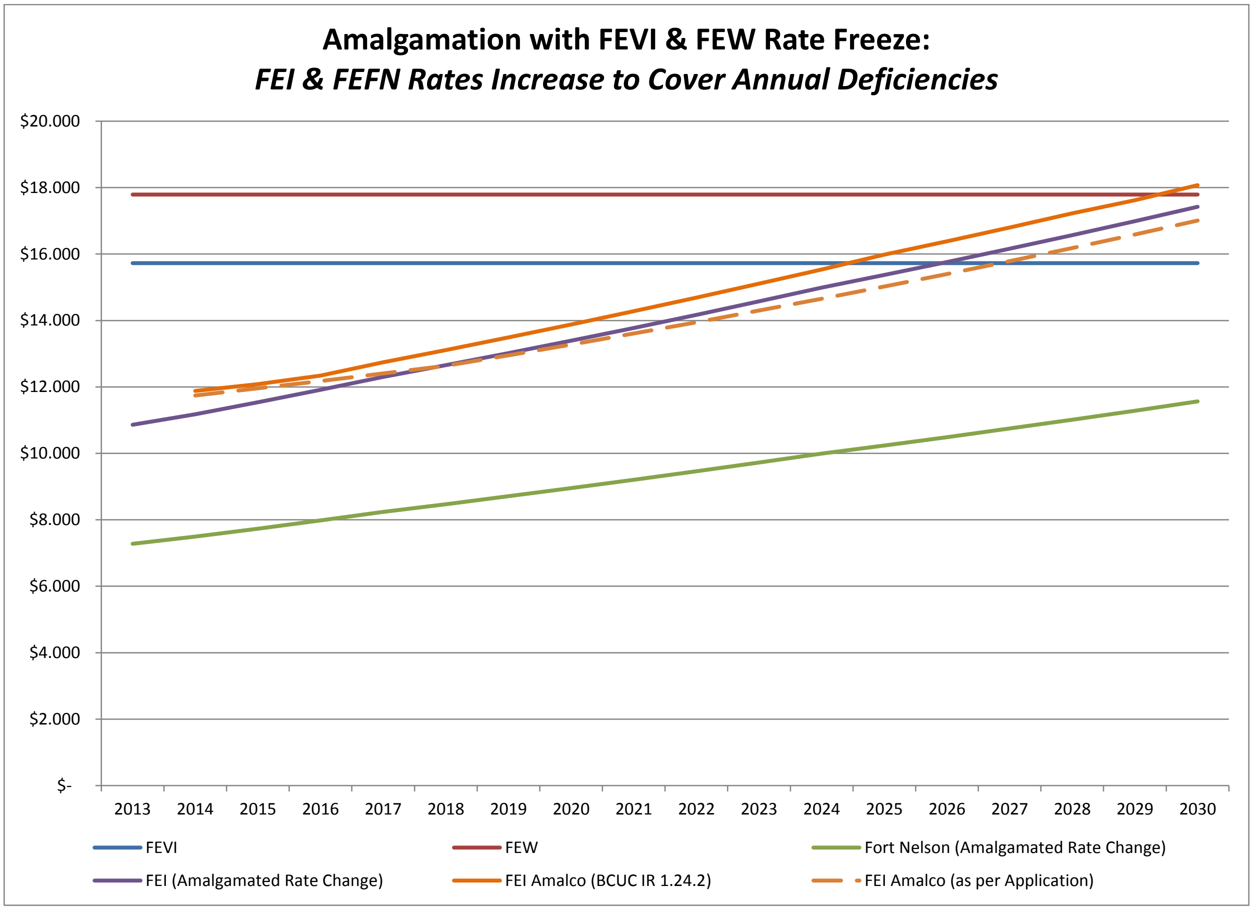
FEI has conducted an analysis to provide the approximate impacts of such a scenario. As the first graph below highlights, if FEVI and FEW residential rates were frozen, and existing stand-alone FEI and FEFN rates were increased annually to subsidize the FEVI and FEW rate freeze, it would take approximately 13 years for FEI to reach parity with the existing FEVI rates and it would take approximately 18 years to reach rate parity with existing FEW rates.[29]

If FEI and FEFN were first transitioned to postage stamp rates and increased annually to subsidize the FEVI and FEW rate freeze, it would take approximately 12 years for the postage stamp rates to reach parity with the existing FEVI rates and 17 years to reach parity with FEW rates.

Please note that this is a high level analysis, based on existing gas costs and a significant fluctuation in gas costs would either shorten or lengthen the amount of time required to reach parity. Further, it is important to note that this scenario results in an over collection of revenue from the FEI and FEFN regions, relative to their cost of service, as shown in the second graph. This occurs because the entire revenue requirement increase in each year is allocated to FEI and FEFN customers. This means that a surplus of revenue is collected from FEI and FEFN customers in relation to the costs attributable to those regions.

[29] FEU have not extended this analysis out to determine the point at which FEFN may reach parity. It is expected that this would take at least another 10 to 15 years.

Graph 1: Effective Rate Comparison for Residential Customers with FEVI & FEW Rate Freeze[30],[31]

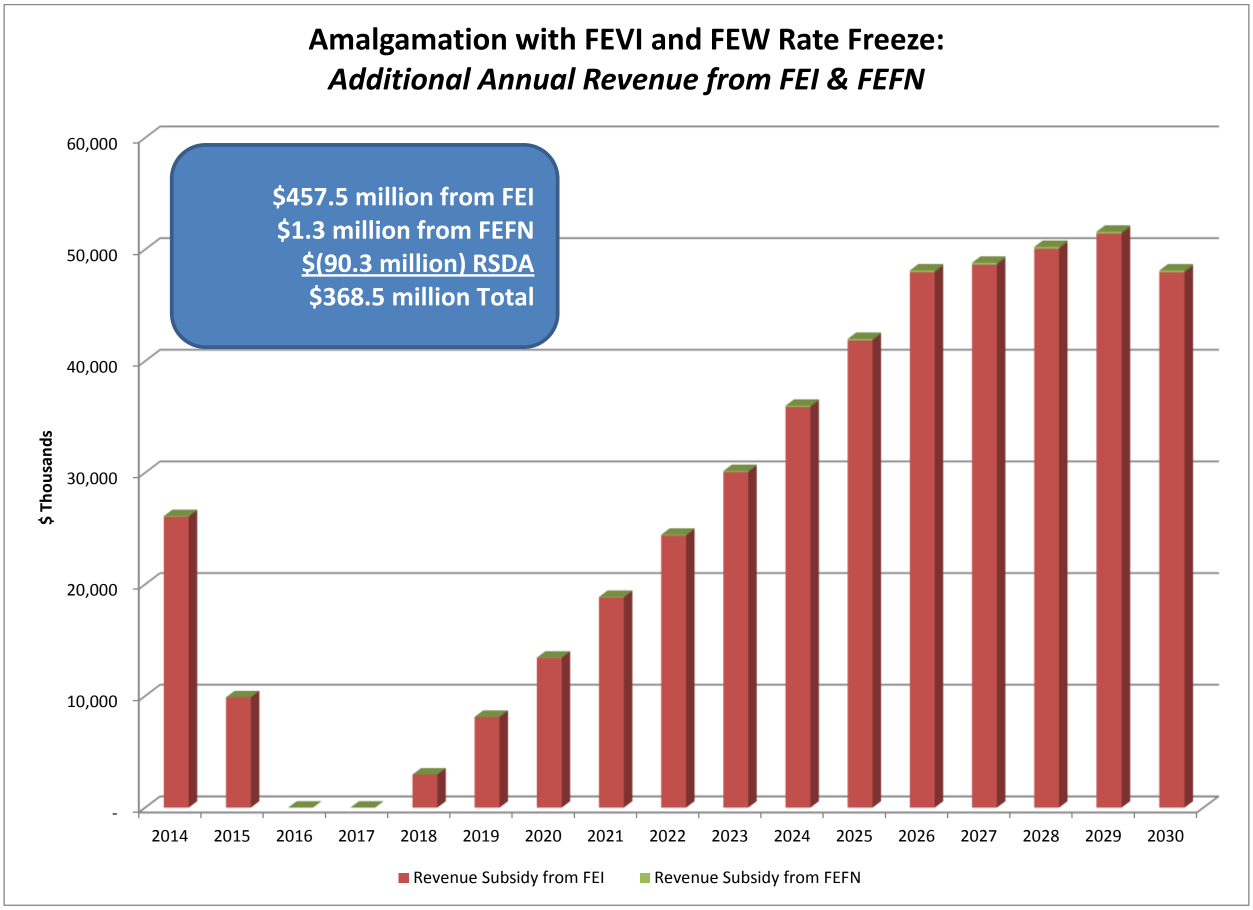


For additional comparison, FEU has extrapolated the FEI-Amalco effective delivery rate as provided in Figures 6-2 and 6-3 (pages 112 and 113) of the Application. As shown above, the FEI-Amalco effective rate calculated using the assumptions underlying BCUC IR 1.24.2 is approximately $1/GJ higher by year 2030 as compared to common rates implemented in 2014 as proposed in this Application.

30 The graph above is based on the underlying delivery margin assumptions used to provide projections in Figure 6-1 of the Application for the years 2014 - 2016. For the years 2017 and beyond, a delivery rate margin increase of 2% per year and cost of gas increase of 3% per yearis assumed. The effective rates for each region are based on an annual consumption of 90 GJs in order to provide a fair basis for comparison. Rates are exclusive of all riders.

31 Once parity is reached with FEVI rates, it is assumed that the FEVI region will experience rate changes.

Graph 2: Additional Revenue Provided by FEI and FEFN for Rate Freeze



Based on this analysis, FEI does not believe that it is appropriate to freeze FEVI and FEW rates while FEI and FEFN rates gradually increase, bearing all revenue requirement increases for the amalgamated entity.

As an alternative to the rate freeze scenario suggested in the question, FEI considered two scenarios which would allow FEI, FEVI and FEW to transition to common rates over a 3 and 5 year period. The FEU did not include FEFN in this analysis because the proposed Fort Nelson Phase-In Rider accomplishes the gradual delivery rate increase.

Under both of these scenarios, instead of transitioning FEI, FEVI and FEW to common rates immediately in 2014, the three entities would gradually reach rate parity over a number of years. In the case of a 3 year phase in period, rate parity would occur in 2017, and based on a 5 year phase in period, rate parity would occur in 2019. In both scenarios, the additional revenue created by maintaining FEVI and FEW rates at higher levels is used to offset the lower revenue from maintaining FEI rates at a lower level.

The results of that analysis are presented below in the table below, which shows the cumulative percentage increases for each scenario in each year:

Phase In Analysis Scenarios	2014	2015	2016	2017	2018	2019
FEI						
FEI - No Phase In	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%
FEI - 3 Year Phase In	3.6%	4.1%	4.7%	5.3%	0.0%	0.0%
FEI - 5 Year Phase In	3.4%	3.8%	4.1%	4.5%	4.9%	5.3%
FEVI						
FEVI - No Phase In	-25.5%	0.0%	0.0%	0.0%	0.0%	0.0%
FEVI - 3 Year Phase In	-9.6%	-14.9%	-20.2%	-25.5%	0.0%	0.0%
FEVI - 5 Year Phase In	-7.8%	-11.4%	-14.9%	-18.4%	-22.0%	-25.5%
FEW						
FEW - No Phase In	-36.0%	0.0%	0.0%	0.0%	0.0%	0.0%
FEW - 3 Year Phase In	-5.2%	-15.4%	-25.7%	-36.0%	0.0%	0.0%
FEW - 5 Year Phase In	-1.8%	-8.6%	-15.4%	-22.3%	-29.1%	-36.0%

*Exclusive of RSDA & MCRA Rider Impacts

Please also refer to the responses to BCUC IR 1.93.6 and 1.93.6.1 which analyze and discuss the impact of amalgamation where annual postage stamp rate increases are applied to existing rates without a transition to common rates.

24.3 Please calculate a range of potential 'burner tip' bill impacts, by customer class of FEI, FEVI, FEW or FEFN assuming gas prices of $3/GJ and $6/GJ (assuming postage stamp rates are not approved). Please prove an estimate of the likelihood of these events occurring.

Response:

The FEU interpret this question to be seeking the burner tip bill impacts of a floating price of natural gas at $3/GJ and $6/GJ, respectively.

An estimate of the likelihood of these events occurring can be determined from the implied price volatility used to derive the value of natural gas options instruments. Implied volatility, in simple terms, is the collective market's view of the potential future variability in prices at a specific point in time. While it is difficult to determine the probability of market prices averaging specific values of $3/GJ and $6/GJ for 2013, it is possible to estimate the probability of market prices averaging below these values for 2013 using available market information. Using the implied market volatility for AECO/NIT prices (as a proxy for market prices) as of April 30, 2012, it is estimated that there is a 97.5% probability that prices will average below $6/GJ for 2013. As one moves down towards current market prices, this probability falls. There is a 55% probability that prices will average below $3/GJ for 2013. Looking further out in time, as the forward market prices increase, the probability of market prices averaging below $6/GJ and $3/GJ decreases. For example, for 2016, there is an 86% probability that prices will average below $6/GJ and a 28% probability that prices will average below $3/GJ.

The annual bill impacts noted in the table below use the stand-alone 2013 rates and typical annual use for FEI, FEW, and FEFN sales customers as provided in Appendix J-3. The analysis for FEVI is provided in an additional table.

The following assumptions were made with respect to this analysis:

- To simplify the analysis, no winter - summer differential was used in the forecasts based on the average floating prices of $3/GJ and $6/GJ (e.g. storage injections are based on the average commodity costs of $3/GJ and $6/GJ, plus all related costs);
- Storage withdrawals related to winter 2012/2013 are not affected under either scenario as they are based on the forecast weighted average value of gas in storage at December 31, 2012, whereas storage withdrawals related to winter 2013/2014 are affected by the injection prices during summer 2103 under each scenario; and,
- Hedging contracts are assumed to remain unchanged.

Rate Schedule	Approximate Burner Tip Impact	
	$3/GJ	*$6/GJ*
Lower Mainland		
RS1- Residential	-6.29%	16.14%
RS2- Small Commercial	-7.11%	18.21%
RS3- Large Commercial	-8.15%	20.87%
RS4- Seasonal	-10.55%	27.02%
RS5- General Firm	-8.83%	22.63%
RS6- NGV	-7.68%	19.68%
RS7- Interruptible	-7.77%	19.92%
Inland		
RS1- Residential	-6.08%	15.58%
RS2- Small Commercial	-6.97%	17.85%
RS3- Large Commercial	-8.11%	20.79%
RS4- Seasonal	-10.96%	28.10%
RS5- General Firm	-8.94%	22.92%
RS6- NGV	-7.85%	20.09%
RS7- Interruptible	-7.77%	19.92%
Columbia		
RS1- Residential	-6.18%	15.85%
RS2- Small Commercial	-7.19%	18.47%
RS3- Large Commercial	-8.28%	21.23%
RS5- General Firm	-8.81%	22.59%
Whistler		
Res	-3.71%	9.51%
Comm	-3.85%	9.86%
LCS1	-3.91%	10.01%
LCS2	-3.92%	10.04%
LCS3	-3.92%	10.05%
Fort Nelson		
RS 1	-10.07%	24.43%
RS 2.1	-9.42%	22.85%
RS 2.2	-10.10%	24.50%

FEVI does not have a separate cost of gas component to their rate; under the scenario where common rates are not approved, FEVI is expected to continue with the use of the RSDA to maintain a rate freeze. Therefore, a burner tip analysis of the impact of these scenarios by FEVI rate schedule is not applicable. However, the following analysis provides the approximate impact to the cost of service as a result of these scenarios, producing a range of a decrease to the cost of service of approximately 3.9% to an increase in the cost of service of approximately 6.5%:

($ Thousands)

Vancouver Island	**As Filed**	**$3/GJ**	**$6/GJ**
Delivery Cost of Service	130,486	130,486	130,486
Cost of Gas	77,435	69,222	91,018
Total Cost of Service	207,921	199,708	221,504
Approx Increase (Decrease) ($)		(8,213)	13,583
Approx Increase (Decrease) %		-3.9%	6.5%

Further, under the $3/GJ scenario, a rate freeze using the RSDA would be expected to continue through 2017 with a rate increase required in 2018. Under the $6/GJ scenario, a rate freeze using the RSDA would be expected to continue through 2015, with a rate increase required in 2016.

24.4 Please discuss the possibility of introducing a new rate class for "low-use" or "discretionary use" (i.e. non-space heating customers) in the Amalco.

Response:

The FEU are not proposing any new rate classes as part of the Application. As described in section 9.8 of the Application, if amalgamation and the adoption of common rates is approved, the FEU will review the cost allocation and customer segmentation in 2016.

In general, the FEU do not agree with the use of the terms "low-use" or "discretionary use" to refer to non-space heating customers. If a customer does not use natural gas for space heating, it does not necessarily follow that customer is a "low use" or "discretionary" customer.

25.0 Reference: Implementation of Common Rates

Exhibit B-3, Section 7.4, p. 134

Operational Effects

The FEU Application state: "To reflect the harmonized tariff, rate design principles and rate classifications across areas served by FEI Amalco and to be mindful of the necessary rate riders, the Company proposes to make amendments to FEI's effective GT&Cs. The most notable amendments include, but are not limited to:

1. Removing the use of the defined term "Service Area" used to distinguish the previously distinct Service Areas (or Divisions) of Inland, Columbia and Lower Mainland for FEI. This is replaced with the phrase "Areas Served by FortisBC Energy" where appropriate."

25.1 Given that the term "Service Area" is used to distinguish not only the divisions of the FEU utilities but also to distinguish the regional areas where the utilities operate. How does the re-phrasing of Service Area align with the requirements of the *UCA* under section 60 where the Commission must segregate the various kinds of service into distinct classes of service?

Response:

"Service Areas" and "Classes of Services" are two distinct concepts. Under amalgamation, the Commission will continue to be able to "segregate the various kinds of service into distinct classes of service" as contemplated under section 60(1)(i).

"Service Area" as defined in the current FEI GT&Cs mainly refers to major geographic areas and various locations currently served by FEI, including Lower Mainland, Inland, Columbia, and Fort Nelson. If amalgamation is approved, the geographic areas to be served by FEI Amalco will include the same geographical areas that are currently served by FEI, FEFN, FEVI, and FEW.

25.1.1 Will the re-phrasing the term "Service Area" decrease or enhance the Commissions ability to segregate the various kinds of service into distinct classes of service?

Response:

The proposed amendments referenced in the preamble to the question will not impact the Commission's ability to segregate services into distinct classes of service. Please refer to the response to BCUC IR 1.25.1.

25.1.2 How does the re-phrasing either enhance the Commissions' ability under section 60(2) of the *UCA*?

Response:

Re-phrasing the term does not impact the Commission's ability under section 60(2) to consider a "distinct or special area served by a public utility" in setting a rate. As discussed in the response to BCUC IR 1.25.1, the amalgamation does not change the geographic areas to be served by FEI Amalco; it combines all the service areas currently served by FEI, FEFN, FEW, and FEVI under FEI Amalco.

25.1.3 What is the definitive meaning of the phrase "Areas Served by FortisBC Energy"?

Response:

Please refer to the response to BCUC IR 1.25.1.

26.0 Reference: Implementation of Common Rates

Exhibit B-3, Section 7.4, p. 135

Operational Effects

The FEU Application state: "FEVI's Standard Terms and Conditions contain provisions relating to a transmission transportation service offering. After amalgamation, these services are required to be maintained to facilitate the continued provision of service to FEVI's two significant transmission transportation customers, the Vancouver Island Gas Joint Venture and BC Hydro. An addition to the proposed GT&Cs is thus necessary for FEI Amalco to continue to provide the transmission transportation service offering upon amalgamation."

26.1 Please indicate where in the application the FEU have included the FEVI terms and conditions relating to transmission transportation service, if these have not been provided please prepare a proforma version and black-lined version.

Response:

In the Application, the FEU did not include the FEVI terms and conditions relating to transmission transportation service. As mentioned in footnote 171 of the Application, the agreements and associated GT&Cs, including the Transmission Transportation Service Tariff, for BC Hydro and VIGJV will be filed once the agreements are signed. The agreement with VIGJV is now signed and is included in Attachment 26.1 to this response. The FEU will provide the agreement with BC Hydro once that agreement is executed and will also at that time provide a revised general terms and conditions that contain provisions relating to a transmission transportation service offering.

27.0 Reference: Implementation of Common Rates

Exhibit B-3, Section 7.4, p. 136

Operational Effects

The FEU Application state: "Amended Tariff Supplements issued by FEVI, FEW and Fort Nelson, changed only to reflect the FEI Amalco name, will be required to be updated and submitted for endorsement to the Commission. As amending the Tariff Supplements requires both the Company and the customer to sign the amended document, the FEU believe it is more efficient to wait until the LGIC consents to the amalgamation before beginning this work."

27.1 Given that the FEU have not provided the proposed amended Tariff supplements how would using only a proforma Tariff allow the Commission to fulfill its mandate under Section 53 (1) (a) (i) of the *UCA* to provide a report to the LGIC including an opinion on whether the consolidation, amalgamation or merger would be beneficial in the public interest?

Response:

Under the proposed amalgamation, terms and conditions of individual tariff supplements currently in existence will not change except for the name change as mentioned in the preamble. Thus, in terms of the public interest analysis under the identified UCA section, the FEU believe that the Commission can take this fact into consideration, without seeing each tariff supplement.

There are over 100 Tariff Supplements that would have to be updated with the FEI Amalco name. The FEU did not provide each tariff supplement with the Application to reflect this minor change as it would be inefficient. Upon approval of the amalgamation, the FEU will provide tariff supplements to reflect the name change.

27.2 Please provide a black-lined version of the GT&C and tariffs for FEV, FEFN and FEW that shows the changes to those tariff pages given the changes to the proforma GT&C and tariff schedules shown in Appendix B-1 and Appendix B-2.

Response:

A Black-lined proforma FEI Tariff with GT&C and Rate Schedules was provided in the Application under Appendix B-3 in electronic format. A black-lined version of the GT&Cs and tariffs for FEVI, FEFN and FEW under FEI Amalco has been submitted as Attachment 27.2 as requested, in electronic format only to conserve paper. Upon amalgamation the GT&Cs and tariffs for FEVI, FEFN and FEW will be cancelled.

28.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, p. 136

Continuance of FEI/FEVI's Main Extension Test

On page 136 of the Application, FEU are requesting approval for: "The continuation and application of the FEI and FEVI approved MX [main extension] Test (with the same established PI thresholds) to the FEI Amalco, and the discontinuance of the MX Test applied currently in Whistler; and the use of amalgamated inputs into the MX Test."

28.1 Please provide applicable sections of the *Utilities Commission Act* that FEU are applying under with regard to the proposed request for the main extension test and its reporting requirements.

Response:

FEI and FEVI's 2007 System Extension and Customer Connection Policies Review Application sought and received approval under section 61 of the UCA to establish the MX test as a rate schedule. The FEU are similarly asking for continuation and application of the FEI and FEVI approved MX Test (with the same established PI thresholds) to the FEI Amalco, and the discontinuance of the MX Test applied currently in Whistler under sections 59 to 61 of the UCA, as stated in section 2 h. of the Draft Order in Appendix K-2 of the Application. The FEU consider the reporting requirements to be part of the rate. A "rate" is defined in section 1 of the UCA to include:

(a) a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility,

(b) a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate, and

(c) a schedule or tariff respecting a rate.

In addition, the Commission has jurisdiction to require reporting pursuant to section 43 of the UCA.

28.2 Would the proposed changes in the MX Test in any regard change the ability of the Commission to conduct prudency of past main extensions? If so, please elaborate.

Response:

No, the changes in the MX Test would not change the ability of the Commission to conduct a prudency review of past main extensions.

Please refer to the response to BCUC IR 1.29.1 for a detailed description of how FEI Amalco will report on pre and post amalgamation main extensions.

29.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, p. 136; Commission Order G-152-07, Decision dated December 6, 2007, p. 37; Commission Letters L-67-11 and L-19-12

Continuance of FEI/FEVI's Main Extension Test

On page 136 of the Application, FEU's request for the continuance of FEI/FEVI's Main Extension Test are as follows:

> "In their 2007 System Extension and Customer Connection Policies Review Application, FEI (including Fort Nelson) and FEVI sought and received approval to establish the main extension [MX] test, applicable to those entities. The FEU are requesting approval for:
>
> - The continuation and application of the FEI and FEVI approved MX Test (with the same established PI thresholds) to the FEI Amalco, and the discontinuance of the MX Test applied currently in Whistler; and
> - The use of amalgamated inputs into the MX Test.
>
> In support of these requests, the FEU have analysed the FEI, FEVI and FEW main extensions from 2008-2010 to determine the impact of using amalgamated inputs on historical MX Tests. As discussed below, the FEU's customers would have experienced no major changes in MX Test results flowing from amalgamation, suggesting that the Companies' proposal is consistent, reasonable and will closely preserve the status quo."

The Commission, by Order G-152-07 and accompanying Decision dated December 6, 2007 (2007 Decision) on page 37, has ordered Terasen Gas (Vancouver Island) Inc. (TGVI, as FEVI was formerly known) and Terasen Gas Inc. (TGI, as FEI was formerly known) the following:

> "… the Commission Panel directs Terasen to update all Geo-codes and MX test input parameters at the beginning of each year. To determine the appropriate Geo-code for each area, both historical costs and a forecast of future costs will be used. Terasen is to provide the Commission with schedules comparing the existing and updated Geo-codes and MX test input parameters. Given that the 2002 REUS does not include TGVI data, the REUS use per appliance should not be used to estimate TGVI consumption, and the Commission Panel directs Terasen i) to update the consumption estimates in the TGVI MX test to reflect TGVI use per appliance; and ii) to reflect in the

Companies' MX tests their experience of consumption "ramp-up" in the early months of service.

The Commission Panel directs the Companies to file with the Commission on an annual basis, within 90 days of calendar year end, a Main Extension Report including the following:

- a review of a random sampling of MX test results representing a confidence interval of +/-12 percent at a 95 percent confidence level and the five highest cost main extensions to determine if the aggregate PI [profitability index] thresholds need to be adjusted on a go forward basis in order to achieve the aggregate PI of 1.1. The review is to include a comparison of forecast and actual costs; consumption; and PI for the first five years of main extensions in the sample;

- a concise explanation of the random sampling methodology used ; and

- a comparison of the forecast and actual cost for all service line and main extension installations."

On August 30, 2011, the Commission issued Letter L-67-11 notifying FEI and FEVI that 2010 FEI and FEVI Year End Main Extension and FEI Vertical Subdivision reports (2010 MX Report) dated June 1, 2011 fell short of compliance reporting requirements. Letter L-67-11 clarified for FEI and FEVI that in order to meet compliance requirements, FEI and FEVI should address and remedy certain deficiencies.

On March 22, 2012, the Commission further issued Letter L-19-12 advising FEI and FEVI that the Addendum to the 2010 MX Report filed on October 14, 2011 did not comply with the requirements as ordered and as clarified. FEI and FEVI had not fully addressed and remedied deficiencies. FEI and FEVI were requested to file a fully compliant 2010 MX Report in the next annual MX filing.

29.1 Please explain how the proposed FEI Amalco would report MX differently when compared to the existing MX reporting where FEI and FEVI are reported separately for each utility.

<u>Response:</u>

The MX reporting methodology is outlined below followed by changes that would result from the proposed FEI Amalco reporting methodology. In short, the content and form of the report will remain consistent with the exception that pre-amalgamation main extensions will continue to be reported on in the same manner as by the pre-amalgamation individual utilities (FEI and FEVI) whereas post-amalgamation main extensions will be reported on as a single entity (FEI Amalco).

As per Commission reporting compliance requirements, the 2011 FEI and FEVI Year End Main Extension and FEVI Vertical Subdivision report ("2011 MX Report") will contain the following:

Geo Codes and MX Test Inputs

- Schedules comparing the existing (i.e. 2010) and updated (i.e. 2011) geo codes and MX test input parameters for FEI and FEVI.
- A schedule comparing the existing and updated use per appliance for Lower Mainland, Interior and Vancouver Island.

Random Samples & Top 5 Data

- Random samples of MX test results from the FEI and FEVI mains populations for 2008, 2009, 2010 and 2011. All eight samples (4 FEI and 4 FEVI) will have a confidence interval of +/- 12 percent confidence level.
- The 5 highest cost main extensions for both FEI and FEVI mains populations for 2008, 2009, 2010 and 2011.

Review of Random Samples and Top 5 Data

- A comparison of forecast and actual costs, consumption and PI for the samples and the top 5 for both FEI and FEVI.
- FEI and FEVI's experience of ramp up.

The information provided above allows the Commission "…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."

The Companies are proposing to continue this approach to annual MX reporting until the 2014 MX Report is filed since the proposed Amalco rates go into effect January 1, 2014 and 2014 will be the first year that incorporates system extensions performed under the Amalco entity.

From 2014 onwards, the Companies will continue using the same MX reporting methodology described above with the exception that pre-amalgamation main extensions will continue to be reported on in the manner as by the pre-amalgamation individual utilities (FEI and FEVI) whereas post-amalgamation main extensions will be reported on as a single entity (FEI Amalco). Specifically, this means that the 2009-2013 main extensions will continue to be reported on for the first five years of their existence segmented by FEI and FEVI random samples and top 5 mains whereas the 2014 and later mains will be reported on by the FEI Amalco entity.

For example, the 2014 MX Report will contain the following:

Geo Codes and MX Test Inputs

- Schedules comparing the existing (i.e. 2013 FEI and FEVI) and updated (i.e. 2014 Amalco) geo codes and MX test input parameters.
- A schedule comparing the existing and updated use per appliance for the Lower Mainland, Interior and Vancouver Island.

Random Samples & Top 5 Data

- Random samples of MX test results with a confidence interval of +/- 12 percent confidence level drawn from the following:
    - The FEI and FEVI mains populations for 2009-2013 (i.e. 10 samples total)
    - The FEI Amalco main population for 2014 (i.e. 1 sample)
- The 5 highest cost main extensions:
    - The FEI and FEVI populations for 2009-2013
    - The 2014 FEI Amalco main population

Review of Random Samples and Top 5 Data

- A comparison of forecast and actual costs, consumption and PI for the samples and the top 5 for the following:
    - FEI and FEVI for 2009-2013.\
    - FEI Amalco for 2014
- Ramp up
    - FEI and FEVI for 2009-2013
    - FEI Amalco for 2014

Continuing this example, 2014 will be the last year of reporting compliance for 2009 mains, meaning that the 2015 MX Report would no longer include this data set. The 2015 MX Report would also be different in that the geo code and MX Test inputs would provide comparisons of existing 2014 FEI Amalco data versus the updated 2015 FEI Amalco data.

29.1.1 Would the proposed reporting now roll-in past and present years five highest cost main extensions for FEI Amalco or would reporting stay the same and continue by each utility for past years five highest cost main extensions and rolled-in thereafter, or other?

Response:

Please refer to response to BCUC IR 1.29.1.

29.2 The MX reporting requirements state: "… 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." Please explain the current reporting process and the future reporting process for the proposed FEI Amalco to satisfy that requirement of the annual MX report.

Response:

Please refer to the response to BCUC IR 1.29.1.

29.3 As FEI and FEVI have yet to file a fully compliant 2010 MX Report at this time, how would the proposed FEI Amalco ensure information filed in the amalgamated annual MX reports is consistent and comparable year to year for MX Test monitoring?

Response:

Please refer to BCUC IR 1.29.1.

29.4 In the proposed FEI Amalco, how would PI values be reported and updated in the annual MX filing?

Response:

Please refer to BCUC IR 1.29.1.

29.5 The System Extension and Customer Connection Policies Review took place in the second half of 2007, and by 2012 it would have been four and a half years. In FEU's view, when would be an appropriate time to conduct a full review of the System Extension and Customer Connection Policies to assess whether the policies continue to be appropriate?

Response:

The Companies believe that the System Extension Test ("SET") and Customer Connection Policies continue to be appropriate and should continue. Similarly, the proposed MX reporting described in the response to BCUC IR 1.29.1 meets the compliance requirements described in Commission Order Nos. G-152-07 and G-06-08.

As stated in Section 9.8 of the Application[32], if amalgamation and the adoption of common rates is approved, the FEU will review the cost allocation and customer segmentation in 2016. The Companies are proposing that the SET may also be reviewed at that time but not sooner.

It is appropriate to hold a SET review no sooner than 2016, as that time frame would have 3 populations of pre-amalgamation mains (i.e. 2008, 2009, and 2010) that will have completed the requisite five years of reporting to the Commission as well as mains from the Amalco that will have seen some attachments (2014-5).

[32] Page 221

30.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, p. 137

MX Test Background

On page 137 of the Application, the FEU note that if the PI is less than 0.8, a customer contribution in aid of construction (CIAC) would be required to make up the shortfall to bring the PI up to the 0.8 threshold, before the system extension can be built.

30.1 For each of 2009, 2010, and 2011 please provide the number of contributory mains, total mains, and total customer CIAC amount for each utility.

Response:

The table below contains the total number of mains, total contributory mains and total CIAC amount for FEI and FEVI between 2009 and 2011.

	2011		2010		2009	
	FEI	FEVI	FEI	FEVI	FEI	FEVI
Total Number of Mains	490	173	432	202	560	211
Total Contributory Mains	40	19	40	31	53	29
Total CIAC Amount	$348,107	$89,909	$526,590	$156,434	$521,573	$275,421

30.2 If the Application is approved as proposed, what impact, if any, will there be on customer CIAC amounts.

Response:

In general, more main extensions in the existing FEVI and FEW areas will likely require a CIAC due to the proposed rate reductions whereas there will likely be slightly fewer main extensions in the existing FEI area that will require a CIAC due to the proposed rate increases. Overall, the FEU expect a minimal impact on net CIAC of the FEI Amalco entity.

The CIAC impact is similar to the PI impact from amalgamation described on page 140 of the Application. The analysis shows that amalgamation would have minimal impact on average overall PI values with PI values for existing FEI customers increasing and PI values for existing FEVI and FEW customers decreasing.

30.2.1 With some areas receiving proposed rate reductions, will some main extensions become contributory when they were not before? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.30.2.

30.3 If a developer provides input into the utility's customer attachment and customer use forecasts and the main extension is non-contributory since the PI is above 0.8 but subsequently the realized load is well below the customer attachment and/or customer use forecast, are there any consequences for the developer providing input into forecasts that did not materialize?

Response:

In general, the developer provides a good faith estimate of the future attachments and appliances to be installed in the main extension project. The Companies use its knowledge and experience to finalize these forecasted customer/appliance attachements. The Companies multiply the attachment and appliance forecast by the average use per appliance estimates derived from its Residential End Use studies to determine consumption forecasts. As the developer does not have control over the usage rate of the end use customer, it is not reasonable for the developer to carry this risk, nor would it be reasonable to hold and end use customer to commitments for usage of specific appliances. Similarly, existing customers change their load and usage profiles over time as a result of changing equipment or moving from one form of energy to another for a specific appliance (ie: electric stove to gas stove or vice versa). These existing customers are not penalized for changing their load profiles, on the contrary, through EEC, these customers are actually encouraged to use less than what they previously used. In this manner, is it inconsistent, and unequal from an intergenerational standpoint, to hold new customers/developers to a different standard than existing customers.

However, in certain instances where there is concern over the forecasts, a security deposit may be obtained from the developer which may be retained by the FEU, although this is very infrequent.

30.3.1 Please provide any guidelines or corporate policies that FEU use to evaluate forecasts provided by developers.

<u>Response:</u>

FEU relies on the knowledge and expertise of its Planning and Energy Solutions management team to evaluate forecasts from developers. For example, the team uses the following guidelines and sources of information when evaluating forecasts:

Lot size

- This information gives an indication as to the size of homes. Larger lots and therefore larger homes generally take longer to sell so the load would be weighted to come on later in the five year forecast in this scenario. Smaller lots tend to sell quickly and are built on sooner.

Dwelling type

- In most subdivisions, there is a mix of single family and duplex or town homes. This can significantly affect the load forecast.

Load

- The Planning and Energy Solutions team determine with the developer the type of appliances in the dwelling(s). The FEU then apply average use per appliance to determine the forecast consumption. The FEU use the findings from its Residential End Use Studies to derive average use per appliance. These values are reported annually to the Commission in the MX Report. Finally, the Companies account for the fact that consumption may take time to "ramp-up" in the early months of service.

Will the developer be the builder, or sell the lot(s) to a builder?

- If the developer is also the builder, the outcome is much more predictable. If the developer is developing the lots and selling them, then the FEU adopt a more conservative approach to forecasting. Often there is a combination of both scenarios.

Developer relationship

- If the FEU have had positive dealings with a particular developer, the Companies are more inclined to place higher value in their forecasts. If the FEU have found a developer to make changes mid-project that would affect the attachment or our load forecast, then the Companies would be more inclined to ask for a refundable security deposit before construction were to begin.

Market intelligence

- The FEU make use of market intelligence from a variety of activities that enable our team to make informed attachment and consumption forecasts. For example, the FEU make use of publications such as the Canadian Mortgage and Housing Corporation's Quarterly Housing Market Outlook for the BC region. The FEU are also involved in organizations such as the Urban Development Institute ("UDI") Pacific Region. With over 600 corporate members, UDI Pacific represents thousands of individuals involved in all facets of land development and planning, including: developers, property managers, financial lenders, lawyers, engineers, planners, architects, appraisers, real estate professionals, local governments and government agencies. UDI focuses on fostering effective communication between the industry, government, and the public.

The FEU also have approval criteria for main extensions summarized below:

Main Extension Cost Threshold	Written Approval Required
$0-$50,000	Planning & Design Work Leader and Energy Solutions Manager
$50,000-$100,000	Planning & Design Manager and Manager, Residential & Commercial Energy Solutions
$100,000-$250,000	Director, Operations Centre and Director, Energy Solutions
$250,000-$500,000	VP, Operations and VP, Energy Solutions and External Relations
$500,000-$2,000,000	President

These criteria ensure that the cost of the main extension project being proposed corresponds to the requisite level of FEU management needed for project approval.

31.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, pp. 137-138

Adoption of FEI/FEVI PI Thresholds upon Amalgamation

On page 137 of the Application, the FEU state:

> "Upon amalgamation and the adoption of common rates it is appropriate to continue with the PI methodology as approved by the Commission under Order No. G-152-07 for FEI and FEVI whereby an individual PI threshold of 0.8 and an aggregate PI of 1.1 are to be used. This means that FEW will be adopting the FEI and FEVI PI thresholds to bring all service areas across the areas served by the FEU into alignment. They will also continue to apply to Fort Nelson as they are today."

31.1 Is it possible under Amalgamation if there was a single approved service area that FEI Amalco would still be able to report the MX by region (VI, FEI-Mainland, FEW, FN).

<u>Response:</u>

Although it may be possible to report the MX by region, the Companies have not conducted a feasibility study to determine what internal capabilities would be required to report by region following amalgamation. As described in the response to BCUC IR 1.29.1, the Company is proposing to continue to report on pre-amalgamation main extensions for FEI and FEVI for the requisite five years. Post-2014, the Companies will be reporting on new main extensions from the single entity, FEI Amalco. This proposal is more efficient than continuing to report on the pre-amalgamation service areas.

31.2 Hypothetically, if the legal amalgamation were approved but the existing service areas were maintained, please discuss the option of having a 1.1 PI aggregate threshold for each of Vancouver Island, FEI-Mainland, Whistler, and Fort Nelson.

<u>Response:</u>

The FEU assume that this IR is referring to a hypothetical scenario whereby legal amalgamation, postage stamp rates and a common set of FEI Amalco MX Test inputs were approved along with a 1.1 PI aggregate threshold for each of Vancouver Island, FEI-Mainland, Whistler and Fort Nelson.

In section 7.4.2.3 of the Application, the FEU provide an analysis comparing PI values of the individual entities versus FEI Amalco. This analysis shows that FEVI and FEW customers PI values would decrease, FEI PI values would increase and, overall, amalgamation would have a minimal impact on PI values in aggregate. This means that more FEVI and FEW customers will be required to make a contribution to reach the requisite individual PI value of 0.8. If an aggregate PI threshold was maintained for each existing service area this would be inconsistent with the use the FEI Amalco MX Test inputs resulting in the FEVI and FEW regions likely being unable to maintain an aggregate PI of 1.1 in each region. In addition, the efficiency gains of having postage stamp rates with a single PI threshold would be reduced if the Companies had to record, maintain and report on different PI thresholds.

Consequently, it is in the best interests of customers to have common postage stamp rates, a common set of FEI Amalco MX Test inputs and an aggregate PI threshold of 1.1 for FEI Amalco. This proposal is methodologically consistent (i.e. it uses FEI Amalco inputs and an FEI Amalco aggregate PI), accomplishes the purposes of the MX test and allows for more efficient reporting.

32.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, pp. 138-139

Use of PI Inputs Reflecting FEI Amalco

On page 138 of the Application, FEU provide a summary of the changes to the inputs into the PI calculation resulting from amalgamation in Table 7.1 for 2013 test year numbers. Table 7.1 is reproduced below:

Table 7.1: High Level Overview of Changes to MX Test Inputs Resulting from Amalgamation172

Utility	SI	Discount Rate	O&M[173]	Property Tax	Variable Margin	Fixed Margin
2013 FEI	$ 0.160	6.8%	$ 89.47	2.01%	$ 3.880	$ 142.08
2013 FEVI	$ 0.151	6.5%	$ 72.83	1.90%	$ 7.376	$ 126.00
2013 FEW	$ 0.160	6.2%	$ 65.00	2.01%	$ 11.686	$ 90.00
2013 FEI AMALCO	$ 0.159	6.7%	$ 87.57	1.99%	$[174] 4.361	$ 141.99

32.1 By Letters L-67-11 and L-19-12, the Commission requested FEI and FEVI to update the System Improvement (SI) charge each year to reflect changes with an escalation factor. Also, page 13 of the 2010 MX Report notes that the next SI assessment will take place in 2012. Table 7.1 above appears to show no updates in the SI charge when compared to the 2010 MX Report. Please explain why the 2013 FEI Amalco values for the amalgamated SI charge appear to have not been updated. If it has been updated what are the updated 2012 and 2013 values?

<u>Response:</u>

On pages 138-141 of the Application, the FEU described the use of MX Test inputs and proposed that FEI Amalco will use one set of inputs to run the MX test.

At the time the MX analysis was performed for the Application, it was assumed that the individual entity SI rates were a carry forward of the rates used for the 2009-2011 MX Test SI rates. The individual entity rates are then weighted by the 2013 projected total average customers to arrive at the amalgamated SI fee. As stated in the Application, the inputs in Table 7.1 were provided for illustrative purposes only to compare the individual to the amalgamated entities and were subject to change. Following acceptance of the Application, the Companies will develop actual FEI Amalco MX test inputs to be used in MX Tests starting in 2014.

The FEU have had recent discussions with Commission staff[33] about the 2012 SI rates changing to $0.36 for FEI and FEW and $0.49 for FEVI. In follow up correspondence[34], the FEU and Commission staff agreed that the 2012 MX Report would explain how the SI values were updated. 2013 SI values have not been established.

32.2 With respect to the O&M rates, FEU note on page 139 in Exhibit B-3 that the individual entity O&M per customer was derived using the 2011 MX Test residential O&M rates and applying an annual inflation rate to arrive at the 2013 amounts per customer. Please explain the appropriateness of applying an annual inflation rate given the general rate increases approved for FEI over the last number of years.

Response:

Applying an annual inflation rate of 2% to the 2011 MX Test residential O&M rates is a conservative and reasonable method to use in calculating the 2013 O&M per customer for the MX Test. The approved delivery rate changes from the FEU revenue requirement applications are made up of many factors including changes to rate base assets and the related earned return, depreciation and amortization, property taxes, income taxes, and O&M costs. The O&M increases approved in the FEI 2012/2013 Revenue Requirement Application result in a 1.84% delivery rate increase in 2012[35] and a further 1.34% delivery rate increase in 2013.[36] This indicates that using an annual inflation rate increase of 2.00% for the MX Test O&M per customer is a more conservative approach than applying an inflation rate based on the 2012/2013 approved delivery rate increases.

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33 Main Extension Test Overview presentation to Commission staff, April 26, 2012.

34 Email from Commission staff sent April 27, 2012

35 Calculation is derived using the RRA Decision Compliance filing FEI financial schedules. ($195,213 2012 Total Forecast O&M as shown on Section 7, Tab 7.1, Schedule 5, Column 5 - $184,625 2011 Total Approved O&M as shown on Section 7, Tab 7.1, Schedule 4, Column 3) / $575,111 2012 Forecast Gross Margin as shown on Section 7, Tab 7.1, Schedule 2, Column 6.

36 Calculation is derived using the RRA Decision Compliance filing FEI financial schedules. ($202,963 2013 Total Forecast O&M as shown on Section 7, Tab 7.1, Schedule 6, Column 5 - $195,213 2012 Total Forecast O&M as shown on Section 7, Tab 7.1, Schedule 5, Column 5) / $576,730 2013 Forecast Gross Margin as shown on Section 7, Tab 7.1, Schedule 3, Column 6.

32.2.1 Would applying the approved/proposed delivery rate increase in the most recent revenue requirements application test year(s) be more appropriate and reflective when considering O&M rates? Why or why not?

Response:

Please refer to the response to BCUC IR 1.32.2.

32.3 Please explain how FEU will account for MX Test inputs from 2008 to 2012 in those MX that were installed prior to Amalgamation. Would it be appropriate for FEU to continue to use the FEI Amalco inputs for years 2008 to 2012 or continue to use the original MX test inputs for each utility? (e.g. original variable margin for the specific utility or amalgamated margin in the proposed FEI Amalco.)

Response:

Please refer to the response to BCUC IR 1.29.1 for a complete description of the MX reporting proposal.

Note that MX tests are a calculation based upon inputs at a certain "point in time". For example a main extension test originally run in 2009 would use 2009 inputs such as SI, margin (delivery rates), O&M per customer, property tax and discount rate. When reporting on 2009 main extensions, or comparing actual attachments and volumes and therefore actual PI to original PI, original inputs such as discount rate, O&M etc. must be used. Using different inputs, for example current year fixed margin for inputs, would result in main extensions having different PI's and as such it would not be comparable to the original MX.

For pre-amalgamation main extensions, the FEU propose to continue to use the original MX Test inputs from 2008-2013 when providing data for review by the Commission to ensure consistency.

33.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, pp. 138-141

Aggregate PI Values Resulting from Amalgamation

On pages 139 and 140 of the Application, FEU performed analysis on the FEI, FEVI, and FEW main extension populations from 2008-2010 to determine the impact of implementing the FEU Amalco input parameters on historical MX Test results. The FEU generated random samples from FEI, FEVI, and FEW main extensions from 2008-2010 and then re-ran the MX Tests holding all inputs constant except the six listed in Table 7.1 on p. 138 of the Application. FEU provided Table 7-2 which shows the aggregated PI values resulting from amalgamation, as reproduced below:

Table 7-2: Aggregate PI Values Resulting from Amalgamation

	2008 PI		2009 PI		2010 PI	
Utility	Individual Utilities	Amal-gamated	Individual Utilities	Amal-gamated	Individual Utilities	Amal-gamated
FEI	1.5	1.6	1.7	1.9	1.5	1.7
FEVI	1.7	1.1	1.4	0.9	2.0	1.2
FEW	N/A[182]	N/A	4.8	1.8	1.0	0.4
Average	1.5	1.5	1.7	1.6	1.6	1.4

The FEU noted the results of this analysis indicate that in aggregate FEU customers would have experienced no material changes resulting from amalgamation.

33.1 As shown in Table 7-2, FEI's PI in 2008, 2009, and 2010 would have increased when using the inputs of the amalgamated entity. Please explain whether this increase in PI is primary driven by higher variable margin as a result of common rates.

Response:

The increase in FEI's PI is driven primarily by the higher variable margin whereas FEVI and FEW's decrease is driven by lower variable margin.

33.1.1 Similarly, please explain FEVI and FEW's decrease in PI for 2008, 2009, and 2010 when using the inputs of the amalgamated entity.

Response:

FEVI and FEW's decrease in PI is driven by the lower variable margins arising from the common rates proposal.

33.2 Since FEVI and FEW's PI is expected to decrease when using the inputs of the amalgamated entity, should the PI be reported by regional areas for monitoring? Why or why not?

Response:

No, as described in the responses to BCUC IRs 1.29.1 and 1.31.1, for post amalgamation main extensions, the FEU are recommending reporting on the single entity FEI Amalco. This is the most efficient way to approach MX reporting. The purpose of Table 7-2 was to show the PI impact to the entities that existed pre-amalgamation (i.e. FEI, FEVI, FEW) compared to the post-amalgamation entity, FEI Amalco. This analysis shows that overall amalgamation would have minimal impact on PI values.

The FEU have proposed a common set of FEI Amalco inputs and MX Test PI thresholds. Consistent with this proposal, the Companies should report on the FEI Amalco post amalgamation.

34.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, p. 139; Exhibit B-3-1, Appendix C-1, p. 12

MX Random Sampling Methodology

On page 12 of Appendix C of Exhibit B-3-1 of the Application, FEU provide Table 3 which includes the 2010 average number of customers, as reproduced below:

Table 3: FortisBC Energy Utilities Overview

	FEI[9]	FEVI[10]		FEW	
Rate Base ($000) (mid-year 2010) ($000s)	$2,525,213	$547,661	(21.7%)	$45,400	(1.8%)
Cost of Service in ($000s)	$1,302,417	$166,099	(12.8%)	$ 14,019	(1.1%)
# of Customers (2010 Average)	839,017	98,924	(11.8%)	2,586	(0.3%)
Rate Base per Customer	$3,010	$5,536		$17,556	

34.1 Would the proposed FEI Amalco's MX reporting allow the ability to differentiate characteristics and performances between FEVI, FEVI, and FEW, or by different service areas?

Response:

The proposed FEI Amalco MX reporting will continue to provide the Commission with the following data segmented geographically:

- Appliance use inputs for MX Test inputs segmented by Lower Mainland, Interior and Vancouver Island (Note that this information is provided by the Residential End Use Study that does not require FortisBC to maintain separate systems to track usage by utility or region. In the future, similar to Geo code pricing, if different zones show different usage patterns additional zones may be either added or deleted).
- Geo code pricing segmented by geography. Currently the FEU segment based on Vancouver and Richmond, North Shore and Squamish, North of Fraser River, South of Fraser River, Interior North, Interior South and Vancouver Island.

All other data presented in the MX Report relating to post-amalgamation main extensions will be reported on an amalgamated basis.

Please refer to the response to BCUC IRs 1.29.1 and 1.31.1 for a detailed description of the proposed MX Test reporting.

34.2 Should the random sampling methodology be used for each utility or for each service area? Why or why not?

Response:

The random sampling methodology would apply to the FEI Amalco aggregate population as the FEU are proposing a single FEI Amalco set of MX Test inputs, an aggregate PI threshold of 1.1 and reporting on the FEI Amalco mains. Random sampling for each utility or service area should not be used because the FEU are not proposing separate utility or service area MX Test inputs, PI thresholds or reporting. Further, one of the benefits of amalgamation is the efficiency gained from tracking only one utility's costs and inputs. This would be lost if the FEU needed to keep costs separate for each of the current FEVI, FEI and FEW.

35.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, p. 140; Addendum to the 2010 MX Report, dated October 14, 2011, pp. 8-9

Five Highest Cost Main Extensions Historical Information and Amalgamation

On page 140 of the Application, Table 7-2 provides an analysis of the aggregate PI values resulting from amalgamation. From that analysis, the FEU conclude the following:

- Overall amalgamation would have minimal impact on PI values as seen by the fact that the average PI values would have been reduced by 0.1 on average;
- PI values for FEI customers would have increased as seen by the fact that the PI value increased in 2008, 2009 and 2010 when using the inputs of the amalgamated entity; and
- PI values for FEVI and FEW customers would have decreased as seen by the fact that PI values decreased in 2008, 2009 and 2010 when using the inputs of the amalgamated entity.

On October 14, 2011, FEI and FEVI filed with the Commission an Addendum to the 2010 MX Report which includes the five highest cost main extensions starting from 2008, as shown in Tables 4 and 6 of the Addendum. The five highest cost main extension tables in the Addendum are reproduced as follows:

Table 4: 2009 Top 5 Cost Main Extensions (Re-stated Table 12)

Utility	Cost ($ 000)			Attachments			Consumption (GJ)			Consumption (GJ/Attachment)			PI
	Years 1-5 Forecast	Year 1 Forecast	Year 1 Actual	Years 1-5 Forecast	Year 1 Forecast	Year 1 Actual	Years 1-5 Forecast	Year 1 Forecast	Year 1 Actual	Years 1-5 Forecast	Year 1 Forecast	Year 1 Actual	Years 1-5 Forecast
FEI													
Tronson Road	$ 500,549	$ 337,574	$ 254,851	205	0	0	24,100	0	0	118	0	0	0.9
2nd Avenue	$ 548,442	$ 248,628	$ 183,331	306	48	2	29,733	4,685	92	97	98	46	1.3
Upper Hyde Creek	$ 186,765	$ 186,765	$ 141,224	115	115	26	13,161	13,161	1,115	114	114	43	1.5
108 Avenue	$ 168,699	$ 101,352	$ 127,932	78	15	21	8,699	1,638	844	112	109	40	1.0
S of University Way	$ 211,465	$ 182,972	$ 98,482	78	0	1	10,489	0	344	134	0	344	0.8
FEVI													
Shawnigan Lake	$ 936,219	$ 936,269	$2,053,682	193	193	88	9,914	15,402	10	51	80	0	0.9
West Coast Road	$ 410,472	$ 410,439	$ 401,092	201	201	0	14,070	14,070	0	70	70	0	1.6
Wild Ridge Way	$ 91,923	$ 91,923	$ 146,739	64	64	22	4,480	4,480	367	70	70	17	1.9
Hammond Bay Road	$ 164,340	$ 90,840	$ 84,142	80	20	3	4,262	1,400	53	53	70	18	1.2
Kettle Creek Station	$ 114,424	$ 76,918	$ 70,261	58	20	0	5,067	1,747	0	87	87	0	1.7

Table 6: 2008 Top 5 Cost Main Extensions (Re-stated Table 14)

Utility	Cost ($ 000)			Attachments			Consumption (GJ)			Consumption (GJ/Attachment)			PI
	Years 1-5 Forecast	Years 1-2 Forecast	Years 1-2 Actual	Years 1-5 Forecast	Years 1-2 Forecast	Years 1-2 Actual	Years 1-5 Forecast	Years 1-2 Forecast	Years 1-2 Actual	Years 1-5 Forecast	Years 1-2 Forecast	Years 1-2 Actual	Years 1-5 Forecast
FEI													
Trans-Canada Highway	$1,321,079	$1,153,110	$ 836,121	511	280	2	79,801	41,906	129	156	150	65	0.9
Juniper Road	$ 63,521	$ 42,041	$ 119,211	44	20	0	5,500	2,500	0	125	125	0	1.7
Crystal Creek Drive	$ 64,646	$ 64,646	$ 119,192	22	22	3	3,070	3,070	358	140	140	119	1.0
163 & 61A Avenue	$ 242,492	$ 183,512	$ 172,841	171	110	46	16,507	10,619	3331	97	97	72	1.4
Rio Drive	$ 187,818	$ 180,434	$ 112,712	92	85	0	3,649	3,371	0	40	40	0	0.7
FEVI													
Players Drive	$ 265,791	$ 265,808	$ 219,888	74	74	0	13,307	13,307	0	180	180	0	1.5
French Road	$ 107,795	$ 107,793	$ 179,714	50	50	15	3,500	3,500	290	70	70	19	1.2
Hutchinson Road	$ 136,457	$ 136,457	$ 103,959	75	75	13	4,125	4,125	105	55	55	8	1.4
Sewell Road	$ 60,723	$ 60,712	$ 108,883	25	25	19	2,750	2,750	459	110	110	24	1.0
Phillips Road	$ 287,608	$ 287,649	$ 77,316	87	87	1	4,670	4,670	1	54	54	1	0.9

35.1 The tables above appear to show that attachments and consumption are underperforming for both FEI and FEVI when comparing forecast against actual. Would FEU agree with this observation?

Response:

No. The FEU do not agree with the observation that "…attachments and consumption are underperforming for both FEI and FEVI when comparing forecast against actual." There are two primary reasons for this:

First, the performance of main extensions should be examined in aggregate, not at an individual main extension level whereas the tables quoted above only show the top 5 highest cost mains. In the Commission's Decision accompanying Order No. G-152-07, at p. 36, the Commission Panel found that the policy of ensuring that the addition of a full year's cohort of customers does not adversely affect the customers in existence at the beginning of the year was in the public interest and conformed with the Commission's Guidelines. The Commission approved the establishment of an aggregate PI of 1.10 as the threshold for all main extensions completed on an annual basis. The Decision directed that the annual report include a "review of a random sampling of MX test results representing a confidence interval of +/-12 percent at a 95 percent confidence level and the five highest cost main extensions 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*." [Emphasis added.] Consistent with the Commission's Decision, it is the aggregate threshold that demonstrates whether the existing customers are positively or negatively impacted from the attachment of new customers on an aggregate basis.

When examined from an aggregate perspective, as shown in the Addendum to the 2011 MX Report, 2008 and 2009 aggregate PI values were 1.5 and 1.2 for FEI and 0.7 and 1.4 for FEVI, respectively. All these values are above the aggregate PI threshold of 1.1 except for FEVI in 2009. If Shawnigan Lake were removed, the FEVI 2009 PI changes to 1.0. The FEU believe that the cost estimating issues regarding Shawnigan Lake have been addressed and are unlikely to occur in the future. Thus, the 1.0 PI value for the 2009 portfolio is more indicative of FEVI results. In short, the aggregate PI performance for 2008 and 2009 are reasonable, particularly given the economic downturn experienced in 2008/2009.

Second, since the MX Test approved by the Commission is a twenty year discounted cash flow ("DCF") model, the appropriate time frame to review the performance of main extensions in aggregate should be at the end of twenty years. The annual MX reports provided to the Commission represent a "snap shot" in time view of a main extension or group of main extensions out of the 20 year DCF time frame. The BC housing market and the Companies' attachment and consumption results are closely related and cyclical in nature. Inevitably, there will always be uncertainty and variability year to year inherent in forecasting attachments, despite the Companies' best efforts to apply their industry knowledge, experience and conservative approach to forecasting. The risk of focusing on performance of an individual year is that attachments that didn't materialize in a given year may do so at some point in the future of the 20 year DCF time frame. Furthermore, over the 20 years, there may be attachments that materialize that weren't originally forecast by the Company. In sum, the performance of main extensions in aggregate cannot be fairly evaluated until the end of the 20 DCF timeframe.

35.2 In the proposed FEI Amalco, please explain how the requested changes could affect the PI of the five highest cost main extensions.

Response:

The effect on the PI of the top 5 post amalgamation main extensions would be the same as the effect on the aggregate PI values described in the IR above. Overall, the impact would be positive for FEI main extensions (i.e. higher PI values), whereas for FEVI main extensions, the impact will be negative (i.e. lower PI values) due to changes in delivery margins resulting from the common rates proposal. Please also refer to the responses to BCUC IRs 1.33.1 and 1.33.2.

Pre-amalgamation main extensions would not be affected by amalgamation because the historical MX Test inputs would continue to be used.

As discussed in the response to BCUC IR 1.29.1, post amalgamation, the FEU plan to report the top 5 and aggregate data to the Commission for pre-amalgamation (i.e. 2008-2013, FEI and FEVI) and post amalgamation (2014 and onwards, FEI Amalco) main extensions.

35.3 Based on the five highest cost main extensions information above, in light of the proposed FEI Amalco changes, would it be appropriate for the annual MX report to include the highest five cost main extensions by each existing utility or by each existing service area to ensure that the Commission is kept informed about their respective performance?

Response:

Please refer to the response to BCUC IR 1.29.1 for a detailed description of the proposed MX reporting.

35.4 In the Decision dated April 12, 2012, on the FEU 2012-2013 Revenue Requirements and Rates, the Commission Panel on page 91 notes concerns that the FEU may be constructing high cost main extensions without adequate assurance that customers will connect to the extensions. West Coast Road is one main extension that has high cost and has no customer connections. Please explain whether the proposed FEI Amalco, in the annual MX report, would provide adequate monitoring on under-achieving main extensions such as the West Coast Road.

Response:

Please refer to the response to BCUC IR 1.29.1 for a detailed description of the proposed MX Reporting. As discussed in the response to BCUC IR 1.29.1, the proposed MX reporting will provide adequate monitoring for all main extensions.

36.0 Reference: MX Test

Exhibit B-3, Section 7.4.2.3, p. 140

Individual PI Value Range Resulting from Amalgamation

On page 140 of the Application, the FEU provide Table 7-3 which shows individual PI value range resulting from amalgamation. Table 7-3 is reproduced as follows:

Table 7-3: Individual PI Value Range Resulting from Amalgamation

	2008 PI Range		2009 PI Range		2010 PI Range	
Utility	Individual Utilities	Amal-gamated	Individual Utilities	Amal-gamated	Individual Utilities	Amal-gamated
FEI	0.9 - 2.3	1.0 - 2.6	1.0 - 7.4	1.1 - 8.0	1.0 - 3.8	1.2 - 4.3
FEVI	1.0 - 2.4	0.6 - 1.5	1.0 - 2.3	0.6 - 1.6	1.0 - 3.3	0.6 - 2.0
FEW	N/A	N/A	4.8 - 4.8	1.8 - 1.8	0.8 - 1.5	0.3 - 0.6

36.1 Please provide supporting calculations and underlying assumptions to the range of PI values shown in Table 7-3.

Response:

The calculations and underlying assumptions used to create the P.I. results shown in Table 7-3 above are described in the methodology section on page 137 – 139 of the Application. The MX formula as approved in BCUC Order G-152-07 is provided below for reference purposes.

$$\textbf{P.I.} = \frac{\substack{\textbf{Net Present Value of Net Cash Inflows} \\ \text{(Delivery Margin + Connection Fees – O\&M - System Improvement Charge – Property Tax – Income Tax)}}}{\substack{\text{(Mains, Services, Meter Costs)} \\ \textbf{Net Present Value of Capital Costs}}}$$

The difference between Table 7-2 and Table 7-3 on page 140 of the Application is that Table 7-2 provides an average PI calculation based on running the MX test for each main in the sample under both individual and amalgamated scenarios whereas Table 7-3 presents PI results based on the highest and lowest PI value mains within the sample.

36.2 Please explain the purpose of calculating a range of PI. Would this be part of a re-forecasting calculation of PI using actual historical customer addition and use data?

Response:

As described in the response to BCUC IR 1.36.1, the difference between Table 7-2 and Table 7-3 on page 140 of the Application is that Table 7-2 provides an average PI calculation based on running the MX test for each main in the sample under both individual and amalgamated scenarios, where Table 7-3 presents PI results based on the highest and lowest PI value mains within the sample.

The purpose of providing the data in Table 7.3 is to show a low to high range within the sample.

37.0 Reference: MX Test

Exhibit B-3-1, Appendix C-1, p. 10; Exhibit B-4 of the TGVI 2010 and 2011 Revenue Requirements and Rate Design Application, Response to BCUC IR No. 1 #44.0, submitted on August 28, 2009

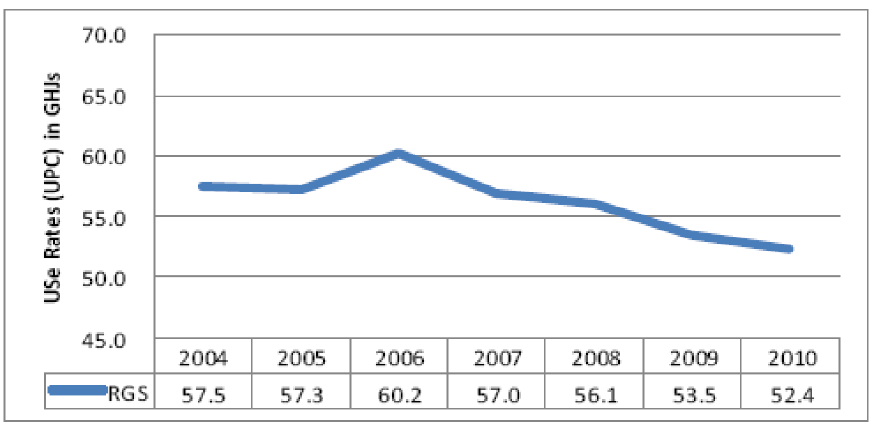
Declining Use of Natural Gas per Customer Accounts

On page 10 of Appendix C-1, the FEU state:

> "Since 2006 the FEVI Residential General Service UPC [use per customer] has declined by almost 2 per cent per year, despite relatively stable UPC for small and large commercial service in the Vancouver Island service area as illustrated by Figure 5 below. Normalized average residential customer usage has declined from approximately 60.2 GJ/year in 2006 to 52.4 GJ/year in 2010."

Figure 5 in Appendix C-1 shows FEI natural gas use rates per customer, as reproduced below:

Figure 5: FEVI Natural Gas Use Rates per Customer



Terasen Gas Inc. (TGVI, now known as FEVI) Information Request (IR) response to BCUC 1.44.0 to the 2010-2011 Revenue Requirements and Rate Design Application submitted on August 28, 2009, Exhibit B-4, provides the following tables pertaining to actual annual consumption (June 1, 2006 to May 31, 2007) of 981 new services installed for TGI (now FEI) and TGVI (FEVI):

Company	Rate Class	Number of Customers	Actual Annual Consumption
TGI	Rate 1	623	58,192.7
TGI	Rate 2	66	38,453.8
TGI	Rate 3	2	2,548.0
TGI	Rate 23	1	10,564.1
TGVI	RGS	263	10,663.1
TGVI	SCS1	21	4,342.3
TGVI	SCS2	2	1,113.4
TGVI	LGS1	3	3,890.8

The same IR response above also provides the following table that illustrates the normalized annual consumption by rate class for the same set of FEVI customers included in the above table over the period 2006 to 2008:

		Normal Annual Cons(GJ)		
Rate Class	Number of Customers	June 1st 2006 to May 31st 2007	2007	2008
RGS	263	10,601.0	11,537.3	11,683.1
SCS1	21	4,307	5,043	4,941
SCS2	2	1,118	701	223
LGS1	3	3,878	3,583	3,021

37.1 From the IR response to BCUC IR No. 1.44.0 submitted in August 2009, it appears that new customers' UPC in RGS was estimated to about 44 GJ for years 2008 and 2007. Would FEU agree that new FEVI customers, compared to FEI customers, generally have lower annual use? Please elaborate.

Response:

For the customers listed in the referenced tables, the FEU agree that new FEVI residential customers on average have lower consumption rates compared to residential FEI customers. However, this group represents only customers who were attached to the system over a specific and very short time frame, as dictated in the referenced IR submitted in August 2009. It is possible, for example, that these attachments on Vancouver Island were made up primarily of a new subdivision that may have lower consumption on average than older homes due to higher efficiency appliances, smaller size and/or better insulation.

The FEU have not done any specific analysis of new FEVI residential customers to determine whether they have, on average, lower UPC than new FEI customers. However, anecdotal evidence suggests that *new* FEVI customers compared to *new* FEI customers have generally lower annual use rates, similar to the relationship between *existing* FEVI and *existing* FEI customers.

Please refer to the response to BCUC IR 1.37.1.1 for further discussions on the probable trends impacting the declining UPC rates in FEVI.

37.1.1 Is one reason for the declining use in FEVI due to new residential customers attaching at use rates well below the FEVI system average. Please elaborate.

Response:

One reason for declining use in FEVI is due to new residential customers attaching at use rates below the FEVI system average, however it is not the only reason. The FEU believe the declining UPC is a result of a combination of trends affecting both new and existing housing.

New Construction/Housing

In British Columbia and elsewhere in North America, a number of general trends directly affect the use rates for natural gas, such as the improved energy efficiency of new applications and more energy efficient homes due to improved insulation. Thus similar sized newly constructed housing using a similar combination of appliances tends to use less gas than the historical average. Further, there is an increased level of high density housing where low consumption per customer tends to occur more frequently.

In addition to improved insulation, more efficient appliances and increased level of high-density housing (i.e. smaller living space) as elaborated in Appendix C-1 of the Application, overall natural gas plays a less prominent role as the main energy option for space/water heating in new construction in FEVI. For example, according to the latest Residential New Construction Research prepared by Sampson Research for the FEU, on Vancouver Island the two most common gas-end use combination include fireplaces alone (i.e. no other gas end-use) and fireplaces paired with BBQ (both are low demand appliances). On average 19% of Vancouver Island homes with gas service and built since 2005 have one gas end-use (typically a gas fireplace) [37], which leads to lower UPC rates. The FEU believe there are different contributing factors to this trend; however, anecdotally, two issues arise – initial capital cost and the perceived value, as discussed below.

- **Initial capital cost**: Electric baseboards are cheaper to install and are individually metered with the rest of their electric use reducing upfront non-visible construction costs

[37] 2010 Residential New Construction Research Analysis & Highlights Final Report (Exhibit B-3-1, Appendix G-11), pg. 5.

and allowing higher expenditure allocations to aesthetic items. Similarly electric water heaters are cheaper and easier to place in the middle of the home than gas fired equipment. This leads to an increase in the proportion of newly constructed gas homes with only one or two gas end uses.

- **Perceived value:** Mid to higher end home builders have been adopting heat pump technology as a viable option to a forced air furnace, as it also offers air conditioning. This is perceived as an additional value in this market segment and is a small increase to the overall cost of the home. This option is being sold more to the mature home buyer (i.e. less price sensitive) as an appliance that will drop the overall operating expense due to its perceived efficiency. This trend also contributes to the use of natural gas as a secondary fuel for space heating *(often gas fireplace at 58%))*.[38]

Existing Housing

For existing housing, the main trend that contributes to the declining UPC rates is the improved efficiency. In general, old gas equipment is being replaced with much higher efficiency natural gas equipment, or replaced with non-natural gas equipment. It is not uncommon to have a 20 year old natural gas furnace replaced with a heat pump. Air conditioning is becoming more popular with the aging demographic and heat pumps have become more affordable, both contributing to declining UPC levels.

[38] Ibid, pages 29 and 34.

38.0 Reference: MX Test

Exhibit B-3, Chapter 3, Sections 3.2.3 and 3.3.2, pp. 32-46

Exhibit B-1 of the FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application, pp. 363 and 367

Operating Data for FEI and FEVI

The following table is based on information provided by FEU in its 2012-2013 Revenue Requirements & Natural Gas Rates Application.

Line #	Mainland and Vancouver Island Services Activities, Unit Costs & Expenditures 2012-2013 Forecast				
1		2012 Forecast		2013 Forecast	
2		Mainland (a)	Vancouver Island (b)	Mainland (a)	Vancouver Island (b)
3	Net Customer Additions	6,656	2,557	6,923	2,656
4	Gross Customer	10,667	2,714	11,095	2,820
5	Ratio of Service Additions to Gross Customer Additions	0.72	0.81	0.72	0.81
6	Activities (risers or services)	7,677	2,187	7,985	2,272
7	Unit Costs ($ per service - riser)	$1,569	$2,252	$1,616	$2,320
8	Expenditures ($000's)	$12,044	$4,926	$12,903	$5,270

[1] Mainland data from Table 6.2-15, page 363, Exhibit B-1 of the FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application

[2] Vancouver Island data from Table 6.2-18, page 367, Exhibit B-1 of the FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application

38.1 Please confirm, or update otherwise, the above table is accurate.

Response:

The table above reflects the numbers filed in the original RRA dated May 4, 2011. The table was revised/updated on September 28, 2011. The changes were minor and are provided below:

	2012 Forecast		2013 Forecast	
	Mainland (a)	Vancouver Island (b)	Mainland (a)	Vancouver Island (b)
Net Customer Additions	6,656	2,557	6,923	2,658
Gross Customer Additions	10,672	2,715	11,100	2,823
Ratio of Service Additions to Gross Customer Additions	0.72	0.81	0.72	0.81
Activities (risers or services)	7,681	2,188	7,989	2,274
Unit Costs ($ per service - riser)	$ 1,569	$ 2,252	$ 1,616	$ 2,320
Expenditures ($000's)	$ 12,050	$ 4,927	$ 12,910	$ 5,276

38.2 Why are the Vancouver Island unit costs ($ per service – riser) higher than the Mainland unit costs? Please elaborate by detailing the costs for the main, service, and meter for each area.

Response:

The unit cost for Services is a blended services unit cost consisting of a variety of service types (including new services, conversion services, services off stubs, vertical subdivision services, etc.) installed in a variety of municipalities and ground conditions by both internal and external workforces. There are many variables which contribute to the overall blended services unit cost for FEI and FEVI.

The main reason the blended service unit costs in the 2012-2013 forecast are higher on Vancouver Island than on the Mainland are the higher proportion of conversion services on the Island. These are services where customers have chosen to replace an existing oil or propane system with a natural gas service. These types of services are generally located in mature neighborhoods, are done one at a time, and require pavement cutting and installation in fully landscaped yards as opposed to the relative ease of installing multiple new services in new subdivisions. The Mainland sees relatively few conversion services as natural gas has been available for a considerable period of time. The Island derives approximately one third of its new customers from conversion services which is a reflection of natural gas being made available to the Island in 1991.

Conversion services typically require a manual estimate from our planning group which necessitates a site visit. Island municipalities also have more onerous requirements (than Mainland municipalities) for the utilities including a pre-site inspection, permit requirement and a paving inspection.

Although the cost to install a service is higher on the Island, contributions continue to be required from the customer if the service cost exceeds the Service Line Cost Allowance ($1,535). This customer contribution appears in the CIAC – Services account which is not reflected in the FEVI service installation cost (i.e. the services unit costs is not net of the customer contribution; it is the cost to install the service excluding the contribution).

The cost to install the main and the meter are not included in the cost to install the service.

39.0 Reference: Ancillary Benefits of Facilitating Consistent Access to Service Offerings

Exhibit B-3, Section 6.5, pp. 116 – 122, section 6.8, p. 127

Access to Other Services

39.1 Please describe, separately for each of FEVI, FEW and Fort Nelson, the barriers, if any, that currently prevent FEU from introducing Customer Choice to the three regions.

Response:

The extension of Customer Choice is contingent upon commodity unbundling for FEVI, FEW and FEFN. Currently FEVI has an 'Energy Charge' that bundles together the delivery, midstream and commodity components. FEFN has a 'Cost of Gas' charge that bundles together the midstream and commodity components; and while FEW's charges are effectively unbundled, they are not reflected as such on the customer bill. These charges need to be unbundled to reflect the separate charge components, as it does for FEI. To execute this, commodity unbundling would entail rate configurations in the Customer Information Systemand bill print modifications to reflect the separate charge components on the billing statement.Lastly, it would be necessary to create margin related deferral accounts for FEVI and FEFN similar to FEI and FEW's MCRA and CCRA accounts. These new deferral accounts would need to replace the Gas Cost Variance Account and Gas Cost Reconciliation Account for FEVI and FEFN, respectively, to capture the variances between forecast and actual costs of the midstream and commodity separately. Until commodity unbundling is executed, the FEU would not be able to deploy Customer Choice to FEVI, FEW and FEFN.

Under amalgamation with common rates as proposed in this Application, FEVI, FEW and FEFN will adopt the same rate structure as FEI, and FEI and FEW's MCRA and CCRA accounts would be expanded to include both FEVI and FEFN. As a result, the Delivery, Midstream and Commodity costs will be unbundled for each of the regions. This will allow the FEU to deploy the Customer Choice program concurrently to all regions.

If amalgamation with common rates is not approved, the FEU would need to apply to the Commission for commodity unbundling and the extension of the existing ESM Model and respective business rules to each of the three regions (see response to BCUC IR 1.42.1 for reasons why the current Essential Service Model and respective business rules are required for the extension of Customer Choice to each of the three regions). As part of the unbundling process, the FEU would have to undergo the system and bill print changes discussed in BCUC IR 1.42.3. In addition, it would be necessary to create margin related deferral accounts for FEVI and FEFN (i.e., similar to FEI and FEW's MCRA and CCRA accounts) to capture the variances between forecast and actual costs of the midstream and commodity separately. Once commodity unbundling is completed and the system modifications executed, the FEU would be able to extend Customer Choice to FEVI, FEW and FEFN.

39.1.1 Please explain separately for each of the three areas how amalgamation addresses or overcomes these barriers.

Response:

Please see response to BCUC IR 1.39.1

39.1.2 Please describe alternatives to amalgamation that would facilitate the introduction of Customer Choice to each of the three areas.

Response:

Please see response to BCUC IR 1.39.1

39.1.3 What obstacles, if any, would having a common set of rate classes and structures (but with customer and or energy charges that reflect regional differences in the cost of service) present to the extension of the Customer Choice program to FEVI, FEW and FEFN?

Response:

If FEVI, FEW and FEFN had a common set of rate classes and a rate structure that unbundles the Delivery, Midstream and Commodity components, then the FEU may be able to deploy the Customer Choice program to FEVI, FEW and FEFN.

39.2 Please describe, separately for each of FEVI, FEW and Fort Nelson, the barriers, if any, that currently prevent FEU from introducing the extension of Biomethane service to the three regions.

Response:

In order to extend Biomethane service to the FEVI, FEW, and FEFN service regions under the current regulatory construct, the criteria identified within the FEI, then called Terasen Gas Inc., Biomethane Application dated June 8, 2010 (and approved pursuant to Commission Order No. G-194-10 and the accompanying Decision, both dated December 14, 2010), would have to be met for each region.

The table below provides an outline of the requirements that would have to be in place for each region in order to facilitate extension of Biomethane service to FEVI, FEW, and FEFN, based on the model currently in place for FEI. In the table, a checkmark has been used to denote those requirements that are not currently in place for the separate regions of FEVI, FEW, and FEFN (i.e. changes would be required).

Requirements to Extend Biomethane Service	FEVI	FEW	FEFN
Unbundling of Current Rate Structures • Separation of the currently bundled rates into delivery, commodity, and midstream components similar to FEI region. Although FEW gas costs are not currently unbundled into commodity and midstream components in the tariff, the underlying detail is currently available as the FEW and FEI gas supply portfolios were fully amalgamated effective January 1, 2010.	√		√
Regulatory Framework / Approvals • Expansion requires entity specific proposals and approvals related to the development of Biomethane supply projects within each region, the development of cost recovery mechanisms for program costs to be recovered from all non-bypass customers, and the development of new rate schedules and energy cost recovery mechanisms for the Biomethane costs to be recovered from those customers electing the Biomethane service offering.	√	√	√
IT and Billing System Improvements • Changes to infrastructure to support separation of the currently bundled customer bills to facilitate bill line items for delivery, commodity, and midstream components, as well as the Biomethane charges.	√	√	√

Requirements to Extend Biomethane Service	FEVI	FEW	FEFN
Customer Education • An enhanced customer education program would be required in each of the regions as customers within the FEVI, FEW, and FEFN regions currently have bundled rates – the customer education program would need to address the separation of the current rates into delivery, commodity, and midstream components, as well as communication of the new Biomethane service offering.	√	√	√

The FEI Biomethane Program model was based on the then existing FEI rates and customer bills already being fully unbundled into delivery, commodity, and midstream components for those customer classes that would be eligible for the Biomethane service offering. Currently, the FEVI, FEW, and FEFN rates and customer bills are not fully unbundled.

In order to offer Biomethane service in the FEVI, FEW, and FEFN service areas, each entity would have to develop supply projects within their specific region or, as an alternative approach, would develop a mechanism where FEI could sell Biomethane to the other FEU entities.

Based on the existing FEI model, the capital and O&M costs incurred to inject the Biomethane into the distribution system are associated with making the Biomethane service offering available to all customers within that service area and would be recovered from all non-bypass customers (as discussed in section 10.4 of the Biomethane Application dated June 8, 2010) via delivery margins that are entity specific today. The costs associated with making the Biomethane service offering available to customers in the FEVI, FEW, and FEFN service areas would require entity specific delivery margin related deferral accounts and cost recovery approvals.

The cost of the Biomethane from each supply project varies. Therefore, the costs associated with the energy supply for customers choosing the Biomethane service offering within a particular service area, based on the FEI model, would be recovered from those customers electing that offering via an entity specific Biomethane Energy Recovery Charge. FEVI, FEW, and FEFN would each require entity specific Biomethane energy cost deferral accounts and cost recovery approvals.

Further, the FEI Biomethane Program was approved on a test basis for a two year period, with an added criteria that limits the total production of Biomethane for all projects to 250,000 GJ per year during the test period and sets a maximum commodity price at $15.28 per GJ.

Thus while entity specific Biomethane programs could be implemented in any region, the FEI Biomethane Program, which so far has only been approved on a pilot basis, could be expanded to FEVI, FEW, and FEFN more effectively and efficiently under an amalgamated model with a common rate structure.

39.2.1 What obstacles, if any, would having a common set of rate classes and structures (but with customer and or energy charges that reflect regional differences in the cost of service) present to the extension of Biomethane service to FEVI, FEW and FEFN?

Response:

As reflected in the response to BCUC IR 1.39.2, there are a number of requirements that would need to be in place to facilitate extension of Biomethane service to FEVI, FEW, and FEFN, based on the model currently in place for FEI.

Having a common set of rate classes and structures would provide fully unbundled rates structures for all of the FEU regions, and it is expected that unbundled customer bills would also result. However, in the absence of Common Rates, the FEU would still be required to develop separate rate schedules (or riders) for each region to appropriately recover any costs that would be streamed to the various regions.

In the case of a common set of rate classes/structures with regional customer and/or energy charges, cost recovery mechanisms for capital and O&M costs, and recovery of costs associated with making the Biomethane program available including customer education program costs, would need to be developed in each region separately. Further, energy cost recovery mechanisms for the Biomethane costs to be recovered from those customers electing the Biomethane service offering (including any regional allocation of those energy costs) would need to be developed.

39.3 Please confirm that the EEC service offering is now available in FEI, FEVI, FEW and FEFN.

Response:

Confirmed. The following text is an excerpt from the Commission's Decision in the FEU's 2012 – 2013 Revenue Requirement Application:

"The Commission Panel believes the requests of the FEU are reasonable and approves the request to expand EEC program eligibility to interruptible industrial, FortisBC Energy (Whistler) Inc and FortisBC Energy Inc. Fort Nelson Service Area customers." (page 170)

The FEU sought further clarification from the Commission regarding eligibility for EEC funding of interruptible customers on FEVI, and eligibility of interruptible customers of FEVI for EEC funding was confirmed by the Commission on May 11, 2012.

40.0 Reference: Ancillary Benefits of Facilitating Consistent Access to Service Offerings

Exhibit B-3, Section 6.5.3, pp. 120-121, Section 6.8, p.127

LNG Service Extended to FEVI, FEW and Fort Nelson

"The benefits of CNG and LNG service can be extended throughout the larger transport market across British Columbia where distribution infrastructure already exists."

"…that among other things, the Provincial Government would work…to promote natural gas as a transportation fuel' and 'introducing a regulation under the *Clean Energy Act* to advance a proposed natural gas vehicle program'…"

40.1 Please describe, separately for each of FEVI, FEW and Fort Nelson, the barriers, if any, that currently prevent FEU from introducing the extension of CNG and LNG service to the three regions.

Response:

In the current regulatory constructs, separate rate schedules are required for CNG service to each of FEI, FEVI, FEW and FEFN. In the amalgamated regulatory construct, a singular rate schedule would be applicable for all regions of the FEU thus simplifying the administration, approvals and accounting of the services.

Under the current situation, delivery rates for FEVI and FEW customers are higher than delivery rates for FEI or FEFN customers. Potential CNG customers on the FEVI and FEW systems would therefore have to pay higher rates for the same CNG service. The FEU have encountered this situation in providing proposals to customers such as BC Transit. The result was that the CNG offering proposed for Nanaimo was significantly more expensive than a similar offering for Abbotsford.

With respect to the provision of CNG and LNG fueling station service, provision of these services is only presently permitted under FEI's tariffs, specifically under GT&C 12B. Thus, at present the FEU are not able to offer CNG or LNG fueling services to customers in FEVI, FEW or FEFN service territories.

Other than the tariff barriers listed above the FEU do not believe there are any non-regulatory barriers which currently prevent the FEU from introducing the extension of CNG and LNG service to all of the FEU's service territories. The provision of CNG service requires a connection from the customer's fueling station to the FEU's natural gas distribution system. Depending upon the customer's fueling station location, a new service line, a service line upgrade, main extension, or main extension upgrade may be required. FEVI, FEW and Fort

Nelson are capable of receiving this service in the same fashion that FEI's NGT customers already receive CNG service.

The provision of LNG service pursuant to FEI's GT&Cs 12B would require similar terms and conditions to be introduced to all regions. Under GT&C 12B, FEI installs and maintains a LNG fueling station and dispenses LNG to customers at the site. Amalgamation and postage stamp rates would make FEI's GT&Cs 12B applicable to all regions, thereby facilitating the expansion of the service.

At this time, the FEU have not made a final determination as to whether or not there are regulatory barriers to providing LNG supply under Rate Schedule 16 to the different service areas. The provision of FEI's Rate Schedule 16 LNG service is accomplished by the transport and delivery of LNG by tanker from FEI's Tilbury Island facility. At present, the Tilbury Island facility is the only location which can provide physical LNG supply to an LNG service customer. LNG delivery by road tanker to a fueling station may be performed by the FEU or another third party. Customers in the FEVI, FEW and Fort Nelson service areas may be capable of receiving this service in the same fashion that FEI's LNG customers already receive LNG service.

40.2 What obstacles, if any, would having a common set of rate classes and structures (but with customer and or energy charges that reflect regional differences in the cost of service) present to the extension the CNG and LNG service to FEVI, FEW and FEFN?

Response:

Having a common set of rate classes and structures does not present any obstacles to the extension of CNG and LNG service to the three regions. As described in the response to BCUC IR 1.40.1, there are no barriers from introducing the extension of CNG and LNG service to FEVI, FEW and FEFN, other than the CNG and LNG service offering itself.

Under amalgamation and postage stamp rates, CNG and LNG service agreements will continue to be executed with each individual company and will comply with the approved GT&C's 12B. Regional differences in the cost of LNG service may arise due to a customer's proximity to LNG supply from an LNG production facility. LNG service customers further from this facility may incur greater transport costs than those customers closer to LNG supply. Other regional differences reflected in the cost of service for CNG and LNG service may arise from the cost of materials and construction, property tax rates, and energy demand at each customer's CNG/LNG fueling station.

40.3 Please explain if there is any reason why the provision of Liquefied Natural Gas (LNG) fuelling service would be restricted to areas where the distribution infrastructure already exists.

Response:

LNG fueling service would not be restricted to areas where distribution infrastructure already exists. LNG service includes the transport and delivery of LNG by tanker from the FEU's LNG facility to the customer's fueling station (determined pursuant to Rate Schedule 16). Thus any LNG service customer across British Columbia could benefit from LNG supply through transport and delivery by tanker.

CNG service may be somewhat "restricted to areas where distribution infrastructure already exists". As discussed in the response to BCUC IR 1.40.1, CNG service requires a connection from the natural gas distribution system to the customer's fueling station facility. The transport and delivery of CNG via tube trailers may be a feasible option in certain situations.

40.4 Do FEU believe that the provision of a CNG fuelling service in these areas is dependent on amalgamation? If so, please explain. Does FEI General Terms and Conditions - Section 12B for LNG Service, restricts the location of the service offering, specifically the construction, ownership and operation of LNG fuelling stations by FEI, to FEI Service Areas.

Response:

The provision of a CNG or LNG fuelling service in FEVI, FEW and Fort Nelson is not dependent on amalgamation. As discussed in Section 6, page 116 of the Application, the expansion of service offerings could be achieved through entity specific proposals and approvals, however, amalgamation and the adoption of common rates facilitates and accelerates the process of extending Commission-approved service offerings to FEVI, FEW and Fort Nelson customers.

In its current form, FEI's GT&Cs – Section 12B does not restrict the location of CNG or LNG service offerings to FEI service areas, however, as Section 12B is part of the GT&Cs for FEI, the service area definitions page (Page D-6) applies and therefore restricts CNG and LNG service to the areas and surrounding areas defined within that part of the GT&Cs. However, the

FEU propose to amend the GT&Cs to remove this restriction. Please refer to Appendix B-1 of the Application for the proposed FEI Amalco GT&Cs that includes Fort Nelson, FEW and FEVI as service areas, thereby extending Section 12B to those service areas.

40.5 How will the proposed increased FEI NGT (previously NGV) rates, resulting from adoption of a postage stamp rate structure, affect the Provincial Government's initiative to promote natural gas as a transportation fuel referred to above? Please discuss.

Response:

The FEU expect adopting a postage stamp rate structure will have no significant impact, positively or negatively, on the Provincial Government's efforts to promote natural gas as a transportation fuel. The FEI rate schedules under which CNG service customers receive gas (e.g. Rate Schedule 6, 23, 25) are proposed to increase by approximately 3 to 5 percent as stated in this Application (Appendix J-3, at pages 6, 9 and 10). This increase will have an impact on the net CNG refueling price of approximately $0.01 per diesel litre equivalent increase.[39] The FEU do not expect this will materially impact the value proposition for CNG refueling within FEI. Conversely, prospective CNG customers within regions such as FEVI may benefit from common rate schedules. Overall FEU believes that there will be no material impact on the Provincial Government's initiative.

Similar to CNG service, the FEU do not expect any significant impact on common rates (e.g. Rate Schedule 16) for providing LNG service, positively or negatively, to the Provincial Government's initiatives. LNG charges under Rate Schedule 16 are impacted as a portion of the variable charge (transportation from Huntington to Tilbury is on based on the Rate Schedule 22 delivery charge).[40] However this impact is less than $0.01 per diesel litre equivalent, which the FEU do not expect will negatively impact the value proposition for LNG refueling.[41] FEI's forthcoming Rate Schedule 16 Application will provide further discussion on the components of the delivery charge under Rate Schedule 16.

39 For example, an increase under Rate Schedule 6 of $0.331 per GJ (Line 36 Page 6 of J-3, divided by conversion factor of 25.9) is equivalent to $0.013 diesel litre equivalent.

40 Please refer to FEI's 2009 Rate Schedule 16 Application at page 5 for discussion on Transportation from Huntington to Tilbury.

41 The increase to Rate Schedule 22 under an Amalgamated Rate is $0.145 per GJ (Appendix J-3, Page 8). Divided by the conversion factor of 25.9, this represents less than $0.01 per diesel litre equivalent.

The FEU are currently reviewing the broader implications of the Provincial Government's initiative for the FEU's natural gas for transportation strategy and will apply to the Commission for approvals in future applications as necessary.

40.5.1 Have the FEU conducted any directly related impact studies? If not, why not?

Response:

The FEU have not conducted any impact studies as adopting postage stamp rate classes for CNG and LNG service customers will not impede efforts to promote natural gas as a transportation fuel. The FEU are presently analyzing the broader implications of the new Provincial Government regulation.

41.0 Reference: Ancillary Benefits of Facilitating Consistent Access to Service Offerings

Exhibit B-3, Section 6.5.1, p. 117

Access to Other Services – Gas Marketer Interest in Expanding Customer Choice

41.1 Have marketers participating in the Customer Choice program expressed interest in expanding the Customer Choice program to Vancouver Island, Whistler or Fort Nelson?

Response:

The marketers participating in the Customer Choice program have expressed interest in expanding the Customer Choice program to the remaining FEU service areas, particularly to Vancouver Island, since Customer Choice was introduced to residential customers in 2007.

Continued interest was expressed at Annual General Meetings, first in 2010 at the request of Just Energy, and then in the 2012 at the request of Access Gas. While there is no official correspondence or reports that document this expression of interest, the topic of expanding the Customer Choice Program, particularly to Vancouver Island, was discussed in the aforementioned AGMs, which the Commission was a party to.

41.1.1 If so, which of the three areas have they expressed an interest in?

Response:

Please refer to the response to BCUC IR 1.41.1.

41.1.2. Please provide copies of any correspondence or reports that document this expression of interest.

Response:

Please refer to the response to BCUC IR 1.41.1.

42.0 Reference: Ancillary Benefits of Facilitating Consistent Access to Service Offerings

Exhibit B-3, Section 6.5.1, p. 117

Access to Other Services – Customer Choice Essential Services Model

"The business rules of the Customer Choice Program are defined by the Essential Services Model (ESM)."

42.1 To what extent is the extension of Customer Choice to FEVI, FEW and Fort Nelson dependent on the use of the same business rules as used to provide Customer Choice to FEI customers?

Response:

The extension of the Customer Choice Program to FEVI, FEW and Fort Nelson is dependent on the extension of both the current set of Customer Choice Business Rules in its entirety and the Essential Service Model ("ESM"). The FEU believe it would be imprudent and likely cost prohibitive to implement a different supply model and/or business rules for FEVI, FEW and Fort Nelson, especially given each region's relatively small market size. Given the Customer Choice program's maturity and the extensive IT infrastructure and systems already in place and operating smoothly, the FEU are of the opinion that extending existing business rules to these regions remains the best and only cost effective solution.

The ESM model and the associated business rules have served as the foundation of Customer Choice since the program's inception, and their adoption was a result of a formal regulatory process that included extensive consultation with interested parties. Due to the BC Province's limited transmission infrastructure, the ESM model was selected as the preferred approach to ensure that FEI can safely address potential or imminent commodity supply shortfalls. As such, FEI remains the supplier of last resort in the event of marketer failure. Most importantly, this safeguards customers from possible service disruptions.

Under the ESM, FEI maintains control of its underlying assets. FEI contracts for and manages midstream resources including pipeline and storage capacity, and provides balancing to support annual load shaping and peaking gas services. By utilizing midstream resources together with its distribution system assets, FEI can ensure the delivery of natural gas from regional supply/market hubs to a customer's premise regardless of supplier under the ESM. Additionally, FEI provides agency billing and collections services for marketers. Marketers benefit by receiving remittance on their monthly delivery requirements based on 100% load factor gas.

The business rules that were developed in conjunction with the ESM serve to ensure the longevity of the ESM model and to protect the customers who elected to purchase their commodity from an independent gas marketer. IT systems and infrastructure were developed and implemented that specifically support the ESM model and associated business rules.

To extend a supply model and business rules to FEVI, FEW and FEFN that is different than the ESM and business rules of the current program would be equivalent to introducing a new program to the aforementioned areas. Two Customer Choice programs would exist that could be incompatible in process, systems and design. Significant capital expenditures and effort would be necessary to design, develop and implement new program rules and IT systems and infrastructure. Moreover, additional administration costs would be incurred to manage the separate systems and business rules.

In summary, setting up a new program is likely cost prohibitive and not in the best interest of customers. For these reasons, the FEU are of the opinion that the extension of the Customer Choice Program to FEVI, FEW and Fort Nelson is dependent on the extension of both the current set of Customer Choice Business Rules and the Essential Service Model.

42.1.1 In FEU's view, should Customer Choice be extended to these areas if the business rules for Customer Choice are different from those established for FEI? Please provide reasons for the answer.

Response:

Please refer to the response to BCUC 1.42.1.

42.1.2 Are there some business rules that could be different or should be different for a Customer Choice program in each of FEVI, FEW and Fort Nelson? Please elaborate.

Response:

Please refer to the response to BCUC 1.42.1.

42.2 In FEU's view, is the extension of Customer Choice to each of FEVI, FEW and Fort Nelson dependent on the use of the Essential Services Model? Please provide reasons for the answer provided.

Response:

Please refer to the response to BCUC 1.42.1.

42.2.1 Would FEU consider extending Customer Choice to FEVI, FEW and Fort Nelson with a supply model different than the Essential Services Model currently employed to offer Customer Choice to FEI customers?

Response:

Please refer to the response to BCUC 1.42.1.

42.3 Does the new Customer Care system that was implemented January 1, 2012 support the expansion of Customer Choice to each of FEVI, FEW and Fort Nelson? Please describe any modifications that would be required and the estimated cost of these modifications.

Response:

The new Customer Care system that was implemented January 1, 2012 is scalable to support the expansion of Customer Choice to each of FEVI, FEW and FEFN.

As a first step, the FEVI, FEW and FEFN's rates need to be unbundled. A preliminary analysis of the system modifications required for commodity unbundling, which includes rate configuration and bill print changes is provided below. These changes are required to facilitate common rates, regardless of whether or not Customer Choice is extended to FEVI, FEW and FEFN.

The execution of system modifications involves:

1) Functional Tasks – technical resources that translate business requirements and facilitate the technical pieces of the business process change.
2) Advanced Business Application Programing (ABAP) – the technical programming changes to SAP at the code Level
3) Business Task – the business unit that defines the business requirements and process change and participates in user acceptance testing.

The preliminary analysis below provides a rough estimate of the number of days required as well as estimated costs to complete rate configuration and bill print changes for commodity unbundling.

Rate Configuration & Bill print changes: **Approximate Number of Days**

Item	Description of Effort	Functional	ABAP	Business
Analysis & Design	Gather requirements from business: how system should handle pro-ration scenarios, reversals & re-bills, any impacts to estimation process, bills across cutover etc.	30	0	10
Build - Rate Configuration	Configure changes: 1. if geographical rate categories still exist (40 Rate Classes): - 7 days for building rates & schemas - 0.25 x 40 = 10 days for price keys, rate cat facts, rate determination 2. if collapsed rate categories (4 Rate Classes): - 7 days for building rates & schemas - 0.25 x 4 = 1 day for price keys, rate cat facts, rate determination	17	0	0
Build - Custom program to handle block price/decimal issue	Create a custom program which allows decimal values and simulates SAPs block price function; ensure it can handle degree day proration.	12	18	5
Unit Test	Unit test: 1. if geographical rate categories still exist (40 RCs): - 1 x 40 = 40 days 2. if collapsed rate categories (4 RCs): - 1 x 4 = 4 days	40	0	5

Item	Description of Effort	Functional	ABAP	Business
Bill print changes	Includes build, unit test and user acceptance testing	30	23	15
Integration testing	Integration points: - bill print - reporting - FICA	10	0	0
User Acceptance Testing	Run test scripts through any business processes impacted; Enterprise Application Support and Delivery department to support user acceptance testing	7	0	15
Regression test Bill to Invoice to Print	Coordinate meter read upload for various areas and rates; run batch processing; run print processing. Review output (samples from various rate categories).	10	0	5
		Functional	**ABAP**	**Business**
Total Approximate number of days by Subcategory		**126**	**41**	**45**
Estimated Cost by Subcategory		**\$100,800**	**\$32,800**	**\$19,300**
Total Estimated Costs for Rate Configuration and Bill Print Changes		**\$152,900**		

Once the rate configuration and bill print changes are completed, the extension of the Customer Choice program would require modest modification to the Customer Choice Modules. The preliminary analysis below provides a rough estimate of the number of days required, as well as estimated costs to complete the changes to the Customer Choice Function modules for the extension of Customer Choice to FEVI, FEW and FEFN. These costs and modifications are specific to the extension of Customer Choice under amalgamation.

Changes to Customer Choice Function Modules: Approximate Number of Days

Item	Description of Effort	Functional	ABAP	Business
Build - Changes to Function Modules	Change Function Modules to accept Customer Choice enrolments for all regions	0	4	0
Unit Test	Unit test: 1. Test enrolments in 'new' regions 2. Test of enrolments in existing regions 3. Test of portability in existing regions / new regions / between regions 4. Test of extracts, reports and letters	10	0	5

Item	Description of Effort	Functional	ABAP	Business
Integration testing	Integration testing of the Customer Choice systems applications and servers.	10	0	5
UAT Testing	Run test scripts through any business processes impacted; Enterprise Application Support and Delivery department to support user acceptance testing	5	0	15
		Functional	**ABAP**	**Business**
Total Approximate number of days by Subcategory		**25**	**4**	**25**
Estimated Cost by Subcategory		**$20,000**	**$3,200**	**$10,700**
Total Estimated Costs for Changes to Customer Choice Function Modules		**$33,900**		

The modifications and costs described above for rate configuration, bill print changes and changes to customer choice function modules for commodity unbundling and the extension of Customer Choice to FEVI, FEW and FEFN are based on a preliminary analysis. While the above analyses are a good indication of the effort required, the actual modifications and costs required may vary.

43.0 Reference: Ancillary Benefits of Facilitating Consistent Access to Service Offerings

Exhibit B-3, Section 6.5.1, p. 117

Access to Other Services – Customer Choice Education

43.1 Do FEU anticipate that any additional customer education will be required to expand Customer Choice to FEVI, FEW and Fort Nelson?

Response:

Customer education will be required to expand the Customer Choice Program to eligible customers of FEVI, FEW and Fort Nelson. The FEU believe the nature of the Customer Education plan should be consistent with the communication plan objectives approved in Commission Order G-181-08. In general, the communication plan should:

1) Educate customers on the new rate structure in general, particularly with respect to the different components of the bill relevant to Transportation Service and Customer Choice since the rate structures for FEVI, FEW and FEFN currently differ markedly from that of FEI.

2) Inform eligible gas customers that there is a value distinction between a variable rate and a fixed rate for the gas commodity;

3) Provide customers with information concerning the issues they could consider to determine which rate plan represents best value in their circumstances;

4) Identify the gas commodity marketplace as a competitive market and provide information on where and how the various product offerings may be compared; and

5) Communicate the consumer protection policies in place to actively mitigate customer complaints to the Commission.

The costs associated with the Customer Education Plan would depend on the desired audience reach (i.e., the percentage of customers that are exposed to the communication), frequency of advertising, and the type of media selected. Currently, the Commission approved Customer Education Costs for 2012 are $300,000, and include the use of bill inserts, radio ads, cost comparison newspaper ads and bill messaging. These costs, however, are incurred to maintain existing levels of consumer awareness and understanding about Customer Choice, rather than the more difficult task of introducing a new product. Increased communication costs would be incurred to introduce the program to customers in FEVI, FEW and FEFN.

Consistent with current and past practice, the FEU expect all Customer Choice communication costs to be recovered from all eligible customers. At this time, the FEU have not yet assessed the communication requirements associated with a roll-out of Customer Choice to these additional markets. Rather, the FEU believe the specifics of the Customer Education Plan for the FEVI, FEW and FEFN roll out should be determined in a separate regulatory filing for the Customer Choice Program following a decision on Amalgamation.

43.1.1 If so, what is the anticipated nature and cost of the additional customer education?

Response:

Please refer to the response to BCUC IR 1.43.1.

43.1.2 How will these costs be recovered?

Response:

Please refer to the response to BCUC IR 1.43.1.

43.1.3 If FEU do not anticipate the need for additional customer education, please explain.

Response

Please refer to the response to BCUC IR 1.43.1.

43.2 With the opening of new areas to Customer Choice, do FEU anticipate that new marketers who are not currently operating in British Columbia will take this opportunity to enter the marketplace?

Response:

The FEU cannot comment on the intentions of new marketers who are not currently operating in British Columbia. However, the opening of new areas to Customer Choice may represent an expanded business opportunity for gas marketers compared to what currently exists. This opportunity is available to those currently operating both inside and outside BC.

43.2.1 What training or administrative costs are incurred by FEI when a new marketer enters the Customer Choice marketplace? Who bears these costs?

Response:

The system and program infrastructure in place for the Customer Choice Program is scalable to accommodate the entrance of new marketers with little training and/or administrative costs. Upon request, FEU Customer Choice staff provide existing and new gas marketers with technical assistance. However, these and any other administrative costs incurred when setting up a new gas marketer are recovered from gas marketer fees. .

44.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 6.5.2, p. 120

Transportation Service to Be Uniform - Entity Specific Changes

"although expansion could be achieved through entity specific changes, proposals and approvals, amalgamation and the adoption of common rates will facilitate and accelerate the process of providing a uniform Transportation Service across all regions."

44.1 How many industrial or commercial customers have expressed an interest in transportation service in any service area?

Response:

The FEU have spoken with numerous customers over the years but have not tracked the number of customers that have expressed an interest in transportation service across the various service areas. FEI's current transportation service offering has been successful and could be used as a proxy for estimating the interest in other service areas. For example, approximately 20% of customers that are eligible for service under Rate Schedule 3 (Large Commercial) currently take service under Rate Schedule 23 (Large Commercial Transportation). Similarly, almost 70% of eligible Rate Schedule 5 (General Firm Service) customers take service under Rate Schedule 25 (General Firm Transportation Service). Further, 96% of our customers who have elected small volume Interruptible service have chosen Rate Schedule 27 (General Interruptible Transportation Service) instead of Rate Schedule 7 (General Interruptible Service). Finally, customers who have elected service under Rate Schedule 22 (Large Volume Transportation), Rate Schedule 22A (Transportation Service [closed] Inland) and Rate Schedule 22B (Transportation Service [closed] Columbia) do not have a bundled equivalent service offering from FEI and therefore 100% of these customers receive transportation service. The FEU anticipate that over time customers in other service areas will similarly elect to take transportation service if the FEU are able to provide uniform transportation service across all regions.

44.2 How many industrial customers are there in the Fort Nelson Service Area?

Response:

Currently there are only two industrial customers in Fort Nelson. Both customers take transportation service under FEFN's only transportation service offering (Rate Schedule 25) instead of Rate Schedules 3.1, 3.2 or 3.3. Both of these sites are closed and currently utilizing natural gas for space heat only. There are approximately 30 other customers in FEFN that have an annual consumption exceeding 2,000 GJ annually and therefore these customers would meet FEI's current minimum criteria for transportation service under Rate Schedule 23 if uniform transportation service was provided across all regions.

44.3 How many customers does FEVI have with annual consumption greater than 6,000 GJ?

Response:

FEVI has approximately 135 customers with an annual consumption greater than 6,000 GJ and an additional 650 customers that would have an annual consumption from 2,000 to 6,000 GJ. FEVI would therefore have approximately 785 customers that would qualify for transportation service based upon FEI's current minimum criteria for transportation service if a uniform transportation service was provided to FEVI.

44.4 What barriers exist, if any, to offering transportation service to FEW customers?

Response:

Please refer to the response to BCUC IR 1.44.5.

44.5 Separately, for each of FEVI, FEW and Fort Nelson, please describe, in the absence of amalgamation, the entity specific changes, proposals and approvals that would be required to introduce additional transportation service options to these customers.

Response:

The table below provides an outline of the requirements to offer transportation service and uses a checkmark to denote those requirements that are currently not met for FEVI, FEW and FEFN (i.e. changes would be required).

Requirements to Extend Transportation Service	FEVI	FEW	FEFN
Unbundling of appropriate rate structures • Separate Energy charge per GJ to delivery and commodity costs per GJ	√	×	√
Rate Design • Develop appropriate number of transportation service offerings in each entity	√	√	√
Regulatory Framework / Approvals • Expansion requires entity specific proposals and approvals of the new rate classes	√	√	√
IT and Billing Improvements • Changes to infrastructure to support and invoice transportation service offerings	√	√	√
Customer & Gas Marketer Education	√	√	√

45.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 6.5.3, pp. 120-121

Supply of LNG for LNG Service

"Under General Terms and Conditions 12B, FEI customers benefit from the increased system throughput resulting from NGT volumes, while the forecast cost of service associated with the fueling stations is recovered from NGT customers through a take-or-pay contract."

45.1 Please confirm that the "increased system throughput" associated with LNG Service currently flows through Rate Schedule 16 which provides LNG supply from the Tilbury peak shaving plant located on the FEI system. If this is not confirmed, please elaborate.

Response:

Confirmed. Increased system throughput from LNG fueling service volumes generates incremental Rate Schedule 16 revenues to the benefit of all FEI customers. Please refer to the response to BCUC IR 1.45.4 for a breakdown of gross and net revenues under Rate Schedule 16.

45.2 Please confirm that there are currently only two sources of LNG supply available in British Columbia: the Tilbury peak shaving plant on the FEI system and the Mt. Hayes peak shaving plant on the FEVI system. If this is not confirmed, please elaborate.

Response:

Confirmed. Tilbury and Mt. Hayes Storage Facilities are currently the only two sources of LNG supply available in British Columbia.

45.3 Please confirm that the Mt. Hayes facility does not currently have truck loading facilities and would require an investment in additional infrastructure in order for this facility to supply LNG similar to the Rate Schedule 16 LNG supply from the Tilbury facility. If this is not confirmed, please elaborate.

Response:

The Mt. Hayes Storage Facility currently does not have an LNG truck loading facility and would require capital investment in additional infrastructure in order to make LNG available for NGT customers.

On May 14, 2012, the Provincial Government passed the Greenhouse Gas Reduction (Clean Energy) Regulation (the "GHG Regulation"), which prescribes undertakings for the purpose of Section 18 of the Clean Energy Act. The GHG Regulation permits public utility companies, including the FEU, to invest up to $104.5 million on fueling infrastructure, helping develop heavy-duty fleets to adopt natural gas as a transportation fuel. The GHG regulation includes a specific provision which authorizes the FEU to spend up to $4 million on a truck loading facility. In a future application to the Commission, the FEU intend to seek the requisite approval of the investment in a truck loading facility at Mt. Hayes.

45.4 Please quantify the gross revenues and the net revenues, on a per GJ basis, that flow to FEI core natural gas ratepayers under current Rate Schedule 16 rates.

Response:

Under the current Rate Schedule 16, gross revenues that flow to FEI core natural gas ratepayers are $3.96 per GJ (2011 variable charge as stated in the tariff). This rate has been updated to $4.05 per GJ for 2012 and was filed with the Commission for endorsement on May 15, 2012. The remainder of this response uses the 2011 approved rate of $3.96 per GJ to explain the net revenues under current Rate Schedule 16.

The Rate Schedule 16 variable charge is broken down into the following components:

	Approved January 1, 2011 Rate
O&M Charge - Liquefaction, Storage & Dispensing	$ 1.98
Capital Recovery	1.11
Transportation from Huntingdon to Tilbury	0.79
Peaking Arrangement Cost	0.08
Total Variable Charge	$ 3.96

In the CNG/LNG Service Application proceeding (BCUC IR 2.25.2) FEI had previously characterized the net revenues (also referred to as delivery margin benefit) under Rate Schedule 16 as approximately 48 percent of the total variable charge. Using the 2009 approved rate of $3.73 per GJ, the analysis illustrated the incremental cost associated with increased production of LNG at Tilbury of $1.95 per GJ. Using the rates in table above, this approach yields net revenues of 50 percent ($1.98/$3.96). However this approach is limited in its depth and accuracy. The approach does not consider the actual volume of LNG currently consumed by the LNG service customers or the incremental cost of adding production and liquefaction for transport customers. Furthermore the underlying O&M charge for liquefaction, storage & dispensing reflects 2008 actual costs.

The following analysis shows the FEU’s refined methodology which more accurately reflects the actual net revenue benefits under the current Rate Schedule 16. A similar methodology was used in the 2009 Rate Schedule 16 Application at Appendix 3.

Under this methodology, the FEU calculated the total annual O&M for liquefaction and storage using the 2011 actual costs. Table 1 below shows a cost of $1.82 million is required to meet core demand of 340,000 GJ of liquefaction during 2011.

Table 1: Baseline Tilbury Liquefaction and Storage O&M Costs
Baseline = 248,000 GJ of core LNG plus boil off = 340,000 GJ

Cost Elements	Total Costs	Liquefaction	Storage	Vaporization
M&E labor	1,751	613	876	263
COPE Labor	170,000	59,500	85,000	25,500
IBEW Labor	968,401	338,940	484,200	145,260
Total Labor Costs	**1,140,152**	**399,053**	**570,076**	**171,023**
Vehicle costs	12,235	4,282	6,117	1,835
Employee Expenses	10,000	3,500	5,000	1,500

Cost Elements	Total Costs	Liquefaction	Storage	Vaporization
Materials	65,442	39,265	19,633	6,544
Office Furn & Equi	873	305	436	131
Computer Costs	151	53	76	23
Total Fees & Admin Costs	33,359	11,676	16,680	5,004
Contractors costs	155,075	93,045	46,523	15,508
Facilities	7,577	2,652	3,789	1,137
Recoveries & Reven	0	0	0	0
Non-Labour Costs	**284,713**	**154,779**	**98,253**	**31,681**
Total	**1,424,865**	**553,832**	**668,329**	**202,704**

Own used Gas	52,540	17,940	5,800	28,800
Electricity	339,100	204,000	116,400	18,700
Total	**1,816,505**	**775,772**	**790,529**	**250,204**

Using this information, the O&M cost at Tilbury on a per GJ basis to serve core customers is $1,816,505/340,000 GJ which equates to $5.34 per GJ. This cost of $5.34 per GJ represents the O&M cost for core market application in the absence of sales volumes generated by NGT customers such as Vedder Transport.

The variable charge under Rate Schedule 16 was originally calculated by adding the estimated incremental O&M costs to meet the core baseline with the estimated incremental O&M costs to meet demand of 1,040 GJ per GJ as approved in Rate Schedule 16. This produces a Baseline + 1 Tanker per Day scenario which can be divided over the total demand. The 2011 costs associated with this scenario are shown below.

Table 2: Baseline + 1 Tanker per Day Tilbury Liquefaction and Storage O&M Costs
Baseline + 1 Tanker = 340,000 GJ of core plus 380,000 of transport = 720,000 GJ

Cost elements	Total costs	Liquefaction	Storage	Vaporization
M&E labor	1,751	613	876	263
COPE Labor	170,000	59,500	85,000	25,500
IBEW Labor	968,401	338,940	484,200	145,260
IBEW Labor (additional)	22,400	22,400		
Total Labor Costs	**1,162,552**	**421,453**	**570,076**	**171,023**
Vehicle costs	12,235	4,282	6,117	1,835
Employee Expenses	10,000	3,500	5,000	1,500
Materials	65,442	39,265	19,633	6,544

Cost elements	Total costs	Liquefaction	Storage	Vaporization
Materials (additional)	21,902	21,902		
Office Furn & Equi	873	305	436	131
Computer Costs	151	53	76	23
Total Fees & Admin Costs	33,359	11,676	16,680	5,004
Contractors costs	155,075	93,045	46,523	15,508
Facilities	7,577	2,652	3,789	1,137
Recoveries & Reven	0	0	0	0
Non-Labour Costs	**306,615**	**176,681**	**98,253**	**31,681**
Total	1,469,167	598,134	668,329	202,704

Own used Gas	52,540	17,940	5,800	28,800
Own used Gas (additional)	21,415	21,415		
Electricity*	362,905	218,321	124,571	20,013
Electricity (additional)	237,665	237,665		
Total	**2,143,691**	**1,093,474**	**798,700**	**251,517**

Using the costs from both Tables 1 and 2, the incremental O&M cost to serve LNG transport customers is $2,143,691 less the base costs of $1,815,505 = $328,186. Thus 380,000 GJ of load addition has an incremental O&M cost of $0.86 per GJ. The addition of the 380,000 GJ of LNG transport load also reduces the average O&M costs from $5.34 per GJ to $2.98 per GJ ($2,143,692/720,000 GJ).

Using the 2011 Rate Schedule 16 variable charge of $3.96 per GJ, the incremental benefit to all natural gas ratepayers is $3.96 less $0.86, or $3.10 per GJ. In other terms, the benefit represents 78 percent of the 2011 variable charge rather than the 50 percent expressed under the previous methodology.

A more complete analysis will be included in FEI's forthcoming proposed amendments to Rate Schedule 16 Application. This application will address issues regarding cost allocation between the core market application and the commercial LNG market application in the context of determining a revised Rate Schedule 16 rate for expected future growth in Rate Schedule 16 volumes. In sum, the addition of incremental LNG load can be done with low incremental costs which are to the benefit of the overall system.

46.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 7.4.3, pp. 141-143; 2012-2013 RRA, Exhibit B-9, pp.122-124

Separate Gas Supply Portfolios

In Section 7.4.3 of the Application, the FEU state:

"The FEU are seeking approval for a combined natural gas procurement portfolio as part of this Application. Combining the current separate gas procurement portfolios and the associated policies and rate constructs as part of the amalgamation will provide a consequential benefit to customers. The potential benefits of a single gas procurement portfolio include greater operational effectiveness, expanded contracting flexibility, and regulatory efficiency. While the Company anticipates a number of benefits from the creation of a single combined portfolio, this change is not expected to provide immediate cost savings in any material way. This change however, will allow the Company to optimize the portfolio so that cost savings can be realized over the longer term. The benefits expected from the creation of a single combined portfolio are reviewed below in greater detail.

In the event that the amalgamation is not approved, FEI and FEVI would continue to maintain separate gas supply portfolios."

FEU go on to list the benefits in more detail in section 7.4.3.1. (Exhibit B-3 of the Amalgamation Application, pp.141-143)

In the FEU 2012-2013 Revenue Requirements proceeding (2012-2013 RRA),[42] in response to BCUC IR 1.38.3 which requested FEU confirm that it intended to proceed with the amalgamation of the FEI and FEVI gas procurement portfolios regardless whether or not the full amalgamation of the utilities proceeds, FEU responded that "FEU are proposing to proceed with the amalgamation of the gas portfolios regardless of the decision on full amalgamation. Please refer to the response to BCUC IR 1.38.6 for a description of the benefits of moving to a single gas portfolio. It is FEU's view that these benefits would be realized whether or not full amalgamation of the Utilities proceeds. 2012-2013 FEU RRA." The benefits detailed in the response to BCUC IR 1.38.6 appear to be the same ones quoted in more detail on pages 142 of the Amalgamation Application. (2012-2013 RRA, Exhibit B-9, BCUC 1.38.3 – 1.38.6)

[42] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28091_B-9_FEU%20Rsp%20to%20BCUC%20IR-No1.pdf

46.1 Please explain why FEU have changed its view on the matter of proceeding with amalgamation of the gas portfolios regardless of whether full amalgamation proceeds, particularly given FEU's response to BCUC IR 1.38.3 in the recent Revenue Requirement Proceeding that indicates that there are benefits to be achieved through amalgamation of the gas portfolios that are not dependent on full amalgamation.

Response:

As described in the preamble to this question, the FEU initially indicated in the FEU 2012-2013 RRA that it intended to proceed with amalgamation of the gas portfolios in either scenario. However the FEU changed their view prior to the conclusion of the FEU 2012-2013 RRA proceeding. This change in position was provided in responses to second round BCUC information requests in the FEU 2012-2013 RRA proceeding (see Exhibit B-17, responses to BCUC IRs 2.11.3.1, 2.11.4.1, and 2.11.4.5).

This change in view was largely driven by the impact of the Commission's Decision set out in Order No. G-120-11 dated July 12, 2011, regarding the FEI 2011 Price Risk Management Plan ("PRMP") and the FEU Review of Price Risk Management Objectives and Hedging Strategy. In this Decision the Commission, among other items, did not agree that the need to manage the competitiveness of natural gas with other energy sources as an objective of the PRMP had been established. The Commission also determined that a number of strategies the Company proposed to use to help manage natural gas price volatility were not appropriate at this time. However, the Commission did indicate that it would consider hedging proposals on behalf of ratepayers in the future if there was a change in market conditions.

This Decision has effectively narrowed the tools the Company assumed it had immediately available to manage gas commodity costs and help address the unique challenges for FEVI. It is for these reasons that the Company reconsidered its assumptions under which conditions it is reasonable to pursue the establishment of a single combined gas portfolio.

This change in view was communicated to the Commission in the FEVI letter dated August 4, 2011 in which FEVI withdrew its 2012-2013 hedging request. FEVI had submitted this request to the Commission on June 23, 2011 to help mitigate FEVI's cost and competitiveness challenges with the expiry of the royalty revenue arrangement at the end of 2011 and in consideration of the favourable market gas price environment.

The FEU now believe that that it is appropriate to maintain separate gas portfolios if full amalgamation with common rates does not proceed. In the absence of common rates, separate gas portfolios will need to be maintained in order to give FEVI more flexibility to propose different price risk management strategies that take into account the unique circumstances of the utility. This could, for example, include a different hedging strategy or physical resource portfolio (perhaps including more storage) for FEVI.

Furthermore, the FEU may also consider rate structures for FEVI that are different than those for FEI if legal amalgamation with common rates is not approved. While FEI currently reviews commodity rates on a quarterly basis, FEVI uses a bundled variable rate including delivery, midstream, and commodity costs and rates have been held constant under the rate freeze mechanism for a number of years. This has enabled FEVI to help manage costs and rate volatility given FEVI's higher cost structure and competitiveness challenge.

46.1.1 If there are cost savings that can be realized over the longer term, please explain why FEU would not wish to combine the gas supply portfolios.

Response:

Cost savings or other benefits may be realized from an amalgamated gas portfolio over the longer term through further optimization of the resources in response to changing market conditions and availability of storage and pipeline transportation capacity. However, the cost savings or other benefits are not expected to be material in the immediate term as the management of the portfolios is already combined and the portfolios are already derived from a similar pool of resources. Furthermore, at this time, FEVI does not believe that these benefits would outweigh the impacts of reduced flexibility to manage the gas portfolios and any related price risk management activities in response to FEVI's unique circumstances. As a result, at this time the FEU do not believe it is prudent to combine the gas supply portfolios if legal amalgamation with common rates is not approved. Please refer to the discussion in the response to BCUC IR 1.46.1.

47.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 7.4.3.1, p. 142

Fort Nelson Gas Supply

"Operational Effectiveness

The total pool of available resources can be more effectively utilized within a single portfolio in order to better manage the total system load on a daily basis."

47.1 Describe the portfolio of resources, including any third party transportation or storage utilized to meet the daily load requirements of Fort Nelson.

Response:

To meet the daily load requirements of Fort Nelson, FEI uses commodity supply and third party transportation services. Gas supply is sourced by FEI from a producer at the outlet of the Fort Nelson gas processing plant for delivery to customers in Fort Nelson. FEI also contracts for third party transportation capacity from Westcoast Energy Inc. ("Westcoast") on its T-North system in order to move gas supply each day from the plant's outlet for delivery to the town.

FEI contracts commodity supply for Fort Nelson with a producer who is one of the qualified counterparties that FEI uses for its overall gas supply requirements. Because of the strong and long term supply relationship with this producer, FEI is able to contract separately for firm term supply to Fort Nelson on favourable and flexible terms for its daily requirements. This relationship enables secure, flexible, and cost effective supply to Fort Nelson's customers.

From an operational perspective, FEI schedules the required amount of gas supply with the supplier and the pipeline each day based on forecast load requirements for the next day. FEI's unique arrangement with the producer, and the relatively small volume compared to FEI's overall supply portfolio, enables FEI to take only what it requires based on the next day's load forecast for Fort Nelson rather than taking 100% of the contracted quantity each day. Most firm term gas supply contracts require the seller to deliver and the purchaser to take the full quantity of supply that is contracted under the terms of a deal on a daily basis.

Any excess or shortfall in gas supply based on the town's demand for the actual gas day is managed via a balancing agreement that FEI has with Westcoast that governs imbalances related to the total T-North transportation capacity FEI holds in its overall portfolio. FEI and Westcoast then settle the cumulative imbalance due to over-or-under deliveries over the course of the month in order to manage imbalances on a timely basis.

47.1.1 Are these resources different than those that have been contracted for to meet the Fort Nelson peak day design load requirement? If so, please explain.

Response:

No, the resources are not different. The nature of the resources described in the response to BCUC IR 1.47.1 also provide enough flexibility for FEI to meet Fort Nelson's peak day design load as part of its overall portfolio.

47.2 Is any portion of the FEI and FEVI on-system storage resources (i.e. Tilbury and Mt Hayes) currently allocated to meet the peak day design load requirement of Fort Nelson? I f so, please provide the quantities.

Response:

No portion of Tilbury and Mt. Hayes LNG is currently specifically allocated to serve Fort Nelson. However, in certain situations, these resources provide a benefit to customers located in Fort Nelson because they are part of a diversified portfolio that is flexible enough to provide service during an emergency or critical event.

As discussed in the response to BCUC IR 1.47.1.1, FEI contracts for resources based on the regional needs across its diverse system. The resources of FEI are designed to provide security of supply and diversity in the portfolio while minimizing the costs of the total portfolio. As a result, the supply of gas during cold and peak weather conditions required in the FEU's large operating region is provided by a variety of resources located in various places.

Although Tilbury and Mt. Hayes LNG do not directly provide supply for the town of Fort Nelson, they can be used to ensure that supply is available there via other means. An example would be if the Fort Nelson gas plant had an upset or outage during the winter months and it is only able to provide very limited gas supply during that period to producers. In such a situation, the producers would only allocate a portion of required volumes to each of their customers. This situation could lead to a scenario whereby a producer is unable to provide the full scheduled quantity of gas to Fort Nelson. However, FEI has other contracted gas supply that it purchases at the outlet of the Fort Nelson gas plant for delivery to its other regions, such as the Lower Mainland. Therefore, it has the ability to redirect an appropriate level of supply to Fort Nelson that minimizes the likelihood of delivery cuts to the town. Subsequently, FEI would use supply from Tilbury and Mt. Hayes LNG as alternate resources for the customers of the Lower Mainland. It is by this means that Tilbury and Mt. Hayes LNG could be employed to assist the town of Fort Nelson during an emergency or critical event. This method of substituting gas supply from one point to another point is known as displacement. Other resources such as gas purchased in Alberta or storage resources such as seasonal and market area contracted by FEI can also be used via displacement to serve the other regions of FEI including Fort Nelson during certain situations.

FEI has employed the Tilbury plant to provide supply during upstream outages in the winter months, which has aided in maintaining the integrity of our own and third-party pipeline systems that interconnect with the FEI system. The availability of Mt. Hayes LNG has further strengthened the ability of FEI to manage and balance its various load centres during critical winter periods and emergencies. FEI's diversified portfolio of resources has the ability to provide reliable service to all customers, including customers that are located in smaller and remote areas like Fort Nelson.

47.2.1 Have these resources ever been utilized to meet the daily load requirement of Fort Nelson customers?

Response:

Yes. FEI's total pool of resources is used collectively as required in order to manage the total daily load for FEI, which includes Fort Nelson. The total pool of resources and contracting with a diverse set of counterparties enable the reliable and safe delivery of gas to all customers on the system.

Please also refer to the response to BCUC IR 1.47.2 for additional information.

47.3 Where does FEI take delivery of gas supply that is contracted for Fort Nelson customers?

Response:

FEI takes delivery of gas supply that is contracted for Fort Nelson's customers at the Fort Nelson gas plant outlet.

Please also refer to the response to BCUC IR 1.47.1.

47.4 Describe how the supply is currently balanced to the daily load requirements of Fort Nelson customers.

Response:

Please refer to the response to BCUC IR 1.47.1.

47.5 Are daily nominations required by the interconnecting pipeline to meet load balancing requirements for Fort Nelson?

Response:

Yes. Please also refer to the response to BCUC IR 1.47.1.

47.5.1 Are intra-day nomination cycles available and/or employed to meet load balancing requirements for Fort Nelson?

Response:

Yes, intraday nominations are available for Fort Nelson; however, intraday fluctuations between supply and demand are managed by FEI via its balancing agreement with Westcoast.

Please also refer to the response to BCUC IR 1.47.1.

47.6 If Fort Nelson were to be supplied from a single portfolio, please describe how, from an operational perspective, resources beyond those currently employed to meet the Fort Nelson daily load requirement could be utilized and how this would be more efficient than current practices.

Response:

There would no change to the contracting practices since FEI already optimizes its total pool of resources as a single portfolio on a total regional level that includes Fort Nelson. As a result Fort Nelson customers are already benefiting from being part of FEI's overall portfolio. For example, as discussed in the response to BCUC 1.47.1, the customers in Fort Nelson currently benefit from FEI supplier relationships that allow for the contracting of a unique and flexible supply arrangement and from the ability to manage intraday fluctuations via FEI's balancing agreement on Westcoast's T-North System.

47.7 Please describe the specific operational efficiencies achieved by combining the Fort Nelson supply portfolio into the total pool of resources.

Response:

Please refer to the responses to BCUC IRs 1.47.1 and 1.47.6.

47.8 Please describe any other benefits or cost savings specifically achieved by combining the Fort Nelson supply portfolio into the total pool of resources.

Response:

FEI already optimizes its portfolio by combining the Fort Nelson requirements into its total pool of resources. However, Fort Nelson's commodity rates are derived from an allocation of certain costs of the overall portfolio. As part of this Application, the FEU are seeking to apply common commodity and midstream rates across all its service areas. Although the adoption of common rates by Fort Nelson will not in itself result in additional benefits to the overall gas portfolio, it does more appropriately recognize the benefits that Fort Nelson customers already receive by being part of the overall FEI portfolio and contracting activities. Please also refer to the responses to BCUC IRs 1.47.1, 1.47.2, and 1.47.6.

48.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 7.4.3.2, p.143

Price Risk Management

"Price risk management includes activities that mitigate the impact of market price volatility on customers' commodity rates."

48.1 Is managing market price volatility the only objective of FEU's price risk management activities? If not, please describe the other objectives.

Response:

The primary objective of the FEU's price risk management activities is to cost effectively reduce the impact of market price volatility on customers' rates. These activities include mitigating the risk of regional price disconnections, which primarily involves managing Sumas price spikes that can occur during peak winter demand periods. The FEU also consider the ability of its price risk management activities to help maintain competiveness of natural gas rates with other sources of energy given the circumstances of the utility and external market conditions. This is particularly important for FEVI, which faces more of a challenge due to its higher cost structure. While full amalgamation with common rates would help with this challenge, price risk management activities could also help in this regard.

48.2 Describe the price risk management activities and/or Price Risk Management Plans currently approved by the Commission for FEI and FEVI, respectively.

Response:

The Commission has approved a number of rate stabilization mechanisms for FEI and FEVI to use that play a role in managing natural gas price volatility. These mechanisms include the Price Risk Management Plans ("PRMP"), gas cost deferral accounts and rate setting mechanisms, the Annual Contracting Plans, and the Customer Choice Program. In addition, the Equal Payment Plan is also available to customers as a bill smoothing mechanism.

For FEI, price risk management includes the use of a PRMP that allows for the implementation of Sumas/AECO basis swaps per the FEI 2011 PRMP, which help mitigate Sumas price disconnections during peak winter demand. FEI also uses a commodity deferral account and quarterly rate adjustment mechanism to help manage the recovery of forecast commodity costs on a 12-month prospective basis, including any incurred commodity cost variances to the end of the current period, from customers. The commodity deferral account essentially captures the differences between the actual gas costs incurred and the forecast gas costs embedded in the commodity recovery rate, with these resultant deferral balances to be recovered from, or refunded to, customers through future commodity rates. In this way, the commodity deferral account and quarterly rate adjustment mechanism provide some commodity rate stability by smoothing/deferring the impact of commodity market volatility on gas costs over the current/future prospective 12-month periods. With regard to midstream costs, a midstream deferral account and rate setting mechanism is in place; the midstream rates, under normal circumstances, are typically adjusted on an annual basis using a January 1 effective date and year end midstream deferral balances are recovered from, or refunded to, customers over the following three year period, which contributes to stability in the FEI midstream rate.

For FEVI, the bundled variable rate has been held constant under the rate freeze mechanism for a number of years; the FEVI bundled rate includes the delivery, commodity, and midstream cost components of rates and has not be subject to quarterly gas cost flow throughs. This approach has enabled FEVI to help manage costs and rate volatility. In recent years, due to the royalty revenue arrangement and lower commodity prices, this structure has also enabled FEVI to accumulate surpluses in the Rate Stabilization Deferral Account ("RSDA").

For both FEI and FEVI, Annual Contracting Plans ("ACP") also help mitigate the impact of market price volatility. The ACPs outline the commodity, transportation and storage resources required to meet the load requirements of core customers. By contracting for a diverse mix of resources, including both daily and monthly priced commodity supply and storage capacity at several different facilities, FEI and FEVI are able to cost effectively mitigate supply disruptions and constraints, and adverse market price movements.

There are also other mechanisms available to customers for mitigating market price volatility and its impacts on rates. They include the Customer Choice Program for FEI customers, where customers can choose to purchase their commodity supply from a Gas Marketer at a fixed rate for up to five years. Although not a true price risk management mechanism, both FEI and FEVI customers are able to participate in the Equal Payment Plan, which allows them to smooth out their monthly gas bills over a twelve month period.

In past years, in addition to the activities described above, FEI and FEVI had engaged in more comprehensive hedging activities as proposed to and approved by the Commission. However, following a regulatory review process in 2011, these hedging activities have been suspended, with the exception of the Sumas/AECO basis swaps. However, the FEU may in the future propose new hedging strategies in response to market conditions, customer preferences and/or unique circumstances of the different entities.

48.3 Please describe any differences between the price risk management objectives currently employed for FEVI versus FEI.

Response:

The price risk management objectives currently employed for FEI and FEVI are the same; however, the strategies employed may be different depending on the unique circumstances of the different utilities and external conditions at the time. For example, as the cost challenge is greater for FEVI if legal amalgamation with common rates is not approved, different price risk management strategies and activities may need to be developed and used by FEVI. Please also refer to the response to BCUC IR 1.48.1.

48.4 Do FEU envision any differences in the price risk management objectives or activities that would be employed for FEVI and/or FEI if legal amalgamation is not approved as proposed versus the case where legal amalgamation is approved? Please explain.

Response:

The FEU believe that the same price risk management objectives apply to FEI and FEVI regardless of whether or not full amalgamation is approved. However, different price risk management activities may be required to meet these objectives if common rates are not approved and would support the maintenance of separate gas portfolios.

In the case where legal amalgamation with common rates is approved, the FEU would employ a single price risk management plan for the FEU. Price risk management activities may include hedging and other alternatives, such as fixed price purchases, that the FEU are currently exploring in light of the Commission's Decision set out in Order No. G-120-11 dated July 12, 2011 regarding the FEU Review of Price Risk Management Objectives and Hedging Strategy.

If legal amalgamation with common rates is not approved, it is likely that FEVI would need to employ different price risk management activities to help address FEVI's unique cost challenges. These activities could include, for example, greater amounts of hedging, storage, or fixed price purchases compared to FEI (as a proportion of total load requirements).

48.5 In the case where legal amalgamation is not approved, do FEU envision any differences in the price risk management objectives or activities that would be employed for FEVI and/or FEI if the FEVI and FEI gas supply procurement portfolios were amalgamated versus the case the FEI and FEVI gas supply portfolios were not amalgamated? Please explain.

Response:

As discussed in the response to BCUC IR 1.46.1, the FEU believe that it is appropriate to maintain separate gas portfolios if amalgamation with common rates does not proceed. To be clear, the FEU are not proposing to amalgamate gas portfolios if legal amalgamation with common rates is not approved.

In the absence of amalgamation with common rates, FEVI's customers will continue to have much higher rates for gas service and face increasing costs due to the discontinuation of the royalty arrangement with the Province of B.C. Maintaining separate gas portfolios in this circumstance will provide FEVI more flexibility to use different price risk management strategies, or tools, to manage natural gas commodity costs that take into account the unique circumstances of the utility. If the gas portfolios were amalgamated in the absence of common rates across the FEU, FEVI would have fewer tools and reduced flexibility to manage these cost pressures.

49.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 7.4.3.1, p.142

Gas Supply Mitigation Incentive Program

"The resource base eligible for the incentive mechanism will increase under an amalgamated entity but this should have no impact on the overall mitigation strategy."

49.1 If the amalgamation will not have any impact on the overall mitigation strategy, does this mean that FEVI has been mitigating the FEVI gas portfolio as effectively as FEI has mitigated the FEI gas portfolio but without the need for an incentive? Please explain.

Response:

FEI has in the past, and continues today, to optimize the gas supply portfolio of resources on behalf of all FEU customers. Although the FEU maintain two distinct natural gas portfolios, from an operational perspective FEI manages the FEU's total natural gas supply portfolio of resources, including mitigation activities, on a combined portfolio basis. The costs associated with the FEVI gas supply resources and an allocation of mitigation revenue generated by the FEU's optimization of the combined set of resources are accounted for in FEVI's total cost of gas. Although FEVI customers benefit from FEI's mitigation activities, the mitigation incentive model currently approved does not include the mitigation revenues allocated to FEVI in the Gas Supply Mitigation Incentive Program ("GSMIP") calculation.

As part of FEI's July 2010 application for a revised incentive program beginning in November 2010, FEI requested that that all mitigation revenue be included in the GSMIP calculation, including the consideration of mitigation revenue allocated to FEVI. However, in its decision, the Commission did not approve the proposed plan and instead directed that the 2009/10 program be extended for one more year and that the Company undertake a consultative review with stakeholders, including Commission staff, to develop a new program beginning in November 2011. By that time, it was generally known that the FEU would be seeking to amalgamate the gas utilities and therefore it was agreed that development of the new GSMIP program would be limited to FEI until such time a decision on amalgamation was known.

49.1.1 If FEVI has not been mitigating as effectively as FEI, to what extent were FEVI's portfolio resources not mitigated due to the lack of an incentive mechanism? Please quantify to the extent possible.

Response:

Please refer to the response to BCUC IR 1.49.1.

50.0 Reference: A Combined Approach to Gas Supply

Exhibit A2-18, p.2

FEVI GCVA 2011 Status Report - FEVI Cost of Gas in 2011

50.1 Please confirm that the FEVI Gas Cost Variance Account (GCVA) recorded a pre-tax surplus balance of $10.2521 million and an after-tax surplus balance of $7.5353 million at the end of 2011. If not confirmed, please provide the correct figures.

Response:

Confirmed.

50.2 Please confirm that the Royalty Credit recorded into the FEVI GCVA for 2011 was $17,315.50 with an adjustment of a debit of $2,012.7 for 2010 resulting in a net Royalty Credit of $15,302.90. If not confirmed, please provide the correct figures.

Response:

Confirmed.

50.2.1 Please explain the nature of the adjustment of the debit for 2012.

Response:

The royalty adjustment is the result of the annual reconciliation of royalty revenue, which is the difference between the aggregate royalty revenue of each quarter of the applicable calendar year and the aggregate quarterly amounts paid by the Province of British Columbia (the "Province"). In June of each year, FEVI provides the Province with a statement setting out the Weighted Average Annual Price for the preceding year (based on the Provincial Gas Production Report that FEVI normally receives in early to mid-June from the Province), and a recalculation of royalty revenue determined by multiplying the deemed volume of gas set forth in the Vancouver Island Natural Gas Pipeline Agreement by the Weighted Average Annual Wellhead

Price for such year. If the recalculation of the royalty revenue, as shown on the statement, is less than or greater than the aggregate quarterly payments of the royalty revenue made by the Province to FEVI, then an adjustment payment will be made by FEVI or the Province, as the case may be.

The 2010 royalty adjustment, calculated and paid in June 2011, was a payment by FEVI to the Province.

Calendar 2011 was the last year of the royalty credit arrangement with the Province and the 2011 royalty adjustment is expected to be calculated and settled in June 2012.

50.3 Please confirm that the actual recorded Weighted Average Cost of Gas for FEVI in 2011 before the Royalty Credit was applied was $5.8388 per GJ. If not confirmed, please provide the correct figure.

Response:

Confirmed.

50.4 Please confirm that the weighted average cost of gas for FEVI in 2011 after the application of the 2011 Royalty Credit was $4.4588 per GJ. If not confirmed, please provide the correct figure.

Response:

The recorded weighted average Royalty Adjusted Cost of Gas ("RACOG") for 2011 was $4.6192 per GJ. The recorded weighted average RACOG for 2011 includes the royalty revenues received in 2011, as well as the royalty adjustment calculated and paid in 2011 but related to the prior year.

Please refer to the response to BCUC IR 1.50.2.1 for further discussion related to the calculation and payment of the prior year royalty adjustment.

50.5 Please confirm that the royalty credit received by FEVI for 2011 was the equivalent of $1.38 on a per GJ basis. If not confirmed, please provide the correct figure.

Response:

The total royalty revenues received by FEVI in 2011 includes the royalty adjustment calculated and paid in 2011 but related to the prior year. Accordingly, FEVI expects a royalty adjustment related to 2011 will be determined in June 2012; however, the value of that adjustment is not known at this time. Thus, the value of the royalty revenues received by FEVI during 2011, including the 2010 adjustment FEVI paid to the Province in June 2011, was the equivalent of $1.22 per GJ of total sales volumes.

Please refer to the response to BCUC IR 1.50.2.1 for further discussion related to the calculation and payment of the prior year royalty adjustment.

50.6 Based on the Core Market rate approved for 2011 for FEVI ,and the data reported in the Gas Cost Variance Account 2011 Status Report, please break the rate for a typical residential customer into the following components on a per GJ basis: delivery margin, weighted average cost of gas, royalty credit and revenue surplus.

Response:

Please refer to the table below which provides the 2011 approved rate, including the approved Royalty Adjusted Cost of Gas ("RACOG"), broken down into the requested components. Please note that this provides an approximation only and may not be representative of the actual components of the rate if the Energy Charge were to be unbundled.

Approximate Components of FEVI Residential Energy Charge

Line	Particulars		2011 Approved
1	Basic Charge per Month	$	10.50
2			
3	Delivery Margin	$	9.352
4	Weighted Average Cost of Gas	$	8.631
5	Royalty Credit	$	(3.225)
6	Revenue Surplus (Deficiency)	$	(0.434)
7	Energy Charge ($/GJ)	$	14.325

The variance between the approved 2011 RACOG of $5.407/GJ ($8.631 less $3.225) and the actual 2011 RACOG of $4.619/GJ, as reported in the FEVI 2011 Gas Cost Variance Account ("GCVA") Status Report, was captured in the GCVA deferral account as an addition in 2011. This addition has been amortized through 2012 FEVI rates, as a component of the delivery margin.

51.0 Reference: A Combined Approach to Gas Supply

Exhibit A2-17, Cover letter, p.1, FEVI 2012 First Quarter Report, p. 5,

FEVI 2012 First Quarter GCVA and RDSA Report - Breakdown of FEVI Rate for 2012

"Based on the five-day average of the February 13, 14, 15, 16, and 17, 2012 forward prices for natural gas, the annual outlook indicates that the GCVA is forecast to be at a surplus balance of approximately $6.2 million before tax at year end December 31, 2012 while the revenue forecast is forecast to be approximately $5.5 million after tax." (Exhibit A2-17, Cover Letter, p. 1)

51.1 Please confirm that the 2012 outlook for the weighted average cost of gas for FEVI is $5.81 per GJ based on the information presented in the 2012 First Quarter Report.

Response:

Confirmed, the 2012 outlook for the weighted average cost of gas for FEVI was calculated at approximately $5.81 per GJ based on the information presented in the FEVI 2012 First Quarter Report on the GCVA and RSDA (the "2012 First Quarter Report").

Further, as noted in the 2012 First Quarter Report, the forecast December 31, 2012 GCVA surplus balance was calculated utilizing an approved cost of gas based on the forecast of gas costs for 2012 included in the updated FEVI financial schedules submitted on October 11, 2011 as Undertaking No. 24 (Exhibit B-52) of the FEU 2012-2013 RRA.

On May 1, 2012 the FEU filed revised financial schedules, which included updated 2012 and 2013 forecast cost of gas for FEVI, to comply with the modifications directed pursuant to the Commission Decision on the 2012-2013 RRA, issued concurrently with Commission Order No. G-44-12. The 2012 approved weighted average cost of gas for use in calculating the GCVA has now been set at approximately $5.78 per GJ, and will be reflected in the 2012 outlook that will be provided in the FEVI 2012 Second Quarter Report on the GCVA and RSDA, due to be filed in early June.

51.2 Please confirm that there is no royalty credit projected for 2012.

Response:

Confirmed, the Royalty Rebate arrangement under which FEVI received royalty revenues from the Province expired on December 31, 2011 and no royalty revenues have been forecast for 2012.

However, as described in the response to BCUC IR 1.50.2.1, a true-up adjustment related to the prior year's royalty revenues is typically calculated, based on the Provincial Gas Production Report, and settled in June of the following year – FEVI expects an adjustment related to the 2011 royalty revenues will be determined in June 2012 but, at this time, does not know whether it will be a debit or a credit adjustment.

51.3 Based on the Core Market rate currently approved for FEVI, and the data reported in the 2012 First Quarter Report on the Gas Cost Variance Account and the Rate Stabilization Deferral Account, please break down the rate for a typical FEI residential customer into the following components on a per GJ basis: weighted average cost of gas, delivery margin and projected revenue surplus.

Response:

The FEU interpret this question to be asking for the rate for a typical FEVI Residential customer and not a typical FEI residential customer as noted in the question.

Please refer to the table below which provides the currently approved FEVI residential rate, and which includes the annual outlook for the Weighted Average Cost of Gas ("WACOG") as reported in the 2012 First Quarter Report on the Gas Cost Variance Account and the Rate Stabilization Deferral Account, broken down into the requested components. Please note that this provides an approximation only and may not be representative of the actual components of the rate if the Energy Charge were to be unbundled.

Approximate Components of FEVI Residential Energy Charge

Line	Particulars	2012	Reference
1	Basic Charge per Day	$ 0.3450	
2			
3	Delivery Margin	$ 9.352	Rate freeze; equal to 2011 approved
4	Weighted Average Cost of Gas	5.806	2012 FEVI Q1 Gas Cost Report
5	Royalty Credit	-	Not applicable for 2012; 2011 true-up expected in June
6	Revenue Surplus (Deficiency)	(0.834)	Line 7- (Line 3 + Line 4 + Line 5)
7	Energy Charge ($/GJ)	$ 14.325	

52.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 9.6.2.4 pp.204-205, 212; Exhibit A2-16, RS16 2011 Annual Report, pp.1-3

Classification of Tilbury Storage Function

"<u>Classification of Tilbury Storage Function</u>

The Tilbury LNG Storage Facility (Tilbury) was designed and constructed between 1969 and 1971. Since its commissioning in 1971, Tilbury has been in operation providing important system capacity to meet loads on the coastal transmission system during extreme winter peaking events. In this way, Tilbury primarily provides benefits related to security of supply, reliability and flexibility to serve loads within FEI"s system during extreme events and by mitigating potential temporary operational issues associated with pipeline infrastructure supplying FEI's customers.

On June 4, 2009, the Commission issued Order No. G-65-09 approving Rate Schedule 16, which allows FEI to make liquid natural gas (LNG) available to customers so as to allow the adoption of this fuel for emerging markets, such as transportation applications. Under this service, FEI utilizes LNG supply from Tilbury for transport applications. FEI is also assessing how Tilbury can be further utilized for expanded transportation applications.

The Tilbury LNG Storage facility was included as a function in the FEI's 1993, 1996 and 2001 rate design applications. The Tilbury function was consistently classified as demand-related in each of those proceedings. For the purposes of this Application, the FEU have maintained this classification approach for the Amalgamated Entity COSA." (Exhibit B-3, pp.204-205)

"Tilbury is primarily a peaking resource providing critical system capacity during extreme winter peaking events and provides system reliability and security of supply benefits. In the 2001 RDA, the total cost of service associated with Tilbury was included in the delivery margin and allocated based on peak day demand. All firm customers were allocated costs associated with Tilbury based on peak demand since all customers benefit from the peaking and operational flexibility that Tilbury provides. This approach was accepted by the Commission and was a simple, easy to understand approach that appropriately allocated costs to those customers who benefit from Tilbury.

As discussed in section 9.6.2.4, Tilbury is also used to provide LNG supply under Rate 16 and FEI is currently assessing ways to further utilize the facility for transportation applications. Any future filings related to the expanding the uses of the Tilbury facility will address any associated cost allocation considerations at that time. For the purposes of this Application, however, FEU believes that it is appropriate to continue to use the allocation approach currently in place."

52.1 In the past 12 years, please list each of the times that the Tilbury Storage facility has been used to provide peaking gas supply. Please provide dates and quantities for each event.

Response:

The following table sets out the volumes that FEI withdrew from Tilbury LNG storage over the last 12 years to help manage cold weather events.

Year	Gas Day	Withdrawal GJs
2000	Sunday, December 10, 2000	8,732
2001	Wednesday, February 07, 2001	52,900
	Thursday, February 15, 2001	16,275
2003	Monday, February 24, 2003	90,204
	Tuesday, February 25, 2003	36,698
	Friday, March 07, 2003	20,350
	Sunday, March 09, 2003	29,082
	Tuesday, November 04, 2003	5,894
2004	Saturday, January 03, 2004	96,559
	Sunday, January 04, 2004	86,493
	Monday, January 05, 2004	121,178
	Tuesday, January 06, 2004	44,993
2005	Friday, January 14, 2005	41,452
	Saturday, January 15, 2005	75,263
2006	Monday, November 27, 2006	18,337
	Tuesday, November 28, 2006	32,599
2009	Thursday, February 26, 2009	26,171

Year	Gas Day	Withdrawal GJs
	Friday, February 27, 2009	10,934
	Monday, March 09, 2009	63,112
	Tuesday, March 10, 2009	28,451
	Wednesday, March 11, 2009	31,653
2010	Monday, November 22, 2010	85,717
2012	Tuesday, January 17, 2012	26,591
	Wednesday, January 18, 2012	8,298

In the Rate Schedule 16 2011 Annual Report FEI states: "Over the past year FEI reached significant milestones in the provision of LNG for transportation applications. During 2011 FEI contracted with three customers for LNG sales under Rate Schedule 16. ….

Despite the notable growth during 2011, inherent limitations associated with Rate Schedule 16 exist. In order to further LNG sales and accommodate high demand customers such as BC Ferries, FEI intends to file an application with proposed amendments to Rate Schedule 16 in the coming months." (Exhibit A2-16, pp. 1-3)

52.2 Please describe the "inherent limitations associated with Rate Schedule 16" that restrict FEI's ability to further develop the natural gas vehicle (NGV) transportation market.

Response:

A few of the inherent limitations associated with Rate Schedule 16 are summarized at a high level below:

1) The categorization of Rate Schedule 16 as a "pilot" and the expiry of Rate Schedule 16 effective on December 31, 2014 is a factor that limits the ability to sell LNG for transportation applications. Customers investing in LNG vehicles require a long term

service option and need to have the confidence that LNG will be available to service their needs. In FEI's experience, the designation of the Rate Schedule 16 as a pilot implies to some customers a temporary service that could be revoked, leaving them with facilities and vehicles that cannot be used cost-effectively and without nearby supply redundancy.

2) Rate Schedule 16's volume cap of 1,040 GJ per day limits FEI's ability to attract new LNG service customers. FEI's only LNG service customer, Vedder Transport, is contracted through Rate Schedule 16 for 11,500 GJs of LNG per month, which calculates to approximately 36 percent of the present volume cap. Vedder has indicated an intention to increase its volume commitment to around 14,600 GJ per month, or 46 percent of the volume cap. LNG sales to other LNG customers such as Westport Power and Encana Corporation also represent a portion of this cap. Rate Schedule 16's limitation on availability of LNG supply means FEI could only contract with one more trucking fleet with similar or lower fuel demand than Vedder.

3) Rate Schedule 16 as an interruptible service is an impediment to growing the LNG for transportation as the nearest current alternative for LNG supply is in Portland, Oregon (Northwest Natural Gas peak shaving facility). The Mt. Hayes Storage facility could also become a source of LNG supply for transportation if a truck loading facility is added. Customers are concerned about the potential limitation in supply, but recognize that actual supply interruptions have been very limited and may be mitigated to a limited extent by the customer's on-site supply of LNG in the fueling facility.

The constraints associated with Rate Schedule 16 are not limited to the three issues described above. These and potentially others will be detailed in a future application to the Commission.

52.3 Please elaborate on the nature of the amendments that FEI will be applying for in the coming months. If the amendments include increasing the daily volume limitation, please quantity the daily volume limitation FEI intends to propose.

Response:

At this time, FEI foresees proposed amendments to Rate Schedule 16 which may include the following:

- Transition from "pilot" to "permanent" status and to amend the service offering from an Interruptible offering to a Firm Service offering;

- Expand the volume cap that is in place for shipments from the Tilbury LNG facility;
    - FEI is presently analyzing the impacts of a volume increase under different scenarios. The analysis will be fully explained in FEI's Rate Schedule 16 application.
- Establish LNG supply from Mt. Hayes;
- Establish terms of service and rate treatment for supply of LNG under Rate Schedule 16;
- Allocate a portion of the available LNG storage capacity at both Tilbury and Mt. Hayes to service the LNG transport market;
- Adding an optional feature whereby customers may receive LNG transport and delivery services utilizing FEI tank trailers (as directed by the Commission in Order No. G-144-11); and
- Adding the option for a Rate Schedule 16 customer to receive biomethane commodity supply as part of their commodity choice.

52.4 When does FEI expect to file the subject Rate Schedule 16 application?

Response:

At this time, FEI expects to file an application for proposed amendments to Rate Schedule 16 in the third quarter of 2012.

52.5 Please provide a table similar to Table 1 of the Rate Schedule 16 Pilot Program 2011 Annual Report (Exhibit A2-16, p. 2)showing the customers and sales volumes to date in 2012.

Response:

The table below shows current LNG customers and LNG sales volumes from January through April 2012.

Customer	Total Contract Demand (GJ/month)	2012 Sales Volume (GJ)	2012 LNG Delivery Sales (@ $3.96/GJ)	2012 LNG Commodity Sales ($)	Total Sales ($)
Encana Corporation	spot supply	-	0	0	0
Vedder Transport	11,500	26,148	103,546	62,209	165,755
Westport Power	spot supply	2,737	10,839	6,508	17,347
Total	11,500	28,885	114,385	68,717	183,102

The sales volume of 28,885 GJ shown in the above table represents approximately 23% of the volume cap available under Rate Schedule 16.

52.6 Please explain why FEU have not proposed any modifications to the functionalization, classification and allocation of the Tilbury Storage facility costs in light of the significant milestones that have been reached to date in the use of the facility for the provision of LNG for transportation use through Rate Schedule 16.

Response:

Tilbury has been used to supply LNG for transport applications under Rate Schedule 16 as well as for other end uses (e.g., Adams Lake Mill). Over the past few years FEI reached significant milestones in the provision of LNG for transportation applications and the company anticipates the LNG market to continue to grow and evolve in coming years. FEI believes that it will be appropriate to evaluate the rate design methodology of the Tilbury storage facility at the time specific applications are made for expansion of Rate Schedule 16 service or expansion of the facility itself.

52.7 Please describe the nature of the impact that the provision of significant quantities of LNG under Rate Schedule 16 would be expected to have on the functionalization, classification and allocation for the Tilbury Storage facility with respect to Rate Schedule 16 customers and with respect to core natural gas customers.

Response:

The provision of significant quantities of LNG under Rate Schedule 16 has no impact to the rate design methodology of Tilbury facility and costs allocated to core natural gas customers as long as the costs and revenues associated to serve customers under Rate Schedule 16 are allocated in the same manner as proposed in the Application.

Also, as mentioned in the response to BCUC IR 1.52.6, the FEU are proposing to make no changes to the current rate design treatment of Tilbury storage facility. Any future filings related to expanding the uses of the Tilbury facility and the Mt. Hayes facility will address any associated cost allocation considerations at that time.

The FEU are currently assessing how the Tilbury and Mt. Hayes storage facilities can be further utilized for expanding the LNG transport applications without impacting the core natural gas customers.

52.8 Does FEI intend to reserve any portion of the Tilbury Storage tank capacity or the current Tilbury liquefaction capability for use by the NGV transportation market?

Response:

As indicated in the response to BCUC IR 1.52.3, FEI will be proposing to allocate a portion of the existing Tilbury Storage tank capacity for buffer against variability in supply and demand for LNG transport customers. This buffer storage would help alleviate any supply concerns from LNG customers while preserving the ability of the system to perform its primary function of peaking and emergency backup service.

FEI will also be proposing to increase the amount of available liquefaction capability at Tilbury for use by the NGT market. FEI is presently analyzing various scenarios which will be presented in the forthcoming Rate Schedule 16 Application.

52.8.1 If so, please provide the anticipated storage capacity and liquefaction capability to be reserved.

Response:

As discussed in the response to BCUC IR 1.52.3, FEI is presently analyzing the impacts of utilizing additional storage capacity and liquefaction capability under different scenarios. The analysis will be described in FEI's Rate Schedule 16 application.

52.8.2 Please explain how the reservation of a portion of the Tilbury capacity and capability for NGV transportation use or for other LNG emerging markets would impact the Amalgamated Entity COSA?

Response:

Please refer to the response to BCUC IR 1.52.7.

52.9 How does the Tilbury LNG peaking facility serve Fort Nelson customers?

Response:

The ability of Tilbury LNG to serve Fort Nelson customers is discussed in the response to BCUC IR 1.47.2.

53.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 9.6.2.4 p. 205

Classification of Mt. Hayes Storage Function

"Classification of Mt. Hayes Storage Function

The Mt. Hayes LNG Storage Facility (Mt. Hayes) was successfully brought into service in 2011. Mt. Hayes provides system capacity for FEVI and a peaking gas storage resource as part of the FEVI and FEI gas supply portfolios. Mt. Hayes also improves the overall system reliability in the event of transmission system or upstream outages. The FEU also are currently assessing how the Mt. Hayes storage facility can also be utilized to offer LNG service for emerging markets including transport applications.

Since the Mt. Hayes storage facility has recently been added as a new asset in FEVI's rate base, the FEU are treating Mt. Hayes as a separate function in order to assess cost allocation alternatives. The FEU believe that it is appropriate to classify the Mt. Hayes storage function as demand-related at this time. EES Consulting has reviewed the Mt. Hayes LNG Storage facility classification methodology and believes it to be reasonable."

53.1 Since the Mt. Hayes facility came into service in 2011, please describe the times that the facility has been used to provide either system capacity and/or peaking gas supply. Please provide dates, quantities and identify whether the use was for system capacity or peaking gas supply purposes.

Response:

Since the Mt. Hayes facility was ready for use starting November 2011, FEI has called on it one time to provide peaking gas supply. This occurred on Wednesday, January 18, 2012, when 24,512 GJs were required to manage colder than normal weather to meet Core load requirements.

53.2 When do FEU anticipate that the Mt. Hayes storage facility would be needed to provide LNG service for emerging markets?

Response:

The FEU are currently assessing how the use of both Mt Hayes and Tilbury can be optimized on an integrated basis to support the NGT and other markets without impacting the use of the facilities to meet the requirements of existing customers. It is anticipated that the use of Mt. Hayes would be required as soon as is practical. This will be fully examined in the forthcoming Rate Schedule 16 Application proceeding.

53.3 What facility modifications are required at the Mt. Hayes Storage Facility to accommodate its utilization to offer "LNG service for emerging markets including transportation applications"?

Response:

Mt. Hayes requires a truck loading facility similar to Tilbury's truck loading facility to offer LNG service. This will enable the physical supply of LNG by tanker truck to NGT customers and emerging markets. The FEU estimate the capital cost of this facility will be between $3 and $4 million. The FEU are presently analyzing the impact of the Greenhouse Gas Reduction regulation and its provision for an investment in a truck loading facility, as described in the response to BCUC IR 1.45.3.

53.4 Would the utilization of Mt. Hayes to offer LNG service for emerging markets be provided through a Rate Schedule similar to FEI Rate Schedule 16?

Response:

Yes, the FEU intend to include Mt. Hayes as an additional supply facility of LNG service for NGT customers and emerging markets and would propose amendments to Rate Schedule 16 to reflect that. A more detailed discussion on the use of Mt. Hayes will be provided in the future Rate Schedule 16 Application.

53.5 Does FEI intend to reserve any portion of the Mt. Hayes Storage tank capacity or the liquefaction capability for use by the NGV transportation market?

Response:

As indicated in the response to BCUC IR 1.52.3, as part of its forthcoming Rate Schedule 16 application FEI will be proposing to allocate a portion of the existing Mt. Hayes Storage tank capacity for buffer against variability in supply and demand for LNG transport customers. This buffer storage would help alleviate any supply concerns from LNG customers while preserving the ability of the system to perform its primary function of peaking and emergency backup service.

FEI will also be proposing that available liquefaction capability at Mt. Hayes be used to support the NGT market. FEI is presently analyzing various scenarios which will be presented in the Rate Schedule 16 Application.

53.5.1 If so, please provide the anticipated storage capacity and liquefaction capability to be reserved.

Response:

As discussed in the response to BCUC IR 1.52.3, FEI is presently still analyzing the impacts of adding storage capacity and liquefaction capability under different scenarios. The analysis will be fully explained in FEI's Rate Schedule 16 application. The FEU believe that the requirements from Mt. Hayes for NGT customers have no bearing on the current application and such matters can be fully explored in the Rate Schedule 16 Application to be filed later this year.

53.5.2 If so, also describe the impact on the Amalgamated Entity COSA.

Response:

Based on the proposed treatment of customers served under Rate Schedule 16, there will be no impact on the Amalgamated Entity COSA even with the Mt. Hayes storage facility being utilized to offer LNG service for emerging markets including transport applications. This is because the proposed COSA allocates costs associated with the storage facility and revenues generated from Rate Schedule 16 customers in the same manner without negatively impacting other natural gas customers

53.6 How does the Mt. Hayes LNG storage facility serve Fort Nelson customers?

<u>Response:</u>

The ability of Mt. Hayes LNG to serve Fort Nelson customers is discussed in the response to BCUC IR 1.47.2.

54.0 Reference: A Combined Approach to Gas Supply

Exhibit B-3, Section 9.6.2.5, pp. 212 – 216

Exhibit B-3-1, Appendix D-1, p. 13

Exhibit A-2-22, TGVI and TGI Mt. Hayes LNG Storage Facility Application, June 2007, p. 99

Exhibit A-2-23, TGI 2010 Long Term Resource Plan, pp. 135, 137

Exhibit A-2-24, Reasons for Decision attached to G-139-07 (Approval of long term service agreement with BC Hydro), p. 2

Allocation of Mt. Hayes LNG Storage Facility

"FEVI owns and operates the Mt Hayes facility as part of its overall system and provides storage and delivery services to FEI pursuant to the terms of a long-term storage and delivery agreement (the "Storage and Delivery Agreement"). The facility provides transmission system capacity benefits to FEVI, and also provides a peaking gas storage resource that is included in the gas supply portfolios of both FEVI and FEI. The current cost allocation methodology effectively allocates costs to both delivery and cost of gas for FEVI and to cost of gas for FEI." (Section 9.6.2.5, p. 212)

"The underlying cost causation for Tilbury and Mt. Hayes differs from wholesale storage as they are used to provide storage to meet short-term peaking needs, to provide reliability in the event of transmission outages, to offset the need for additional transmission facilities, and to assist with balancing daily customer needs of natural gas. These functions are available for both the core sales and transportation customers of the FEU and are therefore appropriate to include in the delivery margin for all customers, with the exception of the portion of Mt Hayes assigned to the midstream function. For that reason, the costs are classified on the basis of demand, consistent with past practice." (Appendix D-1, p. 13)

54.1 To what extent does the Mt. Hayes LNG storage facility offset the need for additional transmission facilities to serve Mainland customers?

<u>Response:</u>

With the Mt. Hayes facility available to provide on-system supply to FEVI during peak demand periods, FEVI's transport requirements across the Coastal Transmission System ("CTS") are reduced. In addition, the delivery of FEI's peaking supplies from the Mt. Hayes Facility, largely through displacement, further reduces physical transport requirements to FEVI across the CTS. In this way, the Mt. Hayes facility effectively provides up to 150 mmcfd of additional CTS capacity during peaking periods to serve Lower Mainland loads, and thereby defers or avoids capacity upgrades or expansions to serve FEI load growth.

As discussed in Exhibit A2-22, TGVI and TGI Mt. Hayes LNG Storage Facility Application, June 2007, p. 87, at the time of the Mt. Hayes CPCN application, it was demonstrated that Mt. Hayes would defer the need for CTS upgrades or reinforcement beyond the 20-year planning horizon. More specifically, the evidence in that proceeding demonstrated that without Mt. Hayes, CTS upgrades would have been required as early as 2013 or 2014 in the scenario where BC Hydro continued to require FEI to provide firm transportation service to Burrard Thermal pursuant to the Bypass Transportation Agreement (the "BTA"). At the time of the Mt. Hayes application there was some uncertainty on whether Burrard would continue to operate beyond 2014. As events have unfolded, BC Hydro continues to require firm service across the CTS to ensure the availability of Burrard Thermal, if and when required.

> "Improved system reliability is realized by the availability of an alternate supply source for TGVI's customers in the event of an interruption or loss of system pressure on TGVI's System (Section 7.3.3). This significantly reduces the risk of service interruptions and associated relight costs" (TGVI Mt. Hayes LNG Storage Facility CPCN Application, p. 99)

54.2 How do transportation customers benefit from the availability of an alternative supply source in the event of an interruption on TGVI's system?

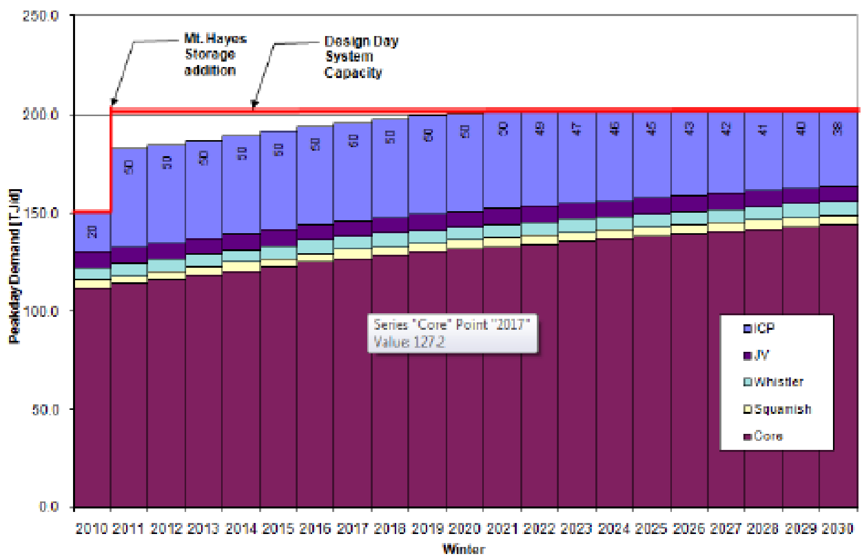
Response:

Depending on the severity of the event, Mt. Hayes can be used to provide system pressure support and gas supply to help meet its system requirements while the problem is rectified, benefitting all customers. For example, an event that causes a brief interruption of supply from the lower mainland, or a significant cold weather event that results in unexpected increase in heating loads in the Victoria area (the end of the FEVI system) could result in sudden reduction in system pressure and require FEVI to reduce service to transportation customers to avoid wide spread outages. The location of the Mt. Hayes facility on the FEVI system allows FEVI to manage this type of event without any service interruption.

In the case of a more significant event that results in a loss of transmission capacity from the lower mainland (e.g. pipeline damage) for an extended length of time, FEVI would use Mt. Hayes to maintain gas supply to core market and critical customers on the remaining system, but may be required to curtail transportation customers if necessary to maintain system pressure, while repairs are being completed.

"Figure 6-2 shows that further capacity constraints on the TGVI system are not expected until 2021, based on the requirement to meet peak demand for core TGVI customers under the reference case demand forecast, plus transportation requirements for the VIGJV mills (8 TJ/d) and the Island Cogeneration Project (50 TJ/d)." (TGI 2010 Long Term Resource Plan, p. 135)

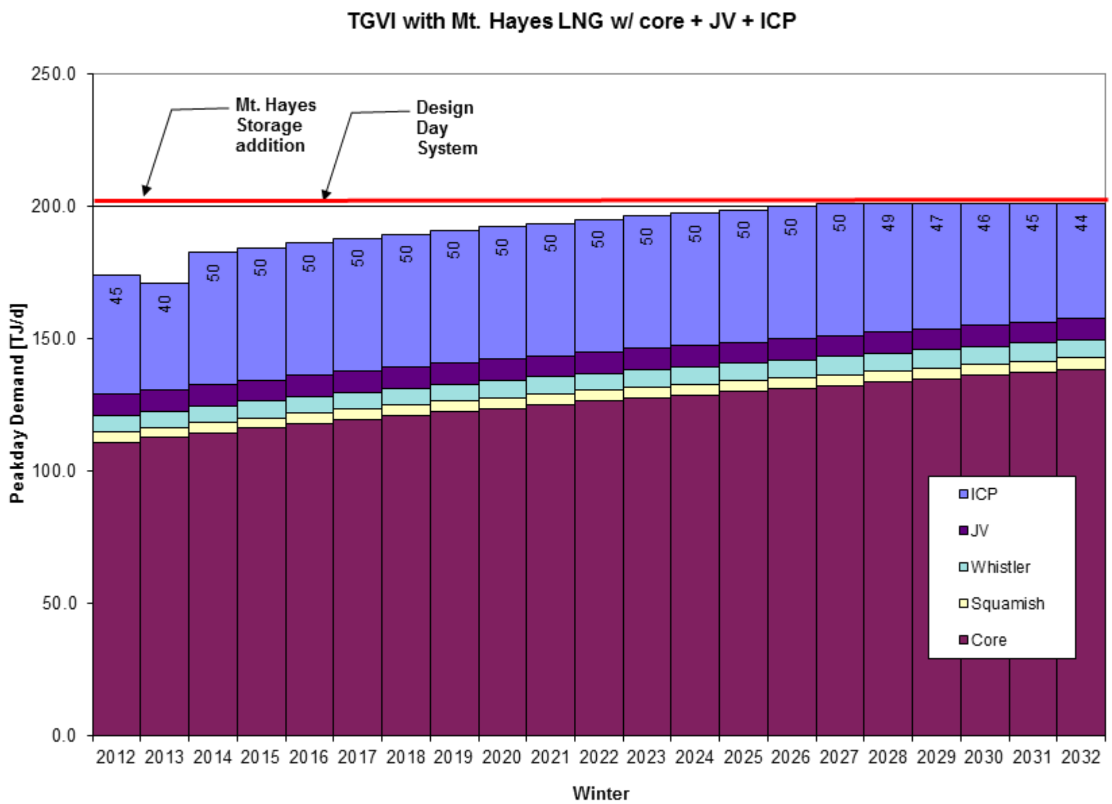
Figure 6-2: TGVI Demand-Capacity Balance with Mt. Hayes Facility



54.3 Please update Figure 6-2 to reflect the latest demand forecast for the TGVI system.

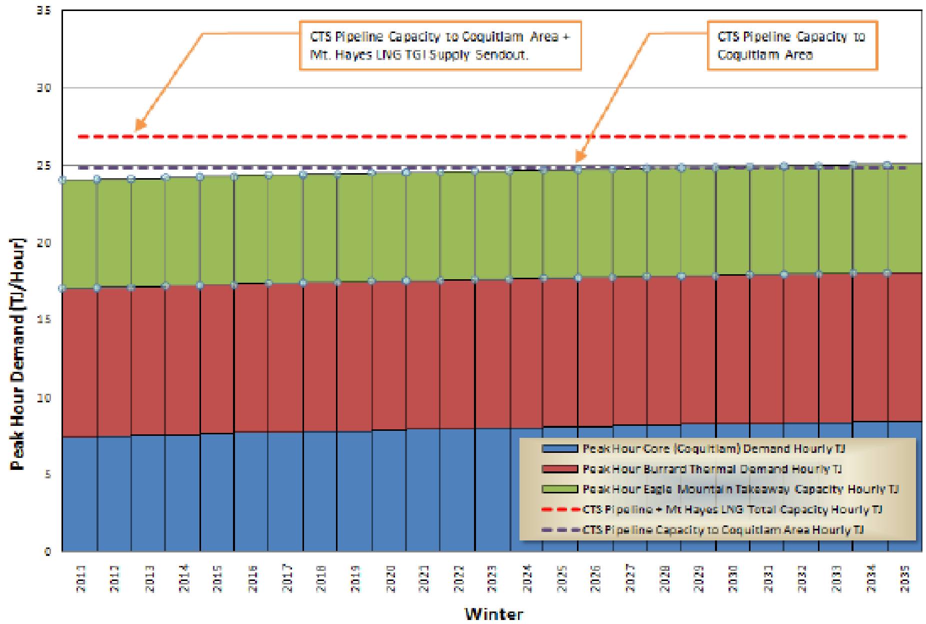
Response:

An update to Figure 6-2 follows:



"Figure 6-4 shows that the addition of the Mt. Hayes storage facility, slated to be in service by the winter of 2011/2012, alleviates the capacity constraint identified on the CTS [Coastal Transmission System] for the duration of the planning period." (TGI 2010 Long Term Resource Plan, p. 137)

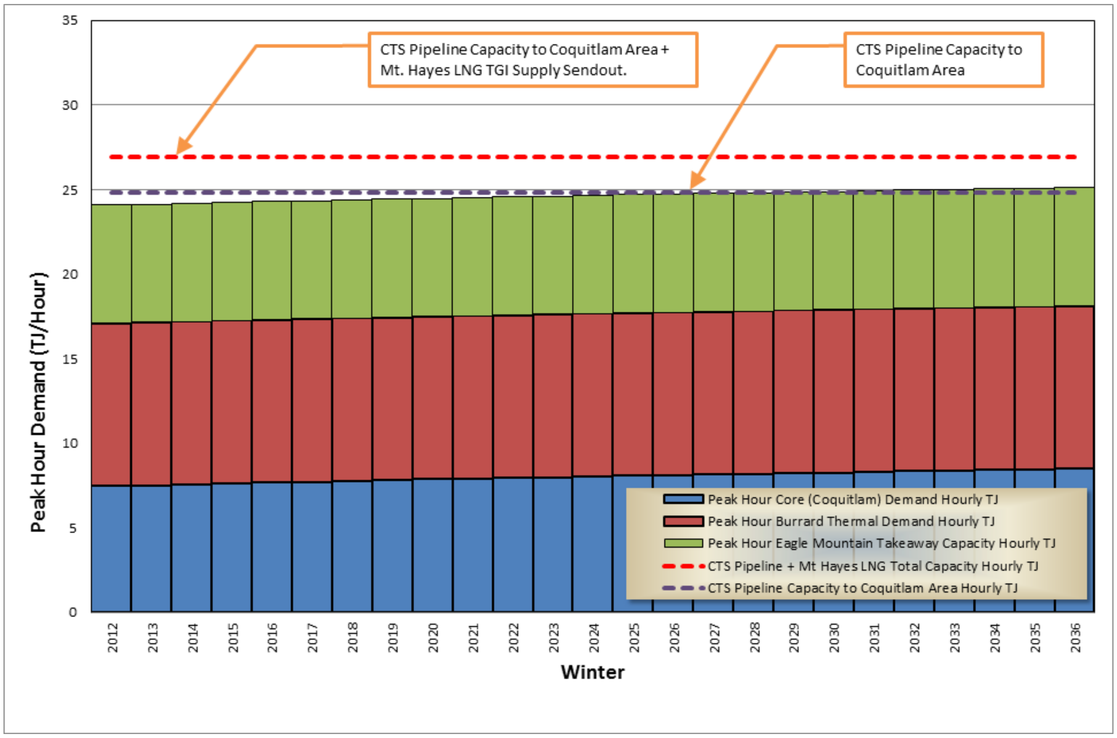
Figure 6-4: TGI Demand and CTS Capacity to Serve Coquitlam Area



54.4 Please update Figure 6-4 to reflect the latest demand forecast for the CTS.

Response:

The following chart reflects the latest demand forecast:



TGVI and BC Hydro entered into a Transportation Service Agreement (TSA) under which TGVI provides firm transportation service to BC Hydro for the Island Cogeneration Plant (ICP) located on Vancouver Island. The initial term of the TSA is from January 1, 2008 to April 12, 2022, matching the remaining period of the initial term of BC Hydro's electricity purchase agreement with ICP. The agreement provides BC Hydro the flexibility to terminate the agreement after November 1, 2015 upon giving two years notice. The initial contract demand is 45 TJ/d and can be adjusted to a minimum of 40 TJ/d or to a maximum of 50 TJ/d upon BC Hydro giving 12 months notice. (Reasons for Decision attached to G-139-07, p. 2)

54.5 What is the current contract demand?

Response:

The current contract demand with BC Hydro for Island Cogen is 45 TJ/d.

54.6 Has BC Hydro provided notice requesting an adjustment of the contract demand?

Response:

BC Hydro gave notice to FEVI that the Contract Demand under the TSA shall be reduced from 45 TJ/day to 40 TJ/day for one year commencing November 1, 2012 to October 31, 2013. BC Hydro also provided notice that unless they provide FEVI with another notice to extend the period of Contract Demand reduction, the Contract Demand shall revert back to 45 TJ/day commencing November 1, 2013.

54.7 Has BC Hydro given any indication that they intend to terminate the agreement prior to the end of the initial term?

Response:

No, BC Hydro has not provided any indication that they intend to terminate the agreement prior to the end of the initial term.

54.8 In consideration of the foregoing information, do the FEU now forecast the TGVI system having surplus capacity over the next two years? Over the next five years?

Response:

As illustrated in Figure 6-2 from the Terasen Utilities' 2010 Long Term Resource Plan (also referenced in IR 54.2 above), the Vancouver Island Transmission System ("VITS") has reached its capacity limit to meet its core market demands, the VIGJV firm contract demand and the ICP contract demands. It is the addition of the Mt. Hayes Facility that adds to capacity of the overall system. The FEVI system combined with the capacity provided from Mt. Hayes has some level of surplus capacity up to Year 2020. As contemplated during the Mt. Hayes CPCN proceeding, any surplus capacity from Mt. Hayes is redeployed to provide peaking gas supply resource for the Lower Mainland.

54.9 In consideration of the foregoing information, do the FEU now forecast the CTS having surplus capacity over the next two years? Over the next five years?

Response:

Please refer to the response to BCUC IR 1.54.1. In addition to a peaking gas supply resource, Mt. Hayes provides capacity benefits to the Coastal Transmission System ("CTS") that defer the need for any system reinforcement to the CTS beyond a 20-year plan horizon. FEVI's requirements to serve ICP do not have any relevance to the amount of available CTS capacity.

54.10 In consideration of the foregoing information is it a reasonable alternative to classify the costs associated with the Mt Hayes LNG Storage facility as energy-related?

Response:

The Mt. Hayes Facility provides system capacity for FEVI (and indirectly to FEI) and is a peaking and seasonal gas storage resource in both the FEVI and FEI gas supply portfolios. Accordingly, as proposed in the CPCN application, the Mt. Hayes costs are being allocated to both delivery margin and to midstream gas costs. Based on the cost causation factor, it is appropriate to classify Mt. Hayes costs as demand-related as the costs associated with this facility are required to meet the peak day demand requirements for customers. The current cost methodologies, as proposed in the application, effectively classify and allocate costs associated with the Mt. Hayes Facility.

Energy-related costs are generally those incurred for and directly correlated to the provision of the normalized, or baseload, annual demand volumes of gas for customers. However, costs associated with all storage facilities are incurred to provide either system capacity or to meet the peak demand requirements for customers. Therefore, the FEU believe that it is not reasonable to classify costs associated with the Mt. Hayes Facility as energy-related.

54.11 Provide examples of, and comment on, the methods used by other utilities to classify and allocate peaking storage costs.

Response:

FEVI (formerly TGVI) completed and filed a brief survey of peaking methods in the FEVI 2010-2011 Revenue Requirements and Rate Design Application. The response to BCUC IR 1.175.4 (Exhibit B-4, FEVI 2010-2011 RR & RDA proceeding) is provided as Attachment 54.11. Note that the methods used vary according to the circumstances associated with the storage facilities in question.

55.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 6.6.3, p. 123

Interest Expense Savings

FEU state that "Interest expense savings of approximately $2.0 million are expected to occur upon amalgamation of the Utilities. … Savings in interest expense are expected to occur primarily as a result of the application of the FEI short-term debt rate to the FEVI and FEW short-term debt components of approximately $144.2 million."

55.1 Please provide the annual short-term debt rate of FEI, FEVI and FEW respectively for the period 2012 to 2014 (actual and forecast).

Response:

The following responds to BCUC IRs 1.55.1 and 1.55.2. The information provided below is forecast; there is no actual data for the years requested as they are in the future.

The short term debt rate for the forecast test years 2012 and 2013 from the FEU's Compliance Filing (May 1, 2012) regarding the Commission's recent decision on the two year RRA is as follows:

	2012			2013		
	Amount $000's	% of Capitalization	Embedded Cost	Amount $000's	% of Capitalization	Embedded Cost
FEI	$ 52,425	1.93%	2.50%	$ 84,007	3.03%	3.50%
FEVI	$ 102,406	13.13%	4.00%	$ 134,867	16.69%	5.00%
FEW	$ 187	2.44%	2.50%	$ 332	3.52%	3.50%

There is no test year forecast for 2014 for short term debt. The current forecast of the short term debt rates is the following: FEI 4.0%, FEVI 5.6%, and FEW 4.9%. The Companies do not have a forecast budget for the dollar amount and percent of capitalization for 2014; however, it is anticipated the capitalization would be similar to the 2013 values.

55.2 Please provide the annual balances (value and percentage share to total debt) of short-term debt for FEI, FEVI and FEW respectively for the period 2012 to 2014 (actual and forecast).

Response:

Please refer to the response to BCUC IR 1.55.1.

55.3 Do FEU agree with the statement that the decrease in FEI Amalco's cost of debt resulting from the application of FEI's short-term debt rate to the FEVI and FEW short-term debt components lead to lower cost of service and hence lower business risks for the amalgamated utility compared to the pre-amalgamation utilities (weighted-average?)

Response:

The FEU agree with the first part of the statement that the decrease in FEI Amalco's cost of debt resulting from the application of FEI's short-term debt rate to the FEVI and FEW short-term debt components may lead to lower cost of service.

The FEU do not agree with the second part of the statement. The interest savings that may accrue is minor relative to the overall cost of service of FEI Amalco, and does not change the business risk of the amalgamated entity. Second, the savings are an estimate based on the time period covered by the revenue requirement reflecting both an average forecast short term debt balance, and a forecast interest rate differential. These forecasts are assumptions that may change from revenue requirement to revenue requirement.

56.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3, p. 158

FEU's Proposed ROE for FEI Amalco

FEU state "The FEU believe for the reasons outlined in this section, that it is reasonable to have a 12 basis points premium over the benchmark ROE, which is currently 9.5%, and a capital structure of 40% equity and 60% debt for FEI Amalco. … The FEU's proposal reflects the weighted average of the existing ROE of the FEU and the current capital structure of the FEU. The FEU's proposal therefore reflects the status quo and is reasonable to approve on an interim basis until the GCOC Proceeding is complete."

56.1 Please provide the ROE calculations and the respective FEI, FEVI and FEW 2013 forecast rate bases supporting the resulting weighted-average of 9.62 percent for the Amalgamated Entity.

Response:

Please refer to Appendix J-1 of the Application, Schedule 2 and Schedule 3. Please note that the figures below exclude the minor rate base amalgamation adjustments. These adjustments do not impact the calculation of the weighted average ROE for the Amalgamated Entity.

Line	Particulars		Reference
1	Rate Base		
2	FEI	2,810,535	Appendix J-1, Schedule 2, Row 2, Line 33
3	FEVI	815,684	Appendix J-1, Schedule 2, Row 3, Line 33
4	FEW	41,346	Appendix J-1, Schedule 2, Row 4, Line 33
5	FN	9,241	Appendix J-1, Schedule 2, Row 5, Line 33
6	Amalco	3,676,806	
7			
8	Equity Component of Rate Base		
9	FEI	1,124,214	Line 2 x 40%
10	FEVI	326,274	Line 3 x 40%
11	FEW	16,538	Line 4 x 40%
12	FN	3,696	Line 5 x 40%
13	Amalco	1,470,722	
14			
15	Equity Component of Earnings		
16	FEI	106,800	Line 9 x 9.5%
17	FEVI	32,627	Line 10 x 10.0%
18	FEW	1,654	Line 11 x 10.0%
19	FN	351	Line 12 x 9.5%
20	Amalco	141,433	
21			
22	Amalco Weighted Avg ROE	9.62%	Line 20 / Line 13

56.2 Assuming FEU's Application is approved, do FEU expect FEI Amalco to file an application to review and establish the appropriate risk premium for FEI Amalco in relation to the benchmark ROE established in the GCOC Proceeding? If so, when?

Response:

Assuming the FEU's Application for amalgamation and common rates is approved, the FEU expect to file an application to review and establish the appropriate risk premium for FEI Amalco in relation to the benchmark. The timetable for submitting this application is dependent on when a decision is received on this application as well as the GCOC proceeding. The Companies recognize that the GCOC is not a proceeding for determining a specific company's cost of capital, but rather a generic hearing to establish the cost of capital of a benchmark or a benchmark low-risk utility. As noted in Commission Order No. G-20-12, the individual utilities would establish separate future proceedings to set risk premiums or multiple individual utilities could apply to set their premiums by establishing a multi-utility cost of capital proceeding.

In a letter filed to the Commission regarding Submission on the Preliminary Minimum Filing Requirements on May 3, 2012, the FEU expressed their view that a two-step approach is required in the regulatory process, where the first part of the process should address the identity or characteristics of a "benchmark" utility. The FEU believe that the determination of the benchmark will affect the risk premium for the Amalgamated Entity. Hence, following a determination of the benchmark utility within the GCOC , the FEU will file an application to review and establish a risk premium in relation to the benchmark for FEI Amalco.

56.3 Until when do FEU anticipate the rates to be interim?

Response:

As discussed in the Application, if amalgamation is approved, the delivery rates sought in this Application will be superseded by the rates sought in the 2014 Revenue Requirements Application (the "2014 RRA") for the Amalgamated Entity to be filed in 2013 and the fourth quarter 2013 gas cost filing, and rate adjustments to reflect the results of the Generic Cost of Capital ("GCOC") Proceeding and any related subsequent proceeding.[43]

The FEU have proposed that the midstream and commodity rates for the Amalgamated Entity would be set based on quarterly gas costs filing in the same manner as presently done for FEI. Through FEI's fourth quarter 2013 filing, the Commission can approve the permanent gas costs (commodity and midstream) for the Amalgamated Entity beginning January 1, 2014.

With respect to the Delivery rates, given the timetables of the GCOC and 2014 RRA proceedings discussed below, the FEU anticipate that the interim delivery rates sought in this Application will be superseded by other approved delivery rates before January 1, 2014.

The regulatory timetable for the GCOC proceeding has not been made known yet. In the Commission's scoping document the anticipated timing would have the results of the GCOC Decision effective January 1, 2013. If amalgamation is approved, and depending on the outcome of the GCOC Decision, FEI may have to apply for a risk premium over the benchmark in a subsequent proceeding. It is possible that this could be determined before January 1, 2014.

The 2014 Revenue Requirement Application(s) is not yet on the Regulatory Calendar. If common rates are approved, then FEU would hope to file and receive a 2014 Revenue Application decision before the end of 2013. If it appears unlikely that the FEU will receive a decision on the 2014 Revenue Requirements Application before the end of 2013, the FEU would likely apply for updated interim rates reflecting 2014 forecast costs to supersede the interim delivery rates that would have been approved as an outcome of the present Application.

[43] Application, Page 15

57.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3.2, p. 161

BC Government Energy Policies

The FEU state: "In the 2009 Return on Equity and Capital Structure proceeding, the following items were discussed and accepted as key drivers affecting the business risks of the benchmark utility, FEI.

1. BC Government policies on climate change and energy policies;…"

57.1 Please elaborate on the impact of the 2012 BC Government Natural Gas Strategy – Fuelling B.C.'s Economy for the Next Decade and Beyond – on the business risks of the benchmark utility FEI, as well as on the business risks of stand-alone FEVI and FEW utilities.

Response:

The impact of the 2012 BC Government Natural Gas Strategy – Fuelling B.C.'s Economy for the Next Decade and Beyond is the same on each of FEI, FEVI and FEW and are therefore addressed together below.

In the 2009 ROE and Capital Structure proceeding, the FEU indicated that the BC government policies on climate change and energy policies have put pressure on natural gas in *its traditional role in providing heat for space and water heating*. Since the 2009 ROE and Capital Structure proceeding, two major government policy announcements have come about: *Clean Energy Act* ("CEA") (2010) and British Columbia's Natural Gas Strategy (2012). These are further described in Section 1.6 and Section 1.7 of Appendix G-0.

The CEA sets out "British Columbia's energy objectives", which have implications for the role of public utilities in the Province, including FEI, in delivering on the provincial government's initiatives to reduce GHG emissions and improve energy efficiency. The *CEA* has increased the business risks of FEI since the 2009 ROE and Capital Structure proceeding due to the fact that it focuses on the role of electricity and renewable and alternative energy, and not the direct use of natural gas. For example, the *CEA* does not consider fuel switching as a "demand side measure" if it leads to higher GHG emissions. Further, many of the government objectives focus on GHG emissions reductions.

More recently, on February 3, 2012, the BC government announced British Columbia's Natural Gas Strategy, focusing on the importance of natural gas in the development of the LNG sector, for exports and transportation. Although the government's new priority and greater emphasis on market diversification to increase the value of BC's natural gas is a positive one, such an effort does not directly promote the role of natural gas in its traditional role of space and water heating. Furthermore, the *CEA* still requires the BCUC to consider British Columbia's energy objectives in the context of long term plans, applications for a CPCN, applications for approval of expenditure schedules and energy purchase contracts under the *UCA*. As such, all else equal, British Columbia's Natural Gas Strategy has no material effect on the overall business risk at this time.

British Columbia's Natural Gas Strategy recognizes that natural gas can play an important role in the transportation sector. This is further complemented by the BC government's new Greenhouse Gas Reduction (Clean Energy) Regulation under section 18 of the *Clean Energy Act* announced on May 15, 2012. As the FEU have identified since its 2008 Resource Plan, adding load to the natural gas system plays an important role in providing economic and environmental benefits and reducing GHG emissions. Recognizing these benefits, the FEU have been actively pursuing opportunities to provide Natural Gas for Transportation ("NGT") Service since the 2010-2011 Revenue Requirements Application. Progress has been limited, however, due to regulatory proceedings, such as the AES Inquiry, decisions with respect to the structure of fuelling arrangements and incentives and, most recently, the direction to create a separate class of service for NGT in the BFI Decision (Order No. C-6-12). Given that the NGT market is a relatively new market and in the early stages of development, and policies and regulation that promote natural gas for transportation, albeit important, are fairly recent as well, it is premature to determine the degree of impact on FEU's overall business risk at this time.

The FEU believe that the various energy policies and legislation produce conflict and competition between different energy forms in the Province. The lack of clear and well defined policies and legislation in British Columbia creates some confusion among key stakeholders in the energy sector with respect to the role of natural gas in its traditional market for space and water heating, which further impacts the FEU's business risk.

58.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3.2, pp. 161-162

FEVI and FEW Long-Term Risks

The FEU state "These additional risks, as outlined in the Business Risks Evidence filed as part of Appendix C-1 of this Application are the following:

- Both FEVI and FEW are relatively smaller utilities that cannot diversify their risks to the same extent as FEI, whose assets, geography and economic bases are less concentrated;
- Greater supply risk due to dependency on a single pipeline system that traverses rugged terrain and incorporates numerous stream crossings and, in the case of FEVI, a high pressure marine crossing; and
- FEVI faces the elimination of Royalty Revenues at the end of 2011 that have ranged from $17 to $43 million in recent years and cover approximately 15%-25% of the current cost of service."

58.1 With regard to the first risk listed above, do FEU agree with the fact that, under the proposed Amalgamated Entity, FEVI and FEW will be able to diversify their risks, at least to the same extent as FEI currently does, because they will benefit from FEI's assets, geography and economic bases, which are less concentrated? If not, please explain why not.

Response:

With amalgamation, FEVI and FEW no longer exist; they are integrated into FEI Amalco. In order to compare risks pre- and post-amalgamation it is only feasible to compare the risks of those entities that exist both prior to and subsequent to amalgamation. Specifically, the appropriate comparison is between FEI pre-amalgamation and FEI Amalco as was done by Ms. McShane in Exhibit B-3-1, Appendix C-4. As Ms. McShane's evidence concluded, in a portfolio framework, amalgamation does not create any meaningful diversification for FEI Amalco (page 7). Stated in the terms referenced in the question preamble, amalgamation does not materially change FEI's ability, pre- and post-amalgamation, to diversify its risks.

58.2 With regard to the third risk listed above, do FEU agree with the fact that, under the proposed common rates for the Amalgamated Entity, the risk faced by FEVI related to the elimination of the Royalty Revenues would be significantly reduced, if not eliminated? If not, please explain why not.

Response:

As indicated in the response to BCUC IR 1.58.1, with amalgamation, FEVI no longer exists as it is integrated into FEI Amalco and the only feasible comparison is that between FEI pre-amalgamation and FEI Amalco. The proposal to harmonize rates will address the increase in the competitive price pressures in the former FEVI service area brought about by the termination of the royalty revenues. Rate harmonization will improve the competitiveness of natural gas in the former FEVI service area, as well as in the former FEW service area from a strictly price (operating cost) perspective, but will tend to decrease the Mainland's competitive price advantage, leading, on balance, to slightly higher competitive price risk for FEI Amalco compared to FEI pre-amalgamation. Further, it is important to recognize that competitiveness relates to broader considerations than operating costs. As discussed in the Application, customers' energy choices and usage are informed by capital cost investment, type of housing being built, government policy, and perceptions about the green attributes of the energy source.

FEU also state on page 162 that "… on a portfolio basis, FEI Amalco will assume <u>some of the FEVI and FEW long-term business risks</u>, thus will face a higher risk than the benchmark utility, FEI." [Emphasis added]

58.3 Please provide an exhaustive list of the FEVI and FEW long-term business risks that the Amalgamated Entity would assume and explain why the latter entity would assume those risks.

Response:

Please refer to the response to BCUC IR 1.70.1. The risks identified in BCUC IR 1.70.1 identify the key risks unique to FEVI and FEW that are assumed by the Amalgamated Entity.

58.4 Please explain which of the FEVI and FEW long-term business risks would not be assumed by the Amalgamated Entity? Please explain why.

Response:

Please refer to the responses to BCUC IRs 1.58.2 and 1.70.1.

Whether the key risks unique to FEVI and FEW are eliminated or mitigated as a result of amalgamation is discussed in the response to BCUC IR 1.70.1.

On page 162, the FEU state that "This conclusion of credit neutrality is also highlighted by DBRS in its September 2011 Report: "…At this time DBRS anticipates that the potential amalgamation and associated rate harmonization will likely be credit neutral to FEI provided that there are no material changes that will negatively affect its deemed capital structure, allowed ROE or <u>fundamental low-risk business model</u>." (Emphasis added)

58.5 Please elaborate on the kinds of "<u>material</u> changes" that would negatively affect the capital structure, allowed ROE or fundamental low-risk business model referred to by DBRS. [Emphasis added]

Response:

The FEU's capital structure and allowed ROE are decided upon by the Commission, so any material change to these two items would be the result of a Commission decision. A Commission decision to "materially change" capital structure and allowed ROE that would be negative (from the perspective of a DBRS credit rating downgrade) would be a decision that results in a lower equity component in the capital structure or lower allowed ROE that would result in greater financial risk. For example, a "material change" in fixed obligations of the company (i.e. an increase in debt to reduce equity) while receiving the same cash flow would result in greater financial risk to possibly warrant a downgrade. Also, under a scenario where the allowed ROE were "materially changed" negatively, or reduced, there would now be lower cash flow to support the same fixed obligations of the business, which would result in greater financial risk to possibly warrant a downgrade.

Although the FEU cannot speak for DBRS, the term "fundamental low-risk business model" used by DBRS appears to refer to the operations and the regulatory structure of the FEU generally. While it is not clear what would be considered a material change to this model, the FEU do not anticipate any material changes, resulting from the proposed amalgamation and common rates, to their operations or the manner in which the FEU are regulated.

58.5.1 Are fluctuations in commodity, delivery and mid-stream rates considered material changes?

Response:

As the aforementioned report was authored by DBRS, the FEU is not in a position to speculate to what degree fluctuations in commodity, delivery and mid-stream rates are considered material changes by DBRS.

58.6 In FEU's view, under what conditions would the credit agencies upgrade or downgrade the post-amalgamated FEI.

Response:

The credit rating agencies will upgrade or downgrade the post-amalgamated FEI if there is a material change to FEI's business and financial risks that warrant a ratings change within their methodology. At this time, the FEU do not foresee a material change in business risks affecting the post-amalgamation FEI that is caused by the proposed amalgamation and common rates that would lead to a change in ratings. A material reduction in equity thickness and/or approved ROE could cause a downgrade; likewise an increase could prompt an upgrade. Please refer to the response to BCUC IR 1.58.5.

58.7 Do FEU agree that DBRS views the Amalgamated Entity as fundamentally low-risk, as highlighted in the quote above? If not, please explain why not.

Response:

While DBRS views the amalgamated FEI as having a "fundamentally low-risk business model", the FEU do not believe it actually is "low-risk".

Despite improved commodity market cost advantages over other energy forms (such as electricity), natural gas continues to face challenges, mainly with respect to maintaining its market share and meeting the energy and climate change policy requirements in British Columbia, all of which impact the competitiveness of natural gas, and therefore, its demand and throughput levels in the long term. Some of the drivers of increased business risk for the FEU are as follows:

- New technology introductions
- Changes in the housing mix and upfront cost requirements for natural gas equipment for new construction
- Changes in energy use for existing customers
- Perception of natural gas and customers demand of greener alternatives
- Government policy at the provincial and municipal level support reduction of GHG emissions reductions

All these challenges continue to impact the long term throughput levels for the utility and as a result continue to increase the FEU's business risk.

The introduction of climate change-related risks was recognized in the 2009 ROE and Capital Structure Decision (Order No. G-158-09) and the Commission concluded that FEI's "business risk has increased since 2005" (p. 37). While FEI was once referred to as the benchmark "low - risk" utility, this is no longer the case in this Decision (p. 78-80).

58.8 Would postage stamp rates, if approved, provide FEU with a competitive advantage over other investors in acquiring new gas utility operations in BC? Please explain.

Response:

The FEU assume the question is making reference to an acquisition of an existing regulated utility operations, as opposed to an extension of the existing operations in a given service area.

Under the acquisition scenario, no, the FEU do not believe the approval of postage stamp rates within its service areas would provide a competitive advantage to bid a higher price over other investors to acquire new utility operations. In most acquisitions, an approved rate base already exists. The price paid would consider factors such as the existing rate base and approved cost of capital and future growth prospects to determine the price, not the assumption on extension of postage stamp rates.

59.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit A2-11, 2002 Article on Used and Useful Test, Energy Law Journal, Vol 23, p. 364; Exhibit A2-12, 1998 Article on Regulatory Compact, Energy Journal, Vol 19:3, p. 71-81; Exhibit A2-13, 1994 Briefing Document for State Commissions on Regulatory Treatment of Embedded Costs Exceeding Market Prices; Exhibit A2-14, New Brunswick EUB 2010 Decision on Enbridge Gas Cost of Capital, p. 11; Reasons for Decision for Order G-99-06, pp. 23–27; Exhibit A2-3, Inquiry Report for Order G-100-96, pp. 1-18

Who Bears Competition Risk?

A 2002 Energy Law Journal article by Jonathan Lesser titled "The Used and Useful Test: Implications for a Restructured Electric Industry"[44] stated on page 364 (Exhibit A2-11):

> "One of the tenets of a competitive marketplace is the absence of any guarantee of success. Competitive enterprises succeed and fail, not only because of their own actions, but also because of the overall changes in markets for the goods and services they provide. In a well-known 1945 Supreme Court case, Market Street Railway, the appellant argued that a rate reduction ordered by California Railroad Commission constituted a regulatory taking under the Fifth and Fourteenth Amendments of the Constitution.
>
> The Market Street Railway Company had been formed in 1893 as a consolidation of a number of existing companies. It operated a system of street cars and buses in the San Francisco area. The Court noted the various cycles the Company had been through, stating "[t]his property has passed through cycles of competition, consolidation and monopoly, and new forms of competition; it has seen days of prosperity, decline, and salvage." Seeing a decline in service quality, the Railroad Commission ordered the company to reduce its rates. The Commission also noted the inherent price elasticity of services offered, concluding "the Company would reap no lasting benefit from rates in excess of five cents, due to the tendency of a higher rate to discourage patronage." Market Street Railway appealed the rate reduction. The Supreme Court, however, affirmed the appeals court decision, stating:
>
>> [t]his company obviously is up against a sort of law of diminishing returns; the greater amount it collects per ride, the less amount it collects per car mile. . . . While the Company does not assert that it would be economically practicable to obtain a return on its investment, it strongly

44 http://www.jalesser.com/publications/other/elj_november2002.pdf

contends that the order is confiscatory by the tests of Federal Power Commission v. Hope Natural Gas Co. . . . Even monopolies must sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use.

The Court had thus established a competitive "out." Regulators were under no obligation to guarantee the returns of firms facing inevitable competitive pressures."

A 1998 Energy Journal article by James Boyd titled "The "Regulatory Compact" and Implicit Contracts: Should Stranded Costs be Recoverable"? states[45] (Exhibit A2-12):

"It has been suggested that principles of "fairness" and "pragmatism" should guide the recoverability decision. Fairness is used as a metric primarily by those in favour of recovery. The claim is that it is unfair to saddle utility stockholders with stranded costs and to force costs onto creditors when high-cost utilities are forced into bankruptcy by competition. The problem with using fairness as a criterion is that it is highly subjective. Electricity customers can just as plausibly claim unfairness if utilities are allowed to pass stranded costs to them. Why should a consumer pay to reduce the losses suffered by a shareholder in a company that failed to invest in a manner that appropriately anticipated changing market conditions? Claims based on fairness can be used by opponents, as well as advocates, of recovery." (p. 71)

"In summary, the case for an implicit regulatory contract guaranteeing utility cost recovery is weak. However, this does not imply that cost recovery should never occur. In cases where a utility was compelled by its franchise agreement to make investments or sign supply contracts that it otherwise would not have, the argument for recovery may be strong. But many, and perhaps most, utility investments do not fall in this category. For this broader class of investments legal precedent does not indicate a reasonable presumption of guaranteed cost recovery." (p. 78)

"The analysis of stranded cost recovery as a contract issue leads to the conclusion that cost recovery should not be assumed by default. First, underlying principles of regulatory and case law do not point toward recovery. Second, even when it appears clear that firms made investments to serve franchise obligations, compensation may already have occurred via rate of return adjustments. The most favourable case for recovery assumes that

[45] http://www.regulationbodyofknowledge.org/documents/094.pdf

competition was unanticipated and that utility expenditures should be viewed as reliance investments. Even here, however, contract theory implies that compensation should only be partial. Moreover, advocates of compensation must still explain why utilities failed to secure explicit contractual cost recovery guarantees. And to do so they must argue that the likelihood of competition at the time franchises were granted was too small to be worth the cost of explicitly including it in contracts." (p. 81)

A 1994 Briefing Document for State Commissions by Scott Hempling titled "The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market" (Exhibit A2-13)[46] stated:

"To disallow prudent costs, a regulator should be able to point to a pre-investment understanding about how the market risks were to be shared. Alternatively, there should be a post-investment action, such as utility claims for a risk premium added to the authorized return on equity, to compensate the utility for market risk. ...

There also is the concept of "voluntary risk. "An investor can choose to build capacity voluntarily, without legal obligation and without any customer commitment. Where such a speculative builder fails to recover the costs, the result is not "stranded investment; "it is" risked but lost" investment. Consider a utility which builds new plant to serve an existing wholesale customer in 5 years, where the utility has no obligation to serve that customer after 5 years, is such a voluntary risk-taker. It has not incurred an obligation and it is not entitled to receive a quid pro quo." (p. 4)

"If the decision is asymmetrical against the utility's shareholders, it means that the shareholders were compelled by government to take a risk but then not compensated by government for that risk. That type of asymmetry could be confiscatory, in violation of the U.S. Constitution. If the decision is asymmetrical against a utility's customer, it means that the government compelled the customer (due its captive status) to cover a utility's risk (e.g., by paying for a return on equity reflecting the risk of unmarketability) and then also to pay for that risk when it did not work out. That type of asymmetry, while not necessarily unconstitutional (since it is not clear that ratepayers have a property right in fair treatment by regulators), is certainly a cross-subsidy and likely to be unlawful under State law on that basis. If the regulator intends to act within the limits of regulatory law and logic, therefore, he or she has no choice but to determine the historic quid pro quos." (p. 15)

[46] http://scotthemplinglaw.com/files/pdf/ppr_embedded_costs_1194_0.pdf

"Ratepayers are not inherently risk guarantors: Some utilities argue that no costs should go unrecovered because ratepayers are guarantors. This approach does not induce efficiency. It is one thing to say that historically, a utility's legally compelled investments were not subject to systematic competition. It is another thing to say that no matter what the external event, utility shareholders have no risk. That statement sounds wrong when made, and it is. If there were no risk, regulators would set authorized return on equity at the level of a highly-rate bond. (p. 19)

Even large utility financial difficulties do not justify government intervention if the difficulties were of the utility's own making. ... The possibility that market alternatives will develop lies at the heart of any contract. It is not a possibility but inevitability, and does not justify government intervention." (p. 41)

"A utility which incurred costs to serve a customer, while having "no reasonable expectation of continuing to serve that customer," is not a "prudent" utility for purposes of ratemaking. Such a utility, by definition, was not acting on behalf of its customers when it incurred costs based on "no reasonable expectation of continuing to serve that customer." The utility was a knowing risk-taker, but the risk was not incurred for the customers who now would cover it. Reallocating these costs to other customers amounts to captive customer subsidy of utility business risk." (p. 43)

"Shifting costs to captive customers .... is low in both dynamic efficiency and regulatory consistency." (p. 99)

The New Brunswick Energy and Utilities Board, in its November 30, 2010 Decision on a review of the Cost of Capital for Enbridge Gas New Brunswick, (Exhibit A2-14)[47] stated on p. 11:

"What truly separates EGNB from mature utilities and what makes EGNB much more risky than a mature utility is its large and growing deferral account.

The Deferral Account was original forecast to peak at $13 million and has ballooned in the last ten years. At the end of 2009, the account was estimated at $155 million and EGNB predicts that this account will peak at $173 Million in 2011. ... The Board finds that the risk that not all of the Deferral Account will be recovered is a real and significant risk facing EGNB's investors. Not only is the

47 http://156.34.203.123/Documents/Decisions/NG/E/2010%2011%2030%20EGNB%20Cost%20of%20Capital%20Decision%20-%20E.pdf

> size of the debt to be paid large but EGNB's ability to recover it is dependent on market forces which are out of EGNB's control."

The Commission, in its August 16, 2006 Reasons for Decision on an Application by Pacific Northern Gas Ltd for Approval of 2006 Rates (G-99-06)[48] stated on pages 23 to 27:

> "...although PNG is unique, it is and has been regulated by the Commission under the Act on a traditional cost of service basis. ... The Commission Panel notes BCOAPO's comment that for some time now PNG's residential rates have been either barely competitive or uncompetitive with electricity rates ...
>
> It goes without saying that it is incumbent upon a regulated gas utility, and particularly so in this era of rising natural gas prices and the potential further loss of customers, to make best efforts to control and, where possible, reduce costs and the Commission Panel accepts that PNG has and will continue to do so.
>
> The Commission Panel notes that PNG conducts detailed monthly reviews of its financial and operating results. PNG suggests, therefore, that it would be in a position to determine whether lower customer rates would improve cost recovery and prevent PNG's recoverable margin from declining (PNG May 29, 2006 Response, Question 4, p. 7) and that PNG would, in such case, make an appropriate application to the Commission to reduce customer rates.
>
> The Commission Panel therefore anticipates that PNG will continue to carefully monitor loss of load and decreases in volumes and margin and to be in a position to take steps as it considers appropriate and as discussed in its May 29, 2006 Response to Letter No. L-19-06, Question 4, and/or to report to the Commission on this subject in its next RRA."

On October 7, 1996, the Commission issued Order G-100-96 which included at Appendix A and Inquiry Report into BC Gas Utility Ltd. and Propane Prince Increases in the City of Revelstoke (Exhibit A2-3). This related to an application by BC Gas for approval to pass-through an increase in the cost of propane which would have represented an average increase to residential customers of approximately 24% and to commercial customers of 32 percent.

[48] http://www.bcuc.com/Documents/Proceedings/2006/DOC_12354_G-99-06_PNG_2006RR_Reasons.pdf

The Commission directed BC Gas to phase in the required rate increase over 2 years. The Commission recognized that, if propane prices continue to rise, the utility may become faced with non-competitive rates and substantial unrecovered liabilities.

59.1 Do FEU agree that regulatory precedent supports that the shareholder, and not the ratepayer, should bear the risk of asset impairment resulting from competition pressure (in the absence of evidence that the utility was compelled by its franchise agreement to make investments or sign supply contracts that it otherwise would not have, and for which it has not been compensated for through its return on equity)?

Response:

The FEU are unable to answer the question as posed. As discussed in the response to BCUC IR 1.60.1, asset impairment is an accounting term which indicates that the carrying cost of an asset is not fully recoverable. Asset impairment is therefore the result of a regulatory decision indicating that part or all of the costs of an asset should not be recovered, usually as the result of the imprudent management of the utility. Therefore, by definition, asset impairment is at the risk of the shareholder.

The IR appears to be inquiring into whether the Commission could disallow recovery of investments due to competition pressure. The FEU disagree with this suggestion. The case law demonstrates that the FEU have a statutory right to a fair return and that prudent investments are to be recovered in rates. The response to competitive pressures is to seek solutions through rate design or other measures to ensure that the utility can continue to provide service to customers and recover the costs of and return on its investments.

The FEU submit that the issue raised is premature. The FEU do not have any impaired assets due to competition pressure and, as discussed in the response to BCUC IR 1.61.1, the FEU do not foresee asset impairment at this time. There is therefore no factual context to ground the issue.

Nonetheless, based on a cursory review of the authorities, the FEU make the following comments on the items cited in the preamble to the IR:

1. The *Market Street Railway Company* case referred to in the preamble is a 1945 U.S. Supreme Court decision and is included in Attachment 59.1. The case considered the appeal of the Market Street Railway Company, which at the time operated a system of passenger transportation by street car and by bus in San Francisco and its environs. The company faced competition from the San Francisco municipal street railway line, which was not under the regulator's jurisdiction, and charged a rate of 5 cents. The regulator permitted the Market Street Railway Company to raise its rates to 7 cents on

an experimental basis. When service failed to improve, the regulator reduced the rate to 6 cents anticipating that the reduced fare would increase patronage. As it turned out, the Market Street Railway Company sold its assets to the municipality, which then charged a 7 cent fair, so the regulator's expectations were never tested.

Two of the key facts of the case were as follows:

- The company was poorly managed. The Court states: "The Commission found, however, that the service had constantly deteriorated and was worse under the seven-cent fare than under the former five-cent rate. It recognized that some of the causes were beyond the Company's control. But after allowance for those causes, it also found evidence of long-time neglect, mismanagement, and indifference to urgent public need."

- The company was in a hopeless state and no rate set by the regulator would allow a reasonable return. The Court found that cases such as *Hope Natural Gas* were "obviously . . . inapplicable to a company whose financial integrity already is hopelessly undermined, which could not attract capital on any possible rate, and where investors recognize as lost a part of what they have put in." It appears that this was the state of many urban street railway systems at the time (see footnote 8 of the decision).

The Market Street Railway Company appealed the regulator's decision to reduce the fare to 6 cents, arguing that it was confiscatory under the U.S. Constitution. The Court states:

> *"The appeal raises constitutional issues only. The contention is that the order deprives the appellant of its property without due process of law, contrary to the Fourteenth Amendment."*

The Court determined that the regulator's decision to reduce the fare to 6 cents was not forbidden by the U.S. Constitution.

In sum, the case shows that a poorly managed utility that cannot recover its costs under any possible rate structure cannot complain that the rates set by the regulator expropriate its property contrary to the U.S. Constitution. Thus, neither the facts nor the ruling in this case are applicable to the FEU.

2. The preamble references two articles (Exhibits A2-12 and A2-13) that discuss the recovery of stranded costs in the context of the deregulation of the electricity market in the U.S. The context is therefore very different than those of the FEU and caution should be used in drawing conclusions from these resources. Furthermore, the articles

present one particular view in the extensive academic debate on the issue of stranded costs. Included in Attachment 59.1 is Baumal and Sidak, "Stranded Costs," 18 *Harvard Journal of Law and Public Policy* 835. This article explains why it generally benefits consumers for stranded costs to be recovered as part of the price of service. For example, on pages 840-841, the author describes the implicit regulatory compact between utility and regulator and states:

> *"Failure to permit recoupment of stranded costs clearly will violate the implicit regulatory compact. Aside from any inequity that this may entail, it is also a threat to economic efficiency because of its deterrent consequences for investment. It is true that it will be too late for current investors in the utilities to do anything in response to a prohibition on recoupment. But investors can learn the lesson and conclude that investment in electric utilities, with partial regulation continuing, is to be avoided assiduously in the future. More important, other prospective investors, seeing the compact abrogated are certain to conclude that it may well be abrogated again whenever it is convenient for regulators, and they too may take their resources elsewhere in the economy. The resulting shortage of capital for the electric industry, and the consequent impediments to maintenance, modernization, and needed expansion, hardly can benefit the long-term interests of consumers or contribute to the efficiency and competitiveness of the economy. In short, there is a compelling efficiency reason for regulators to permit substantial recoupment of stranded costs in the course of transition to competition. …"*

At the end of the article, the authors describe some of the suggested means by which stranded costs may be recovered, including rate design options.

3. The preamble references the article entitled 'The "Regulatory Compact"' (Exhibit A2-12). The FEU do not respond to every part of the article, but note the following. As quoted in the preamble, the author discards "fairness" as a guide to deciding whether stranded costs should be recoverable. As indicated in the article, the author favours an economic efficiency and contract theory rationale for determining the issue of the cost recovery related to stranded assets. However, the UCA incorporates the concept of fairness through the requirement that rates must be "just and reasonable." Nowhere is economic theory given the same status. The author criticizes arguments from fairness because fairness is "subjective" and "Claims based on fairness can be used by opponents, as well as advocates, of recovery." However, arguments based on economic and contract theory are subject to the same criticisms; they are not scientifically "objective" as the author would appear to advocate. The author's distinction between investments that are compelled by a franchise agreement and those that are not is without merit (refer to the

response to BCUC IR 1.21.4). Despite the author's theoretical arguments, regulators such as FERC have held that stranded costs are recoverable and such decisions have been upheld by the courts, as briefly discussed below.

4. The preamble references the 1994 Briefing Document for State Commissions entitled "The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market" (Exhibit A2-13). The FEU do not respond to every part of the article, but note the following. As explained in the document, it comments on FERC's Noticed of Proposed Rulemaking regarding stranded costs in the context of the opening of access to the electric transmission market. Regardless of the point of view expressed in the paper, FERC's Final Rule on this issue – FERC's landmark ruling Order No. 888 – permits the recovery of stranded costs.[49] As stated in the Introduction/Summary of the lengthy Order:

   > *"With regard to stranded costs, the Final Rule adopts the Commission's supplemental proposal. It will permit utilities to seek extra-contractual recovery of stranded costs associated with a limited set of existing (executed on or before July 11, 1994) wholesale requirements contracts and provides that the Commission will be the primary forum for utilities to seek recovery of stranded costs associated with retail-turned-wholesale transmission customers. It also will allow utilities to seek recovery of stranded costs caused by retail wheeling only in circumstances in which the state regulatory authority does not have authority to address retail stranded costs at the time the retail wheeling is required. The Rule retains the revenues lost approach for calculating stranded costs and provides a formula for calculating such costs."*

   In Order No. 888, FERC indicates that it was following its past decision in Order No. 636 which permitted the recovery of stranded costs in the context of the restructuring of the interstate natural gas pipeline industry. FERC also indicates that the courts had upheld its decision in Order No. 636 to permit recovery of stranded costs.

5. The preamble quotes a short portion of the New Brunswick Energy and Utilities Board's November 30, 2010 Decision on a review of the Cost of Capital for Enbridge Gas New Brunswick regarding EGNB's large deferral account balance. The Decision does not determine that the deferral account balance would not be recovered, but was discussing potential risks in determining the return on equity for EGNB.

[49] Available online at: http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp.

6. The preamble references a part of the August 16, 2006 Reasons for Decision on an Application by Pacific Northern Gas Ltd for Approval of 2006 Rates (G-99-06) (the "PNG Decision"). The PNG Decision did not determine that any costs were unrecoverable due to competition pressure. On the issue before the Commission at that time, the PNG Decision determined as follows:

> *"However, although PNG is unique, it is and has been regulated by the Commission under the Act on a traditional cost of service basis. What this means is that this utility, which is a virtual monopoly provider of natural gas in its service area, is permitted under the Act to recover the reasonable and prudent costs of providing its services in exchange for the obligation to provide safe and reliable service. One of the regulator's tasks, therefore, is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates. Rates charged to customers are based on costs incurred by the utility to provide service. If the Commission finds certain costs to be imprudent or unreasonable, it will disallow such expenditures and reduce proposed rates accordingly.*
>
> *The statutory obligation to approve rates which will afford a fair compensation for the services rendered and provide the utility with a fair and reasonable return was articulated by Mr. Justice Locke in B.C. Electric, (at pp. 846 and 848):*
>
>> *"In my opinion the true meaning of the relevant sections of the Public Utilities Act is that <u>a utility is given a statutory right to the approval of rates which will afford to it fair compensation of the services rendered and that the quantum of that compensation is to be the fair and reasonable rate of return upon the appraised value of the property of the company</u> referred to in s. 16(1)(b) [ss. 59(5)(a) and (b) and 60(1)(b)(i). …*
>>
>> *The obligation to approve rates which will provide the fair return to which the utility has been found entitled is, in my opinion, absolute, which does not mean that the obligation of the Commission to have due regard to the protection of the public, as required by s. 16(1)(b) [ss. 59(5)(a) and (b) and 60(1)(b)(i)], is not to be discharged. It is not a question of considering priorities between "the matters and things referred to in Clauses (a) and (b) of subsection (1) of s. 16 [now ss. 59(5)(a) and (b)]. The Commission is directed by s. 16(1)(a) [now s. 60(1)(a)] to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that the obligation to approve rates which will give a fair and reasonable return is absolute."* [emphasis added]

The Commission Panel considers, therefore, that it is required, by virtue of sections 59 and 60 of the Act to allow the utility to recover its reasonable and prudent cost of service, to be determined on the basis of its 2006 RRA and the evidence adduced in this proceeding.

As noted by PNG, the revenue deficiency arising from the termination of the Methanex contract does not represent any specific costs of providing service. It is simply the extent to which PNG's overall costs of providing service exceeds forecast margin recovery from PNG's customers now that Methanex has terminated its contract. A revenue deficiency (or surplus) simply dictates whether an increase (or decrease) in rates is required.

The Commission Panel, therefore, does not consider the revenue deficiency, in the context of cost of service regulation, to be a separate line item that, in and of itself, is capable of adjustment or reduction.

The Commission Panel, therefore, finds that to allocate any of the net revenue deficiency resulting from the termination of the Methanex contract to PNG's shareholders, as advocated by BCOAPO and Mr. Childs, would result in rates that do not permit PNG to recover its costs of providing service and would, therefore, contravene sections 59 and 60 of the Act. The Commission Panel agrees with PNG that the allocations proposed by BCOAPO and Mr. Childs would simply be an arbitrary disallowance of PNG's forecast costs, without any evidentiary or legal basis having been established for such a disallowance.

Given the statutory obligations imposed upon the Commission, there is simply no principled basis before the Commission Panel in this proceeding to allow it to appropriately deviate from the statutory requirement to allow the utility to recover its prudent and reasonable cost of providing service, and certainly there is no evidence to support an allocation or to select a specific allocation of the revenue deficiency, other than to the utility's customers."

7. The preamble quotes a comment from the Inquiry Report into BC Gas Utility Ltd. and Propane Price Increases in the City of Revelstoke (Exhibit A2-3) referring to "non-competitive rates and substantial unrecovered liabilities". Neither the Inquiry Report nor the accompanying Order of the Commission decided that these potential future liabilities would not be recovered. Furthermore, a review of the Inquiry Report following the quote shows that the Commission did not expect there to be unrecovered liabilities, as the expectation was that propane costs would moderate.

The suggestion in the information request that investments may not be recoverable due to competition pressure is inconsistent with the utility's right to recover and earn a fair return on its prudent investments in providing utility service. As quoted above, the Commission Panel in the PNG Decision concluded that it is required, by virtue of sections 59 and 60 of the UCA to allow the utility to recover its reasonable and prudent cost of service. The test of prudence has been considered by the Courts in the cases of *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355 and A*TCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2005 ABCA 122 (included in Attachment 59.1). In BC Hydro's F2009 and F2010 Revenue Requirements proceeding the Commission also heard detailed submission on the prudence test and, consistent with the PNG decision quoted above, concluded:[50]

> *"**Having considered the extensive submissions and authorities cited by the parties, the Commission Panel determines that in the case of reviewing the cost consequences of BC Hydro's past management decisions a rebuttable presumption of prudency is relevant, and that the two-part test arising from the Enbridge Gas and ATCO 2005 decisions applies.**"*

As also noted by the Commission Panel in the PNG Decision quoted above, the Canadian courts have spoken on the utility's right to a fair return on its investment. In *Hemlock Valley Electrical Services Ltd. v. British Columbia Utilities Commission et al.*, [1992] 12 B.C.A.C. (see Attachment 59.1) 1 at 20-21 (C.A.)), the B.C. Court of Appeal confirmed that the utility has a "statutory right to the approval of rates which will afford it the opportunity to earn a fair and reasonable rate of return upon the appraised value of its property." In *Transcanada Pipelines Ltd v. Canada (National Energy Board),* 2004 FCA 149, the Federal Court of Appeal determined that the utility's cost of capital cannot take into account the impact on customers. These decisions confirm that the utility's right to a fair return is, in the words of Justice Locke in *B.C. Electric Railway Co. Ltd. v. Public Utilities Commission of B.C.* [1960] S.C. R. 837*,* absolute.[51]

All of the FEU's investments in rate base have been made in the provision of utility service and have been either explicitly judged by the Commission to be prudent or are presumed to be so. The FEU are under a duty to serve and have made these investments in the provision of safe and reliable service to customers. As discussed above, the courts and the Commission in past decisions have affirmed that the utility has a right to recover and earn a fair return on its prudent investment. Based on the FEU's review of the authorities, the presence of competition pressure does not negate these rights.

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50 Decision, *In the Matter of British Columbia Hydro and Power Authority and F2009 and F2010 Revenue Requirements*, March 13, 2009 (BCUC Order No. G-16-09), at pp. 31 to 39.

51 The cases referenced are included in Attachment 59.1.

59.1.1 If no, please explain why not, and the criteria FEU proposes should be used in determining whether the shareholder or the ratepayer should bear the risk. Please provide examples of relevant Commission decisions/papers to support your position.

Response:

Please refer to the response to BCUC IR 1.59.1.

60.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application, Exhibit B-9, page 26, Oral Hearing Transcript, p. 237, 238; TGVI 2010 and 2011 Revenue Requirements and Rate Design Application, Exhibit B-7, p. 76

FEVI/FEW Competition Risk – Impairment Reporting

FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application Exhibit B-9[52] page 26, Fortis stated: "FEVI and FEW have in place financial reporting processes that monitor for asset impairment on an annual basis. FEVI and FEW have not reached the stage where asset impairment should be considered. FEVI and FEW do not have any assets currently in impairment."

In the FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application Hearing (Transcript volume 2,[53] pp. 237, 238):

> "MR. FULTON: ... One of the documents that is in A2-2 is an excerpt from Mr. Phillips' book *The Regulation of Public Utilities Theory and Practice*, and at page 325 under the heading Used and Useful, you'll see if you look down to the emboldened Used and Useful, and just before the quote he says:
>
> > "Today, however, used and useful has been held by some commissions to be a broader concept. The Massachusetts Commission, to cite one example, holds that under the used and useful standard it must "determine whether a utility investment is needed and economically desirable"…"
>
> And then provides the explanation. Would you agree with the definition of Used and Useful based on your long experience in the utility business, that to be used and useful a utility investment must be needed and economically desirable? Would you agree with the definition of Used and Useful based on your long experience in the utility business, that to be used and useful a utility investment must be needed and economically desirable?
>
> MR. WALKER: A: By definition, yes."

Exhibit B-7 to TGVI 2010 and 2011 Revenue Requirements and Rate Design Application, TGVI stated in response to BCUC IR 2.32.1.1[54] (p. 76):

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[52] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28091_B-9_FEU%20Rsp%20to%20BCUC%20IR-No1.pdf

[53] http://www.bcuc.com/Documents/Transcripts/2011/DOC_28695_10-03-2011-Transcript-Volume-2.pdf

"In a non-regulated company, the need for acceleration in amortization rates may be a possible indicator of impairment triggering a valuation test. However, for a regulated entity a more appropriate indicator of possible impairment is more likely to be its recoverability from ratepayers. The recent exposure draft on rate regulated activities indicates that there may be situations where the net effect of the regulatory assets and regulatory liabilities an entity recognizes will result in significant increases in future rates to be charged to customers. A significant increase in an entity's future rates may create a strong incentive for customers to reduce their consumption or switch to an alternative. When it is not reasonable to assume that an entity will collect sufficient revenues and earn a fair return, this may be an indicator of impairment. ..."

60.1 Please define the criteria used by FEU to monitor and identify asset impairment, and provide legal/regulatory support for the definition used.

Response:

As stated in the FEU 2012-2013 RRA response to BCUC IR 2.68.1, long-lived assets (deferral accounts, tangible and intangible assets) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset and eventual disposition. If the carrying amount of an asset exceeds its estimated future cash flows and eventual disposition, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. An example of an event or change in circumstance that would trigger an impairment review would be where certain assets are removed from rate base and/or denied partial or full recoverability from the customer.

Asset impairment is an accounting term and the FEU are not aware of any relevant legal or regulatory definitions.

Please also refer to the response to BCUC IR 1.60.2 for the reference to GAAP.

60.1.1 Please state if the criteria used above is consistent with the 'used and useful' concept referred to above. If no, please explain why not.

[54] http://www.bcuc.com/Documents/Proceedings/2009/DOC_22908_B-7_TGVI-BCUC-IR2-Response.pdf

Response:

The criteria used by the FEU to test for impairment of assets (which is based on the guidance in Generally Accepted Accounting Principles) is aligned with the traditional used and useful concept as discussed in the response to BCUC IR 1.60.1.

The FEU do not agree that the "used and useful" concept referred to in the cross-examination of Mr. Walker is the appropriate concept to consider. In its submissions in the 2011-2012 RRA, the FEU disagreed with the use of the concept and argued for the application of the traditional used and useful test. The Commission's Decision on the FEU's 2011-2012 RRA applied a traditional used and useful test when determining the inclusion of main extensions in rate base (pp. 90-91), rather than the economic concept referred to above.

The "used and useful" concept referred to above is also not endorsed by the article put on the record by Commission staff in the 2011-2012 RRA or this proceeding.

- In the excerpt quoted above, Commission counsel referred specifically to the "broader concept" used by the Massachusetts commission. As identified in the article from which the quote is taken, the "broader concept" is an alternative approach taken by some Commissions in the U.S., and it is contrasted to the traditional concept that has been used "for decades". The article *does not endorse* the broader approach.
- The broader approach is also discussed in the article entitled "The Used and Useful Test" filed by Commission staff as Exhibit A2-11. The thesis of that article is that an economic used and useful test is inappropriate. The author states that there is no legal precedent for the economic used and useful test.

The FEU are not aware of any case in Canada in which the broader or economic used and useful approach has been endorsed. The broader concept of used and useful is also inconsistent with the prudence test, which has been considered by Canadian courts. The "used and useful" test is a distinct test from the assessment of prudence, but they must be applied harmoniously. In order to remain analytically consistent with the accepted prudence test, the "used and useful" concept as applied to distribution assets must focus on the use and usefulness of the assets in the provision of utility service, and not an ex post assessment of the economics of the investment.

Therefore, although the "economically desirable" argument has been advanced in some jurisdictions in the U.S., this definition should not supersede the traditional, accepted definition of used and useful.

60.2 Please discuss the impact of the exposure draft (as referred to in TGVI response to BCUC IR 2.32.1.1 in the TGVI 2010 and 2011 Revenue Requirements and Rate Design Application) on the criteria to monitor and identify asset impairment.

Response:

The exposure draft referred to in TGVI's response to BCUC IR 2.32.1.1 in the TGVI 2010 and 2011 Revenue Requirements and Rate Design Application was the July 2009 International Accounting Standards Board Exposure Draft on Rate Regulated Activities. This Exposure Draft shows a status of "paused" on the IFRS website: "This project is paused until the IASB concludes its ongoing deliberations about its future work plan (visit the Agenda consultation project page for more information)."

The FEU are now under US GAAP and not IFRS. Since the Exposure Draft is not considered to be GAAP, the criteria set forth in the Exposure Draft cannot be considered a valid basis for the FEU to assess asset impairment.

Under US GAAP, the standard to assess asset impairment is ASC 360-35, an excerpt of which is reproduced below.

> *"Measurement of an Impairment Loss*
>
> *360-10-35-17 An impairment loss shall be recognized only if the carrying amount of a long lived asset (asset group) is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset (asset group) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset (asset group). That assessment shall be based on the carrying amount of the asset (asset group) at the date it is tested for recoverability, whether in use (see paragraph 360-10-35-33) or under development (see paragraph 360-10-35-34). An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset (asset group) exceeds its fair value."*

In summary, under ASC 360, impairments are not recognized unless the carrying amount of the asset in use exceeds its undiscounted cash flows, so that if the regulator allows recovery of the asset, but not a return on it, the asset would not be impaired under US GAAP. FEU's criteria to monitor and identify asset impairment are aligned with ASC 360.

60.3 Please provide the most recent FEVI and FEW asset impairment financial reports.

Response:

Impairment of assets in FEVI and FEW (as for FEI) is considered on an annual basis where indications of impairment exist as of year -end. Under US GAAP, a new standard on impairment was effective January 1, 2012 where FEVI and FEW (and FEI) do not have to prepare a detailed quantitative analysis of impairment unless circumstances have changed.

As of December 31, 2011, neither FEVI nor FEW had any impaired assets so no impairment reports exist for these two entities. Annual financial statements for both FEVI and FEW have been filed with the BCUC and no impairment charge was taken for the year ended December 31, 2011.

61.0 Reference: Delivery Rate Design – Maturing Utility

Exhibit B-3, Section 3, pp. 43, 49; Exhibit B-3-1, Appendix C-1, p. 9

FEVI/FEW Competition Risk – Analysis

The FEU state on page 43 of the Application:

> "FEVI is a relatively new utility, and has the highest rate base per customer of all the regions. In addition, it has the lowest use per customer at approximately 50 GJs annually for residential customers. This is in contrast to Mainland and Fort Nelson residential customers, who use approximately 95 and 140 GJs respectively. ...
>
> "The table [Table 3-7] highlights the downward trend in the normalized average use rate for residential customers. At the same time, rate base per customer is forecast to continue increasing. From 2006 to 2013, it is estimated that the average use rate will fall from 60 GJs to 47 GJs or decrease 3 per cent on average each year, while rate base per customer will increase from $5,440 to $7,669, or an average of 6 per cent per year."

The FEU state on page 9 of Appendix C-1 of the Application: "FEVI and FEW is capturing a declining percentage of the new housing starts in their respective service areas."

The FEU state on page 49 of the Application: "Table 3-9 highlights a concerning trend in FEW, the forecast decrease in sales volumes. ... An economic downturn may have a disproportionate impact on FEW customers."

61.1 A October 2011 Foster Associates Opinion on Impact of FEU Amalgamation on Cost of Capital filed at Appendix C-4 of the Application states on page 11, "All other things equal, the improved competitive position of FEVI and FEW resulting from rate harmonization would tend to reduce their stand-alone long-term business risk and costs of capital." Information included in the Application indicate that FEVI and FEW are facing competitive challenges. Do FEU consider that FEVI or FEW are at risk of having an asset impairment issue over the next 30 years if postage stamp rates are not approved? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.60.1 for a discussion on asset impairment.

The FEU do not believe that FEVI or FEW are at risk of having an asset impairment issue at this point in time or in the foreseeable future, but are unable to determine if an asset impairment will arise 30 years from now. Although FEVI has seen declines in its residential use rate from 2006 to 2013, during that same time period residential volumes remained flat and overall system volumes increased from 28.3 PJS to 34.2 PJs (see Table 4-1 on page 54 of the Application). In addition, the increase in rate base per customer during that period was primarily due to the addition of the Mt. Hayes LNG facility and the Customer Care project. The rate base impact of both of these projects will lessen in future years as they begin to depreciate.

Both FEVI and FEW continue to experience some customer growth and the companies do not forecast a large erosion of the customer base in the foreseeable future; thus, the Companies expect that there will be a sufficient customer base over which to collect its cost of service. In addition, the FEU are taking steps to mitigate the trend of declining throughput on the natural gas system through programs such as natural gas for transportation.

That said, the significantly higher rates in FEVI and FEW will pose a higher business risk for connecting new customers to the system and keeping existing customers on the system, as alternative forms of energy may have a competitive cost advantage. Further, the cost of gas is at very low levels and is anticipated to remain low in the short term, but as with any market commodity, the prices could rise due to changes in the demand and supply mix.

61.1.1 If yes, please describe and provide estimates as to the dollar amount at risk and the probability of the event occurring.

Response:

Please refer to the response to BCUC IR 1.61.1.

62.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3.2, p. 162 and Appendices C-6 and C-8

Credit Neutrality

On page 162, the Application quoted DBRS's conclusion that the potential amalgamation and associated rate harmonization will likely be credit neutral to FEI provided that there are no material changes that will negatively affect its deemed capital structure, allowed ROE or fundamental low-risk business model.

In Appendix C-6, Moody's credit opinion dated July 21, 2011 states that potential amalgamation of FEI. FEVI and FEW will likely be credit neutral.

In Appendix C-8, DBRS says that key cash-flow metrics remain moderately lower than those of similarly rated gas distribution peers. It further notes that the stability of FEI's coverage metrics continues to be a key factor in its ratings.

62.1 Page 3 of the Application outlined four options for amalgamation and implementation of postage stamp rates. Do FEU know if the credit agencies are aware of FEU's four options? If so, do FEU believe that the credit agencies' conclusions on credit neutrality could change under different option scenarios?

Response:

The FEU have informed the credit rating agencies of its application and have directed the agencies to the BCUC website for the full application and appendices. The FEU are not aware if the agencies have reviewed the application in full or if they are aware of each option.

FEU do not expect that the credit agencies' conclusions on credit neutrality would change under the four options laid out on page 3 referred to in the question above, but the FEU have not had discussions on each option with the agencies.

62.1.1 If Option F (page 3 of Application) is approved, do FEU anticipate an upgrade of credit rating from the current ratings by DBRS and Moody's? Why or why not?

Response:

No, the credit rating agencies have indicated that amalgamation with postage stamp rates will likely be credit neutral.

62.2 Please comment if the amalgamation of FEI, FEVI and FEW is expected to improve the financial profile of the post-amalgamation FEI, for example, stronger cash-flow metrics.

Response:

As the application is based on an amalgamated cost of service and an allowed ROE and capital structure consistent with the current allowed ROE and capital structure, no material change is expected to the financial profile of the post-amalgamation FEI.

62.2.1 In Appendix C-6, Moody's credit opinion presents the key indicators of FEI from 2006 to the last 12 months ending March 31, 2011. Moody's describes them as among the rating factors. Please provide, in similar format, information on the key indicators for the post-amalgamation FEI.

Response:

FEU have undertook to calculate the key indicators as per the Moody's reports for the 2006 to March 31, 2011 time period. Please note that Moody's calculations involve adjustments to the financial statements that are proprietary to Moody's methodology. While we have attempted to calculate the ratios on a similar basis, the calculations if undertaken by Moody's may vary. The calculations are based on the combined financial statements of the three entities (FEI, FEVI, FEW), which have not been restated. Any change to the resulting combined financials would not materially adjust the ratio calculations from those presented.

The key indicators for the post – amalgamation FEI are as follows:

Key Indicators	TTM[1]	2010	2009	2008	2007	2006
(CFO-pre WC + Interest)/Interest Expense	3.1x	3.1x	2.8x	2.8x	2.7x	2.7x
(CFO - pre WC)/Debt	12.5%	11.8%	10.5%	10.8%	9.6%	10.3%
(CFO-pre WC - Dividends)/Debt	6.9%	7.1%	7.2%	5.7%	3.6%	8.1%
Debt/Book Capitalization	57.2%	58.8%	60.8%	67.1%	67.1%	65.6%

Note: Calculated by FEU based on FEU's interpretation of Moody's Regulated Electric and Gas Utilities rating methodology. FEU's calculations may vary as Moody's may make adjustments to the financial statements that FEU may not be aware of.
[1] - Trailing 12 months ending March 31, 2011

62.2.2 If the credit rating is upgraded as a result of improved metrics from amalgamation, please describe the savings and benefits to shareholders and customers that would flow from approval of amalgamation.

Response:

Similar to today, if a credit rating is upgraded, the benefits of a tighter credit spread would result in a lower cost of debt, than otherwise. This benefit would flow to the customer through a reduction in the Cost of Service and overall rates over time as debt would be incurred at lower rates, all else equal.

62.2.3 If no improvement to cash-flow metrics flow from the amalgamation, would it be fair to conclude that the proposed amalgamation and harmonized rate provide little impact to mitigating financial risks?

Response:

Yes, it would be fair to conclude that the proposed amalgamation and harmonized rates would provide little impact to mitigating post-amalgamation FEI's financial risks

63.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3.2, p. 161; Exhibit B-3-1, Appendix C-1, pp. 1, 2

FEVI and FEW Long-Term Business Risks

The 2009 Return on Equity and Capital Structure proceeding discussed and accepted a number of key drivers affecting the business risks of the benchmark utility FEI. Page 161 of the Application lists, among others, BC Government policies on climate change and energy policies and Aboriginal Rights issues. Page 2 of Appendix C-1 states that the long-term business risk profile relating to FEI also apply to FEVI and FEW, and FEW and FEVI also face additional long-term business risks related to smaller utilities, supply risk and elimination of Provincial royalty revenues.

63.1 With respect to the long-term business risk as a result of Aboriginal Rights or First Nations issues, please provide the number of applications, along with their descriptions, for regulatory approval of projects that involve First Nations consultations for FEI, FEVI and FEW in the last 28 months since the release of the 2009 ROE/CAP Decision on December 16, 2009.

<u>Response:</u>

There are many First Nations in BC and few of these First Nations have signed treaties. The FEU's activities span large parts of British Columbia where these First Nations groups have overlapping territories and competing claims for aboriginal title.

The Court of Appeal has ruled that the BCUC must determine the adequacy of First Nations consultation and accommodation and the Commission's CPCN Guidelines now specify that a CPCN application must include consideration of First Nations consultation. In addition, a Consultation and Notification Regulation ("CNR") created pursuant to the Oil and Gas Activities Act ("OGAA") prescribes a formal process for pipeline companies who are seeking British Columbia Oil and Gas Commission ("OGC") permits to formally notify and/or consult with individuals or organizations that may be affected by OGC permits. The OGC has also created an extensive and step-by-step Consultation and Notification Manual to ensure that the requirements are clearly understood and followed by industry.

While the FEU recognize the significant risk to Projects as a result of Aboriginal Rights and First Nation issues, the FEU have been successful in mitigating most of the risk for projects initiated since the release of the 2009 ROE/CAP Decision on December 16, 2009. This is due primarily to the successful management of First Nation relationships by the FEU and by the FEU's External Relations and Community Relations staff responsible for the development of relationships and consultation with over 90 First Nations and 134 municipal entities in BC. The FEU consult with First Nations on a continuous basis on a variety of issues.

Five projects since December 16, 2009 that have been submitted for regulatory approval and required First Nations consultation are as follows:

1) Highland Valley Pipeline Project

The OGC approved FEI's application to construct the relocated pipeline.

An existing FEI gas pipeline was relocated because the Highland Valley Copper Mine expanded their waste rock storage area. Approximately 3.5 km of FEI gas pipeline was relocated south and west of the existing pipeline, outside the limits of the new waste rock area. As part of the project FEI was required to obtain new right of way ("RoW") for the relocation. The existing gas pipeline was abandoned in place and subsequently buried under the proposed waste rock area.

Construction commenced in May 2010. Local First Nations were employed during the site work for the archaeological assessment. A First Nations Environmental Monitor from Lower Nicola was contracted to provide environmental monitoring during the construction phase. Local First Nations from the Coldwater Indian band were contracted to support company crews during the INS. The project was successfully completed.

The FEU and the OGC contacted the following First Nations and Tribal Organizations:

Shuswap Nation Tribal Council

- Bonaparte Indian Band
- Skeetchestn Indian Band

Nicola Tribal Association

- Shackan Indian Band,
- Coldwater Indian Band (Esh-kn-am Joint Ventures)
- Cook's Ferry Indian Band (Esh-kn-am Joint Ventures)
- Siska Indian Band (Esh-kn-am Joint Ventures)
- Nooaitch Indian Band (Esh-kn-am Joint Ventures)
- Lower Nicola Indian Band
- Upper Nicola Band
- Nicomen Indian Band

Nlaka'pamux Nation Tribal Council

- Oregon Jack Creek Band

- Ashcroft Indian Band

2) Kootenay River Crossing - Shoreacres Upgrade Project

The BCUC approved the FEU's application to construct the relocated pipeline. The FEU obtained a CPCN to upgrade an aerial crossing that is located on the FEI Interior Transmission System (the "ITS"), Savona-Nelson Main Line ("SNML"). The aerial structure, built in 1957, crosses the Kootenay River near the community of Shoreacres and serves approximately 5,700 customers downstream of the crossing. The Kootenay River Crossing - Shoreacres Upgrade Project involves the decommissioning of the existing 8 inch (219.1mm) Kootenay River aerial crossing near the community of Shoreacres. Abandonment of approximately 650 m of 6 inch (168.3 mm) transmission pressure pipe and replacement of both with approximately 880 m of new 6 inch transmission pressure pipe to be installed using Horizontal Directional Drill ("HDD") technology.

Work has begun on this project however there was an 8 months delay driven by First Nation consultation process by the OGC, in which the FEU were involved. The FEU consulted with the Okanagan Nation Alliance, the Ktunaxa Nation Council, and the Sinixt Nation Society.

The three First Nations groups have each participated in archeological studies of the crossing site. All three First Nations had members participate during the archeological field work. Capacity funding was provided for the Ktunaxa Nation Council to review a temporary water use application.

The Kootenay River Crossing - Shoreacres Upgrade Project is currently under construction.

3) Kingsvale to Oliver Pipeline Feasibility Assessment

The FEU are currently undertaking field studies related to the possible expansion of its natural gas transmission system in the BC Interior to increase efficiency, meet emerging demand and improve the ability of moving natural gas across its pipeline system.

The possible project under consideration could be comprised of a 160 km pipeline loop of the existing FEU's pipeline system built in the 1970s between Oliver and Kingsvale. The consideration for additional compression facilities on the interior transmission system is also being considered at locations yet to be determined.

In 2000 to 2002, the FEU initially initiated field studies along the proposed route intended at that time as an extension of the Southern Crossing Pipeline ("SCP") which was completed in 2000 between Yahk and Oliver.

In addition to the proposed pipeline loop and compression, the project may include the construction of a short 8 km pipeline extension between Yahk and Kingsgate in the East Kootenays.

In 2010, the FEU received BCUC approval to conduct feasibility-level assessments for the proposed Kingsvale to Oliver pipeline route. Approximately $1 million was expended to gather biophysical, geotechnical and commercial information to reduce risk and confirm project feasibility. The two biggest issues facing the project are First Nations and archaeological issues and risks. Resources have been expended to identify and define those First Nations risks.

The Canadian Environmental Assessment Agency (the Agency) has allocated a total of $10,200 to the Métis Nation BC to support their participation in the federal environmental assessment of the proposed Kingsvale-Oliver Reinforcement Project in British Columbia.

The pipeline route crosses the traditional territories of numerous First Nations. The pipeline route is located within 5 km of 10 Indian Reserves. The pipeline route will cross the boundaries of two Lower Similkameen band reserves, including Ashnola 10 and Blind Creek 6. The Kingsvale to Oliver Pipeline is at the feasibility assessment stage.

Consultation activities are taking place with the following First Nation groups:

Nicola Tribal Association

- Coldwater First Nation
- Cook's Ferry First Nation
- Nicomen First Nation
- Nooaitch First Nation
- Sxe'xn'x (Shackan) First Nation,
- Siska First Nation
- Upper Nicola First Nation - also a member of the Okanagan Nation Alliance

Unaffiliated

- Lower Nicola Indian Band

Okanagan Nation Alliance

- Westbank First Nation
- Lower Similkameen Indian Band
- Upper Similkameen Indian Band
- Osoyoos Indian Band
- Penticton Indian Band

- Okanagan Indian Band
- Upper Nicola Indian Band - also part of the Nicola Tribal Association

Nlaka'pamux Nation Tribal Council

- Ashcroft First Nation
- Boothroyd First Nation
- Boston Bar First Nation
- Oregon Jack Creek Band
- Lytton First Nation
- Spuzzum First Nation (also a member of the Fraser Canyon Indian Administration)

Fraser Canyon Indian Administration

- Kanaka Bar First Nation
- Skuppah First Nation
- Spuzzum First Nation (also a member of the Nlaka'pamux Nation Tribal Council)

These 6 First Nations are located within a possible construction area of a nine kilometer pipeline extension between Yahk, BC and Kingsgate, BC in the East Kootenays.

1. Tobacco Plains Indian Band
2. Shuswap Indian Band
3. Akisqnuk First Nation
4. Lower Kootenay Band
5. St. Mary's Indian Band
6. Métis Nation BC

4) Coquitlam Dam Pipeline Relocation Project

The portion of the FEU's existing 12 inch gas pipeline that crosses the old BC Hydro Coquitlam dam is to be moved to the new BC Hydro Coquitlam dam (to ensure the pipeline meets seismic safety standards). This requires the FEU to obtain RoW across a small piece of Crown land from the Province of BC (Oil and Gas Commission). As the existing pipeline is on a disturbed area (the old dam) and will be relocated on to the new dam there will be no additional disturbance or environmental impacts.

The FEU are applying for regulatory approval from the BC OGC. FEI is also seeking to obtain a replacement RoW from BC Hydro in order to commence relocation of the pipeline.

Kwikwetlem First Nation is the only First Nation needs to be consulted for this project. The Kwikwetlem First Nation's biggest concern is regarding a future a fish ladder that may be incorporated into the dam. This fish ladder is very important to Kwikwetlem and they want reassurance that the pipeline relocation will not interfere with it being added in the future.

The FEU's discussions with Kwikwetlem First Nation have included the development of a protocol agreement and a capacity funding agreement to enable the review of the proposed project and engage in the consultation portion of the OGC application. Kwikwetlem First Nation is providing an archaeologist support for the OGC application.

The Coquitlam Dam Pipeline relocation Project is pending with proposed construction in 2013.

5) Mt. Hayes LNG Storage Facility Project

While a CPCN for the Mt. Hayes Project was granted by the BCUC in 2007, final accommodation of First Nations in the area included an agreement for the Cowichan Tribes and the Stz'uminus First Nation to obtain an equity stake of 7.5% each in the project.

The BCUC approved the Mt. Hayes Storage Limited Partnership ("Mt. Hayes LP") investment structure in 2011 and the transaction became effective January 1, 2012 with the transfer of beneficial ownership to Mt. Hayes LP. The Mt. Hayes LP provides the Chemainus First Nation ("Stz'uminus") and Cowichan Tribes ("Cowichan") with an option to invest alongside the FEU in the Mt. Hayes liquefied natural gas ("LNG") Storage Facility near Ladysmith, BC. The Stz'uminus and Cowichan each chose to acquire a 7.5% equity interest (up to a combined total of 15%) in the Mt. Hayes LP. Attachment 63.1 contains the press release announcing this arrangement.

The Mt. Hayes LP gives the two First Nations a unique opportunity to build on capacity and business skills within their respective communities. It provides a direct economic benefit to the communities, which in turn will assist both First Nations in pursuing other economic opportunities and development. This is another example of the FEU building successful relationships with First Nation communities across the province. While each project situation will likely be different, this represents an example of the increased complexity in accommodating First Nations interests.

63.1.1 Please provide the amount spent on managing or mitigating this First Nations risk factor and please describe the outcome.

Response:

The FEU are unable to provide the amount spent on First Nations consultation and related activities. The FEU have a number of groups who are involved in the management of First Nations relationships including External Relations, Property Services, Business Development, Corporate Communications and Sales. The primary group is External Relations who manage the relationships with local communities, governments, organizations, other stakeholders and First Nations. The External Relations Group includes 10 staff members (including a First Nations subject matter expert) who all participate in some way in consultation activities with all stakeholder groups. However, the FEU do not track whether consultation is with First Nations or any other community group. The total number of FEU FTEs who consult with First Nations, fluctuates from year to year and month to month depending on the initiatives that are underway in a given time period. Costs related to the External Relations group including salaries, expenses and community investments are approximately $2 million for 2012, but the amount and time spent specifically allocated for First Nations is not tracked. Time spent by other individuals and groups in the FEU on First Nations consultation or relationships is also not tracked in this manner.

As described below, however, the effort and resources required to appropriately address the unique rights of the many First Nations in the FEU's service areas is significant.

The FEU have implemented a holistic First Nations program that includes communications, visibility, providing specific skills training and business opportunities, supporting community and cultural interests, and collaboration with other industry players. A key objective of the program is to increase the recognition of the FEU and its business interests by First Nations throughout BC by being visible at many regional, provincial and some national meetings and conferences like the national Aboriginal Business Opportunities Conferences. Another connection with aboriginal peoples is through key organizations like the Canadian Council for Aboriginal Business and the Industry Council for Aboriginal Business (ICAB), who host events specifically for the purpose of bringing business and First Nations together.

The FEU have made a focussed effort on building good relationships with the many First Nations communities in its service areas, not only with respect to specific projects but through more general community events. Community investment is an important role in developing the relationship between the Companies and Indian Bands, whose co-operation and/or approval is often required to carry out services to our customers. Councils and officials often expect utilities to contribute to health, education, arts, environment and community development initiatives as part of being good citizens of the community. For example, the First Nations Skill Builder program that has been created by the FEU, and now partners with all major utility companies in BC, delivers capacity and skills to First Nations allowing them to gain meaningful and sustainable employment.

Whenever the FEU consider a project, such as the Victoria Regional Office, Biomethane Supply Applications, Fraser River Crossing South Arm, Southern Crossing Pipeline Project and CNG-LNG projects, the FEU assess whether there is a duty to consult with First Nations. The FEU research the project area and identify which First Nations need to be consulted. Consultation begins with notification through written correspondence followed by in person meetings with the goal of developing a consultation strategy with each. The FEU, whenever possible, undertake efforts to make First Nations aware of any economic opportunities and employment training relating to the FEU's project. Aboriginal use studies are also vetted with First Nations and, when feasible, First Nations are contracted by the FEU to complete the same. To the extent required, the FEU will work with each First Nation to support involvement in the regulatory process.

Consultation and accommodation of Aboriginal interests takes a significant amount of time to do well. Aboriginal consultation is often based on a variety of agreements. These negotiations must be founded on strong relationships and each negotiated over months or years. Examples of different arrangements made with First Nations in respect to particular projects are provided in BCUC IR 1.63.1.

Through the efforts described above, the FEU have been successful in working with First Nations. For example, the FEU have had success in building good working relationships with the Squamish Nation and Lil'wat First Nation around the construction of the Whistler Pipeline. As described in the response to BCUC IR 1.63.1, the Cowichan Tribes and the Stz'uminus First Nation have also invested into a limited partnership with FEVI in the Mt. Hayes storage facility. More information with respect to the outcomes of specific projects is also provided in the response to BCUC IR 1.63.1.

63.1.2 Have there been projects that could not proceed as a result of Aboriginal Rights issues? If so, please describe the impact on revenues for respectively FEI, FEVI and FEW as a result of First Nations risk in the last two years.

Response:

No projects have been cancelled. However, the Kootenay River Crossing - Shoreacres Upgrade Project was delayed due to First Nations consultation issues as discussed in the response to BCUC IR 1.63.1.

Projects have proceeded as a result of the proactive relationship building approach maintained by the FEU.

63.2 With respect to the long-term business risk as a result of BC Government policies on climate change and energy policies (cross-reference, p. 64 of Application), please provide the number of applications for regulatory approval in the last 28 months since the release of the 2009 ROE/CAP Decision on December 16, 2009 that involve projects/initiatives/proposals that have elements in GHG emissions reductions, carbon neutral commitments, or routine applications that require consideration of the *Clean Energy Act* and B.C. Climate Action Charter & Municipal Government Commitment.

Response:

Of the approximately thirty-five applications that sought approval or an order from the Commission since December 2009 (excluding applications of a routine nature which do not normally trigger a public review process), nineteen have been identified during that period which involved elements of government energy policy considerations regarding the environment, GHG emissions, carbon neutrality, and related policy, legislative or statutory obligations. Those nineteen applications sought approval or an order from the Commission, and either have been, are, or are likely to be, subject to public regulatory review process. Although included in the list below, the AES Inquiry was not an application by FEI, but rather a process initiated by the Commission. The AES Inquiry has dealt considerably with the issues listed in the IR, and has developed into a comprehensive public regulatory review process with a large procedural record. The following is a list of the nineteen filings identified.

There are numerous pending applications which involve elements of government energy policy considerations regarding the environment, GHG emissions, carbon neutrality, and related policy, legislative or statutory obligations.

	Company	Submission Subject
1.	**TGI**	Application to Provide Firm Transportation Service to Westcoast Energy Inc. - Transportation by Others ("TBO")
2.	**TGI**	Biomethane Application
3.	**Terasen Utilities**	2010 Long Term Resource Plan
4.	**TGI Fort Nelson**	Fort Nelson 2011 Revenue Requirements Application
5.	**TGI**	CNG and LNG Service for Vehicles Application

	Company	Submission Subject
6.	**TGVI**	Regional Operations Centre CPCN Application
7.	**FEU**	2012-2013 Revenue Requirements and Rates Application including EEC
8.	**FEI**	Application for Approval of a Compression Rate Schedule, Compression & Dispensing Rate Calculation and Resulting Effective Rate to Provide for Public NGV Refueling at FEI Surrey Ops Centre
9.	**FEI**	Application for Approval of Agreements for Compression and Dispensing to Service to Waste Management
10.	**FEI**	Application for Approval of Service Agreement for LNG Service & LNG Delivery and Daily Charge for the Use of a LNG Tanker & Mobile LNG Refueling Station (Vedder)
11.	**FEI**	Delta School District No. 37 Application for Approval of Contracts for Thermal Energy Services (TES)
12.	**FEI**	An Inquiry regarding the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (AES Inquiry)
13.	**FEI**	Biomethane Purchase Agreement with Fraser Valley Biogas
14.	**FEI**	Application for a CPCN for Constructing and Operating a CNG Refueling Station at BFI Canada Inc.
15.	**FEI**	Tsawwassen Springs Development Thermal Energy Services (TES) GTC12A Application
16.	**FEI/FEVI**	Price Risk Management Plan
17.	**FEU**	Common Rates, Amalgamation and Rate Design Application
18.	**FAES**	PCI Marine Gateway CPCN Application
19.	**FEI**	Biomethane Purchase Agreement with City of Kelowna

63.2.1 Does the government energy policy also create new opportunities for FEI, FEVI and FEW? For example, businesses in alternative energy solutions and new initiatives? Please elaborate.

Response:

This response addresses BCUC IRs 1.63.2.1 and 1.63.2.2.

The government's energy policy has contributed to the emergence of some opportunities for the FEU. Based on government energy policy and the needs of customers, the FEU have initiated its TES, NGT and Biomethane services, which have been brought to the Commission for approval in various applications.

TES is a separate class of service, or will be operated out of a separate entity. The significance of this structure is that the risks and revenues associated with TES are kept separate. The business will neither add nor mitigate business risk facing the natural gas class of service except to the extent that it affects natural gas throughput. Evaluating that impact is not straightforward. TES results in a net loss of load when existing natural gas customers switch to TES, but adds some new load as a back up supply when a non-customer takes TES. The impacts are not readily ascertainable at this early stage of the business and are a long way from the point at which they can have a material impact on throughput on the overall system. These impacts would occur regardless of who is providing the TES offering to customers.

The FEU are looking to Biomethane to help to retain customers that might otherwise adopt a different thermal energy solution due to environmental considerations. The FEU are looking to NGT as a means of building load on the system to help maintain throughput levels for the system. These initiatives come with their own risks, including risks related to customer acquisition and regulatory risks, as evidenced by the AES inquiry in particular. These initiatives are in their nascent form and have yet to make a material impact on total throughput. To the extent that these initiatives are successful in the long term, they can help to mitigate further increases in long term business risk. However, the presence of these opportunities do not outweigh the challenge posed by government energy policies for the much larger traditional market for natural gas use (discussed in Section 4.1.4 and Appendix G-0 of the Application) in a way that would reduce business risk.

63.2.2 Do FEU agree that new business opportunities have mitigated the risks and provided FEU with potential for increased revenues?

Response:

No, while the new opportunities may increase revenue for the FEU they have not reduced the business risk. Please refer to the response to BCUC IR 1.63.2.1.

63.2.3 Where possible, please quantify the energy policy risk's that has had an impact on revenues for respectively FEI, FEVI and FEW in the last two years.

Response:

While it is clear that energy policy risk has had an impact on revenues (see Appendix G of the Application), the FEU do not believe it is possible to specifically quantify the impact of energy policy risk on revenues. For example, while energy policy has contributed to the decrease in market share of natural gas in the new construction market and the lower UPC rates in new and existing homes (see Appendix G-10 for example), there are many variables leading to these decreases and the FEU do not have the analysis or information to isolate the direct or specific impact of energy policy as distinct from other economic or social drivers.

64.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3.2, p. 162; Exhibit B-3-1, Appendix C-4, p. 13

Proposed Capital Structure for FEI Amalco

On page 162 of the Application, FEU state "Ms. McShane's evidence supports that the FEW and FEVI stand-alone capital structure should have a greater equity component (at 45% equity); FEI Amalco is seeking to maintain the 40% equity 60% debt ratio on an amalgamated basis as <u>the Companies recognize that amalgamation will mitigate certain business risks that are unique to stand alone FEVI and FEW</u> and a 40% Common Equity ratio for FEI Amalco would set a reasonable capital structure." [Emphasis added]

In her Opinion on Impact of Amalgamation on Cost of Capital, Ms. McShane submits that "In my "Opinion on Common Equity Ratios for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.", I concluded that, if FEVI and FEW are to continue to operate as stand-alone utilities, their regulated (deemed) common equity ratios should be set at 45%. Since these common equity ratios reflect the two utilities' pre-amalgamation costs of capital, they should be used for the purpose of estimating the upper end if the range of an appropriate common equity ratio for FEI post-amalgamation. The indicated weighted average common equity ratio of the three utilities is 41.2%."

64.1 In FEU's statement above, are FEU implying that the mitigation of certain business risks unique to FEVI and FEW, as a result of amalgamation with FEI, translates in a lower equity thickness for FEI Amalco, i.e., 40 percent, as compared to the indicated weighted average common equity ratio of the three utilities at 41.2 percent, as calculated by Ms. McShane? If not, please explain why not.

<u>Response:</u>

The expert opinion of Ms. McShane, as quoted above, supports an *appropriate range* for common equity ratio for the amalgamated entity of 40% (FEI's pre-amalgamation cost of capital) to 41.2%. The 41.2% figure reflects the indicated weighted average common equity ratio of the three utilities, based on Ms. McShane's recommended stand-alone 45% equity ratios for FEVI and FEW, which reflect their unique long-term business risks in the absence of amalgamation.

The FEU agree with Ms. McShane that amalgamation will mitigate, but not eliminate, business risks that are unique to stand- alone FEVI and FEW (as discussed in the response to BCUC IR 1.70.1), and that, in principle, the common equity ratio of FEI Amalco should lie toward the upper end of the range of 40% to 41.2% . Nevertheless, Ms. McShane's evidence indicates that FEI Amalco's cost of capital lies within a range, with the bottom end of the range representing FEI's pre-amalgamation cost of capital. Thus, for purposes of interim rates, the FEU believe that FEI's pre-amalgamation equity ratio of 40% is reasonable, if slightly conservative, for FEI Amalco.

64.1.1 If yes, please confirm that, in FEU's view, the appropriate reduction in equity thickness for the Amalgamated Entity versus the three stand-alone utilities is 1.2 percent, calculated as the difference between Ms. Mcshane's 41.2 percent and FEU's requested 40 percent. If not, please reconcile with FEU's statement quoted above.

Response:

Please refer to the response to BCUC IR 1.64.1.

64.2 Please list the specific business risks of FEVI and FEW that an amalgamation with FEI would mitigate and also explain how the amalgamation would mitigate each of these risks.

Response:

Please refer to the response to BCUC IR 1.70.1.

64.2.1 Do FEU want to be given credit for "only" requesting a 40 percent common equity ratio for FEI Amalco as opposed to requesting the higher common equity ratio of 41.2 percent as indicated by Ms. McShane? If not, please reconcile with FEU's underlined statement quoted above.

Response:

Please refer to the response to BCUC IR 1.64.1.

64.3 While Ms. McShane states that the 45 percent common equity ratios reflect the two utilities' pre-amalgamation costs of capital, is it not true that Ms. McShane's opinion has in fact not yet been tested in a regulatory review and approved by the Commission?

Response:

The discussion and the analysis of FEVI's and FEW's long- term business risks and equity ratios was prepared and submitted as part of this proceeding to satisfy the Commission's directive to provide evidence on FEVI and FEW's equity component , as discussed in Section 8 of the Application. This expert opinion, and Ms. McShane's other expert opinion on "Impact of Amalgamation on Cost of Capital for the FortisBC Utilities" (Appendix C-4 of the Application), are expected to be tested in a regulatory review as part of this process.

In addition, with the Generic Cost of Capital ("GCOC") Proceeding initiated by the Commission, the FEU expect that a full examination of FEVI's and FEW's long-term business risks will be completed in a future proceeding following the outcome of the GCOC proceeding to establish the equity ratios and risk premiums for the individual entities in the event amalgamation does not proceed.

64.3.1 Please comment why a proposed 45 percent should be used in the analysis instead of the currently approved 40 percent. Should the Commission give any weight to Ms. McShane's statements that the 45 percent common equity ratios reflect of the two utilities' pre-amalgamation cost of capital when the weighted-average common equity ratio of the three utilities is 41.2 percent?

Response:

The current common equity ratios for FEVI and FEW were confirmed as a result of the 2009 Return on Equity and Capital Structure proceeding. While neither FEVI nor FEW had applied for a change to their capital structures as part of the 2009 proceeding, the Commission acknowledged that both FEVI and FEW have greater long term business risk than FEI and directed those utilities to file evidence as to what equity component best reflects their respective long-term business risks by Order G-158-09 dated December 16, 2009.

The evidence and the expert opinion filed as part of this Application indicate that the current approved common equity ratios of 40% for both FEVI and FEW do not reflect the true long term business risks for those utilities. Ms. McShane's assessment of the capital structures of other Canadian and US gas distribution utilities, along with the relative business risk of FEVI and FEW, indicates that "a reasonable common equity ratio for each of FEVI and FEW should be in the range of 45-50% with emphasis on the lower end of the range"[55]. Thus, the 45% stand-alone equity component for each of FEVI and FEW is a more appropriate starting point to estimate the appropriate capital structure for FEI Amalco.

64.4 Ms. McShane, please explain why you recommend that the equity thickness for FEVI be increased from 40 percent to 45 percent when Moody's credit rating for FEVI's senior unsecured debt is A3 (i.e., the same as FEI's senior unsecured debt) and that A3 rating is based on an equity thickness of 40 percent and ROE of 10.0 percent?

Response:

The rationale for Ms. McShane's recommended 45% common equity ratio for FEVI on a stand-alone basis is found on pages 16 to 24 of Exhibit B-3-1, Appendix C-2, Opinion on Common Equity Ratios for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. With specific reference to Moody's, as stated on page 23, the August 1 2011 debt rating report concluded that FEVI was of higher business risk than most LDCs, including U.S. natural gas distribution utilities, due to its high cost of service and small size. In principle, since, in Moody's view, FEVI is of higher business risk than most LDCs, the average equity ratio maintained by U.S. gas LDCs, which averaged approximately 49% over the period 2008-2010, should be viewed as a conservative benchmark for the equity ratio that reflects FEVI's stand-alone long-term business risks.

Further, as Ms. McShane stated on pages 23-24 of her Opinion, "It bears noting that Moody's assessment of FEVI's business risk is predicated on its belief that it is unlikely that the Province would allow FEVI to fail due to uncompetitive conditions in FEVI's service area. While Moody's states that it is not predicting the outcome of this proceeding, it is assuming that ultimately either amalgamation or rate harmonization will occur should FEVI's stand-alone long-term business

[55] Opinion on Common Equity Ratios for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. (Appendix C-2, Common Rates, Amalgamation and Rate Design Application), pg. 26-27.

risks crystallize. Effectively, Moody's business risk assessment, and the corresponding debt rating of A3, partially discounts FEVI's stand-alone long-term business risks. In other words, the existing rating is dependent in part on FEVI's perceived ability to amalgamate or implement postage stamp rates. In the absence of these avenues to address FEVI's competitive challenges, i.e., if FEVI were required to operate on a true stand-alone basis, its Moody's rating would likely be lower than A3 at the current allowed 40% common equity ratio. A higher common equity ratio does not guarantee the preservation of FEVI's A3 rating, as PNG's circumstances demonstrate...despite an actual common equity ratio of close to 50%, PNG is only rated BBB(low) by DBRS. Nevertheless, a higher common equity ratio is required to bolster preservation of FEVI's A3 rating, which is an appropriate objective, should FEVI continue to operate as a stand-alone utility."

64.4.1 To maintain the same A3 credit rating from Moody's with an increased common equity component at 45 percent instead of 40 percent, do FEU agree that FEVI's ROE should be adjusted to 8.9 percent (8.9 percent is calculated as the rate of return on equity required to maintain the total cost of equity amount constant)? If not, please explain why not.

Response:

No. First, the question is based on the erroneous assumption that FEVI's bond rating is the determinant of what is a fair return for FEVI. Neither Moody's nor any of the other debt rating agencies determine what the fair return is for the utilities that they rate. Their function is to assess the ability of a utility to meet its debt obligations. Second, Moody's refers to the weakness in FEVI's credit metrics, with the rating based on its expectation that the weakness in the credit metrics will be short lived. If an increase in the equity ratio were to be offset by a reduction in the equity return, the credit metrics, by definition, would remain weak, which would put pressure on FEVI's bond rating. From a purely qualitative perspective, given Moody's views on the relative business risk of FEVI, i.e., higher risk than most gas LDCs, offsetting an increase in the equity ratio with a corresponding decrease in the allowed ROE, would likely be viewed as a reduction in regulatory support, which has been an underpinning of the existing debt rating.

On page 159 of the Application, FEU provide an excerpt from Commission Order G-158-09: "… the evidence suggests that both TGVI and TGW have greater long-term business risk than TGI while possessing similar deferral mechanisms to enable them to earn their allowed ROEs in the short-term. The Commission Panel further notes Ms. McShane's testimony that both utilities require greater equity thickness than 40 percent."

64.5 Do FEU agree that nothing in this excerpt from Commission Order G-158-09 suggests that the appropriate common equity component in FEVI and FEW's capital structures is or should be 45 percent? If not, please explain why not.

Response:

Agreed. The excerpt was quoted to provide background information, not to show that the capital structure is or should be 45 percent. The Decision did, however, note that the evidence suggested greater long-term business risks for FEVI and FEW and noted Ms. McShane's testimony stating that both FEVI and FEW require greater equity thickness than 40 percent.

64.5.1 If yes, do FEU agree that the appropriate common equity ratios for FEVI and FEW on a stand-alone basis would fall in the range between 40 percent (lower end of the range at current equity thickness) and 45% (upper end of the range recommended by Ms. McShane)? If not, please explain why not.

Response:

No. The FEU do not agree that the appropriate common equity ratio for FEVI and FEW on a stand-alone basis would fall in the range between 40-45%. Based on the evidence and expert opinion of Ms. McShane, the appropriate range would be 45 percent (lower end) to 50 percent (upper end). In her report Ms. McShane states that

> "*… based on the relative risk of FEI compared to FEVi and FEW, a reasonable common equity ratio for FEVI and FEW to compensate for their stand lone long-term business risks is within the approximate range of 45.0%-50.0%."* and that since "*the indicators summarized … are clustered toward the lower end of the range, i.e. closer to 45% than 50%, I recommend that, if FEVI and FEW continue to operate as stand-alone utilities, a 45% deemed common equity ratio be established for both FEVI and FEW"*.[56]

[56] Exhibit B-3-1, Appendix C-2,pg. 24-25.

The evidence on the long term business risks and the expert opinion for the appropriate equity ratio for FEVI and FEW as provided as part of the Common Rates, Amalgamation and Rate Design Application suggests that both FEVI and FEW face higher long-term business risks than the benchmark utility and thus should have a higher common equity component within the range of 45%-50% - closer to the lower end of this range at 45%.

Reference: Table IR 64.10: Capital Structures for FEI Amalco, FEI, FEVI and FEW

	Source	FEI Amalco	FEI	FEVI	FEW
1	Ms. McShane (Exhibit B-3, Appendices C2 and C4)	41.2%[a] (recommended)	40% (approved)	45% (recommended)	45% (recommended)
2	FEU (Exhibit B-3, Section 8.3.2, p. 162)	40% (proposed)	40% (approved)	40% (approved)	40% (approved)
3	Line 1 – Line 2[b]	1.2%	-	-	-
4	Hypothetical scenario	40.5%[a] (hypothetical)	40% (approved)	42% (hypothetical)	42% (hypothetical)
5	Line 4 – Line 3[b]	39.3%	-	-	-

[a] Weighted-average common equity ratio for FEI Amalco
[b] This calculation is done for FEI Amalco only

64.6 If the appropriate equity thickness for stand-alone FEVI and FEW were hypothetically 42% (as shown in the preamble Table IR 64.10) above, and not 45percent as recommended by Ms. McShane, do FEU agree that the weighted average common equity ratio of the three utilities would be 40.5 percent and not 41.2 percent calculated by Ms. McShane? If not, please explain why not.

Response:

The FEU confirm that if the appropriate equity thickness for stand-alone FEVI and FEW were hypothetically 42% each, the weighted average common equity ratio of the three utilities would be 40.5%.

64.6.1 If yes, do FEU agree that the mitigation of certain business risks unique to FEVI and FEW as a result of amalgamation would translate in a common equity ratio for FEI Amalco of 39.3 percent, as shown in Table IR 64.10 above?

Response:

No, the FEU disagree with this rationale.

As elaborated in the response to BCUC IR 1.64.1, Ms. McShane suggests that an *appropriate range* for common equity ratio for the amalgamated entity is bounded at the lower end of the range by FEI's cost of capital pre-amalgamation and at the upper end of the range by the weighted average of the appropriate stand-alone equity ratios of FEI pre-amalgamation, and FEVI and FEVI on a stand-alone basis. If the appropriate equity thickness for stand-alone FEVI and FEW were hypothetically 42% (as shown in Table IR 64.10 in the preamble above), this would only lower the *upper end* of the range to 40.5%, as calculated above, without having any impact on the lower end of the range.

64.7 Do FEU agree that, in Order G-158-09, the Commission confirmed the 40 percent common equity ratios in FEVI's and FEW's capital structures and that, since then, the Commission has not reviewed the capital structures of FEVI and FEW?

Response:

Yes. As neither FEVI nor FEW had applied for a change to their capital structures in the 2009 ROE Application, the Commission consequently confirmed the 40 percent common equity ratios for both utilities through Order No. G-158-09.

As discussed in the response to BCUC IR 1.64.1, as part of the same proceeding, the Commission also acknowledged Ms. McShane's testimony that both utilities require greater equity thickness than 40 per cent and directed the utilities to file evidence as to what equity component best reflects their respective long -term business risks through Directive No. 8 of the same order. The FEU's evidence filed pursuant to Directive 8 indicates a more appropriate common equity ratio for each of FEVI and FEW on a stand-alone basis should be in the range of 45-50% with emphasis on the lower end of the ranges.

64.7.1 As a result, do FEU agree that the weighted-average common equity ratio of the three utilities is currently 40 percent?

Response:

Yes.

64.7.2 If so, please indicate what adjustment, in FEU's view, should be applied to the current weighted average equity thickness of 40 percent to obtain an appropriate equity thickness for FEI Amalco, such that it would recognize that amalgamation will mitigate certain business risks unique to FEVI and FEW, as underlined in FEU's quote on page 162 of the Application.

Response:

No adjustment should be applied. Please refer to the response to BCUC IR 1.64.1.

Even if, hypothetically, the current equity thickness of 40 percent for FEVI and FEW were the appropriate stand-alone equity ratios reflective of their long-term business risks, the applicable equity ratio for FEI Amalco would be 40%, given Ms. McShane's conclusion that amalgamation will not lower FEI's cost of capital.

64.8 Are FEU aware of the fact that significant increases in deemed equity (e.g., from the current 40 percent to 45 percent) for FEVI and FEW, all other things being equal, would require rate increases that would exacerbate existing competitive challenges in FEW and FEVI? Please provide the magnitude of the change in rates for FEVI and FEW based on the recommended 45% from the current 40 percent.

Response:

As explained in the Application, the FEU are not seeking in this Application an increase to the deemed equity for FEVI or FEW. While not relevant to the determination of the cost of capital, the FEU estimate that an increase in deemed equity for FEVI and FEW from 40% to 45% would require rate increases in the order of approximately 2% for FEVI and 3% for FEW.[57]

[57] Due to bundled energy charge, average burner tip increase provided for FEVI. The average delivery rate increase is provided for FEW; the average burner tip increase for FEW is estimated at approximately 2%.

The Federal Court of Appeal in *TransCanada Pipelines Ltd v. Canada (National Energy Board)*, 2004 FCA 149, [2004] F.C.J. No. 654 (QL), held that the determination of the cost of capital cannot take into account the impact on customers. The *TransCanada Pipelines* case is consistent with *Hemlock Valley Electrical Services Ltd. v. British Columbia Utilities Commission et al.*, [1992] 12 B.C.A.C. 1 at 20-21 (C.A.)), where it was confirmed that the utility has a "statutory right to the approval of rates which will afford it the opportunity to earn a fair and reasonable rate of return upon the appraised value of its property." These cases have been included in Attachment 59.1.

Consistent with these cases, the Commission's 2006 Decision on Terasen's ROE, Capital Structure and the Automatic Adjustment Mechanism stated:

> *"In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."*

64.8.1 If FEU are aware of the consequences of significant increases in deemed equity, would FEVI and FEW still apply for the increase recommended by Ms. McShane if the Amalgamation Application is not approved?

Response:

In line with the court decision referred to in the response to BCUC IR 1.64.8, a determination regarding the cost of capital should not take into account the impact on customers. If FEVI and FEW continue as standalone utilities, they will apply for changes to their equity component and risk premium following the GCOC proceeding, making reference to both the characteristics of the benchmark utility that will be determined in that proceeding and the relevant risk factors prevalent at that time. This approach is consistent with the preliminary scoping document in the GCOC Proceeding (Order No. G-20-12) which indicates that the individual utilities' risk premiums will be set in a separate future proceeding for that utility or in a future Multi-Utility Cost of Capital proceeding.

65.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendix C-4, pp. 3-5

Size of Firms by Market Capitalization

Ms. McShane states "… 1,400 stocks traded on the TSX Exchange as of June 20, 2011 with market price data were grouped into deciles by market capitalization…"

65.1 Ms. McShane, please explain the choice of the June 30, 2011 date to assess the market capitalization of the firms traded on the TSX Exchange?

Response:

At the time the analysis was performed, the end of June 2011 represented the most recent month-end date for which market capitalization data were readily available, and thus represented the then-prevailing investor view of the values of companies in the market indices.

65.1.1 Why not choose a date at the end of 2010 that would have corresponded to the date at which FEI's book value of common equity was assessed at $1 billion?

Response:

The analysis could have been done using market data ending December 2010. Whether it had been done at year end 2010 or June 2011, FEI would have been a large cap stock both pre- and post-amalgamation, as confirmed in the response to BCUC IR 1.65.7.

65.2 Ms. McShane, please re-submit Table 1 with an added column showing the number of companies in each decile and in each of the four larger groups?

Response:

Table 1 is re-submitted below with the additional column requested. The minimums and maximums for the Low Cap (6-8) group have been corrected from the values that appeared in Ms. McShane's Opinion.

Table 1: Revised and Corrected

Market Capitalization ($ millions)

Decile	**Minimum**	**Maximum**	**Median**	**Number of Companies**
1	2,327.2	79,177.9	6,573.8	141
2	884.5	2,251.0	1,374.4	141
3	430.9	879.8	606.9	140
4	237.5	430.6	302.1	140
5	148.0	237.3	189.2	140
6	88.9	147.4	113.1	140
7	49.8	88.7	65.4	140
8	28.4	49.7	37.8	140
9	12.3	28.4	20.3	140
10	0.1	12.2	6.9	140
	Minimum	**Maximum**	**Median**	**Number of Companies**
Large Cap (1-2)	884.5	79,177.9	2,268.3	282
Mid Cap (3-5)	148.0	879.8	302.1	420
Low Cap (6-8)	28.4	147.4	65.4	420
Micro Cap (9-10)	0.1	28.4	12.3	280

65.3 Ms. McShane, please re-submit Table 1 using data on the stocks traded on the TSX Exchange as of the end of 2010?

Response:

Table 1 is re-submitted below based on the market capitalizations of the companies on the TSX Exchange as of the end of 2010.

Table 1 Revised 2010

Market Capitalization ($ millions)

Decile	Minimum	Maximum	Median	Number of Companies
1	2,498.8	77,408.0	5,834.8	132
2	998.2	2,469.8	1,490.4	132
3	462.3	997.1	614.0	132
4	264.4	458.4	341.9	131
5	155.3	264.0	205.5	131
6	91.4	154.9	119.5	131
7	54.6	91.3	70.7	131
8	29.7	54.6	38.7	131
9	12.8	29.6	20.3	131
10	0.2	12.7	7.4	131
	Minimum	**Maximum**	**Median**	**Number of Companies**
Large Cap (1-2)	998.2	77,408.0	2,484.3	264
Mid Cap (3-5)	155.3	997.1	302.1	394
Low Cap (6-8)	29.7	154.9	70.7	393
Micro Cap (9-10)	0.2	29.6	12.7	262

Ms. McShane also states "While the equity of FEI is not publicly traded, based on the typical price/earnings ratios of publicly traded Canadian utilities and relatively pure play low risk U.S. gas and electric distribution utilities (approximate range of 16 to 18 times), the pre-amalgamation market capitalization of FEI can be estimated broadly in the range of $1.5 to $1.9 billion compared to $1.9 to $2.2 billion post-amalgamation."

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the pre-amalgamation market capitalization of FEI can be estimated broadly in the range of $1.5 to $1.9 billion compared to $1.9 to $2.2 billion post-amalgamation."

65.4 Ms. McShane, please identify the typical price/earnings ratio of publicly traded Canadian utilities? How many publicly traded Canadian utilities are there?

Response:

The following table shows the price/earnings ratios for the six publicly traded Canadian utilities used to gauge the range of likely P/E ratios for FEI. At the time of the analysis, there were seven publicly-traded Canadian utilities, the other one being Pacific Northern Gas.

	Price/Earnings Ratios				
	2007	**2008**	**2009**	**2010**	**January to June 2011**
CANADIAN UTILITIES	17.1	14.7	11.7	14.3	15.2
EMERA INC	19.4	15.3	16.6	16.4	18.8
ENBRIDGE INC	20.7	20.8	16.1	17.4	22.9
FORTIS INC	20.1	18.2	15.7	18.9	19.5
TRANSCANADA CORP	18.6	16.8	15.0	19.1	19.8
VALENER INC	14.0	11.0	11.6	12.4	16.9
Median	**19.0**	**16.0**	**15.4**	**16.9**	**19.1**

65.5 Ms. McShane, please identify the typical price/earnings ratio of publicly traded relatively pure play low risk U.S. gas and electric distribution utilities? How many of these utilities are there?

Response:

The following table shows the price/earnings ratio for the publicly traded relatively pure play low risk U.S. gas and electric distribution utilities used to gauge the likely range of P/E ratios for FEI. The 13 utilities included in the table below represent the universe of U.S. low risk relatively pure play gas and electric distribution utilities.

	Price/Earnings Ratios				
	2007	**2008**	**2009**	**2010**	**January to June 2011**
AGL RESOURCES INC	15.1	13.4	10.2	12.3	13.2
ATMOS ENERGY CORP	13.7	13.6	12.6	14.3	17.3
CH ENERGY GROUP INC	15.9	16.4	20.9	16.9	17.8
CONSOLIDATED EDISON INC	14.7	12.3	15.0	13.8	14.2
INTEGRYS ENERGY GROUP INC	19.8	16.6	25.6	17.6	14.9
NEW JERSEY RESOURCES CORP	10.7	27.6	23.3	19.3	21.3
NICOR INC	14.3	13.6	13.2	13.2	18.3
NORTHWEST NATURAL GAS CO	18.1	17.9	15.5	16.6	17.9
NSTAR	17.1	15.5	14.6	16.2	17.9
PIEDMONT NATURAL GAS CO	18.3	18.5	15.8	16.7	19.4
SOUTH JERSEY INDUSTRIES INC	15.0	20.0	13.9	22.3	21.6
VECTREN CORP	17.1	15.5	14.1	14.7	17.5
WGL HOLDINGS INC	15.5	14.0	13.3	15.3	15.3
Median	**15.5**	**15.5**	**14.6**	**16.2**	**17.8**

65.6 Ms. McShane please provide the detailed calculations and supporting assumptions for the lower end and upper end of the market capitalization range for: 1) the pre-amalgamation FEI; and 2) the post-amalgamation FEI?

Response:

The following table presents the detailed calculations underlying the market capitalization ranges pre- and post-amalgamation. Please note that there was a typographical error on page 5, line 104. The range of market cap for FEI pre-amalgamation should have read $1.5 billion to $1.7 billion.

	Equity ($M)	ROE	Earnings
	(1)	(2)	(3)=(1)*(2)
FEI	$1,010.87	9.50%	$ 96.03
FEVI	$ 219.06	10.00%	$ 21.91
FEW	$ 18.16	10.00%	$ 1.82
Total	$1,248.09		$ 119.76

	Market Cap ($M)	
	Pre-Amalgamation	
P/E	16X	18X
FEI Earnings * P/E	$1,536.52	$ 1,728.59
	Post-Amalgamation	
P/E	16X	18X
Total Earnings * P/E	$1,916.08	$ 2,155.59

65.7 Ms. McShane, please confirm if the pre and post-amalgamation market capitalization of FEI would still fall within the same (second) decile in the updated Table 1 using data as of the end of 2010?

Response:

It is confirmed that the pre and post-amalgamation market capitalization of FEI would still fall with the same (second) decile in the updated Table 1 using data as of the end of 2010.

66.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendix C-4, pp. 6-7

Correlation of Cash Flows

On page 6, Ms. McShane states: "However, the identification of a lower cost of capital has been associated with diversification among business segments, e.g., different but related lines of business, and where the cash flows from the different lines of business are less correlated."

On page 7, Ms. McShane states: "Given all of the similarities in the fundamental characteristics (e.g., same provincial economy, same provincial energy policy, similar competitive pressures, same regulator) of each of the FortisBC Energy Utilities, the cash flows will be highly correlated. <u>With a high degree of correlation in cash flows among the three individual utilities, amalgamation does not create any meaningful diversification for FEI</u>. Thus, from a diversification perspective, amalgamation does not lower FEI's overall cost of capital." [Emphasis added]

66.1 Ms. McShane, please provide the specific evidence of the high correlation in cash flows among the three individual utilities on which she is basing her concluding statement that amalgamation does not create diversification?

<u>Response:</u>

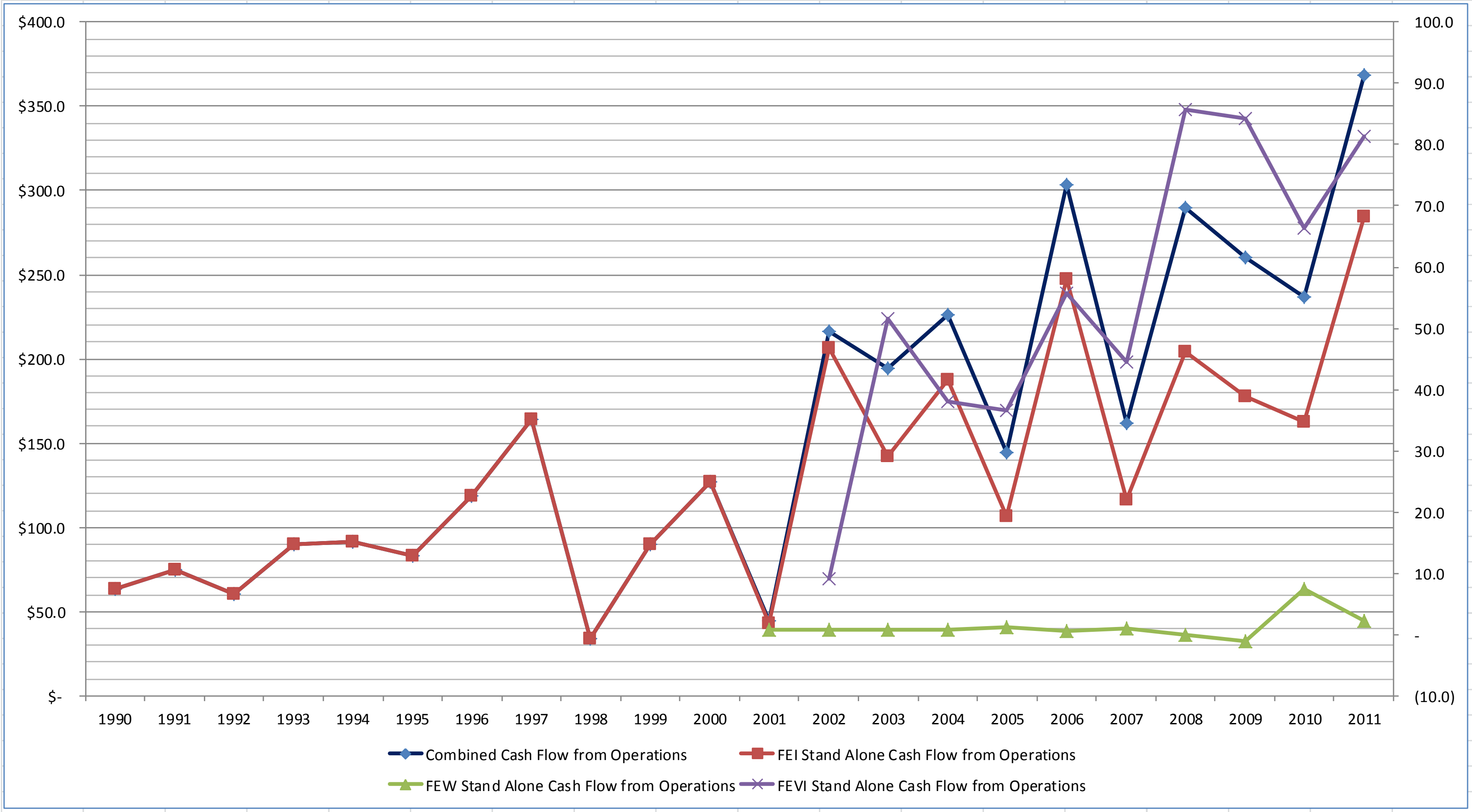
Ms. McShane's conclusion set forth in the preamble to the question that "from a diversification perspective, amalgamation does not lower FEI's overall cost of capital" is based on the correlation of cash flows in the future. As stated (again in the preamble), "Given all of the similarities in the fundamental characteristics (e.g., same provincial economy, same provincial energy policy, similar competitive pressures, same regulator) of each of the FortisBC Energy Utilities, **the cash flows will be highly correlated**." (emphasis added) Please also refer to the response to BCUC IR 1.66.2.

66.2 Please provide a graph showing the cash flows of the three stand-alone utilities, FEI, FEVI and FEW from 1990 to 2011 and describe the graph.

Response:

The graph below shows the operating cash flows for FEI from 1990 to 2011 and the operating cash flows for FEVI and FEW from the point that these companies were acquired by FortisBC Holdings Inc.

Cash Flow From Operations



66.2.1 Are there specific circumstances where the cash flows of the three utilities exhibit less correlation? More correlation? Please elaborate.

Response:

Please refer to the response to BCUC IR 1.66.2 which contains a graph of the operating cash flows from FEI, FEVI and FEW. FEI's and FEVI's cash flows exhibit very similar movements over the period. It is far more difficult to see the similarity in patterns as between FEW and either FEI and FEVI due to the differences in scale. However, it is clear that since conversion, FEW's cash flows have more closely correlated with those of the other two utilities.

66.3 Please calculate the correlation coefficient of cash flows between: 1) FEI and FEVI; 2) FEI and FEW; and 3) FEVI and FEW over the 1990 to 2011 period and over the last 10-year period. Please comment on the results.

Response:

The operating cash flows for FEVI and FEW are only available from the point that these companies were acquired by FortisBC Holdings Inc.

Based on the available historical data, the estimated correlation coefficients are:

FEI FEVI	0.33	2002-2011
FEI FEW	0.00	2001-2011
FEVI FEW	0.04	2002-2011

Please refer to the response to BCUC IR 1.66.1 for comments on the results of how the cash flows of FEI, FEVI and FEW have been correlated over the past ten years and how FEI, FEVI and FEW would expect the cash flows would be correlated in the future.

67.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendix C-4, p. 6

Characteristics of FEI, FEVI and FEW

Ms. McShane states that "The amalgamation of the FortisBC Energy Utilities combines three utilities that share similar characteristics that define their short-term and long-term business risks, including: (1) Line of business; (2) Geographic location; (3) Provincial economy; (4) Provincial energy policy; (5) Competitive environment; (6) Aboriginal issues; (7) Sources of gas supply and access to mainline transmission of that supply; and (8) Regulatory jurisdiction and regulatory model."

67.1 Ms. McShane, please indicate which of the characteristics listed above pertain to the three utilities' short-term business risks and which define their long-term business risks?

Response:

All of the characteristics listed have both short and long term elements. The short-term elements relate to the utility's ability to earn a fair return during a test period, and hence are largely a function of the specific regulatory framework and forecasting risks with respect to customers, load and costs of providing service. The longer-term elements relate to the utility's viability and probability that, over the long-term, the utility will be able to recover the capital invested and a fair return thereon.

67.2 Ms. McShane, please clarify whether the long-term business risks related to "sources of gas supply and access to mainline transmission of that supply" similarly apply to FEI as they apply to FEVI and FEW? Please explain.

Response:

The three utilities have access to the same sources of supply and the same mainline transmission of that supply. The aspects of supply risk that distinguish FEI pre-amalgamation from FEVI and FEW, and which result in higher supply risk for FEVI and FEW than for FEI pre-amalgamation are described in Exhibit B-3-1, Appendix C-2, page 13, lines 336 to 342, specifically:

"An additional business risk not identified by FEI, but one which distinguishes FEI from both FEVI and FEW, is supply risk. FEVI is dependent on the submarine crossing from

the Mainland to Vancouver Island. While the recently constructed Mt. Hayes LNG storage facility improves security of peak supply, FEVI's dependence on the submarine crossing exposes it to higher supply disruption risk than FEI. FEW also faces higher supply interruption risk than FEI, as it is dependent on a single pipeline, the Whistler Pipeline, for delivery of natural gas to its service area."

67.3 Ms. McShane, do you agree with the regulatory practices in many jurisdictions in Canada that capital structures should be reviewed only when there is a significant change in financial, business or corporate fundamentals? If not, why not?

Response:

Broadly speaking, yes. However, these are not the only factors that would warrant a review of the capital structure. Changes in capital market conditions and changes in the returns (combination of capital structure and ROE) available to other utilities could also warrant a review of and change in capital structure in order to ensure that the comparable investment returns requirement of the fair return standard is met.

67.3.1 Please comment on the significant changes that FEW and FEVI have undergone in recent years. Please provide the comments in the context of the short-term and long-term risks in the preamble.

Response:

It is not clear from the question what constitutes "recent" in determining the significant changes that FEW and FEVI have undergone. For clarity purposes, the following table focuses on the events following the Commission's most recent change to FEVI's equity thickness in 2006.

Risk Factors	FEW	FEVI
1.Line of Business (long term)	• Conversion from Propane to Natural Gas service	• No changes

Risk Factors	FEW	FEVI
2. Geographic Location (long term)	• Limits on growth as part of Whistler 2020 plan	• No changes
3. Provincial Economy (short term)	• 2008/2009 Recession • Since the recession , there have been improvements in GDP, employment rates and housing starts • 2010 Winter Olympic Games increased fiscal spending	• 2008/2009 Recession • Since the recession, there have been improvements in GDP, employment rates and housing starts
3. Provincial Economy (long term)	• There have not been any major changes in the long term economic outlook (i.e. no major change in long term pre/post recession predictions)	• Same as FEW
4. Provincial Energy Policy (both short term and long term)	• Climate change and energy policies and legislation now require GHG emissions reductions and focus on energy efficiency and renewable energy sources • Natural gas is typically not promoted for space and water heating, but rather supported for exports and transportation. • Natural gas is subject to Carbon Tax	• Same as FEW
5. Competitive Environment (both short term and long term)	• Competing with electricity and alternative energy sources from a cost, market share, and customer perception perspective • Natural gas commodity prices are lower, however uncertainty over long-term prospects persist • Natural gas capture less of the market for new housing and buildings for space and water heating • Declining UPC trends due to changing energy environment and factors, such as technological advancements that improve appliance and insulation efficiency, changing customer preferences towards energy mix and high density housing • Customers' negative perception of natural gas as a fossil fuel	• Same as FEW • Cessation of Royalty Revenues will pose a significant long term challenge for Vancouver Island customers and FEVI itself by placing upward pressure on rates
6. Aboriginal Issues (long term)	• Uncertainty of the nature and extent of aboriginal rights and title and the lack of treaties as recognized in the 2009 ROE and Cost of Capital Proceeding	• Same as FEW

Risk Factors	FEW	FEVI
7. Sources of gas supply and access to mainline transmission of that supply (both short term and long term)	• The shale-gas revolution put a downward pressure on commodity price of natural gas – however the overall potential for shale gas and its related environmental impact still remains uncertain. • Lower prices have potential to impact supply (i.e. investment in natural gas) negatively • The new supply resources still need to be connected to FEU natural gas markets.	• Same as FEW • Recent construction of Mt. Hayes LNG storage facility partially mitigated the supply risk arising from the submarine crossing
8. Regulatory jurisdiction and regulatory model (long term)	• There is a regulatory lag and disconnect between government policy and utility regulation	• Same as FEW

In Exhibit B-3, Appendix C-1 (pages 2 and 11), FEU make the case that FEVI and FEW have certain business risks that are unique to them: 1) both FEVI and FEW are relatively smaller utilities that cannot diversify their risks to the same extent as FEI, whose assets, geography and economic bases are less concentrated; 2) greater supply interruption risks; and 3) FEVI faced with the risks related to the elimination of Provincial royalty revenues.

67.4 When stating that FEI's assets, geography and economic bases are less concentrated than those of FEVI and FEW, do FEU mean that they are more diversified? If not, please clarify the meaning of "less concentrated."

Response:

Yes. When stating that FEI's assets, geography and economic bases are less concentrated, the FEU mean that they are "more diversified" compared to FEVI and FEW.

67.5 If, on the one hand, FEU state that the three utilities share similar characteristics such as geography and economy, how can FEU argue, on the other hand, that both FEVI and FEW cannot diversify their risks to the same extent as FEI, whose assets, geography and economic bases are less concentrated?

Response:

It is important to distinguish between endogenous (comes within) and exogenous (comes from outside) factors while determining the company specific risk profiles, as exogenous and endogenous factors both contribute to a utility's risk profile. For the FEU, exogenous factors include the same provincial economy, energy policy and regulator for all three utilities and similar competitive pressures (example: cost and perceived attributes of natural gas). These attributes broadly arise from operating in the natural gas market in British Columbia.

Endogenous factors on the other hand are utility specific attributes – such as the customer and asset base. For example, FEI has a more diversified customer base compared to FEVI and FEW, who are dependent on a few industries such as ICP, pulp mills and tourism. Since diversification across sectors and a larger customer base reduces the probability of financial distress, less diversified or a smaller customer base often translates into higher business risks.

Thus two separate utilities that operate in similar environments (thus subject to similar exogenous forces) may have different business risks as highlighted in Moody's August 1, 2011 debt rating repot for FEVI (Exhibit B-3, Appendix C-7):

> *"…FEVI's system has a high capital cost per customer and since inception FEVI has relied heavily on regulatory and political support to ensure that its rates have been competitive with the costs of other forms of energy. FEVI's high capital costs per customer reflect the significant investment in transmission infrastructure required to reach its relatively small customer base on the Sunshine Coast and Vancouver Island and its lower market penetration relative to other gas LDCs [Local Distribution Companies) including FEI."*

67.5.1 Specifically, can FEU clarify whether factors like assets, geography and economic bases of the three utilities are similar or those of FEI are less concentrated?

Response:

Please also refer to the responses to BCUC IRs 1.67.4 and 1.67.6.

As described in the FEVI and FEW long term Business Risks discussion (Exhibit B-3, Appendix C-1), FEVI and FEW are smaller utilities that have a relatively higher cost structure (partially due to the relative age of the respective systems) and smaller, less diverse customer base compared to FEI. This less diverse customer base is a function of both concentrated geography and economic base. For example, FEW serves an area that is a fraction of FEI where nine out of ten largest customers are tourism related enterprises. This concentrated economic base leaves FEW highly susceptible to the economic well-being of the tourism industry.

On page 7, Ms. McShane states that "Given all of the similarities in the fundamental characteristics (e.g. same provincial economy, same provincial energy policy, similar competitive pressure, same regulator), of each of the FortisBC Energy Utilities, the cash flows will be highly correlated. With a high degree of correlation in cash flows among the three individual utilities, amalgamation does not create any meaningful diversification for FEI. Thus, from a diversification perspective, amalgamation does not lower FEI's overall cost of capital." [Emphasis added]

In Exhibit B-3, Appendix C-2 (pages 13-14), Ms. McShane states that "… both FEVI and FEW have less diverse customer bases than FEI. In contrast to FEI, which has a highly diversified industrial base, FEVI has only two large industrial customers, …, representing five pulp mills, and BC Hydro's Island Cogeneration Project (ICP). … FEW's economic and customer base is also less diverse than FEI's, being largely dependent on a single cyclical industry, tourism."

67.6 Ms. McShane, please explain why you consider the fact that the three individual utilities are in the same provincial economy a relevant factor when you also acknowledge that both FEVI and FEW have less diverse customer bases in contrast to FEI, which has a highly diversified industrial base?

Response:

The demand for utility services is in part a reflection of the broad economic conditions, public perception towards energy form, government policy at the provincial and municipal level, costs of energy equipment being installed and demographic trends in their service areas, e.g., population growth which impacts new construction, trends in prices of goods and services, consumer wealth and spending patterns, trends in housing construction (single family houses versus multi-family), and the composition of the key drivers of the economy. Further, the utilities may be regulated by the same regulator and may face First Nations that span across the region.

As utilities operating in British Columbia, all three utilities are affected by the broad economic and demographic trends in British Columbia, and thus are subject to similar economic influences and pressures, as well as being similarly affected by other factors that are inter-related with the provincial economy, e.g., the competitive landscape and provincial energy policy. Nevertheless, FEVI and FEW are more exposed to specific economic pressures, e.g., a less diverse customer bases.

67.6.1 In particular, how would FEI pre-amalgamation be impacted by negative events affecting primarily the pulp mills and tourism sector respectively? And how would FEI Amalco be impacted by those events?

Response:

Pre-amalgamation, FEI has material exposure to negative events in the pulp and paper and the related wood products industry. The combined pulp and paper and wood products industries account for over 25% of pre-amalgamation FEI's industrial throughput and make up, by a wide margin, the largest proportion of the utility's industrial throughput. Given the relative size of FEVI and the volumes attributable to the pulp mills, FEI Amalco's exposure to negative events in the pulp, paper and wood products industry will not be materially different from that of FEI pre-amalgamation.

Regarding tourism, the industry is a major contributor to the British Columbia economy; according to Tourism British Columbia, it is the largest contributor to the province's real GDP of the primary resource industries. The tourism industry includes accommodation and food services, transportation and retail activities, all sectors that are served by pre-amalgamation FEI. A downturn, or a secular decline, in a major contributor to the B.C. economy would have a negative impact on the throughput of pre-amalgamation FEI. Amalgamation of FEW, whose exposure to the tourism industry is significantly higher than pre-amalgamation FEI's, will tend to increase FEI's exposure to negative events in the tourism industry.

In Exhibit B-3, Appendix C-2 (pages 14-15), Ms. McShane states that "Compared to FEI, FEVI faces: (1) as a maturing utility, higher-price-related competitive risks against alternative energy sources, increasing with the loss of royalty revenues; …" and "Compared to FEI, FEW faces: (1) higher competitive risks with electricity due to higher delivery costs; … (4) higher competitive risk from alternative renewable energy sources resulting from service area's commitment to reducing reliance on fossil fuels and commitment to renewable energy initiatives; …"

67.7 Ms. McShane, please reconcile your statement that both FEVI and FEW face higher competitive risks than FEI, risks that will increase for FEVI with the loss of royalty revenues, with your statement that the three individual utilities face similar competitive pressure.

Response:

The term "similar" in the context of "similar competitive pressures" means that the sources of the competitive pressures are similar, e.g., competition from electricity and other sources of energy, and the impacts of energy policy on customer preferences and choices. It does not follow that the degree to which those competitive pressures impact each utility is the same. All three of the utilities experience competition from similar alternative energy sources; however, the competitive risks are higher for FEVI and FEW than for FEI.

68.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendix C-4, p. 8

Range for FEI's post-amalgamation cost of capital

Ms. McShane states: "… FEI's post-amalgamation cost of capital lies within a range, bounded at the lower end by FEI's pre-amalgamation, i.e. the benchmark, cost of capital and at the upper end by the weighted average of the pre-amalgamation costs of capital of the three individual utilities. As regards the upper end of the range, the relevant costs of capital for FEVI and FEW would include not only their utility-specific equity risk premiums but also the common equity ratios that best reflect their long-term business risks."

68.1 Ms. McShane, please state in percentage terms the lower end and upper end of the range for FEI Amalco's cost of capital with respect to ROE and common equity ratio, and provide supporting calculations.

Response:

The lower end of the range referred to the combination of FEI's pre-amalgamation ROE and equity ratio as determined in the Commission's 2009 cost of capital decision, i.e., a 9.5% ROE on a 40% common equity ratio. The upper end of the range includes: (1) the weighted average pre-amalgamation allowed ROEs of FEI, FEVI and FEW, where the allowed ROEs for FEVI and FEW include the 0.50% risk premiums adopted in the 2009 cost of capital decision and (2) the weighted average of the common equity ratios for the three utilities, where the equity ratios include, for FEI, the 40% common equity ratio adopted in the 2009 cost of capital decision and, for FEVI and FEW, the 45% common equity ratios, determined to reflect the two utilities' pre-amalgamation stand-alone costs of capital. The tables below show how the weighted average ROE of 9.62% and common equity ratio of 41.2% were calculated.

ROE:				
	Company 2013 Rate Base ($Millions)	**Percent of Total Rate Base**	**ROE**	**Weighted Average ROE**
FEI	$2,810.54	76.6%	9.5%	7.28%
FEVI	$815.68	22.2%	10.0%	2.22%
FEW	$41.35	1.1%	10.0%	0.11%
Total	$3,667.57			**9.62%**

Equity Ratio:				
	Company 2013 Rate Base ($Millions)	**Equity Ratio**	**Equity ($Millions)**	**Weighted Average Equity Ratio**
FEI	$2,810.54	40.0%	$1,124.22	
FEVI	$815.68	45.0%	$367.06	
FEW	$41.35	45.0%	$18.61	
Total	$3,667.57		$1,509.88	**41.2%**

69.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendix C-4, pp. 3-8

Impact of Amalgamation on Size and Diversification

The expert evidence from Ms. McShane concludes that FEI has already reached sufficient market captalization such that, from a capital markets perspective, the increase in size arising from amalgamation would not lower its cost of capital.

Ms. McShane's evidence also concludes that the amalgamation lacks any meaningful diversification, and concludes that the required return for FEI post-amalgamation would reflect the required returns of the individual utilities weighted by their individual rate bases.

69.1 With respect to the impact of amalgamation on size, would it not be true that the increased size of post-amalgamation FEI would somehow benefit from greater liquidity of the firm's securities and better ability to weather negative events? If not, please explain why not.

Response:

No. Amalgamation produces efficiencies across the portfolio that helps to lower rates for customers. However, the amalgamation is not a recapitalization of each of FEI, FEVI or FEW, but rather an amalgamation of their current capital structures and therefore does not produce any reduction in financial risks relative to the current portfolio. In addition, amalgamation has no effect on overall business risks at a portfolio level which could result in a change to the financial risks and capital structure of FEI at a portfolio level relative to the status quo.

69.2 Page 6 of Appendix C-4 lists eight characteristics that define the three utilities' short-term and long-term business risks. Please comment on the following:

69.2.1 The amalgamated utility would enable the service areas in FEW and FEVI to venture into new initiatives such as alternative energy solutions.

Response:

As discussed in the Application and other IRs, amalgamation and the adoption of postage stamp rates is not a requirement to venture into new initiatives and amalgamation and the adoption of postage stamp rates will primarily facilitate and accelerate the process of extending Commission-approved service offerings. Consequently, while amalgamation and common rates will reduce the total regulatory burden by elimination of regulatory approval processes, amalgamation and common rates do not change the FEU's ability to venture into new initiatives and have no impact on FEI Amalco's long-term business risk compared to FEI pre-amalgamation

Specifically, these initiatives include what the FEU call New Initiatives (Biomethane, NGT, TES).

Currently, the Commission has approved both Biomethane and NGT Services for FEI, within its service territory (with the exception of Revelstoke for Biomethane). Please refer to the responses to BCUC IRs 1.39.2 and 1.40 series for the requirements to expand these service offerings in the absence of amalgamation and common rates.

Amalgamation would have no impact on the ability of FEI to offer TES in the service areas of FEW and FEVI. Under the approved 2010-2011 NSAs for FEI and FEVI, TES activities (alternative energy solutions) have been carried out by FEI regardless of service territory. To the extent TES projects are undertaken by FEI in the future, amalgamation and postage stamp rates would allow this to continue. If TES projects are undertaken by a separate affiliate as suggested by the recent Delta School District Application decision (Order No. G-31-12), then the affiliate would offer TES across the Province and the amalgamation and postage stamp rates for FEI would have no impact on the offering of TES in the existing FEW and FEVI service territories.

69.2.2 A more diverse geographic location and the resulting wider range in winter weather for the heating season would help the Amalgamated Entity?

Response:

As elaborated in the response to BCUC IR 1.58.1, with amalgamation FEVI and FEW are integrated into FEI Amalco. Therefore, in order to compare risks pre and post amalgamation it is appropriate to compare the risks of those entities that exist both prior to and subsequent to amalgamation, namely pre-amalgamation FEI and FEI Amalco.

The FEU do not believe that there will be any meaningful diversification arising from geographic location and the resulting wider range in winter weather for FEI Amalco. The risk associated with a shorter winter for the weather heating season would not be eliminated but transferred to FEI Amalco given the added exposure of post amalgamation FEI to the customers in FEVI compared to pre-amalgamation. Please also refer to the response to BCUC IR 1.70.1 for an examination of risk profiles.

69.2.3 FEW, with its concentration in the tourism industry, and FEI, with its dependence on the intra-provincial economy, would benefit from diversification due to amalgamation.

Response:

The FEU agree that amalgamation and common rates will create a more diverse customer base, and consequently help to mitigate the risks for FEW compared to its stand-alone profile. The amalgamation and common rates, however, would not provide any significant diversification for FEI given its relative size.

Please note that, as described in the response to BCUC IR 1.70.1, the risks associated with FEW's dependence on the tourism industry would not be eliminated as result of amalgamation and common rates application. The risk associated with FEW's tourism focused customer base will transfer to FEI Amalco. In other words, amalgamation will tend to increase post-amalgamation FEI's exposure to negative events in the tourism industry compared to pre-amalgamation FEI.

70.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendix C-4, pp. 9-10

Utility-Specific Risks

Ms. McShane states that "Certain risks that distinguished FEVI and FEW from the benchmark utility, i.e., FEI pre-amalgamation, do not disappear as a result of amalgamation. Instead, with amalgamation, certain risks unique to FEVI and FEW that caused their cost of capital to exceed that of the benchmark utility will be, to a large extent, transferred to FEI post-amalgamation. To illustrate, while FEVI will no longer exist as a separate corporate entity, a material portion of FEI's post-amalgamation service area will still be maturing and thus exposed to the risks associated with a maturing market. The risks associated with FEW's highly concentrated (in the tourism industry) customer base also transfer to FEI."

70.1 Please complete the following tables.

Risk unique to FEVI (as compared with FEI) (Exhibit B-3, Appendix C-2, p. 14)	Is the risk eliminated as a result of amalgamation? Yes / No; please explain your response	Is the risk mitigated (reduced) as a result of amalgamation? Yes / No; please explain your response
As a maturing utility, higher price-related competitive risks against alternative energy sources, increasing with the loss of royalty revenues		
Higher supply interruption risk		
Higher risks due to smaller size and higher asset concentration		
A less diverse economic and customer base, with material reliance on two major industrial customers		

Risk unique to FEW (as compared with FEI) (Exhibit B-3, Appendix C-2, p. 15)	Is the risk eliminated as a result of amalgamation? Yes / No; please explain your response	Is the risk mitigated (reduced) as a result of amalgamation? Yes / No; please explain your response
Higher competitive risks with electricity due to higher delivery costs		
Higher competitive risks from alternative renewable energy sources resulting from service area's commitment to reducing reliance on fossil fuels and commitment to		

renewable energy initiatives		
Higher supply interruption risk		
Higher risks related to small size and concentration of assets in a small geographic area		
A less diverse economic and customer base, with heavy reliance on a single industry		

Response:

The requested tables have been populated based on the premise of the FEU Application, that is, amalgamation and common rates. Further, as was stated in response to BCUC IR 1.58.1, with amalgamation, FEVI and FEW no longer exist; they are integrated into FEI Amalco. In order to compare risks pre- and post-amalgamation, it is appropriate to compare the risks of those entities that exist both prior to and subsequent to amalgamation.

Risk unique to FEVI (as compared with FEI) (Exhibit B-3, Appendix C-2, p. 14)	Is the risk eliminated as a result of amalgamation? Yes / No; please explain your response	Is the risk mitigated (reduced) as a result of amalgamation? Yes / No; please explain your response
As a maturing utility, higher price-related competitive risks against alternative energy sources, increasing with the loss of royalty revenues	No, the risk associated with the loss of royalty revenues is not eliminated, as the amalgamated utility will continue to face competitive risks (in terms of price, market share, and customer preference) against alternative energy sources and will have additional exposure to a maturing market.	Yes, the risk associated with the loss of royalty revenues is reduced in the Vancouver Island service area given that common rates will improve the price competitiveness in that area. However, the amalgamated utility would face marginally higher competitive risks (in terms of price, market share, and customer preference) against alternative energy sources due to the slight decrease in the Mainland service area's price advantage.
Higher supply interruption risk	No, the supply interruption risk is not eliminated, as the existing supply interruption risk to the Vancouver Island service area is a physical asset risk and is not affected by amalgamation.	No, the supply interruption risk is not mitigated, as the existing supply interruption risk to the Vancouver Island service area is a physical asset risk and is not affected by amalgamation.
Higher risks due to smaller size and higher asset concentration	From the perspective of FEI pre-amalgamation, there has not been a specific risk associated with small size given the current size of pre-amalgamation FEI. In the context of market capitalization, FEI Amalco's relative size will be larger but not to an extent that materially changes the risk associated with size. The higher risks associated with the small size of the Vancouver Island service area do not transfer to FEI Amalco. Asset concentration risk relates to the physical concentration of assets, which, as part of a $3.5 million rate base, would be largely eliminated under the proposed amalgamation and common rates.	See column to the left.

Risk unique to FEVI (as compared with FEI) (Exhibit B-3, Appendix C-2, p. 14)	Is the risk eliminated as a result of amalgamation? Yes / No; please explain your response	Is the risk mitigated (reduced) as a result of amalgamation? Yes / No; please explain your response
A less diverse economic and customer base, with material reliance on two major industrial customers	No, the risk is not eliminated. Pre-amalgamation FEI has a large, diverse customer base, but with exposure to industrial margin. Amalgamation of FEVI transfers risk associated with exposure to the two major industrial customers in the Vancouver Island service area to FEI Amalco, resulting in marginally higher exposure for FEI Amalco compared to pre-amalgamation.	See column to the left.

Risk unique to FEW (as compared with FEI) (Exhibit B-3, Appendix C-2, p. 15)	Is the risk eliminated as a result of amalgamation? Yes / No; please explain your response	Is the risk mitigated (reduced) as a result of amalgamation? Yes / No; please explain your response
Higher competitive risks with electricity due to higher delivery costs	No, the risk will not be eliminated, as the amalgamated utility will continue to face competitive risks (in terms of price, market share, and customer preference) with electricity.	Yes, the risks will be mitigated in the Whistler service area, given that common rates will improve the price competitiveness in that area. However, the amalgamated utility would face marginally higher competitive risks (in terms of price, market share, and customer preference) with electricity due to the slight decrease in the Mainland service area's price advantage.
Higher competitive risks from alternative renewable energy sources resulting from service area's commitment to reducing reliance on fossil fuels and commitment to renewable energy initiatives	No, amalgamation does not change the service area's commitment to reducing reliance on fossil fuels and commitment to renewable energy initiatives.	No, assuming no influence of common rates, amalgamation does not change the service area's commitment to reducing reliance on fossil fuels and to renewable energy initiatives.
Higher supply interruption risk	No, the supply interruption risk is not eliminated, as the existing supply interruption risk to Whistler service area is a physical asset risk and is not affected by amalgamation.	No, the supply interruption risk is not mitigated, as the existing supply interruption risk to the Whistler service area is a physical asset risk and is not affected by amalgamation

Risk unique to FEW (as compared with FEI) (Exhibit B-3, Appendix C-2, p. 15)	**Is the risk eliminated as a result of amalgamation? Yes / No; please explain your response**	**Is the risk mitigated (reduced) as a result of amalgamation? Yes / No; please explain your response**
Higher risks related to small size and concentration of assets in a small geographic area	From the perspective of FEI pre-amalgamation, there has not been a specific risk associated with small size given the current size of pre-amalgamation FEI. In the context of market capitalization, FEI Amalco's relative size will be larger but not to an extent that materially changes the risk associated with size. The higher risks associated with the small size of the Whistler service area do not transfer to FEI Amalco. Asset concentration risk relates to the physical concentration of assets, which, as part of a $3.5 million rate base, would be largely eliminated under the proposed amalgamation and common rates.	See column to the left.
A less diverse economic and customer base, with heavy reliance on a single industry	No, the risk is not eliminated. Pre-amalgamation FEI has a large, diverse customer base , but with exposure to industrial margin. Amalgamation of FEW transfers risk associated with exposure to tourism industry in the Whistler service area to FEI Amalco, in principle resulting in marginally higher exposure for FEI Amalco compared to pre-amalgamation.	See column to the left.

As noted in the paragraph preceding the table, the changes in risks have been evaluated under the assumption of amalgamation and common rates. If amalgamation were to be approved, but not common rates, i.e., the Vancouver Island and Whistler service areas were simply to be divisions of FEI, consistent with the stand-alone principle, none of the risks that are unique to FEVI and FEW would be either eliminated or mitigated. Effectively, they would continue to operate as stand-alone utilities, and their risks assessed on that basis.

70.2 Please discuss why FEU does not see benefits in terms of reduced business risks resulting from FEW – a utility with a highly concentrated customer base – amalgamating with FEI – a utility that has a highly diversified industrial customer base.

Response:

Please refer to the responses to BCUC IRs 1.69.2.3 and 1.70.1.

70.2.1 In particular, would FEW not benefit from a much more diverse customer base following amalgamation? If not, please explain why not.

Response:

Please refer to the responses to BCUC IRs 1.69.2.3 and 1.70.1.

70.3 Please explain how the risk to the respective shareholders of FEVI and FEW on a stand-alone basis is altered when these two utilities amalgamate with FEI.

Response:

As described in the response to BCUC IR 1.58.1, with amalgamation FEVI and FEW no longer exist as they are integrated into FEI Amalco. Hence, in order to compare risks to shareholders pre and post amalgamation it is only feasible to compare the risks of those entities that exist both prior and subsequent to amalgamation. Specifically, the appropriate comparison is between FEI pre-amalgamation and FEI Amalco as done by Ms. McShane in Exhibit B-3-1, Appendix C, which concluded that amalgamation does not materially change FEI's ability to diversify its risks. Please also refer to the response to BCUC IR 1.70.1 for a detailed evaluation of the changes in risks under the assumption of amalgamation and common rates.

FEI, FEVI and FEW are all subsidiaries of FortisBC Holdings Inc., which is owned by Fortis Inc. and therefore have the same shareholders.[58] Since the expert evidence indicates that amalgamation with FEVI and FEW will not have any material impact on FEI's ability to diversify its risks, and that FEI, FEVI and FEW have the same shareholders, the FEU submits that risk to the respective shareholders of FEVI and FEW will not be materially changed as a result of amalgamation.

70.3.1 Specifically, who bears the risk of having stranded assets in the Vancouver Island service area under the stand-alone FEVI? Under FEI Amalco? Please elaborate on how is the stranded assets risk altered with respect to the shareholders when comparing stand-alone FEVI with FEI Amalco?

Response:

As elaborated in the response to BCUC IR 1.70.3, FEI, FEVI and FEW are all subsidiaries of FortisBC Holdings Inc., which is owned by Fortis Inc. and consequently have the same shareholders. Therefore, the same shareholders would bear the risk of having stranded assets in the FEVI service area under stand alone and amalgamated scenarios. Stranded asset risk is higher for FEVI stand-alone than for FEI pre-amalgamation, and slightly higher for FEI Amalco than for FEI pre-amalgamation, with the latter reflecting the marginally higher competitive risk faced by FEI Amalco than by FEI pre-amalgamation. Please also refer to the response to BCUC IR 1.70.1 for a comparison of pre- and post-amalgamation business risks.

[58] The corporate structure of the FEU is explained in pages 21 and 22 of the Application.

70.3.2 Specifically, who bears the risk of having stranded assets in the Whistler service area under FEW? Under FEI Amalco? Please elaborate on how is the stranded assets risk altered with respect to the shareholders when comparing stand-alone FEW with FEI Amalco?

Response:

As elaborated in the response to BCUC IR 1.70.3, FEI, FEVI and FEW are all subsidiaries of FortisBC Holdings Inc., which is owned by Fortis Inc. and consequently have the same shareholders. Therefore, the same shareholders would bear the risk of having stranded assets in the Whistler service area under stand alone and amalgamated scenarios. Stranded asset risk is higher for FEW stand-alone than for FEI pre-amalgamation, and slightly higher for FEI Amalco than for FEI pre-amalgamation, with the latter reflecting the marginally higher competitive risk faced by FEI Amalco than by FEI pre-amalgamation.

71.0 Reference: Return of Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendices C-5 and C-8

DBRS Credit Rating for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy Inc.

71.1 Please provide DBRS's credit rating reports for FEI for the last five years.

Response:

The requested DBRS credit rating reports for FEI are attached.

71.1.1 Please provide DBRS credit rating reports for FEVI since the beginning of DBRS credit rating for this utility (confidentially if necessary).

Response:

The requested DBRS credit rating reports for FEVI since the beginning of DBRS credit rating for FEVI have been filed separately as confidential. Confidential Attachment 71.1.1, includes reports dated January 28, 2008, June 1, 2009, November 15, 2010, November 15, 2011 and February 15, 2012.

Pursuant to the Commission's Practice Directive on Confidential Filings, the FEU request that the DBRS credit rating reports filed as Confidential Attachment 71.1.1 be treated confidentially. These reports reflect a private rating provided by DBRS and are subject to confidentiality requirements requested by DBRS. In accordance with the Practice Directive, the FEU request that the reports only be made available to interveners for the exclusive purpose of this proceeding and upon execution of the Undertaking of Confidentiality attached as Appendix K-3 to the Application.

71.2 Are the DBRS rating reports for FEVI and FEI dated respectively November 15, 2010 and September 19, 2011the most recent ones? If not, please provide the most recent ones (confidentially if necessary).

Response:

The DBRS rating report for FEVI dated November 15, 2010 is not the most recent report for FEVI. The DBRS rating report for FEI dated September 19, 2011 is also no longer the most recent. The most recent report for FEI is dated February 29, 2012 and it has been provided in the FEU's response to BCUC IR 1.71.1. Also, the most recent report for FEVI is February 15, 2012 and it has been provided in the response to BCUC IR 1.71.1.1.

72.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3-1, Appendices C-6 and C-7

Moody's Credit Rating for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy Inc.

72.1 Please provide Moody's credit rating reports for FEI for the last five years.

Response:

Moody's credit rating reports for FEI for the last five years are included in Attachment 72.1.

72.1.1 Please provide Moody's credit rating reports for FEVI since the beginning of Moody's credit rating for this utility (confidentially if necessary).

Response:

Moody's credit rating reports for FEVI since the beginning of Moody's credit rating for FEVI are included in Attachment 72.1.1, including Moody's reports dated January 30, 2008, March 16, 2009, March 12, 2010 and August 1, 2011.

72.2 Are Moody's rating reports for FEVI and FEI, dated respectively August 1, 2011 and July 21, 2011 the most recent ones? If not, please provide the most recent ones.

Response:

Yes, the Moody's rating reports for FEVI and FEI, dated August 1, 2011 and July 21, 2011, respectively, are the most recent.

72.3 Please confirm that, according to Moody's, both FEVI and FEI have a credit rating of A3 for the category "Senior Unsecured – Dom Curr." If not, please clarify the credit rating for FEI and FEVI.

Response:

Confirmed. According to the Moody's reports in Exhibit B-3-1, Appendices C-6 and C-7, both FEVI and FEI have a credit rating of A3 for the category "Senior Unsecured – Dom Curr".

72.3.1 If confirmed, please also confirm that the fact FEI and FEVI have the same credit rating from Moody's for the same type of debt means that, for an unsecured bond holder, the two utilities have similar long-term business risks. If not, please explain why not.

Response:

Not confirmed. Moody's rationale for its opinions on the credit ratings of FEI and FEVI is found in the referenced reports. Moody's opinions reflect the different long-term business risks in relation to the debentures of FEVI and FEI and Moody's beliefs regarding the prospect of amalgamation of FEVI and FEI and the harmonization of rates.

For instance, the Summary Rating Rationale for FEI is:

> *"FEI's A3 senior unsecured rating and stable outlook reflect its low-risk LDC business model and supportive regulatory environment which are balanced by its weak financial metrics. We recognize that the weakness of FEI's financial metrics relative to similarly rated U.S. peers is largely a function of the relatively lower deemed equity and allowed ROE permitted by the BCUC. We believe that FEI's weak financial profile is balanced by its relatively low business risk as a gas LDC and by the supportiveness of the business and regulatory environments in Canada generally and in British Columbia specifically. We expect FEI's financial profile to strengthen modestly in 2012 and 2013. Regulatory ring-fencing mechanisms effectively insulate FEI from its weaker parent companies, FHI and FTS. Growth in FEI's franchise area tends to be predictable and capital spending is not expected to tax the company's resources. FEI maintains sufficient liquidity resources."*

In contrast, the Summary Rating Rationale for FEVI is:

> *"FEVI's A3 senior unsecured rating and stable outlook reflect FEVI's status as a regulated Gas LDC. However, FEVI's high cost of service and small size cause its business risk to be higher than that of most gas LDCs. In addition, FEVI's credit metrics are weaker than those of international peers. However, we consider FEVI's high cost of service, small size and weak metrics to be balanced by the relatively supportive business and regulatory environments in Canada in general and FEVI's long history of supportive regulatory and political decisions in particular.*
>
> *The rating also reflects our belief that FEVI's cash flow and financial metrics will be significantly weaker in 2012 due to the scheduled cessation of royalty revenues from the Province of British Columbia at the end of 2011. We believe the weakness in FEVI's metrics will be short-lived because the company will either merge and harmonize rates with sister gas LDC, FEI, causing FEVI's rates to fall or increase its rates to offset the cessation of the royalty revenues. While a significant increase in FEVI's rates would be positive for FEVI's cash flow and financial metrics, it would reduce the relative competitiveness of gas versus electricity in FEVI's service territory. If an increase in FEVI's rates were to lead to a cycle of demand destruction and further rate increases, we continue to believe that amalgamation and rate harmonization, with FEI would be the most likely outcome.*
>
> *FEVI's A3 rating is consistent with the A3 rating implied by Moody's Regulated Electric and Gas Utilities Rating Methodology."*

72.3.2 Please confirm that "Dom Curr" means "domestic currency."

<u>Response:</u>

Confirmed. "Dom Curr" means "domestic currency".

72.4 If FEI Amalco issued debt after the amalgamation how would FEU see the credit spread for long-term bonds being affected as a result of the amalgamation?

Response:

Based on the proposed application, the FEU do not anticipate a change in the credit ratings of FEI pre and post amalgamation, nor a material change in capital structure or allowed ROE. Therefore, the FEU anticipate that the pre-existing long-term bond credit spreads of FEI will change very little due to amalgamation, such that any increase or decrease in the credit spread will be minor. All else equal, the FEU also anticipate that post amalgamation, the credit spreads of the pre-existing long-term bonds of FEVI will contract to the lower credit spread of FEI's existing long-term bonds. Therefore, the FEU anticipate that FEI Amalco credit spreads will closely reflect that of FEI's existing long-term bonds.

73.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 2.1.2, p. 10

Allowed ROE of BC Hydro

"Common rates provide a fair and equitable approach for all customers of the FEU going forward by eliminating the complexity and rate disparity that currently exists. This approach is consistent with the electric utilities in the Province, including British Columbia Hydro and Power Authority (BC Hydro) and FortisBC Inc. (FBC)."

73.1 The postage stamp policy has been in place for BC Hydro since it first came under independent regulation by the British Columbia Utilities Commission in 1980. Do FEU agree that BC Hydro is comparable to the investor-owned FEI for purposes of establishing its allowed rate of return? If no, please explain why not.

Response:

The FEU do not agree that BC Hydro is comparable to the investor owned FEI for purposes of establishing the allowed rate of return for FEI, as FEI believes BC Hydro faces less business, regulatory and financial risk.

The FEU agree that BC Hydro and FEI have commonalities in that they are the largest utilities in BC in electricity and natural gas, respectively. The FEU also acknowledge that BCUC-allowed return on equity (ROE) for FEI, adjusted for income taxes, is the basis for calculating BC Hydro's ROE. The linkage between BC Hydro's ROE and FEI's ROE is based on Heritage Special Direction No. HC2. The use of the approach in Heritage Special Direction No. HC2 has the benefit of pegging BC Hydro's ROE to a Commission-determined value but it is not based on the same process and principles of assessing the riskiness of an investor-owned utility and then establishing a capital structure and ROE. Further, the Government has on occasion over-ridden the outcome based on the Commission's determination of FEI's ROE, such as, for example, by adding 163 basis points to the otherwise determined ROE value for the three fiscal years F2010, F2011 and F2012 (OIC No. 074 dated Feb. 17, 2009).

However, BC Hydro is a non-taxable crown corporation, whose capital is financed through the Province of BC and as such does not face the same financing risk as FEI. From a regulatory perspective, while BC Hydro is subject to regulation, ultimately, its shareholder (the Province of BC) has the ability to protect BC Hydro from any adverse regulatory decision. Further, the BC Hydro system is an integrated system that includes generation (and power purchases from third parties) as well as the transmission, distribution and customer-related functions while FEI's system does not include the equivalent of the generation function since the commodity portion of gas rates is unbundled and market based.

Further, related to long term business risks the two utilities face different challenges. FEI has experienced and continues to experience declines in use rates per customer, while seeing reductions in market capture rates for new construction. This is in contrast to BC Hydro, where electricity is part of every new building and use per customer has either increased or remained relatively unchanged. Finally, the underlying provincial energy policy in the in FEU's opinion is one that promotes the use of electricity, while providing challenges to the use of natural gas. Provincial energy policy is in many ways written with the perspective of BC Hydro, which as a crown corporation, is often used to implement energy policy.

73.2 For each year during the 10-year period 2003 to 2012, please provide the allowed rate of return approved by the Commission for FEI and compare the allowed rate of return (after tax and pre-tax rate of return; with and without adder from Special Direction) for BC Hydro.

Response:

BC Hydro's return on equity has been established since the 1990s using the pre-tax equivalent of the return on equity of the most comparable investor owned utility (which has been FEI). FEI's allowed ROE is effectively therefore the after-tax equivalent of the BC Hydro ROE.

	FEI Allowed ROE[59]	BC Hydro ROE[60]		
		Allowed (Target)[61] (pre-tax)	Actual	Allowed ROE w/o Special Direction Adjustment[62]
2003 (BCH F2004)	9.42%	14.33%	3.60%	Same as Allowed
2004 (BCH F2005)	9.15%	13.91%	14.24%	Same as Allowed
2005 (BCH F2006)	9.03%	13.51%	9.26%	Same as Allowed
2006 (BCH F2007)	8.80%	13.10%	13.44%	Same as Allowed
2007 (BCH F2008)	8.37%	12.05%	11.33%	Same as Allowed
2008 (BCH F2009)	8.62%	11.78%	11.75%	Same as Allowed
2009 (BCH F2010)	8.47%	13.05%	12.49%	11.42%
2010 (BCH F2011)	9.5%	14.37%	14.13%	12.74%
2011 (BCH F2012)	9.5%	14.38%	n/a	12.75%
2012 (BCH F2013)	9.5%	11.73%[63]	n/a	12.75%

73.3 Based on the data from the response to the above question, do FEU agree that FEI has served as the low-risk benchmark utility for BC Hydro, which adopts a postage stamp rate? Please comment if BC Hydro's allowed rates of return largely resemble FEI's allowed rates of return?

Response:

FEI has served as the reference utility for BC Hydro's ROE in accordance with the Heritage Special Direction No. HC2, which sets BC Hydro's allowed ROE to equal, on a pre–income tax basis, to that of the most comparable investor-owned utility, which the Commission has determined to be FEI. As shown in the graph below, BC Hydro's allowed rates of return

59 For years 2003 to 2009, the allowed ROE for FEI is set in November of the previous year.

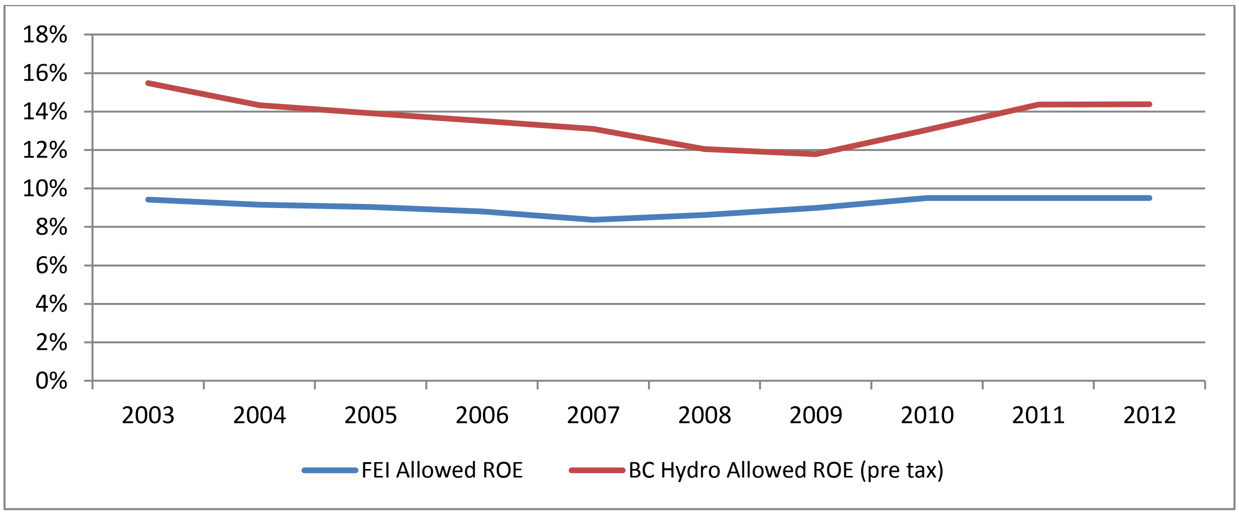
60 BC Hydro ROE values for years 2003-2011 are obtained from corresponding BC Hydro Annual Reports (http://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html), The BC Hydro 2012 ROE value is obtained from the BC Hydro First Quarter Report for Fiscal Year 2012 (http://www.bchydro.com/etc/medialib/internet/documents/about/company_information/reports/2012_q1_report.Par.0001.File.2012_q1_report.pdf).

61 BC Hydro's allowed return on equity is calculated to equal, on a pre–income tax basis, that of the most comparable investor–owned utility as per Heritage Special Direction No. HC2 (i.e. FEI)

62 OIC No. 074 dated February 17, 2009 amended Heritage Special Direction No. HC2 to allow for an addition of 1.63 basis points to the BC Hydro ROE in fiscal years 2010, 2011 and 2012.

63 OIC No. 314 dated May 22, 2012. F2013 ROE reduced by 1.02% relative to the HSD No. HC2 calculation.

resembles FEI's allowed rate of return with a premium to reflect the income taxes payable by FEI as a taxable entity, subject to other ROE adjustments arising from orders-in-council or special directions. Please see also the response to BCUC IR 1.73.1. However, FEI is not a "low-risk" utility. Its role as the benchmark utility is in respect of being the "benchmark" or "standard" used to set the ROE of other utilities in BC.[64]



73.3.1 If postage stamp or common rates delivery is approved in this proceeding, should the Amalgamated Entity be given a lower allowed ROE than BC Hydro on the basis of the elimination of the complex rates and disparity in rates?

Response:

No, the ROE or capital structure for the Amalgamated Entity should be set independently of any comparison to BC Hydro. The linkage between FEI's ROE and BC Hydro's ROE is a function of section 4(d) of Special Direction HC2 that obliges the Commission to set rates for BC Hydro that enable it to achieve an ROE equal to the pre- income tax annual rate of return allowed by the Commission to the most comparable investor- owned energy utility regulated under the Act. The ROE for BC Hydro is not based on a formal assessment of BC Hydro's riskiness in relation to FEI's.

In 2009, the Commission, through Order G-158-09 and its accompanying Decision, had confirmed that the ROE for FEI would serve as the Benchmark ROE for any other utility in BC.

64 The BCUC "TGI-TGVI-TGW Return on Equity and Capital Structure" Decision , 16 December 2009, pages 78-80.

Thus, in support of the rates sought in the Application, FEU addressed the cost of capital for FEI Amalco in comparison to the existing Benchmark, i.e. pre-amalgamation FEI (and not BC Hydro). For the reasons outlined in Section 8 of the Application and in line with Ms. McShane's evidence on Impact of Amalgamation on Cost of Capital, it is reasonable to have a 12 basis point premium over the benchmark ROE (pre-amalgamation FEI at 9.5%) on an interim basis, pending the outcome of the 2012 GCOC Proceeding.

74.0 Reference: Delivery Rate Design – Cost Based Rates

Exhibit B-3, Section 9, p. 181; Reasons for Decision for Order G-156-10, pp. 77, 78; Exhibit A2-8, New Brunswick EUB, July 14, 2011 Decision on Rate Application by Enbridge Gas, pp. 12-15

Acceptable Revenue to Cost Ratios

The FEU, on page 181 of the Application, state "The Company compared class revenues to allocated cost of service and considered 90 percent to 110 percent as a reasonable range to be used as a guide for rate setting."

The Commission, in its Reasons for Decision on an Application by FortisBC Inc. for Approval of a 2009 Rate Design and Cost of Service Analysis (G-156-10), stated on pages 77 to 78:[65]

> "The Commission Panel notes BCMEU and BCOAPO's comments concerning the relative accuracy of FortisBC's load data as compared to BC Hydro's but also notes that neither party presented empirical evidence justifying their position that the range of reasonableness should be increased to 90 to 110 percent. The Commission Panel accepts FortisBC's assessment that there is no indication of systematic bias in the COSA. The Commission Panel also accepts FortisBC's position that the range of reasonableness is based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the range of reasonableness for BC Hydro.
>
> In addition, the Commission Panel considers that the load profiles of FortisBC and BC Hydro's Southern Interior delivery area are sufficiently comparable to give a degree of confidence in FortisBC's use of the latter's load research data.
>
> Accordingly, the Commission Panel finds that the range of reasonableness of 95 percent to 105 percent is the correct range for the purpose of future rebalancing in the circumstances of FortisBC. FortisBC's proposed range of reasonableness of 95 percent to 105 percent is approved...
>
> Accordingly, the Commission Panel finds that the appropriate target for revenue-to-cost ratios in each class is unity or one, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness."

65 http://www.bcuc.com/Documents/Proceedings/2010/DOC_26325_FortisBC-2009-RDA_WEB.pdf

A July 14, 2011 Decision by New Brunswick Energy and Utilities Board (EUB) on a Rate Application by Enbridge Gas New Brunswick (ENGB)[66] stated on pages 12 to 15 (Exhibit A2-8):

> "It was always understood that some level of cross subsidization was necessary for the continued survival of the franchise, but the Board finds that some limit to the cross-subsidization is appropriate. The Board has determined that customers who are paying more than their cost of service can no longer have rates determined solely by the market value but rather, such rates must incorporate a cost-based component. The question becomes how and when to move from the current system to a revised rate-setting mechanism. ...
>
> The Board finds that this is the appropriate time. EGNB has held the natural gas distribution general franchise in excess of ten years. A cost of service study has been completed, reviewed and approved by the Board. The study indicates that certain groups of customers are paying more than their cost of service while others are paying much less. These costs are unlikely to change in the near future. Recent rates of growth, while significant, do not suggest that EGNB's throughput is likely to increase substantially in the near term. This is particularly true in those classes containing larger volume customers. ...
>
> EGNB has taken the first step towards a consideration of cost of service issues. The Board directs EGNB to present a transition plan that maps the next steps in this transition. The objective of this transition would be to arrive at level of cross-subsidization which would be appropriate over the medium term, taking into consideration the interests of both the utility and its customers."

74.1 Do FEU agree that, for a mature utility, for each customer class in a "distinct or special area," the range of reasonableness for future rebalancing, based on the results of the Fully Distributed COSA Study, can be influenced by the accuracy of the cost data and policy considerations, such as previous Commission decisions regarding the range of reasonableness for other utilities? If no, please explain why not.

Response:

As indicated in this Application, ideally the revenue to cost ratio should equal 100 percent for each rate class. However, achieving unity implies a level of precision that does not exist with any COSA. This sentiment is echoed in Commission Order G-23-91. For this reason, a 'Range

[66] http://156.34.203.123/Documents/Decisions/NG/E/20111407EGNBVariousRatesE.pdf

of Reasonableness' is necessary to determine at which point rate re-balancing is necessary, as determined by whether the Revenue to Cost ratios fall within or outside of a prescribed Range of Reasonableness.

Policy considerations and data accuracy both influence the Range of Reasonableness in different ways. Policy considerations, such as past decisions regarding the Range of Reasonableness for other utilities, help guide what an acceptable band range (i.e. +-5%; +-10% etc.) could be before triggering the need to rebalance rates. Data accuracy determines how close revenue can be matched up to costs in a COSA study. The more accurate the input data for a COSA study, the closer in line class revenue to allocated cost of service can be to 100% and vice versa.

In this application, the FEU used a Range of Reasonableness for its class revenues to allocated cost of service of 90% to 110% rather than the Range of Reasonableness used for the Electric Utilities in BC of 95% to 105%. As indicated in the Application, the FEU adopted the 90% to 110% range for the following reasons:

1. The accuracy of the system demand data is relatively imprecise compared to the system demand data used for electric utilities, to the extent that the FEU believes the 95% to 105% range is not appropriate for natural gas utilities[67].

2. Policy Considerations specific to the Natural Gas Industry support the 90% to 110% Range:

    i. Commission Order G-42-91, which endorses the 90% to 110% Range of Reasonableness for Pacific Northern Gas's 1991 Rate Design Application.

    ii. The commission accepted as a guide to rate setting, a "range of reasonableness" of 90% to 110% in the BC Gas 1993 Phase B Rate Design. The same range was used in the BC Gas 1996 Rate Design.

3. EES Consulting has considered the appropriate "Range of Reasonableness" and concludes that a 90% to 110% range is warranted for natural gas utilities.

See Section 9.7.1.2: The "Range of Reasonableness" Defined, p. 217 – 220 for full rationale.

[67] See Section 9.7.1.2: The "Range of Reasonableness" Defined, p. 217 - 220

74.2 Do FEU agree that, for a mature utility, for each customer class in each "distinct or special area," the appropriate target for revenue: cost ratios in each class is 100 percent? If no, please explain why not.

Response:

As indicated in the Application and in response to BCUC IR 1.74.1, ideally the revenue to cost ratio should equal 100 percent for each rate class. However, achieving unity implies a level of precision that does not exist with any COSA. For this reason, a range of reasonableness of 90% to 110% is more appropriate for natural gas utilities, as discussed in greater detail in response to BCUC IR 1.74.1.

74.3 Do FEU agree that, for a mature utility, for each customer class in each "distinct or special area," future rebalancing is required when a customer class falls outside of the range of reasonableness? If no, please explain why not.

Response:

Generally, when a customer class falls outside of the appropriate range of reasonableness, rebalancing would be suggested. There may be circumstances where this would not be appropriate, such as when it is very close to the range of reasonableness, when it creates rate shock, when the COSA does not adequately measure the costs for a particular class, or when expected changes to costs in the near future would bring the class within the range of reasonableness.

74.4 Do FEU consider that FEVI and/or FEW should be allowed greater flexibility to vary from the reasonable range of acceptable revenue: cost ratios as they are maturing utilities?

Response:

The FEU believe that maturing utilities, like FEVI and FEW, should be allowed greater flexibility in setting rates, including the acceptable range of reasonableness. In the event amalgamation is not approved, the FEU will address the appropriate range of reasonableness for FEVI and FEW in future rate applications.

74.4.1 If yes, please describe the approach FEU recommends in determining acceptable revenue: cost ranges for these companies, and how the transition to cost based rates for each customer class would be achieved.

Response:

Please refer to the response to BCUC IR 1.74.4. In the event amalgamation is not approved, the FEU will address the appropriate range of reasonableness for FEVI and FEW in future applications.

74.5 Please explain why FEU has used a range of reasonableness for its class revenues to allocated cost of service of 90 percent to 110 percent, rather than 95% to 105%.

Response:

Please refer to the response to BCUC IR 1.74.1.

74.5.1 Do FEU consider that there is systemic bias in any of its companies' Fully Distributed Cost of Service Allocation Studies? If yes, please explain.

Response:

No, the FEU do not consider there is a systemic bias in the results.

74.5.2 Please describe the degree of confidence of FEU's consumption data used in each of its Fully Distributed COSA Studies.

Response:

The FEU have a high degree of confidence in the datasets for consumption and weather used to calculate load factors for the purposes of COSA Study. FEU has been using these datasets for nearly a decade and they are considered stable and reliable.

74.5.3 Do FEU consider that it is appropriate for the COSA Model to also include gas revenues and costs, when these costs are not allocated to customers but are passed through directly? If yes, please explain what purpose is served by their inclusion.

Response:

It is appropriate for the COSA model to include gas revenues and costs even though the cost of gas is passed through directly to core market customers. The purpose of their inclusion is explained below.

The COSA model is one of the primary tools used to establish cost guidelines for the evaluation of rate class revenue levels. This evaluation process includes a comparison of the total revenues collected from the rate class (including gas revenues) with the corresponding total cost to serve them (including the cost of gas). This comparison is often termed as revenue to cost ratio. Generally, a COSA model uses an established range of reasonableness to assess the appropriateness of the resulting revenue to cost ratio or rates to serve customers. The exclusion of gas revenues and costs from total revenues and total cost of service would reflect inappropriate revenue to cost ratios, making it difficult to assess if rates for any customer class are reasonable and adequate to recover their allocated cost of service.

It is important that the revenue to cost ratio reflects the total costs that are seen by a customer class so that it can be considered on a comparable basis to other utilities in both the gas and electric industries. This allows the guidelines on the range of reasonableness to be compared on an equal footing.

75.0 Reference: Delivery Rate Design – Cost Based Rates

Exhibit B-3, Section 2, p. 12, Section 3, p. 31 – 49

Rate Base

The FEU state on page 12 of the Application:

> "In their report, EES Consulting recognizes that "the current regional differences in delivery rates… [for the FEU]…do not necessarily reflect the same regional separation that would occur based on operating and cost differences alone." The end result is rate disparity across the areas served by the FEU that is based more on history rather than necessarily being based on cost of service."

The FEU state in Section 3 (pp. 31, 36, 43, 49) of the Application that the rate base per customer for 2010 was: FEI (Mainland): $3,010; FEFN: $2,292; FEVI: $5,536; FEW: $17,556."

75.1 Do FEU consider that rate base per customer of (for 2010): FEI (Mainland) of $3,010; FEFN of $2,292; FEVI of $5,536; FEW of $17,556 indicate postage stamp rates would move the utilities further away from cost based rates than the status quo? If no, please explain why not.

Response:

The proposed rate methodology is cost-based. Postage stamping does not mean that rates are not cost-based. Costs can be anywhere on a continuum from costs per individual customer to a cost that is averaged over all customers on the system, regardless of customer class. The proposed postage stamping of rates will provide rates that are cost-based for each rate class averaged over the entire service area.

76.0 Reference: Delivery Rate Design – Cost Based Rates

Exhibit B-3, Section 3, pp. 35-50, Section 9, p. 210, 220

Revenue to Cost Ratios

The FEU, on pages 35 to 50 and 220 of the Application include the following revenue to cost ratios:

Table 3-3: 2013 FEI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	92%
Rate 2 - Small Commercial	103%
Rate 6 - Seasonal	124%
Rate 3 & 23 - Combined	117%
Rate 5 & 25 - Combined	146%

Table 3-5: 2013 FEFN COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	81%
Rate 2.1 - General Service 2.1	116%
Rate 2.2 - General Service 2.2	129%
Rate 25 - Firm Transportation Service	126%

Table 3-8: 2013 FEVI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
RGS - Residential	82%
AGS - Apartment General Service	115%
SCS1 - Small Commercial 1	112%
SCS2 - Small Commercial 2	152%
LCS1 - Large Commercial Service 1	124%
LCS2 - Large Commercial Service 2	121%
LCS3 - Large Commercial Service 3	117%
High Load Factor	140%
Inverse Load Factor	173%

Table 3-10: 2013 FEW COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Residential	76%
Commercial	114%
LGS1 - Large Commercial Service 1	115%
LGS2 - Large Commercial Service 2	150%
LGS3 - Large Commercial Service 3	114%

Table 9-10: Amalgamated Entity Rate Class Revenue to Cost Ratio

Rate Schedule	Revenue to Cost Ratio
Rate 1 – Residential	93.4%
Rate 2 – Small Commercial (<2000 GJ/yr)	104.6%
Rate 6 – Natural Gas Vehicle	112.7%
Rate 3 & 23 Combined	107.9%
Rate 5 & 25 Combined	110.4%

The FEU state on page 210 of the Application that "... no demand-related costs are allocated to these [interruptible] customer classes in the COSA."

76.1 Please confirm that the COSA Model Revenue to Cost Ratios results included in tables 3-3, 3-5, 3-8 and 3-10 of Section 3 of the Application are consistent with schedules included in Appendix H. If not, please provide updated tables.

Response:

The FEU confirm that Tables 3-5 and 3-10 are consistent with schedules included in Appendix H.

However, Tables 3-3 and 3-8 of Section 3 of the Application had a few typographical errors in the R:C Ratio column. The FEU confirm that R:C Ratio numbers presented in the schedules included in Appendix H are correct. Therefore, updated Tables 3-3 and 3-8 are shown below.

Table 3-3: 2013 FEI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	92%
Rate 2 - Small Commercial	103%
Rate 6 - Natural Gas Vehicle	124%
Rate 3 & 23 - Combined	113%
Rate 5 & 25 - Combined	116%

Table 3-8: 2013 FEVI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
RGS - Residential	82%
AGS - Apartment General Service	114%
SCS1 - Small Commercial 1	112%
SCS2 - Small Commercial 2	152%
LCS1 - Large Commercial Service 1	124%
LCS2 - Large Commercial Service 2	120%
LCS3 - Large Commercial Service 3	116%
High Load Factor	139%
Inverse Load Factor	171%

76.1.1 Please explain how the amalgamated revenues for residential customers are more closely aligned to amalgamated costs than in each of the individual companies.

Response:

The closer alignment of the amalgamated revenues and costs for residential and commercial customers is an outcome of the Amalgamated COSA study.

Tables 3-3, 3-5, 3-8 and 3-10 are based on the legacy COSA methodology that was followed for the individual companies. However, the FEU's Amalgamated results provided in Table 9-10 reflect a different COSA methodology that mainly adopts FEI's approved COSA methodology with a few modifications as outlined in the Table 9-5 (refer to page 196 of the Application).

Specifically, the minimum system study under the Amalgamated COSA has used a Peak Load Carrying Capability ("PLCC") adjustment that tends to allocate relatively lower costs to residential customers. Please refer to page 194 of the application explaining the use of PLCC adjustment in Amalgamated COSA model. This results in closer alignment of the amalgamated revenues to amalgamated costs for residential customers.

Just as the PLCC reduces costs to the residential class, those costs are shifted to the other rate classes, including the commercial customers. This has the impact of shifting the R:C ratios for commercial customers closer to unity.

Further, the Amalgamated COSA model assumed mapping of FEVI, FEW and FEFN customers over to existing FEI rate schedules (i.e. Rate Schedule 1, Rate Schedule 2 and Rate Schedule

3). As proposed in the Application, residential customers of FEVI, FEW and FEFN were mapped straight to Rate Schedule 1 of FEI. However, other rate schedules in FEVI, FEW and FEFN were mapped to either Rate Schedule 2 or Rate Schedule 3. Due to the proposed customer mapping, the customer weighting factors and the load factors for these commercial customers changed in the Amalgamated COSA model impacting their allocated cost of service. This has also resulted in closer alignment of amalgamated revenues to amalgamated costs for commercial customers than in each of the individual companies.

76.1.2 Please explain how the amalgamated revenues for large commercial customers are closer aligned to amalgamated costs than in each of the individual companies.

Response:

Please see response to BCUC IR 1.76.1.1 explaining why amalgamated revenues for residential and commercial customers are more closely aligned to amalgamated costs than each of individual companies.

76.2 Do FEU plan to rebalance rates of FEI, FEVI, FEW, and FEFN that currently fall out of the acceptable range if postage stamp rates are not approved by the Commission? If not, why not? If yes, please explain how. In your response, please comment on the option of also using changes to regional rate designs (such as higher fixed charges or minimum bills) to better realign rates with costs within each customer class.

Response:

If amalgamation and postage stamp rates are not approved, then the FEU will consider filing rate design applications for each utility, which may involve rebalancing given the current R:C ratios as shown above. As a part of the individual rate design applications, FEU may also evaluate the current rate schedules and rate structures in place for each individual entity.

76.3 FEI's residential customers are currently just within FEU's proposed range of reasonableness when commodity plus midstream costs and revenue are included (92 percent), but FEFN, FEVI and FEW customers are outside the range of reasonableness (81 percent, 82 percent, 76 percent respectively). Do FEU consider that postage stamp rates would also increase the risk that FEI residential customers will see additional rate increases in the future as a result of rate rebalancing? If no, please explain why not.

Response:

The numbers in the tables provided in the question above demonstrate that postage stamp rates as proposed in the Application bring FEI residential customers closer to unity (93.4 percent under FEI Amalco as compared to 92 percent under FEI) in terms of the resulting R:C Ratios. This means that there is less risk that FEI residential customers will see additional rate increases in future due to rate rebalancing.

76.4 Do FEU expect any of the customer revenue: cost ratios for the customer classes of FEI, FEVI, FEFN or FEW (assuming postage stamp rates are not approved) to change significantly over time. If yes, please provide information on which customer classes, and the direction and likely magnitude of the change.

Response:

Generally speaking, revenue to cost ratios change gradually over time and therefore FEU do not expect the revenue to cost ratios for FEI, FEVI, FEFN or FEW to change significantly. However it is important to note that major upgrades of the existing system and construction of new facilities could trigger the need to conduct a COSA study in the future for one or more of utility ratebases, which might result in some changes to the R:C Ratios. For example, with the Mt. Hayes storage facility now being in service, in the future it will be prudent to look at the changes in the allocated costs for each rate class as a result of the additional costs that this facility brings to the Fully Distributed Cost of Service Allocation Study.

Since the movement in the R:C Ratios is dependent on many different factors in the COSA model, it is difficult to provide a direction or likely magnitude of the change in R:C Ratios over time for any customer class.

76.5 Do FEU expect any of the customer revenue: cost ratios for the amalgamated company (assuming postage stamp rates are approved) to change significantly over time. If yes, please provide information on which customer classes, and the direction and likely magnitude of the change.

Response:

Please see response to BCUC IR 1.76.4.

As discussed in section 9.7.2, page 220 of the Application, FEU does anticipate some movement of customers in the short term as they adjust to the choices amongst the FEI Amalco rate classes. The FEU expect that a period of two years from the implementation of common rates is the required timeframe to evaluate the results of any such movement.

76.5.1 Please explain why FEU are proposing to exclude these customers from postage stamp rates.

Response:

FEU are not proposing to exclude interruptible customer classes from postage stamp rates.

Please see response to BCUC IR 1.126.4 explaining why no demand related costs are allocated to these interruptible rate classes. It should be noted that the postage stamp rates for interruptible rate classes as proposed in the Application are established in an independent process outside the COSA results. The rates for these interruptible customer classes are based on a market driven discount relative to firm rates. This rate setting approach was approved by the Commission in its Phase B Rate Design Application Decision from October 1993, and subsequently continued to be used in later negotiated settlement agreements.

76.5.2 Do FEU have any contracts with customers (firm or non-firm) which it is not proposing to postage stamp but where the contract is linked to a rate which will be postage stamped (for example, a set discount from a firm rate which will be postage stamped)? If yes, please describe the impact on these customers of FEU's postage stamp rate proposal.

Response:

FEFN and FEW currently do not have any special agreements or tariff supplements in place. In addition to FEVI's special transmission transportation service agreements in place with the VIGJV and BC Hydro, FEVI currently have two other tariff supplements in place with Western Forest Products and CFB Comox. The long term agreements in place with the VIGJV and BC Hydro would be maintained upon the implementation of postage stamp rates; however, the two tariff supplements in place with Western Forest Products and CFB Comox would be cancelled. The Western Forest Products LCS3 tariff supplement is the FEVI actual cost of gas +$1.75/GJ for any consumption in excess of 72,000 GJ annuallyat. The CFB Comox LCS3 tariff supplement is a set discount of $0.49/GJ on LCS3 for being interruptible. Western Forest Products and CFB Comox would see an overall rate reduction and they will have numerous rate options to which they may move subsequent to the implementation of postage stamp rates like transportation and interruptible service offerings. The FEU have been in contact with these customers regarding our proposal and the existing tariff supplements and will be in continuing discussions on the potential service options that would be available to them.

In addition to the special bypass tariff supplements that FEI currently have in place, FEI also currently have a small number of other approved tariff supplements in place with customers that reference FEI's current rate schedules and the FEU intend to maintain all of these FEI tariff supplements upon the implementation of postage stamp rates. A summary of these non-bypass FEI tariff supplements is as follows:

Customer	Rate	Tariff Supplement	Summary
Teck Coal – Greenhouse	23	A-4	Rate 23 delivery charge -$0.35/GJ
Central Heat	22	G-21	Rate 5 Demand charge x 55% plus Rate 5 delivery charge for firm service. All interruptible consumption in excess of firm service will be based upon Rate 22 delivery charges
Chemical Lime	22	G-3	Rate 22 + Rate 25 Basic Charges to retain 2 meters but receiving all service under Rate 22
Weyerhaeuser Trusjoist	22	G-2	Rate 25 demand and delivery charges for firm service. All interruptible consumption will be based upon rate 22 delivery charges.
Teck Coal – Fording River	22B	G-14	Delivery charges for interruptible service are based upon Firm Rate 22B demand and delivery costs

Customer	Rate	Tariff Supplement	Summary
Teck Coal – Greenhills	22B	G-15	Delivery charges for interruptible service are based upon Firm Rate 22B demand and delivery costs
Teck Coal – Line Creek	22B	G-19	Delivery charges for interruptible service are based upon Firm Rate 22B demand and delivery costs
Teck Coal – Elkview	22B	G-13	Delivery charges for interruptible service are based upon Firm Rate 22B demand and delivery costs

For the FEI customers outlined in the table above, the impact on these customers as a result of the common rates postage stamp rate proposal would be any incremental costs identified in the FEI Amalco bill impact schedules for the applicable rate schedules referenced in these tariff supplements.

77.0 Reference: Delivery Rate Design – Cost Based Rates

Exhibit B-3, Section 10, p. 232; Reasons for Decision for Order G-138-10, pp. 5 to 24

Whistler Propane Conversion

The FEU state on page 232 of the Application that "there is a very high seasonal occupancy rate for properties in Whistler (during the conversion project from propane to natural gas FEW found that approximately 70% of the residential dwellings in Whistler were not occupied year-round), ... many property owners live outside of British Columbia."

The Commission, on pages 5-24 of the September 1, 2010 Reasons for Decision on Terasen Gas (Whistler) Inc. 2010-2011 Revenue Requirements Application (G-138-10) stated:

> "By Order C-3-06 dated June 27, 2006, the Commission approved a Certificate of Public Convenience and Necessity (CPCN) for TGW's application to convert its Whistler propane system to natural gas (Conversion project) and for the Pipeline project." (p. 5)
>
> "TGW's Application includes a request for approval to include the full $11.87 million cost of the Conversion project in its rate base." (p. 15)
>
> "In its communication program to its Whistler customers, TGW stated that it would cover the costs of converting appliances to natural gas. ... TGW subsequently made modifications to the conversion policy, including:
>
> - absorbing (including in the project costs) the cost of developing and installing substitute conversion kits if they were not available from the manufacturer; and
> - absorbing the costs of remedial work in cases where there were requirements to upgrade piping and related installations which did not even meet the standards for propane installations.

Notwithstanding its original policy communications, TGW absorbed all costs relating to the Conversion project other than those cases, some 400, where the appliances were 'red tagged' as they were unsafe and required replacement." (pp. 22, 23)

In its opening remarks, TGW states: "The project, which was approved in 2006 and was completed in 2009, has delivered the anticipated benefits to customers. Specifically, customers now pay less to meet their energy requirements previously served by propane based on the delivery charge proposed in the Application and the favourable forecast cost differential between natural gas and propane. ... It has also provided greater security of supply." (p. 23)

The Commission Panel acknowledges the CEC's concern that the Conversion project costs should be charged directly to customers in cases where they caused the costs. However, the Commission Panel accepts TGW's view that purpose of the project was to accomplish the conversion of propane based appliances to natural gas, and considers that TGW's change in policy to absorb the costs related to all installations which were not issued a red tag was a reasonable and pragmatic decision. The Commission Panel accepts TGW's submission that the issues were widespread across customer classes, and that the policy change mitigated potential risk of load loss to TGW, which in turn would negatively impact rates to remaining customers." (p. 24)

77.1 In the C-138-10 Decision, the Commission accepted FEW recovering conversion costs from its customers on the basis that "issues were widespread across customer classes, and that the policy change mitigated potential risk of load loss to FEW, which in turn would negatively impact rates to remaining customers." Are these issues also widespread across the FEI, FEVI and FEFN customer classes? Please explain.

Response:

The Whistler Conversion Project was specific to the customers of FEW, and the issues related to converting FEW customers from propane to natural gas were therefore not "widespread across the FEI, FEVI and FEFN customer classes." Please refer to the response to BCUC IR 1.77.1.1.

77.1.1 If no, do FEU consider it is appropriate that FEI, FEVI and FEFN residential customers pay for the cost of converting appliances in FEW residential homes (the majority of which homes FEU state are not occupied year round). Please explain why or why not.

Response:

Yes. Under a postage stamp rates scenario, the FEU consider it appropriate that all customers pay for the impact of localized projects, whether they be propane conversion projects or other types of projects.

The localized nature of the Whistler Conversion Project is similar to most CPCN projects (such as the Shoreacres Project discussed on page 76 of the Application), which would be shared by all customers if adoption of common rates is approved. This highlights one of the benefits of the adoption of common rates – the impact of localized projects is diluted when spread over the larger customer base.

This treatment has also been applied in the past in relation to customer conversions. A natural gas conversion project was undertaken in 1991 in the Squamish area which was later integrated into FEI. In addition, the FEU have a long-standing program offering incentives to customers to switch from fuel oil to natural gas, in which the incentives payments are recovered in rates for all customers.

The FEU submit that the recency of the Whistler conversion project (within the past five years) is not a reasonable basis on which to single out this project. As stated by EES Consulting in the Application, on page 106:

> *"In general, customers that were hooked up to the system long ago have lower costs than those hooked up more recently just because of when the facilities were built and the level of depreciation of facilities."*

Despite these differences, customers that connect to the system more recently do not pay a higher rate.

As a point of comparison, the FEU would expect that if Revelstoke were to be converted to natural gas in the future, all FEI customers (or FEI Amalco customers if amalgamation is approved), would share in the costs of that conversion.

77.2 As FEW customers are the primary beneficiary of the conversion costs, does FEU consider it would be appropriate for FEW customers to be charged a surcharge on their bill to recover conversion costs? Please explain why or why not.

Response:

The FEU do not consider it appropriate for FEW customers to be charged a surcharge on their bill for conversion costs. The reasons why this would not be appropriate are discussed in response to BCUC IRs 1.77.1 and 1.77.1.1. In addition, the FEU submit that the conversion project does provide benefits to the Province as a whole since it serves to reduce greenhouse gas emissions and maintains or increases load on the system. Other localized projects often result in similar benefits.

77.2.1 Please calculate the size of the surcharge for a typical residential customer required to recover their share of the total conversion cost.

Response:

The following table provides the approximate 2013 cost of service associated with the Whistler Conversion costs. The cost of service divided by the total 2013 FEW throughput reflects the approximate $ per gigajoule charge of $1.01/GJ attributable to conversion costs. This impact will decline over time as the balance remaining in the deferral account is amortized.

FEW Natural Gas Conversion Costs

2013 Approximate Cost of Service

Line	Particulars	$ Thousands		Reference
1	Mid Year Balance of Conversion Cost Account	$	7,224	Exhibit B-1, 2012/13 RRA, Table 6.3-12
2				
3	Amortization Expense		441	Exhibit B-1, 2012/13 RRA, Table 6.3-12
4	Earned Return		31	Line 3 x 2013 Return on Rate Base
5	Income Taxes		243	
6	Total Cost of Service	$	715	Sum of Lines 3 through 5
7				
8	2013 FEW Demand (TJ)		709	Appendix H-10
9	Approximate Conversion Cost ($/GJ)	$	1.01	Line 6 / Line 8
10				
11	Typical Residential Customer Annual Use (GJ)		90	
12	Residential Customer Annual Conversion Cost ($)	$	90.78	Line 9 x Line 11

77.3 Are there expected to be any additional ongoing conversion costs related to conversion of new FEW customers from propane to gas? If yes, please estimate the magnitude of these costs.

Response:

No additional ongoing conversion costs related to the conversion of new FEW customers from propane to gas are expected.

78.0 Reference: Delivery Rate Design – Cost Based Rates

Exhibit B-3, Section 6.9, p.129

Whistler Propane Conversion

"Common rates will similarly bring more economic rates to FEW, which currently experiences much higher natural gas rates than elsewhere in the Province served by the FEU."

78.1 Please provide a brief background on the main drivers, which are causing FEW customers to currently experience much higher natural gas rates than elsewhere in the Province served by the FEU.

Response:

The higher natural gas rates currently being experienced by FEW customers are primarily due to the age of the natural gas system in Whistler, due to the recent conversion from propane to natural gas, and the smaller customer base of FEW over which costs are spread. Detailed background on the conversion of FEW customers from propane to natural gas is included in response to BCUC IR 1.78.2.

78.2 Who were the main proponents for those drivers?

Response:

FEVI (then TGVI) and FEW (then TGW) were the proponents of the applications that resulted in the conversion of the FEW system from propane to natural gas. The interveners who registered and participated in the CPCN regulatory review process for the CPCN applications were the Resort Municipality of Whistler, the Ministry of Energy & Mines, the Vancouver Island Gas Joint Venture, the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO"), British Columbia Hydro and Power Authority, Commercial Energy Consumers Association ("CEC") and Squamish First Nation. In addition, there were a number of individuals who also registered. While not all of the registered parties may have expressed specific opinions or support for all elements or aspects of the applications, the Commission took into consideration and gave weighting to all submissions by the participants in granting approval.

The conversion of the FEW system from propane to natural gas was approved after a thorough public review process was conducted by the Commission when FEVI in 2005 applied for a

CPCN to construct an IP Pipeline to connect Whistler with its high pressure transmission system at Squamish, and FEW concurrently applied for a CPCN to convert its propane system to natural gas. The result of the public review process was that the Commission granted a CPCN to FEVI and FEW by Order No. C-3-06. In that review process, there were three main reasons why the Whistler pipeline and conversion project were put forward by the proponents, reviewed by interveners and ultimately approved by the Commission. They were the age and capacity limitations of the FEW propane system, the environmental benefits of a natural gas system, and the lower commodity costs of natural gas as compared to propane. Each of these reasons is described further below.

1. Age and Capacity Limitations

The Commission's Decision dated May 18, 2006 (the "Decision"), at page 27, stated the following:

> *"…the Commission Panel accepts that the current capacity of the existing propane storage facility is becoming marginal and, depending on future demand growth, may be inadequate to meet the long-term needs of Whistler.*
>
> *….*
>
> *…the Commission Panel cannot rule out the possibility that TGW will need to meet the Business as Usual (High) Scenario and accepts that it is prudent to plan to meet long-term needs that can only be met by either a new pipeline or by some form of expansion of propane facilities, either by increasing the tank size in Nesters plant or by the acquisition of a new site. The Panel notes the RMOW's opposition to a new site and concludes that converting from propane to natural gas with the new pipeline is the more suitable method of meeting the long-term needs of Whistler, all else equal."*

2. Environmental Benefits of a Natural Gas system

There are environmental benefits of a natural gas system compared to a piped propane system. The CPCN applications supported the RMOW's comprehensive sustainability plan, "Whistler 2020: Moving Toward a Sustainability Future".

3. Lower Commodity Costs

There were forecast to be lower commodity costs of natural gas compared to propane. The Commission found the differential forecast to be acceptable in the Decision, at page 23:

> *"The Commission Panel accepts TGW's forecast of propane and natural gas prices. The Panel's view of the differential is that although it is forecast by TGW to hover in the $4.20 range, compared to the recent history in the $3.20 range, the forecast appears*

reasonable when compared to what the NYMEX strips are telling the marketplace. The Panel finds the differential forecast to be acceptable."

Further, in the FEW 2010-2011 Revenue Requirements Application ("RRA") Decision dated October 25, 2010 (Order No. G-138-10), following a thorough review of the RRA including an Oral Public Hearing on the Whistler Conversion Project, the Commission approved the resulting rates to include the majority of the Whistler Conversion Project costs.

The interveners who registered and participated in the regulatory review process for the RRA were the BCOAPO and CEC.

In the RRA Decision, the Commission cited at page 23:

> *"In its opening remarks, TGW states: "The project, which was approved in 2006 and was completed in 2009, has delivered the anticipated benefits to customers. Specifically, customers now pay less to meet their energy requirements previously served by propane based on the delivery charge proposed in this application and the favourable forecast cost differential between natural gas and propane. The project has reduced greenhouse gas emissions and has contributed to improved air quality in the Whistler region. It has also provided greater security of supply. TGW acknowledges the interest and concern of customers and the Commission about the divergence between the estimate for the appliance conversion and the final appliance conversion costs." (T1:16)"*

78.2.1 Were the proponents aware that these drivers would cause much higher natural gas rates than elsewhere in the Province served by the FEU? If not, why not? If yes, does that imply that the much higher natural gas rates were acceptable (i.e. they are now part of the approved FEW tariff)? Furthermore, why should rates, which appear to have been acceptable to the proponents, be now substantially reduced and as a direct consequence cause FEI and FEFN customers to experience rate increases? Please discuss.

Response:

The current natural gas rates in FEW, although higher than elsewhere in the FEU's service territory, are lower than they would have been had the conversion not been undertaken. At the time the CPCN for the pipeline and conversion project was approved, and in the 2010-2011 RRA for FEW, the appropriate comparison for consideration of the public interest aspect of the project was not the natural gas rates on the Mainland or on Vancouver Island, but the existing propane rates in Whistler. Therefore, the proponents of the project were aware that the project would result in lower rates for Whistler customers.

While all parties should have been aware that FEW's rates were higher than elsewhere in the FEU service territory, this was not relevant to the approval of the project. Except under the proposal in the present Application, Whistler customers have not had an opportunity to enjoy rates at the same level as in other FEU service areas.

The FEU discuss why it is appropriate to include the Whistler conversion project, along with other localized investments, in the postage stamp rates, in response to BCUC IRs 1.77.1, 1.77.1.1 and 1.77.2.

79.0 Reference: Delivery Rate Design – Efficient Rates

Reasons for Decision for Order G-116-05, p.5; Exhibit B-3, Section 3, pp. 35-50, Section 4, p. 67, Section 10, p. 232, Exhibit B-3, Appendix G-4, p. 39

General

Bonbright Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy)";[68]

Policy Action No. 4 of the 2009 BC Energy Plan (p. 39), filed at Appendix G-4 of the Application, states "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation."

79.1 Do FEU consider that regional rate designs would be generally be considered more efficient than postage stamp rate designs? If no, please explain why not. In your response, please specifically address if postage stamp rates can be as efficient as regional rates where there are current and potentially future regional variations in the following areas:

- Customer consumption profiles;
- Customer price responsiveness and uneconomic bypass risks;
- Customer price/security of supply trade-offs;
- Consumption growth expectations;
- Customer willingness to contribute to social and environmental programs (as well as the type of program contributed to); and
- Delivery incremental costs.

<u>Response:</u>

The FEU do not believe that regional rate designs would be considered more efficient than postage stamp rate designs. For the most part, the costs included in the delivery charges that are the subject of this application are for facilities that are in place today. Reduced consumption by customers will not lead to reduced costs on the delivery system. The delivery system is designed on the basis of peak day forecasts and the location of customers, and as such is classified on those factors for the most part. From a pure cost basis, most of the delivery costs are fixed and would not necessarily vary with the level of consumption. The cost of gas,

68 http://www.bcuc.com/Documents/Proceedings/2011/DOC_27176_G-45-11_BCH-RIB-Re-Pricing-Reasons.pdf

however, is directly related to consumption and can be reduced by energy efficiency and conservation.

While the factors listed may differ to some extent between the regions, the FEU believe that the reasons it has provided in the Application to support postage stamped rates outweigh these issues.

80.0 Reference: Delivery Rate Design – Efficient Rates

Exhibit B-3-1, Appendix G-5; Reasons for Decision for Order G-120-11, p. 22;

FEVI and FEW Customer Fuel Choice - Policy

Section 2 of the Clean Energy Act, filed as Appendix G-5 of the Application, includes the following British Columbia energy objectives: Ensure the authority's [BC Hydro's] rates remain among the most competitive of rates charges by public utilities in North America; reduce BC greenhouse gas emissions,and encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia.

The Commission stated, in its July 12, 2011 Reasons for Decision on an Application by FortisBC Energy Inc. and Fortis BC Energy (Vancouver Inc.) for Approval of the Price Risk Management Plan Effective April 2011 – October 2014 (G-120-11),[69] p. 22: "Promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate."

80.1 Do FEU agree with Commission Decision G-129-11 that "Promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate"? If no, please explain why not.

Response:

The FEU generally agree with the statement provided it is put in the right context.

In the FEU's view, the Commission made the statement referred to above in the Decision on FEI's price risk management plan in part to support its conclusion that the objective of maintaining competitive rates versus other forms of energy (primarily electricity) was inappropriate. FEI's evidence provided during the proceedings was that maintaining competitiveness with electricity is not only in the best interests of FEI's customers, but it is also in the best interests of electricity consumers in the province (Exhibit B-1, pages 32-35, Sec 4.4.1 of in that proceeding). This is consistent with the Government's objective expressed in the Clean Energy Act of ensuring that BC Hydro's rates remain among the most competitive rates charged by public utilities in North America.

The FEU continue to believe that natural gas is the appropriate fuel to use in space and water heating applications and that government policy objectives can best be achieved in these energy end uses by using natural gas in combination with alternative energy solutions. Even in

[69] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28130_G-120-11_FEI-FEVI_PRMP_2011-2014-Reasons.pdf

situations where electricity may appear to be the appropriate energy source there may be conflicting policy objectives and resolving such competing issues is not always straightforward. A simple example of competing policy objectives in the section of the Clean Energy Act quoted in the preamble to this question is the apparent conflict between keeping BC Hydro's electricity rates among the lowest in North America and at the same time expanding electricity use to displace GHG emitting energy sources (with the accompanying cost pressures of adding new electricity load).

With respect to this Application, as indicated in Section 6.8, p 127 to 129 of the Application, amalgamation and the adoption of common rates is in line with provincial energy policy and the provincial government's Strategy on Natural Gas.

81.0 Reference: Delivery Rate Design – Efficient Rates

Exhibit B-3, Section 6, p. 129, Section 4, p. 67; FEU 2012-2013 Revenue Requirements Rates Application, Exhibit B-1, p. 24, Exhibit B-17, pp. 14, 15

FEVI and FEW Customer Fuel Choice - Impact

The FEU state on page 129 of the Application that "the FEU do not expect any material fuel switching to take place from electricity to natural gas for space heating and hot water as a result of amalgamation and common rates."

On Page 67 of the Application the FEU state: "On Vancouver Island, only 32% (lowest of all regions) of new homes constructed used natural gas as its main space heating fuel compared to 70% of homes built prior to 2006. On the Lower Mainland, which includes Whistler in the study, 80% of new homes constructed used natural gas as its main space heating compared to 94% of homes built prior to 2006."

FEU, in its 2012-2013 Revenue Requirements & Natural Gas Rates Application, Exhibit B-1, page 24, stated "Based on these figures it is evident that FEVI will be more competitive under an amalgamated scenario than left as a standalone utility. ... FEW in many regards has similar challenges as FEVI with respect to remaining competitive from a 'price point' perspective vis-a-vis alternative energy options, e.g., electricity."[70]

The FEU, in its 2012-2013 Revenue Requirements & Natural Gas Rates Application Exhibit B-17, pages 14, 15, states:[71]

> "The FEU's analysis indicates the price elasticity of demand coefficient for FEI residential customers is approximately -0.22 and for FEI commercial customers is approximately -0.19. ... The FEU's analysis of FEW and FEVI did not result in reliable elasticity estimates. ... However, the American Gas Association ("AGA") estimated long-run price elasticity of -0.18 and concluded that their price elasticity estimates were "relatively consistent with previous works on this subject." Given that the AGA's elasticity numbers are similar to those estimated by the FEU for FEI, the FEU believe that it is reasonable to estimate that the price elasticity for FEW and FEVI would likely range between -0.18 and -0.22."

81.1 The FEU state in the application that they are do not expect any material fuel switching to take place from electricity to natural gas for space heating and hot water as a result of amalgamation and common rates, however FEU does note

70 http://www.bcuc.com/Documents/Proceedings/2011/DOC_28081_B-1_FEU-2012-2013-RRA-REDACTED-Public-Version-R.pdf

71 http://www.bcuc.com/Documents/Proceedings/2011/DOC_28404_B-17_FEU-IR2-Response-BCUC.pdf

that FEVI and FEW have challenges with regard to remaining competitive with electricity. For each of FEVI, FEW, FEI and FEFN (assuming postage stamp rates are not approved):

81.1.1 Ignoring differences in upfront capital costs, is residential gas heat/hot water typically lower cost for a residential customer in a single family dwelling compared to electric heat /hot water. In this analysis, please compare the gas price with the average electricity price (not just Tier 2), and provide the results for both 90% and 75% appliance efficiency. Please state all assumptions used in the analysis.

Response:

This response is in respect to both BCUC IRs 1.81.1.1 and 1.81.1.2.

The FEU's analysis as shown in the charts below, following the assumptions, demonstrates that the cost of natural gas is favorable relative to electricity on a simple operating cost basis, except for under the 75% efficiency cases for FEW and FEVI. With the addition of incremental maintenance and upfront capital costs for natural gas, only Fort Nelson is significantly favorable relative to electricity.

The capital cost assumptions used in the analysis are as follows:

Capital Cost Assumptions Applicable to All Service Areas *New Home Construction*	
Capital Cost for High Efficiency Furnace (90%) and ducting/Installation:	$7,000.00
Capital Cost of NG Water Heater and Installation	$1,400.00
Total Cost for Natural Gas High Efficiency Furnace and Water Heater	**$8,400.00**
Capital Cost for Electric Baseboards	$2,500.00
Capital Cost for Electric Water Heater and Installation	$ 975.00
Total Cost for Electric Baseboard and Water Heater	**$3,475.00**
Difference in upfront Capital Costs	**$4,925.00**
Interest Rate	6%
Measurable Life of Furnace (years)	18
Amount Needed to be Recovered Annually to Payoff Difference in Capital Cost	**$ 454.86**
NG Furnace Maintenance (per Year)	$ 100.00
Total Amount Needed to be Recovered Annually to Payoff Difference in Capital Cost	**$ 554.86***

* This figure is divided by typical energy consumption for natural gas Space and Water Heating in the various service areas to derive the additional $/GJ required for natural gas customers to recover the difference in maintenance and upfront capital cost

** Natural gas capital and maintenance cost differential not applied to the 75% efficiency scenario since 90% efficiency furnaces are mandatory for new home construction

Other assumptions in the analysis are as follows:

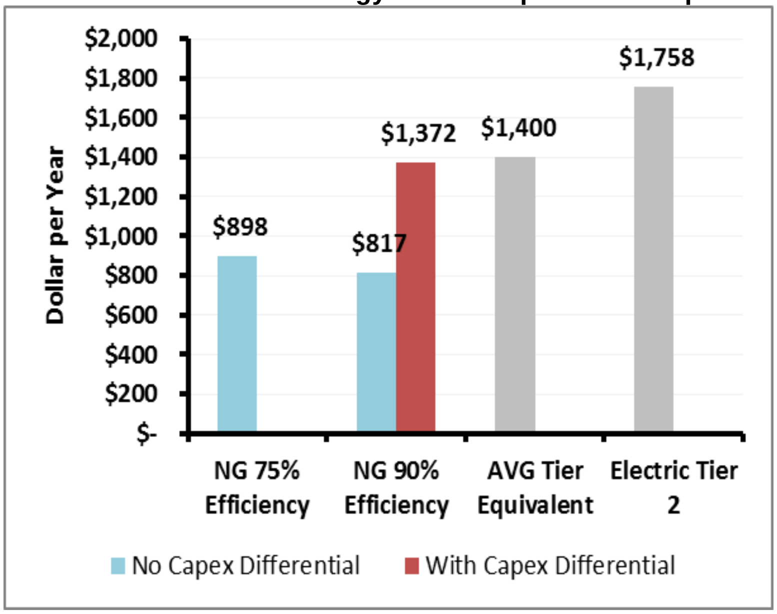
1. **Annual Electric Bill Assumptions:**
   - Average Step 1 / Step 2 rate - $0.0852/kWh applied to all kWh in the respective cases
   - Step 2 rate - $0.1070/kWh applied to all kWh in the respective cases
   - (Above rates include the current BC Hydro 5% Rate Rider.)

2. **Annual Natural Gas Bill Assumptions:**
   - Based on current natural gas rates for the respective Service Areas and includes Basic Charge and Carbon Tax @ $1.50/GJ

3. **Appliance Efficiency Assumptions:**
   - Electric space heating efficiency calculated @ 100% for Space Heating
   - Natural gas space heating efficiency calculated at stated appliance efficiencies
   - Water heater efficiencies: Natural Gas: 56%; Electric 90%

Based on the assumptions above, the following four tables show the results of the FEU's analysis of natural gas costs to electricity for FEI, FEVI, FEW and FEFN.

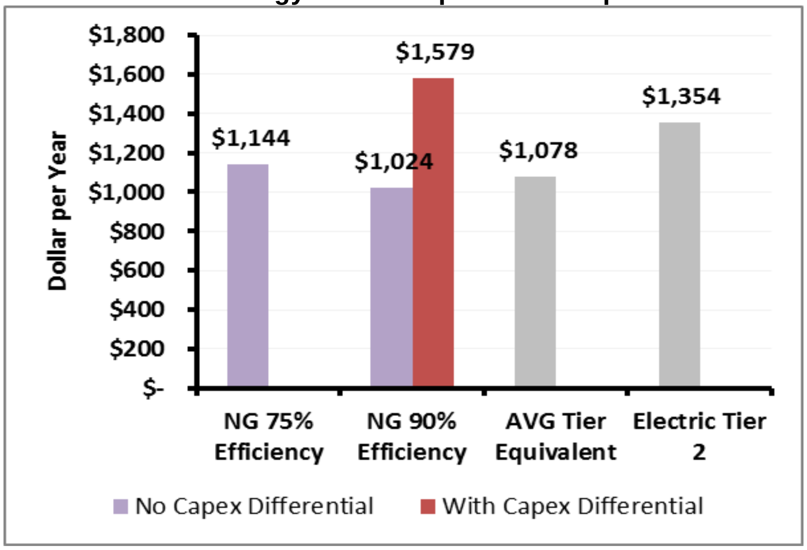
Table 1: FEI Lower Mainland Residential Energy Cost Comparison for Space and Water Heating*



*Lower Mainland Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 46.5 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 11.4 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $7.70/GJ

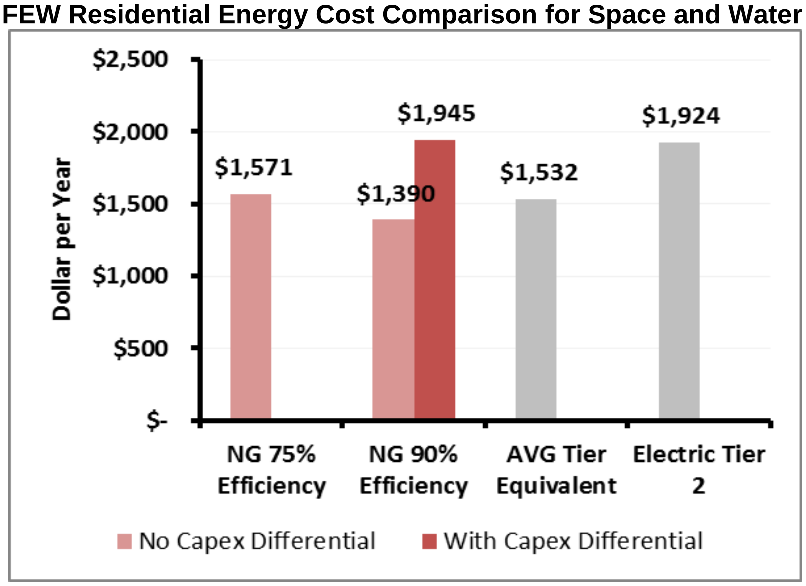
Table 2: FEVI Residential Energy Cost Comparison for Space and Water Heating*



*Vancouver Island Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 33.9 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 10.5 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $9.83/GJ

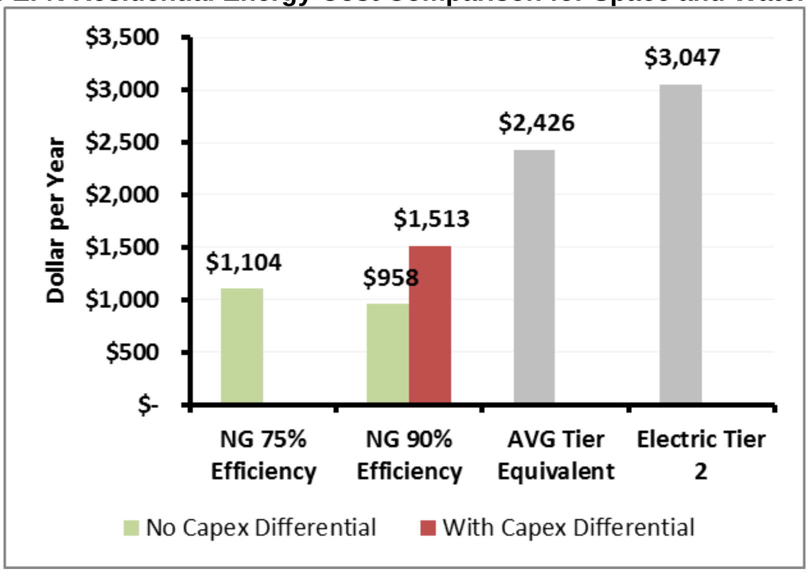
Table 3: FEW Residential Energy Cost Comparison for Space and Water Heating*



*Whistler Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 53.5 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 10.1 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $7.16/GJ

Table 4: FEFN Residential Energy Cost Comparison for Space and Water Heating*



*Fort Nelson Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 88.4 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 12.7 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $4.59/GJ

81.1.2 Please provide an update of the response to the question above, this time taking into account differences in upfront capital costs. Please state all assumptions used in the analysis.

Response:

See response to BCUC IR 1.81.1.1.

81.2 For each of FEVI and FEW, FEI and FEFN please repeat the above analysis assuming postage stamp rates are approved.

Response:

The FEU's analysis as shown in the charts below, following the assumptions, demonstrates that with the proposed postage stamp rates the cost of natural gas is favorable relative to electricity on a simple operating cost basis. With the addition of incremental maintenance and upfront capital costs for natural gas, only Fort Nelson is favorable relative to electricity.

The capital cost assumptions used in the analysis are as follows:

Capital Cost Assumptions Applicable to All Service Areas *New Home Construction*	
Capital Cost for High Efficiency Furnace (90%) and ducting/Installation:	$7,000.00
Capital Cost of NG Water Heater and Installation	$1,400.00
Total Cost for Natural Gas High Efficiency Furnace and Water Heater	**$8,400.00**
Capital Cost for Electric Baseboards	$2,500.00
Capital Cost for Electric Water Heater and Installation	$ 975.00
Total Cost for Electric Baseboard and Water Heater	**$3,475.00**
Difference in upfront Capital Costs	**$4,925.00**
Interest Rate	6%
Measurable Life of Furnace (years)	18
Amount Needed to be Recovered Annually to Payoff Difference in Capital Cost	**$ 454.86**
NG Furnace Maintenance (per Year)	$ 100.00
Total Amount Needed to be Recovered Annually to Payoff Difference in Capital Cost	**$ 554.86***

* This figure is divided by typical energy consumption for natural gas Space and Water Heating in the various service areas to derive the additional $/GJ required for natural gas customers to recover the difference in maintenance and upfront capital cost

** Natural gas capital and maintenance cost differential not applied to the 75% efficiency scenario since 90% efficiency furnaces are mandatory for new home construction

Other assumptions in the analysis are as follows:

1. **Annual Electric Bill Assumptions:**
    - Average Step 1 / Step 2 rate - $0.0852/kWh applied to all kWh in the respective cases
    - Step 2 rate - $0.1070/kWh applied to all kWh in the respective cases
    - (Above rates include the current BC Hydro 5% Rate Rider.)

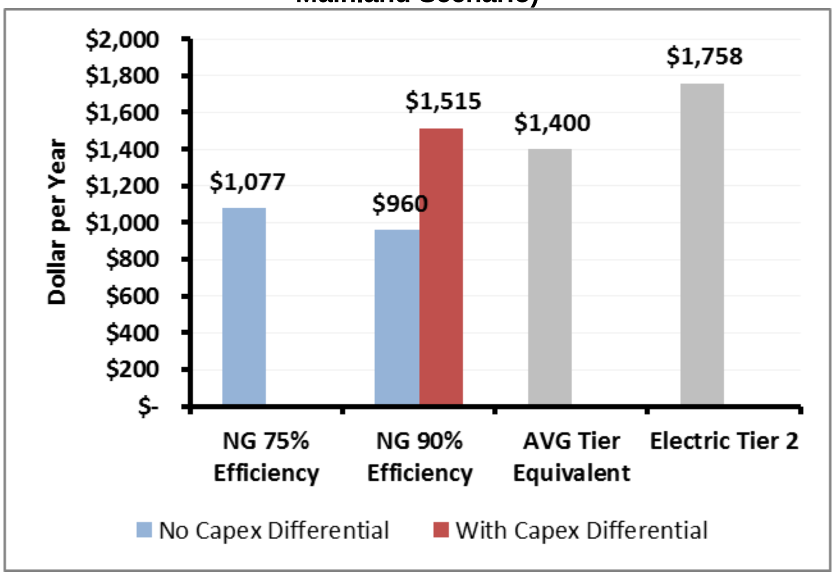
2. **Annual Natural Gas Bill Assumptions:**
    - Based on current natural gas rates for the respective Service Areas and includes Basic Charge and Carbon Tax @ $1.50/GJ

3. Appliance Efficiency Assumptions:

- Electric space heating efficiency calculated @ 100% for Space Heating
- Natural gas space heating efficiency calculated at stated appliance efficiencies
- Water heater efficiencies: Natural Gas: 56%; Electric 90%

Based on the assumptions above, the following four tables show the results of the FEU's analysis of natural gas costs to electricity for FEI, FEVI, FEW and FEFN.

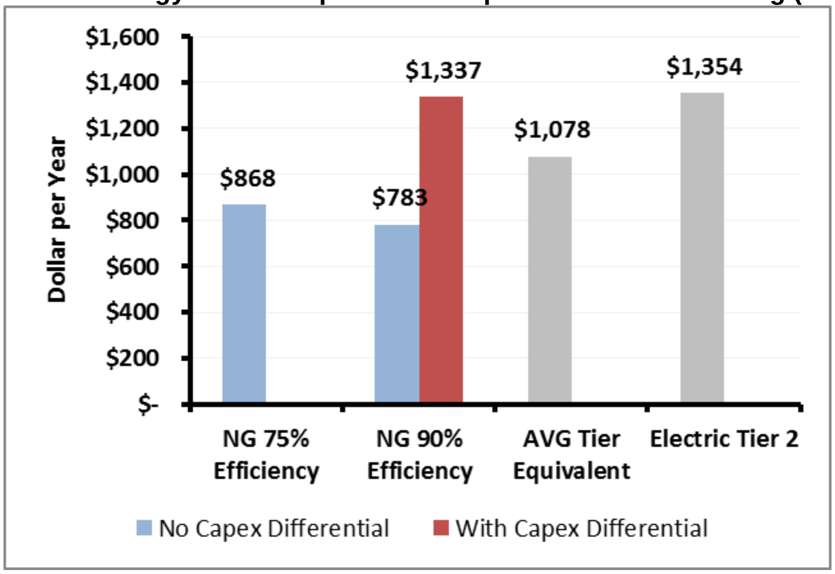
FEI Amalco Residential Energy Cost Comparison for Space and Water Heating (FEI Lower Mainland Scenario)



*Lower Mainland Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 46.5 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 11.4 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $7.70/GJ

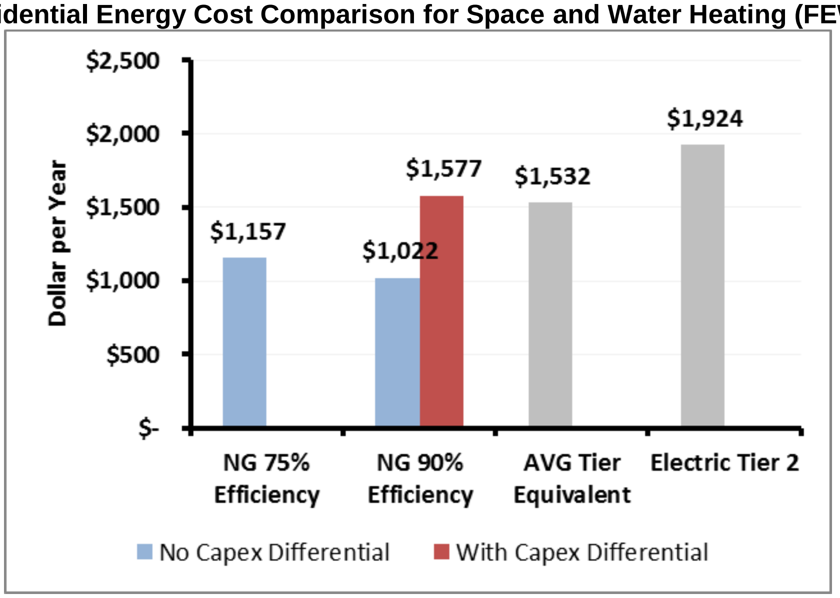
FEI Amalco Residential Energy Cost Comparison for Space and Water Heating (FEVI Scenario)



*Vancouver Island Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 33.9 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 10.5 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $9.83/GJ

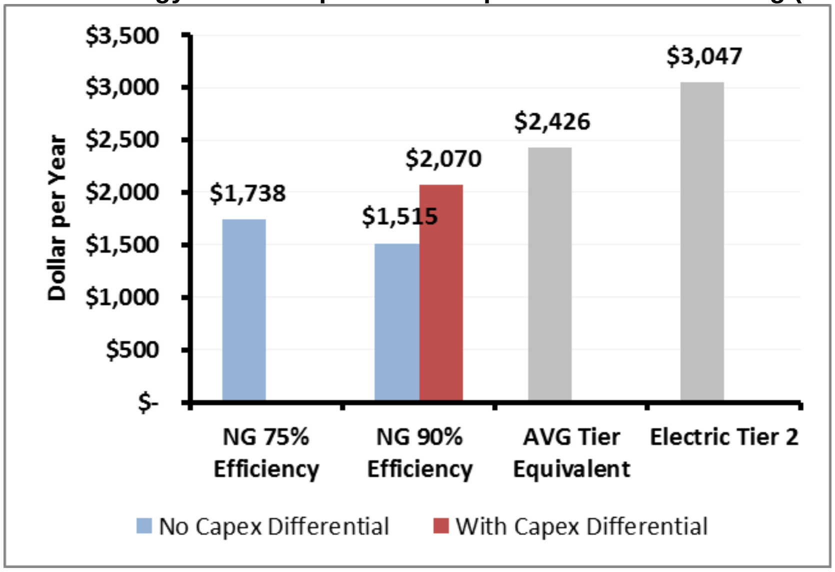
FEI Amalco Residential Energy Cost Comparison for Space and Water Heating (FEW Scenario)



***Whistler Typical Consumption Characteristics:**

- Typical Residential Space Heating Consumption @ 100% Efficiency: 53.5 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 10.1 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $7.16/GJ

FEI Amalco Residential Energy Cost Comparison for Space and Water Heating (FEFN Scenario)



*Fort Nelson Typical Consumption Characteristics:

- Typical Residential Space Heating Consumption @ 100% Efficiency: 88.4 GJ/year
- Typical Residential Water Heating Consumption @ 100% Efficiency: 12.7 GJ/year
- Natural Gas Maintenance and Capital Cost Differential: + $4.59/GJ

81.3 Given that if common rates are accepted FEVI customers will see rate decreases of between 25 per cent and 44 per cent. FEW customers will see rate decreases of between 37 per cent and 45 per cent, please discuss whether FEU have made any projections for Vancouver Island and Whistler for new homes to use natural gas as its main space heating fuel. Please include any projections if available.

Response:

The FEU have not made any projections for Vancouver Island and Whistler for new homes to use natural gas as its main space heating fuel at the moment. To the extent that customers can be expected to respond to changes in price by changing their gas consumption it might be reasonable to expect that lower rates in the FEVI and FEW service areas to have some localized impact on natural gas use, including increased use of natural gas as the main space heating fuel in new homes; however, the actual impact is difficult to quantify. As discussed in several other IRs, the cost of natural gas service is only one of a number of factors involved in a customer's energy purchasing decision. Other factors include the higher capital cost to install the natural gas equipment and necessary in-house ducting, the system extension test and connection policies used, and consumer perceptions about the desirability of an energy source such as its green attributes. The charts provided in the response to BCUC IR 1.81.2 indicate that, even with the rate reductions from postage stamp rates, when the upfront capital cost differential is included in the analysis natural gas continues to be challenged for FEVI and FEW relative to electricity. In addition, the decision on heating systems in the new home market is generally made by a builder or developer so their expectations and perceptions about whether they will be able to recover the additional upfront capital costs in their sale price is a key factor influencing their willingness to install gas heating.

81.4 Given that if common rates are accepted FEI customers in the Lower Mainland, Inland and Columbia service areas will see a rate increase would FEU expect a decrease for new homes to use natural gas as its main space heating in the Lower Mainland? Please include any projections if available.

Response:

The FEU have not made any projections for new homes to use natural gas as its main space heating fuel within existing FEI service areas.

Similar to the response to BCUC IR 1.81.3, to the extent that customers can be expected to respond to changes in price by changing their gas consumption it might be reasonable to expect that higher rates in the FEI service areas would have some impact on natural gas use; including decreased use of natural gas as the main space heating fuel. However, given the magnitude of rate increases for the FEI service areas, coupled with the fact that the cost of natural gas service is only one of a number of factors involved in a customer's energy purchasing decision, the FEU do not expect the impact to be material.

81.5 Please document any other benefits/concerns that a residential customer may take into consideration in making a fuel choice decision between gas/electricity/propane, such as fuel price certainty, environmental benefits, reliability, space saving considerations etc.

Response:

According to studies commissioned by the FEU, it was found that in addition to Residential customer preferences, builders/developers exerted considerable influence over the fuel mix found in homes. Appendix G-13: Residential User Preference Study and Appendix G-17: Gas Influencer Energy Preferences Study of the Application explore the attitudes and preferences towards traditional and alternate energy options.

According to the Gas Influencer Energy Preferences Study, there are three main considerations that affect the decision to choose one energy form over another for this segment.

1. **Focus on Overall Efficiency – Not Fuel**: Engineers and contractors asserted that their energy decisions for a particular project revolved around obtaining the greatest overall efficiency with the available equipment regardless of the fuel. That being said, the following four factors weigh in their decision:
   i. Initial cost of installing a gas line and corresponding equipment
   ii. Other available fuels and their ongoing costs
   iii. Efficiency of end-use equipment
   iv. Tenant or owner needs and requirements.

   No preference for one fuel over another was expressed in this consideration.

2. **Anticipation of Higher Costs**: This consideration is more revealing with respect to influencer fuel preferences. All respondents stated that installing natural gas is always more expensive and that the increased capital costs made it difficult to "sell" either to themselves or to a client. Such costs include:
   i. Bringing natural gas from the street to the side of the building
   ii. Increased material and labour costs to accommodate natural gas systems
   iii. Higher project complexity resulting for increased planning and installation requirements.

   As such, from the perspective of upfront capital costs, electricity is the easier "sell", suggesting that it may be the preferred option.

3. **Cyclical Energy Prices**: Cognizant of historical energy pricing, respondents in the study were inclined to choose the cheapest energy available and then compensate for future price increases by using the most energy efficient equipment possible in accounting for market cycles in energy prices. By doing so, they felt they could overcome the threat of subsequent price increases with greater efficiencies.

The Energy Mix Influencers in the study were not inclined to express a "favorite" energy type without knowing the particular situation, since considerations are deliberated in light of what makes the most sense in a given situation. However, commercial and residential respondents indicated that 'installing natural gas is always more expensive…[and] that the increased capital costs of installing natural gas system made natural gas difficult to "sell" either to themselves or to clients depending on their ability to pay for them.'[72] This suggests that the Energy Mix Influencers are more partial to electricity given the differences in upfront capital costs between electricity and natural gas.

With respect to residential customer preferences, the following summarizes some key points with respect to fuel choice:

1) Those who took an active role in making a fuel choice had strong feelings towards a certain fuel type as a result of either previous negative experience or attachment to a preferred, specific kind of energy.

2) In all discussions regarding fuel choice, a fundamental point was that the energy choice was usually based on the appeal of an end use rather than the fuel itself. Purchases did not consider "natural gas" for instances, as much as they considered a natural gas fireplace. It is the value bestowed by the appliance on gas that created an attraction to natural gas use. People identified first with the equipment that produces the heat and later, the fuel that runs it.

3) When space heating, water heating, or cooking options were provided, respondents often made their choices based on the attributes considered to be important to living in the home rather than a straightforward choice about a specific fuel or energy sources and its other implications such as versatility, benefits or payback over time.

4) Generally speaking, respondents considered having electricity and natural gas as lending flexibility to the residence by increasing the renovation choices that could be made now and further down the road.

See Appendices G-13 and G-17 of the Application for the full studies.

81.6 To what extent do FEU consider that the price elasticity of FEVI, FEW, FEI and FEFN customers is affected by the size of the increase or decrease in gas prices, both in the short-term and in the long-term. Please explain.

[72] FortisBC Builder Preference Study p. 4

Response:

The FEU's analysis indicates the price elasticity of demand coefficient for FEI residential customers (including Fort Nelson) is approximately -0.22 and for FEI commercial customers (including Fort Nelson) is approximately -0.19.

As a generic study, the American Gas Association ("AGA") estimated price elasticity of -0.18 and concluded that their price elasticity estimates were "relatively consistent with previous works on this subject"[73]. Given that the AGA's elasticity numbers are similar to those estimated by the FEU for FEI, it is reasonable to conclude that FEI has an inelastic price elasticity of demand. Based on the elasticity values and, *all else being equal,* the FEU do not expect FEI customers to be materially change their consumption levels by the increases or decreases in natural gas prices in the short term.

The FEU's analysis of FEW and FEVI did not result in reliable price elasticity estimates. The regressions resulted in very low R-squared results (less than 0.10 in several cases), p-values that were not significant for the resulting parameters and in several cases implausible results. In these implausible cases the models returned satisfactory R-squared results and p-values, but the model resulted in positive elasticity. This would imply that when prices go up, consumption does also, the opposite of what economic theory says about price elasticity. As a result, these models were rejected. There are several potential causes for these results. One reasonable explanation is that there are other non-controlled variables driving the decline in UPC, overpowering any effects that price has on consumption. However, to the extent that customers can be expected to respond to changes in price by changing their gas consumption it might be reasonable to expect that natural gas rates in the FEVI and FEW service areas will have some impact on natural gas use; however, similar to FEI and FEFN customers, the FEU do not expect FEVI/FEW customers to be materially affected by the price increases in the short run

In terms of long term trends for FEI, FEVI, FEW and FEFN, the FEU expect price elasticity of demand to be more elastic in the long run due to reduced constraints. A common example for this tendency is the reaction to the oil price shock of the 1970s -- while the response to higher oil prices were modest immediately after the increase, consumers adjusted their behavior in the long run for higher oil prices. Thus, the FEU expect all customers to be more responsive to the natural gas price changes in the long run. However there will still be some barriers to fuel switching for existing housing in the long run due to physical constraints. For example, the equipment adjustments necessary for residential customers to go from electric systems to natural gas systems are not likely to occur due to the physical limitation of the buildings - e.g. ducting or hydronic systems. Anecdotally, oil to natural gas switching is considered to be more

[73] Joutz, F. and Trost, R.P., (2007) "An Economic Analysis of Consumer Response to Natural Gas Prices", Prepared for the American Gas Association

likely in the similar pricing environment, and thus, this is to be reflected in the long run price elasticity of demand.

81.7 Do FEU consider that postage stamp rates will translate into increased or decreased gas sales in FEVI and FEW than would otherwise have been the case? Please provide an estimate of any expected difference in the volume of gas consumed.

Response:

As discussed in the response to BCUC IR 1.81.6, the FEU's analysis indicates the price elasticity of demand coefficient for FEI (including FEFN) residential and commercial customers is between -0.18 and -0.22, whereas elasticity estimates for FEW and FEVI are unreliable. However, in general, gas sales are believed to be inelastic in the short run, thus price is expected to have a non-material effect on natural gas demand for residential or commercial customers in the short run.

81.7.1 Based on this analysis, do FEU consider there will be a net increase or decrease in gas sales as a result of postage stamp pricing? Please explain why or why not.

Response:

As described in the response to BCUC IR 1.81.6, the FEU's analysis of price elasticity of demand in FEW and FEVI did not result in reliable estimates, thus it is difficult to determine the impact of postage stamp pricing in gas sales within the FEU as a whole. To the extent that customers can be expected to respond to changes in price by changing their gas consumption it is reasonable to expect that lower rates in the FEVI and FEW service areas to increase natural gas use. However, the increase is more likely to be customers converting to natural gas from a higher GHG emission source as opposed to existing customers who are unlikely to change their existing consumption behavior. Even with the lower gas costs, potential new customers will continue to have the installation capital cost hurdle to overcome in making their energy choice, and potentially negative perceptions of natural gas as a fossil fuel. Therefore, significant new customer additions as a result of lower rates in FEVI and FEW may be limited.

At the same time FEI and Fort Nelson customers will be paying higher delivery rates as a result of common rates. Even a relatively small reduction in use per customer for FEI's customers, when multiplied by the much larger FEI customer base, could have the effect of offsetting a significant portion of any increased load in FEVI and FEW, given the relative size of FEI's customer base to that of FEVI's and FEW's combined. Therefore, the FEU expect the net difference to not be material one way or the other.

82.0 Reference: Delivery Rate Design – Efficient Rates

TGVI 2012-2013 Revenue Requirement and Rates Application, Exhibit B-1, p. 41

Delivery Incremental Costs

Terasen Gas (Vancouver Island) Inc (TGVI), on page 41 of Exhibit B-1 to its 2010 and 2011 Revenue Requirements and Rates Application stated:[74]

> "TGVI has relatively large capital expenditure requirements in comparison to TGI. To illustrate, the 2009 projected TGVI capital expenditure dollars per customer is $250. This amount is in comparison to TGI's 2009 projected capital expenditure dollars, which is projected to be $106 per customer."

FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application Oral Hearing, Transcript Volume 3,[75] page 380:

> "MR. ANDREWS: Q: All right. And when the phrase "rate structure" is used, does that mean simply the rate, or the amount of rate increase at the time? Or is that a rate design concept?
>
> MR. THOMSON: A: I think it's the rate design concept, and what immediately springs to mind is currently with Vancouver Island we've got a rate freeze and a rolled-in rate, as opposed to the structure that we have on the mainland. So, in 2014, absent amalgamation, we may have a different rate design structure in place than -- we might continue to have a different rate design structure in place. Whereas if we're amalgamated, then it may simplify that, that recovery. So one size won't necessarily fit all."

82.1 The statement that TGVI has relatively large capital expenditure requirements in comparison to TGI indicates that there are significant regional variations in incremental delivery costs between FEI and FEVI. Do FEU agree? If no, please explain why.

Response:

The FEU does not dispute the fact that there are regional cost differences between FEI, FEVI, FEFN and FEW. The proposal for rate harmonization is partly driven by the need to eliminate the delivery rate discrepancies amongst the Utilities which are inherently reflective of regional cost variations.

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74 http://www.bcuc.com/Documents/Proceedings/2009/DOC_22335_B-1_TGVI_Application_2010-2011_RRA_RDA-part1.pdf

75 http://www.bcuc.com/Documents/Transcripts/2011/DOC_28703_10-04-2011-Transcript-Volume-3.pdf

FEVI has a larger rate base and capital expenditures requirement on a per customer basis than the FEI area. This is partly due to the fact that the FEVI system is newer on average than the FEI system and the smaller customer base over which to recover the costs. However, there are undoubtedly areas within FEI that have a higher rate base and capital expenditure requirements than other areas within FEI.

82.2 Please describe any major new delivery infrastructure investments <u>driven by load growth</u> (or which could be avoided if load decreased) expected over the next 15 years for FEI, FEFN, FEW and FEVI. Please provide an estimate of the cost of each of these investments.

82.2 Please describe any major new delivery infrastructure investments <u>driven by load growth</u> (or which could be avoided if load decreased) expected over the next 15 years for FEI, FEFN, FEW and FEVI. Please provide an estimate of the cost of each of these investments.

<u>Response:</u>

The most recently available information with regard to load growth related infrastructure investments over the long term is contained in the 2010 Long Term Resource Plan (LTRP) and the 2012-2013 Revenue Requirement Application. Sections 6.1.1 (page 131) and Section 6.1.2 (page 143) of the LTRP discuss transmission and distribution system requirements over a 20 year planning horizon and consider major resource additions to be those greater than $1.0 million. Appendices D-1 through D-4 of the LTRP provide additional information for major projects within the 5-year capital planning horizon. Section 6.2.7.2 of the 2012-13 RRA provides updated information for one of these projects – the Okanagan Reinforcement Project.

Table 82.2 summarizes the load growth related projects discussed in these documents.[76] Recent changes where available are noted under the "Most Recently Available Estimate and Information" column of Table 82.2.

Table 82.2 Anticipated Major Growth Related Infrastructure Projects (i.e. greater than $1.0 million)

[76] Those projects that were discussed in the 2010 LTRP, but which have since been completed are not included in Table 82.2

Project	Approximate Timing	Preliminary Cost Estimate	Most Recently Available Estimate and Information
FEVI Service Area			
TGVI System Capacity Expansion	As early as 2017 depending on core load growth, and transportation requirements of VIGJV mills and Island Cogeneration Project	Options include compressor station expansion or contract arrangements. Cost estimate not yet determined.	2010 LTRP page 135
IP System Improvement - Saanich	No longer required	Approximately $1.5 million	2010 LTRP Appendix D -2, page 4. This project is no longer required as the operating pressure has increased to provide additional capacity
FEI Service Area			
Okanagan Reinforcement Project	As early as 2017	$30 million to $131 million depending on option chosen	2012-2013 RRA – page 383
Cache Creek / Ashcroft Lateral pipeline	Only required if the industrial transportation service is changed from interruptible to firm	Cost estimate not yet determined	2010 LTRP – page 143
Metro Vancouver IP System	Phase 1 – 2017 Phase 2 - 2022	$5 million ($2007) $3.9 million ($2007)	2010 LTRP – page 144
Revelstoke Propane System	Dependent on ski resort expansion	Preferred solution and cost estimate not yet determined	2010 LTRP – page 144
36th Ave IP, Delta	2012 Only required if the industrial transportation service is changed from interruptible to firm	$1.2 million	2010 LTRP – Appendix D-1, page 4
72nd Ave IP, Delta	2012 Only required if the industrial transportation service is changed from interruptible to firm	$1.8 million	2010 LTRP – Appendix D-1, page 4

Project	Approximate Timing	Preliminary Cost Estimate	Most Recently Available Estimate and Information
FEW Service Area			
There are no major growth related natural gas delivery infrastructure projects planned for FEW within the next 15 years. Source: 2010 LTRP – Appendix D-3			
FEFN Service Area			
There are no major growth related natural gas delivery infrastructure projects planned for FEFN within the next 15 years. Source: 2010 LTRP – Appendix D-4			

Natural gas system delivery requirements over the long term will be re-examined as part of the next LTRP, to be submitted in 2013. The 2013 LTRP will include the results of an updated analysis of the projects contained in Table 82.2 as well as any potential additional growth related projects that were not yet anticipated in the 2010 LTRP.

82.3 Please describe why FEU stated in the 2012-2013 Revenue Requirements Hearing that FEVI, absent amalgamation, may have a different rate structure than FEI. In your response, please specifically address if this relates to recognition of the historical context (i.e., mitigating bill impacts), differences in consumer consumption profiles and preferences and/or differences in utility incremental cost drivers.

Response:

The quoted passages above were in reference to the period of recovery for the Energy Efficiency and Conservation ("EEC") non rate base deferral account, and were specific to that concept. Mr. Thomson stated that the phrase "rate structure" was intended to be a rate design concept. As he went on to state, if there is no amalgamation, then in 2014 FEVI may follow the rate design concept of a rate freeze, or may pursue some other rate design concept other than cost of service rates. In a utility that is not setting rates based on cost of service, the period of recovery of the EEC non rate base deferral account is not as clear.

Mr. Thomson's response was not intended to be any broader than that, and as such it did not relate to mitigating bill impacts, differences in consumer consumption profiles and preferences and/or differences in utility incremental cost drivers.

82.4 Do FEU consider that postage stamp rates would be easily reversible if, in the future, incremental costs or customer consumption patterns or preferences varied significantly by region? Please explain why or why not.

Response:

The FEU believe that rate structures are a function of each utility's unique circumstances and cost causation principles.

Should a situation arise where the FEU believed that postage stamp rates were no longer appropriate, it would be possible to move back to a regional rate structure, but the degree of ease to move to a regional rate structure would be dependent on a number of factors including, but not limited to:

- The accounting methods and systems maintained to track assets, costs, etc. by region. For example, today, within FEI it would be difficult to introduce regional delivery rates to the three service areas (excluding FEFN) as the accounting and asset records no longer store the regional segregation required to accurately map all assets and costs to each of the three divisions. Therefore, an allocation methodology would be required to be used;
- How the utility is being operated and whether changes are required as a result of moving to a regional rate structure;
- IT system capability, in particular, billing system capability to move to multi-region rate structures; and,
- The nature and extent of regionalization of the system (e.g., 2 regions would be easier to implement than 6) that would impact the number of different rate classes.

82.5 Do FEU consider that a move to postage stamp rates would reduce its ability to divest itself of part of its operations (for example, the FEVI franchise)? Please explain why or why not, and if this could have any negative impact on ratepayers.

Response:

The FEU do not believe that the ability to dispose of part of its operations is a relevant consideration in determining the appropriateness of postage stamp rates. However, the FEU do not consider that a move to postage stamp rates would reduce its ability to divest itself of part of its operations.

Under a scenario in which the FEU determined that a divestiture would occur, the rate base and related cost of service associated with the divested operations would be removed from the

FEU's revenue requirements. The new revenue requirements would reflect the remaining rate base and revenue requirements that would be recovered from FEU's remaining customer base.

It is not clear what impact the existence of a postage stamp rate structure, in and of itself, would have in a divestiture scenario. The degree (positive or negative) to which ratepayers would be impacted would be more dependent on the rate base, cost structure and revenues of the specific operation that was divested relative to the remaining FEU operations. For example, if the FEVI operations were divested (as suggested in the question), the divestiture may not result in a negative impact to the remaining ratepayers as FEVI has a higher rate base per customer ratio compared to the Amalgamated FEI. Therefore, all things being equal, upon divestiture, the amalgamated entity would have a proportionately lower rate base per customer, which in turn may result in lower rates.

83.0 Reference: Delivery Rate Design – Efficient Rates

Exhibit B-3, Section 1, pp. 4, 5, Section 6. p. 123

Administration and Regulatory Costs

The FEU state on page 4 of the Application: "Uniform prices and a reduced number of rate classes and billing determinants (i.e., geographical location) will provide a simpler rate structure that is easier to explain, understand and implement in terms of administration, information requirements and billing procedures. These practical attributes, while not a driver for common rates, are beneficial to our customers."

83.1 The FEU state in the Application that postage stamp rates will result in simpler rate structures which are easier to explain and understand. Do FEU consider that customer confusion resulting from differences in gas rates between its companies are resulting in a reduced level of customer service? If yes, please describe and discuss alternative approaches to addressing these issues other than a move to postage stamp rates.

Response:

The FEU do not believe that customer confusion resulting from differences in gas rates between its companies is resulting in a reduced level of customer service.

Implementing common rates for the FEU's customers will provide a simpler rate structure with reduced administration requirements on an ongoing basis. A common rate structure will also lead to reduced information requirements for customers, including a decrease in the volume of communication activities related to rate changes where currently separate materials are produced for each of the FEU companies. Common rates will also reduce the activities and billing procedures that are currently required to maintain the various rates classes in the billing system.

In addition to these practical attributes that are beneficial to the FEU's customers, as discussed in Exhibit B-3, Section 1.5, p 4, the FEU believe that common rates will facilitate access to natural gas programs and services across the service territory.

84.0 Reference: Delivery Rate Design – Efficient Rates

Exhibit B-3, Section 9.5.2, p. 191

Exhibit B-3-1, Appendix C-1, Figure 2, p. 7

Competitiveness of Natural Gas with Respect to Electricity

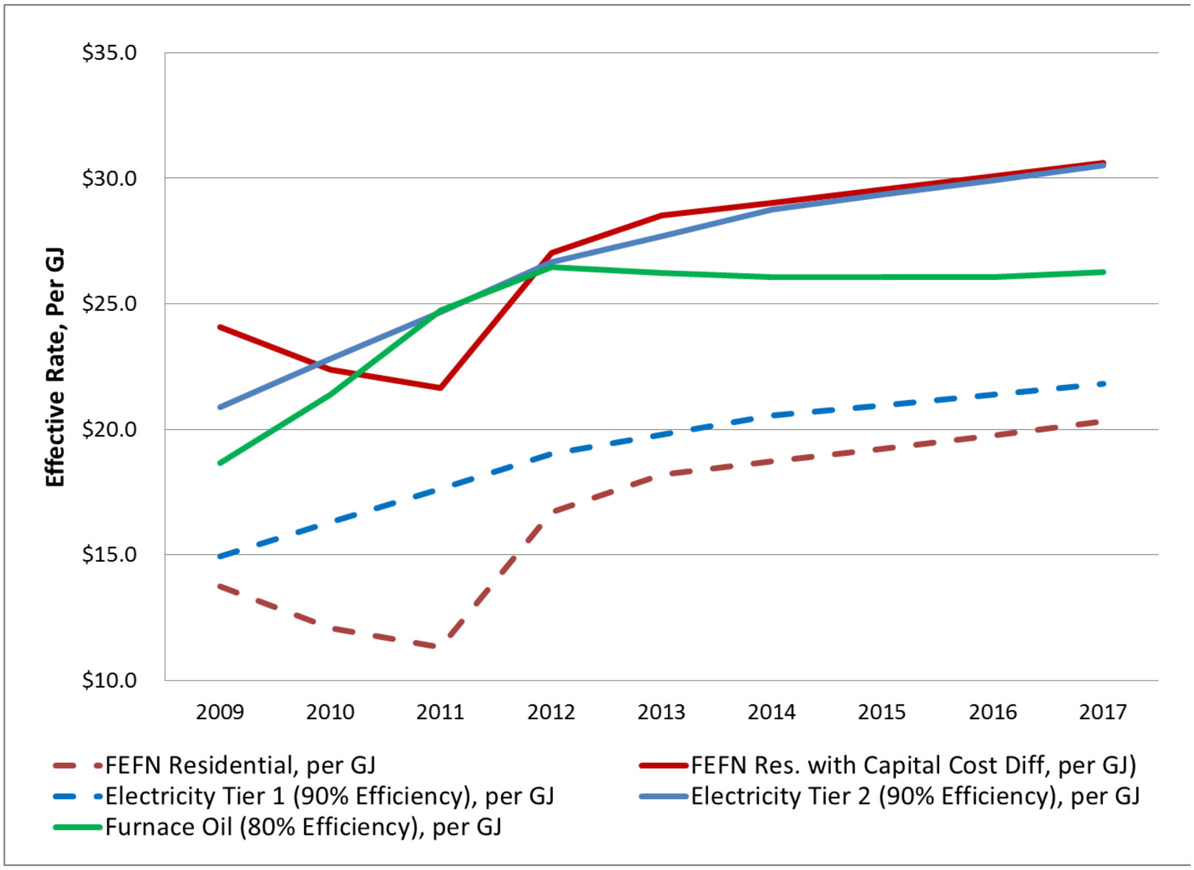
"Competitiveness in rate design refers to designing rates in consideration of other fuel alternatives. The rates proposed in this Application for the Amalgamated Entity will have minimal impact on competitiveness of natural gas for the vast majority of customers currently served by FEI. On the other hand, the rates for FEVI and FEW will become more economic compared with the alternative fuels and become aligned with that experienced by FEI customers."

Figure 2 compares forecasts of FEVI and FEW residential effective natural gas burner tip rates with BC Hydro electricity rates over the period 2009 to 2017.

84.1 Please prepare a chart similar to Figure 2 for FEFN under postage stamp rates and without the impact of the Fort Nelson Phase-in Rider.

Response:

The following chart compares the effective postage stamp rate for a Fort Nelson customer (excluding the phase-in rider) based on an annual consumption of 90 GJ's, with BC Hydro's electricity rates (both Tier 1 and Tier 2), as well as with furnace oil rates. The chart highlights that Fort Nelson's rates are competitive with electricity and furnace oil rates. With the capital cost differential for installing natural gas as a fuel source added in, Fort Nelson's rates remain competitive in comparison to BC Hydro's Tier 2 electricity rates.



Assumptions:

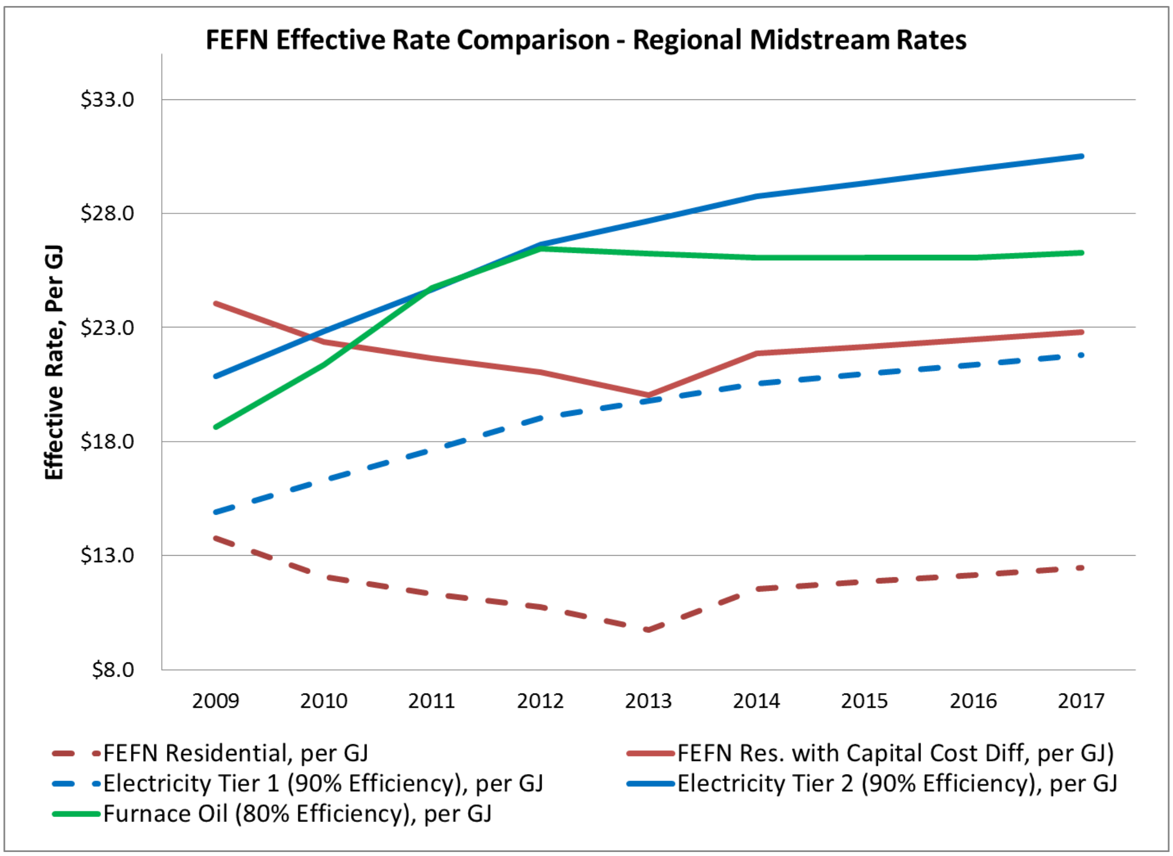
1) Electricty rates are based on BC Hydro Residential rates and assume the following rate increases as per the Government Review. (F2012: 8%, F2013: 3.9%, F2014: 3.9%) The remaining years assume 2.0% inflationary adjustment
2) All Natural Gas Effective per GJ rates are based an annual use rate of 90GJ.
3) The electric rates do not include the fixed monthly charges since it is assumed that a household already pays the base electric charges for non-heating use.
4) The effecitive rates do not include associated costs and taxes but includes the effect of Carbon Tax where applicable
5) The effective rates include the initial capital investment required for using natural gas, estimated at $10.31/GJ
6) The forecast effective rates for FEFN do not represent FEU views as to its future revenue requirement applications beyond 2012-2013.
7) Furnace Oil prices are extrapolated based on NYMEX WTI Crude Oil Futures (strip retrieved on 24 October 2011)
8) For postage-stamp rates beyond 2014, an ongoing increase of 3% per year assumed

84.2 Please prepare a chart similar to Figure 2 for FEFN under postage stamp rates but with regional midstream charges and without the impact of the Fort Nelson Phase-in Rider.

Response:

The following chart illustrates the competitiveness of a Fort Nelson residential customer's effective rate based on an annual consumption of 90 GJs, with BC Hydro's electricity rates (both Tier 1 and Tier 2), as well as with furnace oil rates. The chart assumes postage stamp basic, commodity and delivery charges (excluding the phase-in rider) with regional midstream rates.

The chart illustrates that Fort Nelson residential rates are lower than electricity rates. However, once the capital cost differential of installing natural gas appliances is included, Fort Nelson rates are competitive with BC Hydro's Tier 1 rates, and lower than both Furnace Oil and BC Hydro's Tier 2 rates.



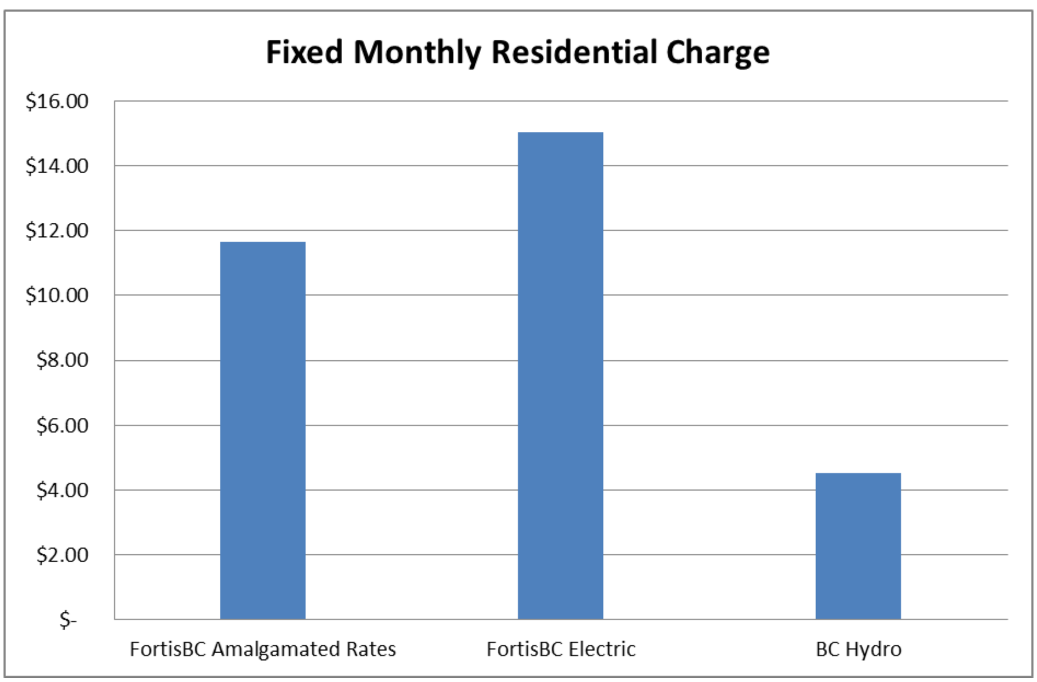
Assumptions:

1) Electricty rates are based on BC Hydro Residential rates and assume the following rate increases as per the Government Review. (F2012: 8%, F2013: 3.9%, F2014: 3.9%) The remaining years assume 2.0% inflationary adjustment
2) All Natural Gas Effective per GJ rates are based an annual use rate of 90GJ.
3) The electric rates do not include the fixed monthly charges since it is assumed that a household already pays the base electric charges for non-heating use.
4) The effecitive rates do not include associated costs and taxes but includes the effect of Carbon Tax where applicable
5) The effective rates include the initial capital investment required for using natural gas, estimated at $10.31/GJ
6) The forecast effective rates for FEFN do not represent FEU views as to its future revenue requirement applications beyond 2012-2013.
7) Furnace Oil prices are extrapolated based on NYMEX WTI Crude Oil Futures (strip retrieved on 24 October 2011)
8) For postage-stamp rates beyond 2014, an ongoing increase of 3% per year assumed

84.3 Please compare the monthly fixed residential charge under the proposed postage stamp rate design with the fixed monthly charges of BC Hydro and FortisBC.

Response:

The following graph compares the fixed monthly residential charges for customers under the proposed postage stamp rate design with those of BC Hydro and FortisBC Electric customers. The basic charge is only one component of a residential customers' total bill.



85.0 Reference: Delivery Rate Design – Maturing Utility

Reasons for Decision for Order G-31-12, p. 52; Exhibit A2-9, Heritage Gas 2011 General Tariff Application, Exhibit H-1, pp. 432-443; Exhibit A2-10, Response to Heritage Gas Limited IR2

Key Criteria for Determining if a Utility is Mature

The Commission stated, in its March 9, 2012 Decision on a CPCN by FortisBC Energy Inc. for Approval of Contracts and Rate for Public Utility Service to Provide Thermal Energy Service to Delta School District Number 37[77] (G-31-12), page 52:

> "FEVI also uses a deferral account mechanisms to capture the shortfall between revenues collected under this rate structure and the actual cost of service. In the case of FEVI, it is expected that the system will eventually be on cost-of-service based rates when the numbers of customers and load have grown to an adequate level."

Heritage Gas Limited included in its June 15, 2011 General Tariff Application (pp, 432-443) an opinion by Kathleen McShane (Foster Associates Inc.) on Criteria for a Mature Utility for Heritage Gas Limited (Exhibit A2-9). McShane proposed the following criteria:

- Revenue deferral account fully recovered;
- Heritage Gas able to set rates for each customer class which recover the full cost of service at revenue to cost ratios of approximately 1.0;
- Heritage Gas demonstrates that it has been able to generate a sustainable (over 3 years)level of revenues that recovers its full cost of service; and
- Growth rates in customers, throughput and rate base have declined to levels that are in line with those experienced by mature utilities.

In Exhibit H-25 to the above proceeding, Richard H. Silkman, Ph.D, Dalhousie University provides the following response to Heritage Gas Limited IR-2 (Exhibit A2-10):

> " ... Whether or not a utility, or any company for that matter, satisfies any of the seven (7) criteria set forth by Ms. McShane has little to do with the characteristics of the utility and all to do with the characteristics of the industry in which it operates. ...
>
> Technology, changes in consumer preferences, changes in the relative prices of other goods or services – these are the types of factors that determine

[77] http://www.bcuc.com/Documents/Proceedings/2012/DOC_30034_03-09-2012-FEI_DeltaSD-37-Decision-WEB.pdf

whether or not a company meets any of the criteria advanced by Ms. McShane (except for criteria 5, of course). And, these factors are not always constant, as the examples and the testimony provided on pages 5-8 demonstrate clearly. When a company such as a railroad appears to satisfy these criteria one year, but ten (10) years later, even though the railroad has not changed at all, no longer satisfies them because of the emergence of a trucking industry, it should be very clear that the criteria are not a reflection of the railroad; rather the criteria are a reflection of the impacts of external market conditions on the railroad."

85.1 Commission Order G-31-12 appears to indicate that key criteria for maturity relates to numbers of customers and load. Heritage Gas, in their 2011 General Tariff Application, also included growth rates in customers, throughput and rate base as key criteria, and while other criteria were also proposed, their inclusion appears to have been disputed by an intervener on the basis that these other criteria can be a reflection of general market conditions rather than the maturity of the utility itself. Does FEU consider that the key criteria for determining if a utility is a mature utility is that growth rates in customers, throughput and rate base have declined to levels that are in line with those experienced by mature utilities? If no, please explain and propose criteria that FEU considers should be used.

Response:

The FEU agree that one criterion for determining if a utility is a mature utility is whether growth rates in customers, throughput and rate base have declined to levels that are in line with those experienced by mature utilities. It is not the only criterion, however. Other criteria which distinguish a mature utility from an immature utility include (1) the utility is able to set rates for different customer classes at revenue/cost ratios of approximately 1.0, where the resulting rates are competitive with alternative energy sources; (2) if the utility has been able to utilize a revenue deficiency account to capture differences between revenues and the cost of service, the preponderance of any accrued revenue deficiency has been recovered; and (3) the addition of customers and load has minimized the excess capacity that was initially built into the system to accommodate future growth and take advantage of economies of scale. The FEU consider that the maturing of a utility is an evolutionary process. The "maturity" of utilities is a continuum, ranging from a start-up, or greenfield, utility to a fully established utility. There is no "bright line" that separates a "mature" utility from an "immature" utility. Further, the FEU consider that the assessment of where a specific utility falls on the continuum should take account of the specific environment in which that utility operates, i.e., it is more appropriate to judge the maturity of FEVI by reference to FEI than by reference to an established mature utility in Alberta or Ontario.

85.2 Do FEU consider it would be appropriate to postage stamp the rates of a mature utility with an immature utility? Please explain why or why not.

Response:

The FEU do not believe that the maturity of the utility is a significant factor in postage stamping of rates. At any given time there are going to be neighborhoods within a utility that are old and established while other neighborhoods are new and facing significant growth. This averaging of costs among various neighborhoods and regions is one of the benefits of postage stamping of rates. Postage stamping provides stability in rates when specific areas are facing different costs at different times because of the timing of projects, the "lumpiness" of capital improvements and the population and housing density of different areas, among other factors. This benefit would also apply to the combining of utilities with different maturity levels.

85.2.1 If yes, please explain if this would result in a transfer of risk (for which the shareholder has previously been compensated for) to the ratepayer.

Response:

The postage stamping of rates does not transfer risks to the ratepayer. The allocation of risk between the shareholder and ratepayer remains the same whether there are postage stamp rates or not.

As discussed in response to BCUC IR 1.70.1 amalgamation and postage stamp rates will mitigate certain business risks that are unique to stand alone FEVI and FEW, however there are no risks transferred between ratepayers and shareholders. While there will be some customers facing higher rates while other customers face lower rates as a result of postage stamping, over time all customers will see more stability in rates as a result of postage stamping over a broader number of customers.

86.0 Reference: Delivery Rate Design – Maturing Utility

TGVI 2010-2011 Revenue Requirement and Rates Application, Exhibit B-1, pp. 41, 44, 55; Reasons for Decision for Order G-35-09, p. 43; Exhibit B-3, Section 3, pp. 43, 49; Exhibit A2-9, Heritage Gas 2011 General Tariff Application, Exhibit H-1, pp. 432-443;
Are FEVI or FEW Immature Utilities – Analysis

Terasen Gas (Vancouver Island) Inc (TGVI), on page 41, 44 and 55 of Exhibit B-1 to its 2010 and 2011 Revenue Requirements and Rates Application stated:[78]

> "TGVI has been in operation for less than 20 years. In comparison with a well established utility like TGI, TGVI has relatively large capital expenditure requirements, low customer base relative to rate base, and comparatively low penetration and use per customer rates.
>
> (1) CAPITAL EXPENDITURE REQUIREMENTS
>
> TGVI has relatively large capital expenditure requirements in comparison to TGI. To illustrate, the 2009 projected TGVI capital expenditure dollars per customer is $250.29. This amount is in comparison to TGI's 2009 projected capital expenditure dollars, which is projected to be $106 per customer. TGVI's capital requirements reflect the fact that the Company has not yet reached a stable level of building rate base. ...
>
> (2) RATE BASE RELATIVE TO NUMBER OF CUSTOMERS
>
> Due to the small number of customers relative to TGVI's rate base, the rate base per customer is substantially larger for TGVI versus TGI. For TGVI, the 2009 rate base per customer is approximately $5,500. In comparison, TGI's 2009 rate base per customer is approximately $3,000. Since the existing customers are carrying a disproportionately large share of rate base, this only increases the imperative to retain and attract customers. Rate base is discussed further in Part III, Section C, Tab 8, Rate Base.
>
> (3) CUSTOMER USE OF NATURAL GAS ON THE TGVI SYSTEM AND HOW IT DIFFERS FROM

[78] http://www.bcuc.com/Documents/Proceedings/2009/DOC_22335_B-1_TGVI_Application_2010-2011_RRA_RDA-part1.pdf

> TGI TGVI's customers use natural gas differently than customers of TGI, a mature utility. This is reflected in its customer penetration and consumption rates. ...
>
> The repayment of the Accumulated Revenue Deficiency is a milestone, but it is the underlying characteristics outlined previously (i.e. use per customer, penetration etc.) that define TGVI as an immature utility. Those characteristics suggest that TGVI still has some ways to go before reaching maturity. ...
>
> ... TGVI's consumption and penetration rates, small customer base, and rate base per customer continue to reflect that of an immature utility. TGVI believes that it continues to be an immature utility and that this reality should be taken into account in considering TGVI's costs and rate design."

The Commission's April 7, 2009 Reasons for Decision on Terasen Gas (Whistler) Inc. and an Application for 2009 Revenue Requirements and for a Return on Equity and Capital Structure (G-35-09)[79] states on page 43:

> "In summary, Ms. McShane considers that having a less diverse customer base and a greater exposure to competitive factors exposes TGW to higher business risks than the large mature gas utilities in Canada (such as TGI, ATCO Gas in Alberta, and Enbridge Gas and Union Gas in Ontario)..."

The FEU state on page 43 and 49 of the Application that FEVI and FEW are 'relatively new' utilities.

Heritage Gas Limited included in its June 15, 2011 General Tariff Application (page 432 to 443) on opinion by Kathleen McShane (Foster Associates Inc.) on Criteria for a Mature Utility for Heritage Gas Limited (Exhibit A2-9) included the following table:

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[79] http://www.bcuc.com/Documents/Decisions/2009/DOC_21534_TGW%202009%20RRA%20ROE%20-%20WEB.pdf

The table below compares historic data for the most recent five-year period available.

Table 1

	Annual Growth in Customers	Annual Growth in Throughput	Annual Growth in Rate Base
Heritage Gas [1,2]	41.5%	63.9%	41.8%
ATCO Gas	2.3%	3.7%	7.3%
Enbridge Gas Distribution	2.2%	-2.3%	2.6%
Gaz Métro	1.6%	0.4%	1.9%
FortisBC Energy Inc.	1.4%	1.2%	1.1%
Union Gas	1.7%	-1.7%	3.2%
Median	**1.7%**	**0.4%**	**2.6%**
AltaGas Utilities [1]	2.8%	-3.0%	8.6%
Gazifère	4.2%	4.1%	2.5%
Enbridge Gas New Brunswick [2]	24.3%	11.3%	20.9%
FortisBC Energy (VI) [1]	3.9%	5.3%	3.5%

[1] Growth rates for Heritage Gas, AUI and FEVI are for 2006 to 2010. For all other distributors, they are for 2005 to 2009.

[2] Rate base data for Heritage Gas and EGNB were calculated excluding the Revenue Deficiency Account (RDA).

86.1 In previous Applications, FEVI (or its predecessor company) has been described as an immature utility, and FEW (or its predecessor company) as having higher business risk compared to large mature utilities. FEU state in the Application that FEVI and FEW are relatively new utilities. Using the definition of a mature utility as one where growth rates in customers, throughput and rate base have declined to levels that are in line with those experienced by mature utilities, does FEU consider that, in comparison to the mature utilities (such as those included in the Heritage Gas Application above) FEVI and/or FEW are mature utilities? Please explain why or why not.

Response:

As indicated in response to BCUC IR 1.85.1, the FEU consider that there are multiple criteria for assessing whether a utility is mature, only one of which is whether the growth rates in customers, throughput and rate base have declined to levels in line with those experienced by mature utilities, and, in particular, in line with growth rates experienced by an established mature utility in a similar economic and operating environment. Whether a utility is mature should also be judged by the utility's ability to set competitive rates at revenue/cost ratios of 1.0, and by whether the addition of customers and load has minimized the excess capacity that was initially built into the system to accommodate future growth and take advantage of economies of scale.

In the case of FEVI, its recent customer, throughput and rate base growth rates have been significantly higher than FEI's and its ability to set competitive rates at revenue to cost ratios of 1.0 is challenged, particularly with the loss of the royalty revenues at the end of 2012, its lower penetration rates and its higher cost structure, as indicated by the relatively high rate base/customer ratio. Given those factors, while FEVI continues to become a more mature utility, the FEU consider that, in comparison, for example, to small, established utilities like AltaGas Utilities or Gazifère, FEVI is a less established utility. While those two utilities are smaller in terms of customers and throughput than FEVI, they have been operating since 1947 and 1959 respectively, which translates into a lower (and more competitive) per customer capital investment cost structure.

As regards FEW, its circumstances are somewhat different than FEVI's. FEW recently converted its system from propane to natural gas, and, in that context, is a relatively young utility. However, in contrast to FEVI, which has been building a new customer base since its inception, FEW had an established customer base at the time of the system conversion. As a result, FEW experienced a one-time significant increase in rate base due to the conversion, but, while they have been higher than FEI's, FEW's corresponding growth rates in customers and load have not been as high as FEVI's. With the conversion from propane to natural gas, FEW's high rate base/customer ratio creates a challenge for the utility to set competitive rates at revenue/cost ratios of 1.0. In that context, FEW would still be considered a less established utility than the major gas utilities, e.g., FEI, and other relatively small utilities (e.g., AltaGas and Gazifère).

86.2 If FEU are proposing an alternative definition of a mature utility, using this alternative definition does FEU consider that, in comparison to the mature utilities included in the Heritage Gas Application above, FEVI and/or FEW are mature utilities? Please explain why or why not.

<u>Response:</u>

As discussed in response to BCUC IR 1.85.1, the FEU consider that (1) there are multiple factors which determine whether a utility is mature; (2) there is a continuum from a start up, or greenfield utility, to a fully established utility and (3) as discussed in response to BCUC IR 1.86.1, on that continuum, FEVI and FEW are maturing utilities, but are both less established utilities than the major gas utilities like FEI and Union..

87.0 Reference: Delivery Rate Design – Maturing Utility

TGVI 2010-2011 Revenue Requirements, Rates Application, Exhibit B-1, p. 45; Exhibit A2-9, Heritage Gas 2011 General Tariff Application, pp. 2-1

Use of RSDA Account if Immature

Terasen Gas (Vancouver Island) Inc (TGVI), on page 45 of Exhibit B-1 to its 2010 and 2011 Revenue Requirements and Rates Application stated:[80]

> "The Soft-Cap mechanism for setting the rates of residential and commercial customers was approved by the Commission in Order No. G-42-03 in June 2003. The Soft-Cap mechanism, by setting rates relative to competitive fuel alternatives has provided TGVI with the opportunity to recover current cost of service while maintaining competitive and relatively stable rates to customers over time."

Heritage Gas Limited stated in its June 15, 2011 General Tariff Application (Exhibit A2-9, pp. 2-1):

> "Since the Company's inception in 2003, rates have been set at levels that are less than what is required to recover the full cost of service, with the shortfall in the recovery of the revenue requirement being deferred to a Revenue Deficiency Account ("RDA").This RDA mechanism allows time for Heritage Gas' "greenfield" distribution system to develop while still allowing its shareholder to earn a fair return on its investment. The RDA recovery mechanism has been used in other jurisdictions where, like in Nova Scotia the development of distribution infrastructure has been financed mainly by private rather than public investment."

87.1 If FEVI is classified as an immature utility, and postage stamp rates are not approved, does FEU consider that continuation of the soft cap mechanism approved in Commission Order G-42-03 could be used to allow time for the distribution system to develop while still allowing its shareholder to earn a fair return on its investment? Please explain why or why not.

[80] http://www.bcuc.com/Documents/Proceedings/2009/DOC_22335_B-1_TGVI_Application_2010-2011_RRA_RDA-part1.pdf

Response:

To clarify, FEVI is not under a soft cap mechanism; the use of the soft-cap mechanism ended in 2009. FEVI has maintained a rate freeze since 2009 through the use of the RSDA. Please refer to the response to BCUC IR 1.85.1 regarding the definition of an immature utility.

FEVI and FEW may consider non-traditional rate designs if postage stamp rates are not approved. Such rate designs may or may not be cost of service based, but in any event would need to allow the shareholder to earn a fair return on and of its investment. To date, the FEU have not explored any such designs as it is premature to do so given the current application before the Commission. However, the two examples provided in the preamble to BCUC IR 1.87 may not be appropriate alternatives for FEVI and FEW at this time because:

- The soft-cap mechanism used in FEVI was a feature unique to the repayment of the revenue deficiency deferral account ("RDDA") and resulted in rates which were set above the cost of service. FEU does not believe that there is a need to set FEVI and FEW rates higher than cost of service at this time and doing so would further compound the issue of rate disparity amongst the FEU; and,
- Revenue deferrals, such as the one used by Heritage Gas, are generally used in situations of newer utilities being established to serve areas that did not previously have access to utility service. This allows the new utility to encourage customer conversion from existing fuel sources by offering reasonable rates in the initial customer adoption phase. Neither FEVI nor FEW fall into this category at this point of time in their development.

Although open to alternatives, FEVI and FEW would be cautious of an approach which may result in the accumulation of a large revenue deficiency for future recovery from customers because this would exacerbate future rate challenges.

87.2 If FEVI or FEW is classified as an immature utility, and postage stamp rates are not approved, does FEU consider that introduction of an alternative revenue deferral mechanism, such as that used by Heritage Gas, could be used to allow time for the distribution system to develop while still allowing its shareholder to earn a fair return on its investment? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.87.1.

88.0 Reference: Delivery Rate Design – FEVI

Exhibit B-3, Section 6.9, p.129

Summary of the Selected Option: Common Rates

"Amalgamation and common rates will improve the basis on which an economic natural gas distribution utility can operate in FEVI's service area."

88.1 Does the above statement imply that FEVI in its current state (i.e. not amalgamated nor on a common rate structure) is an economic [emphasis added] natural gas distribution utility?

Response:

The statement refers to the implementation of amalgamation and common rates improving the ability of a natural gas distribution utility operating in FEVI's service area to provide a service that meets the demands of its customers. The statement is not intended to assess the current state of the utility. However, FEVI is economic in its current state.

88.2 If the answer is yes that FEVI is an economic natural gas distribution utility, please discuss why improvement is needed, especially when such improvement appears to result in rate increases in certain other service areas (e.g. FEI) of the FEU. If the answer is no that FEVI is not an economic natural gas distribution utility, please discuss this subject in light of the apparent growing surplus amount in the Rate Stabilization Deferral Account (RSDA).

Response:

FEVI is an economic utility. The Application is based principally on fairness and the objectives to address rate discrepancies and rate stability for the FEU's customers. Please see sections 4.2 to 4.5 of the Application for a discussion of the issues that this Application is seeking to address.

89.0 Reference: Delivery Rate Design - FEVI

Exhibit B-3, Section 8.4.1.2 and 8.4.1.3, p. 168

FEI- RSDA Amortization; Using the RSDA to Mitigate the Impact on FEI customers

"…based on the current projected December 31, 2013 RSDA balance of $90.3 million (before tax) and after deducting the $18.9 FEFN allocation as discussed above, returning the remaining RSDA balance of approximately $71.4 million to FEI Mainland non-bypass customers…"

"The rationale for accumulating the balance in the RSDA as justified in FEVI's 2009 Rate Design Application was primarily to help transition FEVI's customers to the higher rate that would result after the loss of Royalty Revenues."

89.1 If for this application one were to view the $90.3 million RSDA balance, which will be paid and accumulated by FEVI customers, as a customer contribution, and treated the RSDA balance as no-cost capital in the FEI Amalco capital structure or a deduction from FEI Amalco's rate base, what would be the resultant changes in FEI's, FEFN's rates?

Response:

If the RSDA balance of $90.3 million was treated as a deduction from FEI Amalco's rate base, the result would be a decrease of approximately 1% to the delivery rates currently proposed for the amalgamated entity. In addition, under this scenario the phase-in credit rider for FEI would not exist and the phase-in proposal for FEFN would have to be financed by the other regions, resulting in a minimal off-setting rate increase of approximately 0.1% (or debit rate rider) for Mainland, Vancouver Island and Whistler.

89.2 The amalgamation and common rates option proposed in this application confers the benefit of substantial rate decreases on FEVI and FEW customers. Does the FEU believe it is fair and equitable that FEW customers should receive somewhat the same rate reduction benefit as FEVI customers without apparently contributing any "up-front" monies for the proposed option (i.e. FEVI customers are bringing $90.3 million to the "table")? Please discuss.

Response:

Yes, due to the rationale for amalgamation and common rates and the unique situation of FEVI, it is fair and equitable for both FEVI and FEW to benefit from harmonized rates and for the RSDA to be utilized to phase in the transition to common rates.

The rationale for postage stamp rates does not depend on any service area providing an "up-front" contribution. As discussed in the Application, the primary rationale for harmonizing rates is that it is fair and equitable for all of the FEU's classes of natural gas customers to be charged the same rate for natural gas delivery service regardless of location. This rationale applies whether or not any service area is able to provide an "up front" contribution or not.

The balance in the RSDA is a result of the unique situation in FEVI, which is inapplicable to the FEW. In anticipation and recognition of the loss of government subsidies, rate structures for FEVI were maintained specifically to accumulate a surplus balance in the RSDA which could be used to mitigate future rate increases caused by the loss of the government subsidies. As the postage stamp rate proposal addresses the FEVI rate discrepancy, it is appropriate to utilize the RSDA to offset that rate increases that will result from the move to postage stamp rates. FEW has not developed an equivalent RSDA mechanism and rates have generally been reset each year to reflect the cost of service. Therefore, FEW has no revenue surplus to contribute towards amalgamation.

90.0 Reference: Delivery Rate Design – Affordability / Rate Shock

Exhibit B-3, Section 9, p. 189; Exhibit A2-15, 2011 Court of Appeal Decision, Enbridge Gas New Brunswick Inv. v. the New Brunswick Energy and Utilities Board, pp. 8,9; Reasons for Decision for Order G-99-06, p. 25; PNG April 28, 2006 Submission under BCUC Order No. G-40-06, p.3; Exhibit A2-3, Inquiry Report for Order G-100-96, pp. 1 to 18

Affordability

The FEU, on page 189 of the Application, include customer impact as one of its seven rate design principles. FEU state that "customer impact refers to the relationship between proposed rate changes and a customer's ability to pay."

The April 21, 2011 Decision of the Court of Appeal of New Brunswick on Enbridge Gas New Brunswick Inv. v. the New Brunswick Energy and Utilities Board (NBCA 36) stated on pages 8 and 9. (Exhibit A2-15):[81]

> "In summary, the Federal Court of Appeal [in Transcanada Pipelines Ltd. v. Canada (National Energy Board), 2004 FCA 149, [2004] F.C.J. No. 654 (QL)] ruled that the impact on customers and ultimate consumers is not a relevant consideration when determining the utilities' cost of capital. Correlatively, to the extent that the cost of capital may influence the setting of tolls, the impact which those tolls may have on customers remains irrelevant unless the customer is faced with "rate shock," in which case the increase in tolls may be phased in over time. Ultimately, however, the customer will have to compensate the utility for deferring recovery of its cost of capital. Together these understandings support the principle that what is a "just and reasonable" toll for the utility is a "just and reasonable" toll for the customer or ultimate consumer."

The Commission, in its August 16, 2006 Reasons for Decision on an Application by Pacific Northern Gas Ltd for Approval of 2006 Rates (G-99-06)[82] stated on page 25:

> "The Commission Panel, however, agrees with PNG that "affordability" is not a test under the Act or the relevant case law and that it is a vague, relative and potentially shifting concept."

81 http://www.gnb.ca/cour/03COA1/Decisions/2011/April/20110421EnbridgeRobertson.pdf
82 http://www.bcuc.com/Documents/Proceedings/2006/DOC_12354_G-99-06_PNG_2006RR_Reasons.pdf

Pacific Northern Gas Ltd. April 28, 2006 Submission under BCUC Order G-40-06,[83] stated on page 3:

> "In Hemlock Valley [Hemlock Valley Electrical Services v. British Columbia (Utilities Commission) (1992), 66 B.C.L.R. (2d) 1 (C.A.)], the Commission allowed a rate increase for the utility but declined to permit the full implementation of the increase, and instead directed that it be phased in over three years so as to avoid or lessen the "rate shock" of the increase on the utility's customers. Upon request, the Commission later reconsidered the matter and purported to distinguish British Columbia Electric Railway, concluding that having regard to the impact on customers, phasing in of the rate increase was "an integral part of the finding of just and reasonable rates." (B.C.L.R. p. 11, para. 34)
>
> The Court of Appeal for British Columbia overturned the Commission's decision to phase in the rate increase, reasoning that to do so would preclude the utility from earning the rate of return found by the Commission to be the fair and reasonable return on equity. The Court found that the Commission, having found the fair rate of return on equity, was then required to set customer rates so as to allow the utility the opportunity to earn that return. ...
>
> ... the Court of Appeal cited with approval the following passage from the judgment of Martland J. in British Columbia Electric Railway (B.C.L.R. p. 17, para. 41): "Clearly, as between these two matters there is no priority directed by the Act, but there is a duty imposed upon the Commission to have due regard to both of them. The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. In my view, however, if a public utility is providing an adequate and efficient service (as it is required to do by s. 5 of the Act), without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive. It may be that within the schedule certain rates may operate unfairly, relatively, as between different classes of service or different classes of consumers. If so, the Commission has the duty to prevent such discrimination. But this can be accomplished by adjustments of the

83 http://www.bcuc.com/Documents/Proceedings/2006/DOC_11478_PNG%20Apr%2028%2006%20Submission%20under%20BCUC%20Order%20No%20G%2040%2006.pdf

relative impact of the various rates in the schedule without having to reduce the total revenues which the whole schedule of rates is designed to produce."

On October 7, 1996, the Commission issued Order G-100-96 which included at Appendix A and Inquiry Report into BC Gas Utility Ltd. and Propane Prince Increases in the City of Revelstoke (Exhibit A2-4). This related to an application by BC Gas for approval to pass-through an increase in the cost of propane which would have represented an average increase to residential customers of approximately 24 percent and to commercial customers of 32 percent. The commission stated that this was 'rate shock in the extreme.'

The Commission found that BC Gas had acted responsibly and prudently in entering into a new contract for the supply of propane for Revelstoke, but considered that a direct flow through of the increased cost of propane would create a significant hardship for many of the customers in Revelstoke. The Commission rejected the proposal to roll in the acquisition costs of propane with that of natural gas, in favour of a two-year phase in of the required rate increase.

90.1 Previous regulatory decisions appear to support a position that the impact on customers is not a relevant consideration when setting rates, unless the customer is faced with "rate shock." Do FEU agree with this conclusion? If no, please explain why.

Response:

The FEU agree that the impact on customers or affordability is not a relevant issue when setting rates in the sense of allowing the utility to recover its costs, including a fair rate of return. However, when looking at the COSA and rate design amongst various customer groups, the level of the rate increases is nearly always a consideration in setting the appropriate rate levels through rebalancing of the classes relative to the range of reasonableness. The FEU maintains that the rate impact to customers, whether or not it constitutes rate shock, is a relevant consideration when looking at rate changes as between various customer classes.

90.2 Previous regulatory decisions appear to support a position that, if there is "rate shock," the general response is to consider phasing-in the increase over time? Do FEU agree with this conclusion? If no, please explain why.

Response:

The FEU agree that phasing-in an increase is a common way to mitigate "rate shock". Please see response to BCUC IR 1.91.1 for a discussion on the FEU's view on what level of rate increase could be considered as "rate shock".

91.0 Reference: Delivery Rate Design – Affordability / Rate Shock

Reasons for Decision for Order G-130-07, p. 69; BC Hydro 2008 Residential Inclining Block Application, Exhibit B-11, pp. 30-31; Reasons for Decision for Order G-156-10, p. 79; Exhibit A2-3, Inquiry Report for Order G-100-96, p. 18; FortisBC 2009 Rate Design and Cost of Service Application, Exhibit B-7, Big White Ski Resort IR 2 question 1.1

Rate Shock – Definition

The Commission, on page 69 of its December 17, 2007 Reasons for Decision on BC Hydro's 2007 Rate Design Application - Phase 1 (G-130-07), stated:[84]

> "With regard to acceptable level of bill impact, BC Hydro has endeavoured to limit the combined annual impact of rebalancing and restructuring on any individual customer bill to no more than ten percent, exclusive of any changes arising from general increases. This is not a rule that I intended to be binding in every circumstance. For instance, BC Hydro believed that it is acceptable for bill impacts to exceed 10 percent per annum where the absolute dollar value of the increase is very small."

In the Commission's April 24 1992 Reasons for Decision for BC Hydro's Rate Design Application (filed as part of Exhibit B-11 to BC Hydro 2008 Residential Inclining Block Application),[85] the Commission stated on page 30 to 31 of Exhibit B-11 (pages 17 to 18 of the Decision):

> "No Increases Over 10 Percent
>
> ... In discussing rate shock, the Utility offered two alternative definitions. Rate shock was defined in the Application as increases greater than 10 percent per annum (Exhibit 4, CAC(B.C.) et al Question 3). In a response to a question from CAC (B.C.) et al counsel, Mr. Peterson, a B.C. Hydro witness, noted that the 10 percent level was a guideline rather than a very firm barrier. (T. 176) The second definition made reference to the "two-times rule" which says:
>
>> "...if as a result of rate design bills were to increase by more than double the increase received on average by bills within the customer class, this would begin to encroach on the realm of rate shock, that is unacceptably high rate increases." (T. 485)

[84] http://www.bcuc.com/Documents/Proceedings/2007/DOC_17004_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf

[85] http://www.bcuc.com/Documents/Proceedings/2008/DOC_18926_B-11_BCH_Panel-IRNo1-Rsp.pdf

> This definition would appear to give the Utility more flexibility within the context of a potential 7 percent revenue requirements increase; however, the 10 percent guideline on bill impacts appeared to be the more influential in the Application. (T. 496)
>
> Commission Determination: As indicated by the evidence, whether a particular increase constitutes rate shock depends on the overall rate environment and the circumstances of the particular customer. (T. 175-178) It is the Commission's responsibility to assess these circumstances and determine when rate shock may be properly said to have occurred. The Commission accepts that, in the circumstances of this Application, the two-times rule can be used as a rough guideline.
>
> No Customer Bills Should Decline
>
> The other reason given by B.C. Hydro for not immediately eliminating the declining block rate structure is that one-half of its customers would see their bills go down. ...
>
> B.C. Hydro suggests that no bills to any customer should decline since allowing decreases would result in customers receiving mixed messages as to the future of electricity costs, thereby diluting the incentive to avoid wasteful use of the resource. (T. 571-572) In order to ensure that no customer's bills decrease, the Utility proposed to make changes only at times of revenue requirement increases.
>
> Commission Determinations: The Commission agrees that a substantial decline in rates to a particular customer class or large group within a class would not conform with the spirit of the Special Direction. The Commission does not believe that this precludes decreases in bills to customers who are unlikely to be price sensitive, especially if there are offsetting benefits. The Commission will, where possible, direct the adoption of a strategy which will eliminate the declining block rate structure without creating the problems previously noted or adding to the uncertainties."

The Commission's October 19, 2010 Decision on FortisBC Inc. 2009 Rate Design and Cost of Service Analysis (G-156-10) stated on page 79 that "Rate increases due to rebalancing alone are capped at five percent annually, with a 10 percent cap on increases resulting from rebalancing and revenue requirement increases combined, exclusive of increases to BC Hydro rates flowed through to FortisBC customers. The 10 percent cap does not apply to increases due solely to revenue requirements." On October 7, 1996 the Commission issued Order G-100-96 which included at Appendix A and Inquiry Report into BC Gas Utility Ltd. and Propane Prince Increases in the City of Revelstoke. (Exhibit A2-3) The Commission stated on page 18:

> "Increasing rates immediately to recover the full 37.5% increase in propane costs would have a severe impact on the economy of Revelstoke and the Region. The subject of "rate shock" has come up at a number of public hearings before the Commission. The Commission has generally accepted the definition of rate shock as an increase in rates that is more than double a general increase in cost of service sought by a utility. In this instance a 29% total increase in rates, relative to the Rate Design increases applied for by BC Gas, by any definition, is rate shock in the extreme."

In the FortisBC 2009 Rate Design and Cost of Service Application, Exhibit B-7, Fortis BC response to Big White Ski Resort IR 2 question 1.1 includes the following:[86]

> "FortisBC states that its "rebalancing effort" contains the following elements: "Total increase due to rebalancing and revenue requirements not to exceed 10 per cent unless the revenue requirement increase alone exceeds 10 per cent" and "Increases noted above are exclusive of BC Hydro increases that the Company may apply on a flow-through basis."
>
> Q1.1 Please explain the source of the 10 per cent figure. Is 10 per cent a "hard and fast" rule used in rate-making to define "rate-shock?"
>
> A1.1 FortisBC has not considered what the threshold percentage rate increase would be to cause rate shock to customers. Consideration of any rate increase would be the subject of regulatory proceedings to investigate the nature of the cost drivers that the Company believes would have to be reviewed with the Commission and customers. The determination of whether any particular rate increase would constitute rate shock would thereby be a decision of the Commission and in the context of the current PBR Plan would also reflect stakeholder views through the Negotiated Settlement Process. Thus, the 10 percent figure is not "hard and fast" and was chosen as a number that combined with anticipated revenue requirement and rebalancing increases would bring the revenue to cost ratio of most rate classes to within the range of reasonableness within a reasonable time."

86 http://www.bcuc.com/Documents/Proceedings/2010/DOC_24708_B-7_FortisBC-IR-No-2-Responses-.pdf (page 433 of the pdf)

91.1 Previous regulatory decisions appear to support a position that the 10% rule (bill increases greater than 10 percent per annum) and/or the "two times rule" (bill increases as a result of rate design changes greater than double the average bill increase for that customer class) are a reasonable indicator of rate shock, but should not be used as a 'hard and fast' rule. Do FEU agree with this conclusion? If no, please explain why.

Response:

The FEU believe that the rate design principle of stability is important to balance with the other rate design principles, and that rate shock is one of the guides used to assess the stability of rates and associated rate design changes. Rate shock must be assessed considering the specific circumstances in each rate design proceeding. The 10% and two times rules are useful for assessing rate shock in the case of electric utilities where the electricity commodity is generated within the utility. In the case of gas utilities who source the natural gas commodity at market based prices, commodity cost can introduce a further source of rate shock for customers. FEI has evolved quarterly natural gas commodity cost flow through and deferral mechanisms to help manage rate volatility for customers and to mitigate rate shock in this case.

91.2 Do FEU consider that a different "rate shock" test should be applied to the delivery portion of the gas rate compared to the burner tip impact? Please explain why or why not.

Response:

The FEU consider that rate shock should principally be assessed at the burner tip, as the burner tip price represents the overall impact that customers will see.

91.3 Do FEU consider that the 10 percent rule and/or the "two times rule" is a reasonable indicator of rate shock for delivery rate increases when applied as follows (please explain why or why not):

i. Delivery increases as a percentage of the delivery cost?

ii. Delivery increases only as a percentage of the total cost (i.e., burner tip)?

Response:

Please refer to the responses to BCUC IRs 1.91.1, 1.91.2 and 1.91.4.

91.4 Please describe FEU's preferred methodology for identifying rate shock related to delivery increases (which can be different from the examples provided above), and explain why this approach is preferred.

Response:

The FEU believe that rate shock for a gas utility is properly assessed by examining the burner tip rates faced by customers, and that delivery price changes are only part of the price faced by customers. The FEU believe that both the 10 percent rule and the two times rule can be used as a guide to assess rate shock, but since many factors can contribute to rate shock including volatility in natural gas commodity markets, it should be evaluated based on the specific circumstances involved in each case.

91.4.1 Would this preferred methodology be different if the Application for postage stamp rate was approved by the Commission compared to if the Application was denied? If yes, please explain how it would be different and why.

Response:

As stated in the response to BCUC IR 1.91.4, the FEU believe that evaluation of rate shock should be based on the specific circumstances of each case involved. Both the 10 percent rule and the two times rule could be used as a guide,among other factors, whether or not postage stamp rates were approved.

91.5 The Commission's 1992 Reasons for Decision for BC Hydro's Rate Design Application appears to support a position that a substantial decline in rates to a particular customer class or large group within a class who are price sensitive would be inconsistent with Energy Plan policy action No. 4 to "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation." Does FEU agree with this conclusion? If no, please explain why.

Response:

The FEU believe that the circumstances in the 1992 BC Hydro Rate Design proceeding where BC Hydro proposed to move from a declining block rate structure to a flat rate structure in order to send pricing signals to encourage energy conservation are different than the current application where the FEU are proposing to amalgamate service areas and eliminate the historic developmental rate differences through postage stamping. Therefore the FEU do not agree that the conclusion is appropriately applied to this circumstance where different areas will see different rate changes. As stated in the Application, the FEU believe that any consumption increases through lower rates on FEVI and FEW may be offset by similar aggregate consumption decreases in FEI and thus overall postage stamping will be more or less neutral with respect to the Energy Plan policy action No.4. In addition, the proposed postage stamp rate structure includes flat delivery charges which will send energy conservation pricing signals to the FEU's customers. The recognition by the Commission in the BC Hydro 1992 RDA decision that declining bills would be less of a concern where customers are not price sensitive is relevant for the FEU in the current Application. As discussed in the response to BCUC IR 1.91.5.1 natural gas use is relatively price inelastic so bill decreases will not affect consumption to a large degree.

91.5.1 Do FEU consider that FEVI or FEW customers are price sensitive? Please explain why or why not.

Response:

The FEU do not have any reason to believe that the customers of FEVI and FEW customers are different in their degree of price sensitivity than gas customers are in general. As noted in the preamble of BCUC IR 1.81.1 (and quoted from the Exhibit B-17 of the FEU's 2012-2013 RRA proceeding) the price elasticity estimates for FEI residential customers was estimated at -0.22 and that a broader AGA study had estimated long run price elasticity at -0.18 for residential natural gas consumption. Although the analysis at the time of price elasticity for FEVI and FEW customers was inconclusive, the FEU expect similar price sensitivity behaviour from those customers. Natural gas consumption is therefore relatively price inelastic.

Please refer to the responses to BCUC IRs 1.81.6 and 1.81.7.

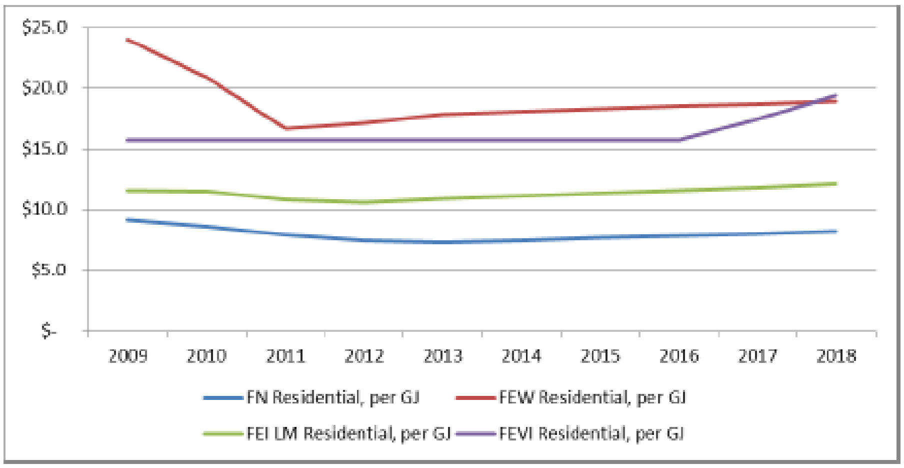
92.0 Reference: Delivery Rate Design – Affordability / Rate Shock

Exhibit B-3, Section 6, p. 111; FEU 2012-2013 Revenue Requirement and Rates Application, Exhibit B-9, p. 54

Rate Shock – Status Quo

The FEU provide the following table on page 111 of the Application:

Figure 6-1: Residential Effective Rates across the FEU[131]



The FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application, Exhibit B-9,[87] page 54, Fortis stated:

> "Please note that the approximate effective burner tip rate changes provided in the table below represent a simplified forecast for 2014 through 2016 and may not reflect the actual forecast cost of service and proposed rate changes for which the Utilities will seek approval."

[87] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28091_B-9_FEU%20Rsp%20to%20BCUC%20IR-No1.pdf

Approximate Burner Tip Rate Increase	2012	2013	2014	2015	2016
FEVI Annual	0.0%	8.9%	4.0%	3.9%	4.0%
FEVI Cumulative	0.0%	8.9%	12.8%	16.7%	20.7%
FEI Annual	2.4%	3.0%	2.6%	2.6%	2.7%
FEI Cumulative	2.4%	5.4%	8.0%	10.6%	13.3%

92.1 If postage stamp rates are not approved, do FEU consider that any customer segment of FEI, FEVI, FEW or FEFN would be faced with rate shock under the status quo? Please describe. For the purpose of this question, please show the results if rate shock is defined as:

i. Annual delivery increases as a percentage of the delivery cost exceeding 10% for any customer; and

ii. Annual delivery increases as a percentage of the total cost (i.e., burner tip) exceeding 10% for any customer

Response:

Please refer to the response to BCUC IR 1.91.1 for a discussion on the definition and applicability of rate shock.

If postage stamp rates are not approved and the RSDA is used to mitigate annual rate increases for FEVI, FEVI customers will experience rate increases in 2017, as well as 2018, once the RSDA is expected to be fully depleted and the impact of the loss of the royalty revenues is experienced. Specifically, FEVI estimates that sales customers will experience an approximate 11% burner tip increase in 2017 followed by a further approximate 13% burner tip increase in 2018. In the absence of rate harmonization, a single energy charge in FEVI is assumed to still apply; therefore, the requested analysis on delivery rate increases is not applicable. Please note that the underlying delivery margin and cost of gas assumptions are the same as those used to produce the rate projections in Figure 6-1 on page 111 of the Application.

There are no customers in FEI, FEW and FEFN that are expected to experience significant rate increases under the status quo scenario.

Further, the table referenced from the 2012-2013 RRA in the question preamble is no longer current and does not reflect the use of the RSDA for rate mitigation in FEVI. To clarify, FEU have provided an updated version of the table which includes the impact of the RSDA, below:

Approximate Residential Burner Tip Rate Change	2012	2013	2014	2015	2016	2017	2018
FEVI Annual	0.0%	0.0%	0.0%	0.0%	0.0%	10.6%	12.7%
FEVI Cumulative	0.0%	0.0%	0.0%	0.0%	0.0%	10.6%	23.3%
FEI Annual	-1.8%	2.7%	2.1%	2.1%	2.2%	2.5%	2.6%
FEI Cumulative	-1.8%	0.9%	3.0%	5.1%	7.3%	9.8%	12.4%

92.2 For FEVI customers, from F2012 to 2016, please provide a table showing the annual and cumulative forecast bill impact for each rate class, both as a percentage of the delivery portion of the rate and as a percentage of the "burner tip." Please also include in this table an estimate of the average dollar bill impact per customer, per year, for each customer class.

Response:

As described in the response to BCUC IR 1.92.1, in the absence of rate harmonization it is expected that the single energy charge in Vancouver Island would still apply, thus only an average burner tip impact exists and has been provided in the table. In addition, the analysis applies the average percent total revenue increase required equally to all sales rate schedules (for example, in 2017 a 10.6% increase is applied to all FEVI sales rates). Finally, the table is limited to 2017 and 2018 because the cost of service changes forecast for 2014 through 2016 are expected to be mitigated by the balance in the RSDA.

Vancouver Island Sales Rate Schedules	Typical Use, GJ/Yr	Existing Rate ($/GJ)	2017 Forecast Rate ($/GJ)	2017 Annual Bill Increase ($)	2017 Burner Tip Increase (%)	2018 Forecast Rate ($/GJ)	2018 Annual Bill Increase ($)	2018 Burner Tip Increase (%)	Cumulative Total Bill Increase ($)	Cumulative Total Burner Tip Increase (%)
RGS	58.6	16.475	18.228	$ 103	10.6%	20.537	$ 135	12.7%	$ 238	23.3%
AGS	1,364.1	12.725	14.079	$ 1,847	10.6%	15.862	$ 104	12.7%	$ 1,951	23.3%
SCS-1	80.3	18.352	20.304	$ 157	10.6%	22.876	$ 151	12.7%	$ 307	23.3%
SCS-2	312.6	17.742	19.63	$ 590	10.6%	22.117	$ 146	12.7%	$ 736	23.3%
LCS-1	929.8	14.140	15.644	$ 1,398	10.6%	17.626	$ 116	12.7%	$ 1,515	23.3%
LCS-2	2,361.9	12.808	14.171	$ 3,219	10.6%	15.966	$ 105	12.7%	$ 3,324	23.3%
LCS-3	17,694.0	12.152	13.445	$ 22,878	10.6%	15.148	$ 100	12.7%	$ 22,978	23.3%
HLF	14,025.0	8.911	9.859	$ 13,297	10.6%	11.108	$ 73	12.7%	$ 13,370	23.3%
ILF	10,183.0	10.392	11.497	$ 11,256	10.6%	12.953	$ 85	12.7%	$ 11,342	23.3%

92.3 Please describe the efforts FEU have taken over the last two years to advise both customers (residential, commercial and industrial) and developers on Vancouver Island of the forecast rate increases should the Application be denied.

Response:

Municipalities have been informed of the forecasted rate increases during Operating Agreement discussions and the FEU have informed the general public through the regulatory process for applications such as the 2010-2011 FEVI (then TGVI) Revenue Requirements and Rate Design Application and the 2012-2013 FEU RRA. In addition to the Stakeholder Engagement section of this Application, some of the larger customers on Vancouver Island were notified of the potential increases through discussions with their account managers as the FEU worked on this Application.

93.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-3, Section 1, p. 6, Section 4, p. 71; Reasons for Decision for Order

G-138-10, p. 23

Rate Shock – Postage Stamp Rates

FEU state on page 6 of the Application that, if postage stamp rate are approved:

> "..FEI customers in the Lower Mainland, Inland and Columbia service areas will see a rate increase. The one-time increase will range from 3.7 per cent to 5.4 percent for residential and commercial customers at the burner tip, depending on level of consumption. The FEU propose to mitigate this rate increase for three years. ...
>
> Fort Nelson customers ... would require an increase of between 24 per cent to 55 per cent at the burner tip ... The FEU propose to phase-in this increase by delaying any impact of common rates for five years and then phase-in the increase over the subsequent 10 years.
>
> FEVI customers will see rate decreases of between 25 per cent and 44 per cent.
>
> FEW customers will see rate decreases of between 37 per cent and 45 per cent."

The September 1, 2010 Reasons for Decision on Terasen Gas (Whistler) Inc. 2010-2011 Revenue Requirement and Rates Application (G-138-10)[88] states on page 23 that "In its opening remarks, TGW states: '... Specifically, customers now pay less to meet their energy requirements previously served by propane.'"

FEU include on page 71 of the Application a comparison of rates for the FEU service areas. This shows an FEW daily basic charge of $0.2464, compared to $0.3890 for FEI, $0.3450 for FEVI and $0.3184 for FEFN.

93.1 If postage stamp rates are approved without the proposed phase-in, does FEU consider that any customer segment of FEI, FEVI, FEW or FEFN would be faced with rate shock under the status quo? Please describe. For the purpose of this question, please show the results if rate shock is defined as:

[88] http://www.bcuc.com/Documents/Proceedings/2010/DOC_26346_G-138-10_TGW_F2011-RRA-Reasons-Appendix-A.pdf

i. Annual delivery increases as a percentage of the delivery cost exceeding 10 percent for any customer; and

ii. Annual delivery increases as a percentage of the total cost (i.e., burner tip) exceeding 10 percent for any customer

Response:

Please refer to the response to BCUC IR 1.91.1 for a discussion on rate shock.

Yes, in the absence of a phase-in approach, the FEU expect that all customers in Fort Nelson will experience rate shock upon amalgamation and the implementation of common rates. As discussed in Section 6.7.2 and Section 8.4.1.1 of the Application, the significant annual bill impact experienced by Fort Nelson customers is the reason that the FEU have proposed a 15 year phase-in to common rates for Fort Nelson.

The following table provides a summary of the customers who may realize rate increases exceeding 10% upon amalgamation and implementation of common rates, excluding the phase-in rate riders as proposed in the Application. The results indicate that approximately 8 rate schedules out of a total of 48 may experience delivery rate increases of greater than 10%. The number of rate schedules which may experience rate increases greater than 10% reduces to 5 out of 48 when the burner tip impact is considered. Please note that this analysis excludes the impact of the RSDA, which is used to finance the phase-in riders and smooth the rate impacts for FEI and FEFN customers.

Customers Who May Experience 10% Rate Increase[1] *Without "Phase-In" Riders*			
Rate Schedule	**Increase > 10% to Delivery[2]**	**Increase > 10% to Burner Tip[3]**	**Notes**
Lower Mainland Rate Schedule 4[4]	21%	No	Burner tip impact of 6%
Lower Mainland Rate Schedule 22[4]	14%	No	Burner tip impact estimated at 4%, using FEI commodity rates
Inland Rate Schedule 4[4]	24%	No	Burner tip impact of 7%
Fort Nelson Rate Schedule 1	88%	55%	
Fort Nelson Rate Schedule 2.1 (A)	24%	28%	Transition to Rate Schedule 2 at Amalgamation (approx. 460 GJ per year)
Fort Nelson Rate Schedule 2.1 (B)	24%	25%	Transition to Rate Schedule 3 at Amalgamation (approx. 2,624 GJ per year)
Fort Nelson Rate Schedule 2.2	22%	24%	
Fort Nelson Rate Schedule 25[5]	18%	18%	

[1]- Increase of 10% or greater

[2]- Effective delivery rate including basic charge & RSAM Rider, calculated using typical annual use per Appendix J-3

[3]- Burner Tip rate including RSAM delivery rate rider and MCRA rate rider, calculated using typical annual use per Appendix J-3

[4]- The delivery rate changes for these rate schedules are based off of RS 5/25, as a result percentage changes are different than other FEI rate schedules

[5]- For purposes of this analysis, it is expected that the two RS 25 customers transitioning to FEI RS 3 will elect a transportation rate schedule upon amalgamation

93.2 Please update the response to the question above, assuming that postage stamp rates are approved with the proposed phase in.

Response:

Please refer to the response to BCUC IR 1.91.1 for a discussion on rate shock.

With the phase-in as proposed, the FEU do not expect any customers to experience rate shock upon amalgamation and the implementation of common rates.

The following table provides a summary of the customers who may realize rate increases exceeding 10% upon amalgamation and implementation of common rates, including the phase-in rate riders as proposed in the Application (i.e. including the impact of the RSDA). The results indicate that approximately 3 rate schedules out of a total of 48 may experience delivery rate increases of greater than 10%. The number of rate schedules which may experience rate increases greater than 10% reduces to zero out of 48 when the burner tip impact is considered.

Customers Who May Experience 10% Rate Increase[1] *With "Phase-In" Riders*			
Rate Schedule	**Increase > 10% to Delivery[2]**	**Increase > 10% to Burner Tip[3]**	**Notes**
Lower Mainland Rate Schedule 4[4]	17%	No	Burner tip impact of 5%
Lower Mainland Rate Schedule 22[4]	10%	No	Burner tip impact estimated at 4%, using FEI commodity rates
Inland Rate Schedule 4[4]	19%	No	Burner tip impact of 6%

[1]- Increase of 10% or greater

[2]- Effective delivery rate including basic charge and RSAM delivery rate rider, calculated using typical annual use per Appendix J-3

[3]- Burner Tip rate including RSAM delivery rate rider and MCRA rate rider, calculated using typical annual use per Appendix J-3

[4]- The delivery rate changes for these rate schedules are based off of RS 5/25, as a result percentage changes are different than other FEI rate schedules

93.3 For FEI, FEVI, FEW and FEFN customers, assuming postage stamp rates are approved without the proposed phase in, please provide a table showing the total forecast bill impact for each rate class, both as a percentage of the delivery portion of the rate and as a percentage of the 'burner tip.' Please also include in this table an estimate of the average dollar bill impact per customer, for each customer class.

Response:

The following tables reflect the forecast annual bill impacts for FEI Mainland, FEVI, FEW and FEFN, assuming postage stamp rates are approved without a phase-in period. The annual bill impact is based on a typical customers' consumption level in each rate class. The change in delivery rate for each rate class, as well as the dollar and percentage change in the total annual bill is summarized in each table.

FEI Lower Mainland

Amalgamated Rate Schedule	Consumption GJ	Delivery Change %	Annual Change %	Annual Change $
Sales Customers				
RS1 - Residential	95	9.1%	5.3%	$ 53.99
RS2 - Small Commercial	300	8.1%	3.8%	$ 108.54
RS3 - Large Commercial	2800	9.1%	4.3%	$ 998.49
RS4 - Seasonal	5400	20.7%	6.4%	$ 2,246.90
RS5 - General Firm	9700	7.6%	4.1%	$ 3,084.33
RS6 - NGV	2900	9.1%	5.7%	$ 1,461.71
RS7 - Interruptible	8100	5.4%	3.2%	$ 1,952.98
Transportation Customers				
RS22 - Large Industrial	467306	14.5%	14.5%	$ 67,739.29
RS23 - Large Commercial	4100	8.9%	8.9%	$ 1,193.18
RS25 - General Firm	19086	8.4%	8.4%	$ 3,691.68
RS27 - Interruptible	53957	9.5%	9.5%	$ 7,430.86

FEI Inland

Amalgamated Rate Schedule	Consumption GJ	Delivery Change %	Annual Change %	Annual Change $
Sales Customers				
RS1 - Residential	75	8.5%	5.4%	$ 45.25
RS2 - Small Commercial	250	7.7%	4.1%	$ 99.20
RS3 - Large Commercial	2600	9.0%	4.6%	$ 1,002.58
RS4 - Seasonal	9300	24.3%	7.1%	$ 4,092.86
RS5 - General Firm	12800	8.2%	4.6%	$ 4,485.59
RS6 - NGV	11900	9.5%	6.0%	$ 6,176.57
RS7 - Interruptible	4000	3.6%	3.0%	$ 1,060.43
Transportation Customers				
RS23 - Large Commercial	4700	9.2%	9.2%	$ 1,367.79
RS25 - General Firm	40671	9.3%	9.3%	$ 7,990.15
RS27 - Interruptible	48904	9.4%	9.4%	$ 6,734.95

FEI Columbia

Amalgamated Rate Schedule	Consumption GJ	Delivery Change %	Annual Change %	Annual Change $
Sales Customers				
RS1 - Residential	80	8.6%	5.0%	$ 44.76
RS2 - Small Commercial	320	8.2%	3.7%	$ 113.21
RS3 - Large Commercial	3300	9.3%	4.2%	$ 1,137.20
RS5 - General Firm	9100	7.5%	3.9%	$ 2,768.74
Transportation Customers				
RS23 - Large Commercial	4200	9.0%	9.0%	$ 1,222.28
RS25 - General Firm	30358	9.1%	9.1%	$ 6,494.24
RS27 - Interruptible	7734	5.1%	5.1%	$ 1,065.08

FEVI

The FEVI rate structure utilizes a bundled Energy Charge for the variable portion of rates. For comparison purposes, a proxy delivery charge has been calculated for each rate class in FEVI. These proxy delivery charges are also summarized in Appendix J-7 of the Application.

As detailed in Section 9.3 of the Application, the FEU are proposing to adopt FEI's rate schedules for the amalgamated entity. Therefore, each rate class in FEVI, FEW and FEFN has been mapped to FEI's Rate Schedule 1, 2 or 3. The tables below provide the original rate schedule in each service area, and the corresponding rate schedule that each rate class has been mapped to. As with FEI, the percentage delivery change, the percentage annual bill change as well as the annual dollar change is presented in the tables below.

FEI

Amalgamated Rate Schedule	Original Rate Schedule	Consumption GJ	Delivery Change %	Annual Change %	Annual Change $
Sales Customers					
RS1 - Residential	RGS	58.6	-32.6%	-25.2%	$ (243.61)
RS2 - Small Commercial	AGS	780	-41.0%	-28.1%	$ (2,841.88)
	SCS1	80	-39.6%	-30.9%	$ (455.89)
	SCS2	313	-60.8%	-44.1%	$ (2,446.34)
	LCS1	930	-50.7%	-34.4%	$ (4,515.93)
RS3 - Large Commercial	AGS	3990	-44.9%	-31.5%	$ (15,709.19)
	LCS2	2362	-43.3%	-31.1%	$ (9,393.51)
	LCS3	17694	-47.0%	-32.1%	$ (69,080.64)
	HLF	14025	23.7%	-7.2%	$ (8,974.79)
	ILF	10183	-21.9%	-20.0%	$ (21,158.63)

FEW

Amalgamated Rate Schedule	Original Rate Schedule	Consumption GJ	Delivery Change %	Annual Change %	Annual Change $
Sales Customers					
RS1 - Residential	Residential	90	-55.2%	-37.6%	$ (621.17)
RS2 - Small Commercial	Commercial	260	-63.2%	-43.0%	$ (1,978.83)
	LCS1	1060	-69.5%	-47.1%	$ (8,707.80)
RS3 - Large Commercial	LCS2	2810	-71.5%	-49.9%	$ (24,397.83)
	LCS3	6200	-73.9%	-51.6%	$ (55,641.41)

FEFN

Amalgamated Rate Schedule	Original Rate Schedule	Consumption GJ	Delivery Change %	Annual Change %	Annual Change $
Sales Customers					
RS1 - Residential	Rate 1	140	88.1%	54.9%	$541.57
RS2 - Small Commercial	Rate 2.1	460	23.7%	27.7%	$ 958.12
RS3 - Large Commercial	Rate 2.1	2624	24.4%	24.6%	$ 4,532.10
	Rate 2.2	3100	21.8%	23.5%	$ 5,115.49
	Rate 25	6890	17.7%	210.1%	$ 38,848.34

93.4 Please update the table above assuming postage stamp rates are approved with the proposed phase-in, by providing annual and cumulative bill impact data until the end of the phase-in period.

Response:

FEI

The following table summarizes the annual and cumulative rate changes for FEI Lower Mainland, Inland and Columbia customers based on a three year RSDA allocation approach as outlined in the Application. Under this approach, the December 31, 2013 RSDA balance of $71.4 million (December 31, 2013 RSDA balance of $90.3 million less $18.9 million required for Fort Nelson Phase In) would be amortized equally over three years to all non-bypass FEI customers. In 2014, customers would see an increase in their annual bill as indicated below. There would be no additional increase in 2015 and 2016, and in 2017, after another slight increase, customers would be fully phased in to amalgamated rates.

FEI Lower Mainland

		2014		2015 - 2016				2017			
Amalgamated Rate Schedule	Consumption	Annual Change	Annual Change	Annual Change	Annual Change	Cumulative Annual Change	Cumulative Annual Change	Annual Change	Annual Change	Cumulative Annual Change	Cumulative Annual Change
	GJ	%	$	%	$	%	$	%	$	%	%
Sales Customers											
RS1 - Residential	95	3.3%	$ 33.68	0.0%	$ -	3.3%	$ 33.68	2.0%	$ 20.31	5.3%	$ 53.99
RS2 - Small Commercial	300	2.1%	$ 60.28	0.0%	$ -	2.1%	$ 60.28	1.7%	$ 48.26	3.8%	$ 108.54
RS3 - Large Commercial	2800	2.8%	$ 651.60	0.0%	$ -	2.8%	$ 651.60	1.5%	$ 346.89	4.3%	$ 998.49
RS4 - Seasonal	5400	5.4%	$ 1,889.59	0.0%	$ -	5.4%	$ 1,889.59	1.0%	$ 357.31	6.4%	$ 2,246.90
RS5 - General Firm	9700	2.9%	$ 2,183.19	0.0%	$ -	2.9%	$ 2,183.19	1.2%	$ 901.14	4.1%	$ 3,084.33
RS6 - NGV	2900	3.7%	$ 958.84	0.0%	$ -	3.7%	$ 958.84	2.0%	$ 502.87	5.7%	$ 1,461.71
RS7 - Interruptible	8100	2.5%	$ 1,496.51	0.0%	$ -	2.5%	$ 1,496.51	0.8%	$ 456.47	3.2%	$ 1,952.98
Transportation Customers											
RS22 - Large Industrial	467306	10.5%	$ 48,936.28	0.0%	$ -	10.5%	$ 48,936.28	4.0%	$ 18,803.01	14.5%	$ 67,739.29
RS23 - Large Commercial	4100	5.1%	$ 685.23	0.0%	$ -	5.1%	$ 685.23	3.8%	$ 507.95	9.0%	$ 1,193.18
RS25 - General Firm	19086	4.4%	$ 1,918.56	0.0%	$ -	4.4%	$ 1,918.56	4.0%	$ 1,773.12	8.4%	$ 3,691.68
RS27 - Interruptible	53957	5.6%	$ 4,390.17	0.0%	$ -	5.6%	$ 4,390.17	3.9%	$ 3,040.69	9.5%	$ 7,430.86

FEI Inland

		2014		2015 - 2016				2017			
Amalgamated Rate Schedule	Consumption	Annual Change	Annual Change	Annual Change	Annual Change	Cumulative Annual Change	Cumulative Annual Change	Annual Change	Annual Change	Cumulative Annual Change	Cumulative Annual Change
	GJ	%	$	%	$	%	$	%	$	%	%
Sales Customers											
RS1 - Residential	75	3.5%	$ 29.22	0.0%	$ -	3.5%	$ 29.22	1.9%	$ 16.03	5.4%	$ 45.25
RS2 - Small Commercial	250	2.4%	$ 58.98	0.0%	$ -	2.4%	$ 58.98	1.6%	$ 40.22	4.1%	$ 99.20
RS3 - Large Commercial	2600	3.1%	$ 680.47	0.0%	$ -	3.1%	$ 680.47	1.5%	$ 322.11	4.6%	$ 1,002.58
RS4 - Seasonal	9300	6.0%	$ 3,477.49	0.0%	$ -	6.0%	$ 3,477.49	1.1%	$ 615.37	7.1%	$ 4,092.86
RS5 - General Firm	12800	3.4%	$ 3,296.46	0.0%	$ -	3.4%	$ 3,296.46	1.2%	$ 1,189.13	4.6%	$ 4,485.59
RS6 - NGV	11900	4.0%	$ 4,113.07	0.0%	$ -	4.0%	$ 4,113.07	2.0%	$ 2,063.50	6.0%	$ 6,176.57
RS7 - Interruptible	4000	2.4%	$ 835.02	0.0%	$ -	2.4%	$ 835.02	0.6%	$ 225.41	3.0%	$ 1,060.43
Transportation Customers						0.0%					
RS23 - Large Commercial	4700	5.3%	$ 785.51	0.0%	$ -	5.3%	$ 785.51	3.9%	$ 582.28	9.2%	$ 1,367.79
RS25 - General Firm	40671	4.9%	$ 4,211.84	0.0%	$ -	4.9%	$ 4,211.84	4.4%	$ 3,778.31	9.3%	$ 7,990.15
RS27 - Interruptible	48904	5.5%	$ 3,979.03	0.0%	$ -	5.5%	$ 3,979.03	3.8%	$ 2,755.92	9.4%	$ 6,734.95

FEI Columbia

		2014		2015 - 2016				2017			
Amalgamated Rate Schedule	Consumption	Annual Change	Annual Change	Annual Change	Annual Change	Cumulative Annual Change	Cumulative Annual Change	Annual Change	Annual Change	Cumulative Annual Change	Cumulative Annual Change
	GJ	%	$	%	$	%	$	%	$	%	%
Sales Customers											
RS1 - Residential	80	3.1%	$ 27.67	0.0%	$ -	3.1%	$ 27.67	1.9%	$ 17.09	5.0%	$ 44.76
RS2 - Small Commercial	320	2.0%	$ 61.74	0.0%	$ -	2.0%	$ 61.74	1.7%	$ 51.47	3.7%	$ 113.21
RS3 - Large Commercial	3300	2.7%	$ 728.37	0.0%	$ -	2.7%	$ 728.37	1.5%	$ 408.83	4.2%	$ 1,137.20
RS5 - General Firm	9100	2.7%	$ 1,923.34	0.0%	$ -	2.7%	$ 1,923.34	1.2%	$ 845.40	3.9%	$ 2,768.74
Transportation Customers						0.0%					
RS23 - Large Commercial	4200	5.2%	$ 701.95	0.0%	$ -	5.2%	$ 701.95	3.8%	$ 520.33	9.0%	$ 1,222.28
RS25 - General Firm	30358	5.2%	$ 3,673.99	0.0%	$ -	5.2%	$ 3,673.99	4.0%	$ 2,820.25	9.1%	$ 6,494.24
RS27 - Interruptible	7734	3.0%	$ 629.25	0.0%	$ -	3.0%	$ 629.25	2.1%	$ 435.83	5.1%	$ 1,065.08

FEFN

The Northern Rockies Regional Council (“NRRC”) representing the Northern Rockies Regional Municipality and service area of Fort Nelson voted in favour of phasing-in the total rate increase over a 15 year period with any impact delayed until year six. Under this approach, Fort Nelson customers would not be subject to a Common Rates, Amalgamation and Rate Design Application related increase for the first five years of the phase-in. For 2014 – 2018, Fort Nelson customers would only be subject to rate increases resulting from FEI Amalco revenue requirement changes as well as any changes to the commodity and/or midstream rates.

In 2019, customers will begin to experience an increase in rates, as a result of a portion of the postage stamp and amalgamation-related cost of service increases being flowed through to rates. This annual increase will continue through to 2027 and in 2028 (i.e., Year 15), Fort Nelson customers reach rate parity with other customers within the Amalgamated Entity.

The shortfall arising from the phase-in of the Fort Nelson rate increases for the fifteen year period will be met through a portion of the balance in the RSDA. The tables below summarize the rate increase for each Fort Nelson rate class from 2014 to 2018. The analysis assumes all other factors affecting rates remain constant, so that the impact of the phase-in can be isolated.

As discussed in the response to BCUC IR 1.99.1, in the absence of amalgamation and common rates, it is likely that a rate design application would be filed for FEFN and include rebalancing for Residential customer rates that may result in an annual bill increase of approximately 21.1% (please refer to Appendix H-12, Tab 1.1, Page 1). It is also expected that Rate 2.1 and Rate 2.2 customers would also see an increase in annual bills, of approximately 4%, in the absence on common rates and if rate rebalancing was to occur (please refer to Appendix H-12, Tab 1.1, pages 2 and 3). These increases would be offset by decreases in the annual bills of Rate 25 customers of approximately 8% upon rebalancing (please refer to Appendix H-12, Tab 1.1, page 4).

The tables below are grouped according to the FEI rate schedule the Fort Nelson customers will be mapped to.

<u>FEI Rate Schedule 1:</u>

Amalgamated Rate Schedule	Original Rate Schedule	Year	Annual Change		Cumulative Annual Change	
			%	$	%	$
RS1 - Residential	Rate 1	2014-2018	0.0%	$ -	0.0%	$ -
		2019	5.5%	$ 54.09	5.5%	$ 54.09
		2020	5.5%	$ 54.16	11.0%	$ 108.25
		2021	5.5%	$ 54.16	16.5%	$ 162.40
		2022	5.5%	$ 54.16	22.0%	$ 216.56
		2023	5.5%	$ 54.16	27.5%	$ 270.72
		2024	5.5%	$ 54.16	33.0%	$ 324.87
		2025	5.5%	$ 54.16	38.5%	$ 379.03
		2026	5.5%	$ 54.16	44.0%	$ 433.19
		2027	5.5%	$ 54.16	49.4%	$ 487.34
		2028	5.5%	$ 54.23	55.0%	$ 541.57
*Based on average annual consumption of 140 GJ						

FEI Rate Schedule 2:

Amalgamated Rate Schedule	Original Rate Schedule	Year	Annual Change		Cumulative Annual Change	
			%	$	%	$
RS2 - Small Commercial	Rate 2.1	2014-2018	0.0%	$ 0.41	0.0%	$ 0.41
		2019	2.8%	$ 95.87	2.8%	$ 96.28
		2020	2.8%	$ 95.77	5.5%	$ 192.05
		2021	2.8%	$ 95.77	8.3%	$ 287.82
		2022	2.8%	$ 95.77	11.1%	$ 383.59
		2023	2.8%	$ 95.77	13.8%	$ 479.36
		2024	2.8%	$ 95.77	16.6%	$ 575.14
		2025	2.8%	$ 95.77	19.4%	$ 670.91
		2026	2.8%	$ 95.77	22.1%	$ 766.68
		2027	2.8%	$ 95.77	24.9%	$ 862.45
		2028	2.8%	$ 95.67	27.7%	$ 958.12
*Based on average annual consumption of 460 GJ						

FEI Rate Schedule 3:

Amalgamated Rate Schedule	Original Rate Schedule	Year	Annual Change		Cumulative Annual Change	
			%	$	%	$
RS3 - Large Commercial	Rate 2.1	2014-2018	-19.7%	$ (3,627.36)	-19.7%	$ (3,627.36)
		2019	4.4%	$ 814.36	-15.2%	$ (2,813.00)
		2020	4.4%	$ 815.95	-10.8%	$ (1,997.05)
		2021	4.4%	$ 815.95	-6.4%	$ (1,181.10)
		2022	4.4%	$ 815.95	-2.0%	$ (365.16)
		2023	4.4%	$ 815.95	2.4%	$ 450.79
		2024	4.4%	$ 815.95	6.9%	$ 1,266.73
		2025	4.4%	$ 815.95	11.3%	$ 2,082.68
		2026	4.4%	$ 815.95	15.7%	$ 2,898.63
		2027	4.4%	$ 815.95	20.1%	$ 3,714.57
		2028	4.4%	$ 817.53	24.6%	$ 4,532.10
*Based on average annual consumption of 2624 GJ						

Amalgamated Rate Schedule	Original Rate Schedule	Year	Annual Change		Cumulative Annual Change	
			%	$	%	$
RS3 - Large Commercial	Rate 2.2	2014-2018	-20.8%	$ (4,524.12)	-20.8%	$ (4,524.12)
		2019	4.4%	$ 962.09	-16.4%	$ (3,562.03)
		2020	4.4%	$ 963.96	-11.9%	$ (2,598.07)
		2021	4.4%	$ 963.96	-7.5%	$ (1,634.11)
		2022	4.4%	$ 963.96	-3.1%	$ (670.14)
		2023	4.4%	$ 963.96	1.4%	$ 293.82
		2024	4.4%	$ 963.96	5.8%	$ 1,257.78
		2025	4.4%	$ 963.96	10.2%	$ 2,221.74
		2026	4.4%	$ 963.96	14.6%	$ 3,185.70
		2027	4.4%	$ 963.96	19.1%	$ 4,149.66
		2028	4.4%	$ 965.83	23.5%	$ 5,115.49
*Based on average annual consumption of 3100 GJ						

Amalgamated Rate Schedule	Original Rate Schedule	Year	Annual Change		Cumulative Annual Change	
			%	$	%	$
RS3 - Large Commercial	Rate 25	2014-2018	94.2%	$ 17,423.54	94.2%	$ 17,423.54
		2019	14.0%	$ 2,596.07	108.3%	$ 20,019.61
		2020	11.6%	$ 2,142.48	119.9%	$ 22,162.09
		2021	11.6%	$ 2,142.48	131.4%	$ 24,304.57
		2022	11.6%	$ 2,142.48	143.0%	$ 26,447.05
		2023	11.6%	$ 2,142.48	154.6%	$ 28,589.53
		2024	11.6%	$ 2,142.48	166.2%	$ 30,732.01
		2025	11.6%	$ 2,142.48	177.8%	$ 32,874.49
		2026	11.6%	$ 2,142.48	189.4%	$ 35,016.97
		2027	11.6%	$ 2,142.48	201.0%	$ 37,159.45
		2028	9.1%	$ 1,688.89	210.1%	$ 38,848.34
*Based on average annual consumption of 6890 GJ						

93.5 Did FEU consider phasing in rate decreases to FEVI/FEW customers to be consistent with conservation messages in the Energy Plan? If no, why not. If yes, please explain the results.

Response:

The FEU did not consider phasing in rate decreases to FEVI and FEW customers in the context of conservation messages in the Energy Plan. As discussed in the Application, common rates are not expected to materially increase consumption and, as such, common rates will not impact the effectiveness of conservation messaging. Conservation messaging was therefore not a relevant factor when considering whether to propose a phase-in of rate decreases to FEVI and FEW.

However, FEU did consider for a phase-in of the rate decrease for FEVI and FEW. Please refer to the response to BCUC IR 1.24.2 for the results of this analysis.

93.6 Please provide the annual rate impact for each customer class of FEVI/FEW/FEFN and FEI, from 2012 to 2016, assuming that postage stamp rates are only approved for incremental rate increases and not existing rates.

Response:

The FEU understand that under this scenario, the revenue requirements for each of the entities is combined; however, the existing rate structures and current rates are maintained. Any changes to revenue requirements in the future would be applied across the rates in all service areas at the same amount. For example, in 2014 if an average delivery rate increase on an amalgamated basis of 4.4% is required all rate schedules in FEI, FEW and Fort Nelson would see a 4.4% rate increase. Please note that because rate harmonization has not occurred in this scenario the existing single energy charge in Vancouver Island is assumed to still apply; therefore, using 2014 as an example, FEVI would see an increase of 3.4% reflecting the combined delivery and cost of gas increase to the burner tip.

The following four tables provide the approximate annual rate impact by customer class under this scenario. Please note that the underlying delivery margin and cost of as assumptions are the same as those used to produce the rate projections in Figure 6-1 on page 111 of the Application. Further, the forecast rate changes are based on a high level analysis only and actual rate changes for 2014 through 2016 will be the subject of future applications before the Commission.

Approximate Annual Rate Changes- Incremental Postage Stamp Rate Changes Commencing 2014[1]

	2012[2]	2013[3]	2014			2015			2016		
	Effective Delivery	Effective Delivery	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate
Lower Mainland											
RS1- Residential					3.3%			2.8%			2.8%
RS2- Small Commercial					3.2%			2.8%			2.8%
RS3- Large Commercial					3.0%			2.8%			2.8%
RS4- Seasonal					2.7%			2.9%			2.9%
RS5- General Firm					3.0%			2.8%			2.8%
RS6- NGV	4.2%	5.9%	4.4%	2.2%	3.3%	2.6%	3.0%	2.8%	2.5%	3.0%	2.8%
RS7- Interruptible					2.9%			2.9%			2.9%
RS22- Large Industrial					4.4%			2.6%			2.5%
RS23- Large Commercial					4.4%			2.6%			2.5%
RS25- General Firm					4.4%			2.6%			2.5%
RS27- Interruptible					4.4%			2.6%			2.5%
Inland											
RS1- Residential					3.3%			2.8%			2.8%
RS2- Small Commercial					3.2%			2.8%			2.8%
RS3- Large Commercial					3.1%			2.8%			2.8%
RS4- Seasonal					2.7%			2.9%			2.9%
RS5- General Firm	4.2%	5.9%	4.4%	2.2%	3.0%	2.6%	3.0%	2.9%	2.5%	0.0%	2.8%
RS6- NGV					3.3%			2.8%			2.8%
RS7- Interruptible					3.2%			2.8%			2.8%
RS23- Large Commercial					4.4%			2.6%			2.5%
RS25- General Firm					4.4%			2.6%			2.5%
RS27- Interruptible					4.4%			2.6%			0.0%
Columbia											
RS1- Residential					3.3%			2.8%			2.8%
RS2- Small Commercial					3.1%			2.8%			2.8%
RS3- Large Commercial					3.0%			2.8%			2.8%
RS5- General Firm	4.2%	5.9%	4.4%	2.2%	3.0%	2.6%	3.0%	2.8%	2.5%	3.0%	2.8%
RS23- Large Commercial					4.4%			2.6%			2.5%
RS25- General Firm					4.4%			2.6%			2.5%
RS27- Interruptible					4.4%			2.6%			2.5%

[1] Approximate rate increase on an amalgamated basis; actual rate changes for 2014-2016 will be determined in future RRAs. Burner tip impacts based on typical annual bill calculations and exclusive of rate riders.

[2] The average delivery rate change approved in Order No. G-44-12

[3] The average delivery rate change approved in Order No. G-44-12 (2013 incremental rate change)

Approximate Annual Rate Changes- Incremental Postage Stamp Rate Changes Commencing 2014[1]

	2012[2]	2013[3]	2014			2015			2016		
	Burner Tip	Burner Tip	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate
Vancouver Island											
RGS											
AGS											
SCS-1											
SCS-2											
LCS-1	0.0%	0.0%	N/A		3.4%	N/A		2.8%	N/A		2.8%
LCS-2											
LCS-3											
HLF											
ILF											

[1] Approximate rate increase on an amalgamated basis; actual rate changes for 2014-2016 will be determined in future RRAs. Burner tip impacts based on typical annual bill calculations and exclusive of rate riders.

[2] The average delivery rate change approved in Order No. G-44-12

[3] The average delivery rate change approved in Order No. G-44-12 (2013 incremental rate change)

Approximate Annual Rate Changes- Incremental Postage Stamp Rate Changes Commencing 2014[1]

	2012[2]	2013[3]	2014			2015			2016		
	Effective Delivery	Effective Delivery	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate
Whistler											
Res					3.8%			2.7%			2.7%
Comm					3.8%			2.7%			2.7%
LCS1	3.6%	5.5%	4.4%	2.2%	3.7%	2.6%	3.0%	2.7%	2.5%	3.0%	2.7%
LCS2					3.7%			2.7%			2.7%
LCS3					3.7%			2.7%			2.7%

[1] Approximate rate increase on an amalgamated basis; actual rate changes for 2014-2016 will be determined in future RRAs. Burner tip impacts based on typical annual bill calculations and exclusive of rate riders.

[2] The average delivery rate change approved in Order No. G-44-12

[3] The average delivery rate change approved in Order No. G-44-12 (2013 incremental rate change)

Approximate Annual Rate Changes- Incremental Postage Stamp Rate Changes Commencing 2014[1]

	2012[2]	2013[3]	2014			2015			2016		
	Effective Delivery	Effective Delivery	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate	Effective Delivery	Cost of Gas	Burner Tip Rate
Fort Nelson											
Rate 1					3.1%			2.8%			2.8%
Rate 2.1	0.0%	1.8%	4.4%	2.2%	3.2%	2.6%	3.0%	2.8%	2.5%	3.0%	2.8%
Rate 2.2					3.1%			2.8%			2.8%
Rate 25					4.4%			2.6%			2.5%

[1] Approximate rate increase on an amalgamated basis; actual rate changes for 2014-2016 will be determined in future RRAs. Burner tip impacts based on typical annual bill calculations and exclusive of rate riders.

[2] The average delivery rate change approved in Order No. G-44-12

[3] The average delivery rate change approved in Order No. G-44-12 (2013 incremental rate change)

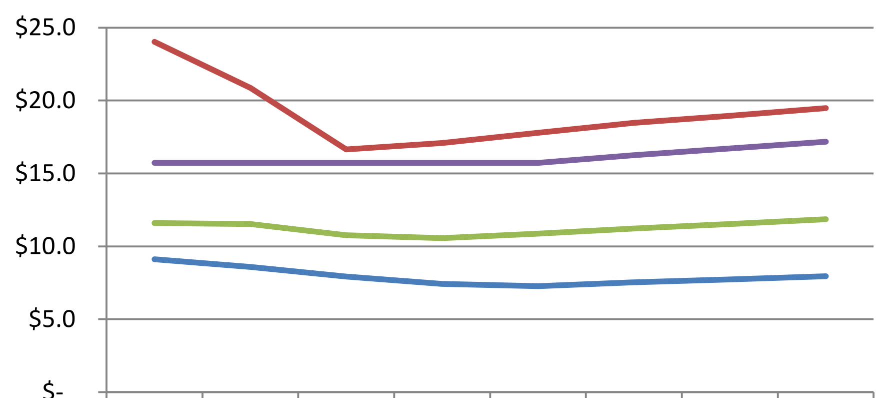
93.6.1 Did FEU consider this option as an alternative to postage stamp rates? If no, why not. If yes, please explain the results.

Response:

No, FEU did not consider this option and alternative to postage stamp rates primarily because it does not address the issue of rate disparity amongst the entities. Further, this scenario may actually increase the rate disparity amongst entities. For example, and as shown in the table below, under this scenario the $/GJ variance between FEVI and FEI grows from $5.20/GJ in 2012 to $5.30/GJ in 2016. In addition, this scenario perpetuates the requirement to maintain separate regulatory books for the four entities, thus minimizing the administrative efficiencies gained through rate harmonization. Finally, the FEU believe that it is inconsistent to approve incremental changes on a postage stamp basis without first transitioning to a common rate.

To demonstrate the perpetuation of the rate discrepancy amongst the regions, Figure 6-1 from page 111 of the Application (Exhibit B-1) has been reproduced using the analysis provided in BCUC IR 1.93.6. Consistent with Figure 6-1 in Exhibit B-1, please note that this figure assumes consumption of 90 GJ per year for Residential customers in all regions for ease of comparison.

Residential Effective Rates across the FEU per BCUC IR 1.93.6



	2009	2010	2011	2012	2013	2014	2015	2016
FN Residential, per GJ	$9.1	$8.6	$7.9	$7.4	$7.3	$7.5	$7.7	$7.9
FEW Residential, per GJ	$24.0	$20.9	$16.6	$17.1	$17.8	$18.5	$19.0	$19.5
FEI LM Residential, per GJ	$11.6	$11.5	$10.8	$10.6	$10.9	$11.2	$11.5	$11.8
FEVI Residential, per GJ	$15.7	$15.7	$15.7	$15.7	$15.7	$16.3	$16.7	$17.2

93.7 The residential basic charge for FEW is significantly lower than for the other companies. Please document the reason for this, and estimate the bill impacts associated with a move to postage stamp rates for FEW low use residential consumers.

Response:

The FEW residential basic charge is the result of past precedent and has remained at the same level since the 2002 acquisition of Centra Gas Whistler Inc. (now FEW).

BCUC Order No. G-74-01 indicates as follows (Appendix A, Order No. G-74-01, page 2 of 20):

> *"The Fixed Monthly Charge of $7.50/month is approved as applied for. Centra Gas will not request an increase in the Fixed Monthly Charge above this amount without a proper study supporting a higher rate."*

FEW has not conducted a rate design study under the ownership of FortisBC Energy Inc. and its predecessors since Order No. G-74-01 was made; therefore, the basic charge has not changed.

The approximate impact on FEW low use residential customers (consuming approximately 30 GJs per year) of the move to postage stamp rates is an annual bill decrease of $171 or 28%. Any residential customer in Whistler that consumes greater than 7 GJs per year is expected to see a decrease in their annual bill upon transition to harmonized FEU rates.

93.8 Do FEU consider that, if postage stamp rates are not approved, there may be potential benefits of adjusting the residential basic charge by region, or introducing a minimum bill amount, to reflect regional differences in customer consumption profiles? Please explain why or why not.

Response:

If postage stamp rates are not approved, the FEU intend to submit at a later date(s), rate designs for some or all of the individual entities. The rate designs for the individual entities may, among other things, include adjustments to the bill components such as the basic charge.

The FEU would anticipate filing individual entity rate designs to address rate rebalancing and to determine whether any changes to existing tariff offerings within individual entities are required, where appropriate.

94.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-3, Section 9.4.2, p. 186

Exhibit B-3-1, Appendix J-5

Mapping of Apartment General Service (AGS) to the FEI Rate Schedules

"AGS did not have a direct 100% mapping to one FEI rate schedule. Therefore, to map the AGS rate class into the appropriate rate schedules, the percentage of customers with consumption that exceeded 2,000 GJ per year was identified along with the corresponding percentage of total volume attributable to these customers. The results showed that 85% of the customers and 52% of the volume in AGS would be mapped to FEI Rate Schedule 2 while the remaining 15% of customers and 48% of the volume would be mapped to FEI Rate Schedule 3." (Section 9.4.2, p. 186)

94.1 What is the primary determinant of a customer's consumption in this rate class? In other words, is the primary determinant the number of residential units in the multi-residential dwelling, rather than the load and consumption characteristics of each individual unit?

Response:

The Apartment General Service rate schedule is for gas supplied to multi-residential dwellings at one point of delivery through one meter to serve the common energy requirements of six or more residential units with an annual consumption of less than 6,000 GJ annually. If the customer's annual consumption is more than 6,000 GJ annually the customer should elect service under FEVI's LCS-3.

FEI has apartment, condo and vertical subdivision customers in Rate Classes 2, 3, 5, 23, 25 and 27. Customers may enter these rate classes if they meet the criteria laid out in the terms and conditions of the rate. Similarly, there is no one determinant of FEI apartment / condo / vertical subdivision consumption.

94.2 What is the ratio of the energy charge for Rate 3, to the energy charge for Rate 2, under the postage stamp rates being proposed by the FEU?

Response:

FEVI rate schedules consist of a basic and energy charge, while FEI rate schedules consist of a basic, delivery, commodity and midstream charge. For comparison purposes, the energy charge is assumed to correspond to a combination of the delivery, midstream and commodity charge. This provides a fair basis for making comparisons between FEVI and FEI rate schedules.

The table below illustrates the unit rate for an AGS customer in FEVI as of January 1, 2014, as well as what the energy charge would be when mapped to both FEI Rate Schedule 1 and Rate Schedule 2. The unit rate under each of these rate schedules is summarized, and the ratio of the energy charge of Rate Schedule 3 to Rate Schedule 2 is presented as well.

	FEVI Rate Schedule	FEI Rate Schedules	
	AGS	**Rate 2**	**Rate 3**
Energy Charge	$ 12.373		
Delivery Charge		$ 3.499	$ 2.954
Midstream Charge		$ 1.316	$ 1.055
Commodity Charge		$ 4.108	$ 4.108
Unit Rate ($/GJ)	$ 12.373	$ 8.923	$ 8.117
Ratio of Energy Charge		1 : 0.91	

*Rates are exclusive of riders

94.3 Please comment on the equitability of a resident in a multi-residential dwelling being subject to the lower energy charge of Rate 3 (either directly or indirectly through rent or strata-fees) by virtue of living in a larger building compared to a resident living in a smaller building that receives service under Rate 2.

Response:

The FEU believe that in this hypothetical example, the resident is being treated equitably.

In the Application, the FEU propose to use FEI's existing rate design methodologies as the basis for the rate design for the Amalgamated Entity. FEI's rates are designed such that a customer who consumes more gas, such as a Rate Schedule 3 customer, pays a lower charge than a customer who consumes less gas, such as a Rate Schedule 2 customer. In this hypothetical example, the building's strata council is the customer paying the gas bill to FEI, not an individual resident in a multi-residential building. FEI has no control over the equitability of how strata councils recover the cost of gas from the individual members of the strata.

The ongoing approvals of FEI's rate design applications highlight the underlying rate design methodology employed as being fair, just and reasonable. The Commission has accepted the appropriateness of rate designs through its ongoing approvals, and the methodologies have generally received the support of interested parties in past years.[89]

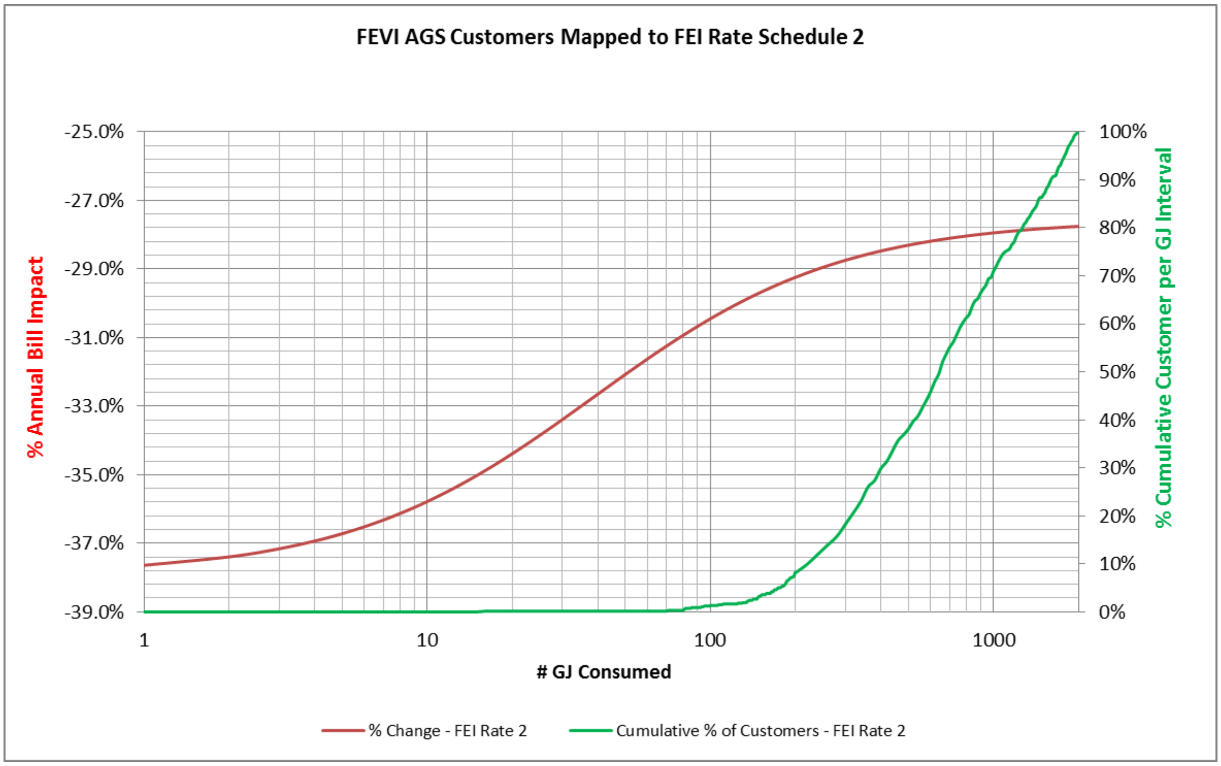
94.4 Appendix J-5 shows a number of graphs showing the bill impacts of customers in the existing FEI service area. Please prepare a bill impact graph for the FEVI AGS rate class showing the impact of moving these customers to either Rate 2 or to Rate 3 as determined by the proposed mapping.

<u>Response:</u>

The following graphs illustrate the bill impacts for an AGS customer in FEVI being mapped to FEI's Rate Schedule 2 (first graph) and Rate Schedule 3 (second graph).

[89] Section 9.3.3.3, page 183 of the Application

AGS Customers Mapped to FEI Rate Schedule 2



Graph Interpretation

The above graph illustrates the percentage bill impacts for FEVI's AGS customers throughout various consumption levels, up to 2000 GJs which is the cutoff point for Rate Schedule 2.

The X-axis represents GJ consumption intervals logarithmically.

The green 'Cumulative % of Customers' line represents the cumulative customers per GJ consumption interval and corresponds with the right Y-axis.

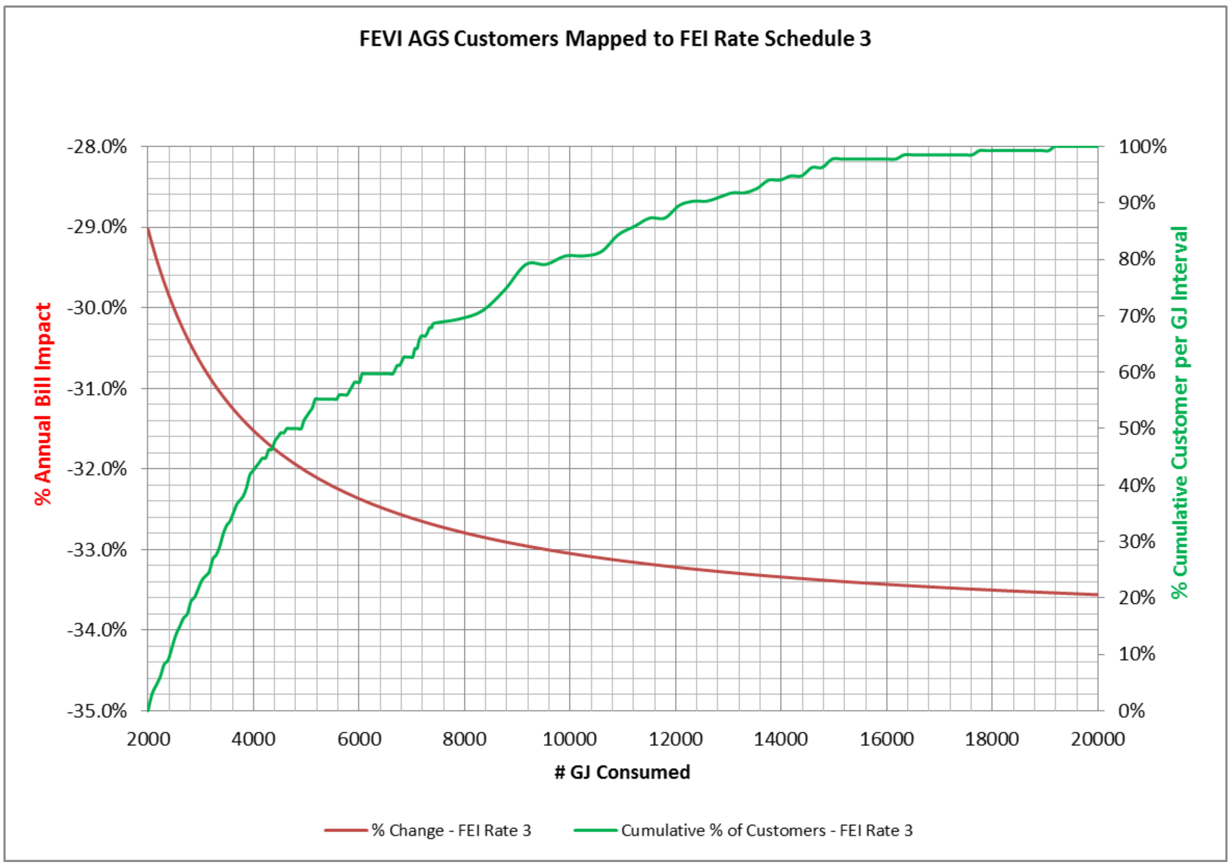
The red '% Change' line represents the bill impact decrease in rates for customers at various GJ consumption intervals, and corresponds with the left Y-axis.

For any given consumption level, a vertical line can be drawn which will intersect both the '% change' and the 'Cumulative % of Customers' lines. The intersection of this line indicates the annual bill impact percentage change at the given consumption level, as well as the cumulative percentage of customers that would be impacted.

For example, at a consumption level of 650 GJs, a customer will receive approximately a 28% bill decrease in 2014 as a result of amalgamation and the adoption of common rates. Also, 50% of customers consume up to 650 GJs annually.

The green 'Cumulative % of Customers' lines in the FEVI bill impact graphs are not as smooth as those in the FEI graphs provided in Appendix J-5 due to the smaller customer base in FEVI.

AGS Customers Mapped to FEI Rate Schedule 3



The "% Annual Bill Impact" line has been adjusted to show bill impacts beginning at a consumption level of 2000 GJs since a minimum consumption level of 2000 GJs is required to take service in this rate class.

The graph illustrates that an FEVI customer consuming 3000 GJs would experience a decrease of approximately 30% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

95.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-3, Section 3.2.4.2, p. 175

Fort Nelson Rate Schedules 2.3, 2.4, 3.1, 3.2, 3.3

No Fort Nelson customers are currently taking service under rate schedules 2.3 (NGV Fuel Service), 2.4 (Compression/Dispensing Service), and 3.1 through 3.3 (Industrial Service).

95.1 If a customer requests service under one of these rates, will these rates include a Fort Nelson phase in rider?

Response:

Yes, all customers in Fort Nelson would receive an appropriate phase in rider. In the scenario in the pre-amble, the customer would have to elect a service prior to January 1, 2014, as upon amalgamation, the Fort Nelson terms and conditions and rate schedules will be cancelled and therefore, no longer available to customers.

96.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-3-1, Section 8.4.2.3, p. 36

Appendix J-6, Tab 1.2, p. 3

Appendix J-3, Tab 1.4, p. 5

Appendix J-4, Tab 1.2, p. 5

Fort Nelson Large Commercial Bill Impacts

Fort Nelson customers currently taking service under RS 2.1 are forecast to receive a 19.6 percent reduction in their annual billings as a result of the amalgamation, postage stamp rates, and Fort Nelson Phase-In Rider. Customers currently taking service under RS 2.2 are forecast to receive a 20.8% reduction. The Fort Nelson Phase-In Riders applied to these two rate schedules mitigate what would otherwise be 23.8 percent and 22.7 percent increases to the effective rate.

96.1 Why have the FEU chosen to reduce the effective rates to RS 2.1 and RS 2.2 customers by approximately 20 % when the level of the Fort Nelson Phase-In Riders for all other Fort Nelson rates have been set so as to hold those rates constant?

Response:

The intent of the Fort Nelson phase-in rate rider is to mitigate the immediate impact of rate harmonization on Fort Nelson customers. FEU based the calculation of this rate rider on existing typical annual bills and consumption in each of the Fort Nelson rate schedules, identifying the total dollar amount on a rate schedule basis that would be required to hold annual bill levels constant. Although an individual rate rider can be applied to each rate schedule in FEU's billing system, currently the system cannot apply different rate riders to customers within the same rate class. Since the Fort Nelson customers will be transitioning to FEI amalgamated rate schedules, the $ per gigajoule phase-in rate rider had to be determined based on the rate schedule into which the customers would be transitioning.

As detailed in Section 9.4.4 of the application, Customer Mapping Methodology, Fort Nelson customers are mapped to FEI rate schedules as indicated in the table below:

Rate Class	Consumption requirements	FEI Rate 1		FEI Rate 2		FEI Rate 3	
		Customers	Volume	Customers	Volume	Customers	Volume
Rate 1	Residential	**100%**	**100%**				
GSR 2.1	0-6000 GJ per year			**99%**	**93%**	**1%**	**7%**
GSR 2.2	6000+ GJ per year					**100%**	**100%**
Rate 25	Firm Transportation					**100%**	**100%**

Therefore, a single weighted average phase-in rate rider had to be calculated for the three groups of Fort Nelson customers transitioning to FEU Rate Schedule 3 upon amalgamation: a small portion of RS 2.1 customers, RS 2.2 and RS 25. Although the total dollar amount of the phase-in rider keeps Fort Nelson whole on a regional basis, as a result of this approach the annual bill impact on each of the three customer groups within Rate Schedule 3 varies: RS 2.1 and RS 2.2 customers will experience annual bill decreases offset by the annual bill increases experienced by RS 25 customers.

It was not the intention of the FEU to create a situation where individual customers within the Fort Nelson region experience increases or decreases in their annual bill as a result of this phase-in approach. As such, the FEU are investigating alternatives in the application of the rate rider to the approximately 35 customers in these three segments.

Appendix J-3, Tab 1.4, p. 5 and Appendix J-4, Tab 1.2, p.5 show the impact on a Rate 25 customer having an annual consumption of 6,890 GJ. The calculation of the annual bill under 2014 rates as per the RRA does not include commodity costs, whereas the bill under the FEI rate structure does.

96.2 How have the FEU determined the level of the Fort Nelson Phase-In Rider for Rate 25?

Response:

Please refer to the response to BCUC IR 1.96.1.

96.3 Please restate Tab 1.4 of Appendices J-3 and J-4 by including the cost of gas received at the Fort Nelson City gate with the Rate 25 charges.

Response:

Fort Nelson's Rate Schedule 25 bill impacts included in Appendices J-3 and J-4 have been re-stated to include the impact of the cost of gas and provided in Attachment 96.3. For simplicity, the cost of gas applied to Rate Schedule 25 is based on the amalgamated cost of gas determined for Fort Nelson core customers. Also, please note that the phase-in rate rider applicable to Rate Schedule 25 is based on the approach as discussed in the response to BCUC IR 1.96.1. The FEU have not recalculated the phase-in rate rider for this scenario; the inclusion of cost of gas in Rate Schedule 25 would result in the restatement of the weighted average phase-in rate rider applicable to a portion of Rate Schedule 2.1 customers, Rate Schedule 2.2 customers and Rate Schedule 25 customers.

97.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-3-1, Appendix J-5; Exhibit B-3, Section 9.4

Bill Impact Graphs

Appendix J-5 illustrates the percentage bill impact increases for FEI Mainland Rate Schedule 1, 2 and 3 customers throughout various consumption levels.

Section 9.4 shows the mapping of FEVI, FEW and FEFN rate classes onto FEI's rate classes.

97.1 Please prepare similar sets of graphs for FEVI for each of the following rate schedules: (i) RGS; (ii) for SCS1, SCS2 and LCS-1 collectively; (iii) for LCS-2, LCS-3, HLF and ILF collectively; and (iv) AGS.

Response:

The bill impact graphs for all of FEVI's rate schedules, with the exception of AGS, are included below. For the AGS bill impact graphs, please refer to the response to BCUC IR 1.94.4.

The graphs have not been provided collectively as requested for certain rate classes. The grouping of several rate classes into one graph results in a graph that is difficult to view, therefore an individual graph has been provided for each rate class.

Each graph illustrates the percentage bill impact at various consumption levels for FEVI customers moving to FEI rate schedules.

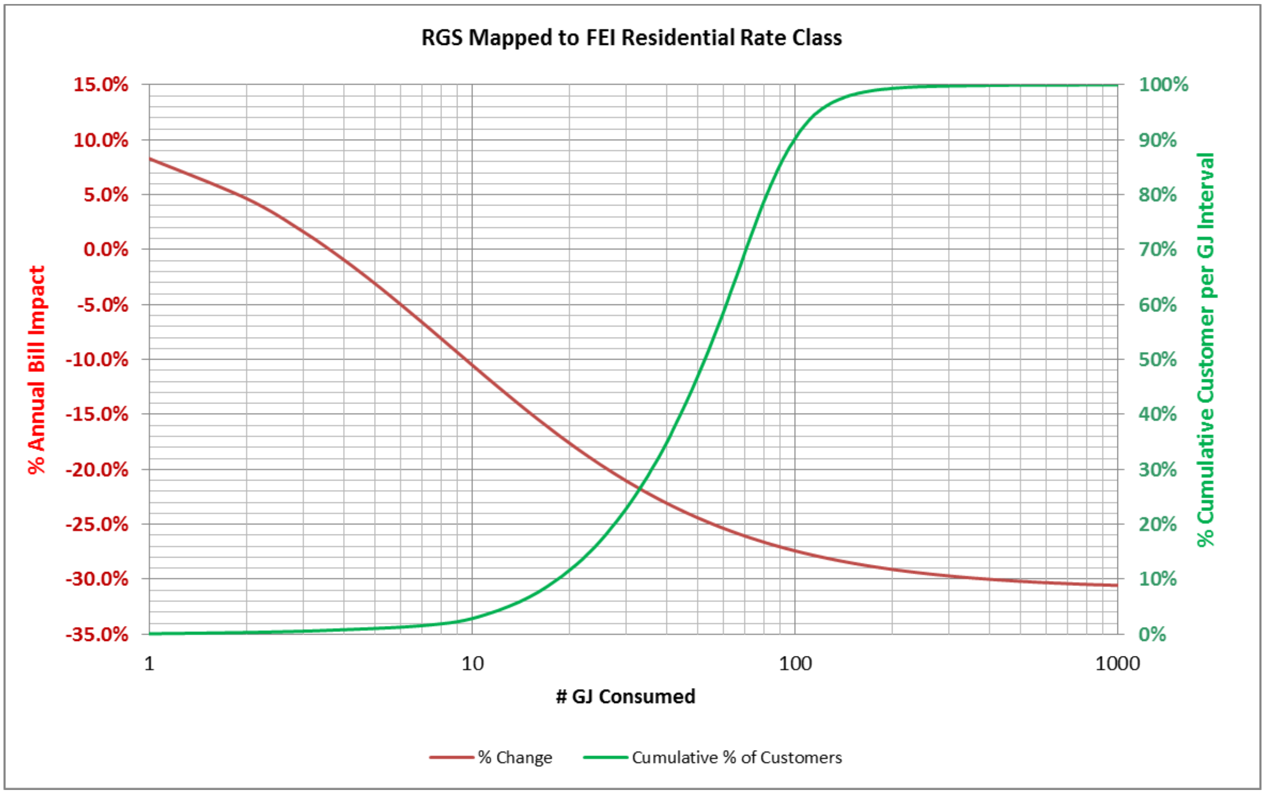
The X-axis represents GJ consumption intervals logarithmically.

The green 'Cumulative % of Customers' line represents the cumulative customers per GJ consumption interval and corresponds with the right Y-axis.

The red '% Change' line represents the bill impacts for customers at various GJ consumption intervals, and corresponds with the left Y-axis.

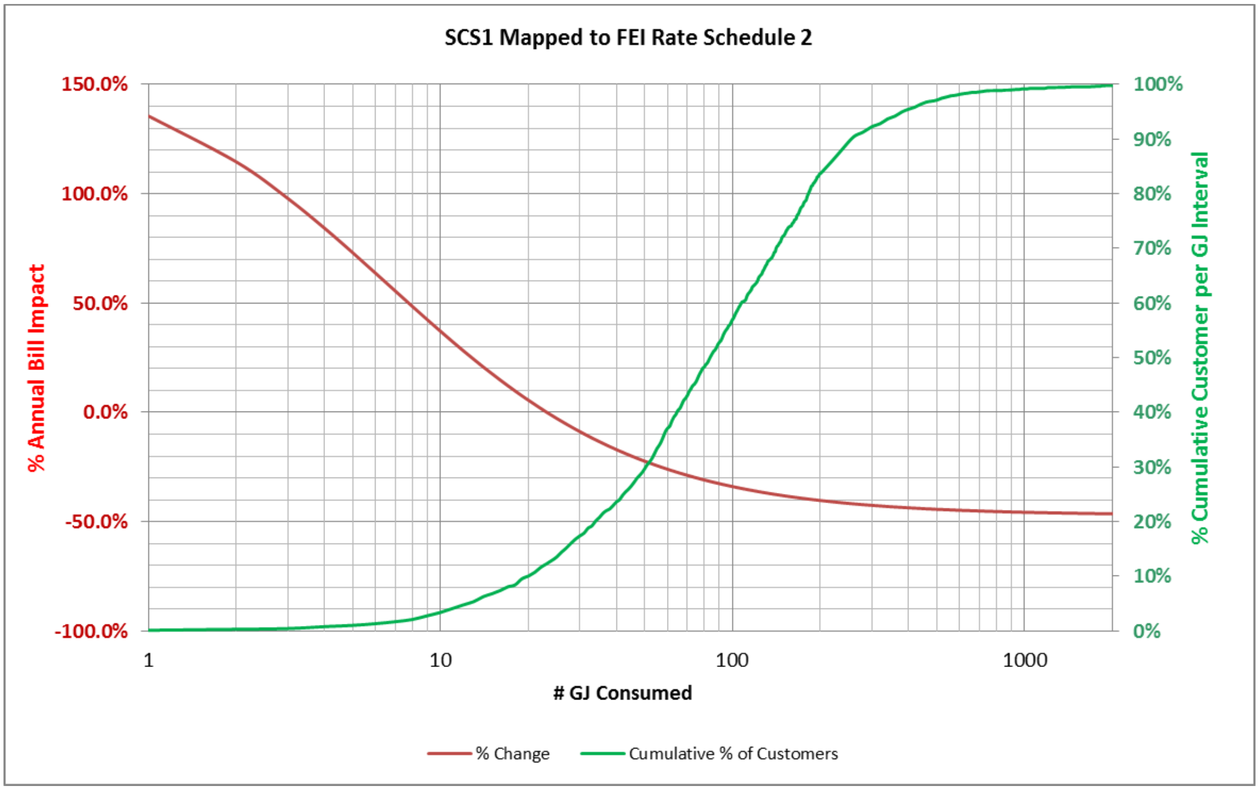
For any given consumption level, a vertical line can be drawn which will intersect both the '% Change' and the 'Cumulative % of Customers' lines. The intersection of this line indicates the annual bill impact percentage change at the given consumption level, as well as the cumulative percentage of customers that would be impacted.

RGS



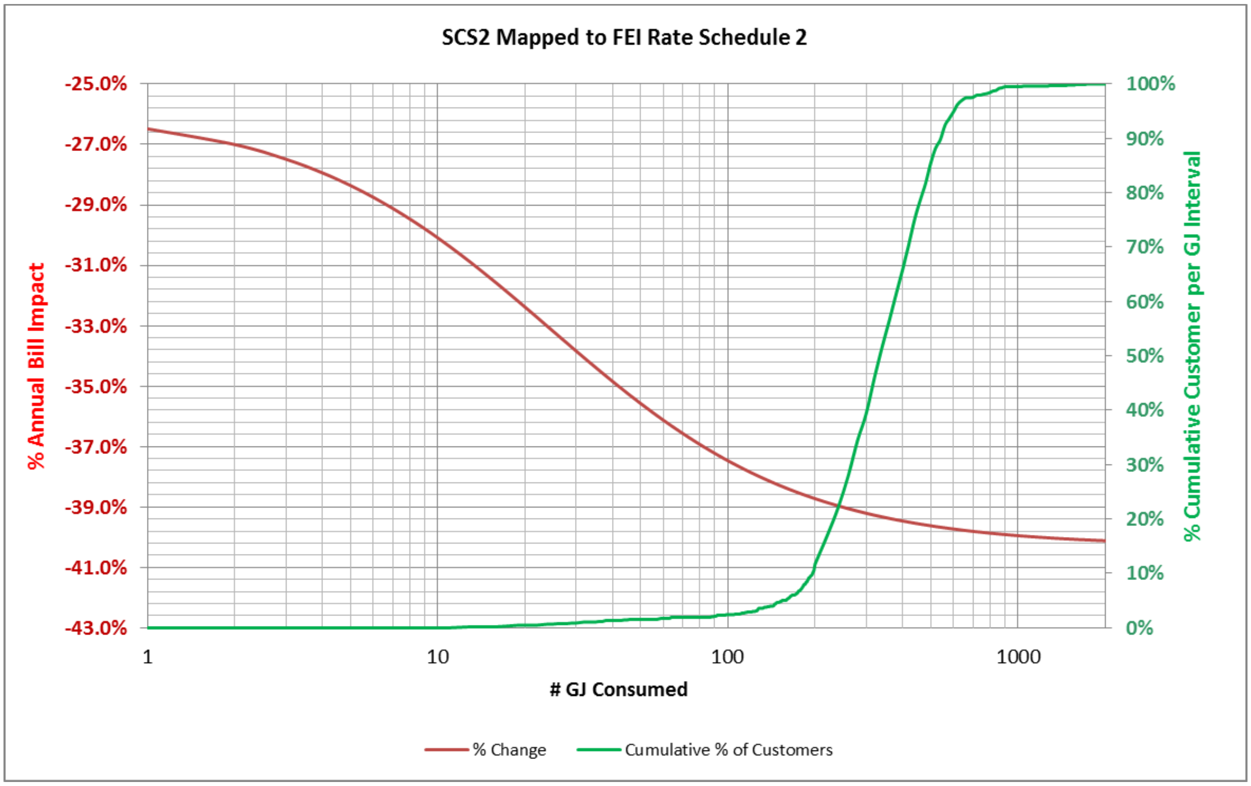
The graph illustrates that an RGS customer consuming 50 GJs would experience a decrease of approximately 24% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

SCS1



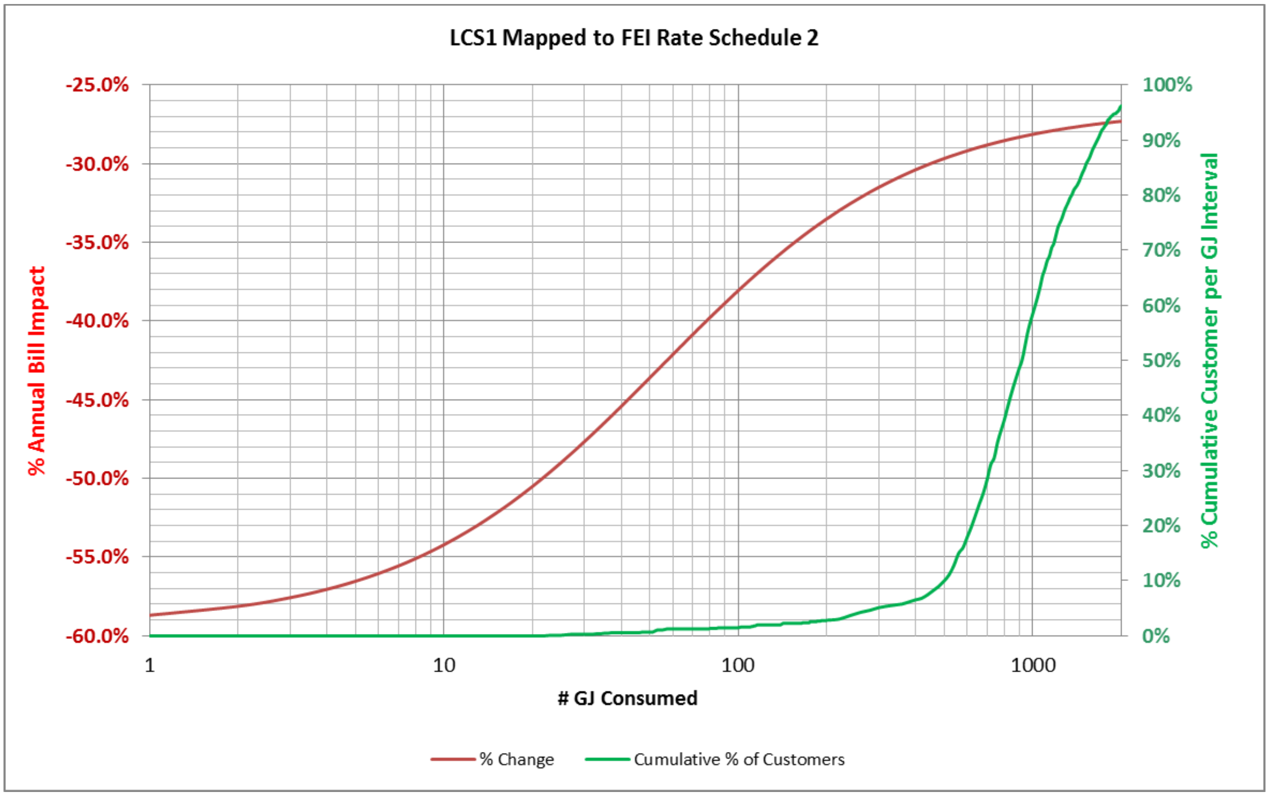
The graph illustrates that an SCS1 customer consuming 100 GJs would experience a decrease of approximately 34% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

SCS2



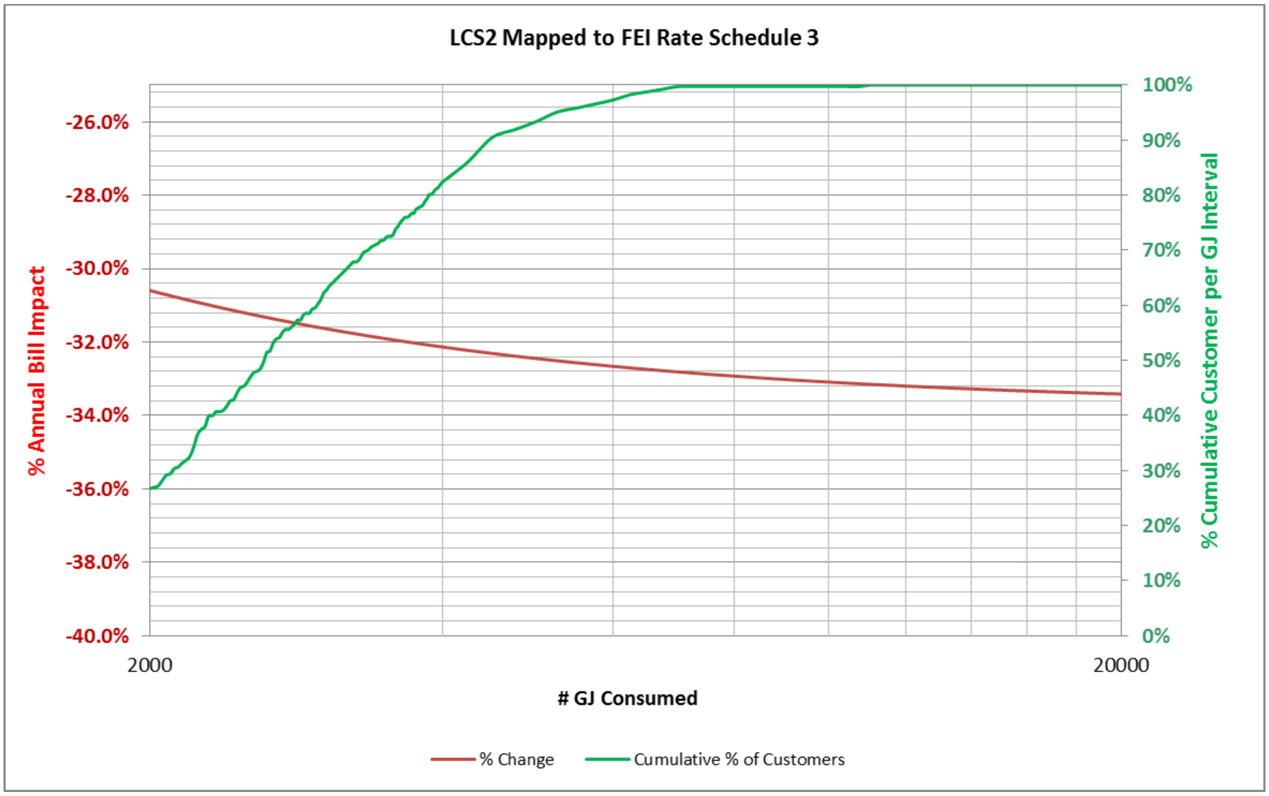
The graph illustrates that an SCS2 customer consuming 300 GJs would experience a decrease of approximately 39% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

LCS1



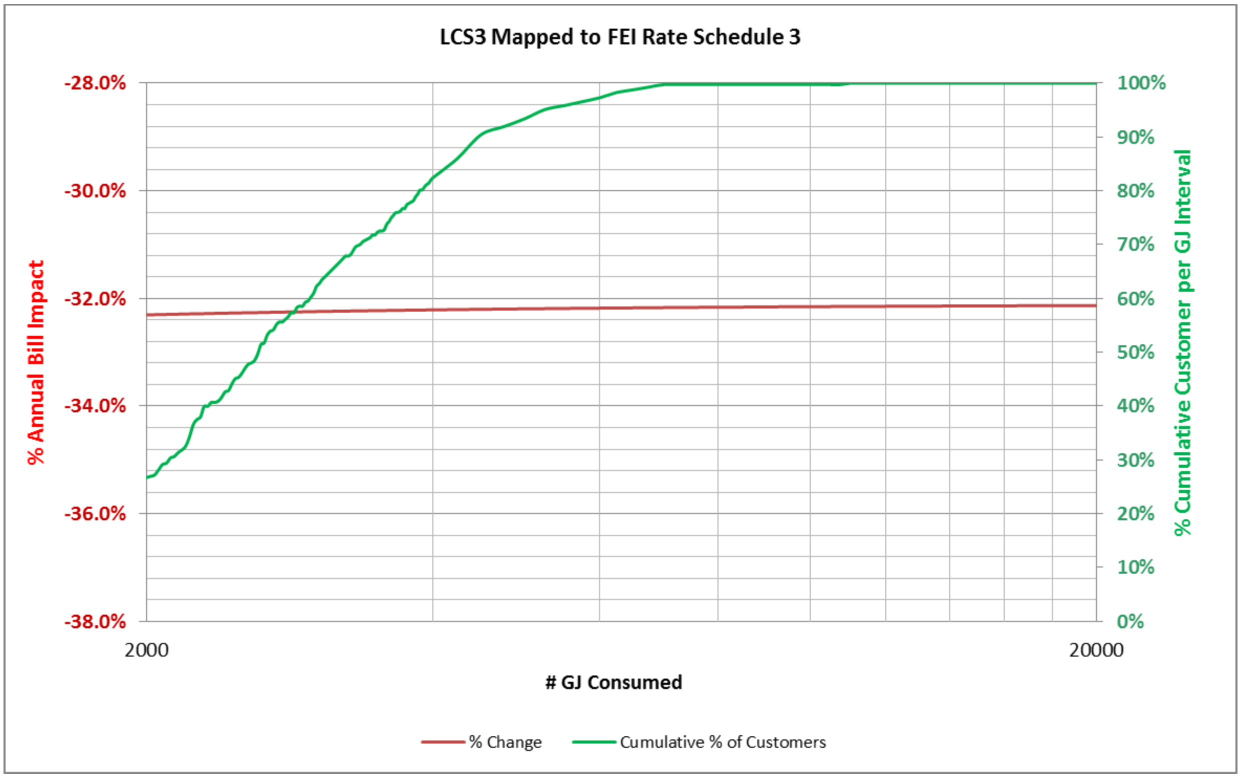
The graph illustrates that an LCS1 customer consuming 1000 GJs would experience a decrease of approximately 28% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

LCS2



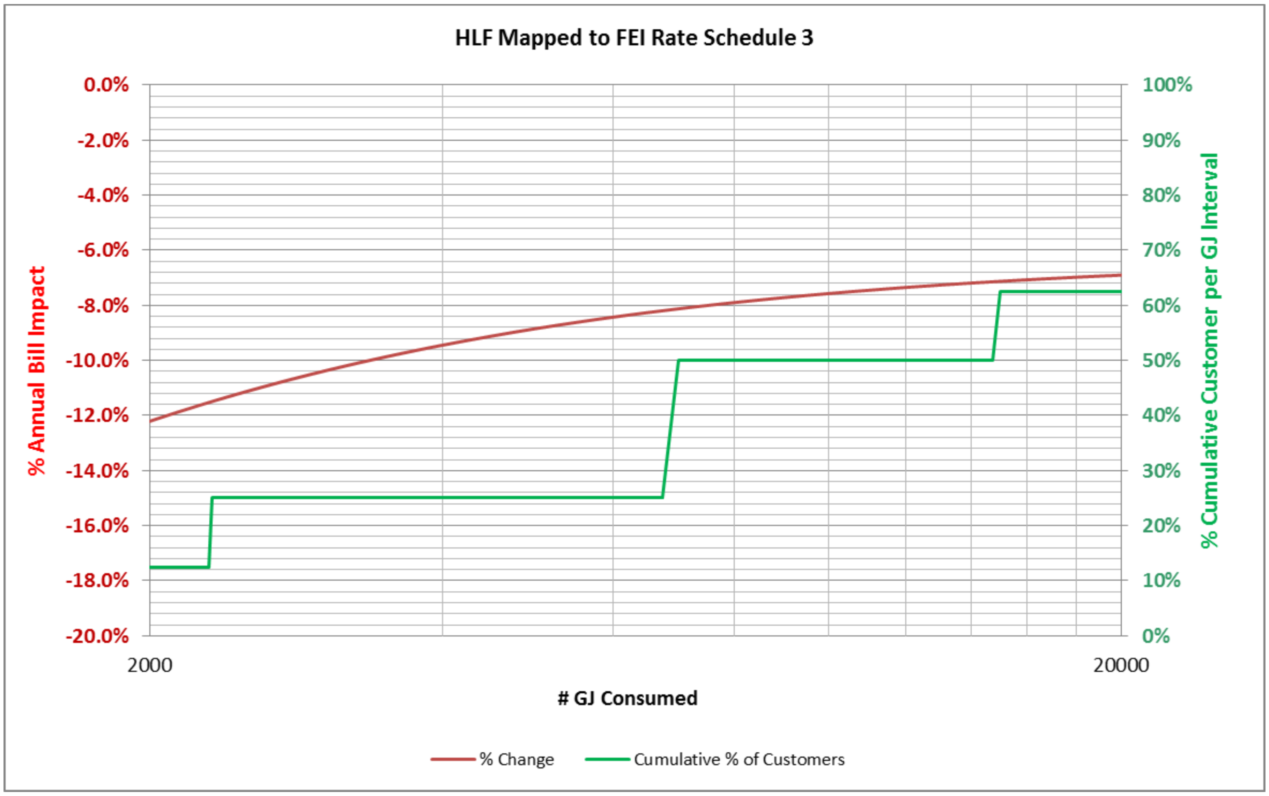
The graph illustrates that an LCS2 customer consuming 3000 GJs would experience a decrease of approximately 32% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

LCS3



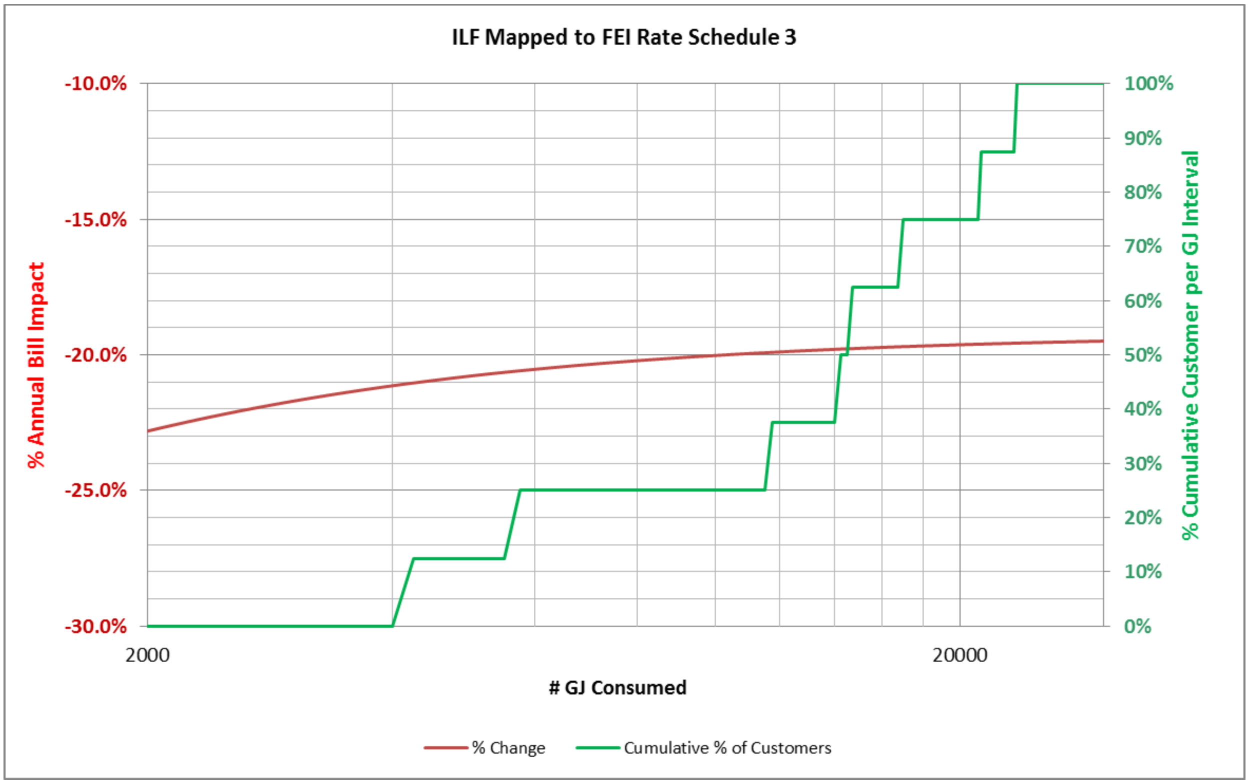
The graph illustrates that an LCS3 customer consuming 10000 GJs would experience a decrease of approximately 32% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

HLF



The graph illustrates that an HLF customer consuming 10000 GJs would experience a decrease of approximately 7% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

ILF



The graph illustrates that an ILF customer consuming 10000 GJs would experience a decrease of approximately 20% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

97.2 Please prepare similar sets of graphs for FEW for each of the following customer groupings: (i) SGS Residential; (ii) for SGS Commercial and LGS 1 collectively; and (iii) for LGS 2 and LGS 3 collectively.

Response:

The bill impact graphs for all of FEW's rate schedules are provided below.

The graphs have not been provided collectively as requested for certain rate classes. The grouping of several rate classes into one graph results in a graph that is difficult to view, therefore an individual graph has been provided for each rate class.

Each graph illustrates the percentage bill impact at various consumption levels for FEW customers moving to FEI rate schedules.

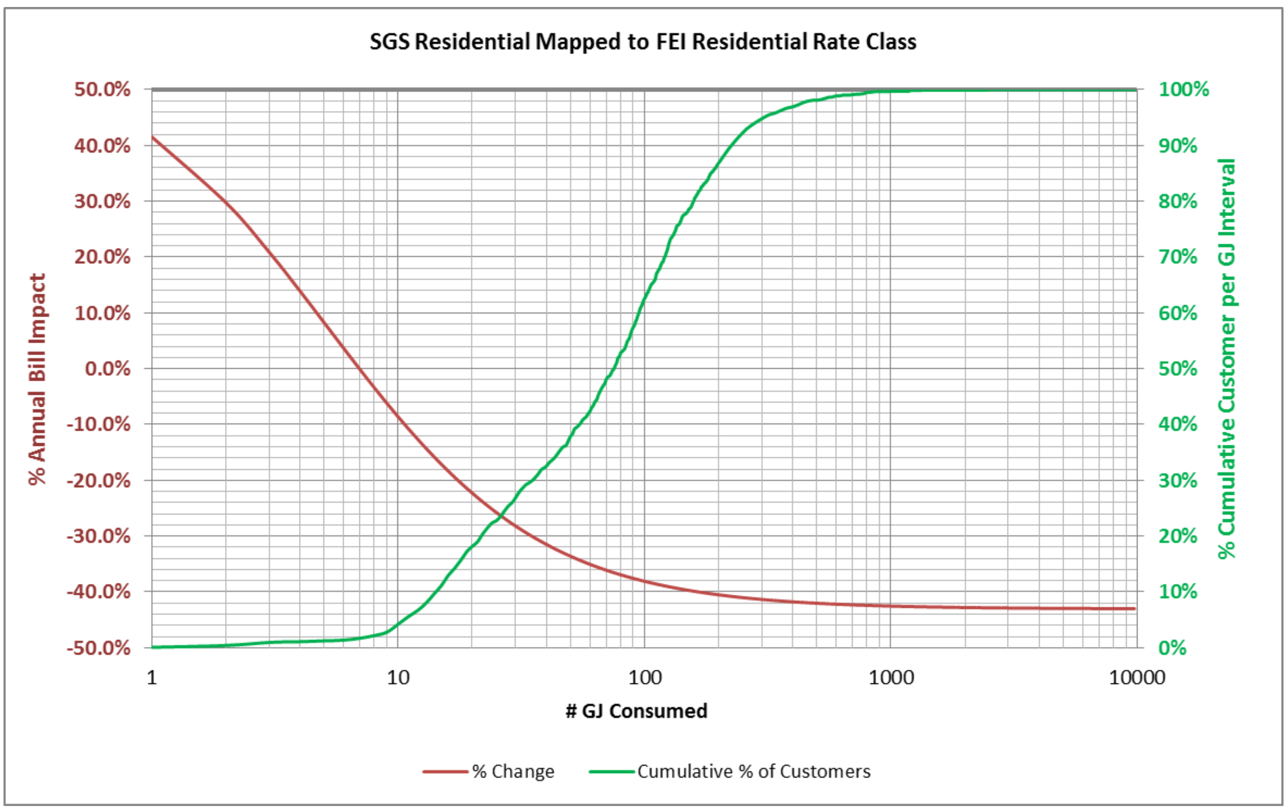
The X-axis represents GJ consumption intervals logarithmically.

The green ‘Cumulative % of Customers’ line represents the cumulative customers per GJ consumption interval and corresponds with the right Y-axis.

The red ‘% Change’ line represents the bill impact increase in rates for customers at various GJ consumption intervals, and corresponds with the left Y-axis.

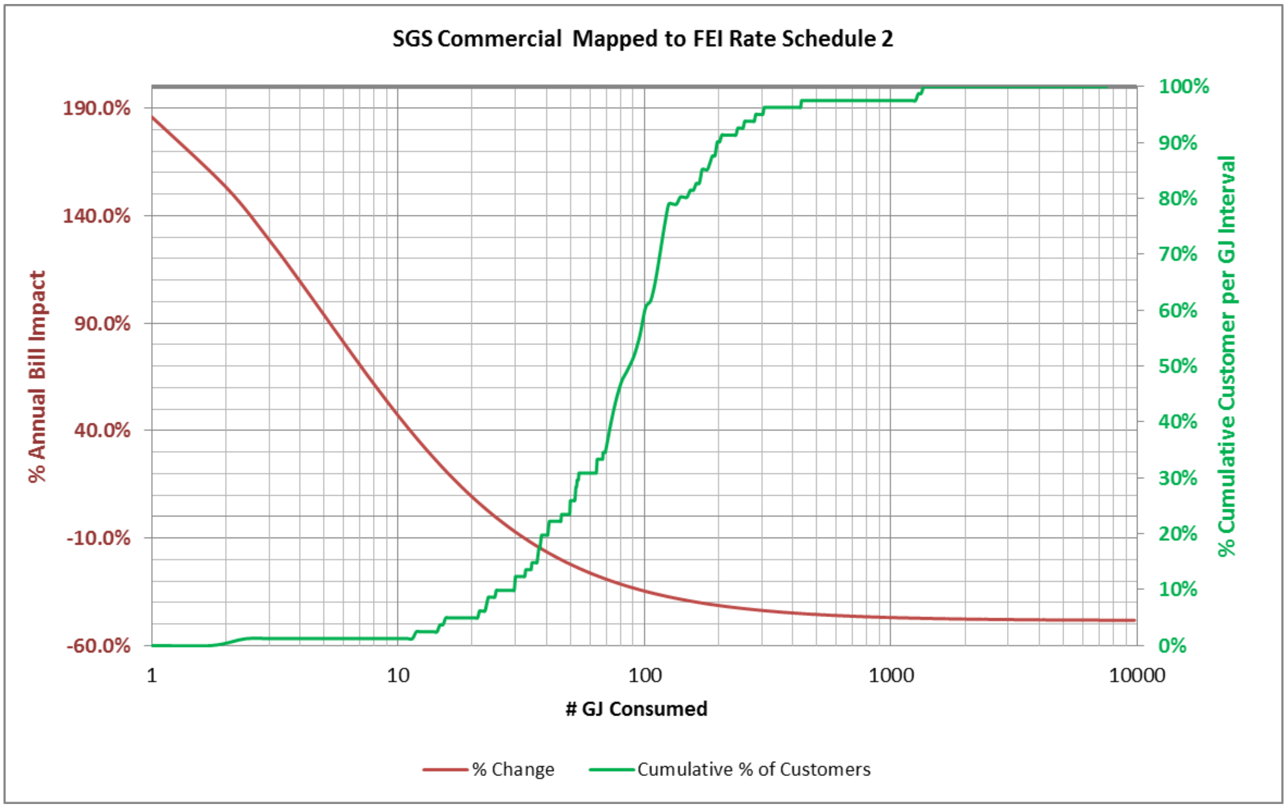
For any given consumption level, a vertical line can be drawn which will intersect both the ‘% Change’ and the ‘Cumulative % of Customers’ lines. The vertical intersection of this line with the ‘% Change’ line indicates the annual percentage change at the given consumption level, while the vertical intersection with the ‘Cumulative % of Customers’ line indicates the cumulative percentage of customers.

SGS Residential



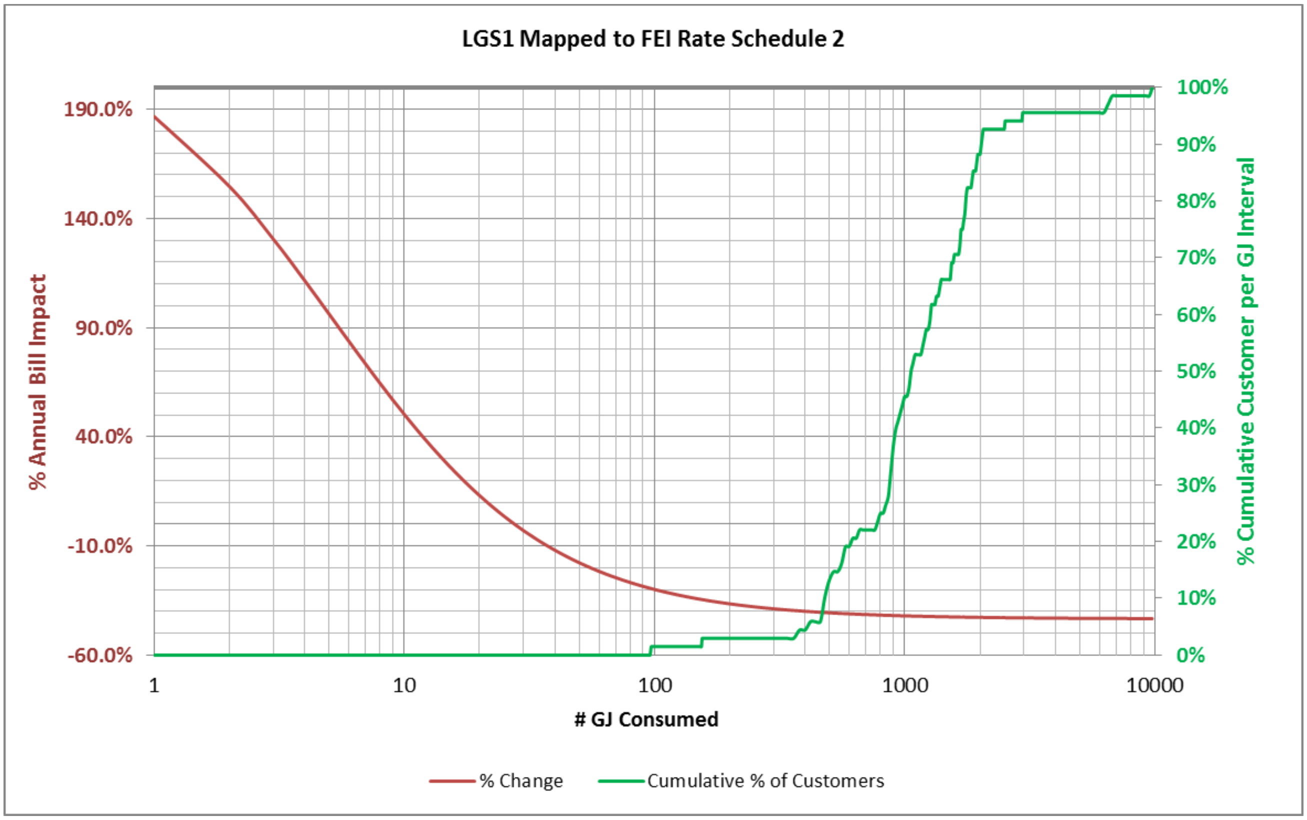
The graph illustrates that an FEW customer consuming 100 GJs would experience a decrease of approximately 38% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

SGS Commercial



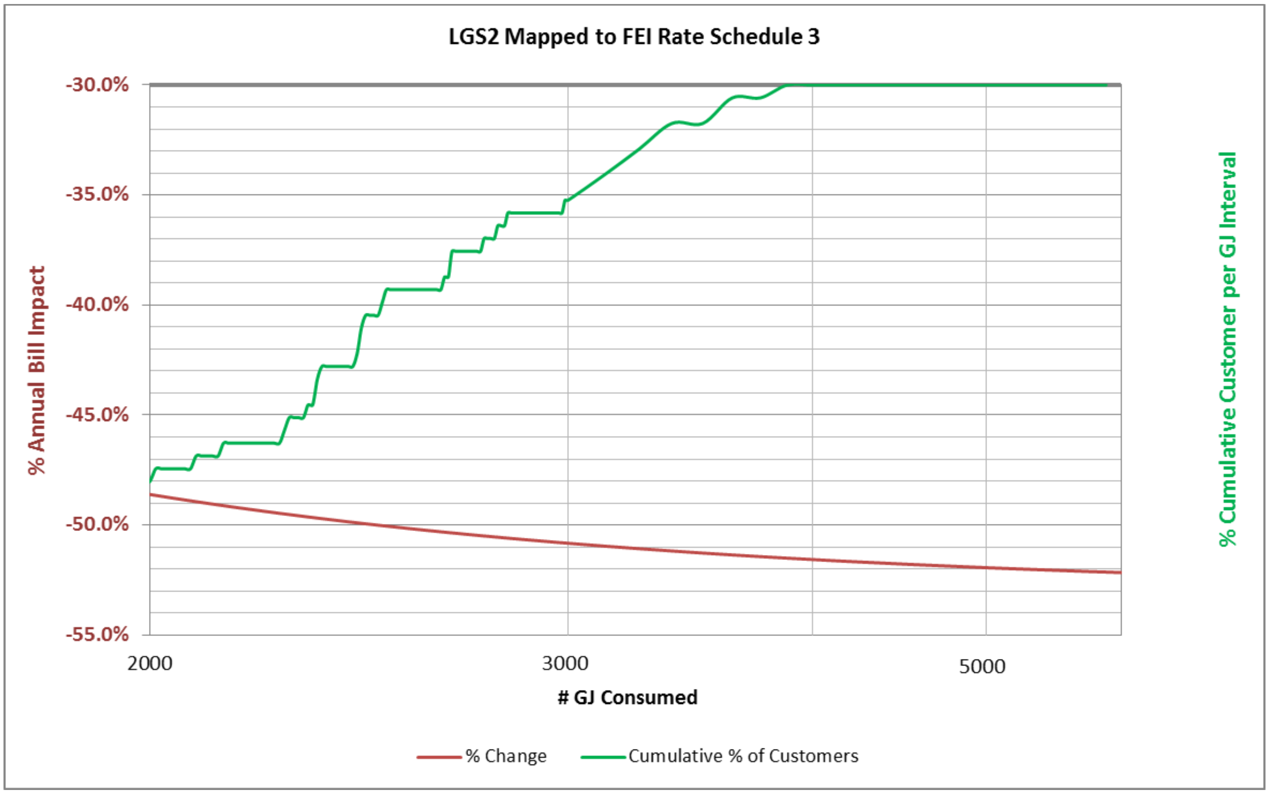
The graph illustrates that an FEW customer consuming 200 GJs would experience a decrease of approximately 40% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

LGS1



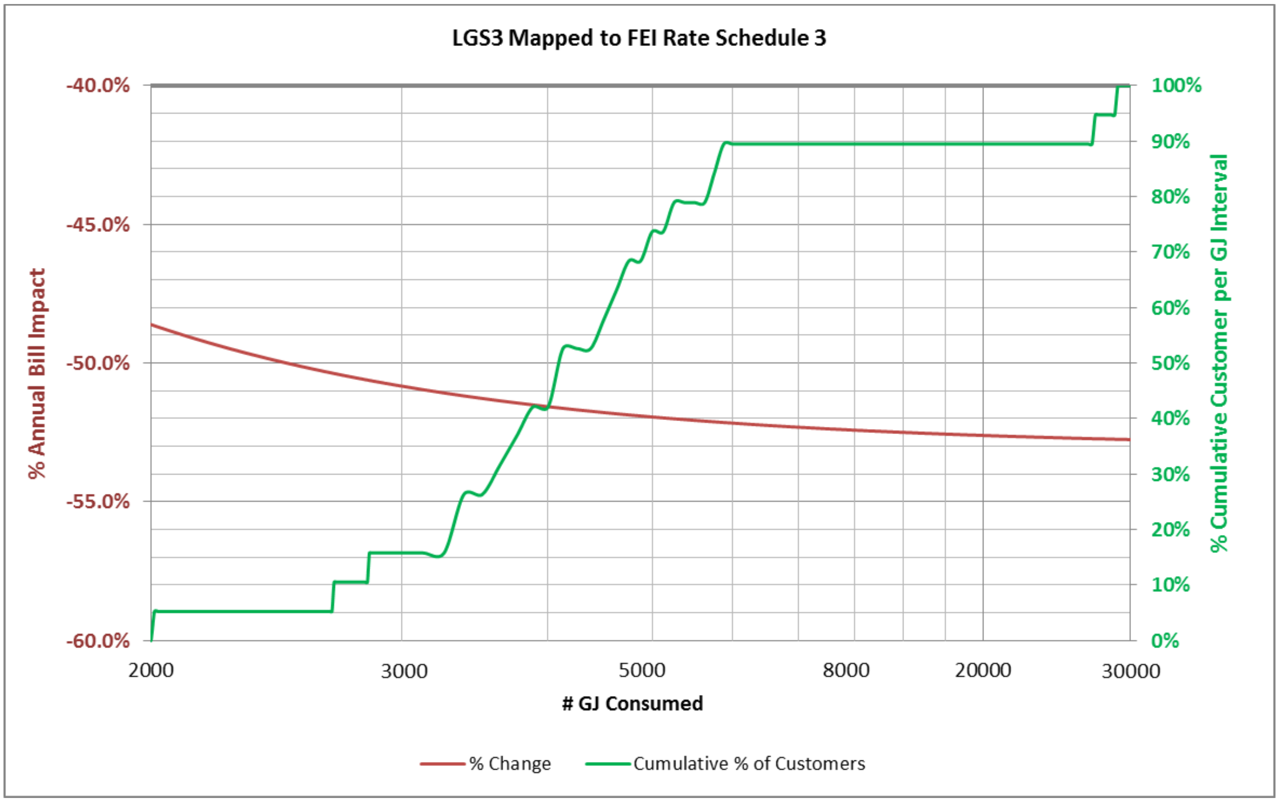
The graph illustrates that an FEW customer consuming 1000 GJs would experience a decrease of approximately 40% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

LGS2



The graph illustrates that an FEW customer consuming 3000 GJs would experience a decrease of approximately 52% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

LGS3



The graph illustrates that an FEW customer consuming 5000 GJs would experience a decrease of approximately 54% to their annual bill in 2014 as a result of amalgamation and the adoption of common rates.

97.3 Please prepare similar sets of graphs for FEFN that includes the impact of the Fort Nelson Phase-In Rider for each of the following customer groupings: (i) Rate 1; (ii) GSR 2.1; and (iii) for GSR 2.2.

Response:

The bill impact graphs for all of FEFN's rate schedules, inclusive of the phase-in rider, are provided below.

Each graph illustrates the percentage bill impact at various consumption levels for FEFN customers moving to FEI rate schedules.

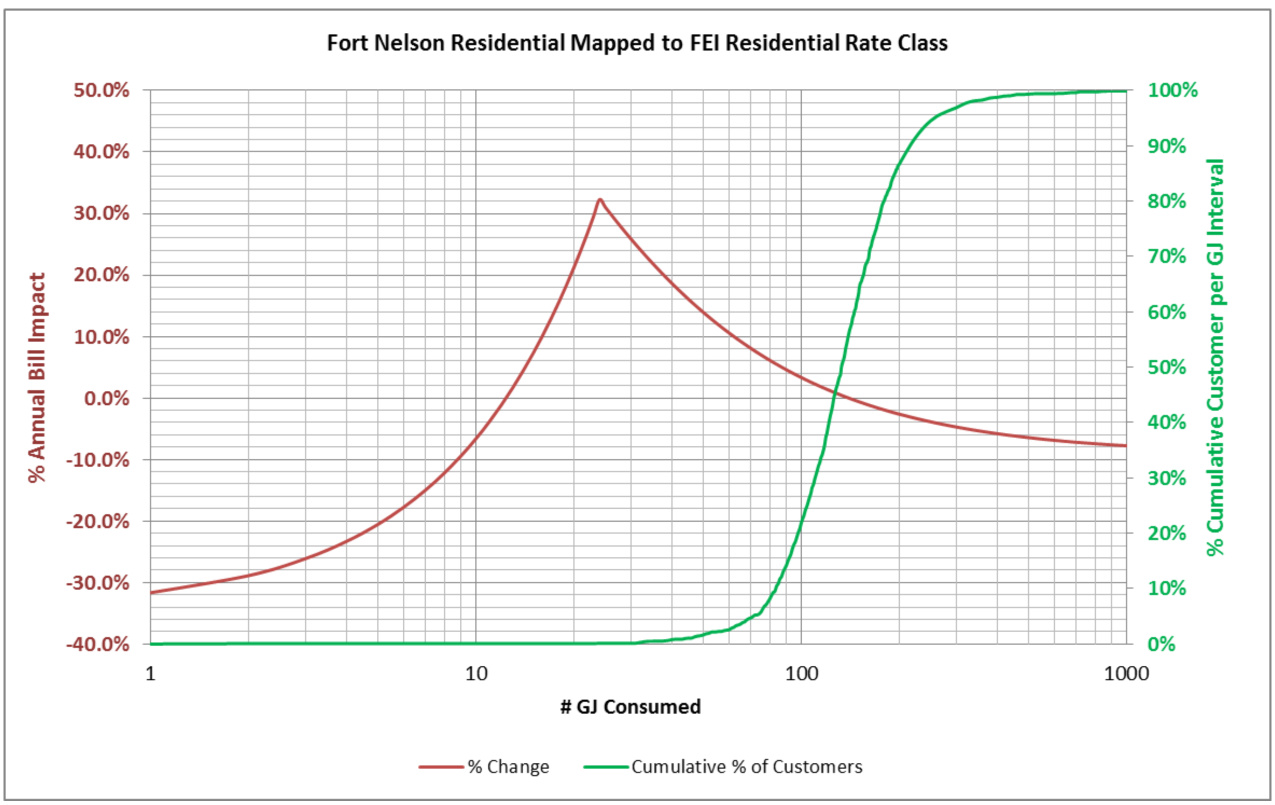
The X-axis represents GJ consumption intervals logarithmically.

The green 'Cumulative % of Customers' line represents the cumulative customers per GJ consumption interval and corresponds with the right Y-axis.

The red '% Change' line represents the bill impact increase in rates for customers at various GJ consumption intervals, and corresponds with the left Y-axis.

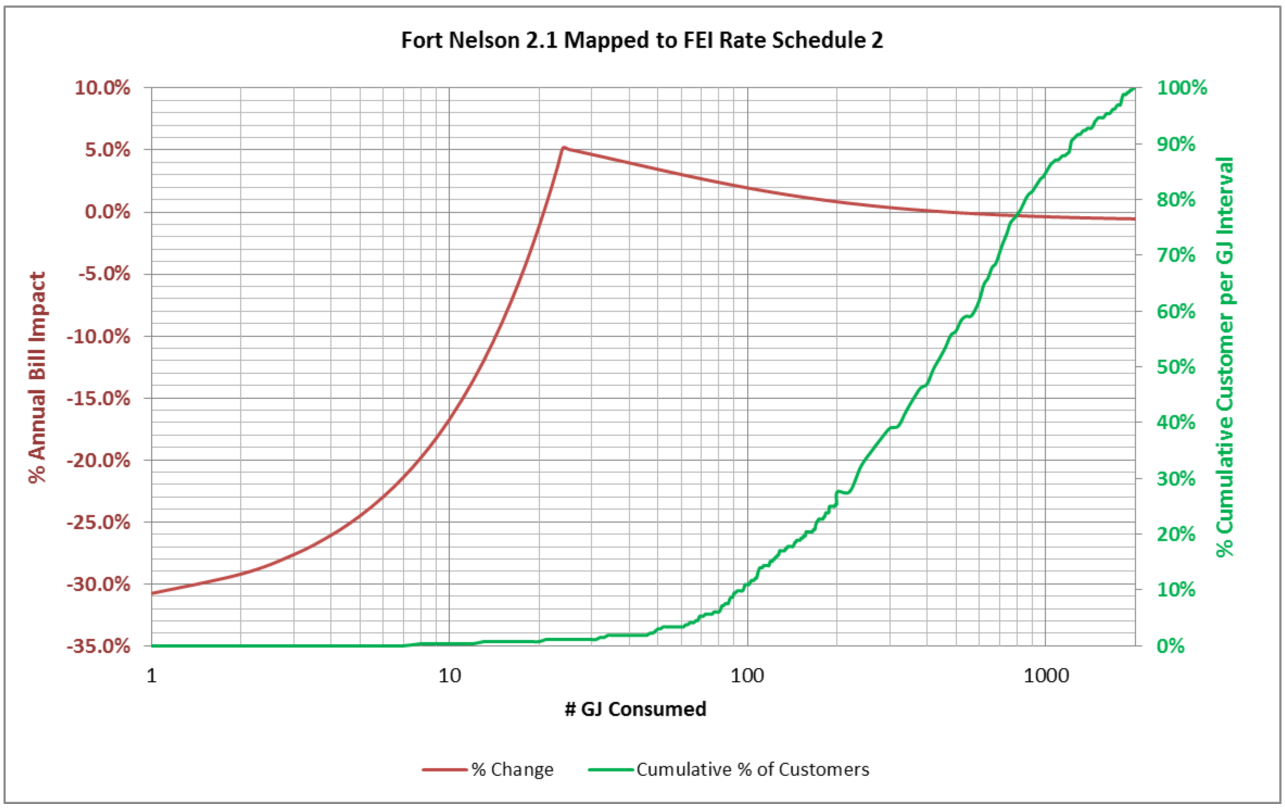
For any given consumption level, a vertical line can be drawn which will intersect both the '% Change' and the 'Cumulative % of Customers' lines. The vertical intersection of this line with the '% Change' line indicates the annual percentage change at the given consumption level, while the vertical intersection with the 'Cumulative % of Customers' line indicates the cumulative percentage of customers.

Fort Nelson Residential

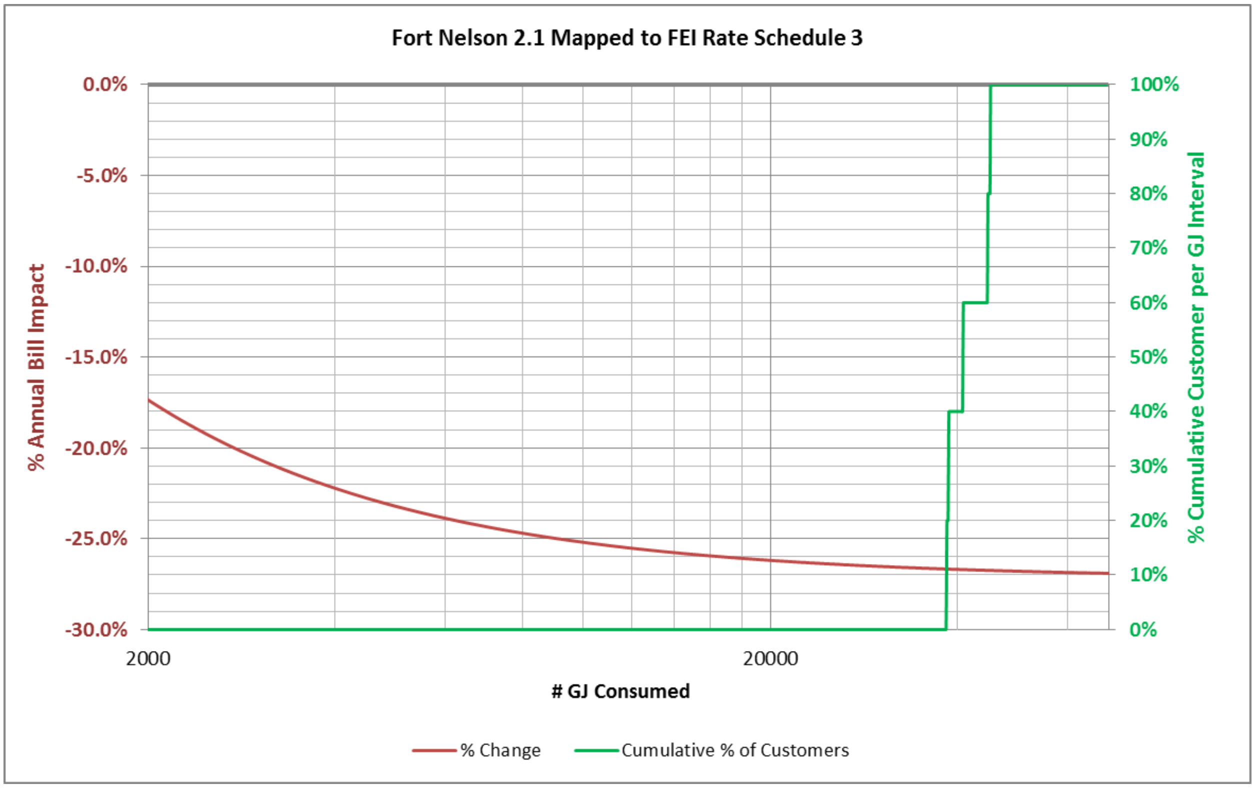


The graph illustrates that an FEFN customer consuming 140 GJs would experience no change in their annual bill in 2014 as a result of amalgamation and the adoption of common rates. The graph highlights the unique rate structure that exists in Fort Nelson; the basic charge includes the cost of the first 2 GJs consumed. As a result, at consumption levels up to 24 GJS, customers would experience an increase in their annual bill. As the graph also highlights, less than 2% of Fort Nelson customers consume less than 50GJs annually, therefore this rate structure affects few residential customers.

Fort Nelson Rate 2.1

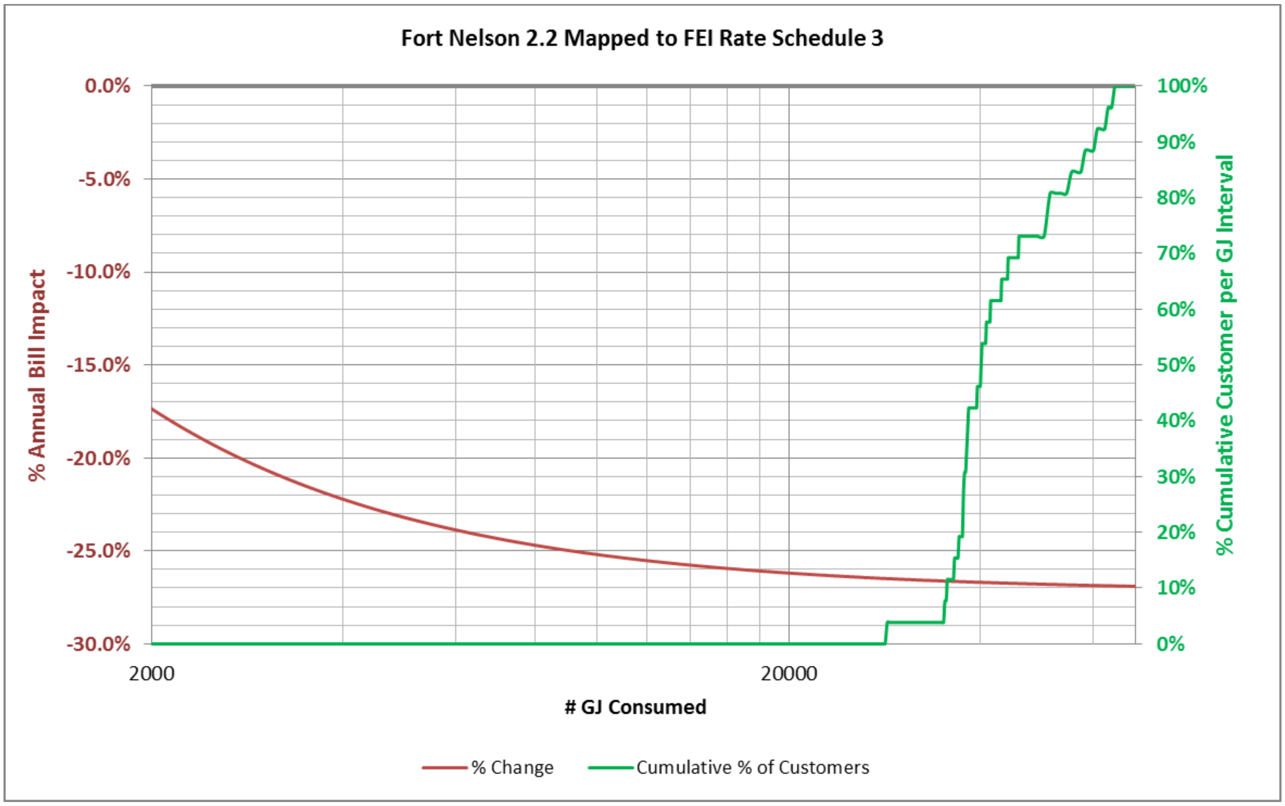


The graph illustrates that an FEFN customer consuming 500 GJs would experience little change in their annual bill in 2014 as a result of amalgamation and the adoption of common rates. Similar to the residential rate structure, this graph presents the Fort Nelson rate structure in which the first 2 GJs of consumption are included in the basic charge. Thus, as consumption approaches 24 GJs, a gradual increase in the annual bill impact occurs. Again, very few customers fall within this range.



The graph illustrates that an FEFN customer consuming 30,000 GJs would experience a decrease of approximately 17% in their 2014 annual bill as a result of amalgamation and the adoption of common rates. As there are only four customers who are mapped from Rate 2.1 to FEI's Rate 3, the graph shows a stepped increase for this rate class.

Fort Nelson Rate 2.2



The graph illustrates that an FEFN customer consuming 30,000 GJs would experience a decrease of approximately 16% in their 2014 annual bill as a result of amalgamation and the adoption of common rates.

97.4 Please prepare similar sets of graphs for FEFN that excludes the impact of the Fort Nelson Phase-In Rider for each of the following customer groupings: (i) Rate 1; (ii) GSR 2.1; and (iii) for GSR 2.2.

Response:

The bill impact graphs for all of FEFN's rate schedules, exclusive of the phase-in rider, are provided below.

Each graph illustrates the percentage bill impact at various consumption levels for FEFN customers moving to FEI rate schedules.

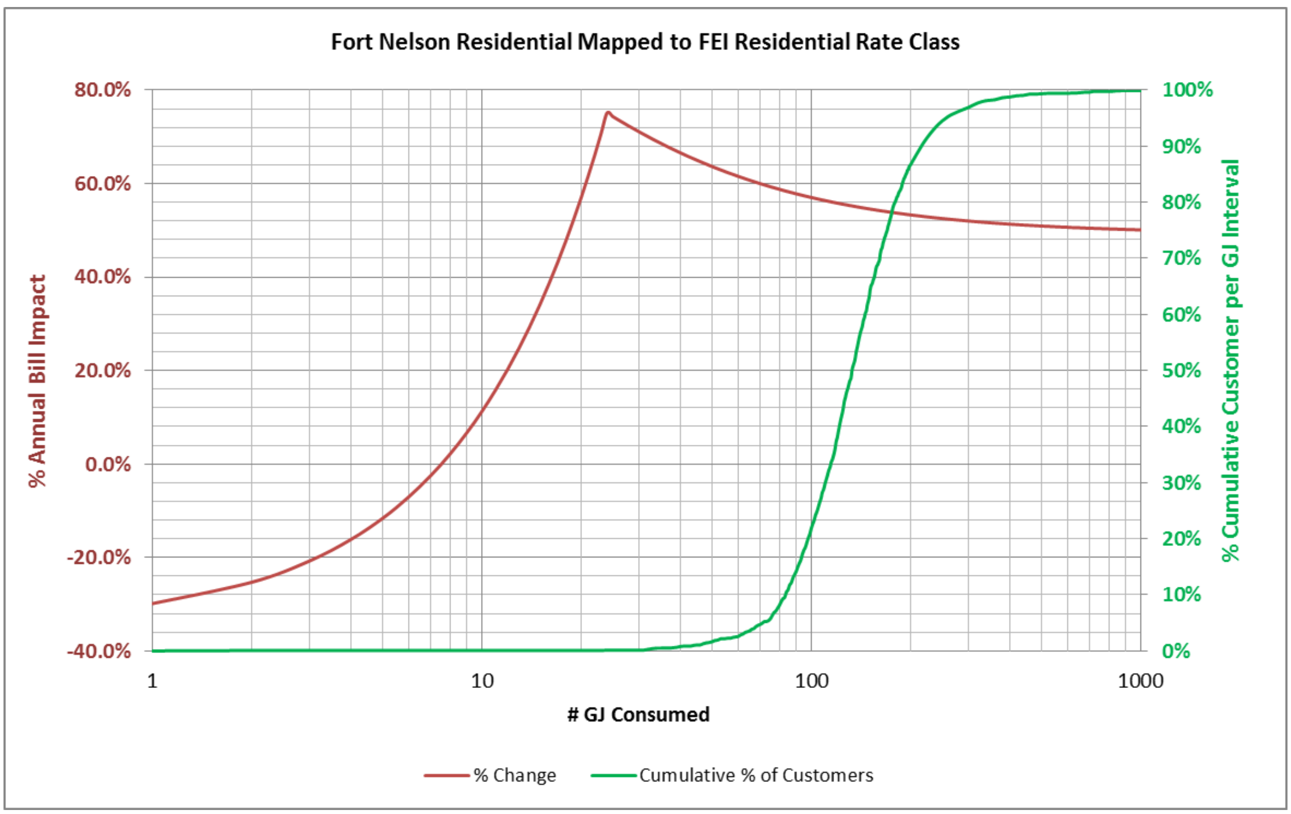
The X-axis represents GJ consumption intervals logarithmically.

The green 'Cumulative % of Customers' line represents the cumulative customers per GJ consumption interval and corresponds with the right Y-axis.

The red '% Change' line represents the bill impact increase in rates for customers at various GJ consumption intervals, and corresponds with the left Y-axis.

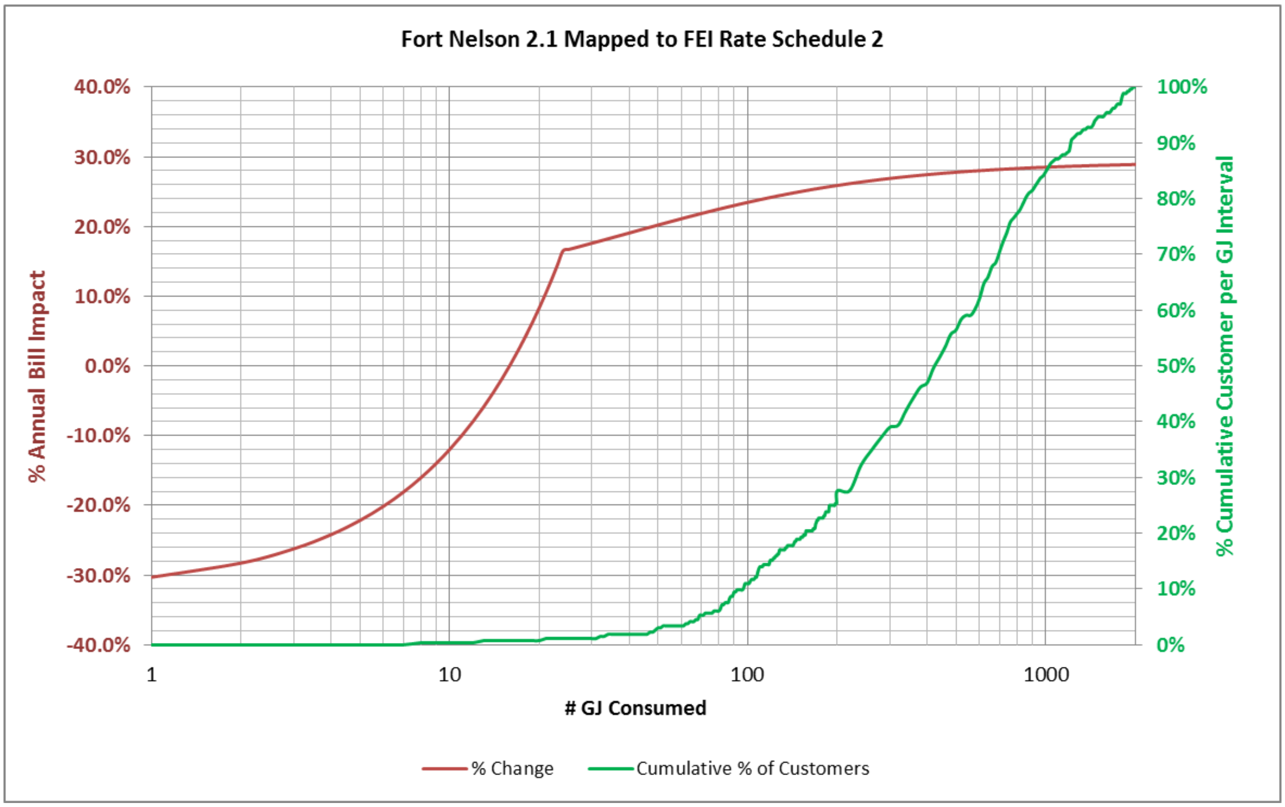
For any given consumption level, a vertical line can be drawn which will intersect both the '% Change' and the 'Cumulative % of Customers' lines. The vertical intersection of this line with the '% Change' line indicates the annual percentage change at the given consumption level, while the vertical intersection with the 'Cumulative % of Customers' line indicates the cumulative percentage of customers.

Fort Nelson Residential

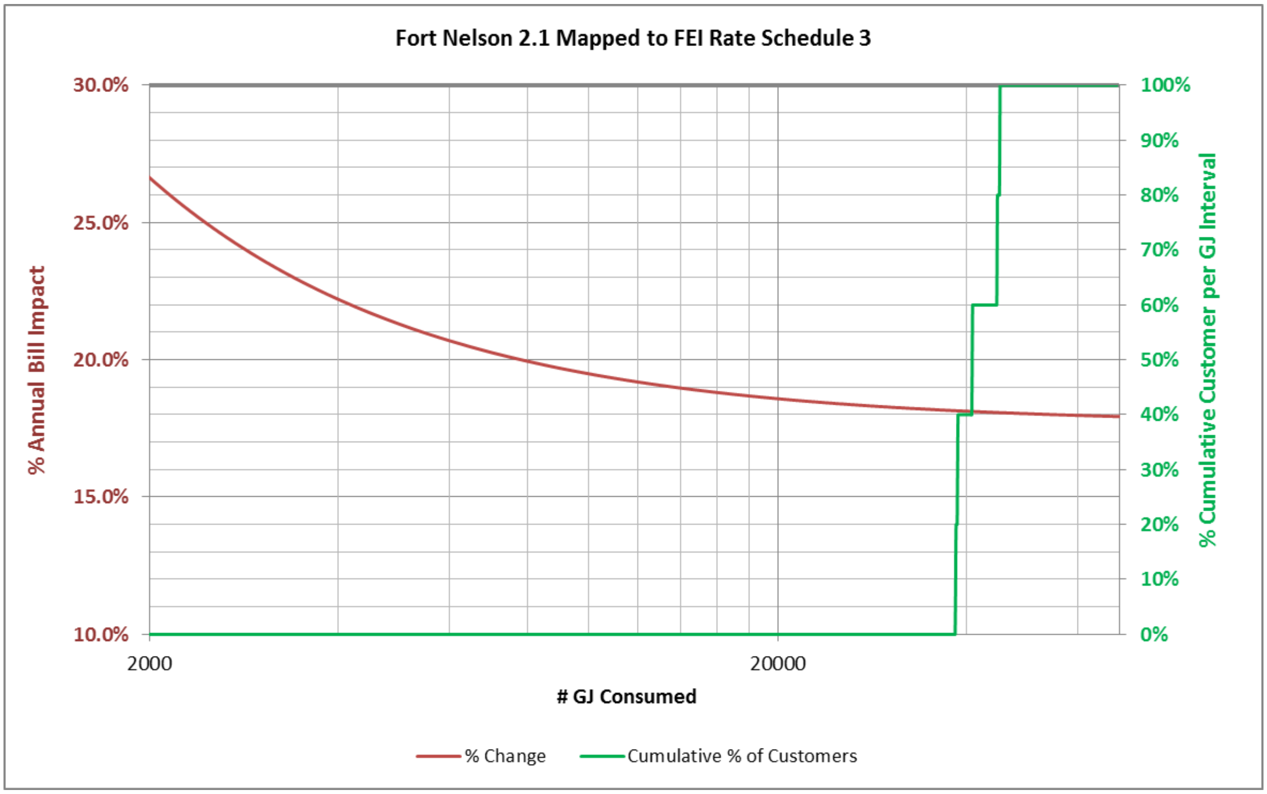


The graph illustrates that an FEFN customer consuming 140 GJs would experience an increase of approximately 56% in their 2014 annual bill as a result of amalgamation and the adoption of common rates. Similar to BCUC IR 1.97.3, this graph highlights the unique rate structure that exists in Fort Nelson; the basic charge includes the cost of the first 2 GJs consumed. As a result, at consumption levels up to 24 GJS, customers would experience an increase in their annual bill. As the graph also highlights, less than 2% of Fort Nelson customers consume less than 50GJs annually, therefore this rate structure affects few residential customers.

Fort Nelson Rate 2.1

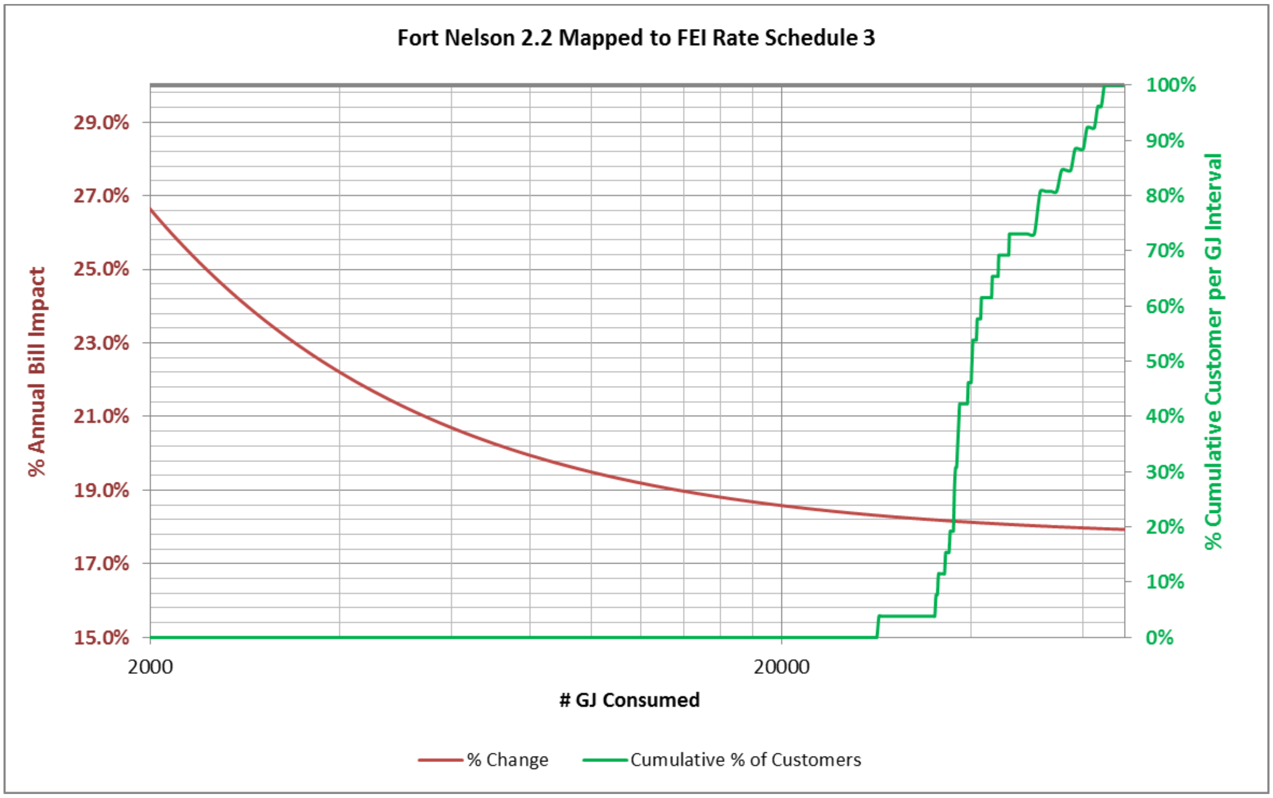


The graph illustrates that an FEFN customer consuming 500 GJs would experience an increase of approximately 28% in their 2014 annual bill as a result of amalgamation and the adoption of common rates. Similar to the residential rate structure, this graph presents the Fort Nelson rate structure in which the first 2 GJs of consumption are included in the basic charge. Thus, as consumption approaches 24 GJs, a gradual increase in the annual bill impact occurs. Again, very few customers fall within this range.



The graph illustrates that an FEFN customer consuming 30,000 GJs would experience an increase of approximately 18% in their 2014 annual bill as a result of amalgamation and the adoption of common rates. As there are only four customers who are mapped from Rate 2.1 to FEI's Rate 3, the graph shows a stepped increase for this rate class.

Fort Nelson Rate 2.2



The graph illustrates that an FEFN customer consuming 30,000 GJs would experience an increase of approximately 22% in their 2014 annual bill as a result of amalgamation and the adoption of common rates.

98.0 Reference: Delivery Rate Design – Affordability / Rate Shock

Exhibit B-3-1, Appendix H-11

FEI Amalco Bill Impact Schedules

98.1 Please update the appendix to show all the bill impacts from each of the six service areas identifying each of the existing (pre FEI Amalco) and then showing the proposed rate class bill impacts (post FEI Amalco) and identifying each of the .

Response:

After seeking clarification on the question posed in this IR, the Commission provided the following revised IR 98.1:

> 98.1 Please update Appendix J-3 to show all the bill impacts from each of the six service areas identifying each of the existing (pre FEI Amalco) customer class showing the proposed rate class bill impacts (post FEI Amalco) for each current customer class and identifying the proposed rate class in the column shown as "PROPOSED JANUARY 1, 2014 AMALGAMATED RATES – BASED ON NO REVENUE REBALANCING". Please include all rate classes in the Bill Impact Summary Tables in Appendix J-6.

The following file provides a set of bill impacts for FEVI, FEW and FEFN which highlights the existing (pre FEI Amalco) rate class, the proposed rate class bill impact and the proposed rate class bill impacts (post FEI Amalco). Revised bill impacts are not provided for the Lower Mainland, Inland and Columbia service areas, as there is no movement proposed for these service areas; all customers will remain in the rate class in which they currently receive service and were provided in Appendices J-3 and J-6.

98.2 Why was NGV left out of the bill impact schedules? Please update the evidence to include the rate impact on NGV customers in each of the six service areas.

Response:

Rate Schedule 6, which is the rate schedule for NGV customers, was included in the bill impacts for the FEI Lower Mainland, Inland and Columbia service areas. The existing rates, as well as the proposed rates for these customers are presented in Appendix J-3 of the Application.

Rate Schedule 16 customers are also NGV customers, however, since this is an interruptible rate class, it was not included in the COSA study. Please see IR 1.138.1 for additional details regarding the rationale for excluding Rate Schedule 16 from the Rate Design Application.

Fort Nelson's NGV rate class, Rate Class 2.3, currently does not serve any customers, nor does FEVI's NGV rate class.

FEW does not currently have an NGV rate class.

99.0 Reference: Delivery Rate Design – Affordability / Rate Shock

Exhibit B-3, Section 9.5.2, pp. 189 – 190; Exhibit B-3-1, Appendix E-3, p. 3

Impact to Fort Nelson Customers

"Because Fort Nelson will see higher percentage rate increases due to common rates, the rate impact of amalgamation and common rates is proposed to be delayed for five years, and then phased in over the following 10 years. At the end of the 15-year transition period, Fort Nelson rates will be the same as for all other customers across the Province."

FEU's presentation to the Northern Rockies Regional Council (Appendix E-3) pointed out that, as a separate service area, Fort Nelson is highly exposed to rate increases. The presentation illustrated the rate impacts expected in 2013 resulting from the loss of industrial load, capital expenditures on the Muskwa crossing, and declines in the use per customer.

99.1 Under the current rate structure, with a separate rate base for the Fort Nelson service area, what are the stand-alone rates forecast to be in 15 years as a result of (i) either increases or further decreases in industrial load, (ii) forecast maintenance capital expenditures, and (iii) forecast declines in residential use per customer?

Response:

For all scenarios the existing approved capital structure, depreciation, CCA and tax rates are assumed to apply. An average delivery rate and burner tip impact for Fort Nelson has been calculated. This means that the burner tip impact shown reflects the average for all customers in Fort Nelson and is calculated as the revenue deficiency divided by the total Fort Nelson revenue at existing rates. The approximate average delivery rate and burner tip impacts of the various scenarios are as follows:

i. **Increases or decreases in industrial load:** Currently FEFN has not forecast additional industrial customers; the potential one time delivery rate and average burner tip impact of the loss of either or both, industrial customers is approximately:

Approximate Rate Impact of Loss of Industrial Load[90]

($ Thousands, unless otherwise stated)

	Rate 25- Industrial Customers		
	Canfor: Takama	Canfor: Polarboard	Total
Volume loss (TJ)	(16.4)	(38.6)	(55.0)
Revenue loss ($ thousand)	$ (47)	$ (94)	$ (141)
Delivery margin at 2013 rates	$ 1,880	$ 1,833	$ 1,786
Approximate delivery rate impact	2.5%	5.1%	7.9%
Revenue at 2013 rates	$ 4,340	$ 4,293	$ 4,246
Approximate average burner tip impact	1.1%	2.2%	3.3%

ii. **Forecast maintenance capital expenditures**: For purposes of this analysis, maintenance or base capital expenditures are expected to average the 2013 forecast of approximately $400 thousand per year inflated by 2% per year, with approximately $7 thousand per year in regular plant retirements. The approximate delivery rate impact of these expenditures is approximately 2.25% per year, or a total cumulative delivery rate increase of approximately 34% over a 15 year period. The approximate average burner tip impact is 1.0% per year or a total cumulative average burner tip increase of approximately 15% over a 15 year period.

90 Delivery margin and revenue at 2013 rates reflects the loss of revenue in each scenario (i.e. 2013 approved delivery margin less the amount of delivery margin collected from the industrial customer(s))

Approximate Rate Impact of Maintenance Capital
($ Thousands, unless otherwise stated)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Assumptions															
Plant Addition	408	416	424	433	442	450	459	469	478	488	497	507	517	528	538
Plant Retirement	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Tax Rate	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Average Depreciation	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
Average CCA Rate	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%	6%
Financing Rate	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Equity Return	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%
Opening Plant Balance	-	401	810	1,228	1,654	2,088	2,532	2,984	3,446	3,917	4,397	4,888	5,388	5,899	6,419
Addition	408	416	424	433	442	450	459	469	478	488	497	507	517	528	538
Retirement	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
Closing Plant Balance	401	810	1,228	1,654	2,088	2,532	2,984	3,446	3,917	4,397	4,888	5,388	5,899	6,419	6,951
Opening Accumulated Depreciation	-	1	(9)	(31)	(66)	(113)	(172)	(244)	(330)	(429)	(541)	(668)	(809)	(964)	(1,134)
Depreciation Expense	(6)	(17)	(29)	(41)	(54)	(66)	(79)	(92)	(106)	(120)	(134)	(148)	(162)	(177)	(192)
Retirement	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Closing Accumulated Depreciation	1	(9)	(31)	(66)	(113)	(172)	(244)	(330)	(429)	(541)	(668)	(809)	(964)	(1,134)	(1,319)
Mid Year NPIS	201	602	999	1,392	1,782	2,168	2,550	2,928	3,302	3,672	4,038	4,400	4,757	5,110	5,458
Cost of Service															
Depreciation Expense	6	17	29	41	54	66	79	92	106	120	134	148	162	177	192
Earned Return	16	47	78	108	139	169	198	228	257	286	314	342	370	397	424
Taxes	0	1	2	3	5	7	9	12	14	18	21	24	28	32	36
Total Cost of Service	**22**	**65**	**109**	**153**	**197**	**242**	**287**	**332**	**377**	**423**	**468**	**514**	**560**	**606**	**653**
Margin at Existing Rates	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927	1,927
Approximate Cumulative Delivery Rate Impact	**1.1%**	**3.4%**	**5.6%**	**7.9%**	**10.2%**	**12.5%**	**14.9%**	**17.2%**	**19.6%**	**21.9%**	**24.3%**	**26.7%**	**29.1%**	**31.5%**	**33.9%**
Approximate Annual Delivery Rate Impact	1.1%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
Revenue at Existing Rates	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387	4,387
Approximate Cumulative Burner Tip Impact	**0.5%**	**1.5%**	**2.5%**	**3.5%**	**4.5%**	**5.5%**	**6.5%**	**7.6%**	**8.6%**	**9.6%**	**10.7%**	**11.7%**	**12.8%**	**13.8%**	**14.9%**
Approximate Annual Burner Tip Impact	0.5%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.1%	1.1%

iii. **Forecast declines in residential use per customer**: For purposes of this analysis, FEFN has assumed an annual decrease in the Residential customer use rate of 0.2% or approximately 0.3GJs per year. This equates to a total forecast reduction in the Residential customer use rate of approximately 4.5 GJs over the 15 year period (from an average of 140 GJs per year to 135.5 GJs per year). The annual delivery rate impact of a decline in use rates of this magnitude is approximately 0.2% per year, or an approximate cumulative 3.5% increase over the 15 year period. The approximate average burner tip impact is 0.1% per year or a total cumulative average burner tip increase of approximately 1.5% over a 15 year period. To isolate the impact of the decline in Residential use rate, the average number of Residential customers has been held constant for the 15 year period.

Approximate Rate Impact of Residential Use Rate Decline[91]

($ Thousands unless otherwise stated)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Cumulative use rate reduction (GJ)	(0.3)	(0.6)	(0.9)	(1.2)	(1.5)	(1.8)	(2.1)	(2.4)	(2.7)	(3.0)	(3.3)	(3.6)	(3.9)	(4.2)	(4.5)
Average residential customers	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973	1,973
Decline in throughput (TJ)	(0.6)	(1.2)	(1.8)	(2.4)	(3.0)	(3.6)	(4.1)	(4.7)	(5.3)	(5.9)	(6.5)	(7.1)	(7.7)	(8.3)	(8.9)
2013 effective delivery rate ($/GJ)	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28	$ 7.28
Approximate decline in revenue	$ (4.3)	$ (8.6)	$ (12.9)	$ (17.2)	$ (21.5)	$ (25.9)	$ (30.2)	$ (34.5)	$ (38.8)	$ (43.1)	$ (47.4)	$ (51.7)	$ (56.0)	$ (60.3)	$ (64.6)
Delivery margin at 2013 rates	$1,923	$1,918	$1,914	$1,910	$1,905	$1,901	$1,897	$1,893	$1,888	$1,884	$1,880	$1,875	$1,871	$1,867	$1,862
Approximate Cumulative Delivery Rate Impact	0.2%	0.4%	0.7%	0.9%	1.1%	1.4%	1.6%	1.8%	2.1%	2.3%	2.5%	2.8%	3.0%	3.2%	3.5%
Approximate Annual Delivery Rate Impact	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Revenue at 2013 rates	$4,383	$4,378	$4,374	$4,370	$4,365	$4,361	$4,357	$4,353	$4,348	$4,344	$4,340	$4,335	$4,331	$4,327	$4,322
Approximate Cumulative Burner Tip Impact	0.1%	0.2%	0.3%	0.4%	0.5%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.3%	1.4%	1.5%
Approximate Annual Burner Tip Impact	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

If all three scenarios materialize, the estimated impact to the average burner tip rate is a cumulative increase of approximately 20% by the fifteenth year. In the absence of amalgamation and the implementation of common rates, it is likely that FEFN rates would be rebalanced to reflect a revenue to cost ratio of 90-110, resulting in an additional burner tip increase to residential customers of approximately 21% (Appendix H-12, Tab 1.1, page 1). The combined impact over the fifteen year period of the three scenarios and the rebalancing of rates is an approximate cumulative burner tip impact of 41% to Residential Fort Nelson customers.

The forecasted overall impact to a typical Residential Fort Nelson customer of amalgamation and implementation of common rates is an annual bill increase of approximately 54% in year 15. Although the annual bill in year 15 is greater under common rates, when the total bill over the 15 year period is compared to the cumulative impact of the scenarios calculated above (i.e. the sum of the annual bills for years 1 through 15), depending on the magnitude and timing of those scenarios, Residential customers may see a net benefit under amalgamation and common rates (with phase-in). Please note that the three scenarios above do not have a cumulative burner tip impact on the amalgamated entity (there is a minor cumulative delivery rate impact of 0.1% over the 15 years).

[91] Delivery margin and revenue at 2013 rates reflects the loss of revenue in each scenario

Fort Nelson Residential Customer, Annual Bill Comparison[92], [93]

Common Rates Phase-In as compared to Rebalancing and BCUC IR 1.99.1 Scenarios

Discount Rate 6.8%
Existing Residential Annual Bill $ 985.60

Common Rates, with Phase-In				
	Annual Bill Impact(%)		*Approximate Annual Bill ($)*	
Year	***Total***	***Annual***	***Total***	***Discounted***
2014	0%	0%	$ 986	$ 923.0
2015	0%	0%	$ 986	$ 864.4
2016	0%	0%	$ 986	$ 809.5
2017	0%	0%	$ 986	$ 758.1
2018	0%	0%	$ 986	$ 709.9
2019	5%	5%	$ 1,040	$ 701.4
2020	11%	5%	$ 1,094	$ 691.0
2021	16%	5%	$ 1,148	$ 679.2
2022	22%	5%	$ 1,202	$ 666.1
2023	27%	5%	$ 1,256	$ 651.9
2024	33%	5%	$ 1,311	$ 636.8
2025	38%	5%	$ 1,365	$ 621.0
2026	44%	5%	$ 1,419	$ 604.6
2027	49%	5%	$ 1,473	$ 587.8
2028	55%	5%	$ 1,527	$ 570.7
			$ 17,762.6	$ 10,475.3

Rebalancing and BCUC IR 1.99.1 Scenarios				
	Annual Bill Impact(%)		*Approximate Annual Bill ($)*	
Year	***Total***	***Annual***	***Total***	***Discounted***
2014	23%	23%	$ 1,210	$ 1,133.3
2015	25%	2%	$ 1,232	$ 1,080.2
2016	27%	2%	$ 1,254	$ 1,029.7
2017	28%	1%	$ 1,265	$ 972.6
2018	29%	1%	$ 1,275	$ 918.7
2019	31%	1%	$ 1,286	$ 867.8
2020	32%	1%	$ 1,298	$ 819.7
2021	33%	1%	$ 1,309	$ 774.2
2022	34%	1%	$ 1,320	$ 731.2
2023	35%	1%	$ 1,331	$ 690.6
2024	36%	1%	$ 1,342	$ 652.2
2025	37%	1%	$ 1,354	$ 615.9
2026	38%	1%	$ 1,365	$ 581.6
2027	40%	1%	$ 1,376	$ 549.2
2028	41%	1%	$ 1,388	$ 518.6
			$ 19,604.1	$ 11,935.6

[92] "Rebalancing and BCUC IR 1.99.1 Scenarios" assumes that rate rebalancing (an impact of 21%) occurs in 2014, the loss of revenues associated with the Takama industrial load occurs in 2014, and the loss of revenues associated with the Polarboard industrial load occurs in 2015. The timing of the maintenance capital and residential use rate decline impacts are as provided in (ii) and (iii).

[93] The FEU expects that year 28 is the break-even point for these scenarios.

100.0 Reference: Delivery Rate Design – Affordability / Rate Shock

Exhibit B-3, Section 4, p. 75, 76; FEU 2012-2013 Revenue Requirements & Rates Application, Oral Hearing Transcript, p.308

Rate Stability

FEU state on page 75 and 76 of the Application

> "A third issue confronting the FEU is that FEVI, FEW and FEFN are more susceptible to rate volatility in response to changes in throughput and large capital expenditures than FEI (Mainland)."

> "The Muskwa River Crossing is the main driver behind the growth in Fort Nelson's rate base from $5.4 million in 2010 to a forecast of $9.3 million in 2013 (an approximate increase of 72 percent). The cost of service associated with the Muskwa River Crossing is approximately $260 thousand in 2013. All else equal, a cost of service increase of $260 thousand for Fort Nelson results in an increase to their delivery rate of approximately 13.7 percent, or roughly a $54 increase to an average residential customer's annual bill."

> "FEVI, FEW and FEFN are further challenged by having a less diverse customer base compared to that of FEI (Mainland). As illustrated in Table 4-10 below, the top 10 highest consuming FEVI customers account for approximately 63 percent of FEVI's total throughput and 16 percent of the total revenues. For FEW, this ratio is 18 percent of total throughput and 21 percent of total revenues, whereas for FEFN this ratio is 17% of total throughput and 11% of total revenue. This suggests that the loss of a major customer for one of these smaller utilities would have a material impact on both throughput and revenue."

In the FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application Oral Hearing (Transcript Volume 3, p. 308):[94]

> "MR. LANGLEY: Q: Fair enough. And it's also fair to say that gas prices are notoriously volatile, right?

> MR. STOUT: A: Notoriously.

> MR. LANGLEY: Q: Very volatile.

[94] http://www.bcuc.com/Documents/Transcripts/2011/DOC_28703_10-04-2011-Transcript-Volume-3.pdf

MR. STOUT: A: They can be very volatile. We've seen that over short periods of time. ...

MR. LANGLEY: Q: Okay. And so over the test period, over the two years, nobody in this room really has any idea what gas prices will do, or really any control over what they do, either, right?

MR. STOUT: A: Nobody in this room anyway, that's for sure. You know, I think most expectations are out there that we are likely to see softer gas prices -- not softer than we are today, but continued lower gas prices over the next couple of years. But none of us has any control over that."

100.1 Please provide a table showing historical yearly capital expenditures over the last 25 year for FEFN and FEW, and anticipated capital expenditures by 5 year intervals for the next 30 years.

Response:

Please see the table below. FEFN and FEW have provided capital additions back to 1994 and 1996, respectively. FEFN and FEW have provided 18 years and 16 years of data rather than the 25 years as requested because the capital addition information back to 1987 is not readily available.

Please note that the forecast capital expenditures for 2012 through 2041 are based on high level assumptions and are subject to change, reflecting maintenance capital expenditures only. Specifically, the maintenance additions for 2014 onwards are assumed to be equal to the 2013 forecast, adjusted for inflation of 2% per year. Further, although not currently identified or included in this analysis, it is possible that both regions may require major capital upgrades as a result of the long term system sustainment plan.

Actual and Forecast Capital Expenditures ($ Thousands)

Year	FEFN	FEW
1994	567	-
1995	221	-
1996	378	733
1997	397	779
1998	573	742
1999	573	350
2000	478	2,120
2001	196	3,038
2002	244	1,180
2003	287	403
2004	227	324
2005	490	489
2006	546	1,174
2007	226	267
2008	238	377
2009	440	3,204
2010	655	657
2011	513	621
2012 - 2016	5,436	2,906
2017 - 2021	2,253	2,817
2022 - 2026	2,488	3,110
2027 - 2031	2,747	3,433
2032 - 2036	3,033	3,791
2037 -2041	3,348	4,185

100.1.1 What impact on rates did and will these capital expenditures have on rates for FEFN and FEW customers?

Response:

The following table provides the approximate average burner tip rate impact of the capital expenditures (plant additions, net of retirements) on a total basis as well as broken out for the periods 1994-2011 and 2012-2041. Please note that this is a high level analysis of the approximate impact of the changes and may not precisely reflect the actual rate impact incurred. Please also note that the Whistler Pipeline Contribution and Conversion costs were included as capital expenditures for FEW; however, they were accounted for in deferred charges rather than plant and accordingly, FEW has included these deferred charges in this analysis.[95]

Year	Plant Additions ($ Thousands)		Plant Retirements ($ Thousands)		Net Plant Additions ($ Thousands)		Approximate Cost of Service Impact ($ Thousands)		Approximate Revenue ($ Thousands)		Approximate Burner Tip Rate Impact (%)	
	FEFN	*FEW*	*FEFN*	*FEW*	*FEFN*	*FEW*	*FEFN*	*FEW*	*FEFN*	*FEW*	*FEFN*	*FEW*
1994 -2011	7,249	42,603	(2,373)	(7,965)	4,876	34,637	621	4,804	4,387	12,299	14%	39%
2012 - 2041	26,553	36,697	(206)	(5,329)	26,347	31,368	1,373	(1,323)			31%	-11%
Total	33,802	79,300	(2,579)	(13,294)	31,223	66,006	1,994	3,481			45%	28%

Although the net plant additions are comparable between the 1994-2011 and 2012-2041 periods, the cost of service in the forecast period is lower due to the amortization of the Whistler Pipeline Capital Contribution and Conversion cost deferrals (the conversion costs deferral is amortized over 20 years at approximately $740 per year while the pipeline contribution is amortized over 50 years at approximately $290 thousand per year).

Please note that while not included in the forecast in the response to BCUC IR 1.100.1, it is possible that FEFN and FEW could require major capital upgrades related to the long term sustainment plan. Major capital projects do have a significant impact on the smaller FEFN and FEW customer bases and have the potential to lead to increases in stand-alone delivery rates greater than postage stamp rates.

Please also refer to the response to BCUC IR 1.99.1 where the impact of maintenance capital expenditures on FEFN, over a 15 year period, is examined.

100.1.2 Do FEU consider there is any reasonable possibility these capital expenditures would increase delivery rates for FEFN customers over the next 30 years to a greater level than would result from approval of postage stamp rates? If yes, please explain.

[95] Approximate revenue is the 2013 forecast revenue as per this Application

Response:

No, the FEU do not expect that changes in maintenance capital expenditures, as estimated in the response to BCUC IR 100.1, will by themselves, increase delivery rates for FEFN customers over the next 30 years to a greater level than would result from approval of postage stamp rates. Please note that this is a high level estimate of capital expenditures, reflecting only maintenance capital. Although not currently forecast, it is possible that FEFN could require major capital upgrades related to the long term sustainment plan. Similar to the Muskwa River Project, major capital projects do have a significant impact on the smaller Fort Nelson customer base and have the potential to lead to increases in stand-alone delivery rates greater than postage stamp rates.

Please also refer to the response to BCUC IR 1.99.1 where the impact of maintenance capital expenditures, over a 15 year period, is examined.

100.2 Please provide a table showing customer consumption over the last 25 year for FEFN and FEW, and anticipated customer consumption for the next 30 years.

Response:

Please see the table below. FEFN and FEW have provided normalized historic total throughput back to 1994 and 1996, respectively. FEFN and FEW have provided 16 years and 18 years of data rather than the 25 years as requested because consumption information back to 1987 is not readily available.

Please note that the forecast consumption for 2012 through 2041 is based on high level assumptions and is subject to change. The long term outlook for customer additions is based on provincial government forecasts and increases gradually. A slight decline in UPC is expected to continue. Together the account and UPC forecasts result in consumption that grows by an immaterial amount of approximately 1 TJ per year after 2024.

Normalized Consumption
(TJ)

Year	FEFN	FEW
1994	798	-
1995	820	-
1996	893	425
1997	937	484
1998	934	549
1999	833	596
2000	843	672
2001	899	687
2002	941	691
2003	973	701
2004	975	724
2005	951	769
2006	906	734
2007	816	742
2008	751	709
2009	621	630
2010	615	766
2011	622	721
2012	633	716
2013	642	709
2014	597	695
2015	596	698
2016	595	702
2017	594	707
2018	593	710
2019	592	712
2020	592	716
2021	592	720
2022	591	723
2023	591	724
2024	590	727
2025	591	731
2026	592	733
2027	592	734
2028	593	737
2029	594	740
2030	595	743
2031	596	745
2032	596	747
2033	597	750
2034	598	752
2035	599	754
2036	599	757
2037	600	759
2038	601	762
2039	602	764
2040	602	766
2041	603	769

100.2.1 What impact on rates did or would these changes in customer consumption have on rates for FEFN and FEW customers?

Response:

The following table provides the approximate average burner tip rate impact of the change in consumption on a total basis as well as broken out for the periods 1994-2011 and 2012-2041. Please note that this is a high level analysis of the approximate impact of the changes and may not precisely reflect the actual rate impact incurred as a result of changes in consumption. Although not estimated due to current forecast methodology, it is possible that FEFN and FEW could experience a significant decline in consumption which could have significant upward pressure on delivery rates during the forecast period. [96],[97]

Year	Use Rate Change (TJ)		Revenue Change ($ Thousands)		Approximate Revenue ($ Thousands)		Approximate Burner Tip Rate Impact (%)	
	FEFN	*FEW*	*FEFN*	*FEW*	*FEFN*	*FEW*	*FEFN*	*FEW*
1994 -2011	(176)	296	(1,879)	3,034	4,387	12,299	43%	-25%
2012 - 2041	(19)	48	(116)	811			3%	-7%
Total	(195)	344	(1,995)	3,845			45%	-31%

Please also refer to the response to BCUC IR 1.99.1 where the impact on Fort Nelson of the loss of industrial load and declines in Residential use rates over a 15 year period are examined.

100.2.2 Do FEU consider that there is any reasonable possibility changes in customer consumption would increase delivery rates for FEFN customers over the next 30 years to a greater level than would result from approval postage stamp rates? If yes, Please explain.

96 Approximate revenue is the 2013 forecast per this Application
97 Total percent impacts are off by 1% due to rounding

Response:

No, the FEU do not expect that changes in customer consumption would increase delivery rates for FEFN customers over the next 30 years to a greater level than would result from approval of postage stamp rates.

Please also refer to the response to BCUC IR 1.99.1 where the impact of the loss of industrial load and declines in Residential use rates over a 15 year period are examined.

100.3 Please provide evidence of concerns raised by FEFN and FEW customers of rate instability resulting from the relatively small size of these utilities.

Response:

The FEU do not have evidence of concerns raised by FEFN and FEW customers with regards to rate instability resulting from the relatively small size of these utilities. Market research, in addition to past regulatory proceedings for the FEU and BC Hydro, indicate that customers are concerned about rate fluctuations and do not like rate increases but further concerns regarding the origination of rate fluctuations have not been raised. Long term rate stability, and particularly its relationship with the size of the utility, is a concept that many of our customers are unlikely to be familiar with. If they were familiar with the concept, it is unlikely they would raise it as an issue as they would have limited knowledge of available options for the utility to address it.

101.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 6.4, p. 115

Stakeholder Approval of Amalgamation

"…most of the FEU customers are supportive of common-rates in principle, even though seeing the actual rate impact of the common rates application reduces support for the initiative."

101.1 For each company (FEVI, FEI, FEFN and FEW) please summarize whether FEU consider, based on the results of consultation undertaken to date, that customers are supportive of this Application. If it is FEU's position that FEI and FEFN customers are supportive of this Application, please provide evidence to support this position.

Response:

Based on the results obtained from Market Research, Public Information Sessions, stakeholder meetings and Commercial & Industrial Customer surveys, the FEU believe that stakeholders do not have an issue with amalgamation or the principle of common rates. However, support for this Application is largely dependent on rate impacts.

Overall, FEVI and FEW customers are supportive of the Application, while FEI customers are split between support and opposition. FEFN customers are generally opposed.

Based on the market research results, 72% of FEVI customers support the move to common natural gas pricing, while only 11% oppose it.[98] With regards to Public Information Sessions and Commercial and Industrial Feedback, FEVI and FEW customers are strongly supportive of the common rates proposal.

With regards to FEI, market research[99] indicates that approximately 37-38% of FEI customers feel that the move to common rates makes sense for FortisBC customers, while approximately 36-39% oppose the move.[100] In addition, approximately 36% of FEI respondents feel that the Application is fair, while approximately 37-39% do not.[101] Based on the Public Information Sessions' feedback and Commercial & Industrial customer surveys, FEI results are split evenly between support and opposition for customers paying the same rate for natural gas regardless of where they live. Given that FEI (Mainland) customers incur a rate impact upon moving to common rates, the FEU have proposed to phase-in common rates over three years.

98 Common Rates, Amalgamation and Rate Design Application, Appendix E-5, page 14
99 Common Rates, Amalgamation and Rate Design Application, Appendix E-5, page 14
100 The remainder of customers surveyed neither supported or opposed the Application or didn't know how they felt.
101 Ibid.

Market research, the Fort Nelson public information session and feedback received from the NRRC, the Chamber of Commerce and Fort Nelson customers, all indicate that Fort Nelson customers are opposed to this Application. We have taken this feedback into consideration and, given the extent of the impact to FEFN customers, the FEU are proposing to phase-in Fort Nelson rates over 15 years to lessen the impact of common rates on the 2,500 Fort Nelson customers.

102.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 10.3.2, p. 226-7

Vancouver Island Gas Joint Venture Engagement

102.1 Please confirm that the three VIGJV customer signatories (Howe Sound Pulp and Paper, Catalyst Paper, and Nanaimo Forest Products) to the VIGJV letter of support for the 5 year extension to the Transportation Service Agreement are the only members of the VIGJV. If not, who are the other members and did the FEU discuss the extension with these members? If there are other members why did they not sign the letter of support?

Response:

The FEU confirm that the three VIGJV customer signatories (Howe Sound Pulp and Paper, Catalyst Paper, and Nanaimo Forest Products) to the VIGJV letter of support for the 5 year extension to the Transportation Service Agreement are the only members of the VIGJV. Western Forest Products (the successor to Western Pulp) was previously a member, but as of October 1, 2011, it no longer holds a Participating Interest with respect to the Contract Demand in the VIGJV Transportation Service Agreement.

103.0 Reference: Stakeholder Engagement

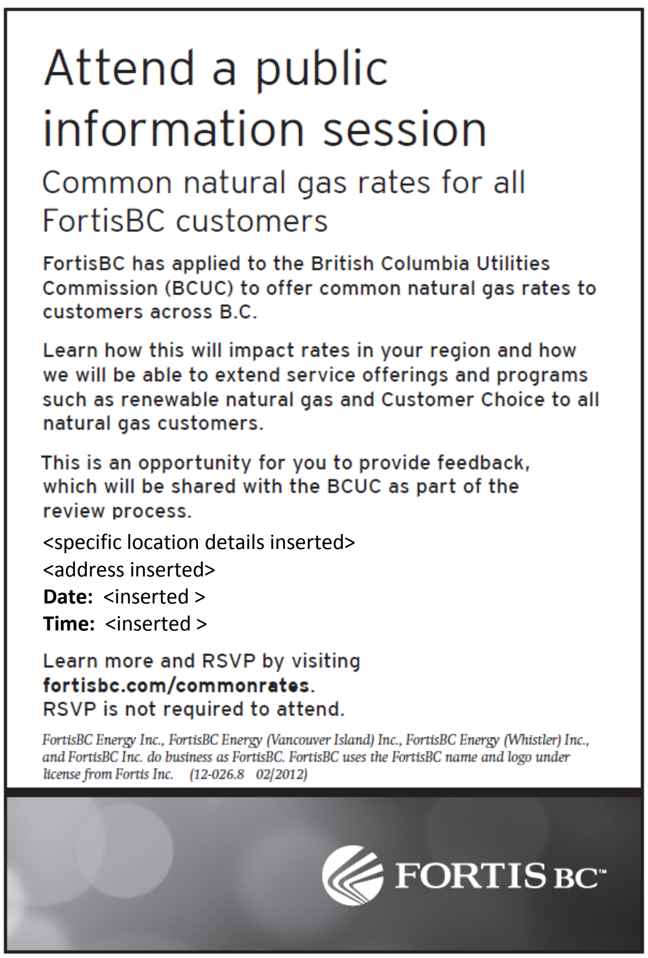
Exhibit B-3, Section 10.4.1.1, p. 229

Communications and Media Outreach – Newspaper Publications

103.1 Please file a copy of every version of the advertisement that was published in the newspapers listed in Table 10.1. If the same advertisement was used for every newspaper, please file only the one version.

Response:

The same advertisement was used for every newspaper, with the exception of the information regarding specific location, address, date and time particular to each session. A copy of the advertisement follows.



104.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 10.4.2.1, p. 233; Appendix E-5

Quantitative Study: Surveys

"For the quantitative study, Vision Critical randomly selected residential customers from the FEU‟s service areas (except Whistler) and invited them to complete a web-based survey... To make the survey results representative of the FEU's residential customer base, Vision Critical collected a sample that was as close to the general population as possible so that less weighting was required when analyzing the results. They did this by "balancing" the survey invitations they sent out so that the data collected reflects the general population variables such as gender and age as closely as possible. Vision Critical then weighted the data to reflect the FEU‟s natural gas regional customer distribution. More "weight" was given to responses from the larger service areas than the smaller service areas when looking at total results. However, Vision Critical also set minimum quotas per region to give the FEU enough completed surveys to look at results within each service area surveyed."

104.1 Please file a copy of the web based survey used for the quantitative study.

Response:

Attachment 104.1 contains the quantitative survey questionnaire. Provided below is a test web link similar to what respondents would have accessed to complete the survey.

To activate the survey, go to https://surveys.angusreidforum.com/R.aspx?a=8407&t=1 and enter postal code V0C 1R0 when prompted.

104.2 Please explain in detail Vision Critical's methodology for selecting survey participants. How did Vision "balance" survey invitations?

Response:

When selecting survey participants and balancing survey invitations, Vision Critical concentrated its efforts on the quota groups[102] set in the survey and the expertise of its research analysts and statistical software. Vision Critical follows generally accepted research practices as

[102] A quota sample is done to ensure a certain distribution of demographic variables. For this research, quotas were set based on region.

per the Marketing Research and Intelligence Association (MRIA). Vision Critical maintains its own list of B.C. residents which was used to select respondents.

When selecting the survey participants or "pulling" the survey sample, Vision Critical:

1. Targeted the quota groups set in the survey;
2. Aimed to get as close to a representative sample[103] as possible; and
3. Used its research analysts to pull a sample that takes into account response rates and the number of completes required per subgroup. For example, from experience Vision Critical knows that young male respondents have a lower response rate than other demographic groups. The statistical software used to pull the sample takes this into account and draws an additional sample for this particular group.

104.3 How did Vision Critical weight the data? For example, Appendix E-5, pp.18-19 contains a sample profile showing weighted and unweighted sample numbers. On what basis were the weightings applied for gender, employment, education, and income?

Response:

The data was weighted to reflect the regional distribution of the FEU's customers (i.e. the data was reflective of the number of FEU natural gas customers in each one of its service territories). Age was also weighted to reflect Statistics Canada data from the 2006 census. The gender representation in the data was very close to the general population of BC. However, Vision Critical did not specifically weight for gender, employment, education or income. The FEU's primary concern was to generally evaluate and contrast the perceptions of the different regional populations.

The weight factors for age and region were calculated using the required percentage (based on the 2006 census data for age and the FEU's regional distribution) divided by the sample percentage (the actual distribution obtained). Results of this weighting procedure are shown below in **Error! Reference source not found.**.

[103] Refer to BCUC IR1 1.104.3 response for further information on how Vision Critical obtained a representative sample.

Table 1: Quantitative Survey Weighting Analysis

		*Sample Percentage	**Required Percentage	Weight	Unweighted Count	Weighted Count
AGE	18-34	8.97%	22.20%	2.47	85	***210***
	35-54	32.91%	42.40%	1.29	312	***402***
	55+	58.12%	35.40%	0.61	551	***336***
REGION	Lower Mainland	54.96%	62.21%	1.13	521	***590***
	Vancouver Island	21.41%	10.56%	0.49	203	***100***
	Interior	22.15%	27.00%	1.22	210	***256***
	Fort Nelson	1.48%	0.23%	0.16	14	***2***

* Sample percentages reflect the percentages obtained from the sample of 948 respondents

** Required percentages reflect the percentages obtained from the 2006 census data for age whereas the required percentages for region were provided by the FEU

104.4 Please file any engagement or contract letters or documents between the FEU and Vision Critical.

Response:

The FEU understand this question is requesting the contractual documents made between the company and Vision Critical. Attachment 104.4 contains a copy of the Letter of Engagement associated with this research project.

104.5 Please explain why customers were first asked if they support common rates in principle, rather than, for example, a principle of cost based rates (customers who cost more paying more than customers who cost less).

Response:

The decision to ask customers if they support common rates rather than cost based rates reflects specified research objectives. Our selected research partner, Vision Critical, was asked to identify the level of support for the common rates proposal on a regional basis. The quantitative study addresses this requirement. As both the existing rates and the proposed common rates are cost-based rates, asking customers whether they support a principle of cost based rates would not have shown whether customers supported common rates or not.

The Survey Questions, such as questions 6, 9 and 11,[104] address customer perceptions regarding existing rates and inferences can be drawn that adequately describe the relative levels of support for common rates versus the status quo.

[104] Please refer to the Common Rates survey questionnaire in response to BCUC IR 1. 104.1.

105.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 10.4.2.2, pp. 233-4; Appendix E-6

Qualitative Study: Focus Groups

"...three web-based bulletin board focus groups were held, encompassing residential customers from the Lower Mainland, Inland, Columbia and Vancouver Island service areas. Each focus group consisted of 12-15 FEU natural gas residential customers. Focus group participants were posed a series of questions over a 2.5 day period and were given the ability to answer questions, pose questions or comment on other responses from focus group members."

105.1 Please provide a copy of the questions that were posed to participants of the online bulletin board over the 2.5 day period.

Response:

Attachment 105.1 provides a copy of the questions posed to participants of the online bulletin board.

Online BB Discussion Group:

FortisBC Residential Customer Opinions & Common Rates Research

Client:	**FortisBC**
Field Dates:	Feb 20th – 22nd
Business Challenge/Big Q: [INTERNAL ONLY - NOT TO BE SHARED WITH PARTICIPANTS]	1) Understand residential customer perceptions and feelings toward general price changes as a benchmark. 2) Gather perceptions of FortisBC in general, and with regards to customer service, and product value for money. 3) Test key messaging statements amongst the target audience. • Understand which message(s) are most influential in moving residential customers to support the amalgamated rate. • What are the res. customers' key takeaways from the amalgamated rate explanation? • Are there any missing messages that FortisBC should consider?

Day 1, Topic 1 – Introductions and Expectations

1. **Hello and welcome to the online bulletin board discussion group!**
Thank you for participating in what we hope will be an interesting discussion.
This discussion is being hosted by Vision Critical; we're an independent market research firm. You'll be sharing your experiences and thoughts with our moderators Aisling & Catriona.
We're hosting this discussion regarding customer service expectations. Please note your personal details are kept confidential throughout this process and thereafter. Your comments from the discussion will be combined with all other feedback, ensuring your responses are kept anonymous and confidential. Please be candid.
Before we continue please make sure you've familiarized yourself with QualBoard 3.0. There is an introductory video to help you learn about the online discussion and how it works.

2. **How does the discussion in the bulletin board work?**
   - You'll answer one question at a time. Please provide rich and robust answers!
   - After you click OK to post your response, you'll see other participants' responses.
   - Please read what others have said and react to those posts you find interesting.
   - Feel free to agree or respectfully provide your alternative opinion.
   - This process is repeated for each question.
   - This is a great forum for sharing experiences, discussion and debate.

We hope you enjoy the process and engage in conversation with us and each other! So let's get

105.2 Please explain how residential customers were chosen to participate in the online bulletin board.

Response:

The process of recruiting/choosing residential customers involved the following steps:

- The FEU briefed Vision Critical and advised on the quotas required, e.g. all participants were to be residential customers who were the individual primarily responsible for paying the utility bills. Additionally, survey participants were required to have access to a reliable high-speed internet connection in order to participate. The research aimed to have a mix of ages, gender, and household incomes.
- Based on the same briefing, a "screener" was then designed and developed in conjunction with the FEU. A screener is a document of questions and instructions that aims to identify the appropriate participants for the research and ensures a representative mix of individuals is recruited.
- Vision Critical partnered with their preferred recruitment vendor, Consumer Vision, to carry out the recruitment phase. Consumer Vision contacted BC residents via telephone to identify the FEU's natural gas customers. If interested in participating, they were talked through the pre-agreed screening questions developed in consultation with the FEU.

- Customers that matched the outlined profile were then provided with the dates and times to participate in the online bulletin board discussion. A log-in for the survey was sent approximately 24 hours prior to the start of the online discussion.

106.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 10.5, p. 235

Feedback

"Feedback from the NRRC, VIGJV, BC Hydro and the broader stakeholder community has been considered and factored into this Application where appropriate."

106.1 Has feedback from the NRRM been considered and factored into the Application?

Response:

Yes, feedback from the NRRM has been considered and factored into this Application. As detailed in Section 10.3.1 of the Application[105], feedback from the NRRC, representing the NRRM, as well as representatives of the NRRM, such as the Mayor and Corporate Staff, was taken into consideration when determining the phase-in approach for Fort Nelson common rates. The FEU also obtained feedback from residents and businesses of Fort Nelson, as outlined in section 10.5 of the Application.

106.2 Did the FEU provide the responses to the Fort Nelson and District Chamber of Commerce letters contained in Appendix E-16 to the Chamber of Commerce?

Response:

Yes, the FEU have provided the responses in a letter dated 28 May 2012 provided in Attachment 106.2.

[105] Refer to page 226 of the Common Rates, Amalgamation and Rate Design Application for further information on the NRRM engagement.

107.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 10.5.5, p. 240-1

Website and Stakeholder Letter Feedback

"With regards to stakeholder letters, over 400 letters were sent out to various types of stakeholders across the Province, including MLAs, municipal Chambers of Commerce, First Nations groups, Mayors and municipal corporate staff (refer to Appendix E-8 for Stakeholder Letter Contact List). Less than 10 responses were received, and each respondent inquired about the impact that common rates would have on their specific municipality. In addition to rate impact inquiries, six letters of support have been received..."

107.1 Please file all versions of the letter that was sent to stakeholders.

Response:

Two versions of the letter were sent out to various stakeholders throughout the course of the FEU's stakeholder engagement – one in January 2012 and one in November 2011 based on the withdrawn application. Please refer to Appendix E-9 for the letter that was distributed in January 2012. Attachment 107.1 to this response provides the letter that was sent out to stakeholders in November of 2011 to initially provide information on common rates and amalgamation. Note that information from the November letter was based on the withdrawn November Application.

107.2 Please file the responses received other than the 6 letters of support contained in Appendix E-17.

Response:

Attachment 107.2 contains copies of the responses received.

Approximately ten responses/enquiries were received from stakeholders after the 400 stakeholder letters were sent out in January regarding the Common Rates, Amalgamation and Rate Design Application. In addition to the letters received this spring, enquiries and letters were received last winter regarding the initial Application filed in November, which has now been withdrawn. The following describes the responses received.

1. **Responses Received from January Stakeholder Letters:**

The following stakeholder letters and responses were received regarding the Common Rates, Amalgamation and Rate Design Application. Many of the communications simply acknowledged receipt of the FEU stakeholder letter, while others requested further information on rate impacts.

- **Duncan – Cowichan Chamber of Commerce:** Attachment 107.2(A) is an email correspondence with the Duncan – Cowichan Chamber of Commerce, including a request for a presentation to the Chamber which was scheduled, then cancelled by the Chamber due to scheduling challenges on their part. FEU are currently waiting on a rescheduled date from the Chamber to conduct the presentation.
- **District of Chetwynd:** Attachment 107.2(B) contains a letter from the District requesting information and the FEU's response, respectively.
- **Nicolas Simons, Powell River-Sunshine Coast MLA:** Attachment 107.2(C) is email correspondence with Mr. Simons regarding the location of information sessions.
- **Blair Lekstrom, Minister of Transportation and Infrastructure**: Attachment 107.2(D) is a message on behalf of Blair Lekstrom, Minister of Transportation and Infrastructure thanking the FEU for the invitation to an information session.
- **Graham Whitmarsh, Deputy Minister of Health:** Attachment 107.2(E) is a message on behalf of Graham Whitmarsh, Deputy Minister of Health thanking the FEU for the invitation to an information session.
- **City of Delta:** Attachment 107.2(F) is a letter from the City of Delta acknowledging receipt of FortisBC January 30 stakeholder letter.
- **Town of Qualicum:** Attachment 107.2(G) is a letter from the Town of Qualicum acknowledging receipt of the FortisBC January 30 stakeholder letter.
- **District of Salmon Arm:** Attachment 107.2(H) is an email from the District of Salmon Arm indicating interest in attending an information session.
- **Steve Thomson, Minister of Forests, Lands and Natural Resource Operations:** Attachment 107.2(I) is a message on behalf of Steve Thomson, Minister of Forests, Lands and Natural Resource Operations thanking the FEU for the invitation to an information session.
- **City of Vernon:** Attachment 107.2(J) is an email from the City of Vernon requesting a copy of the November stakeholder letter and the FortisBC response.

2. Responses Received from November Stakeholder Letters:

In addition to the letters received above, the following letters were received when the initial stakeholder letter was distributed in November 2011 after the FEU's submission of the withdrawn November Application. All stakeholders listed below also received the January stakeholder letter as included in Appendix E-9 of the Application and no further enquiries or responses were received apart from the Fort Nelson and District Chamber of Commerce Letters as included in Appendix E-15 of the Application.

- **City of Surrey:** Attachment 107.2(K) contains a copy of the letter from the City of Surrey requesting a presentation by FortisBC on the Application and the final presentation presented to the City of Surrey Council.
- **Village of Ashcroft:** Attachment 107.2(L) is an email requesting additional information and the FEU response.
- **District of Hudsons Hope:** Attachment 107.2(M) is the FEU's response to a voicemail message from the acting Mayor of the District of Hudson's Hope requesting additional information regarding the Application be sent by email.
- **District of Mackenzie:** Attachment 107.2(N) includes a letter from the District of Mackenzie requesting additional information and the FEU response.
- **District of Summerland:** Attachment 107.2(O) is a request from the District of Summerland for additional information and the FEU response.
- **District of West Vancouver:** Attachment 107.2(P) is a note indicating details of a telephone conversation with the District of West Vancouver.
- **Kelowna Chamber of Commerce:** Attachment 107.2(Q) is an email from the Chamber of Commerce with specific questions on the Application and the FEU response.
- **Fort Nelson and District Chamber of Commerce:** Attachment 107.2(R) is an inquiry about more detailed information and the FEU response.
- **City of Revelstoke:** Attachment 107.2(S) is the FEU's response to a voicemail from the City of Revelstoke requesting additional information.

3. <u>Responses Received Post Application Filing:</u>

- **<u>City of Langley:</u>** Attachment 107.2(T) is the FEU's response to a request from the City of Langley, received after filing of the Application, asking for copies of the two stakeholder letters.

108.0 Reference: Stakeholder Engagement

Exhibit B-3, Section 10, p. 223; Exhibit A2-1 p. 20; October 2007 Decision on BC Hydro's 2007 Rate Design Application Phase 1, pp. 57, 162

Consultation

"The Commission recognized that a financial benefit would accrue to the utility customers as a result of consolidation. While this saving is material, the canvassing of the full impact on all customers is more important. .. The Commission is also concerned that any future intentions of the Company towards rate unification be made known to all customers before the Commission is asked to endorse consolidation. For example, postage stamp rates could have significant policy consideration for all customers." (Exhibit A2-1, August 5, 1992 Decision on BC Gas Inc., p. 20)

"It is clear that Intervenors were not provided the opportunity to participate in meaningful dialogue as to the 'issues and proposals to be addressed in the F2008 RDA' but rather were informed as to what BC Hydro had decided was going to be brought forward, and given limited opportunity to comment on a narrow range of issues and options of a non-strategic nature…The Commission Panel is troubled that BC Hydro's Application and its submissions in support thereof are not informed by those views. Rather, as acknowledged by BC Hydro in its Argument, on its face the 2007 RDA is an application that could have been filed many years ago." (October 2007 Decision on BC Hydro's 2007 Rate Design Application Phase 1, p. 57)[106]

"In the Commission Panel's view the stakeholder engagement should start with the long view rather than vice versa." (October 2007 Decision on BC Hydro's 2007 Rate Design Application Phase 1, p. 162)

108.1 Do FEU consider that it provided stakeholders with the opportunity to participate in meaningful dialogue as to the issues and proposals to be addressed in the Application?

<u>Response:</u>

Yes, the FEU do consider that they provided stakeholders with the opportunity to participate in meaningful dialogue as to the issues and proposals to be addressed in the Application. Feedback was requested and obtained from stakeholders through a variety of channels such as:

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[106] http://www.bcuc.com/Documents/Decisions/2007/DOC_17029_10-26_BCHydro-Rate-Design-Phase-1-Decision.pdf

- Public information sessions held in nine communities across the Province;
- Market research canvassing the residential rate class;
- One-on-one meetings with key stakeholders and stakeholders that have taken an interest in the FEU's regulatory review processes in the past;
- Stakeholder letters to over 400 municipalities, First Nations groups, local government staff, and elected officials;
- Meetings with City Councils;
- Large Commercial and Industrial Customer Letters/Surveys; and
- The FEU's external website, common rates webpage.

Since the rate design portion of the Application was based on previously approved methodologies, the consultation focused primarily on common rates, implementation approaches and impacts to customers. All rate classes were consulted through one or more of the channels listed above. Dialogue from stakeholders was welcomed and stakeholders were given opportunities to comment on the common rates issue and implementation approaches.

108.2 Please explain the efforts made by FEU to target customers or customer groups who could represent specific regions (for example, regional school and heath districts, municipalities etc) to participate in its consultation.

Response:

The response to BCUC IR 1.108.1 outlines the efforts made by FEU to target customers or customer groups across the various service territories.

108.3 Please describe the key differences between FEU's November 1, 2011 Amalgamation and Rate Design Application (now withdrawn) and FEU's April 11, 2012 Common Rates, Amalgamation and Rate Design Application which resulted from consultation with stakeholders.

Response:

The key differences as a result of stakeholder consultation between the FEU's November 1, 2011 Amalgamation and Rate Design Application (now withdrawn) and the FEU's April 11, 2012 Common Rates, Amalgamation and Rate Design Application are as follows:

- FEI Mainland rates phased-in over a three year period using the RSDA;
- FEFN rates phased-in using the RSDA;
- Further information throughout the Application detailing why the proposal is being put forward at this time,[107] why there are three entities[108] and what the benefits of the proposal are;[109] and
- Extension of Customer Notification period from one month to three to six months if Amalgamation and Common Rates are approved.

Stakeholder feedback obtained from FEVI and FEW customers demonstrated support for common rates and the initial plan to phase-in FEVI and FEW rates immediately, therefore the approach taken within the April Application mirrors the initial approach proposed in November. In addition, consultation with key stakeholders, including Fort Nelson, was conducted prior to the November Filing, and as such the 15 year phase-in approach for Fort Nelson common rates does not differ, apart from use of the RSDA, between the applications.

[107] Refer to Section 2.3 of the Common Rates, Amalgamation and Rate Design Application for information on Timing of the Proposal.
[108] Refer to Section 3.1 of the Common Rates, Amalgamation and Rate Design Application for information on Corporate Structure.
[109] Refer to Sections 6.3, 6.4, 6.5 and 6.6 of the Common Rates, Amalgamation and Rate Design Application for information on benefits of the proposal.

109.0 Reference: Stakeholder Engagement

Exhibit B-3-1, Appendix E-3, Slide 4; Appendix E-6, p. 9; Appendix E-12, p. 6

Presented Benefits of Amalgamation and Common Rates

"Amalgamation also brings new service offerings…

1. Energy Efficiency and Conservation…
2. Renewable Natural Gas…
3. Natural Gas Vehicles…
4. Thermal energy Services…" (Appendix E-3)

"Impacts and benefits of common rates…we will also be able to expand service offerings and programs to all of our customers throughout the province." (Appendix E-6)

109.1 If the FEU have previously confirmed that these services offerings could be offered without amalgamation or common rates, could the FEU's presentation of benefits of common rates be seen as misleading to customers. If not, why not?

Response:

No. The FEU's presentation of the benefits of common rates is accurate. As discussed in Section 6.5 of the Application[110] and the response to BCUC IR 1.39.2, the service offerings mentioned could be offered without amalgamation or common rates. Section 6.5 of the Application states:

> *"Although expansion could be achieved through entity specific proposals and approvals, amalgamation and the adoption of common rates will facilitate and accelerate the process of extending Commission-approved service offerings to FEVI, FEW and Fort Nelson customers."*

The communications used by the FEU did not at any point state that amalgamation was the only means of receiving these services.

In addition, at the Public Information Sessions and meetings with key stakeholders, including Fort Nelson, customers who were interested in expanding services were informed that expanding these services to other areas was possible, although would require a separate regulatory process.

[110] FEU Common Rates, Amalgamation and Rate Design Application, page 116

110.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. D-1

General Terms and Conditions

The FEU have deleted the following "or the prorated daily equivalent charge – calculated on the basis of a 365.25- day year (to incorporate the leap year), and rounded down to four decimal places" and replaced with the phrase "during a prescribed period."

110.1 What is the intent of this change and why has it been made?

Response:

The deletion of the phrase "or the prorated daily equivalent charge – calculated on the basis of a 365.25- day year (to incorporate the leap year), and rounded down to four decimal places" was made in error. The Companies originally intended to add the phrase "during a prescribed period" at the end of the definition to make clear that the calculation for the Basic Charge will be done by using the number of billing days in a period and the daily Basic Charge value. However, on further review, the FEU determined that further clarification may be redundant and thus propose to maintain the definition of Basic Charge as it was approved in Commission Order G-2-11:

"Means a fixed charge required to be paid by a customer for service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge - calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places."

See Attachment 110.1, page D-1 of the black-lined version of the revised GT&Cs that reflects this definition. Also included in Attachment 110.1 are corrections to the proposed GT&Cs which were identified as a result of the responses to the series of BCUC IRs 1.115 and 1.117.

110.2 Please provide a definition for "during a prescribed period."

Response:

Please refer to the response to BCUC IR 1.110.1.

110.3 Where in the application does the FEU provide the rational and evidence is support of this GT&C change?

Response:

Please refer to the response to BCUC IR 1.110.1.

111.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. D-5

General Terms and Conditions

The FEU have deleted the following definition, "Service Area - Has the meaning set out at the end of the Definitions in these General Terms &Conditions."

111.1 Why have the FEU chosen not to include the definition of "area served" in the GT&C?

Response:

The "Areas Served by FortisBC Energy" after amalgamation are listed in the proposed General Terms and Conditions. Thus, a definition is not believed to be necessary.

112.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. D-5

General Terms and Conditions

The FEU have provided an alternative definition for Thermal Energy. The GT&C has been modified to provide the definition as "Means the delivery, storage, transport, sale or provision of an agent for the production of heat or cold."

The FEU have deleted the previous meaning "Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.

112.1 Please provide the reasons for this change and give the relevant background justifying the inclusion of a more general term for Thermal Energy.

Response:

Upon further consideration, the FEU have decided to withdraw the proposed definitional change of "thermal energy" from this Application due to the pending resolution of the AES Inquiry. Depending on the outcome of that proceeding, FEI may seek a change to the definition in a separate proceeding.

112.2 Is this change justified in light of recent decisions such as the Delta School District Decision in Order G-31-12?

Response:

Please refer to the response to BCUC IR 1.112.1.

112.3 Where in the current application has the FEU provided a justification for this change?

Response:

Please refer to the response to BCUC IR 1.112.1.

113.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. A-10-3 (formerly 10-3)

General Terms and Conditions Section 10

The FEU have inserted the following under section 10.8 of the GT&C "In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises."

113.1 Please indicate why this change was made, the implications of the change and the rationale provided for this addition?

Response:

The proposed section 10.8 addresses FEI Amalco's ownership with respect to the Service Lines. The addition of the phrase "In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises" is to be consistent with the definition of "Service Line."

In the definition section, "Service Line" is defined to mean "that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises." Thus, the addition is to clarify and stress FEI Amalco's ownership in the case of a Vertical Subdivision, but does not in any way modify or amend the meaning or scope of section 10.8.

This specific addition is not specifically discussed in the Application because it does not in any way modify or amend the meaning or scope of section 10.8. It is for clarification purposes.

113.2 Where in the application has the FEU provided a justification for this change?

Response:

Please refer to the response to BCUC IR 1.113.1.

113.3 What implications does this change in language have for Alternative Energy Extensions in relation to the own/operate model that the FEU intend to provide for district energy systems?

Response:

As explained in the response to BCUC IR 1.113.1, the addition of the quoted phrase is to be consistent with the definition of "Service Lines." The addition specifically addresses the situation of a Vertical Subdivision or a multi-family housing complex, and does not specifically address an Alternative Energy Extension or a district energy system, which is defined in section 12A.1 of the General Terms and Conditions.

113.4 Does the definition of Thermal Energy apply to Geo-exchange piping in the ownership of the service line?

Response:

Please refer to the response to BCUC IR 1.112.1.

114.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. A-10-3 (formerly 10-3)

General Terms and Conditions Section 10

The FEU have modified the Maintenance clause as subject to section 24.2 - Responsibility Before Delivery Point.

114.1 Why was this change made and where in the application has the justification for the change been described?

Response:

Section 10.9 of the General Terms and Conditions was amended as follows: "Maintenance - FortisBC Energy will maintain the Service Line, subject to section 24.2 (Responsibility Before Delivery Point)." The addition of the clause of "subject to 24.2 (responsibility before delivery point)" is to clarify the respective responsibilities of the customer and the utility before the delivery point. Without the added phrase, the two sections - 10.9 and 24.2 - may be viewed as inconsistent. This change was not specifically discussed in the Application as it is for clarification only and does not change how section 10.9 is applied.

For instance, in the case of a vertical subdivision, FortisBC Energy will remain responsible for maintaining the Service Line as that term is defined. To be clear and consistent with section 24.2, FEI Amalco's responsibility will be subject to the customer's responsibility specified in section 24.2, which states:

"The Customer is responsible for all expense, risk and liability with respect to

(a) the use or presence of Gas before it passes the Delivery Point in the Customer's Premises, and

(b) FortisBC Energy-owned facilities serving the Customer's Premises

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the Customer or a Person for whom the Customer is responsible."

114.2 In the instances where Fortis owns the piping in a vertical subdivision, or Geo Exchange system, how would this modification apply to those situations?

Response:

Please refer to the response to BCUC IR 1.114.1.

115.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. A-11-2 (formerly 11-2)

General Terms and Conditions Section 11

The FEU are proposing to recover incremental costs of changes to the Meter Set through monthly and/or daily charge.

115.1 Please explain why this modification to the GT&C is required and implications to the customers of each of the FEU service areas?

Response:

Currently, the FEU recover from their customers the incremental operating and maintenance costs relating to a customer's requested meter relocation and modification through a monthly charge. See section 11.8 of General Terms and Conditions of FEI, FEVI and FEW. The insertion of the word "daily" was made in error; thus, no change will be proposed to section 11.8(b) of the FEI Amalco General Terms and Conditions.

Please see Attachment 110.1, page A11-2 of the black-lined version of the revised GT&Cs.

115.2 How many customers would this modification affect and how would it be included in the daily charge for a specific customer?

Response:

Please refer to the response to BCUC IR 1.115.1.

115.3 How are the FEU currently recovering incremental costs under section 11.8 and how are those costs reflected in the current billing?

Response:

Please refer to the response to BCUC IR 1.115.1.

116.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. A-12A-1 (formerly 12A-1)

General Terms and Conditions Section 12A

116.1 Given the recent decisions in the CPCN for Delta SD 37 and the ongoing AES Inquiry what would be the implications to GT&C 12A should the FEU be required to conduct alternative energy mains extensions through a separate affiliate? How would the GT&C be modified?

Response:

The GT&C Section 12A of FEI describes how FEI should set rates for thermal energy customers. If FEI cannot provide thermal energy service then FEI's GT&C 12A should be removed from FEI's GT&Cs.

116.2 Where do the FEU account for gas taken for use in the provision of thermal energy where the customer is billed for thermal energy based on a contract under GT&C12A?

Response:

As per Order G-141-09, Appendix A, page 8:

> *"Natural Gas service taken in combination with AES will be charged under TGI's natural gas rates."*

There will be a natural gas meter at the site that measures the natural gas that the FEU consume in order to produce thermal energy. Accordingly, the FEU will be a natural gas customer and FEI will account for gas delivered through that meter as it does for any other customer. At these locations, FEU pays for natural gas at the prevailing rates set by the BCUC for the appropriate rate class and FEI accounts for those natural gas deliveries as part of the overall customer sales for that particular rate class. In addition, FEI currently delivers natural gas to thermal energy providers such as Dockside Green, River District, Central Heat and UniverCity. There will be no difference in the accounting of the natural gas sales to the FEU that provide thermal energy and require natural gas service from FEI than any other customer.

117.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. A-17A-1 (formerly 17-1)

General Terms and Conditions Section 17

The FEU have provided an alternative definition for Thermal Energy. The GT&C has been modified to provide the definition as "Means the delivery, storage, transport, sale or provision of an agent for the production of heat or cold."

117.1 Please describe how the change of the definition for Thermal Energy impacts the provisions in Section 17 of the GT&C?

Response:

Please refer to the response to BCUC IR 1.112.1.

117.2 Does Section 17 need to be modified given the proposed definition change?

Response:

Please refer to the response to BCUC IR 1.112.1.

118.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-4.17

Rate Schedules

118.1 Why were the column headers for each of the columns shown in the Table of Charges not updated to show the proposed service areas?

Response:

As stated in the Application, upon amalgamation, the FEU will replace the existing General Terms and Conditions ("GT&Cs") for each of the companies with a common set of GT&Cs for FEI Amalco. The common set of GT&Cs, similar to those of the current FEI service area, will harmonize tariff, rate design principles and rate classifications across all areas served by FEI Amalco. In preparation of responses to IRs relating to proposed tariff language and format changes and particularly the responses to questions regarding whether a separate column is needed to identify rate riders applicable to certain rate classes, the FEU undertook a further review and consideration of the GT&Cs and tariff schedules of FEI to determine whether further clarifications or changes are necessary to make the application of tariff provisions and schedules more consistent and less ambiguous upon amalgamation. Some of the proposed changes are further clarified or amended in the responses to BCUC IRs.

This response addresses the questions in the series of BCUC IR 1.118, 1.119, and 1.121 relating to the addition or omission of "column headers."

As proposed in the Application and shown in Appendix B-3, column headers indicating each service area – Mainland, Fort Nelson, and Vancouver Island and Whistler – are included in Rate Schedules 1, 2, and 3 because customers currently in Fort Nelson and Vancouver Island and Whistler service areas will be mapped into these rate schedules upon amalgamation.

Upon further review, the FEU have decide that similar column headers - Mainland Area/Fort Nelson Area/Vancouver Island & Whistler - for each of the columns shown in the Table of Charges should also be in Rate Schedules 4, 5, 6, 7, 22, 23, 25, 26, and 27. Thus, any omission of the column headers in the Table of Charges in the above mentioned rate schedules was done in error. The proposed change – adding column headers – is not applicable to the remainder of currently existing FEI rate schedules.

The insertion of proposed column headers is to make clear that customers in the current FEI service area will be entitled to a rate rider under these rate schedules to mitigate the rate impact upon amalgamation as discussed in Section 8.4.1.3 of the Application. That is, the additional column headers are in anticipation of customers in Vancouver Island, Whistler and Fort Nelson moving to these rate schedules upon amalgamation and for clarification that upon moving, customers in Vancouver Island and Whistler areas would not be subject to the FEI RSDA rider

(Rider 2), while the customers in Mainland would be. Additionally, the added column for Fort Nelson to reflect that phase-in rider (Rate 4) can be applicable to customers in that area.

Also upon further review, the FEU propose to clarify that in Rate Schedule 22 relating to Charge per Gigajoule of Balancing Service provided on page R-22.28, the charge is not applicable to the Columbia Area under the Mainland Area.

Please refer to Attachment 118.1 for the black-lined version of the amended tariff pages. Attachment 118.1 also contains the black-lined versions of the revised tariff pages relating to BCUC IRs 1.122.1 and 1.124.1.

118.2 Were the column headers purposefully deleted, if not, please update this page.

Response:

Please refer to the response to BCUC IR 1.118.1.

119.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-5.18

Rate Schedules

119.1 Why were the column headers for each of the columns shown in the Table of Charges not updated to show the proposed service areas?

Response:

Please refer to the response to BCUC IR 1.118.1.

119.2 Were the column headers purposefully deleted, if not, please update this page.

Response:

Please refer to the response to BCUC IR 1.118.1.

120.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-6.1 and p R-6P-1

Rate Schedules

The FEU have revised the conditions of service wording to read that Rate Schedule 6 is "available to eligible Customers" from the previous language of "in the territory."

120.1 What is the intent of this revision and why was it made?

Response:

As explained in Section 6.5 of the Application, amalgamation and the adoption of common rates will facilitate and accelerate the process of extending Commission-approved service offerings to FEVI, FEW and Fort Nelson customers. Currently, Rate Schedule 6 is applicable in FEI's service territory. A similar rate schedule also exists in FEVI. With the amalgamation, all customers served by FEI Amalco will be able to have access to this service offering. Thus, the FEU believe that the phrase "in the territory" is no longer necessary.

By using the phrase "eligible Customers," the FEU try to clarify that there are special conditions for receiving such service, such as that "FortisBC Energy has installed at the Delivery Point the facilities and equipment referred to in section 7.1 (Facilities and Equipment)." (See Rate Schedule 6, Clause 2.1(d).) In addition, the phrase "eligible customers" is intended to convey that the number of customers to receive the service may be limited in that the service is subject to adequate gas volumes for such service being available and adequate capacity existing in the system, as described in Rate Schedule 6, Clause 2.1(a) and (b).

120.2 What determines eligibility under Rate Schedule 6 and where is eligibility defined in the GT&C for this rate?

Response:

Please refer to the response to BCUC IR 1.120.1.

121.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-6.14 and p R-7.18 and p R-11B.15

Rate Schedules

121.1 Why were the column headers for each of the columns shown in the Table of Charges not updated to show the proposed service areas?

Response:

Please refer to the response to BCUC IR 1.118.1.

121.2 Were the column headers purposefully deleted, if not, please update this page.

Response:

Yes. Please refer to the response to BCUC IR 1.118.1.

122.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-6A.1 and p R-7.18

Rate Schedules

122.1 Why has the Basic Charge changed to a daily charge as opposed to a monthly charge previously included in this tariff?

Response:

The Basic Charge of Rate Schedule 6A was changed from a monthly charge to a daily charge to reflect the administration and invoicing of the Basic Charge from a monthly basis to a daily basis as approved by Commission Order No. G-2-11 (amended by G-140-11).

However, the Basic Charge in Rate Schedule 7 will continue to be invoiced on a monthly basis. Thus, the change was in error. Attachment 118.1 contains the corrected tariff pages for Rate Schedule 7.

122.2 Where in the application does the FEU discuss the reasons for this change or make application for this change?

Response:

Please refer to the response to BCUC IR 1.122.1.

122.3 If the FEU have not provided the reasons as noted above within the application; please provide and relevant information in support of this change.

Response:

Please refer to the response to BCUC IR 1.122.1.

123.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-14A.1 and p 14A.2

Rate Schedules

In Rate Schedule 14A the FEU have revised the definitions to include the communities within the Lower Mainland, Inland and Columbia service areas.

123.1 Why was this change made?

<u>Response:</u>

Rate Schedule 14A is applied in conjunction with the transportation Rate Schedules 22, 22a, 22b, 23, 25, and 27, for those Transportation customers who also purchase their commodity from FEI. The definitions of Rate Schedule 14A thus have been revised to include the communities within the Lower Mainland, Inland and Columbia service areas to maintain consistency with the Transportation Rate Schedules, since the group nomination and balancing conditions are the same.

The reason for the change is not specifically addressed in the Application.

123.2 Where in the application is this change discussed and what are the reasons for this change?

<u>Response:</u>

Please refer to the response to BCUC IR 1.123.1.

124.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-22A.11 and p. TA-22B.2 and p. R-23.30

Rate Schedules

124.1 Why has the Basic Charge changed to a daily charge as opposed to a monthly charge previously included in this tariff?

Response:

The Basic Charge for rate schedules 22A, 22B and 23 was changed from a monthly charge to a daily charge in error. Please see Attachment 118.1 for the corrected rate schedules.

124.2 Where in the application does the FEU discuss the reasons for this change or make application for this change?

Response:

Please refer to the response to BCUC IR 1.124.1.

124.3 If the FEU have not provided the reasons in the application; please provide and relevant information in support of this change.

Response:

Please refer to the response to BCUC IR 1.124.1.

125.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p.R-36.10

Rate Schedules

125.1 Why have the FEU changed the language in Section 5.08 and what are the reasons for this change?

Response:

The change in language in Section 5.08 of Rate Schedule 36, with respect to customers not renewing with Gas Marketers, was made in accordance with BCUC Order No. A-9-11, which discontinued the automatic renewals of gas marketer contracts.

On February 24, 2012, the FEI filed a revised Rate Schedule 36 to reflect the changes in question for Commission endorsement. Commission endorsement is currently pending.

125.2 Where in the application is this change discussed?

Response:

This change is not specifically discussed in the Application. Please refer to the response to BCUC IR 1.125.1.

126.0 Reference: COSA Methodology

Exhibit B-3, Section 3, pp. 35-50, Section 9, p. 210, 220

Revenue to Cost Ratios

126.1 Please provide the following updated COSA results:

i. Table 9-10 to show revenues assuming end state rates (i.e., assuming no transition period).

ii. Tables 3-3, 3-5, 3-8 and 3-10 to show the revenue: cost ratios where the cost and revenues of commodity and midstream are excluded from the COSA Model.

iii. Tables 3-3, 3-5, 3-8 and 3-10, to show the results of using postage stamp end-point rates (i.e. assuming postage stamp rates are approved without a phase in period) in the COSA Model, but maintaining forecast consumption data and regional costs.

iv. Tables 3-3, 3-5, 3-8 and 3-10 using the same assumptions above, but with total cost and revenues of commodity plus midstream excluded from the COSA Model.

Response:

i. Table 9-10 shows revenue to cost ratios assuming the end state rates of Rate schedules for the Amalgamated entity. The table below shows revenues associated with those revenue to cost ratios.

Please note that the transition period for FEI and FEFN is captured through the RSDA rate rider as mentioned in the Application. This means that Table 9-10 as filed in the Application shows revenues for the Amalgamated Entity assuming end state rates.

Rate Schedule	Revenue to Cost Ratio	Revenues (in $M)
Rate 1 – Residential	93.4%	$832.6
Rate 2 – Small Commercial (<2000 GJ/yr)	104.6%	$250.8
Rate 6 – Natural Gas Vehicle	112.7%	$0.5
Rate 3 & 23 Combined	107.9%	$233.7
Rate 5 & 25 Combined	110.4%	$109.8

ii. Below are Tables 3-3, 3-5, 3-8 and 3-10 revised to show revenue to cost ratios excluding revenues and costs associated with commodity and midstream.

Table 3-3: 2013 FEI COSA Model Revenue to Cost Ratios
(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
Rate 1 - Residential	85%
Rate 2 - Small Commercial	105%
Rate 6 - Natural Gas Vehicle	162%
Rate 3 & 23 - Combined	137%
Rate 5 & 25 - Combined	170%

Table 3-5: 2013 FEFN COSA Model Revenue to Cost Ratios
(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
Rate 1 - Residential	63%
Rate 2.1 - General Service 2.1	146%
Rate 2.2 - General Service 2.2	225%
Rate 25 - Firm Transportation Service	221%

Table 3-8: 2013 FEVI COSA Model Revenue to Cost Ratios
(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
RGS - Residential	74%
AGS - Apartment General Service	132%
SCS1 - Small Commercial 1	120%
SCS2 - Small Commercial 2	209%
LCS1 - Large Commercial Service 1	152%
LCS2 - Large Commercial Service 2	148%
LCS3 - Large Commercial Service 3	140%
High Load Factor	255%
Inverse Load Factor	641%

Table 3-10: 2013 FEW COSA Model Revenue to Cost Ratios
(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
Residential	69%
Commercial	121%
LGS1 - Large Commercial Service 1	124%
LGS2 - Large Commercial Service 2	193%
LGS3 - Large Commercial Service 3	122%

iii. Below are Tables 3-3, 3-5, 3-8 and 3-10 revised to show revenue to cost ratios by using postage stamp end-point rates but maintaining forecast consumption data and regional costs.

Table 3-3: 2013 FEI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	92%
Rate 2 - Small Commercial	103%
Rate 6 - Natural Gas Vehicle	124%
Rate 3 & 23 - Combined	117%
Rate 5 & 25 - Combined	147%

Table 3-5: 2013 FEFN COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Rate 1 - Residential	89%
Rate 2.1 - General Service 2.1	107%
Rate 2.2 - General Service 2.2	119%
Rate 25 - Firm Transportation Service	117%

Table 3-8: 2013 FEVI COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
RGS - Residential	90%
AGS - Apartment General Service	111%
SCS1 - Small Commercial 1	103%
SCS2 - Small Commercial 2	116%
LCS1 - Large Commercial Service 1	112%
LCS2 - Large Commercial Service 2	117%
LCS3 - Large Commercial Service 3	109%
High Load Factor	140%
Inverse Load Factor	163%

Table 3-10: 2013 FEW COSA Model Revenue to Cost Ratios

Rate Schedule	R:C Ratio
Residential	89%
Commercial	111%
LGS1 - Large Commercial Service 1	104%
LGS2 - Large Commercial Service 2	135%
LGS3 - Large Commercial Service 3	96%

iv. Below are Tables 3-3, 3-5, 3-8 and 3-10 revised to show revenue to cost ratios by using postage stamp end-point rates but maintaining forecast consumption data and regional costs and excluding commodity and midstream costs and revenues.

Table 3-3: 2013 FEI COSA Model Revenue to Cost Ratios

(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
Rate 1 - Residential	86%
Rate 2 - Small Commercial	107%
Rate 6 - Natural Gas Vehicle	162%
Rate 3 & 23 - Combined	140%
Rate 5 & 25 - Combined	174%

Table 3-5: 2013 FEFN COSA Model Revenue to Cost Ratios

(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
Rate 1 - Residential	80%
Rate 2.1 - General Service 2.1	121%
Rate 2.2 - General Service 2.2	181%
Rate 25 - Firm Transportation Service	177%

Table 3-8: 2013 FEVI COSA Model Revenue to Cost Ratios

(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
RGS - Residential	86%
AGS - Apartment General Service	124%
SCS1 - Small Commercial 1	105%
SCS2 - Small Commercial 2	134%
LCS1 - Large Commercial Service 1	125%
LCS2 - Large Commercial Service 2	140%
LCS3 - Large Commercial Service 3	121%
High Load Factor	257%
Inverse Load Factor	580%

Table 3-10: 2013 FEW COSA Model Revenue to Cost Ratios
(excluding commodity and midstream costs and revenues)

Rate Schedule	R:C Ratio
Residential	86%
Commercial	117%
LGS1 - Large Commercial Service 1	107%
LGS2 - Large Commercial Service 2	165%
LGS3 - Large Commercial Service 3	94%

126.2 Please provide the table shown below or a table similar to the above example or some other format that shows the COSA revenue: cost ratios results included in tables 3-3, 3-5, 3-8 and 3-10 of Section 3 of the Application as provided in Appendix H for the Legacy Methodology and the comparative revenue to cost ratios from the alternatives in Appendix I. This table is intended to consolidate the information provided for revenue: cost ratios in the accompanying appendices for Exhibit B-3-1.

	Revenue to Cost Ratios Appendix H and Appendix I						
Utility	**Rate Schedule**	**Legacy Methodology**	**Option C-1**	**Option D**	**Option E**	**Option F**	**FEI Amalco Proposed Rate Schedule**
FEI Mainland	Rate 1						
	Etc……..						
FEVI	RGS 1 Residential						
	Etc……..						

Response:

The FEU have consolidated in the table below the revenue to cost ratios from the Legacy Methodology presented in Appendix H with the Options revenue to cost ratios presented in Appendix I. The Companies regret that several of the revenue to cost ratios presented in Tables 3-3 and 3-8 of Section 3 of the Application contained typographic errors and did not match the revenue to cost ratios in Appendices H-5 and H-6 respectively.

FEI

	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Legacy Methodology	92.2%	103.2%	113.2%	116.1%	123.6%
Option C-1 Consolidate Mainland, FEVI and FEW only	93.5%	104.5%	107.7%	110.5%	112.9%
Option D Regional Midstream[1]	92.4%	105.1%	108.2%	111.8%	113.8%
Option E West Region	93.3%	103.0%	107.6%	110.7%	113.1%
Option E East Region	95.4%	106.0%	107.0%	108.9%	115.8%
Option F – Common Rates	93.4%	104.6%	107.9%	110.4%	112.7%

FEVI

	RGS	SCS-1	SCS-2	LCS-1	AGS[2]	LCS-2	LCS-3	HLF	ILF
Legacy Methodology	81.9%	112.1%	151.9%	123.9%	114.3%	120.1%	116.4%	139.0%	171.0%

Options	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	93.5%	104.5%	107.7%	n/a	n/a
Option D Regional Midstream	98.3%	97.4%	105.6%	n/a	n/a
Option E – Redefine Regions - West Region	93.3%	103.0%	107.6%	n/a	n/a
Option F – Common Rates	93.4%	104.6%	107.9%	n/a	n/a

FEW

	SGS Res	SGS Com	LGS 1	LGS 2	LGS 3
Legacy Methodology	75.9%	113.9%	115.2%	150.4%	114.3%

	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option C-1 Consolidate Mainland, FEVI and FEW only	93.5%	104.5%	107.7%	n/a	n/a
Option D Regional Midstream	92.1%	98.8%	114.9%	n/a	n/a
Option E – Redefine Regions - West Region	93.3%	103.0%	107.6%	n/a	n/a
Option F – Common Rates	93.4%	104.6%	107.9%	n/a	n/a

Fort Nelson

	Rate 1	Rate 2.1	Rate 2.2[3]	Rate 25
Legacy Methodology	80.8%	116.2%	128.9%	126.0%
Option C-1 Fort Nelson only	80.8%	116.2%	128.9%	126.0%

	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Option D Regional Midstream	90.4%	106.0%	117.2%	n/a	n/a
Option E – Redefine Regions - East Region	95.4%	106.0%	107.0%	n/a	n/a
Option F – Common	93.4%	104.6%	107.9%	n/a	n/a

1 Lower Mainland service area presented.
2 FEVI AGS customers fall into both RS2 and RS3
3 FEFN Rate 2.2 customers fall into both RS2 and RS3

126.3 Please calculate the rate rider which would be required for each customer class, for each utility, in order to align revenues with costs for the following scenarios:

i. Postage stamp rates (excluding commodity plus midstream revenues), regional costs (excluding commodity plus midstream costs), revenue: cost ratio range of reasonableness of +/- 5% (delivery only), rate rider used to rebalance back to 100 percent if outside of the range of reasonableness.

ii. Postage stamp rates (including commodity plus midstream revenues), regional costs (including commodity plus midstream costs), revenue: cost ratio range of reasonableness of +/- 10%, rate rider used to rebalance back to 100 percent if outside of the range of reasonableness.

Response:

i. Postage stamp rates (excluding commodity plus midstream revenues), regional costs (excluding commodity plus midstream costs), revenue: cost ratio range of reasonableness of +/- 5% (delivery only), rate rider used to rebalance back to 100 percent if outside of the range of reasonableness.

The tables below provide the R:C Ratios and rate riders as requested.

It should be noted that rebalancing R:C Ratios back to 100 percent for some rate schedules would also impact R:C Ratios for the ones who are already within the range of reasonableness. This is because rebalancing of revenues is a redistribution of revenues amongst different rate schedules. The total revenues do not change as a result of the rebalancing exercise. As requested, for the purposes of these scenarios, revenues for rate schedules whose R:C Ratios are already within the range of reasonableness as defined in part i. of this IR (i.e. +- 5% delivery only prior to rate rider calculation) are not rebalanced. The rate rider for these rate schedules is therefore shown as $0.00/GJ although in practice, to achieve the 100 percent R:C ratio for the rate schedules outside of the range, a rate rider would also be required for those within the range of reasonableness.

FEI: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
Rate 1 - Residential	92%	$0.000
Rate 2 - Small Commercial	103%	$0.000
Rate 6 - Natural Gas Vehicle	124%	($1.695)
Rate 3 & 23 - Combined	117%	($0.905)
Rate 5 & 25 - Combined	147%	($1.013)

FEVI: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
RGS - Residential	86%	$2.225
AGS - Apartment General Service	124%	($1.265)
SCS1 - Small Commercial 1	105%	$0.000
SCS2 - Small Commercial 2	134%	($2.021)
LCS1 - Large Commercial Service 1	125%	($1.386)
LCS2 - Large Commercial Service 2	140%	($1.855)
LCS3 - Large Commercial Service 3	121%	($0.977)
High Load Factor	257%	($3.411)
Inverse Load Factor	580%	($4.680)

FEW: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
Residential	86%	$2.548
Commercial	117%	($1.641)
LGS1 - Large Commercial Service 1	107%	($0.636)
LGS2 - Large Commercial Service 2	165%	($3.960)
LGS3 - Large Commercial Service 3	94%	$0.586

FEFN: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
Rate 1 - Residential	80%	$0.927
Rate 2.1 - General Service 2.1	121%	($0.476)
Rate 2.2 - General Service 2.2	181%	($1.023)
Rate 25 - Firm Transportation Service	117%	($0.883)

ii. **Postage stamp rates (including commodity plus midstream revenues), regional costs (including commodity plus midstream costs), revenue: cost ratio range of reasonableness of +/- 10%, rate rider used to rebalance back to 100 percent if outside of the range of reasonableness.**

The tables below provide the R:C Ratios and rate riders as requested. It should be noted that rebalancing R:C Ratios back to 100 percent for some rate schedules would also impact R:C Ratios for the ones who are already within the range of reasonableness. This is because rebalancing of revenues is a redistribution of revenues amongst different rate schedules. The total revenues do not change as a result of the rebalancing exercise.

As requested, for the purposes of these scenarios, revenues for rate schedules whose R:C Ratios are already within the range of reasonableness as defined in part ii. of this IR (i.e. +-10% delivery only prior to rate rider calculation) are not rebalanced. The rate rider for these rate schedules is therefore shown as $0.00/GJ although in practice, to achieve the 100 percent R:C ratio for the rate schedules outside of the range, a rate rider would also be required for those within the range of reasonableness.

FEI: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
Rate 1 - Residential	92%	$0.000
Rate 2 - Small Commercial	103%	$0.000
Rate 6 - Seasonal	124%	($1.695)
Rate 3 & 23 - Combined	117%	($0.905)
Rate 5 & 25 - Combined	147%	($1.013)

FEVI: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
RGS - Residential	90%	$0.000
AGS - Apartment General Service	111%	($1.265)
SCS1 - Small Commercial 1	103%	$0.000
SCS2 - Small Commercial 2	116%	($2.021)
LCS1 - Large Commercial Service 1	112%	($1.386)
LCS2 - Large Commercial Service 2	117%	($1.855)
LCS3 - Large Commercial Service 3	109%	$0.000
High Load Factor	140%	($3.411)
Inverse Load Factor	163%	($4.680)

FEW: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
Residential	89%	$2.554
Commercial	111%	($1.639)
LGS1 - Large Commercial Service 1	104%	$0.000
LGS2 - Large Commercial Service 2	135%	($3.962)
LGS3 - Large Commercial Service 3	96%	$0.000

FEFN: R:C Ratios and Rate Rider

Rate Schedule	R:C Ratio (prior to Rate Rider)	Rate Rider (in $/GJ)
Rate 1 - Residential	89%	$0.926
Rate 2.1 - General Service 2.1	107%	$0.000
Rate 2.2 - General Service 2.2	119%	($1.023)
Rate 25 - Firm Transportation Service	117%	($0.885)

126.4 Please explain why no demand related costs are assigned to interruptible customers in the COSA. In your response, please state if how FEU determines how much contribution these customers should make towards the utility demand related costs.

Response:

Interruptible customers are those customers who can be curtailed by the Company in the event that the demand for the firm customers exceeds the capacity to serve them. Since the interruptible customers are curtailable, these customers do not drive system capacity additions; therefore, no demand-related costs are allocated to these customer classes in the COSA. This approach and methodology is consistent with past practice and allocates a fair portion of costs to interruptible customers. Since no demand-related costs are allocated to these customers, the interruptible rate classes are excluded from the presentation of Revenue to Cost Ratios.

However, it is important to note that interruptible rates are not based on the allocated cost of service as shown for these customers in the COSA. Their rates are set as a discount from the firm rate to reflect the appropriate amount that the interruptible customers should pay for their service. That discount is calculated outside of the COSA process.

126.5 Please provide an estimate of the impact on revenue: cost ratios over time for each customer class if future rate increases were postage stamped between FEI and FEVI, but existing rate levels were not.

Response:

To show the impact on revenue to cost ratios over time for each customer class as requested above, the FEU have created the following table for illustrative purposes based on the following assumptions:

1. Starting revenues were based on the 2013 rates that are projected for FEI and FEVI without amalgamation.
2. Starting costs are based on the expected costs for 2013 with FEI and FEVI as separate entities but using the same COSA methodology.
3. Costs for both FEI and FEVI were increased by 2% per year for the 2013-2018 period to reflect inflationary pressures, with cost increases applied equally to all customer classes. An additional 20% increase was added to FEVI, to reflect the loss of government subsidies as discussed on page 74 of the application.
4. The costs were combined and the resulting rate increase required, when postage stamped between FEI and FEVI, was equal to 12.8%. The rates and resulting revenues for all classes for both FEI and FEVI were increased by 12.8% as shown in table.

5. To simplify, it was assumed that the number of customers and sales remained at 2013 levels.

6. The revenue to cost ratios on a combined basis are calculated for both year 2013 and 2018.

Please note that this table is a very basic illustration on what might be expected to occur. Actual results will depend upon future loads and future costs by account being run through an updated COSA study.

	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22	RATE 3/23	RATE 5/25	RATE 7/27
Total Revenues at Proposed 2013 FEI Rates									
FEI	$ 1,150,967	$ 728,642	$ 204,928	$ 1,052	$ 497	$ 11,910	$ 149,141	$ 46,314	$ 8,484
FEVI	$ 187,209	$ 91,921	$ 46,334	$ -	$ -	$ -	$ 48,955	$ -	$ -
Combined	$ 1,338,176	$ 820,563	$ 251,261	$ 1,052	$ 497	$ 11,910	$ 198,096	$ 46,314	$ 8,484
Total Utility Cost of Service for 2013									
FEI	$ 1,150,967	$ 781,680	$ 195,690	$ 789	$ 445	$ 812	$ 134,833	$ 35,456	$ 1,262
FEVI	$ 187,209	$ 95,412	$ 45,427	$ -	$ -	$ -	$ 48,955	$ -	$ -
Combined	$ 1,338,176	$ 877,091	$ 241,116	$ 789	$ 445	$ 812	$ 183,788	$ 35,456	$ 1,262
2013 Combined Revenue to Cost Ratio	**100.0%**	**93.6%**	**104.2%**		**111.6%**		**107.8%**	**130.6%**	
Total Estimated Revenues for 2018									
FEI	$ 1,298,267	$ 821,893	$ 231,154	$ 1,186	$ 561	$ 13,434	$ 168,228	$ 52,241	$ 9,569
FEVI	$ 211,168	$ 103,685	$ 52,263	$ -	$ -	$ -	$ 55,220	$ -	$ -
Combined	$ 1,509,436	$ 925,578	$ 283,418	$ 1,186	$ 561	$ 13,434	$ 223,448	$ 52,241	$ 9,569
Total Estimated Utility Cost of Service for 2018									
FEI	$ 1,266,064	$ 859,848	$ 215,259	$ 868	$ 490	$ 893	$ 148,316	$ 39,001	$ 1,388
FEVI	$ 243,372	$ 124,035	$ 59,054	$ -	$ -	$ -	$ 63,641	$ -	$ -
Combined	$ 1,509,436	$ 983,883	$ 274,313	$ 868	$ 490	$ 893	$ 211,958	$ 39,001	$ 1,388
Percent Increase Required	12.8%								
2018 Combined Revenue to Cost Ratio	**100.0%**	**94.1%**	**103.3%**		**114.4%**		**105.4%**	**133.9%**	
All numbers in $000's									

126.6 Please estimate the revenue: cost ratios (assuming postage stamp rates are not approved) for all customer classes of each utility (FEFN, FEW, FEI, FEVI) not on interruptible rates which FEU is not applying to postage stamp. Please provide this information for the delivery component only (removing commodity and midstream costs and revenues), and for the total rate (delivery plus commodity and midstream).

Response:

Please refer to the response to BCUC IR 1.126.1 (ii) which shows revenue to cost ratios for customer classes of each utility excluding commodity and midstream costs and revenues.

Tables 3-3, 3-5, 3-8 and 3-10 in section 3 of the Application show revenue to cost ratios for all customer classes of each utility for the total rate (delivery plus commodity and midstream). Please refer to the response to BCUC IR 1.76.1 that shows updated Tables 3-3 and 3-8.

127.0 Reference: COSA Methodology

Exhibit B-3-1, Appendices I-4 and J-2

FEI Amalco COSA Model with Amendments

127.1 Several IR's have identified aspects of the FEI Amalco COSA that Commission Staff desire to be incorporated into a new version. Please incorporate the following amendments into the COSA and produce a set of financial schedules similar to those in Appendix J-2 (FEI Amalco COSA) and Appendix I-4 (Option D Regional Midstream COSA Model). Present revenue to cost ratios that (i) include and (ii) exclude gas and midstream costs.

i. As discussed in BCUC IR 134, please amend the Minimum System methodology to conform to the approach outlined in Exhibit A-20, NARUC Electric Utility Cost Allocation Manual (January 1992), p. 91 which is: (1) determine the average installed cost per length of the minimum size conductor currently being installed, and then (2) multiply the average cost per length by the total length of conductor installed to determine the customer component. Assume a minimum system based on a 2 inch diameter plastic main.

ii. Allocate appropriate costs to the closed rate industrial, special contract and bypass customers and present the revenue to cost ratios for these customer classes.

iii. Classify all of the costs related to the Mt. Hayes LNG storage facility as energy-related.

iv. Please update the COSA's to reflect the appropriate functionalization and classification of the rate base related to the purification of biogas.

v. Please update the COSA's to also reflect the appropriate allocation of the costs related to the Tilbury LNG storage facility to Rate 16 customers.

<u>Response:</u>

Please refer to the Attachment 127.1 that shows the financial schedules for the amended COSA as requested.

i. Minimum System methodology has been updated. Please refer to the response to BCUC IR 1.135.11 for further information on updated Minimum System Results.

ii. For the purposes of this amendment, FEU have treated special contracts, bypass customers and closed rate industrials Rate 22A and Rate22B as a group and shown revenue to cost ratio for the whole group. However, the FEU believe that the COSA model as proposed in the Application reflects the most appropriate treatment of these customers under the Amalgamated scenario. Please refer to the responses to BCUC IRs 1.126.4 and 1.137 series.

iii. For the purposes of this amendment, FEU have classified all costs related to the Mt. Hayes storage facility as energy-related and allocated those costs based on volumes. However, FEU believes that the COSA as filed in the application reflects the appropriate way to classify costs related to Mt. Hayes as demand related. Please refer to the response to BCUC IR 1.54.10.

iv. The COSA as filed in the Application reflects the appropriate functionalization and classification of the rate base related to the purification of biogas. Therefore, no amendment has been made in the schedules attached. Please refer to the responses to BCUC IR 1.133.1 and 1.133.2.

v. The COSA as filed in the Application reflects the appropriate allocation of costs related to the Tilbury LNG storage facility to Rate 16 customers. Please refer to the response to BCUC IR 1.138.1. Therefore, no amendment has been made in the schedules attached.

128.0 Reference: Two Region COSA Model Using Consolidated Methodology

Exhibit B-3-1, Appendix D-1, p. 25

Allocation of Midstream Costs

The cost of gas and midstream costs were also based on the consolidated results without a regional differentiation and were added to the margin to get the total cost of service by region.

128.1 Please run the Two Region COSA using regional midstream rates.

Response:

The Two-Region COSA schedules are included in Attachment 128.1 with regional midstream costs. These COSA schedules show very little difference to the total cost of service by region.

129.0 Reference: Consolidated COSA Model Excluding Fort Nelson

Exhibit B-3-1, Appendix D-1, p. 26

Midstream Costs

The results for this approach were based on the FEU consolidated COSA, with the costs for Fort Nelson, based on the Individual FEFN COSA using the consolidated methodology, deducted from each rate class.

129.1 If applicable, please run the Consolidated COSA Model Excluding Fort Nelson using regional midstream rates for Fort Nelson and postage stamp midstream rates elsewhere.

Response:

Please refer to Appendix D-1, page 26, of the Application. The Consolidated COSA Model excluding Fort Nelson, as described on page 26 of Appendix D-1 provides the requested midstream rates. No midstream rates were included for Fort Nelson under this alternative.

130.0 Reference: COSA Methodology

Exhibit B-3-1, Appendix D-1, p. 17

Functionalization and Classification of Late Payment Fees

The following statement on p. 17 of the EES Cost of Service Review report appears to contradict the model: "Revenues collected from late payment fees are functionalized to the marketing function and classified as "Demand-Related."

The COSA Model (Tab "Classification_TGI Rate Classes," Line 3554) functionalizes these costs to "Customer Accounting" and classifies them as "Customer-Related."

130.1 Please confirm that revenues collected from late payment fees should, in fact, be functionalized to "Customer Accounting" and classified as "Customer-Related." If not, then please explain why.

Response:

Confirmed, the revenues collected from the late payment fees, as shown in the COSA, should be functionalized to "Customer Accounting" and classified as "Customer-Related". The EES report mischaracterizes the classification of revenues collected from late payment fees.

131.0 Reference: COSA Methodology

Exhibit B-3-1, Appendix D-1, p. 12

Functionalization of General Plant and Administrative and General Expenses

"General plant accounts are functionalized across all 8 functions on the basis of the gross plant in service prior to intangible and general plant. Administrative and general (A&G) expenses are functionalized on the basis of all gross plant in service. This approach is consistent with standard practice in the industry."

131.1 Please confirm whether the method used to functionalize gross plant in service and the administrative and general expenses is consistent with the method used in the 2001COSA.

Response:

Confirmed. The COSA methodology used to functionalize gross plant in service and the administrative and general expenses for the Amalgamated Entity is consistent with the 2001 COSA methodology used for FEI.

132.0 Reference: COSA Methodology

Exhibit B-3-1, Appendix D-1

Direct Assignments

132.1 Please identify all costs that have been directly assigned to customer classes.

<u>Response:</u>

There are no costs that have been directly assigned to customer classes in the COSA study filed with the Application.

133.0 Reference: COSA Methodology

Exhibit B-3-1, Appendix D-1, p. 13

Exhibit B-4, COSA Model

Functionalization of Ratebase Related to the Purification of Biogas

"The FEU have a limited amount of rate base for gas supply, all related to purification of biogas. This amount has been classified as energy-related, consistent with all other gas supply accounts. This is appropriate because the facilities are used to allow upgraded biogas to be injected in the system as part of the gas supply, and the costs apply only to the core customers that purchase gas from the FEU."

Commission Staff has reviewed the Cost of Service Allocation Model and determined that the rate base related to the purification of biogas appears to have been functionalized to distribution and classified as demand-related.

133.1 Please provide an explanation of this apparent discrepancy between what EES has described as the functionalization and classification of rate base items related to biogas, and what has been implemented in the COSA model.

Response:

The EES Report refers specifically to purification of biogas. The intent was to treat this account as gas supply; however, the account was set to zero as explained in the response to BCUC IR 1.133.2 and, therefore, there was no corresponding rate base included in the gas supply function. The other biogas accounts are included in the Distribution function, classified as demand-related and are allocated on the basis of peak demand.

133.2 How should the rate base related to the purification of biogas be functionalized and classified? Please provide a justification.

Response:

The rate base and cost of service associated with the Purification Plant is charged to the Biomethane Variance Account (Non-Rate Base Deferral account) and is recovered through the Biomethane Energy Recovery Charge (BERC rate) from customers who have enrolled in the Biomethane service. Since the Amalgamated COSA model does not include these customer classes, the Purification plant cost is not included in the COSA model and the corresponding depreciation provision is also netted to zero cost as well (refer to excel rows 684 and 734 on tab 'Function_TGI' of the COSA model).

This treatment is consistent with the BCUC Order No. G-194-10, attached to the Commission Decision dated December 14, 2010, pages 48-51, wherein the Commission has determined that this approach to allocate costs related to the purification of biogas is appropriate.

If the costs were not treated in this manner and were included in the cost of service, the rate base and cost of service associated with purification of biogas should be functionalized to gas supply and classified as energy-related as these facilities, based on cost causation, are used to inject biogas in the system as a part of gas supply.

Please also refer to the response to BCUC IR 1.127.1.

134.0 Reference: COSA Methodology

Exhibit B-3-1, Appendix D-1, pp. 13-14; Exhibit A-2-20, NARUC Electric Utility Cost Allocation Manual (January 1992), p. 92

Classification of Distribution Rate Base

"Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system."

The NARUC Electric Utility Cost Allocation Manual (January 1992) describes two methods used to determine the demand and customer components of distribution facilities as the minimum system approach, and the zero-intercept cost approach. The zero-intercept method uses statistical regression of cost and capacity information to identify that portion of the distribution plant related to a hypothetical no-load situation. The cost related to the zero-intercept is classified as customer-related.

134.1 Why did the FEU not consider the zero-intercept approach to classifying distribution facility costs?

Response:

The FEU did consider the zero-intercept approach. However, the data did not provide results that showed a clear correlation between size of pipe and per unit cost. Therefore, the zero-intercept value could not be calculated. It is common for the zero-intercept calculations to provide inconclusive or irrational results.

The EES report in Appendix D-1 does not discuss zero-intercept as a separate method as it is really a subset of the minimum system approach. Theoretically, the zero intercept value reflects the absolute minimum system that could be built, even though a "zero-sized" pipe is not technically feasible.

EES supports the theory behind the zero-intercept method. Because it was not a practical approach to use for the FEU at this time, EES recommended that the PLCC method be used in conjunction with the minimum system approach. Both the zero-intercept and PLCC methods are designed to reflect the fact that the minimum system pipe is capable of carrying some amount of demand.

134.2 What is the customer/demand classification of the distribution plant of the amalgamated utility using the zero-intercept method?

Response:

Please refer to the response to BCUC IR 1.134.1.

135.0 Reference: COSA Methodology

Exhibit B-3, Section 9.6.2.4, p. 206; Exhibit B-3-1, Appendix D-3, Tables 1 - 3, pp. 1-3

Exhibit A-2-20, NARUC Electric Utility Cost Allocation Manual (January 1992), p. 91

Exhibit A-2-14, Enbridge Gas New Brunswick 2010 Cost of Service and Rate Design Application, Expert Testimony of Dr. H. Edwin Overcast, p. 13

Minimum System and Peak Load Carrying Capability Studies

"As described in section 9.6.2.4 of the Application (*Classification of Functionalized Costs*), the Minimum System Study assumes that a certain level of plant investment is required to serve the minimum loading requirements of customers throughout the service territory. The FEU have grouped pipe sizes 2" and smaller together to represent the minimum distribution system associated with customers and treats all costs for this group as customer-related costs. The mains larger than 2", which comprise the remainder of the distribution system, serve customer demands for delivery of an amount greater than the minimum loading requirements and costs associated with this portion of the distribution system are regarded as demand-related." (Appendix D-3, p. 1)

Exhibit B-3-1, Appendix D-3, Table 1 shows the derivation of the customer and demand related components from data on the diameter, lengths and unit costs of mains. It appears from the table, that the customer component of the distribution plant is based on pipe sizes having diameters 2.4 inches or less.

135.1 Please explain whether the derivation of the classification factors as described by Table 1 is consistent with the narrative of section 9.6.2.4.

<u>Response:</u>

The derivation of classification factors is consistent with the narrative of Section 9.6.2.4. Table 1 of Appendix D-3 references the outside pipe diameter, instead of the inside pipe diameter, and as such an outside pipe diameter of 2.4 inches corresponds with an inside pipe diameter of 2 inches.

135.2 Referring to Appendix D-3, Table 2, why is there no difference in unit cost per length for steel mains that vary in diameter between 0.6 inches and 2.4 inches?

Response:

Please refer to the response to BCUC IR 1.135.4.

135.3 Referring to Appendix D-3, Table 3, why is there no difference in unit cost per length for plastic mains that vary in diameter between 0.6 inches and 2.4 inches?

Response:

Please refer to the response to BCUC IR 1. 135.4.

135.4 Do the material costs for steel and plastic pipe not vary directly with their diameter? Should Tables 2 and 3 not reflect this dependency by showing a continuously varying unit cost per length amount?

Response:

The unit costs per length listed in Tables 2 and 3 do not solely represent the material costs for steel and plastic pipe. The costs represent the installed unit costs per length and therefore include major costs for labour and installation, in addition to the cost of the pipe. The installed unit costs per length are based on mains Geo code $/metre values and as the Geo code values are segregated into distinct diameter groupings, the costs for steel and plastic pipe do not vary directly with their diameter.

For steel and plastic mains, the following three geo code diameter groupings were used: mains up to 60 mm (2.4 inch outside pipe diameter); 88 mm to 114 mm (3.5 to 4.5 inch outside pipe diameter); and 168 mm (6.6 inch outside pipe diameter). Unit costs for steel pipe diameters larger than 168 mm were based on estimates for recent installations of those diameter steel pipes.

For the Amalgamated Minimum System Study, the Geo code prices were weighted based on number of mains installed by operating zone. Refer to the tables below for steel and plastic geo code prices by grouping.

Weighted Geo Pricing
Table - STEEL

			Geo Price ($/m)			Weighted Total Unit Cost		
Service Order - Zone	Zone	Weighted %	M1 (Up to 60mm)	M2 (88 - 114mm)	M3 (168mm)	M1 (Up to 60mm)	M2 (88 - 114mm)	M3 (168mm)
Vancouver/Richmond	1A	2.72%	$207.50	$352.75	$566.48	$5.64	$9.59	$15.40
North & West Vancouver/Squamish	1B	2.78%	$137.50	$233.75	$375.38	$3.82	$6.50	$10.44
Burnaby, New Westminster & Tri-Cities	2	6.88%	$140.00	$238.00	$382.20	$9.63	$16.37	$26.29
Fraser Valley	3	24.40%	$117.50	$199.75	$320.78	$28.67	$48.74	$78.28
Northern Region	4	6.94%	$87.50	$148.75	$238.88	$6.07	$10.32	$16.58
Okanagan & Kootenay Region	5	21.25%	$65.00	$110.50	$177.45	$13.81	$23.48	$37.71
TGVI North Island	6A	22.14%	$125.00	$212.50	$341.25	$27.67	$47.04	$75.54
TGVI Capital Region	6B	12.17%	$125.00	$212.50	$341.25	$15.21	$25.86	$41.53
TGW Whistler	6C	0.72%	$170.00	$289.00	$464.10	$1.23	$2.08	$3.35
					Total:	$111.76	$190.00	$305.11

Weighted Geo Pricing
Table - PE

			Geo Price ($/m)			Weighted Total Unit Cost		
Service Order - Zone	Zone	Weighted %	M1 (Up to 60mm)	M2 (88 - 114mm)	M3 (168mm)	M1 (Up to 60mm)	M2 (88 - 114mm)	M3 (168mm)
Vancouver/Richmond	1A	2.72%	$83.00	$141.10	$226.59	$2.26	$3.84	$6.16
North & West Vancouver/Squamish	1B	2.78%	$55.00	$93.50	$15.15	$1.53	$2.60	$0.42
Burnaby, New Westminster & Tri-Cities	2	6.88%	$56.00	$95.20	$152.88	$3.85	$6.55	$10.52
Fraser Valley	3	24.40%	$47.00	$79.90	$128.31	$11.47	$19.50	$31.31
Northern Region	4	6.94%	$35.00	$59.50	$95.55	$2.43	$4.13	$6.63
Okanagan & Kootenay Region	5	21.25%	$26.00	$44.20	$70.98	$5.53	$9.39	$15.08
TGVI North Island	6A	22.14%	$50.00	$85.00	$136.50	$11.07	$18.82	$30.22
TGVI Capital Region	6B	12.17%	$50.00	$85.00	$136.50	$6.09	$10.34	$16.61
TGW Whistler	6C	0.72%	$68.00	$115.60	$185.64	$0.49	$0.83	$1.34
					Total:	$44.70	$76.00	$118.29

135.5 Referring to Appendix D-1, Table 1, please confirm that the unit cost per length amounts are determined from the corresponding unit costs per length from Tables 2 and 3 and weighted by the relative lengths of installed steel and plastic mains.

Response:

Confirmed.

"To determine how costs should be split between demand and customer related components, the costs of the minimum system must be compared to the costs of the overall distribution system. To do so, the Minimum System Study assumes that the actual pipe diameters could be replaced with only those pipe diameters that comprise the minimum distribution system (i.e., <u>all pipe diameters equal to or less than 2</u>"). This approach multiplies the unit cost for each size of main by the length and then the cost of mains up to and including 2" is divided by the total cost." (Section 9.6.2.4, p. 206) [Emphasis added]

NARUC in their Electric Utility Cost Allocation Manual, January 1992 describes the minimum system approach on page 91 as: (1) determine the average installed cost per length of the minimum size conductor currently being installed, and then (2) multiply the average cost per length by the total length of conductor installed to determine the customer component.

This approach has been adopted by the gas industry, for example by Enbridge Gas New Brunswick in their 2010 Cost of Service and Rate Design Application (Expert Testimony of Dr. H. Edwin Overcast, p. 13: *The minimum system method calculates <u>the cost of all mains on the system at the cost of the smallest size main installed by the utility. This is usually 2 inch plastic main</u>. These costs are compared to the actual cost of all main (in the same year dollars) to produce a percentage of main costs to be classified as customer related.)* [Emphasis added]

135.6 State whether the approach used by the FEU are consistent with the industry recommended approach (for example as described in NARUC, Electric Utility Cost Allocation Manual, January 1992 and applied to gas distribution utilities).

<u>Response:</u>

The following response addresses BCUC IR questions 1.135.6, 1.135.7, 1.135.8 and 1.135.9.

The NARUC manual is appropriate as a tool to guide the cost allocation process and provides a number of classification approaches. The FEU's approach is consistent with the theoretical definition of a minimum size system.

The NARUC Gas Distribution Rate Design Manual (June 1989) states on page 22 that:

"A portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial. One argument for inclusion of distribution related items in the customer cost classification is the "zero or minimum size main theory." This theory assumes that there is a zero or

minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires.

Under the minimum size main theory, all distribution mains are priced out as the historic unit cost of the smallest main installed in the system, and assigned as customer costs."

In the past, the FEU's calculations of the Minimum System classification split reflected their interpretation of a Minimum Size System. This interpretation is consistent with the description of a Minimum Size System used by NARUC and others in the industry.

To maintain consistency with past practice, the calculations included in this Application reflect the same interpretation on how to calculate the minimum system split as included in the 1993, 1996 and 2001 COSA studies reviewed by the Commission. In order to be consistent with past practice, the FEU chose to update the values used in the analysis but not update how the minimum system split was calculated.

In addition to its 1993, 1996 and 2001 COSA calculation method, the FEU determined the minimum system split using the same calculations as described in the Enbridge Gas New Brunswick case; however, they were used for comparison purposes only. This approach is presented in the response to BCUC IR 1.135.11.

The FEU have not performed a review of classification methods used by other natural gas distribution utilities in Canada because the FEU have not proposed any change to the previously reviewed method. While the calculations described in the Enbridge Gas New Brunswick case are the more commonly used calculations, the FEU's method is consistent with the industry practice of using a minimum size system approach and has been the consistent practice applied by the FEU for approximately 20 years.

135.7 Which natural gas distribution utilities in Canada use the approach used by the FEU in developing the classification factors for distribution plant?

Response:

Please refer to the response to BCUC IR 1.135.6.

135.8 Which natural gas distribution utilities in Canada use the minimum system approach as described in Enbridge's testimony?

Response:

Please refer to the response to BCUC IR 1.135.6.

135.9 Do the FEU agree that the industry standard approach when using the Minimum System method is to base the cost of all mains on the system assuming that the entire system is comprised of 2 inch plastic mains?

Response:

Please refer to the response to BCUC IR 1.135.6.

135.10 Do the FEU agree that the approach used in the COSA is incompatible with the assumptions used in calculating the Peak Load Carrying Capacity (PLCC) adjustment?

Response:

No, the FEU believe that the Minimum System approach used in the COSA is compatible with the assumptions used in calculating the PLCC adjustment. Both the Minimum System Study and the PLCC are intended to reflect a 2" minimum sized system and therefore are consistent with one another. Please also refer to the response to BCUC IR 1.135.6.

135.11 Provide the classification factors for the distribution plant under the amalgamation proposed using the industry recommended approach described in the preamble, above. In other words, assume that the minimum size system is comprised solely of 2 inch diameter plastic pipe.

Response:

Assuming a minimum size system solely comprised of 2" diameter plastic pipe, the following classification factors are determined for customer related (38.5%) and demand related (61.5%) components. Please note that the 2" unit cost per length is based on the 2" weighted unit cost per length for all regions.

COMBINED STEEL & PLASTIC MAINS BASED ON 2" DIAMETER PLASTIC PIPE MINIMUM SIZE

Line No.	Diameter Inches	Diameter mm	Length in Meters	Dia. (mm) x Length (m)	Minimum Size Unit Cost / Length ($/m)	Total Cost	Minimum Size Cost
1	0.6	15	61,973	929,595	$ 44.70	$ 2,819,583	$ 2,770,497
2	0.8	21	20,082	421,722	$ 44.70	$ 2,241,191	$ 897,764
3	1.0	26	1,067,504	27,755,104	$ 44.70	$ 112,880,546	$ 47,722,661
4	1.3	33	18,813	620,829	$ 44.70	$ 2,101,041	$ 841,033
5	1.7	42	7,136,363	299,727,225	$ 44.70	$ 456,795,149	$ 319,030,380
6	1.9	48	59,239	2,843,472	$ 44.70	$ 5,612,678	$ 2,648,274
7	2.4	60	8,733,963	524,037,752	$ 44.70	$ 711,009,421	$ 390,450,932
8	2.9	73	641	46,793	$ 44.70	$ 121,103	$ 28,656
9	3.5	88	1,612,303	141,882,628	$ 44.70	$ 192,561,420	$ 72,077,828
10	4.0	101	892	90,092	$ 44.70	$ 169,476	$ 39,877
11	4.5	114	2,623,589	299,089,146	$ 44.70	$ 389,365,560	$ 117,287,287
12	6.6	168	1,163,274	195,430,029	$ 44.70	$ 275,515,506	$ 52,004,048
13	8.6	219	287,357	62,931,124	$ 44.70	$ 171,757,716	$ 12,846,254
14	10.7	273	49,131	13,412,763	$ 44.70	$ 49,128,355	$ 2,196,396
15	12.7	323	123,760	39,974,480	$ 44.70	$ 123,760,000	$ 5,532,679
16	16.0	406	33,406	13,562,836	$ 44.70	$ 53,449,600	$ 1,493,412
17	18.0	457	1,941	887,037	$ 44.70	$ 3,202,650	$ 86,772
18	20.0	508	57,529	29,224,732	$ 44.70	$ 97,799,300	$ 2,571,828
19	24.0	609	1,459	888,531	$ 44.70	$ 2,626,200	$ 65,224
20	30.0	762	11,699	8,914,638	$ 44.70	$ 23,398,000	$ 523,003
TOTAL			**23,064,916**	**1,662,670,528**		**$ 2,676,314,494**	**$ 1,031,114,805**

Customer Related Component	**38.53%**
Demand Related Component	**61.47%**

135.12 Assuming a minimum system comprised solely of 2 inch diameter plastic pipe, calculate the classification factors for each stand alone utility (i.e. FEI Mainland, FEW, FEVI, FEFN).

Response:

The following table summarizes the customer related and demand related classification factors for each region (FEI Mainland, FEW, FEVI and FEFN) assuming a minimum system comprised solely of 2 inch diameter plastic pipe.

Breakdown by Service Area	FEI Mainland	FEVI	FEW	FEFN
Customer Related Component	35.6%	60.9%	42.5%	53.3%
Demand Related Component	64.4%	39.1%	57.5%	46.7%

For further information specific to each region, please refer to tables below.

FEI MAINLAND

FEI COMBINED STEEL & PLASTIC MAINS BASED ON 2" DIAMETER PLASTIC PIPE MINIMUM SIZE

Line No.	Diameter Inches	Diameter mm	Length in KMS	Length in Meters	Dia. (mm) x Length (m)	Minimum Size Unit Cost / Length ($/m)	Total Cost	Minimum Size Cost
1	0.6	15	16.0260	16,026	240,390	$ 41.65	$ 706,724	$ 667,489
2	0.8	21	20.0780	20,078	421,638	$ 41.65	$ 2,087,643	$ 836,257
3	1.0	26	1,013.3860	1,013,386	26,348,036	$ 41.65	$ 102,853,800	$ 42,207,928
4	1.3	33	18.8120	18,812	620,796	$ 41.65	$ 1,957,444	$ 783,527
5	1.7	42	5,740.2195	5,740,220	241,089,219	$ 41.65	$ 366,799,962	$ 239,082,416
6	1.9	48	39.8680	39,868	1,913,664	$ 41.65	$ 4,149,046	$ 1,660,518
7	2.4	60	7,642.7565	7,642,757	458,565,392	$ 41.65	$ 608,473,685	$ 318,323,838
8	2.9	73	0.6410	641	46,793	$ 41.65	$ 66,545	$ 26,698
9	3.5	88	1,137.5346	1,137,535	100,103,044	$ 41.65	$ 142,758,930	$ 47,378,766
10	4.0	101	0.8920	892	90,092	$ 41.65	$ 157,897	$ 37,152
11	4.5	114	2,209.6950	2,209,695	251,905,230	$ 41.65	$ 321,806,157	$ 92,034,672
12	6.6	168	996.8930	996,893	167,478,021	$ 41.65	$ 228,567,216	$ 41,520,988
13	8.6	219	250.6137	250,614	54,884,404	$ 41.65	$ 141,876,501	$ 8,441,732
14	10.7	273	46.2260	46,226	12,619,698	$ 41.65	$ 46,223,000	$ 1,925,206
15	12.7	323	108.6790	108,679	35,103,317	$ 41.65	$ 108,679,000	$ 4,526,523
16	16.0	406	33.4060	33,406	13,562,836	$ 41.65	$ 53,449,600	$ 1,391,373
17	18.0	457	1.9410	1,941	887,037	$ 41.65	$ 3,202,650	$ 80,843
18	20.0	508	57.5290	57,529	29,224,732	$ 41.65	$ 97,799,300	$ 2,396,106
19	24.0	609	1.4590	1,459	888,531	$ 41.65	$ 2,626,200	$ 60,768
20	30.0	762	11.6990	11,699	8,914,638	$ 41.65	$ 23,398,000	$ 487,268
TOTAL			**19,348.3543**	**19,348,354**	**1,404,907,507**		**$ 2,257,639,300**	**$ 803,870,070**

Customer Related Component	**35.61%**
Demand Related Component	**64.39%**

FEVI

FEVI COMBINED STEEL & PLASTIC MAINS BASED ON 2" DIAMETER PLASTIC PIPE MINIMUM SIZE

Line No.	Diameter Inches	Diameter mm	Length in KMS	Length in Meters	Dia. (mm) x Length (m)	Minimum Size Unit Cost / Length ($/m)	Total Cost	Minimum Size Cost
1	0.6	15	45.9470	45,947	689,205	$ 50.00	$ 2,305,150	$ 2,297,350
2	0.8	21	0.0040	4	84	$ 50.00	$ 500	$ 200
3	1.0	26	52.2340	52,234	1,358,084	$ 50.00	$ 2,672,825	$ 2,611,700
4	1.3	33	0.0010	1	33	$ 50.00	$ 50	$ 50
5	1.7	42	1,374.2730	1,374,273	57,719,466	$ 50.00	$ 69,361,425	$ 68,713,650
6	1.9	48	2.4660	2,466	118,368	$ 50.00	$ 308,100	$ 123,300
7	2.4	60	988.8070	988,807	59,328,420	$ 50.00	$ 56,595,350	$ 49,440,350
8	2.9	73	-	0	0	$ 50.00	$ -	$ -
9	3.5	88	455.9760	455,976	40,125,888	$ 50.00	$ 41,916,135	$ 22,798,800
10	4.0	101	-	0	0	$ 50.00	$ -	$ -
11	4.5	114	364.4770	364,477	41,550,378	$ 50.00	$ 43,981,338	$ 18,223,850
12	6.6	168	164.1270	164,127	27,573,336	$ 50.00	$ 32,852,138	$ 8,206,350
13	8.6	219	26.7930	26,793	5,867,667	$ 50.00	$ 18,755,100	$ 1,339,650
14	10.7	273	2.9050	2,905	793,065	$ 50.00	$ 2,905,000	$ 145,250
15	12.7	323	15.0810	15,081	4,871,163	$ 50.00	$ 15,081,000	$ 754,050
16	16.0	406	-	0	0	$ 50.00	$ -	$ -
17	18.0	457	-	0	0	$ 50.00	$ -	$ -
18	20.0	508	-	0	0	$ 50.00	$ -	$ -
19	24.0	609	-	0	0	$ 50.00	$ -	$ -
20	30.0	762	-	0	0	$ 50.00	$ -	$ -
	TOTAL		**3,493.0910**	**3,493,091**	**239,995,157**		**$ 286,734,110**	**$ 174,654,550**

Customer Related Component	**60.91%**
Demand Related Component	**39.09%**

FEW

FEW COMBINED STEEL & PLASTIC MAINS BASED ON 2" DIAMETER PLASTIC PIPE MINIMUM SIZE

Line No.	Diameter Inches	Diameter mm	Length in KMS	Length in Meters	Dia. (mm) x Length (m)	Minimum Size Unit Cost / Length ($/m)	Total Cost	Minimum Size Cost
1	0.6	15	-	0	0	$ 68.00	$ -	$ -
2	0.8	21	-	0	0	$ 68.00	$ -	$ -
3	1.0	26	1.3910	1,391	36,166	$ 68.00	$ 95,302	$ 94,588
4	1.3	33	-	0	0	$ 68.00	$ -	$ -
5	1.7	42	3.7760	3,776	158,592	$ 68.00	$ 258,502	$ 256,768
6	1.9	48	15.0000	15,000	720,000	$ 68.00	$ 1,020,612	$ 1,020,000
7	2.4	60	21.2130	21,213	1,272,780	$ 68.00	$ 1,477,164	$ 1,442,484
8	2.9	73	-	0	0	$ 68.00	$ -	$ -
9	3.5	88	10.3040	10,304	906,752	$ 68.00	$ 1,242,989	$ 700,672
10	4.0	101	-	0	0	$ 68.00	$ -	$ -
11	4.5	114	35.5840	35,584	4,056,576	$ 68.00	$ 4,247,549	$ 2,419,712
12	6.6	168	2.0110	2,011	337,848	$ 68.00	$ 664,870	$ 136,748
13	8.6	219	9.9500	9,950	2,179,053	$ 68.00	$ 6,855,452	$ 676,601
14	10.7	273	-	0	0	$ 68.00	$ -	$ -
15	12.7	323	-	0	0	$ 68.00	$ -	$ -
16	16.0	406	-	0	0	$ 68.00	$ -	$ -
17	18.0	457	-	0	0	$ 68.00	$ -	$ -
18	20.0	508	-	0	0	$ 68.00	$ -	$ -
19	24.0	609	-	0	0	$ 68.00	$ -	$ -
20	30.0	762	-	0	0	$ 68.00	$ -	$ -
		TOTAL	99.2290	99,229	9,667,767		$ 15,862,439	$ 6,747,573

Customer Related Component	42.54%
Demand Related Component	57.46%

FEFN

FEFN COMBINED STEEL & PLASTIC MAINS BASED ON 2" DIAMETER PLASTIC PIPE MINIMUM SIZE

Line No.	Diameter Inches	Diameter mm	Length in KMS	Length in Meters	Dia. (mm) x Length (m)	Minimum Size Unit Cost / Length ($/m)	Total Cost	Minimum Size Cost
1	0.6	15	-	0	0	$ 35.00	$ -	$ -
2	0.8	21	-	0	0	$ 35.00	$ -	$ -
3	1.0	26	0.4930	493	12,818	$ 35.00	$ 24,553	$ 17,255
4	1.3	33	-	0	0	$ 35.00	$ -	$ -
5	1.7	42	18.0940	18,094	759,948	$ 35.00	$ 711,988	$ 633,290
6	1.9	48	1.9050	1,905	91,440	$ 35.00	$ 166,688	$ 66,675
7	2.4	60	81.1860	81,186	4,871,160	$ 35.00	$ 4,963,140	$ 2,841,510
8	2.9	73	-	0	0	$ 35.00	$ -	$ -
9	3.5	88	8.4880	8,488	746,944	$ 35.00	$ 813,216	$ 297,080
10	4.0	101	-	0	0	$ 35.00	$ -	$ -
11	4.5	114	13.8330	13,833	1,576,962	$ 35.00	$ 1,442,994	$ 484,155
12	6.6	168	0.2430	243	40,824	$ 35.00	$ 34,828	$ 8,505
13	8.6	219	-	0	0	$ 35.00	$ -	$ -
14	10.7	273	-	0	0	$ 35.00	$ -	$ -
15	12.7	323	-	0	0	$ 35.00	$ -	$ -
16	16.0	406	-	0	0	$ 35.00	$ -	$ -
17	18.0	457	-	0	0	$ 35.00	$ -	$ -
18	20.0	508	-	0	0	$ 35.00	$ -	$ -
19	24.0	609	-	0	0	$ 35.00	$ -	$ -
20	30.0	762	-	0	0	$ 35.00	$ -	$ -
		TOTAL	**124.2420**	**124,242**	**8,100,096**		**$ 8,157,406**	**$ 4,348,470**

Customer Related Component	**53.31%**
Demand Related Component	**46.69%**

136.0 Reference: COSA Methodology

Exhibit B-3-1, Appendix D-3, pp. 4-5; Exhibit B-3, Section 9.6.2.4, pp. 206-207

Peak Load Carrying Capability (PLCC) Adjustment

The basis for the calculation of the PLCC adjustment appears to be inconsistent with the basis used for calculating the Minimum System. The calculation of the PLCC adjustment is described in Appendix D-3 as:

“Table 4 presents the total PLCC Adjustment for the Amalgamated Entity (*0.225 GJ/day/customer*) and details associated with the PLCC calculation, which was calculated through the following steps:

1. The System Planning Department calculates the load capacity of each distribution network in the Province for the Amalgamated Entity assuming only 2 inch mains are used.

2. Since each network serves a different number of customers, the average system capacity is calculated by summing the network capacities and dividing by the total number of customers.

The Minimum System Study is described in Section 9.6.2.4:

“To do so, the Minimum System Study assumes that the actual pipe diameters could be replaced with only those pipe diameters that comprise the minimum distribution system (i.e., all pipe diameters equal to <u>or less than 2</u>).” [Emphasis added]

136.1 Please confirm that the FEU have calculated the PLCC adjustment assuming that only 2 inch mains are used throughout the system.

<u>Response:</u>

Confirmed.

136.2 Please confirm that this differs from the approach used in the Minimum System Study which is based on a system having pipe sizes 2 inch and smaller as described in Section 9.6.2.4.

Response:

Not confirmed. As there is no difference in the average installed cost of pipe sizes 2" and below, the cost of the pipes that are already in place that are below 2" would have the same cost as 2" pipes. Therefore, there is no difference in the results if they include pipe sizes below 2" or if those categories are replaced with 2" pipes.

As discussed in the response to BCUC IR 1.135.6, the Minimum System Study is intended to reflect a case where the Minimum Size of the system is based on 2" pipes. The PLCC is also based on a 2" Minimum Size system and we believe that it is consistent with the Minimum System Study approach and results. Because both the Minimum System Study and PLCC are theoretical calculations, it does not matter if there are actually pipes in place below the 2" minimum size. The calculations are not intended to reflect an actual working system but are developed for the sole purpose of classifying and allocating the actual costs of the system.

136.3 Would the FEU agree that the PLCC adjustment, as calculated as described in Appendix D-3 overstates the load carrying capacity of the Minimum System described in Section 9.6.2.4?

Response:

The FEU do not agree that the PLCC adjustment overstates the load carrying capability of the Minimum System because the Minimum System size is assumed to be 2".

136.4 Would the FEU agree that it is not technically feasible to calculate the PLCC in a manner corresponding with the Minimum System described in Section 9.6.2.4?

Response:

The FEU do not agree with the statement in the question. The PLCC and Minimum System are intended to reflect a theoretical Minimum Size system at 2" and there is no inconsistency between the two. Please also refer to the response to BCUC IR 1.135.6.

137.0 Reference: COSA Methodology

Exhibit B-3, Section 9.6.2.5, p. 211; Exhibit B-3-1, Appendix D-1, pp. 17, 31

Allocation of Revenues from Industrial, Contract Rate and Bypass Service Customers

"As shown in Section 8.1 the forecasted revenue associated with closed large industrial, contract rate and bypass service contract customers has been treated as Other Revenue and credited to the cost of service. The Other Revenue credit to the cost of service from these customers is allocated on the basis of revenue margin allocated to each Core Market and non-contract transportation service rate class. The Company has adopted this approach because the contract rate and bypass customers all have rates set in their respective contracts and as such are not subject to rate changes which result from the cost allocation process. EES Consulting has reviewed the allocation of bypass and contract rate customer revenues as a cost of service credit and believes the approach to be appropriate for the Amalgamated Entity COSA." (Section 9.6.2.5, p. 211)

"A large portion of other revenue comes from customer revenues that are set at negotiated rates. The FEU has customers on contract rates that have been negotiated due to the ability of the customer to bypass the system or because of the size and unique characteristics of the customer. This includes certain industrial customers that are on rates that have been closed and are no longer available to new large industrial customers. The cost of serving these customers is difficult to measure within the COSA and the rates are not directly based on the outcome of the COSA process. Generally such rates are set to recover the marginal cost of service plus some contribution to the fixed system. While these customers may not pay the full cost of service, they do provide a benefit to the remaining customers on the system. To ensure that all customers benefit from the revenues associated with these contracted customers, these other revenue items have been credited back to all other customers on the basis of the total margin. This approach is appropriate because it reflects the benefit of the load provided to the remaining customers, it reflects the fact that many of the contract customers do not use the distribution or storage systems to the extent of the remaining customers, and it allows revenue credits to flow to both core and transportation customers." (Appendix D-1, EES Cost of Service Review Report, p. 17)

137.1 Explain why the cost of serving these customers is difficult to measure.

Response:

The fully embedded cost of serving these customers can be calculated in the COSA; however, the rates are based on marginal cost with a partial contribution to fixed costs rather than the fully embedded cost. Therefore it is difficult to measure the appropriate costs for these customers within the context of the COSA which allocates costs on the basis of loads and number of customers. All customers are better off having these customers on the system and remaining customers see a benefit and are therefore better off even though they are assigned a greater share of fixed costs than would otherwise occur. The fully embedded COSA does not measure the costs that are appropriate for these customers. Because the contracted rates are designed outside the COSA to reflect the appropriate costs and benefits of serving these customers, those revenues best reflect the cost that should be allocated to these customers. The practice of using the revenues as an offset to the revenue requirements reflects a case where the costs are equal to the revenues.

137.2 Please confirm that the revenue to cost ratios of the VIGJV and of BC Hydro were calculated in the 2010-2011 TGVI Revenue Requirements and Rate Design Application.

Response:

It is confirmed that the revenue to cost ratios of VIGJV and BC Hydro were calculated in the 2010-2011 TGVI Revenue Requirements and Rate Design application.

137.3 Explain why the FEU have changed its treatment of these customers' costs and revenues from that used in the 2001 COSA.

Response:

The FEU have changed their treatment for these customers from that used in 2001 COSA as the rates for these customers are not directly based on the outcome of the allocated cost of service through the COSA study. However, using the approach as filed in the COSA, these bypass and special contracts customers bring benefits to the remaining customers as explained in the preamble to the IR. For the reasons listed in the preamble, the treatment of allocating these customers' costs and revenues in the Amalgamated Entity COSA is appropriate.

"One particular class that needs to be examined in greater detail in the future is the industrial class. Currently there are customers under Rate 22, 22A and 22B. Some of these different rate options exist on a grandfathered basis and are closed to new customers. Originally they were based on different geographical regions. Customers also differ as to the interruptibility of loads, with nonfirm loads receiving a market-based discount. Other industrial customers have contract rates reflecting either a bypass alternative or other unique circumstances. In many of these cases, the revenues are based on contractual amounts and have been included as an offsetting revenue credit in the COSA. With these various issues, it is difficult to assess whether the COSA reflects the true costs for the remaining industrial customers and whether the different rate setting methods and terms of service are equitable among industrial customers." (Appendix D-1, EES Cost of Service Review Report, p. 31)

137.4 By not allocating any costs to the closed industrial, contract rate and bypass customers, would it not be difficult to assess whether the COSA reflects the true costs for all other customers? Please explain.

Response:

Please refer to the responses to BCUC IRs 1.126.4 and 137.1. If fully embedded costs are assigned to these customers in the COSA, the revenue to cost ratio will be below 100%. The remaining customers will not be assigned the extra portion of fixed costs resulting in the shortfall from these customers. That will make the costs assigned to remaining classes lower than intended, and the resulting revenue to cost ratios will not be correct. Therefore, the method used better reflects the true cost for all other customers.

138.0 Reference: COSA Methodology

Exhibit B-3, Section 9.2, p. 178

NGV and LNG Rate Schedules (RS 6, RS 16 and RS 26)

138.1 Why have no costs been allocated to the NGV and LNG rate schedules (RS 6, RS 16, RS 26)?

Response:

The COSA as filed in the Application allocates costs to Rate Schedule 6.

However, no costs have been allocated to Rate Schedules 16 and 26 in the COSA study for the reasons explained below:

1. There are no customers in Rate Schedule 26.
2. Rate Schedule 16 is an interruptible LNG service. This means that these customers are curtailable in the event that the demand for firm customers exceeds the capacity to serve them. Rate Schedule 16 customers do not drive system capacity additions and therefore, no demand related costs could be allocated to them. Also, as this is an LNG service, there are no meters or services costs to be allocated to these customers. Therefore, for the purposes of the COSA study, the costs related to serve Rate Schedule 16 customers and the revenues collected from them are allocated to all customers such that core customers are not negatively impacted.

138.2 Why have no LNG storage related costs been allocated to Rate 16?

Response:

Please refer to the response to BCUC IR 1.138.1.

139.0 Reference: COSA Methodology

Exhibit B-3, Section 9

Allocation of revenues from Rate Schedule 40

139.1 How have the revenues received through RS 40 (West to East SCP Transportation) been allocated to the customer classes?

Response:

The revenues received through Rate Schedule 40 are functionalized to Transmission SCP, classified as demand related and allocated based on peak demand to all non-bypass firm customers. The costs associated with the Transmission SCP are also allocated in the same manner. This treatment of revenues and costs associated with SCP Transportation is consistent with the previously approved COSA methodology for FEI.

140.0 Reference: COSA Methodology

Exhibit B-3, Section 9.6.2.1, Table 9-6, p. 200

Company Use and Unaccounted For Gas Allocation

Table 9-6 states that the FEU propose "to treat Company Use gas as part of O&M expenses and ***allocate based on peak demand*** to all non-bypass customers." [Emphasis added]

140.1 Please confirm whether or not Company Use gas has been allocated to all non-bypass customers based on peak demand.

Response:

The FEU in its COSA study are proposing to treat the Company Use gas as a part of transmission O&M. This means that this expense is functionalized to Transmission, classified as demand-related and allocated based on peak demand to all non-bypass customers.

Please refer to the response to BCUC IR 1.140.2 that outlines various uses of Company Use gas. Based on cost causation, the FEU believe that the methodology to allocate Company Use gas as proposed in the application is appropriate as Company Use gas is primarily a function of customers' level of daily demand rather than the volume of gas transported during the entire year. Therefore, Company Use gas is allocated to all non-bypass customers based on peak demand and not sales volumes.

140.2 What uses of gas are included in Company Use gas? Which uses are functions of the level of daily demand? Which uses are functions of the volume of gas transported during the entire year?

Response:

Company Use gas is primarily required to deliver natural gas to customers in a safe and efficient manner and includes line heater fuel, compressor fuel, and liquid natural gas (LNG) plant fuel associated with moving natural gas to customers, as well as gas used in the FEU facilities and offices.

- Line heater fuel – the forecast annual consumption of line heater fuel is based on normal weather. (Normal weather is an average of the preceding ten year period.) Customer daily demand is the primary driver of the actual line heater fuel usage.

- Compressor fuel – the forecast annual consumption of compressor fuel is based on normal weather. Customer daily demand is the primary driver of the actual compressor fuel usage.
- LNG plant fuel – the forecast annual consumption of LNG plant fuel is based on a projected utilization as a peak day resource during an average year. Customer daily demand, specifically during a peak day (but also under a system upset / emergency condition), is the primary driver of the actual LNG plant fuel usage.
- FEU facilities and offices gas – the forecast annual consumption of gas, primarily for space and water heating, within the FEU buildings and offices throughout BC is based on the estimated usage during an average year. Actual annual consumption is a result of the daily demand at each individual location, which is primarily affected by weather.

Company Use gas is primarily a function of daily demand and is most appropriately allocated based on peak demand.

140.3 Why is the Company Use gas expense not allocated to all sales and transportation customers (including bypass and special contract customers) on the basis of deliveries?

<u>Response:</u>

Please refer to the response to BCUC IR1.140.1 that explains why the FEU believe that it is appropriate to classify Company Use gas expense as demand-related and allocate it based on peak demand to all sales and transportation customers with the exception of bypass and special contract customers.

Please also refer to the response to BCUC IR1.137.3 that explains why the FEU are not proposing to allocate costs including the Company Use gas expense to bypass and special contract customers.

140.4 Why has the Company Use gas expense not been classified as "Commodity-Related"?

Response:

Please refer to the response to BCUC IR 1.140.1.

Table 9-6 states that the FEU propose "to treat UAF gas consistently across the FEU system and to treat as part of O&M expenses and allocate based on sales volume to all non-bypass customers (similar to treatment of Company Use gas)."

140.5 Please confirm whether or not Company Use gas has been allocated to all non-bypass customers based on sales volume.

Response:

Company Use gas has not been allocated to all non-bypass customers based on sales volume. Please refer to the response to BCUC IR 1.140.1 that explains why it is appropriate to allocate Company Use gas to all non-bypass customers based on peak day demand.

140.6 Why is the UAF gas expense not allocated to all sales and transportation customers (including bypass and special contract customers) on the basis of deliveries?

Response:

As discussed in Sections 8.1.1.1 and 9.6.2.4 of the Application, the FEU are proposing to treat UAF gas expense in a similar manner as Company Use gas, in that costs related to UAF gas expense are recovered from all non-bypass sales and transportation customers as part of delivery rates.

UAF gas expense is treated as a part of Transmission O&M i.e. functionalized to Transmission, and allocated based on sales volume.

Please refer to the response to BCUC IR 1.137.3, which explains why the FEU are not proposing to allocate any costs including the UAF gas expense to bypass and special contract customers.

140.7 Please confirm whether or not the UAF gas expense, as a component of the transmission O&M expense, has been functionalized as "Transmission"?

Response:

Please refer to the response to BCUC IR 1.140.6.

140.8 Please confirm whether or not the UAF gas expense, as a component of the transmission O&M expense, has been classified as "Demand-Related"?

Response:

It is confirmed that UAF gas expense has been allocated based on annual sales volumes. Please also refer to the response to BCUC IR 1.140.6.

140.9 Why have the FEU not classified the UAF gas expense as "Commodity-Related"?

Response:

It is confirmed that UAF gas expense has been allocated based on annual sales volumes. Please also refer to the response to BCUC IR 1.140.6.

140.10 Please identify the common sources of UAF and associate each one with either the transmission, or the distribution system.

Response:

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use and is associated with both the transmission and distribution system. Sources of UAF include, but are not limited to, the following:

- System Leakage – the natural gas system is not 100% hermetically sealed and some leakage occurs. The system leakage is associated with both transmission and distribution systems.
- Lost Gas – gas lost as a result of utility and third party activities, including gas theft. This lost gas is associated with both transmission and distribution systems and includes gas lost as a result of hits to the FEU system, as well as gas lost through system venting (such as intentional operational activities or unintentional relief valve releases). To date, lost gas related to known incidents of gas theft have occurred on the distribution system.
- Measurement Error – measurement error relates to the volumetric variances attributable to differences in the measurement data obtained from transmission system take-off points (typically custody transfer meters located at third party pipeline custody transfer points) and the measurement data obtained from end point meters at customer locations, exclusive of any other sources of UAF, such as those mentioned above. The type of measurement used at the transmission system take-off point (e.g. turbine, orifice, or ultrasonic meters) can differ depending upon the pipeline operator and it is believed that measurement error is a significant component of UAF. Measurement error occurs across the transmission and distribution systems.

UAF cannot be projected with precision and, although the FEU have various programs in place which can influence the amount of UAF (for example, leak survey programs help to reduce the amount of system leakage, and participation in the BC One Call program and "Call Before You Dig" communications help to reduce the third party system damage), the UAF cannot be directly controlled by the utility.

140.11 Are the largest sources of UAF by volume attributable to the transmission system, or the distribution system?

Response:

For the FEI system, the UAF is tracked on a regional basis (e.g. Lower Mainland, Inland, Columbia, and Fort Nelson) and not on a system basis. At this time transmission UAF cannot be isolated from the distribution UAF. Metering exists on the transmission take-off points where custody transfer occurs between a third party pipeline and FEI (e.g. Westcoast Energy Inc. to FEI and TransCanada Pipeline Limited to FEI) but no metering is in place at the FEI transmission system to FEI distribution system take-off points.

For the FEVI system, the UAF on the transmission system and distribution system are tracked separately, and the historical data have shown the FEVI transmission system UAF to be higher than the FEVI distribution system UAF.

Although the FEVI transmission system UAF is higher than the FEVI distribution system UAF, this information does not support a corollary assumption that the FEI transmission system UAF would therefore be higher than the FEI distribution system UAF. Notably, the FEVI transmission system operates at a higher pressure than the FEI Interior and Lower Mainland transmission systems, and also at a higher pressure than the Westcoast Energy Inc. and TransCanada Pipeline Limited pipeline systems.

141.0 Reference: Deferral Accounts

Exhibit B-3, Section 8.2.1.2

Company Use and Unaccounted for Gas Cost Variance Account

141.1 Do the FEU agree that it is reasonable for the Commission to set a cap on the amount of unaccounted for gas (defined as a portion of deliveries to core market and transportation customers) that can be recorded in this proposed deferral account?

Response:

No. The volumes of unaccounted for gas ("UAF") incurred by the FEU are not controllable by the utility. Further, the cost of UAF gas is directly affected by the market price of natural gas which is also not controllable by the FEU.

Please refer to the response to BCUC IR 1.140.10.

142.0 Reference: COSA Schedules

Exhibit B-3-1, Appendix I-4, Schedules 7

Exhibit B-3-1, Appendix J-2, Schedule 7

Postage stamp vs. Regional Midstream Charges

Appendix I-4, Schedules 7 present the unit costs of gas – midstream component forecast for the 2013 Test Year assuming regional midstream charges remain in effect. A separate schedule has been created for each of FEI Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN.

Appendix J-2, Schedule 7 presents the unit costs of gas – midstream component forecast for the 2013 Test Year assuming postage stamp midstream charges.

142.1 In Appendix I-4, on the schedules pertaining to the Lower Mainland, Inland and Columbia regions, the total midstream sales volume presented on line 4 does not agree with the sum of the totals under each rate column. Please explain the reason for this discrepancy.

Response:

The midstream sales volumes indicated at line 4 on the Schedule 7 pages in Appendix I-4 incorrectly include Transportation Service customer volumes; the volumes shown on schedule 7 are not used for any allocation purposes and have no impact on COSA results.

Please refer to the table provided in the response to BCUC IR 1.142.3, wherein the midstream volumes have been adjusted accordingly.

142.2 In Appendix I-4, the "Total" column of midstream sales volumes (line 4) summed over all six regions does not agree with the total presented on Schedule 7 of Appendix J-2 (line 4). Please explain the reason for this discrepancy.

Response:

The midstream sales volumes indicated at line 4 on the Schedule 7 pages in Appendices I-4 and J-2 incorrectly include Transportation Service customer volumes; the volumes shown on Schedule 7 are not used for any allocation purposes and have no impact on COSA results.

Please refer to the table provided in the response to BCUC IR 1.142.3, wherein the midstream volumes have been adjusted accordingly.

142.3 Please complete the following table:

		Lower Mainland	Inland	Columbia	FEVI	FEW	FEFN
A	Midstream Sales Volume (Appendix I-4, Sch. 7, line 4)						
B	Cost of Gas – Midstream (Appendix I-4, Sch. 7, line 14)						
	Regional Midstream Rates Option						
C	Average Midstream Charge (Line B/Line A)						
	Postage Stamp Midstream Rates Option						
D	Midstream Sales Volume (Appendix J-2, Sch. 7, line 4)						
E	Cost of Gas – Midstream (Appendix J-2, Sch. 7, line 24)						
F	Average Midstream Charge (Line E/Line D)						
G	Revenue to Cost Ratio – Midstream Charges (Line F/Line C)						

Response:

The table provided below has been prepared to present the total midstream costs for the amalgamated entity under the two scenarios as presented in Appendices I-4 and J-2 of the Application.

The first section of the table provides the midstream costs for each of the regions based on the regional allocation of the total amalgamated midstream costs, as presented in Appendix I-4 of the Application. While the second section of the table provides the same total amalgamated midstream costs with no regionalization of midstream costs under the postage stamp option, as presented in Appendix J-2 of the Application.

As discussed in the responses to BCUC IRs 1.142.1 and 1.142.2, the midstream sales volumes shown at Lines A and D have been adjusted to appropriately exclude the Transportation Service customer volumes.

Further, a column titled "Combined" has been added to the far right of the table to more clearly show that the total midstream sales volumes and total amalgamated midstream costs are the same under both scenarios.

		Lower Mainland	Inland	Columbia	FEVI	FEW	FEFN	Combined
	Regional Midstream Rates Option							
A	Midstream Sales Volume (Adjusted) [1] (Appendix I-4, Sch 7, line 4)	85,418	24,127	2,567	11,860	709	587	125,268
B	Cost of Gas - Midstream [2] (Appendix I-4, Sch 7, line 14)	$113,419	$31,732	$3,606	$13,264	$943	$138	$163,102
C	Average Midstream Charge (Line B/Line A)	$1.33	$1.32	$1.40	$1.12	$1.33	$0.24	$1.30
	Postage Stamp Midstream Rates Option							
D	Midstream Sales Volume (Adjusted) [1] (Appendix J-2, Sch 7, line 4)							125,268
E	Cost of Gas - Midstream (Appendix J-2, Sch 7, line 24)							$163,102
F	Average Midstream Charge (Line E/Line D)							$1.30
G	Revenue to Cost Ratio - Midstream Charges (Line F/Line C) comparing Common Rate derived in Line F with Regional Rates derived in Line C	98%	99%	93%	116%	98%	554%	100%

[1] Midstream sales volumes reflect adjustment to exclude transportation service volumes.

[2] Lower Mainland midstream cost reflects adjustment to remove Squamish wheeling charge.

The average midstream charges shown at Line C provide an average unitized rate for each region calculated by simply dividing the regionalized midstream cost for each region by that particular region's midstream sales volume. This is *not* how actual midstream rates are determined. The average midstream charge shown at Line F provides an average unitized rate for the amalgamated entity on a postage stamp basis and has been calculated by simply dividing the total amalgamated midstream cost by the total midstream sales volume. Again, this is *not* how actual midstream rates are determined. The midstream rates are established for each rate class based on a load factor adjusted volumetric basis.

The percentage provided at Line G in the table compares the average unitized postage stamp midstream rate (calculated at Line F) to the average unitized regional midstream rate (calculated at Line C).

The ratios presented at Line G provide a rough proxy of the changes in the midstream rates that would occur under the Common Rates amalgamated model where the midstream rates would be postage stamped across the entire FEU region. As further discussed in the response to BCUC IR 1.142.5, the FEU midstream resources are operated as part of an integrated system and support gas supply to the entire FEU region. The FEU believe the non-regionalization of the midstream costs, under the Common Rates scenario as presented in Appendix J-2 of the Application, more fairly represent the costs of providing midstream services to the regions.

142.4 What are the determinants of the midstream charges in each of the six regions (Lower Mainland, Inland, Columbia, FEVI, FEW, FEFN)?

Response:

The FEU interpret the phrase "determinants of the midstream charges" to mean the billing determinants on which the midstream charges are billed.

For the majority of FEI customers the midstream charges are included as a separate charge on customers' bills and are calculated based on the billed volumes. For FEW, FEVI, and FEFN customers the midstream costs are included as part of the bundled variable charges, which are also calculated based on the billed volumes.

142.5 Do the regional midstream charges presented in Appendix I-4, Schedule 7 and summarized on line C of the table above, represent fairly the cost of providing midstream services to each of these delivery regions? Please explain.

Response:

The regional midstream costs presented in Appendix I-4, and summarized on line B in the table provided in the response to BCUC IR 1.142.3, are representative of the current rate design constructs in place today for the various regions.

The regional midstream costs presented on line B are a fair representation of the cost of midstream services assigned to each region under the current regionalized rate design models, however the average midstream charges shown on line C in the table are simply a unitization of the regional midstream costs, as divided by the total regional sales volumes, which is not how rates are determined. Therefore the midstream charges presented on line C do not provide a fair representation of the unit charges for providing midstream services to the various customer rate classes within each region.

In the Common Rates amalgamated model the midstream charges would be postage stamped across the entire region and allocated to the various rate classes on a load factor adjusted basis. The allocation methodology proposed under the Common Rates scenario in the Application appropriately recovers the cost of providing midstream services.

As discussed in the response to BCUC IR 1.145.1, the FEU's transmission and LNG facilities along with the midstream resources are operated as part of an integrated system and support gas supply to the entire FEU region. Thus, the FEU believe the non-regionalization of the midstream costs, under the Common Rates scenario as presented in Appendix J-2 of the Application, more fairly represent the costs of providing midstream services to the regions.

142.6 Does the revenue to cost ratio presented on line "G" in the table above provide a valid indication of whether a particular region would be paying an appropriate portion of the midstream costs required to serve that region?

Response:

Please refer to the response to BCUC IR 1.142.3.

143.0 Reference: Allocation of Midstream Charges

Exhibit B-3, Section 9.6.2.4, p. 203

Fort Nelson Midstream Charges

"The gas supply midstream resources will be managed in a manner consistent with how the FEI (including FEW) midstream portfolio is currently managed. The FEU propose that, effective January 1, 2014, the gas supply midstream costs be classified as demand-related and that a single, common MCRA be utilized for the FEU, which is generally consistent with the cost classification currently in place for FEI and FEW.

The midstream portfolio includes the upstream pipeline capacity, upstream and market-area storage capacity (including storage services provided by Mt. Hayes), balancing and peaking resource requirements, as well as the mitigation activities."

143.1 Do FEU's customers in Fort Nelson currently pay for midstream services through their delivery charge?

Response:

Fort Nelson sales customers within the Domestic Service and General Service rate classes currently pay a gas cost recovery charge component, which includes the costs related to midstream services, and a delivery charge component as part of their bundled, step rates.

The delivery charge component of the bundled, step rates does not include costs related to midstream services.

143.1.1 If the answer to the previous question is "yes" then please explain what midstream services are being provided.

Response:

Although, as described in the response to BCUC IR 1.143.1, the delivery charge component of the Fort Nelson bundled, step rates for sales customers within the Domestic Service and General Service rate classes do not include costs related to midstream services, the gas cost recovery charge component does include the midstream related costs.

The midstream related costs include an allocation of Aitken Creek storage costs from the FEI portfolio within the Fort Nelson gas cost recovery charge component, charges for transportation service provided by Westcoast Energy Inc. to move gas from the Fort Nelson gas processing plant outlet to the Town of Fort Nelson, and the costs related to Unaccounted For ("UAF") gas within the Fort Nelson system. Based on the 2013 test year gas cost forecast, the annual midstream costs allocated to Fort Nelson are approximately $162 thousand, which would equate to an average midstream cost recovery rate of approximately $0.276 per GJ on a forecast sales volume of 586 TJ.

Please refer to the responses to BCUC IRs 1.143.2 and 1.143.3 for discussion on the Aitken Creek storage and Westcoast transportation. Also, please refer to the responses to BCUC IRs 1.47.1 through 1.47.8 for a description on how FEI contracts for and manages the daily and annual requirements for Fort Nelson as part of its overall gas commodity and midstream portfolio.

143.2 How do Aitken Creek storage and third party market area storage serve Fort Nelson customers?

Response:

These resources do not serve the customers of Fort Nelson directly. However, they can provide supply to the town of Fort Nelson via displacement. Further, the allocation, for costing purposes, of a portion of Aitken Creek storage from the FEI portfolio referred to in the response to BCUC IR 1.143.1.1 provides the Fort Nelson portfolio with greater cost diversity by including additional summer priced gas, based on Aitken Creek withdrawals at the average price of that gas in storage, within the winter months.

Also, please refer to the responses to BCUC IRs 1.47.1 and 1.47.2 for additional discussion on the resources that service Fort Nelson.

143.3 Do the FEU hold capacity on Westcoast Zone 3 in order to serve Fort Nelson customers?

Response:

Yes, the FEU hold capacity on Westcoast Zone 3 or the T-North system on Westcoast to service Fort Nelson. Please refer to the response to BCUC IR 1.47.1 for this discussion.

143.4 Do the FEU hold capacity on Westcoast Zone 4 in order to serve Fort Nelson customers?

Response:

No, the FEU do not hold capacity on Zone 4 (i.e. T-South) on Westcoast to directly serve Fort Nelson. However, the capacity held by FEI can be indirectly utilized by FEI to supply the town of Fort Nelson via displacement. Please refer to the response to BCUC IR 1.47.2 for this discussion. Also, please refer to the response to BCUC IR 1.47.1 for discussion on the resources that service Fort Nelson.

143.5 Are postage stamp midstream charges applied to Fort Nelson?

Response:

Yes, the postage stamp midstream rates would be applicable to all customers, including those residing in the Fort Nelson service area, effective January 1, 2014, as proposed in the Application.

144.0 Reference: COSA – Revenue to Cost Ratios

Exhibit B-3-1, Appendix D-1, pp. 29 - 30

Range of Reasonableness

"Anytime there is greater uncertainty in the COSA results, the resulting revenue to cost ratios are less accurate and reliable. This makes it advisable to use +/- 10% to reflect the uncertainty in the COSA. The FEU COSA contains uncertainty due to several factors. … Specifically, the lack of recognition of the contribution of nonfirm revenues towards the fixed cost of the system make the COSA results less accurate."

144.1 Why does the lack of recognition of the contribution of nonfirm revenues towards the fixed cost of the system make the COSA results less accurate?

Response:

Please refer to the responses to BCUC IRs 1.126.4 and 1.137.4. Using the revenues from nonfirm customers as an offset to the revenue requirement provides the best way to determine the revenue to cost ratios for the remaining customers. However, not having system costs allocated to the nonfirm customers leaves some room for inconsistency in the amount of system costs covered by the nonfirm rates, resulting in less certainty in the COSA.

144.2 How could the COSA methodology be modified to allocate capacity related costs to the interruptible rate classes?

Response:

The FEU have not researched or developed a proposed methodology for this purpose. It would likely be based on assigning some portion of total nonfirm load to be included in the coincident peak totals, or assigning a portion of system costs on the basis for total nonfirm loads. The COSA methodology as proposed in the Application is consistent with the previously approved FEI methodology and the FEU believe that it is still appropriate to treat interruptible rate classes in the same manner as FEI has treated those classes since 2001.

The FEU have used a consistent COSA methodology for this Application so that the amalgamation and common rates can be considered at a time when no other significant changes are made. If the request for amalgamation and common rates is approved, it is the intention of the FEU to review the COSA methodology, rate class segmentation and rate design in 2016. This would allow time for amalgamation to be implemented, customer movement between rate classes to occur, and for actual data to be collected on the costs and sales under an amalgamated entity.

145.0 Reference: Two Region COSA Model Using Consolidated Methodology

Exhibit B-3-1, Appendix D-1, p. 25

Allocation of Transmission and Storage

"The next approach was used to determine the impacts of having two separate regions within the COSA rather than the current four individual rate areas. This approach combines the areas that are geographically similar into two regions. The West region includes the Lower Mainland region of FEI along with FEVI and FEW. The East region includes the Inland and Columbia regions of FEI along with FEFN. For this approach, the amalgamated COSA methodology was used, along with all customers being moved to the appropriate FEI rate classes. The consolidated revenue requirements and rate base were used for all of the functions except distribution. This includes transmission, storage, marketing and customer accounting. This reflects the use of these facilities by all of the FEU customers and avoids the requirement to transfer or apportion costs outside of the COSA process."

145.1 Please explain how the transmission system to Vancouver Island is used by the East region.

Response:

This response addresses BCUC IRs 1.145.1, 1.145.2 and 1.145.3.

Although the transmission/LNG assets in the West and East regions are physically and geographically isolated, they do operate together because the two regions are interconnected via Spectra's T-South system. How the West region system would operate affects how the East region system would operate, and vice versa. All the Transmission/LNG assets need to operate as one integrated system in order to optimize the gas supply portfolio for all gas customers in all regions.

Specific to the use of the FEU LNG facilities, changes in sendout from Mt. Hayes and Tilbury, or changes in redelivery from Mist and Jackson Prairie underground storage into the West region system could change the requirements to transport gas from the Spectra T-South system or from the TransCanada Pipelines Limited (BC) ("TCPL(BC)") system via the Southern Crossing Pipeline of the Interior Transmission System ("ITS") to the Lower Mainland (or the West region system). This in turn affects how the East region system would operate.

The FEVI transmission system is primarily used to transport gas to serve FEVI customers. This is similar to the ITS system (other than Southern Crossing) that is primarily used to serve FEI's customers in the Interior and Columbia regions). As part of an integrated system, however, the FEU transmission and LNG facilities along with contracted transportation and storage resources are operated in a way that optimizes the delivery of gas to the different regions in response to daily loads and other conditions. For example, during extreme cold weather events, Mt. Hayes is used to supplement supply to meet FEI's demand in the Lower Mainland via the FEVI transmission system (directly or by displacement). This integration of the pipelines then in turn allows FEI to divert additional gas supply, originally destined to the Lower Mainland, either from Spectra's T-South system or the TCPL(BC) system, to the ITS to meet the requirements of FEI's demand in the Interior.

145.2 Please explain how the Mt. Hayes storage facility is used by the East Region.

Response:

Please refer to the response to BCUC IR 1.145.1.

145.3 Please explain how the Tilbury storage facility is used by the East Region.

Response:

Please refer to the response to BCUC IR 1.145.1.

146.0 Reference: Regional Characteristics

Exhibit B-3, Section 3.2, p. 31

FEI Mainland Operating Data

The FEU evidence shows Table 3-2: FEI Operating Data summarizing annual data from 2006 to 2013F.

146.1 Please provide a similar table for each of the service areas, Lower Mainland, Inland and Columbia.

Response:

The following table provides a breakdown of the FEI data provided in Table 3-2 into the Lower Mainland, Inland and Columbia service areas. The volumes provided for FEI in Table 3-2 included Revelstoke and FEVI Wheeling volumes, while this table excludes those volumes.

A breakdown of rate base and O&M expenses by service area is not available. This data is not tracked by service area, but is recorded for FEI as a whole. Therefore the system is unable to generate regional data.

Lower Mainland, Inland & Columbia Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Sales/Transportation Volumes† (PJ)								
Lower Mainland	124,683	119,662	120,256	119,713	117,050	117,732	117,746	118,052
Inland	48,928	51,682	46,683	42,844	44,875	44,638	45,057	44,961
Columbia	5,723	5,961	6,183	5,752	6,970	6,810	6,852	6,851
Total FEI Sales/Transportation Volumes (PJ)	**179,334**	**177,305**	**173,122**	**168,309**	**168,894**	**169,180**	**169,654**	**169,864**
Customers (Average)								
Lower Mainland	562,139	571,596	576,952	581296	585,484	590,634	595,178	599,987
Inland	219,160	223,079	226,671	229148	231,033	233,169	234,830	236,582
Columbia	21,444	21,752	22,073	22307	22,500	22,719	22,929	23,139
Total Customers (Average)	**802,743**	**816,427**	**825,696**	**832,751**	**839,017**	**846,522**	**852,937**	**859,708**
Normalized Average Use Rate*								
Lower Mainland	103	103	100	100	100	99	98	97
Inland	82	80	76	77	76	75	74	73
Columbia	87	87	83	84	82	81	80	79

†Exclusive of Revelstoke and FEVI Wheeling Volumes
*Based on Residential Customers

Please refer to the response to BCUC IR 1.146.2 for a discussion of the data in the table above.

146.2 For each of the three Mainland service areas please provide explanations for the trends in net customer additions, normalized average use rate, rate base per customer and O&M per customer.

Response:

The table below provides the percentage change in sales/transportation volumes, net customer additions and normalized average use rate for the Lower Mainland, Inland and Columbia service areas. The percentage change in rate base per customer as well as O&M per customer is also provided for FEI. Rate base and O&M expenses are not recorded individually for FEI, therefore a breakdown by service area for these three regions is not available.

The table indicates that sales and transportation volumes have declined since 2006 for both Lower Mainland and Inland. The Columbia region has seen an increase since 2006, due mainly to the increase in Rate 22 volumes in 2010. However, for 2011-2013, either decreases or modest increases are forecast.

The average number of customers has increased slightly since 2006 in all regions, and is forecast to continue to increase no more than 1% annually from 2010 to 2013. This is a reflection of the continued shift away from single family dwellings to multiple-family dwellings. Developers are partial to electric baseboards over natural gas due to the lower upfront capital costs. As well, negative perceptions towards fossil fuels such as natural gas may discourage the use of natural gas.[111]

Normalized average use rate for the three service areas has decreased from 2006 to 2010. This trend is forecast to continue into 2013 due to a number of factors. Older appliances have been replaced with higher efficiency appliances, demand side management programs as well as government policy encourages energy conservation and the impact of the carbon tax deteriorates the competitiveness of natural gas. Please refer to the responses to the BCUC IR 1.158 series for further discussion on regional characteristics regarding consumption.

The change in rate base per customer has remained below 2% for all years with the exception of the forecast increase in 2012, which is largely attributable to the Customer Care Enhancement project and to investments in system sustainment and reliability.

O&M expenses have increased each year since 2006. These increases are due to a number of sources, including labor inflation and benefits, accounting changes, costs related to the ongoing maintenance of the safety and reliability of FEI's system, customer and stakeholder

[111] A recent study completed by Pembina Institute advocates that Government should no longer consider natural gas a bridging fuel toward a cleaner and more sustainable energy mix. Matthew Bramley, The Pembina Institute, "Is Natural Gas a Climate Change Solution for Canada?", 2011.

expectations, demographic challenges and service standards and reliability costs driven by the company's Long Term Sustainment Plan.

These figures highlight the trends in the FEI regions; increasing expenses coupled with decreasing volumes and average use rates across the Mainland, Inland and Columbia service areas.

Lower Mainland, Inland & Columbia Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Sales/Transportation Volumes† (PJ)								
Lower Mainland	124,683	119,662	120,256	119,713	117,050	117,732	117,746	118,052
% Change		-4.0%	0.5%	-0.5%	-2.2%	0.6%	0.0%	0.3%
Inland	48,928	51,682	46,683	42,844	44,875	44,638	45,057	44,961
% Change		5.6%	-9.7%	-8.2%	4.7%	-0.5%	0.9%	-0.2%
Columbia	5,723	5,961	6,183	5,752	6,970	6,810	6,852	6,851
% Change		4.2%	3.7%	-7.0%	21.2%	-2.3%	0.6%	0.0%
Customers (Average)								
Lower Mainland	562,139	571,596	576,952	581296	585,484	590,634	595,178	599,987
% Change		1.7%	0.9%	0.8%	0.7%	0.9%	0.8%	0.8%
Inland	219,160	223,079	226,671	229148	231,033	233,169	234,830	236,582
% Change		1.8%	1.6%	1.1%	0.8%	0.9%	0.7%	0.7%
Columbia	21,444	21,752	22,073	22307	22,500	22,719	22,929	23,139
% Change		1.4%	1.5%	1.1%	0.9%	1.0%	0.9%	0.9%
Normalized Average Use Rate*								
Lower Mainland	103	103	100	100	100	99	98	97
% Change		-0.5%	-3.0%	0.7%	-0.4%	-0.9%	-0.9%	-0.9%
Inland	82	80	76	77	76	75	74	73
% Change		-1.5%	-5.4%	1.2%	-1.6%	-1.3%	-1.2%	-1.2%
Columbia	87	87	83	84	82	81	80	79
% Change		0.1%	-4.3%	0.6%	-2.0%	-1.2%	-1.2%	-1.2%

†Exclusive of Revelstoke and FEVI Wheeling Volumes

*Based on Residential Customers

Unit Figures	2006	2007	2008	2009	2010	2011F	2012F	2013F
Rate Base Per Customer								
FEI	$ 3,043	$ 2,972	$ 2,997	$ 2,957	$ 3,010	$ 3,003	$ 3,228	$ 3,269
% Change		-2.3%	0.8%	-1.3%	1.8%	-0.2%	7.5%	1.3%
O&M Per Customer								
FEI	$ 223	$ 219	$ 225	$ 230	$ 246	$ 253	$ 270	$ 280
% Change		-1.8%	2.6%	2.5%	6.8%	2.7%	6.7%	3.9%

147.0 Reference: Regional Characteristics

Exhibit B-3, Section 3

Operating Data

The FEU provide evidence on operating data for the four utility rate bases in Tables 3-2, 3-4, 3-7 and 3-9.

147.1 Please provide detailed explanations for the trends indicated by the operating results presented in the tables.

Response:

The tables referenced above are also included in the response to BCUC IR 1.154.1, along with the year-over-year percentage change in total volumes, average number of customers and the rate base. The five categories presented in the operating data tables are summarized below, along with an explanation of the trends.

Sales/Transportation Volumes

Total Annual Figures	2006	2007	2008	2009	2010	2011F	2012F	2013F
FEI								
Sales/Transportation Volumes (TJ)	209,077	209,077	210,091	200,822	201,111	205,987	206,716	207,160
Annual Growth		0.0%	0.5%	-4.4%	0.1%	2.4%	0.4%	0.2%
FEVI								
Sales/Transportation Volumes (TJ)	28,277	35,368	34,383	30,693	31,276	33,991	34,132	34,255
Annual Growth		25.1%	-2.8%	-10.7%	1.9%	8.7%	0.4%	0.4%
FEW								
Sales/Transportation Volumes (TJ)	734	742	709	629	765	731	716	709
Annual Growth		1.2%	-4.4%	-11.3%	21.6%	-4.5%	-2.1%	-1.0%
FEFN								
Sales/Transportation Volumes (TJ)	906	816	751	621	615	624	632	641
Annual Growth		-9.9%	-8.0%	-17.3%	-1.0%	1.5%	1.3%	1.4%

The volumes forecast for 2013 are lower than volumes in 2006 for all entities with the exception of FEVI. In 2007, the data shows a large increase in volumes for FEVI. This is due to the closure of the Cogen plant for approximately 5 months in 2006, resulting in approximately 6.4 PJ's less consumption in 2006 compared to 2007.

In 2009, the global financial crisis resulted in declines in total sales and transportation demand volumes for all regions, as reflected in the table above. Since 2009, FEI volumes increased modestly in 2010, and are forecast to continue to increase slowly until 2013. FEVI and FEFN are also forecast to experience increases from 2010 to 2013. FEW experienced a large increase in volumes in 2010, due mainly to the completion of the Whistler Pipeline Conversion project. The project was completed in April 2009, and customers were gradually converted to the natural gas system beginning in August 2009. This resulted in an increase in total volume in 2010, but the increase is forecast to taper off after 2010.

Average Customers

Customers (Average)	2006	2007	2008	2009	2010	2011F	2012F	2013F
FEI								
Customers (Average)	802,743	816,427	825,696	832,751	839,017	846,522	852,937	859,708
Annual Growth		1.7%	1.1%	0.9%	0.8%	0.9%	0.8%	0.8%
FEVI								
Customers (Average)	85,321	89,302	93,006	96,237	98,920	101,266	103,754	106,360
Annual Growth		4.7%	4.1%	3.5%	2.8%	2.4%	2.5%	2.5%
FEW								
Customers (Average)	2,368	2,391	2,434	2,519	2,586	2,592	2,610	2,629
Annual Growth		1.0%	1.8%	3.5%	2.7%	0.2%	0.7%	0.7%
FEFN								
Customers (Average)	2,325	2,340	2,355	2,355	2,360	2,386	2,405	2,427
Annual Growth		0.6%	0.6%	0.0%	0.2%	1.1%	0.8%	0.9%

- The average number of customers in the FEU system have steadily increased from 2006 to 2010, and are forecast to increase slightly from 2011 to 2013. For FEI, the largest region in terms of customers, the increase is forecast to be less than 1% per year. The increases in FEW and FEFN are also modest, and are generally also less than 1% per year. The FEVI region is forecast to experience customer growth of over 2% per year. Although this is greater than the other regions, it is still relatively low compared to the increase in 2007 of 4.7%.

The table highlights that although customer additions are increasing, overall they are increasing at a slower pace than in 2006.This slower growth rate is due to a number of factors. There has been a shift away from construction of single family dwellings and towards multi-family dwellings. Developers are also increasingly choosing to install electric baseboards over natural gas due to the lower upfront capital costs associated with natural gas installation. As well, negative perceptions towards natural gas may discourage the use of natural gas.[112]

Overall, since the financial crisis of 2009, customer additions have to date failed to return to pre-2009 levels.

[112] recent study completed by Pembina Institute advocates that Government should no longer consider natural gas a bridging fuel toward a cleaner and more sustainable energy mix. Matthew Bramley, The Pembina Institute, "Is Natural Gas a Climate Change Solution for Canada?", 2011.

Normalized Average Use Rate

Average Annual Use Rate (GJ)	2006	2007	2008	2009	2010	2011F	2012F	2013F
FEI								
Average Use Rate	97	96	93	93	93	92	91	90
Annual Growth		-0.8%	-3.6%	0.9%	-0.8%	-1.0%	-1.0%	-1.0%
FEVI								
Average Use Rate	60	57	56	54	52	50	49	47
Annual Growth		-5.3%	-1.6%	-4.6%	-2.2%	-3.6%	-3.7%	-3.6%
FEW								
Average Use Rate	86	96	95	83	99	102	104	106
Annual Growth		11.8%	-0.6%	-13.2%	20.4%	2.2%	2.2%	2.2%
FEFN								
Average Use Rate	142	142	140	138	141	141	140	140
Annual Growth		0.3%	-1.7%	-0.9%	1.8%	-0.2%	-0.2%	-0.2%

*Based on Residential Customers

The normalized average use rate for residential customers in FEI and FEVI has declined significantly since 2006. FEW residential customers experienced an increase in average use following the system conversion from a piped propane system to natural gas in 2009, and a shift towards natural gas appliances. FEFN residential customers have also experienced a declining use rate, although not as significant as FEI and FEVI during 2006-2011. The FEFN residential customer use rate experienced a significant decline of approximately 21GJs between 2003 and 2006.

The declines in use rates are attributable to various factors, including the retrofit of higher efficiency appliances, the shift towards more multi-family dwellings in the housing mix, demand side management programs, the carbon tax and government policy. All of these factors have collectively led to the decline in the average use per customer rate. These factors are expected to continue into the future.

Rate Base

Rate Base	2006	2007	2008	2009	2010	2011F	2012F	2013F
FEI								
Rate Base	$ 2,442,352	$ 2,426,180	$ 2,474,447	$ 2,462,143	$ 2,525,213	$ 2,542,002	$ 2,753,641	$ 2,810,535
Annual Growth		-0.7%	2.0%	-0.5%	2.6%	0.7%	8.3%	2.1%
FEVI								
Rate Base	$ 464,180	$ 478,699	$ 511,422	$ 532,925	$ 547,661	$ 676,636	$ 788,314	$ 815,684
Annual Growth		3.1%	6.8%	4.2%	2.8%	23.6%	16.5%	3.5%
FEW								
Rate Base	$ 17,040	$ 16,830	$ 16,782	$ 31,518	$ 45,400	$ 44,892	$ 42,046	$ 41,346
Annual Growth		-1.2%	-0.3%	87.8%	44.0%	-1.1%	-6.3%	-1.7%
FEFN								
Rate Base	$ 4,825	$ 5,048	$ 5,093	$ 5,055	$ 5,410	$ 5,755	$ 7,392	$ 9,241
Annual Growth		4.6%	0.9%	-0.7%	7.0%	6.4%	28.4%	25.0%

Overall, there has been an upward trend in the increase in rate base for each region. The forecast increases for the FEVI region in 2010 and 2011 are largely attributable to costs associated with the Mt. Hayes LNG Facility. FEW experienced a similar large increase in rate base in 2009 and 2010. The increase is due to the Whistler Pipeline Conversion Project which was completed in 2009.

FEFN is forecast to have significant increases in rate base in 2012 and 2013. These increases are driven by recent capital additions, including the Muskwa River Crossing. This project is needed to ensure the safety and reliability of Fort Nelson's distribution system.

Apart from these significant one-time increases, rate base has increased at a moderate rate, and in some cases, even decreased.

Gross O&M Expenses (Nominal)

Gross O&M Expenses (Nominal)	2006	2007	2008	2009	2010	2011F	2012F	2013F
FEI								
O&M Expenses (Nominal)	$ 179,206	$ 178,973	$ 185,739	$ 191,945	$ 206,519	$ 214,035	$ 230,189	$ 241,103
Annual Growth		-0.7%	2.0%	-0.5%	2.6%	0.7%	8.3%	2.1%
FEVI								
O&M Expenses (Nominal)	$ 25,524	$ 24,514	$ 25,782	$ 26,514	$ 29,852	$ 32,617	$ 36,117	$ 36,232
Annual Growth		-4.0%	5.2%	2.8%	12.6%	9.3%	10.7%	0.3%
FEW								
O&M Expenses (Nominal)	$ 821	$ 793	$ 906	$ 791	$ 773	$ 868	$ 904	$ 913
Annual Growth		-3.4%	14.3%	-12.7%	-2.4%	12.4%	4.1%	1.0%
FEFN								
O&M Expenses (Nominal)	$ 820	$ 835	$ 740	$ 784	$ 794	$ 812	$ 884	$ 911
Annual Growth		1.9%	-11.4%	6.0%	1.2%	2.4%	8.8%	3.1%

Overall, O&M expenses have gradually increased since 2006. O&M expenses are driven by five main cost drivers:

1. Labor inflation and benefits
2. Codes and regulations
3. Customer and stakeholder expectations
4. Demographics and
5. A continued focus on service standards and reliability

These form part of the ongoing costs associated with operating the utility system.

147.2 Please provide detailed explanations with regard to the significant differences in the unit figures for each utility and compare/contrast the results shown for each utility explaining the reasons behind any regional differences. Please include any relevant statistical data and explanations of that gives the Commission further insight into the regional characteristics of each service area.

Response:

The unit figures for rate base and O&M per customer is provided for FEI, FEVI, FEW and FEFN below.

Unit Figures	2006	2007	2008	2009	2010	2011F	2012F	2013F
FEI								
Rate Base Per Customer	$ 3,043	$ 2,972	$ 2,997	$ 2,957	$ 3,010	$ 3,003	$ 3,228	$ 3,269
O&M Per Customer	$ 223	$ 219	$ 225	$ 230	$ 246	$ 253	$ 270	$ 280
FEVI								
Rate Base Per Customer	$ 5,440	$ 5,360	$ 5,499	$ 5,538	$ 5,536	$ 6,682	$ 7,598	$ 7,669
O&M Per Customer	$ 299	$ 275	$ 277	$ 276	$ 302	$ 322	$ 348	$ 341
FEW								
Rate Base Per Customer	$ 7,197	$ 7,040	$ 6,895	$ 12,515	$ 17,556	$ 17,322	$ 16,112	$ 15,729
O&M Per Customer	$ 347	$ 332	$ 372	$ 314	$ 299	$ 335	$ 346	$ 347
FEFN								
Rate Base Per Customer	$ 2,075	$ 2,157	$ 2,163	$ 2,146	$ 2,292	$ 2,412	$ 3,073	$ 3,808
O&M Per Customer	$ 353	$ 357	$ 314	$ 333	$ 336	$ 340	$ 368	$ 375

Rate base per customer is highest for FEW customers. This is due mainly to the Whistler Pipeline Conversion Project, which converted Whistler's piped propane system to natural gas. As this is a relatively new system, the capital costs incurred have resulted in relatively higher rate base for this region. As the customer base in Whistler is also relatively small, this has led to a high rate base per customer. Although Whistler has experienced higher rate base per customer as a result of the pipeline and conversion, customers in Whistler have also experienced significantly lower commodity costs as a result, leading to lower overall annual bills than the previous propane system.

FEVI also has higher per customer rate base costs due to the relative age of the system and the higher proportion of transmission and storage assets. Fort Nelson is forecast to see a large increase in its rate base per customer. As part of a scheduled survey in 2008, erosion of the underwater transmission pipeline was detected. An upgrade, called the Muskwa River Crossing Project, is required to maintain system safety and reliability. Project costs for the Muskwa River Project are currently estimated at $3 million based on the existing approved project design, with the first portion of this amount being added to rate base in 2012. However, at this time, the current project design is awaiting Federal Government approval. If approval cannot be obtained, an alternative solution will be required and approval will be sought from the

Commission should that be the case. Based on current estimates an alternative solution will likely be higher in cost.

O&M expenses on a per customer basis are lowest in FEI. There is a larger customer base in this region, allowing these expenses to be allocated over a larger population and resulting in lower O&M costs per customer. FEVI and FEW have comparable O&M costs. These regions are part of a shared services agreement with FEI; however, these regions are much smaller relative to FEI, and therefore per unit O&M costs are higher per customer.

Fort Nelson has the highest O&M costs on a per customer basis. Although Fort Nelson is also allocated O&M costs from FEI, Fort Nelson experiences a higher degree of distribution costs per customer due to the remote location of the system and the geographic dispersion of customers.

147.3 Please calculate delivery costs per km of distribution pipe for FEI,FEVI, FEFN, and FEW. Please explain any significant differences.

Response:

The table below summarizes the delivery costs per kilometer of distribution pipe for FEI, FEVI, FEW and FEFN from 2006 to 2011. The FEU do not forecast kilometers of pipeline, therefore this analysis has not been provided for 2012 and 2013.

	2006	2007	2008	2009	2010	2011P
FEI						
Delivery Costs	$ 495,020	$ 476,498	$ 493,908	$ 512,362	$ 540,079	$ 551,252
Km of Distribution Pipe	36,392	36,724	37,245	37,516	37,670	37,793
Delivery Costs Per Km of Distribution Pipe	**$ 14**	**$ 13**	**$ 13**	**$ 14**	**$ 14**	**$ 15**
FEVI						
Delivery Costs[1]	$ 109,270	$ 122,406	$ 138,043	$ 127,094	$ 123,592	$ 121,683
Km of Distribution Pipe	5,231	5,359	5,461	5,533	5,600	5,673
Delivery Costs Per Km of Distribution Pipe	**21**	**23**	**25**	**23**	**22**	**21**
FEW						
Delivery Costs	$ 2,872	$ 2,899	$ 2,763	$ 4,471	$ 8,854	$ 8,174
Km of Distribution Pipe	128	130	131	135	136	139
Delivery Costs Per Km of Distribution Pipe	**22**	**22**	**21**	**33**	**65**	**59**
FEFN						
Delivery Costs	$ 1,313	$ 1,304	$ 1,354	$ 1,300	$ 1,437	$ 1,797
Km of Distribution Pipe	212	213	214	214	216	222
Delivery Costs Per Km of Distribution Pipe	**6**	**6**	**6**	**6**	**7**	**8**

[1] FEVI delivery costs exclude royalty credits but include embedded revenue deficiency or surplus per year

In the case of FEI and FEFN, the delivery costs per kilometer of pipeline are low when compared to the other regions, as the systems are older relative to FEVI and FEW and therefore have been largely depreciated.

Conversely, newer systems have higher delivery costs. This is evident when comparing the delivery cost for FEW, which is much higher in 2009, 2010 and 2011 than all the other regions. The high delivery cost per kilometer of pipeline is attributable to the completion of the Whistler Pipeline Conversion Project, which converted the piped propane system to natural gas in 2009. Subsequently, delivery costs increased substantially that year.

Along with a comparison of delivery costs per kilometer of pipeline, it can be helpful to analyze this ratio in the same region over a period of time. The discussion below provides details regarding the delivery costs per kilometer of pipeline for the individual entities from 2006 to 2011.

The delivery cost per kilometer of distribution pipe has remained stable from 2006 – 2011 in the FEI, FEFN and FEVI regions. Although delivery costs have generally increased since 2006, the increase in kilometers of distribution pipe has also kept pace, which has meant little impact overall on a delivery cost per kilometer of distribution pipe basis.

FEW delivery costs per kilometer of distribution pipeline are the highest among the four regions. While pipeline kilometers remained stable, delivery costs increased substantially from 2008 to 2009 due to the Whistler Pipeline as described above.

147.4 Please calculate the number of customers per km of distribution pipe for FEI,FEVI, FEFN, and FEW. Please explain any significant differences.

Response:

The table below summarizes the number of customers per km of distribution pipe for FEI, FEVI, FEW and FEFN from 2006 to 2011. FEU does not forecast kilometers of pipeline, therefore this analysis has not been provided for 2012 and 2013.

	2006	2007	2008	2009	2010	2011
FEI						
Customers (Average)	802,743	816,427	825,696	832,751	839,017	846,522
Km of Distribution Pipe	36392	36724	37245	37516	37670	37793
Customers / Km Distribution Pipe	**22**	**22**	**22**	**22**	**22**	**22**
FEVI						
Customers (Average)	85,321	89,302	93,006	96,237	98,920	101,266
Km of Distribution Pipe	5,231	5,359	5,461	5,533	5,600	5,673
Customers / Km Distribution Pipe	**16**	**17**	**17**	**17**	**18**	**18**
FEW						
Customers (Average)	2,368	2,391	2,434	2,519	2,586	2,592
Km of Distribution Pipe	128	130	131	135	136	139
Customers / Km Distribution Pipe	**18**	**18**	**19**	**19**	**19**	**19**
FEFN						
Customers (Average)	2,325	2,340	2,355	2,355	2,360	2,386
Km of Distribution Pipe	212	213	214	214	216	222
Customers / Km Distribution Pipe	**11**	**11**	**11**	**11**	**11**	**11**

The data in the table shows that the number of customers per kilometer of pipeline has remained stable from 2006 to 2011 for each of the entities. This demonstrates that the appropriate amount of distribution pipelines have been installed to keep pace with customer additions.

Although it is a fair comparison to analyze the amount of customers per kilometer of pipeline for a given entity over time, it becomes difficult to make valuable comparisons between different entities and therefore there is little value in the analysis. This is due to differences in factors such as the housing mix and population densities among different regions. Therefore, although the FEI region has twice the number of customers per kilometer of pipeline than the Fort Nelson region, it is difficult to draw conclusions based solely on that data. Fort Nelson has a small population, with customers who are more geographically dispersed.

148.0 Reference: Regional Characteristics

Exhibit B-3, Section 9.6.2.5, pp. 209

Exhibit B-3-1, Appendix D-4, pp. 1-2

COSA Methodology - Customer Weighting Factors for Meters & Services

"By comparing the current meter and service costs of each class to that of the residential rate class, customer weighting factors for meters and services are obtained. The customer numbers weighted for meters and services are then used to allocate costs associated with the Distribution customer-related component to each rate class." (Section 9.6.2.5, p. 209)

The Commission wishes to understand whether or not significant cost differences exist for the meters and services of residential customers in each of FEI, FEVI, FEW and FEFN.

148.1 Please provide the current meter and service cost related to a residential customer in each of FEI, FEVI, FEW and FEFN.

Response:

The current meter and service costs related to a residential customer in each of FEI, FEVI, FEW and FEFN are presented in the table below.

Region	FEI	FEVI	FEW	FEFN
Average meter and service cost per residential customer	$1,441	$1,436	$1,561	$1,437

FEI, FEVI and FEFN average meter and service costs are very similar across the three regions. FEW has a slightly higher average cost as Whistler residential customers have a higher proportion of larger residential meters, thereby increasing the average meter and service cost per customer.

148.2 Please present a separate Table 1 (Appendix D-4, p. 2) for each of FEI, FEVI, FEW and FEFN using the current meter and service cost of a residential customer in FEI as the base cost in each case.

Response:

The current meter and service costs for each of FEI, FEVI, FEW and FEFN relative to an FEI residential customer are presented in the tables below, and generally show the current costs to be similar.

FEI - Customer Weighting Factors for FEI using the current meter and service cost of a residential customer in FEI as the base cost:

Rate Class	2012 FEI Weighting Factors
Rate 1 - Residential	1.0
Rate 2 - Small Commercial	1.7
Rate 3 - Large Commercial	7.0
Rate 4 - Seasonal	13.2
Rate 5 - General Firm	11.8
Rate 6 - NGV Services	14.2
Rate 7 - General Interruptible	37.2
Rate 22 - Large Industrial Interruptible	38.6
Rate 23 - Large Commercial Transportation	9.7
Rate 3 / 23 - Large Commercial	7.6
Rate 25 - General Firm Transportation	16.5
Rate 5 / 25 - General Firm	15.0
Rate 27 - General Interruptible	31.7
Rate 7 / 27 - General Interruptible	31.8

FEVI - Customer Weighting Factors for FEVI using the current meter and service cost of a residential customer in FEI as the base cost:

Rate Class	2012 FEVI Weighting Factors
RGS-1 Residential	1.0
AGS Apartment General Service	3.2
SCS-1/2 Small Commercial Service	1.5
LCS-1 Large Commercial Service (< 2,000 GJ per year)	4.3
LCS-2 Large Commercial Service (≥ 2,000 GJ per year)	5.9
LCS-3 Large Commercial Service (≥ 6,000 GJ per year)	6.8
HLF - High Load Factor (> 85% & ≥ 6,000 GJ per year)	13.1

Rate Class	2012 FEVI Weighting Factors
ILF - Inverse Load Factor (> 150% & ≥ 6,000 GJ per year)	32.2

FEW - Customer Weighting Factors for FEW using the current meter and service cost of a residential customer in FEI as the base cost:

Rate Class	2012 FEW Weighting Factors
TGW Residential	1.0
TGW Small Commercial 0-599GJ	1.6
TGW Small Commercial 600-1999GJ	4.5
TGW Small Commercial 2K-5999GJ	7.7
TGW Large Commercial OVER 6000GJ	14.9

FEFN - Customer Weighting Factors for FEFN using the current meter and service cost of a residential customer in FEI as the base cost:

Rate Class	2012 FEFN Weighting Factors
Rate 1 - Residential	1.0
Rate 2 - Small Commercial	1.8
Rate 3 - Large Commercial	6.6
Rate 25 - General Firm Transportation	32.7

149.0 Reference: Regional Characteristics

Exhibit B-3, Section 9.6.2.5, pp. 210

Exhibit B-3-1, Appendix D-4, pp. 1-2

COSA Methodology - Customer Weighting Factors for Customer Administration and Billing

"Based on recommendations from the FEU‟s customer service and billing representatives, weighting factors for each rate class were developed which take into consideration: the frequency of meter reading; the use of AMR and the method of collecting and retaining load data; the amount of time spent by customer service responding to inquiries; marketing programs and costs for different customer groups; the existence of dedicated account managers for commercial and industrial customers; and the number of resources dedicated to each customer class for customer billing, measurement and marketing. The customer numbers weighted for customer administration and billing are then used to allocate costs associated with the customer administration to each rate class." (Section 9.6.2.5, p. 210)

Commission Staff wish to understand whether or not significant cost differences exist for customer administration and billing of residential customers in each of FEI, FEVI, FEW and FEFN.

149.1 Please provide the current administration and billing cost related to a residential customer in each of FEI, FEVI, FEW and FEFN.

Response:

Under the current common management and operational structure, billing and customer administration for all regions is handled by a common team. Billing and customer administration costs are not broken down by region or rate class and it is for this reason that weighting factors to allocate billing and customer administration related costs are required. Therefore, the FEU are unable to provide the current administration and billing costs by region. There are not significant cost differences amongst the regions based on the shared services approach.

149.2 Please present a separate Table 2 (Appendix D-4, p. 2) for each of FEI, FEVI, FEW and FEFN using the current administration and billing cost of a residential customer in FEI as the base cost in each case.

<u>Response:</u>

Please refer to the response to BCUC IR 1.149.1.

150.0 Reference: Regional Characteristics

Exhibit B-3, Section 9.6.2.5, pp. 208-209

Exhibit B-3-1, Appendix D-1, pp. 19 - 20

COSA Methodology - Peak Demand Allocation

Commission Staff wish to understand whether any delivery areas have distinctive load characteristics.

150.1 For each existing delivery area (Mainland, FEVI, FEW, and FEFN), please provide the load factors for each customer class including all Industrial, Bypass and Contract Service Rate customers.

Response:

The load factors for each customer class including all industrial, bypass and contract service rate customers are provided in the tables below for each of the delivery areas. The comparison shows that generally the load characteristics are similar by class for each of the existing delivery areas.

FEI

Rate Class	Load Factor (%)
1	29.8%
2	31.3%
3/23	36.5%
4	-
5/25	53.2%
6	100%
7/27	-
25 Bypass	100%
22 Interruptible	-
22 Bypass	100%
22A	100%
22B	100%
BC Hydro Burrard Thermal	100%

Fort Nelson

Rate Class	Load Factor (%)
1	32.7%
2.1	30.8%
2.2	40.2%
25	37.7%

FEVI

Rate Class	Load Factor (%)
RGS	29.4%
AGS	42.0%
SCS1	34.9%
SCS2	44.8%
LCS1	45.1%
LCS2	48.2%
LCS3	42.2%
HLF	100%
ILF	-
BC Hydro ICP	100%
VIGJV	100%

FEW

Rate Class	Load Factor (%)
SGS Res	30.0%
SGS Com	43.2%
LGS1	40.2%
LGS2	42.2%
LGS3	40.6%

150.2 Does the FEU expect that the peak demand will occur at the same time on each delivery area (Mainland, FEVI, FEW, and FEFN)?

Response:

Yes, the FEU expect generally that since the bulk of the firm load for each delivery area is heat sensitive that the peak demand will occur during cold weather periods in each delivery area.

150.3 Please provide an estimate of the coincidence factors of each customer class including all Industrial, Bypass and Contract Service Rate customers for each existing delivery area (Mainland, FEVI, FEW, and FEFN).

Response:

The FEU assume the coincidence factors referred to in this information request represents the ratio of the coincident peak to the non-coincident peak demand for each class. The Companies have not calculated the non-coincident peak demands and thus cannot provide the coincidence factors for each class and each existing delivery area; however, the FEU believe it would be reasonable to assume the coincidence factors for the firm classes would be 100%.

"These load factors are then applied to the volumes of the applicable rate class for the forecast period to calculate the peak day demand. … The sum of the classes determines total system demand which is then utilized to calculate the demand allocator for each of the functionalized classified categories of the cost of service." (Section 9.6.2.5, p. 209)

and:

"To be consistent with past COSA studies, the coincident peak day demand numbers were used for all allocation factors. While this is an acceptable methodology, there are cases where both a coincident peak (CP) and non-coincident peak (NCP) allocators are both used within a COSA. This is something that the FEU may want to consider for future applications." (Appendix D-1, p. 20)

150.4 Describe how the calculation of the non-coincident peak demand numbers is different from the method used to calculate the peak demand numbers as described above.

Response:

The FEU have not specifically calculated non-coincident peak demand numbers for use in the COSA and has not identified a detailed methodology for doing so at this point. However, the non-coincident peak would reflect the highest daily demand that might occur on any day of the year for a customer class, whether or not it occurs on the system-wide peak day. The coincident peak demand methodology used in the COSA calculates the class peaks that are coincident with the system wide peak day. In a non-coincident peak demand scenario, it would be reasonable to assume that the seasonal and interruptible classes would also make a contribution to the peak demand in addition to the firm classes.

151.0 Reference: Regional Characteristics

Exhibit B-3-1, Appendix D-1, p. 9

Marginal Costs

"A COSA can be performed using embedded costs or marginal costs. Embedded costs generally reflect the actual costs incurred by the utility and closely track the costs kept in its accounting records. Marginal costs reflect the cost associated with adding a new customer, and are based on costs of facilities and services if incurred at the present time."

Commission Staff wish to understand whether the costs of adding additional customers to the distribution system are significantly different in each service area.

151.1 For the period 2009 - 2011, what was the ratio of metres of distribution mains installed per new customer additions in each of: FEI Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN?

Response:

The ratio of metres of distribution mains installed per new customer additions in FEI Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN is provided below.

		2009	2010	2011
New Mains Installed (metres)	FEI Lower Mainland	46,868	44,367	35,705
	FEI Inland	34,136	25,531	33,861
	FEI Columbia	4,661	10,124	4,415
	FEI Total	85,665	80,022	73,981
	FEVI	24,711	18,282	26,280
	FEW	1,703	1,843	2,933
	FEFN	-	1,237	5,374
	FEU Total	112,079	101,384	108,568
GROSS Customer Additions (New Meters Added)	FEI Lower Mainland	6,926	7,017	4,781
	FEI Inland	2,615	2,374	1,353
	FEI Columbia	264	196	88
	FEI Total	9,805	9,587	6,222
	FEVI	3,165	2,419	1,376
	FEW	100	34	28
	FEFN	11	19	32
	FEU Total	13,081	12,059	7,658
Ratio of New Mains Installed to GROSS (new) Customer Additions	FEI Lower Mainland	6.8	6.3	7.5
	FEI Inland	13.1	10.8	25.0
	FEI Columbia	17.7	51.7	50.2
	FEI Total	8.7	8.3	11.9
	FEVI	7.8	7.6	19.1
	FEW	17.0	54.2	104.8
	FEFN	0.0	65.1	167.9
	FEU Total	8.6	8.4	14.2

In 2011 the new mains installed per new customer were unusually high in both FEW and FEFN. In FEW several phases of the Baxter Creek extension were completed, accounting for 2,885 metres installed in the year. In FEFN several phases of the Cordova Way extension were completed in 2011, accounting for 4,411 metres installed in the year. The timing of customer additions (service attachments) is generally in the years following the main installation, as new subdivision activity ramps up once the infrastructure is put in place. As a result, the ratio of new mains to new customer additions in FEW and FEFN for 2011 appears high due to the timing of the main installations and the forecast customer attachments. In FEI, where both mains and customer additions activities are much higher, these same timing issues occur; however, because of the volume of mains and new customers attachments, the variations year over year are smaller.

151.2 For the period 2009 - 2011, what is the ratio of service header mains/net customer additions in each of: FEI Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN?

Response:

		2009	2010	2011
New Service Header Mains Installed (metres)	FEI Lower Mainland	12,213	13,967	13,470
	FEI Inland	12,334	10,010	10,863
	FEI Columbia	903	1,093	654
	FEI Total	25,450	25,070	24,987
	FEVI	7,701	6,137	3,613
	FEW	254	488	-
	FEFN	-	145	33
	FEU Total	33,405	31,840	28,633
NET Customer Additions	FEI Lower Mainland	3,392	4,521	3,522
	FEI Inland	1,554	2,132	1,745
	FEI Columbia	144	216	114
	FEI Total	5,090	6,869	5,381
	FEVI	2,933	2,432	1,965
	FEW	123	12	57
	FEFN	(2)	21	47
	FEU Total	8,144	9,334	7,450
Ratio of New Service Header Mains Installed to Net Customer Additions	FEI Lower Mainland	3.6	3.1	3.8
	FEI Inland	7.9	4.7	6.2
	FEI Columbia	6.3	5.1	5.7
	FEI Total	5.0	3.6	4.6
	FEVI	2.6	2.5	1.8
	FEW	2.1	40.7	0.0
	FEFN	0.0	6.9	0.7
	FEU Total	4.1	3.4	3.8

Please refer to the response to BCUC IR 1.151.3 for an explanation on the differences between service areas with respect to the costs of adding additional customers to the distribution system.

151.3 For the period 2009 - 2011, what is the cost per service line in each of: FEI Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN?

Response:

		2009	2010	2011
Service Costs (Excludes Service Headers)	FEI Lower Mainland	$ 1,647	$ 1,328	$ 1,678
	FEI Inland	$ 1,525	$ 1,436	$ 1,687
	FEI Columbia	$ 1,302	$ 1,409	$ 1,565
	FEI Total	$ 1,616	$ 1,352	$ 1,673
	FEVI	$ 2,252	$ 1,983	$ 2,286
	FEW	$ 2,777	$ 3,828	$ 3,033
	FEFN	$ 1,081	$ 1,073	$ 970
	FEU Total	$ 1,786	$ 1,493	$ 1,804

The service costs are a blend of several different types of services (mostly new and conversion services) in multiple municipalities and do not include service header main costs. Service header costs are included in the blended Services unit cost at the highest level.

The costs of adding new customers to the distribution system in different service areas can vary. The main variables are the type and size of the service required, the length of the service, installation conditions, and location of the service. FEVI service costs are typically higher than FEI due to the higher proportion of conversion services installed.

Existing customers are protected from costlier new service installations through the Service Line Cost Allowance mechanism which requires a contribution from a customer when the new service installation costs exceed $1,535. The FEU have an established "geo-code" pricing methodology in place for estimating the service installation costs in its service territory. These geo-code rates vary from region to region and are based on the previous year's actual installation costs. Therefore, while the service line costs shown in the table for FEVI, FEW and FEI, for example, are higher than $1,535, the cost to the company does not exceed the SLCA of $1,535. Further, while the costs show variation by existing utility, there is also variation in cost by utility. Service lines in rocky, or densely urban areas of FEI are higher than in sandy areas of FEVI for example.

In areas where installation costs are lower (i.e. sandy conditions), customers will be able to install longer services before reaching the $1,535 service cost maximum before a contribution is required. The same service type and size installed in rockier conditions will cost more on a per metre basis and therefore the $1,535 maximum allowable will be reached sooner and the customer for the same length of service may need to make a contribution.

152.0 Reference: Regional Characteristics

Exhibit B-3, Section 4.1.3, pp. 59 - 60

Frequency Distribution of Residential Use per Customer

Commission Staff wish to gain a better understanding of the range in the residential use per account in each service area.

152.1 Please provide a frequency distribution of residential gas consumption by completing the following table for each of FEI Mainland, FEVI, FEW and FEFN based on weather normalized billed consumption data from 2011:

Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range
0 – 5 GJ	%
5 – 10 GJ	%
etc.	etc.

Response:

A table summarizing the percentage of customers in each 5 GJ interval, as well as the cumulative percentage of customers is provided below for the FEI Mainland, FEVI, FEW and FEFN service areas.

FEI Mainland

Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	1.6%	1.6%
5-10	1.0%	2.6%
10-15	1.3%	3.9%
15-20	1.3%	5.2%
20-25	1.5%	6.7%
25-30	1.7%	8.4%
30-35	2.0%	10.4%
35-40	2.4%	12.8%
40-45	2.8%	15.6%
45-50	3.2%	18.9%
51-55	3.7%	22.6%
55-60	4.1%	26.7%
60-65	4.5%	31.2%
65-70	4.9%	36.1%
70-75	5.1%	41.1%
75-80	5.1%	46.3%
80-85	5.1%	51.3%
85-90	4.9%	56.3%
90-95	4.7%	61.0%
95-100	4.3%	65.3%
100-105	4.0%	69.4%
105-110	3.6%	73.0%
110-115	3.3%	76.3%
115-120	2.9%	79.2%
120-125	2.6%	81.7%
125-130	2.3%	84.0%
130-135	2.0%	86.0%
135-40	1.7%	87.7%
140-145	1.5%	89.2%
145-150	1.3%	90.5%
150-155	1.2%	91.7%
155-160	1.0%	92.7%
160-165	0.9%	93.6%
165-170	0.8%	94.4%
170-175	0.7%	95.1%
175-180	0.6%	95.7%
180-185	0.5%	96.2%
185-190	0.5%	96.7%
190-195	0.4%	97.1%
195-200	0.4%	97.5%
200-205	0.3%	97.8%
205-210	0.3%	98.1%
210-215	0.2%	98.3%
215-220	0.2%	98.5%
220-225	0.2%	98.7%
225-230	0.2%	98.9%
230-235	0.1%	99.0%
235-240	0.1%	99.2%
240-245	0.1%	99.3%
245-250	0.1%	99.4%
250-255	0.1%	99.5%
255-260	0.1%	99.6%
Over 260	0.4%	100.0%

FEVI

Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	5.8%	5.8%
5-10	4.5%	10.3%
10-15	5.6%	15.9%
15-20	5.9%	21.7%
20-25	6.0%	27.7%
25-30	5.8%	33.5%
30-35	6.0%	39.6%
35-40	5.8%	45.4%
40-45	5.7%	51.2%
45-50	5.3%	56.5%
51-55	5.5%	61.9%
55-60	5.0%	67.0%
60-65	4.8%	71.8%
65-70	4.5%	76.3%
70-75	4.0%	80.3%
75-80	3.4%	83.7%
80-85	3.0%	86.7%
85-90	2.4%	89.1%
90-95	2.0%	91.1%
95-100	1.7%	92.9%
100-105	1.3%	94.2%
105-110	1.0%	95.2%
110-115	0.8%	96.0%
115-120	0.7%	96.7%
120-125	0.5%	97.2%
125-130	0.4%	97.6%
130-135	0.4%	98.0%
135-40	0.3%	98.3%
140-145	0.2%	98.5%
145-150	0.2%	98.7%
150-155	0.2%	98.8%
155-160	0.1%	99.0%
160-165	0.1%	99.1%
165-170	0.1%	99.2%
Over 170	0.8%	100.0%

FEW		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	7.4%	7.4%
5-10	4.7%	12.1%
10-15	6.8%	18.9%
15-20	6.9%	25.8%
20-25	5.3%	31.1%
25-30	4.2%	35.3%
30-35	3.2%	38.5%
35-40	2.7%	41.1%
40-45	1.8%	43.0%
45-50	2.2%	45.1%
51-55	2.0%	47.1%
55-60	2.6%	49.6%
60-65	2.4%	52.1%
65-70	1.9%	54.0%
70-75	2.2%	56.3%
75-80	2.6%	58.8%
80-85	2.4%	61.2%
85-90	1.9%	63.1%
90-95	2.5%	65.6%
95-100	1.7%	67.3%
100-105	1.5%	68.9%
105-110	1.3%	70.2%
110-115	1.6%	71.8%
115-120	1.5%	73.3%
120-125	1.4%	74.8%
125-130	1.2%	75.9%
130-135	1.5%	77.5%
135-40	1.1%	78.5%
140-145	1.6%	80.2%
145-150	1.1%	81.2%
150-155	0.7%	82.0%
155-160	0.9%	82.9%
160-165	0.9%	83.8%
165-170	1.0%	84.8%
170-175	0.8%	85.6%
175-180	0.3%	85.8%
180-185	0.8%	86.6%
185-190	0.5%	87.1%
190-195	0.7%	87.8%
195-200	0.4%	88.1%
200-205	0.4%	88.5%
205-210	0.8%	89.3%
210-215	0.5%	89.9%
215-220	0.5%	90.4%
220-225	0.8%	91.1%
225-230	0.2%	91.4%
230-235	0.7%	92.0%
235-240	0.4%	92.4%
240-245	0.5%	92.9%
245-250	0.3%	93.2%
250-255	0.3%	93.5%
255-260	0.3%	93.8%
Over 260	6.2%	100.0%

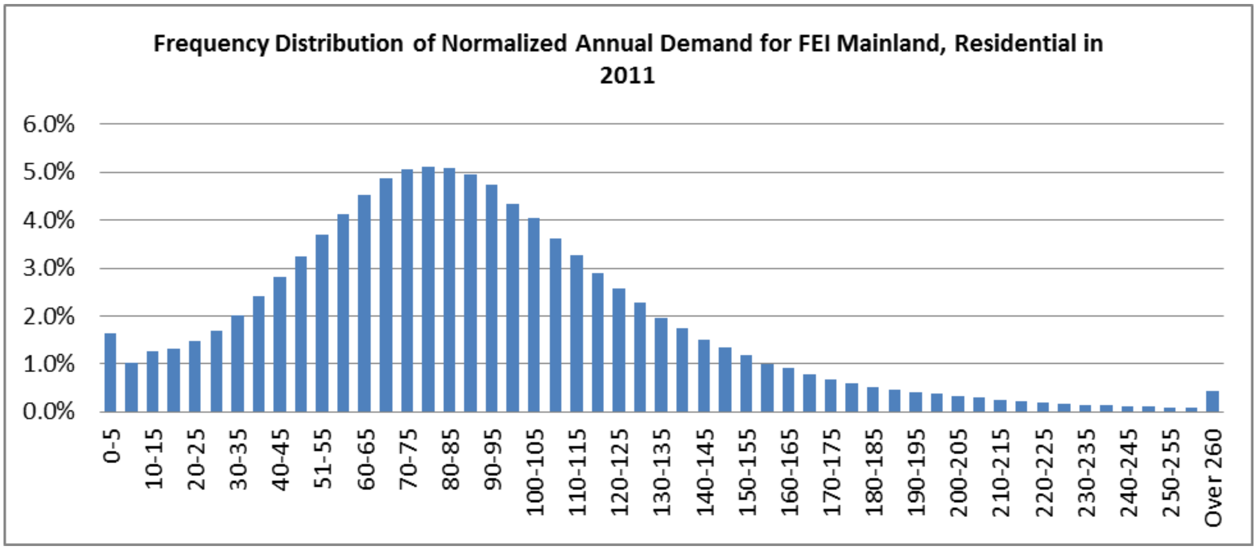
FEFN		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	0.7%	0.7%
5-10	0.1%	0.8%
10-15	0.1%	0.9%
15-20	0.3%	1.2%
20-25	0.4%	1.6%
25-30	0.5%	2.1%
30-35	0.4%	2.5%
35-40	0.5%	2.9%
40-45	0.6%	3.5%
45-50	0.7%	4.1%
51-55	1.1%	5.3%
55-60	0.9%	6.1%
60-65	1.3%	7.4%
65-70	2.0%	9.5%
70-75	1.5%	11.0%
75-80	3.2%	14.2%
80-85	3.4%	17.6%
85-90	3.0%	20.6%
90-95	4.0%	24.7%
95-100	3.8%	28.5%
100-105	3.9%	32.4%
105-110	4.9%	37.2%
110-115	4.0%	41.2%
115-120	4.6%	45.8%
120-125	3.4%	49.3%
125-130	5.1%	54.3%
130-135	3.3%	57.6%
135-40	3.8%	61.5%
140-145	3.4%	64.9%
145-150	2.9%	67.8%
150-155	2.8%	70.6%
155-160	3.1%	73.7%
160-165	2.7%	76.4%
165-170	2.6%	78.9%
170-175	2.1%	81.1%
175-180	1.8%	82.9%
180-185	1.5%	84.3%
185-190	1.8%	86.1%
190-195	1.0%	87.2%
195-200	1.4%	88.6%
200-205	1.0%	89.6%
205-210	0.8%	90.4%
210-215	0.7%	91.0%
215-220	0.7%	91.8%
220-225	0.8%	92.5%
225-230	0.8%	93.4%
230-235	0.6%	93.9%
235-240	0.4%	94.3%
240-245	0.5%	94.8%
245-250	0.3%	95.1%
250-255	0.2%	95.3%
255-260	0.4%	95.7%
Over 260	4.3%	100.0%

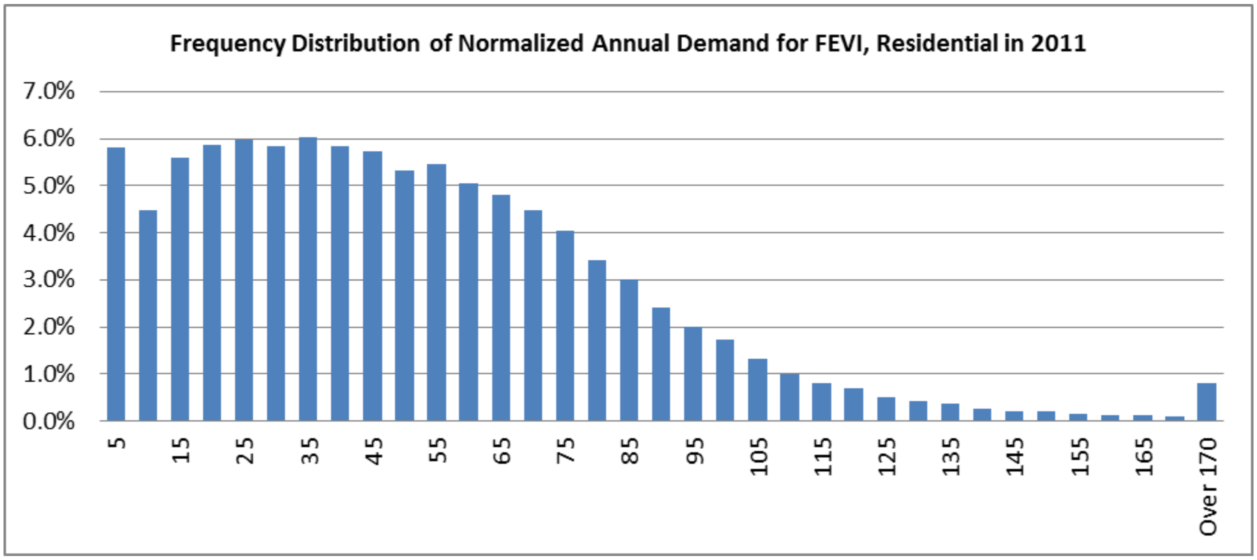
152.2 Please present the data sets provided in response to the previous question in separate graphs.

Response:

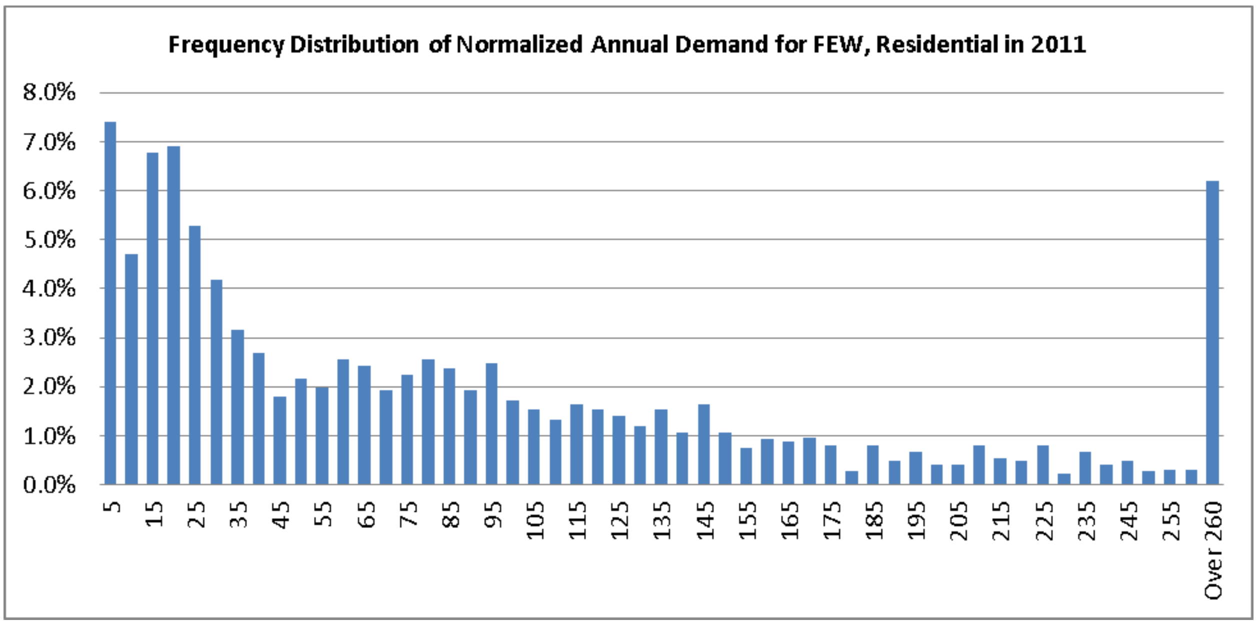
The frequency distribution of natural gas consumption for residential customers in FEI Mainland, FEVI, FEW and FEFN is presented graphically below.

The residential annual use frequency distributions for FEI, FEVI, FEW and FEFN vary according to the number of customers, system age, market penetration and normalized temperature for each of the areas and are generally consistent with the annual average use rate for each area presented in Section 3 Tables 3-2, 3-4, 3-7 and 3-9 of the Application. For example, the FEVI distribution reflects a larger portion than FEI of low consumption customers due to the relative age of the system and moderate temperature. The FEW distribution also has a significant portion of low consumption customers reflecting the seasonal nature of the consumption as well as a significant portion of larger consumption which is associated with larger dwellings in the area. The FEFN distribution is skewed toward higher consumption reflecting the lower normalized temperature in the area.

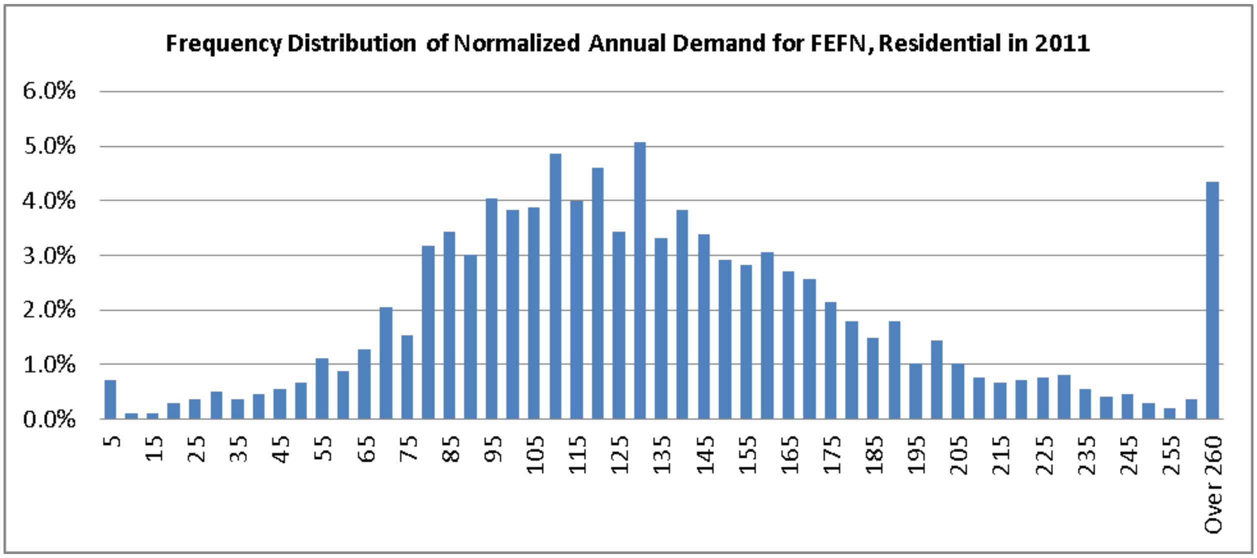




Frequency Distribution of Normalized Annual Demand for FEVI, Residential in 2011
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
Over 170



Frequency Distribution of Normalized Annual Demand for FEW, Residential in 2011
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
175
185
195
205
215
225
235
245
255
Over 260

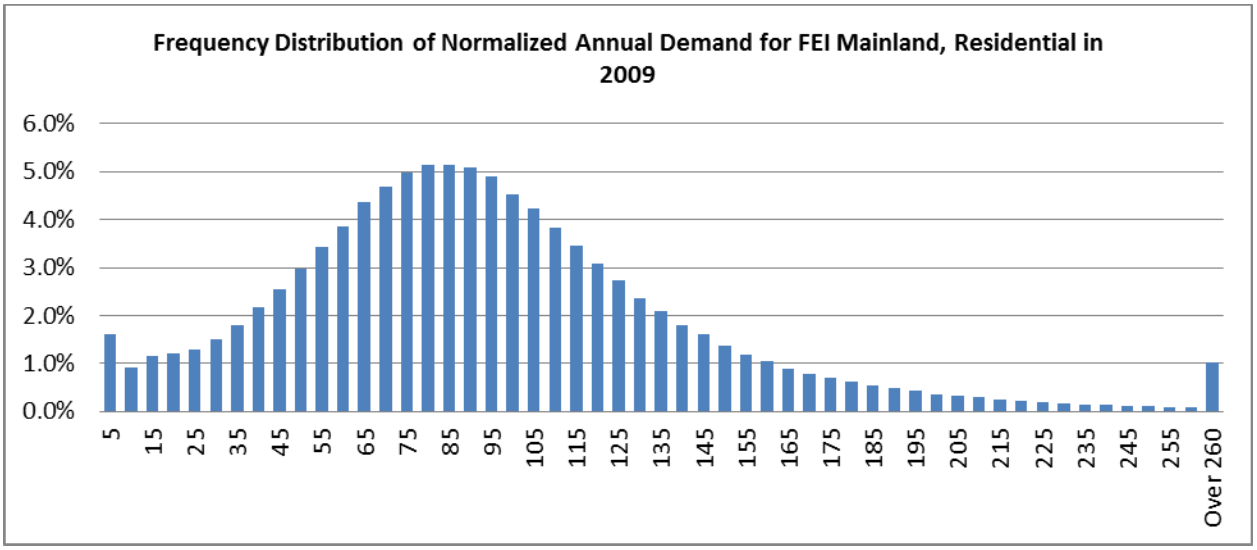


152.3 Please provide the frequency distribution of residential gas consumption for each of FEI Mainland, FEVI, FEW and FEFN based on normalized billed consumption data from 2009. Please provide it in both tabular and graphical form.

Response:

The frequency distribution of residential gas consumption in 2009 for FEI Mainland, FEVI, FEW and FEFN customers based on normalized billed consumption data is provided below, first in graph format, then followed by a table.

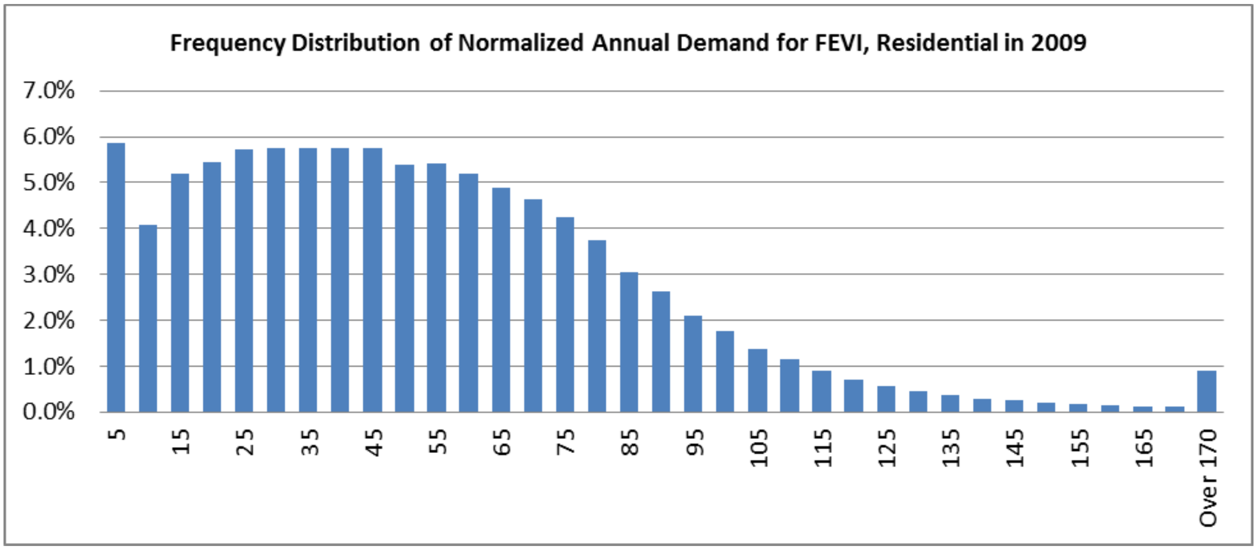
FEI Mainland



FEI Mainland

Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	1.6%	1.6%
5-10	0.9%	2.5%
10-15	1.2%	3.7%
15-20	1.2%	4.9%
20-25	1.3%	6.2%
25-30	1.5%	7.7%
30-35	1.8%	9.4%
35-40	2.2%	11.6%
40-45	2.6%	14.2%
45-50	3.0%	17.1%
51-55	3.4%	20.6%
55-60	3.9%	24.4%
60-65	4.4%	28.8%
65-70	4.7%	33.5%
70-75	5.0%	38.5%
75-80	5.1%	43.6%
80-85	5.1%	48.7%
85-90	5.1%	53.8%
90-95	4.9%	58.7%
95-100	4.5%	63.3%
100-105	4.2%	67.5%
105-110	3.8%	71.3%
110-115	3.5%	74.8%
115-120	3.1%	77.8%
120-125	2.7%	80.6%
125-130	2.4%	82.9%
130-135	2.1%	85.0%
135-40	1.8%	86.8%
140-145	1.6%	88.4%
145-150	1.4%	89.8%
150-155	1.2%	91.0%
155-160	1.1%	92.0%
160-165	0.9%	92.9%
165-170	0.8%	93.7%
170-175	0.7%	94.4%
175-180	0.6%	95.0%
180-185	0.5%	95.6%
185-190	0.5%	96.1%
190-195	0.4%	96.5%
195-200	0.4%	96.9%
200-205	0.3%	97.2%
205-210	0.3%	97.5%
210-215	0.2%	97.7%
215-220	0.2%	97.9%
220-225	0.2%	98.1%
225-230	0.2%	98.3%
230-235	0.2%	98.4%
235-240	0.1%	98.6%
240-245	0.1%	98.7%
245-250	0.1%	98.8%
250-255	0.1%	98.9%
255-260	0.1%	99.0%
Over 260	1.0%	100.0%

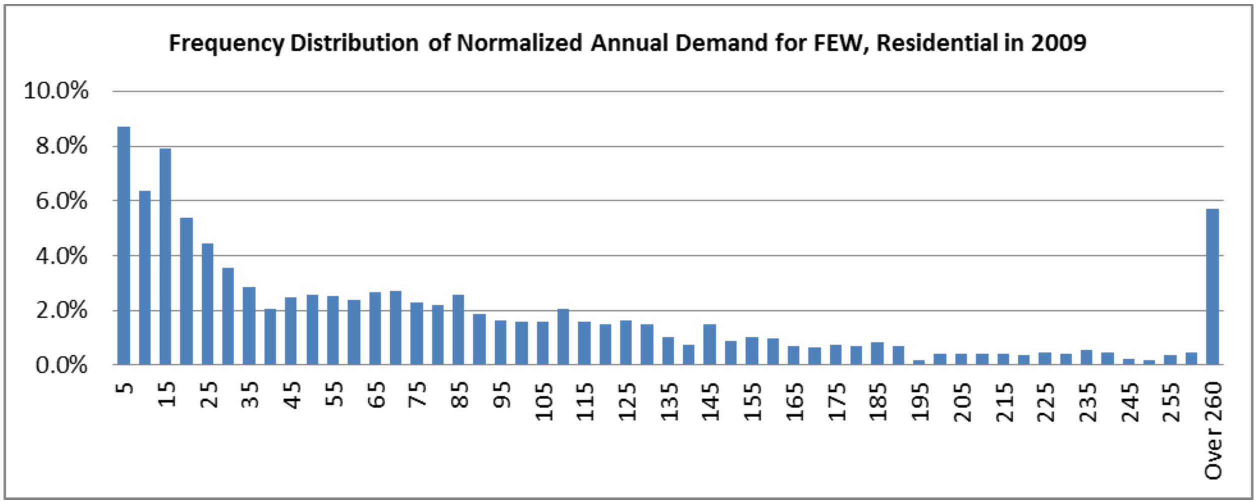
FEVI



Frequency Distribution of Normalized Annual Demand for FEVI, Residential in 2009
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
Over 170

FEVI		
Range of Normalized Annual Consumption (GJ)	**Portion of Residential Customers having consumption in this range**	**Cumulative %**
0-5	5.9%	5.9%
5-10	4.1%	9.9%
10-15	5.2%	15.1%
15-20	5.4%	20.6%
20-25	5.7%	26.3%
25-30	5.8%	32.0%
30-35	5.7%	37.8%
35-40	5.7%	43.5%
40-45	5.8%	49.3%
45-50	5.4%	54.7%
51-55	5.4%	60.1%
55-60	5.2%	65.3%
60-65	4.9%	70.2%
65-70	4.6%	74.8%
70-75	4.2%	79.1%
75-80	3.7%	82.8%
80-85	3.1%	85.9%
85-90	2.6%	88.5%
90-95	2.1%	90.6%
95-100	1.8%	92.3%
100-105	1.4%	93.7%
105-110	1.2%	94.9%
110-115	0.9%	95.8%
115-120	0.7%	96.5%
120-125	0.6%	97.0%
125-130	0.4%	97.5%
130-135	0.4%	97.8%
135-40	0.3%	98.1%
140-145	0.3%	98.4%
145-150	0.2%	98.6%
150-155	0.2%	98.7%
155-160	0.1%	98.9%
160-165	0.1%	99.0%
165-170	0.1%	99.1%
Over 170	0.9%	100.0%

FEW

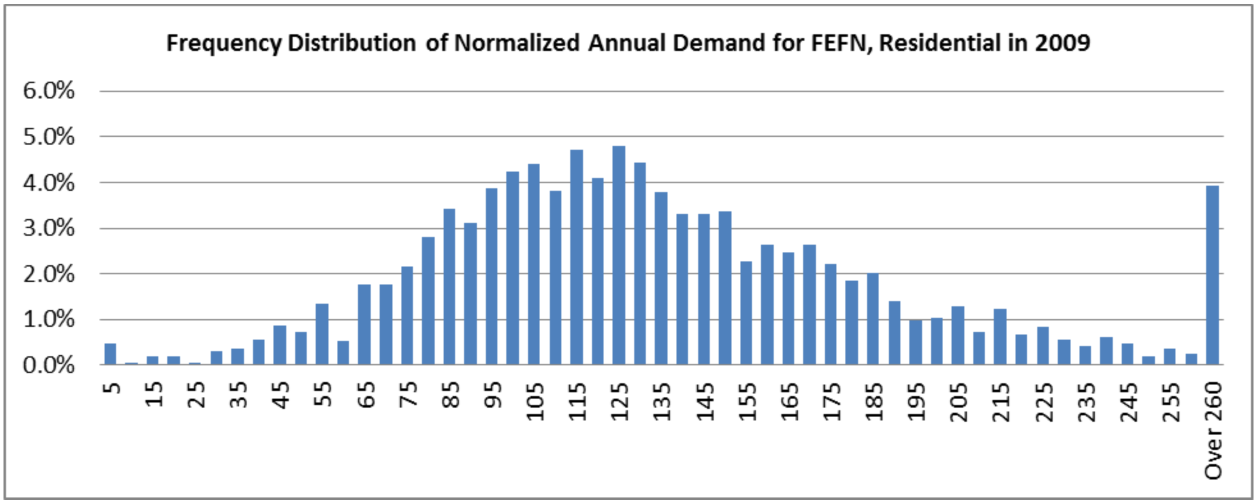


Frequency Distribution of Normalized Annual Demand for FEW, Residential in 2009
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
175
185
195
205
215
225
235
245
255
Over 260

FEW

Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
5	8.7%	8.7%
10	6.4%	15.1%
15	7.9%	22.9%
20	5.4%	28.3%
25	4.5%	32.8%
30	3.6%	36.3%
35	2.8%	39.2%
40	2.1%	41.2%
45	2.5%	43.7%
50	2.6%	46.3%
55	2.5%	48.8%
60	2.4%	51.2%
65	2.7%	53.9%
70	2.7%	56.6%
75	2.3%	58.9%
80	2.2%	61.1%
85	2.6%	63.6%
90	1.8%	65.5%
95	1.6%	67.1%
100	1.6%	68.7%
105	1.6%	70.3%
110	2.1%	72.3%
115	1.6%	73.9%
120	1.5%	75.4%
125	1.6%	77.0%
130	1.5%	78.5%
135	1.0%	79.5%
140	0.8%	80.3%
145	1.5%	81.8%
150	0.9%	82.7%
155	1.0%	83.7%
160	1.0%	84.7%
165	0.7%	85.4%
170	0.6%	86.1%
175	0.8%	86.8%
180	0.7%	87.5%
185	0.9%	88.4%
190	0.7%	89.0%
195	0.2%	89.2%
200	0.4%	89.6%
205	0.4%	90.0%
210	0.4%	90.4%
215	0.4%	90.9%
220	0.4%	91.2%
225	0.5%	91.7%
230	0.4%	92.1%
235	0.5%	92.6%
240	0.5%	93.1%
245	0.2%	93.3%
250	0.2%	93.5%
255	0.4%	93.8%
260	0.5%	94.3%
Over 260	5.7%	100.0%

FEFN



Frequency Distribution of Normalized Annual Demand for FEFN, Residential in 2009
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
175
185
195
205
215
225
235
245
255
Over 260

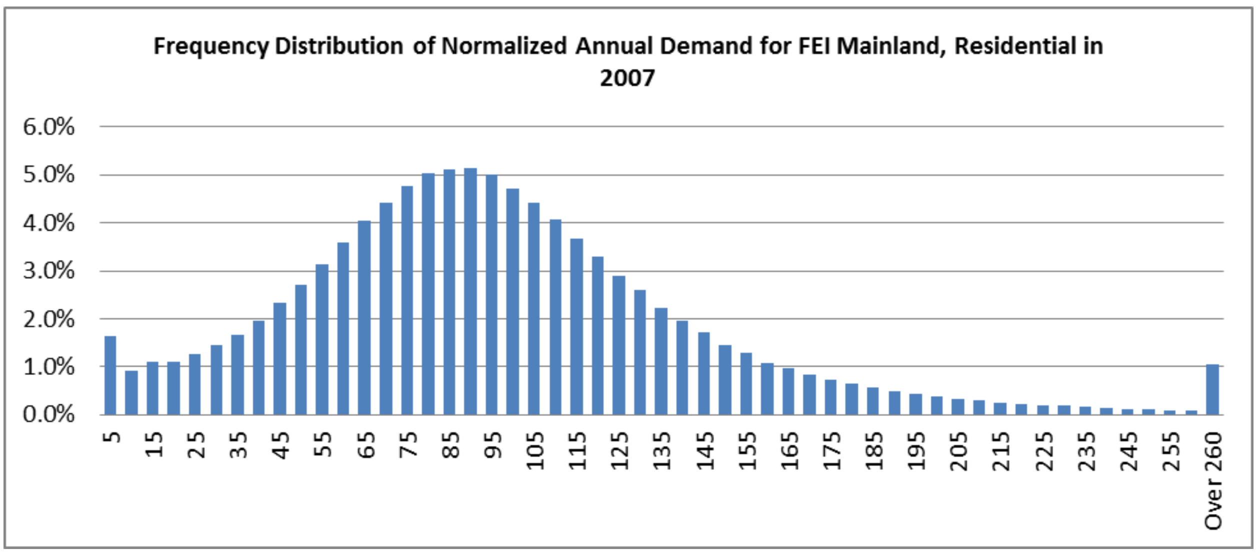
FEFN		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	0.5%	0.5%
5-10	0.1%	0.5%
10-15	0.2%	0.7%
15-20	0.2%	0.9%
20-25	0.1%	1.0%
25-30	0.3%	1.3%
30-35	0.4%	1.7%
35-40	0.6%	2.2%
40-45	0.9%	3.1%
45-50	0.7%	3.8%
51-55	1.3%	5.2%
55-60	0.5%	5.7%
60-65	1.8%	7.4%
65-70	1.8%	9.2%
70-75	2.2%	11.4%
75-80	2.8%	14.2%
80-85	3.4%	17.6%
85-90	3.1%	20.7%
90-95	3.9%	24.6%
95-100	4.2%	28.8%
100-105	4.4%	33.2%
105-110	3.8%	37.0%
110-115	4.7%	41.7%
115-120	4.1%	45.8%
120-125	4.8%	50.6%
125-130	4.4%	55.1%
130-135	3.8%	58.9%
135-40	3.3%	62.2%
140-145	3.3%	65.5%
145-150	3.4%	68.9%
150-155	2.3%	71.1%
155-160	2.6%	73.8%
160-165	2.5%	76.3%
165-170	2.6%	78.9%
170-175	2.2%	81.1%
175-180	1.9%	83.0%
180-185	2.0%	85.0%
185-190	1.4%	86.4%
190-195	1.0%	87.4%
195-200	1.0%	88.4%
200-205	1.3%	89.7%
205-210	0.7%	90.4%
210-215	1.2%	91.7%
215-220	0.7%	92.3%
220-225	0.8%	93.2%
225-230	0.6%	93.7%
230-235	0.4%	94.2%
235-240	0.6%	94.8%
240-245	0.5%	95.2%
245-250	0.2%	95.4%
250-255	0.4%	95.8%
255-260	0.3%	96.1%
Over 260	3.9%	100.0%

152.4 Please provide the frequency distribution residential gas consumption for each of FEI Mainland, FEVI, FEW and FEFN based on weather normalized billed consumption data from 2007. Please provide it in both tabular and graphical form.

Response:

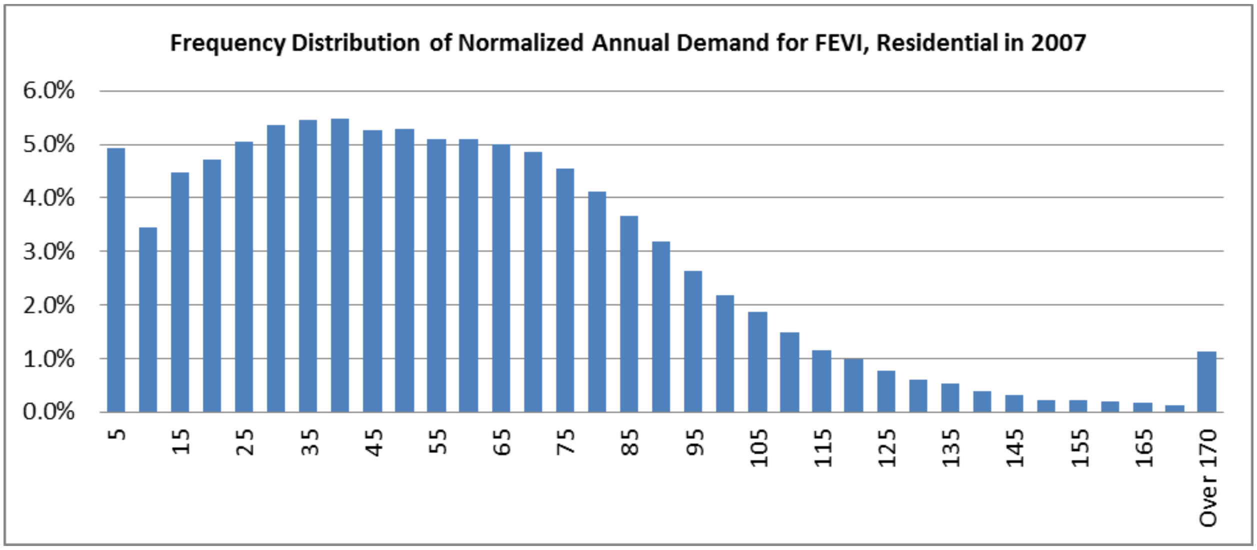
The frequency distribution of residential gas consumption in 2007 for FEI Mainland, FEVI, FEW and FEFN customers based on normalized billed consumption data is provided below, first in graph format, then followed by a table.

FEI Mainland



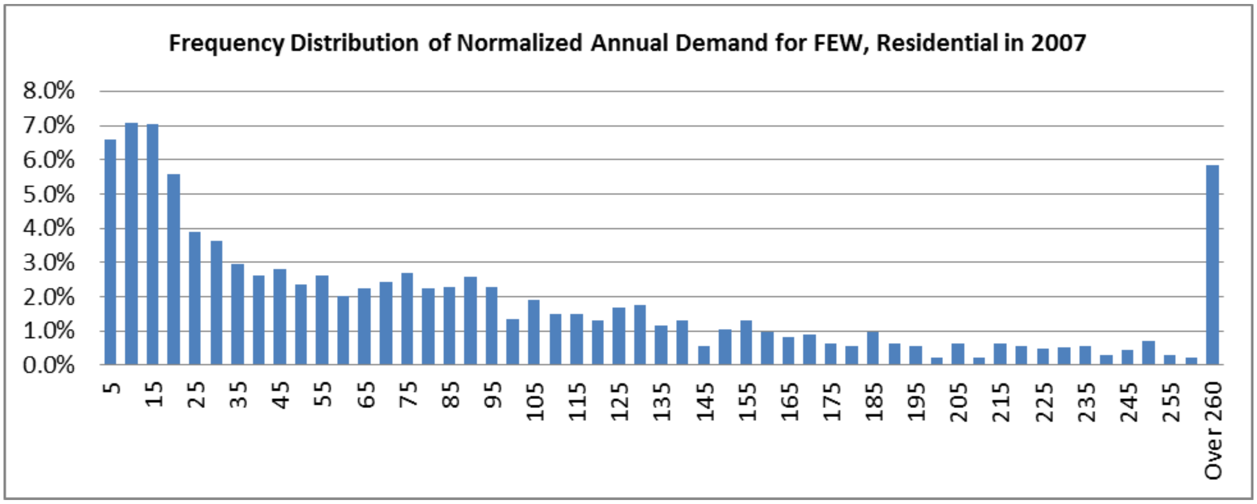
FEI		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
5	1.6%	1.6%
10	0.9%	2.5%
15	1.1%	3.6%
20	1.1%	4.8%
25	1.3%	6.0%
30	1.4%	7.5%
35	1.7%	9.1%
40	2.0%	11.1%
45	2.3%	13.4%
50	2.7%	16.1%
55	3.1%	19.3%
60	3.6%	22.8%
65	4.0%	26.9%
70	4.4%	31.3%
75	4.8%	36.1%
80	5.0%	41.1%
85	5.1%	46.2%
90	5.1%	51.3%
95	5.0%	56.3%
100	4.7%	61.0%
105	4.4%	65.5%
110	4.1%	69.5%
115	3.7%	73.2%
120	3.3%	76.5%
125	2.9%	79.4%
130	2.6%	82.0%
135	2.2%	84.2%
140	2.0%	86.1%
145	1.7%	87.9%
150	1.4%	89.3%
155	1.3%	90.6%
160	1.1%	91.7%
165	1.0%	92.6%
170	0.8%	93.5%
175	0.7%	94.2%
180	0.7%	94.9%
185	0.6%	95.4%
190	0.5%	95.9%
195	0.4%	96.4%
200	0.4%	96.7%
205	0.3%	97.1%
210	0.3%	97.4%
215	0.3%	97.6%
220	0.2%	97.9%
225	0.2%	98.1%
230	0.2%	98.3%
235	0.2%	98.4%
240	0.1%	98.6%
245	0.1%	98.7%
250	0.1%	98.8%
255	0.1%	98.9%
260	0.1%	99.0%
Over 260	1.0%	100.0%

FEVI


Frequency Distribution of Normalized Annual Demand for FEVI, Residential in 2007
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
Over 170

FEVI		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	4.9%	4.9%
5-10	3.4%	8.4%
10-15	4.5%	12.9%
15-20	4.7%	17.6%
20-25	5.0%	22.6%
25-30	5.3%	28.0%
30-35	5.5%	33.4%
35-40	5.5%	38.9%
40-45	5.3%	44.2%
45-50	5.3%	49.5%
51-55	5.1%	54.5%
55-60	5.1%	59.6%
60-65	5.0%	64.6%
65-70	4.9%	69.5%
70-75	4.5%	74.1%
75-80	4.1%	78.2%
80-85	3.7%	81.8%
85-90	3.2%	85.0%
90-95	2.6%	87.7%
95-100	2.2%	89.8%
100-105	1.9%	91.7%
105-110	1.5%	93.2%
110-115	1.2%	94.3%
115-120	1.0%	95.3%
120-125	0.8%	96.1%
125-130	0.6%	96.7%
130-135	0.5%	97.2%
135-40	0.4%	97.6%
140-145	0.3%	97.9%
145-150	0.2%	98.2%
150-155	0.2%	98.4%
155-160	0.2%	98.6%
160-165	0.2%	98.7%
165-170	0.1%	98.9%
Over 170	1.1%	100.0%

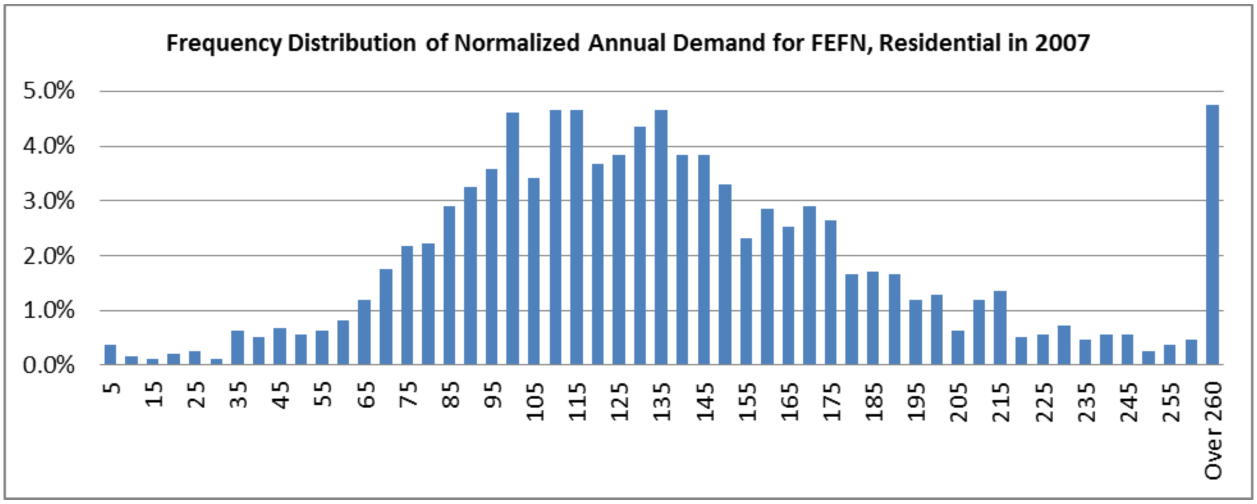
FEW



Frequency Distribution of Normalized Annual Demand for FEW, Residential in 2007
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
175
185
195
205
215
225
235
245
255
Over 260

FEW		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	6.6%	6.6%
5-10	7.1%	13.7%
10-15	7.0%	20.7%
15-20	5.6%	26.3%
20-25	3.9%	30.2%
25-30	3.6%	33.8%
30-35	3.0%	36.8%
35-40	2.6%	39.4%
40-45	2.8%	42.2%
45-50	2.3%	44.6%
51-55	2.6%	47.2%
55-60	2.0%	49.2%
60-65	2.2%	51.5%
65-70	2.4%	53.9%
70-75	2.7%	56.6%
75-80	2.2%	58.8%
80-85	2.3%	61.1%
85-90	2.6%	63.7%
90-95	2.3%	66.0%
95-100	1.3%	67.3%
100-105	1.9%	69.2%
105-110	1.5%	70.7%
110-115	1.5%	72.2%
115-120	1.3%	73.5%
120-125	1.7%	75.2%
125-130	1.8%	76.9%
130-135	1.1%	78.1%
135-40	1.3%	79.4%
140-145	0.6%	80.0%
145-150	1.1%	81.0%
150-155	1.3%	82.3%
155-160	1.0%	83.3%
160-165	0.8%	84.1%
165-170	0.9%	85.0%
170-175	0.6%	85.6%
175-180	0.6%	86.2%
180-185	1.0%	87.1%
185-190	0.6%	87.8%
190-195	0.6%	88.3%
195-200	0.2%	88.6%
200-205	0.6%	89.2%
205-210	0.2%	89.4%
210-215	0.6%	90.1%
215-220	0.6%	90.6%
220-225	0.5%	91.1%
225-230	0.5%	91.6%
230-235	0.6%	92.2%
235-240	0.3%	92.5%
240-245	0.4%	92.9%
245-250	0.7%	93.6%
250-255	0.3%	93.9%
255-260	0.2%	94.2%
Over 260	5.8%	100.0%

FEFN


Frequency Distribution of Normalized Annual Demand for FEFN, Residential in 2007
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
175
185
195
205
215
225
235
245
255
Over 260

FEFN

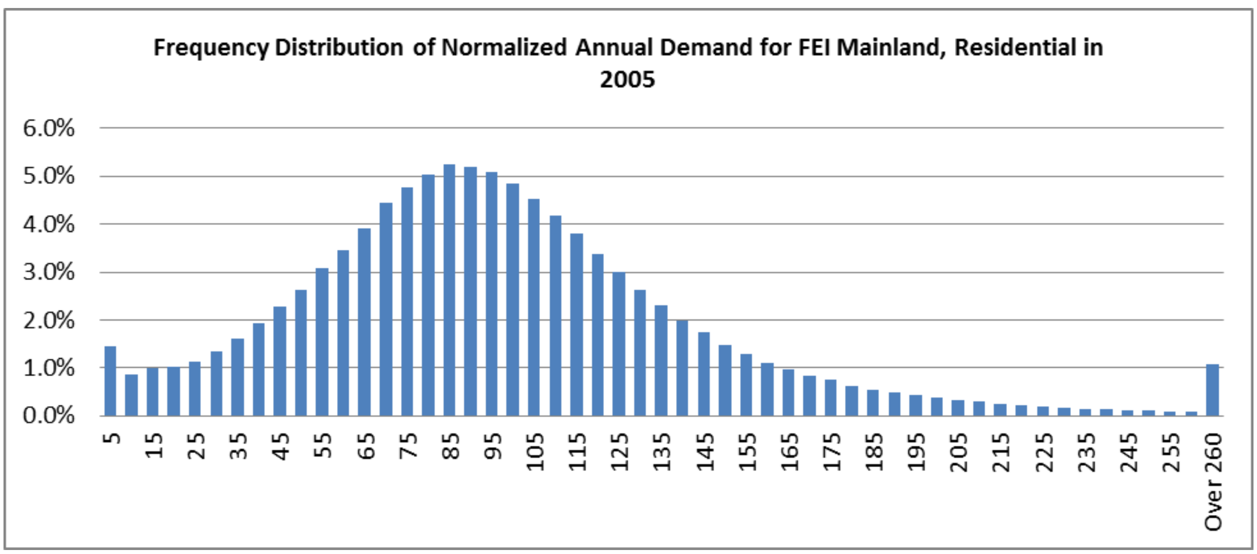
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	0.4%	0.4%
5-10	0.2%	0.5%
10-15	0.1%	0.6%
15-20	0.2%	0.8%
20-25	0.3%	1.1%
25-30	0.1%	1.2%
30-35	0.6%	1.8%
35-40	0.5%	2.3%
40-45	0.7%	3.0%
45-50	0.6%	3.6%
51-55	0.6%	4.2%
55-60	0.8%	5.0%
60-65	1.2%	6.2%
65-70	1.8%	8.0%
70-75	2.2%	10.1%
75-80	2.2%	12.4%
80-85	2.9%	15.3%
85-90	3.3%	18.5%
90-95	3.6%	22.1%
95-100	4.6%	26.7%
100-105	3.4%	30.1%
105-110	4.7%	34.7%
110-115	4.7%	39.4%
115-120	3.7%	43.1%
120-125	3.8%	46.9%
125-130	4.3%	51.2%
130-135	4.7%	55.9%
135-40	3.8%	59.7%
140-145	3.8%	63.5%
145-150	3.3%	66.9%
150-155	2.3%	69.2%
155-160	2.8%	72.0%
160-165	2.5%	74.6%
165-170	2.9%	77.5%
170-175	2.6%	80.1%
175-180	1.7%	81.7%
180-185	1.7%	83.5%
185-190	1.7%	85.1%
190-195	1.2%	86.3%
195-200	1.3%	87.6%
200-205	0.6%	88.2%
205-210	1.2%	89.4%
210-215	1.3%	90.7%
215-220	0.5%	91.3%
220-225	0.6%	91.8%
225-230	0.7%	92.6%
230-235	0.5%	93.0%
235-240	0.6%	93.6%
240-245	0.6%	94.2%
245-250	0.3%	94.4%
250-255	0.4%	94.8%
255-260	0.5%	95.2%
Over 260	4.8%	100.0%

152.5 Please provide the frequency distribution residential gas consumption for each of FEI Mainland, FEVI, FEW and FEFN based on weather normalized billed consumption data from 2005. Please provide it in both tabular and graphical form.

Response:

The frequency distribution of residential gas consumption in 2005 for FEI Mainland and FEFN customers based on normalized billed consumption data is provided below, first in graph format, then followed by a table. This data is not available for the FEVI and FEW customers as billing for these customers was not recorded in the database until March 2006, therefore it is not feasible to produce 2005 frequency distribution data for these two regions.

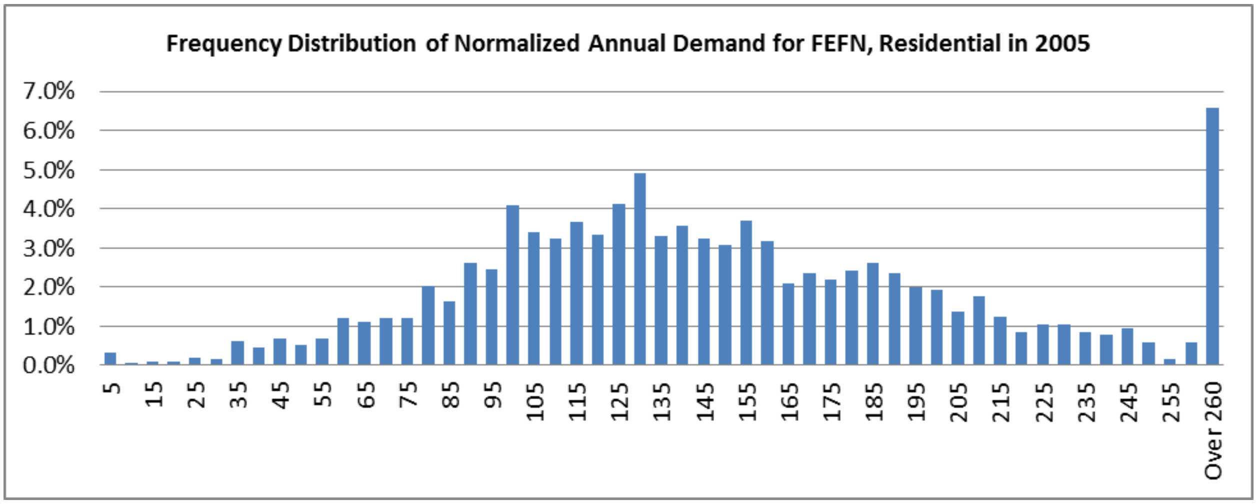
FEI Mainland



FEI Mainland

Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	1.5%	1.5%
5-10	0.9%	2.3%
10-15	1.0%	3.3%
15-20	1.0%	4.3%
20-25	1.1%	5.5%
25-30	1.3%	6.8%
30-35	1.6%	8.4%
35-40	1.9%	10.4%
40-45	2.3%	12.6%
45-50	2.6%	15.3%
51-55	3.1%	18.3%
55-60	3.4%	21.8%
60-65	3.9%	25.7%
65-70	4.4%	30.2%
70-75	4.8%	34.9%
75-80	5.0%	40.0%
80-85	5.2%	45.2%
85-90	5.2%	50.4%
90-95	5.1%	55.5%
95-100	4.9%	60.3%
100-105	4.5%	64.9%
105-110	4.2%	69.0%
110-115	3.8%	72.8%
115-120	3.4%	76.2%
120-125	3.0%	79.2%
125-130	2.6%	81.8%
130-135	2.3%	84.1%
135-40	2.0%	86.1%
140-145	1.7%	87.9%
145-150	1.5%	89.3%
150-155	1.3%	90.6%
155-160	1.1%	91.7%
160-165	1.0%	92.7%
165-170	0.8%	93.5%
170-175	0.7%	94.3%
175-180	0.6%	94.9%
180-185	0.6%	95.5%
185-190	0.5%	96.0%
190-195	0.4%	96.4%
195-200	0.4%	96.8%
200-205	0.3%	97.1%
205-210	0.3%	97.4%
210-215	0.3%	97.6%
215-220	0.2%	97.9%
220-225	0.2%	98.1%
225-230	0.2%	98.2%
230-235	0.2%	98.4%
235-240	0.1%	98.5%
240-245	0.1%	98.6%
245-250	0.1%	98.7%
250-255	0.1%	98.8%
255-260	0.1%	98.9%
Over 260	1.1%	100.0%

FEFN


Frequency Distribution of Normalized Annual Demand for FEFN, Residential in 2005
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
5
15
25
35
45
55
65
75
85
95
105
115
125
135
145
155
165
175
185
195
205
215
225
235
245
255
Over 260

FEFN		
Range of Normalized Annual Consumption (GJ)	Portion of Residential Customers having consumption in this range	Cumulative %
0-5	0.3%	0.3%
5-10	0.1%	0.4%
10-15	0.1%	0.5%
15-20	0.1%	0.6%
20-25	0.2%	0.8%
25-30	0.2%	0.9%
30-35	0.6%	1.6%
35-40	0.5%	2.0%
40-45	0.7%	2.7%
45-50	0.5%	3.2%
51-55	0.7%	3.9%
55-60	1.2%	5.1%
60-65	1.1%	6.2%
65-70	1.2%	7.4%
70-75	1.2%	8.6%
75-80	2.0%	10.7%
80-85	1.6%	12.3%
85-90	2.6%	14.9%
90-95	2.5%	17.4%
95-100	4.1%	21.5%
100-105	3.4%	24.9%
105-110	3.2%	28.1%
110-115	3.7%	31.8%
115-120	3.3%	35.1%
120-125	4.1%	39.2%
125-130	4.9%	44.2%
130-135	3.3%	47.5%
135-40	3.6%	51.0%
140-145	3.2%	54.3%
145-150	3.1%	57.4%
150-155	3.7%	61.1%
155-160	3.2%	64.3%
160-165	2.1%	66.4%
165-170	2.4%	68.7%
170-175	2.2%	70.9%
175-180	2.4%	73.3%
180-185	2.6%	75.9%
185-190	2.4%	78.3%
190-195	2.0%	80.3%
195-200	1.9%	82.2%
200-205	1.4%	83.6%
205-210	1.8%	85.3%
210-215	1.3%	86.6%
215-220	0.8%	87.4%
220-225	1.0%	88.5%
225-230	1.0%	89.5%
230-235	0.8%	90.4%
235-240	0.8%	91.2%
240-245	0.9%	92.1%
245-250	0.6%	92.7%
250-255	0.2%	92.8%
255-260	0.6%	93.4%
Over 260	6.6%	100.0%

152.6 What portion of residential customers had an annual consumption below 50 GJ in 2011. Please provide this number for each of FEI Mainland, FEVI, FEW and FEFN.

Response:

The table below summarizes the percentage of customers consuming less than 50 GJs in each of FEI Mainland, FEVI, FEW and FEFN for the year 2011:

Service Area	Percentage of Customers Consuming Less Than 50 GJs in 2011
FEI Mainland	19%
FEVI	57%
FEW	45%
FEFN	4%

Cumulative consumption data for the four entities is also provided in the response to BCUC IR 1.152.1.

152.7 What portion of residential customers had an annual consumption below 50 GJ in 2009. Please provide this number for each of FEI Mainland, FEVI, FEW and FEFN.

Response:

The table below summarizes the percentage of customers consuming less than 50 GJs in each of FEI Mainland, FEVI, FEW and FEFN for the year 2009:

Service Area	Percentage of Customers Consuming Less Than 50 GJs in 2009
FEI Mainland	17%
FEVI	55%
FEW	46%
FEFN	4%

Cumulative consumption data for the four entities is also provided in the response to BCUC IR 1.152.3.

152.8 What portion of residential customers had an annual consumption below 50 GJ in 2007. Please provide this number for each of FEI Mainland, FEVI, FEW and FEFN.

Response:

The table below summarizes the percentage of customers consuming less than 50 GJs in each of FEI Mainland, FEVI, FEW and FEFN for the year 2007:

Service Area	Percentage of Customers Consuming Less Than 50 GJs in 2007
FEI Mainland	16%
FEVI	50%
FEW	45%
FEFN	4%

Cumulative consumption data for the four entities is also provided in the response to BCUC IR 1.152.4.

153.0 Reference: Regional Characteristics

No Reference

Load Duration Curve

153.1 Please provide a load duration curve for each of: FEI Mainland, FEVI, FEW, and FEFN. Identify the system capacity on each curve.

Response:

The requested load duration curves for FEI, FEVI, FEW and FEFN are provided below. These curves all have a similar shape which reflects the heat sensitive nature of the load in each area.

The following load duration curves ("LDCs") are constructed separately for core customers and transportation customers. The FEU estimate the load profile of its core customers on an annual basis as provided in the Annual Contracting Plan.

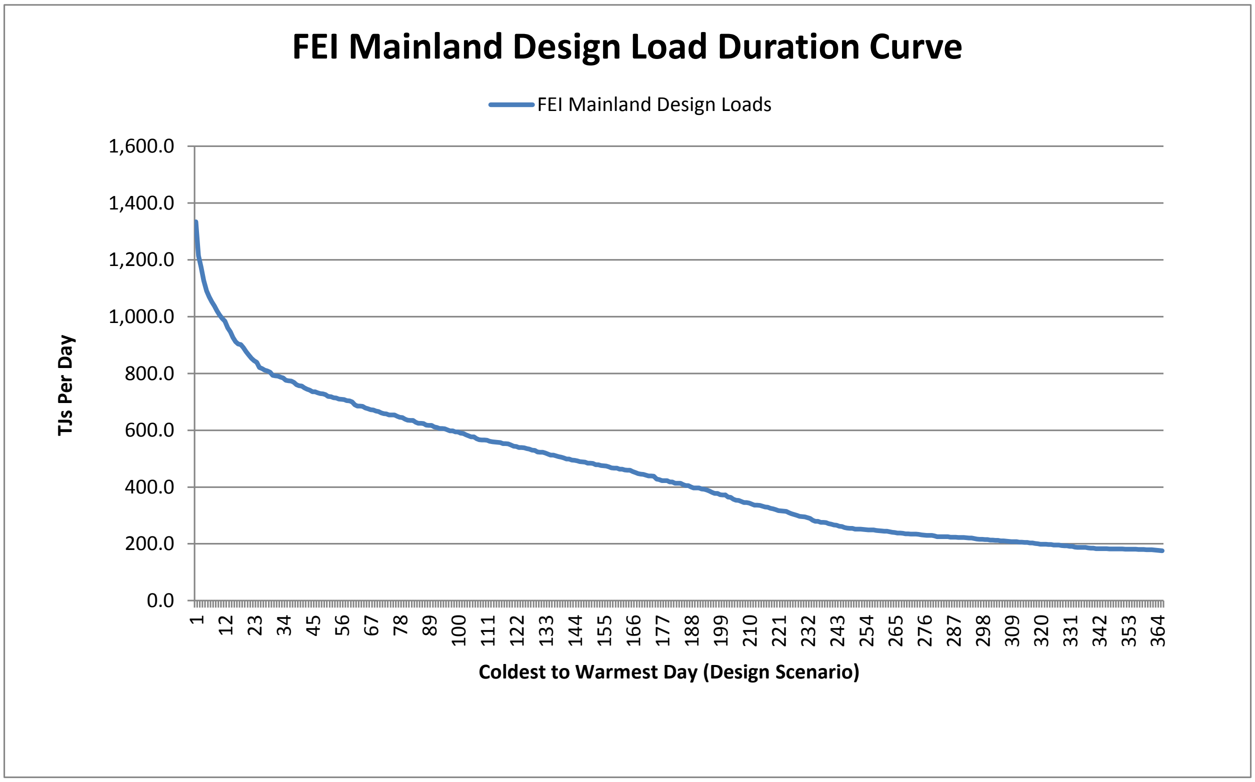
FEI Mainland Transportation (Rate Schedule 22, Rate Schedule 23 and Rate Schedule 25) load profile is estimated by its own rate classes.

- Rate Schedule 23 profile is estimated based on the regression analysis of the daily send out data.
- Rate Schedule 22 and Rate Schedule 25 profiles are assumed to be the maximum daily send out in the past three years. Interruptible customers are not included in this analysis.

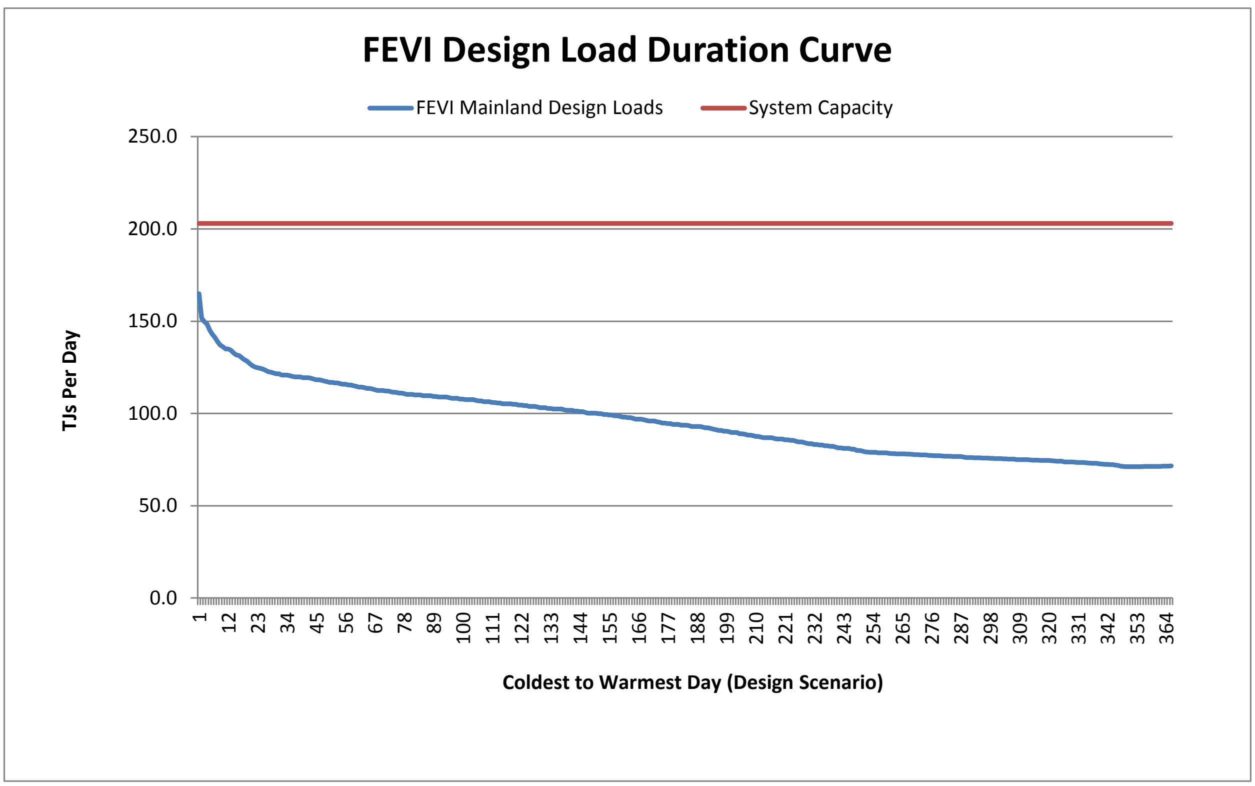
FEVI transportation load profile is based on the contact demand and held constant throughout the year.

Fort Nelson Rate Schedule 25 is estimated based on the maximum daily send out in the past three years.

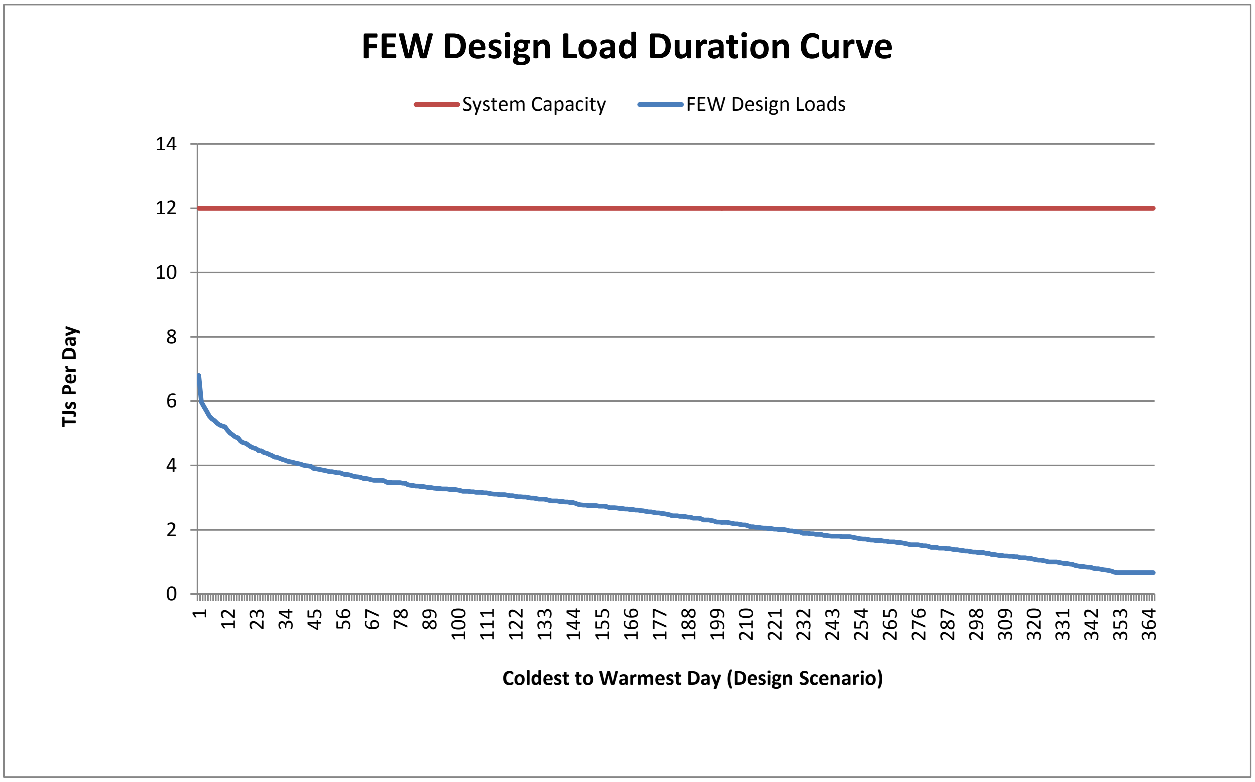
The FEI Mainland system capacity is not shown: Unlike FEVI, FEW and FEFN the FEI Mainland consists of different regional pipelines (for example: Coastal Transmission System, Interior Transmission System, transmission pressure laterals, etc.). Each of these regional pipeline systems has independent capacities, which prevents us from reporting a single capacity value.



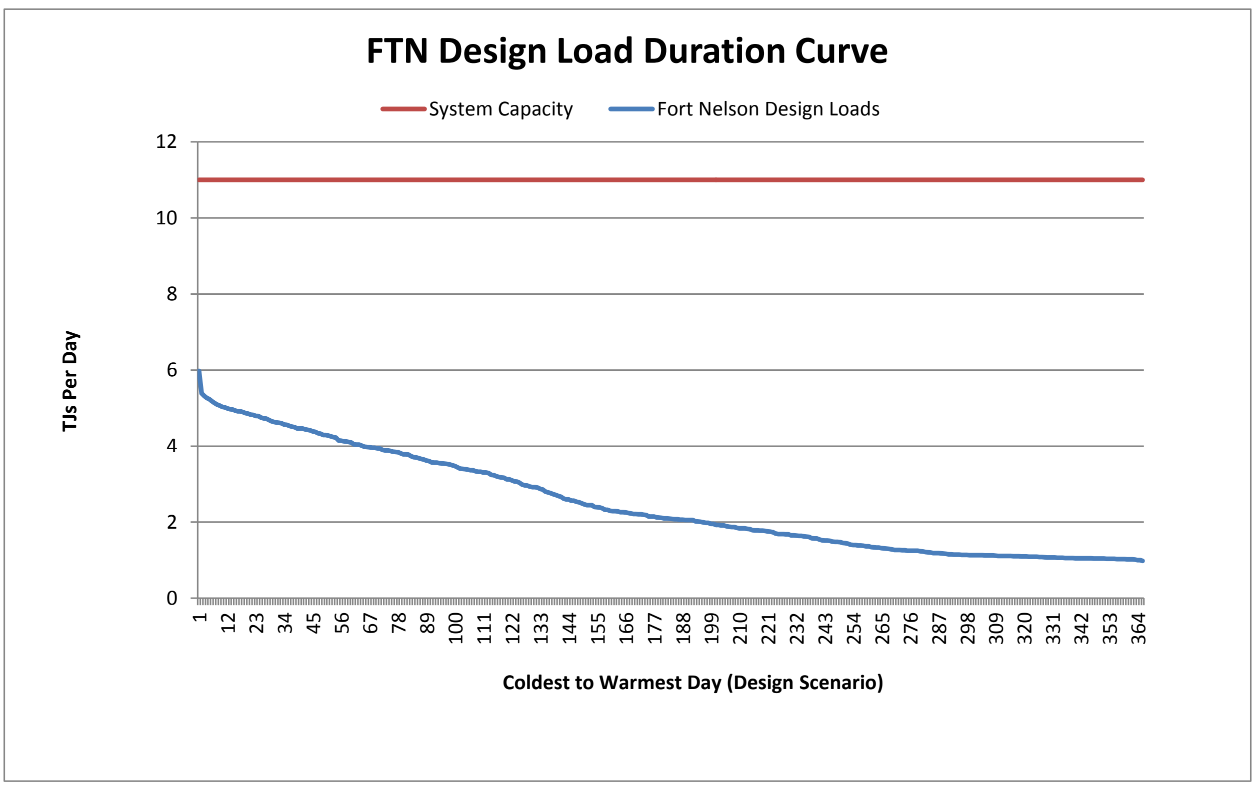
FEI Mainland Design Load Duration Curve
FEI Mainland Design Loads
TJs Per Day
1,600.0
1,400.0
1,200.0
1,000.0
800.0
600.0
400.0
200.0
0.0
1 12 23 34 45 56 67 78 89 100 111 122 133 144 155 166 177 188 199 210 221 232 243 254 265 276 287 298 309 320 331 342 353 364
Coldest to Warmest Day (Design Scenario)



FEVI Design Load Duration Curve
FEVI Mainland Design Loads
System Capacity
TJs Per Day
250.0
200.0
150.0
100.0
50.0
0.0
1 12 23 34 45 56 67 78 89 100 111 122 133 144 155 166 177 188 199 210 221 232 243 254 265 276 287 298 309 320 331 342 353 364
Coldest to Warmest Day (Design Scenario)



FEW Design Load Duration Curve
System Capacity
FEW Design Loads
TJs Per Day
Coldest to Warmest Day (Design Scenario)



FTN Design Load Duration Curve
System Capacity
Fort Nelson Design Loads
TJs Per Day
Coldest to Warmest Day (Design Scenario)

153.2 Please provide the annual load factor in 2007, 2009 and 2011 for each of: FEI Mainland, FEVI, FEW, and FEFN.

Response:

The following table provides the annual load factors by rate class for each of 2007, 2009 and 2011 for the Mainland, FEVI, FEW and FEFN regions.

FEI Mainland	2007	2009	2011
Rate 1	0.293	0.301	0.294
Rate 2	0.289	0.306	0.294
Rate 3	0.359	0.376	0.345
Rate 5	0.470	0.503	0.526
Rate 6	n/a	n/a	n/a
Rate 25	0.514	0.549	0.559
FEVI	**2007**	**2009**	**2011**
RGS	0.292	0.312	0.281
SCS1	0.316	0.373	0.302
SCS2	0.395	0.472	0.413
AGS	0.431	0.415	0.464
LCS1	0.384	0.456	0.420
LCS2	0.410	0.500	0.503
LCS3	0.405	0.410	0.416
FEW	**2007**	**2009‡**	**2011**
SGS1 Res	0.290	0.258	0.306
SGS1 Comm	0.333	0.413	0.365
LGS1	0.376	0.328	0.378
LGS2	0.368	0.345	0.397
LGS3	0.338	0.338	0.358
FEFN	**2007**	**2009**	**2011**
Rate 1	0.323	0.340	0.306
Rate 2.1	0.312	0.325	0.285
Rate 2.2	0.356	0.391	0.352
Rate 25ǂ	0.467	0.255	0.196

NOTES:

‡ Conversion year. Load Factors are for combine propane and natural gas consumption

ǂ Regression Models reported poor fit for years 2009 and 2010

153.3 For 2007, 2009 and 2011, provide the relative portions of the annual sales and transportation deliveries to residential, small commercial, commercial, and industrial customers in each of FEI Mainland, FEVI, FEW, and FEFN.

Response:

The following table provides the normalized relative portions of the annual sales and transportation deliveries for the rate groups and regions shown.

FEI Mainland	2007	2009	2011
Residential	**41%**	**43%**	**40%**
Small Commercial	**14%**	**15%**	**14%**
Large Commercial	**9%**	**10%**	**10%**
Industrial	**36%**	**32%**	**36%**
FEFN	**2007**	**2009**	**2011**
Residential	**33%**	**44%**	**43%**
Small Commercial	**23%**	**31%**	**33%**
Large Commercial	**11%**	**15%**	**15%**
Industrial	**33%**	**10%**	**9%**
FEVI	**2007**	**2009**	**2011**
Residential	**38%**	**38%**	**39%**
Small Commercial	**8%**	**8%**	**8%**
Large Commercial	**45%**	**45%**	**43%**
AGS	**9%**	**9%**	**10%**
FEW	**2007**	**2009**	**2011**
Residential	**25%**	**30%**	**30%**
Small Commercial	**6%**	**7%**	**7%**
Large Commercial	**69%**	**63%**	**63%**

154.0 Reference: Regional Characteristics

No Reference

Customer Growth Rates

154.1 Please provide in table form the annual growth in customers, annual growth in throughput and annual growth in rate base from 2006 to forecast 2013 separately for FEVI, FEI, FEW and FEFN.

Response:

Annual growth data for FEI, FEVI, FEW and FEFN is provided in the tables below. Please note that normalized sales and transportation data is reflected for FEI, FEVI, FEFN and FEW:

FEI

FEI Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	209,077	209,077	210,091	200,822	201,111	205,987	206,716	207,160
Annual Growth in Sales/Transportation Volumes (TJ)		0.0%	0.5%	-4.4%	0.1%	2.4%	0.4%	0.2%
Customers (Average)	802,743	816,427	825,696	832,751	839,017	846,522	852,937	859,708
Annual Growth in Customers (Average)		1.7%	1.1%	0.9%	0.8%	0.9%	0.8%	0.8%
Rate Base	$ 2,442,352	$ 2,426,180	$ 2,474,447	$ 2,462,143	$ 2,525,213	$ 2,542,002	$ 2,753,641	$ 2,810,535
Annual Growth in Rate Base		-0.7%	2.0%	-0.5%	2.6%	0.7%	8.3%	2.1%

FEVI

FEVI Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	28,277	35,597	35,368	34,383	30,693	31,276	34,132	34,255
Annual Growth in Sales/Transportation Volumes (TJ)		25.9%	-0.6%	-2.8%	-10.7%	1.9%	9.1%	0.4%
Customers (Average)	85,321	89,302	93,006	96,237	98,920	101,266	103,754	106,360
Annual Growth in Customers (Average)		4.7%	4.1%	3.5%	2.8%	2.4%	2.5%	2.5%
Rate Base	$ 464,180	$ 478,699	$ 511,422	$ 532,925	$ 547,661	$ 676,636	$ 788,314	$ 815,684
Annual Growth in Rate Base		3.1%	6.8%	4.2%	2.8%	23.6%	16.5%	3.5%

FEW

FEW Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	734	742	709	629	765	731	716	709
Annual Growth in Sales/Transportation Volumes (TJ)		1.2%	-4.4%	-11.3%	21.6%	-4.5%	-2.1%	-1.0%
Customers (Average)	2,368	2,391	2,434	2,519	2,586	2,592	2,610	2,629
Annual Growth in Customers (Average)		1.0%	1.8%	3.5%	2.7%	0.2%	0.7%	0.7%
Rate Base	$ 17,040	$ 16,830	$ 16,782	$ 31,518	$ 45,400	$ 44,892	$ 42,046	$ 41,346
Annual Growth in Rate Base		-1.2%	-0.3%	87.8%	44.0%	-1.1%	-6.3%	-1.7%

FEFN

FEFN Financial Data	2006	2007	2008	2009	2010	2011F	2012F	2013F
Total Annual Figures								
Sales/Transportation Volumes (TJ)	906	816	751	621	615	624	632	641
Annual Growth in Sales/Transportation Volumes (TJ)		-9.9%	-8.0%	-17.3%	-1.0%	1.5%	1.3%	1.4%
Customers (Average)	2,325	2,340	2,355	2,355	2,360	2,386	2,405	2,427
Annual Growth in Customers (Average)		0.6%	0.6%	0.0%	0.2%	1.1%	0.8%	0.9%
Rate Base	$ 4,825	$ 5,048	$ 5,093	$ 5,055	$ 5,410	$ 5,755	$ 7,392	$ 9,241
Annual Growth in Rate Base		4.6%	0.9%	-0.7%	7.0%	6.4%	28.4%	25.0%

Please refer to the response to the BCUC IR 1.147 series for an explanation of operating trends, including rate base, amongst the regions.

155.0 Reference: Regional Characteristics

No Reference

Residential Customers

155.1 What is the level of the FEU's penetration into the residential energy market? In other words, what is ratio of households that are customers of the FEU, to the total number of households to which natural gas service could be provided? Please provide this ratio for each of FEI Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN for 2007, 2009 and 2011.

Response:

Currently, this level of market intelligence is not readily available. The last time a formal study to examine overall on-main market share[113] was performed by the Companies was in 2005.

On Vancouver Island, for example, a significant amount of main was installed between 1991 and 2004 with the intent to expose potential conversion opportunities as well as new construction. As a result, Vancouver Island and the Sunshine Coast are at approximately 50% to 55% on-main saturation. This is based on the study performed in 2005 and the limited number of on-main conversions attached over the last 6 years.

In the Interior, it is estimated that approximately 60-65% of existing homes on-main are currently gas customers. Similar numbers are estimated for the Lower Mainland, with the exception of the Greater Vancouver Regional District where the mains saturation is believed to be much higher, around 75-80%.

[113] On-main market share refers to the number of FEU customers attached to natural gas mains divided by number of households that could be served (i.e. the number of FEU customers plus non-customers attached to natural gas mains).

156.0 Reference: Regional Characteristics

No Reference

Regional Differences

156.1 Do FEU consider that there are regional variations between FEI, FEFN, FEW and FEVI on the cost required to meet municipal standards as to the quality of extensions (for example, use of concrete slurry compared to native fill)? Please explain why or why not.

Response:

Costs to construct mains and services vary throughout the FEU service areas and are based on varying conditions (travel time, job site conditions, crew size, external versus internal workforce, municipal requirements, etc.). Municipal standards vary across the province for mains and services work and the cost to meet those standards is one element in the variability of installation costs between municipalities. Typically the municipal standards for installing new services are less onerous than installing conversion services. The latter type of service, depending on the municipality, may require a pre-site inspection, a permit to install and a post installation paving inspection. The standards can and do vary across the specific municipalities themselves and within the various regulatory entities.

156.1.1 Do FEU consider that implementation of postage stamp rates could result in municipalities served by FEFN, FEW and FEVI requesting higher quality standards for extensions on the basis that the associated costs would primarily be paid for by FEI customers? If no, please explain why not.

Response:

If postage stamp rates are implemented, the FEU do not believe that municipalities in the FEFN, FEW and FEVI areas will require higher quality standards for extensions. The FEU's experience over the past years indicates that municipal engineering standards do not change based on the utility serving the municipality nor on which customers pay. Rather, municipal engineering standards are established based on mitigating risk to municipal infrastructure and planning a coordinated approach to installation and operation of a variety of municipal and utility services, and are normally applied consistently across all utility sectors.

156.2 Do FEU consider that there are there regional variations between FEI, FEFN, FEW and FEVI on the willingness to contribute towards social and environmental programs (for example, demand-side management, charities, Olympic Cauldron), and/or preferences with regard to which programs to contribute to (for example, customers may be more willing to contribute to social initiatives in their own community)? Please explain why or why not.

Response:

No, the FEU do not consider that there are regional variations on the willingness to contribute to these programs. The FEU believe that while it is true that communities do value investment in local initiatives, there can also be support for initiatives that have regional or national value. The Olympic Cauldron is a good example of an investment that individuals in communities beyond Vancouver would value. The Olympics was not seen as a Vancouver event but rather a provincial and national event of which the Cauldron is a lasting legacy. Another example would be a regional hospital or school. Communities value these types of facilities and the FEU believe there is general understanding that some facilities are regional in nature. The FEU also believe that companies that are seen to be supporting community investments are viewed favourably by communities whether or not there is necessarily direct funding in a community in a particular year. The fact that Companies are supportive of community initiatives is valued by all communities.

Further, the FEU believe that there are no regional variations in the willingness to contribute. For example, there is no region in the Province that is generally less willing to contribute to these types of initiatives than others.

156.3 Do FEU consider that FEI, FEFN, FEW and FEVI also have significant variations in customer price elasticities? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.81.6.

156.4 Does FEU consider that there are variations in uneconomic delivery bypass risks (today or over time) between FEI, FEFN, FEW and FEVI? Please explain why or why not.

Response:

The FEU do not understand what is meant by the term "uneconomic delivery bypass risks". The FEU currently only have bypass agreements with certain large customers in FEI due to their proximity to Spectra's Westcoast or TransCanada's Foothills major transmission pipeline systems. Therefore, the FEU do not see variations in bypass agreements between FEI, FEFN, FEW, and FEVI.

156.4.1 Please include in your response an explanation of why industrial customers are leaving the system, and if there are variations of the extent that this is occurring between FEI, FEFN, FEW and FEVI.

Response:

Over the years, the FEU have seen a few industrial customers across different sectors leaving the system or shutting down their businesses in FEI, FEFN and FEVI due to economic reasons and cycles in the economy, while FEW does not have an industrial customer base. In some instances where the FEU have experienced industrials leaving the system it appears customers have elected to consolidate their businesses and shut down some of their least efficient operations. The impact of industrials leaving the system in the smaller service territories like FEFN versus the much larger diverse customer base in FEI can result in a much greater impact to the remaining customers in that small service territory. The closure of Canfor's Tackama and Polarboard Mills in FEFN resulted in the loss of the process load for FEFN's only industrial customers. As these two sites were closed indefinitely, they remained FEFN customers with space heating requirements only. In December 2011, Canfor announced the permanent closure of Tackama and FEFN will likely lose the space heating requirements for this site in the future. The loss of the process loads has already placed significant upward pressure in rates for the remaining FEFN customers and the potential loss of the space heating load could put further upward pressure on rates as indicated in the response to BCUC IR 1.99.1.

Some examples of these indefinite or permanent plant closures over the years across the various service territories would be: Western Pulp in Squamish (FEVI), Catalyst Paper's Elk Falls Mill (FEVI), Canfor's Tackama and Polarboard Mills (FEFN), Domtar's Delta plant (FEI), Canfor's Panel & Fibre in New Westminster (FEI), OI Canada in Lavington (FEI) and more recently Georgia Pacific in Surrey (FEI) who expects their plant to be idle for a few years due to the current economy and U.S. housing market.

157.0 Reference: Regional Characteristics

Exhibit B-3-1, Appendix G-10. Sections 3.3 and 12

Residential End Use Survey - Socio-Demographic Profiles of Service Regions

Commission Staff wishes to determine the socio-economic and demographic characteristics of each of the FEU's service regions. Some of this information may be in the 2008 Residential End Use Survey (Appendix G-10), and publicly available statistics may provide additional information.

157.1 Please present bar charts (showing the data values plotted) that present the following information for each service region of FEI (Lower Mainland, FEI Inland, FEI Columbia, FEVI, FEW, and FEFN):

157.1.1 The portion of FEU customers in each service region who are seniors (age 65 years or older) and the portion of the total population in each service region who are seniors.

Response:

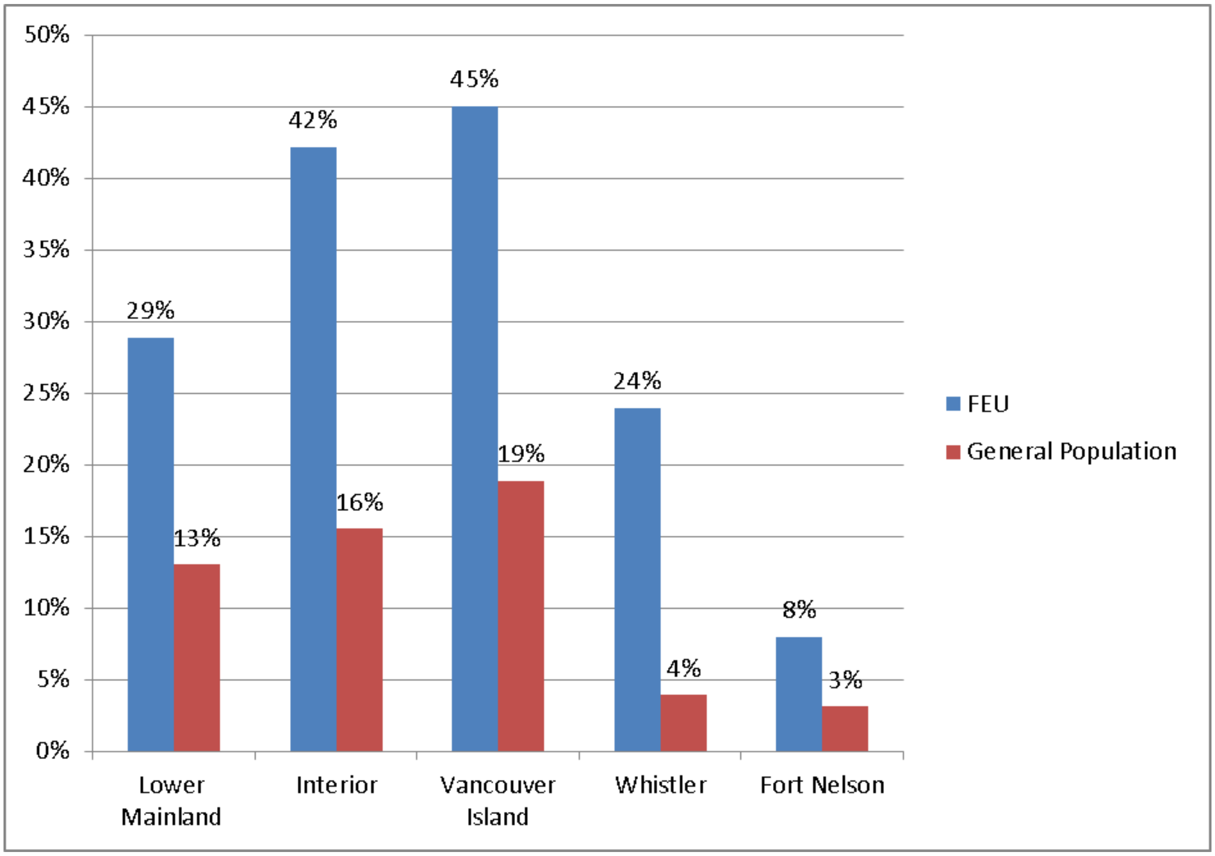
The following response was prepared using information from the FEU's Residential End Use Survey (REUS) and publicly available census data.

The figure below shows the percentage of the FEU's customers who are ages 65 and up alongside the percentage of the general population who are ages 65 and up. Because the Residential End Use Study combined FEI Inland and FEI Columbia into the "Interior" region, they are represented as such for these socio-demographic profiles as well. The FEU have selected specific regional districts to act as proxies for FortisBC service territory.[114]

The FEU's customers tend to include a higher percentage of individuals aged 65 and up than does the general population. Part of the reason for this difference is likely due to the fact that children are an age group included in the general population, but not in the FEU's customer base.

[114] The Lower Mainland service territory comprises the Fraser Valley and Greater Vancouver Regional Districts. The Vancouver Island service territory includes the Capital and Nanaimo Regional Districts, while the Interior region is represented by the Central Okanagan and Fraser-Fort George Regional Districts. Where Fort Nelson and Whistler could be segregated they were, and where they could not be separated from their regional districts, they were respectively represented by the Northern Rockies and Squamish-Lillooet Regional Districts.

Figure: Percentage of FEU Customers and of the General Population who are Seniors



157.1.2 The portion of FEU customers in each service region whose household income is less than $20 thousand per year and the portion of the total population in each service region whose household income is less than $20 thousand per year.

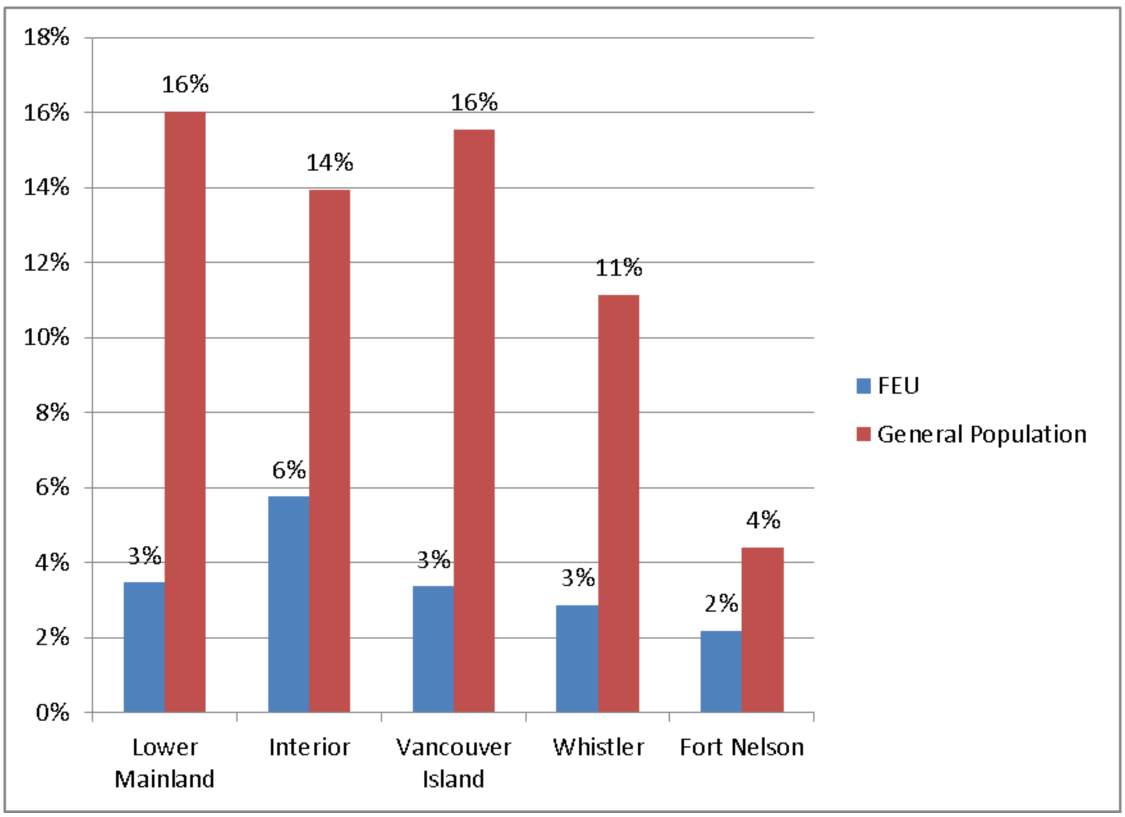
Response:

The following response was prepared using information from the FEU's REUS and publicly available census data. Because the REUS combined FEI Inland and FEI Columbia into the "Interior" region, they are represented as such for these socio-demographic profiles as well.

Additionally, the FEU have selected specific regional districts to act as proxies for the FEU's service territory for census and BC Stats data.[115]

The figure below shows the percentage of the FEU customers whose annual household income is less than $20,000 alongside the percentage of the general population with annual household income below $20,000. Because the REUS combined FEI Inland and FEI Columbia into the "Interior" region, they are represented as such for these socio-demographic profiles as well. In all areas, the FEU's customers with an annual household income of less than $20,000 are a smaller proportion of all FEU customers than are people with income less than $20,000 in the general population.

Figure: The Percentage of FEU Customers and of the General Population with Annual Income Less Than $20,000.



[115] The Lower Mainland service territory comprises the Fraser Valley and Greater Vancouver Regional Districts. The Vancouver Island service territory includes the Capital and Nanaimo Regional Districts, while the Interior region is represented by the Central Okanagan and Fraser-Fort George Regional Districts. Where Fort Nelson and Whistler could be segregated they were, and where they could not be separated from their regional districts, they were respectively represented by the Northern Rockies and Squamish-Lillooet Regional Districts.

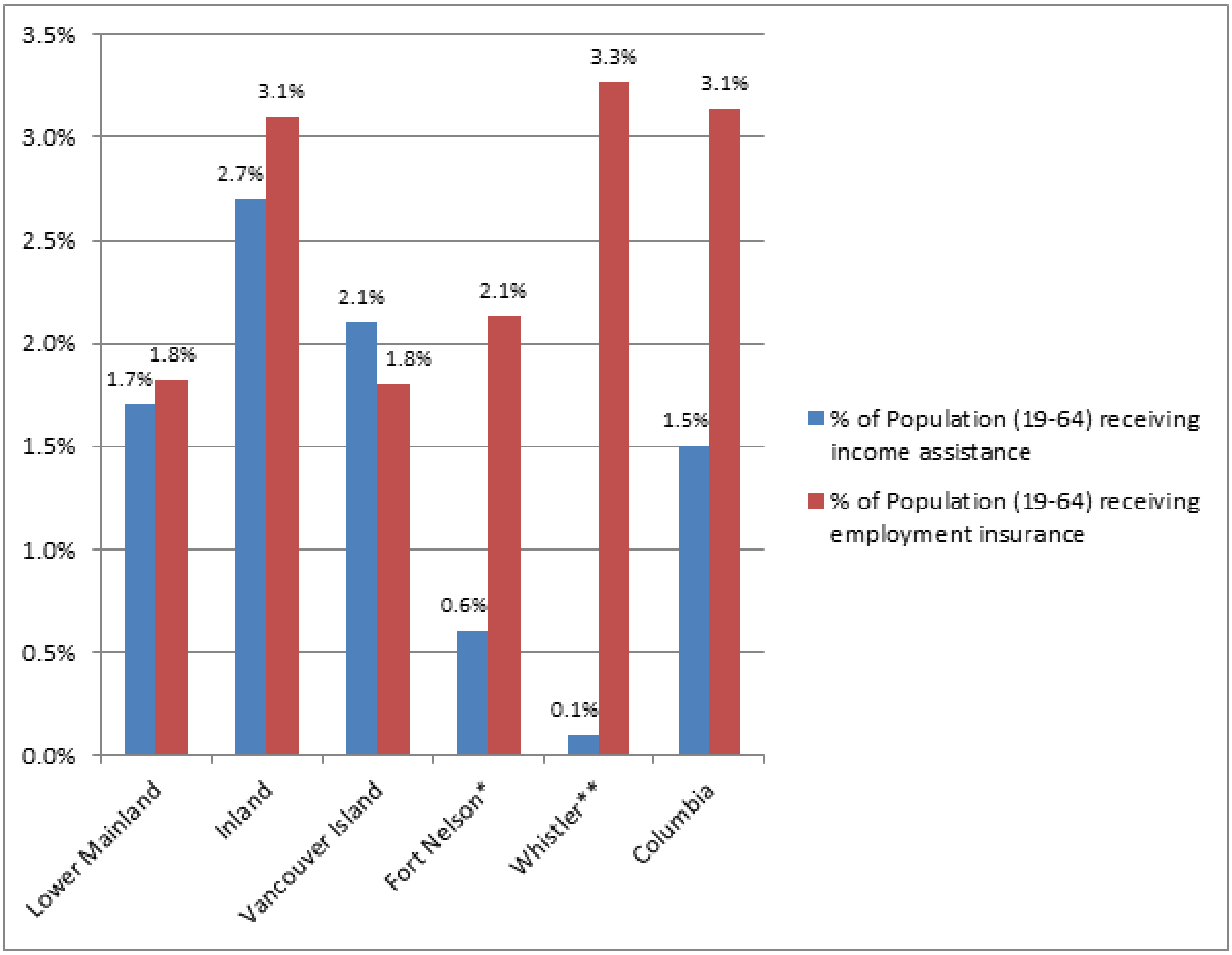
157.1.3 The portion of the total population in each service region who are on income assistance and the portion of the total population in each service region who are collecting employment insurance benefits.

Response:

The percentage of the total population aged 19-64 who are currently on Income Assistance and the number of people receiving Employment Insurance benefits was obtained from BC Stats and is current as of 2012. The data was aggregated by regional district, and the FEU have selected specific regional districts to act as proxies for FEU's service territory.[116] The results are shown in the figure below.

[116] The Lower Mainland service territory comprises the Fraser Valley and Greater Vancouver Regional Districts. The Vancouver Island service territory includes the Capital and Nanaimo Regional Districts, the Inland region is represented by the Central Okanagan and Fraser-Fort George Regional Districts, and the Columbia region is represented by the East Kootenay Regional District. Where Fort Nelson and Whistler could be segregated they were, and where they could not be separated from their regional districts, they were respectively represented by the Northern Rockies and Squamish-Lillooet Regional Districts.

Figure: Proportion of the General Public Receiving Income Assistance and Receiving Employment Insurance Benefits.



* Northern Rockies Regional District
** Squamish-Lillooet Regional District

157.1.4 The median household income of FEU customers in each service region and the median household income of the total population in each service region.

Response:

The following response was prepared using information from the FEU's REUS and publicly available census data. Because the REUS combined FEI Inland and FEI Columbia into the

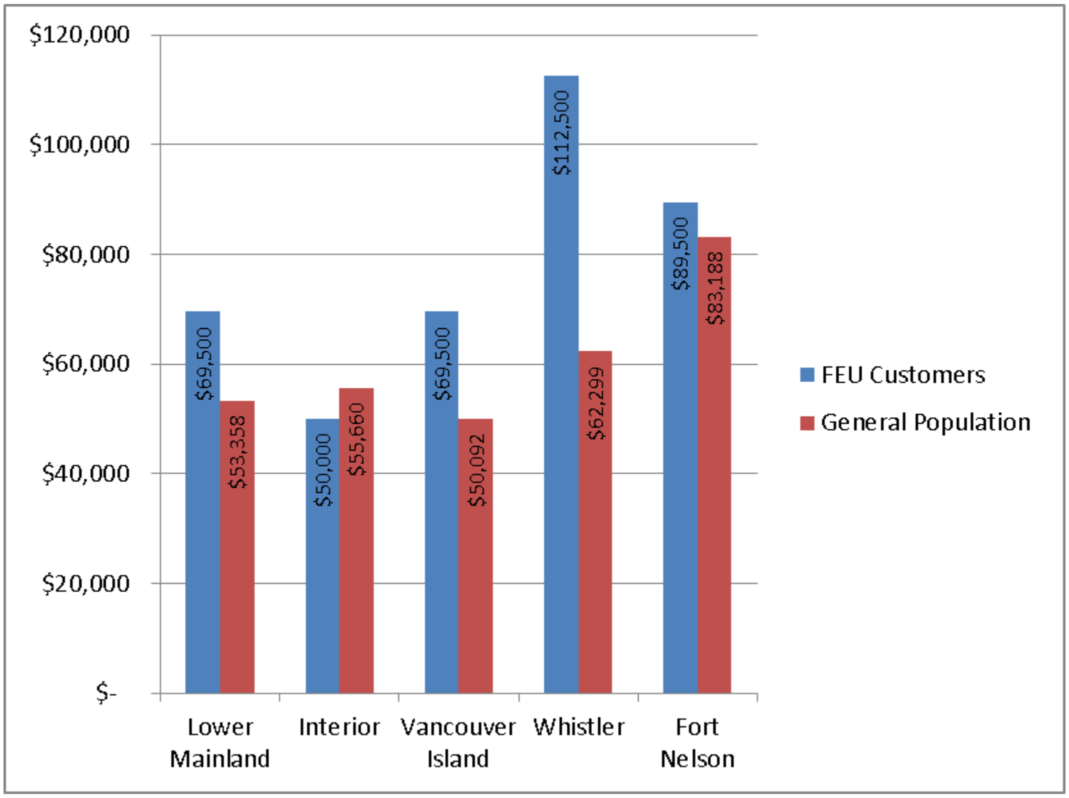
"Interior" region, they are represented as such for these socio-demographic profiles as well. Additionally, the FEU have selected specific regional districts to act as proxies for the FEU's service territory for census and BC Stats data.[117]

The REUS did not calculate a median income, however, as the income figures were captured as categorical responses. For this reason, the median incomes for the FEU's customers are estimates. Respondents identified a range in which their household income was contained, and the median of the range in which the median number of respondents fell was used to represent the median income. For example, in the Lower Mainland, there were 589 respondents. The median number of respondents is 295, which fell in the income category $60,000-$79,000. The median income in that category is therefore estimated at $69,500.

The results for each service region are provided in the figure below. The median household income for the FEU's customers tends to be slightly higher than that of the general population, with the exception of the Interior service territory.

[117] The Lower Mainland service territory comprises the Fraser Valley and Greater Vancouver Regional Districts. The Vancouver Island service territory includes the Capital and Nanaimo Regional Districts, while the Interior region is represented by the Central Okanagan and Fraser-Fort George Regional Districts. Where Fort Nelson and Whistler could be segregated they were, and where they could not be separated from their regional districts, they were respectively represented by the Northern Rockies and Squamish-Lillooet Regional Districts.

Figure: Median Householde Income of the FEU Customers and of the General Population by the FEU Service Area



The median income for the general population is provided at the census district level by the 2006 census data, but as some service territories include multiple census districts, the median income between the districts was used. For example, the GVRD and FVRD are used to represent the FEU Lower Mainland service territory. The median household income for the GVRD is $55,231, while the median household income for the FVRD ia $51,484. The median income for the combination of those two regional districts is $53,358.

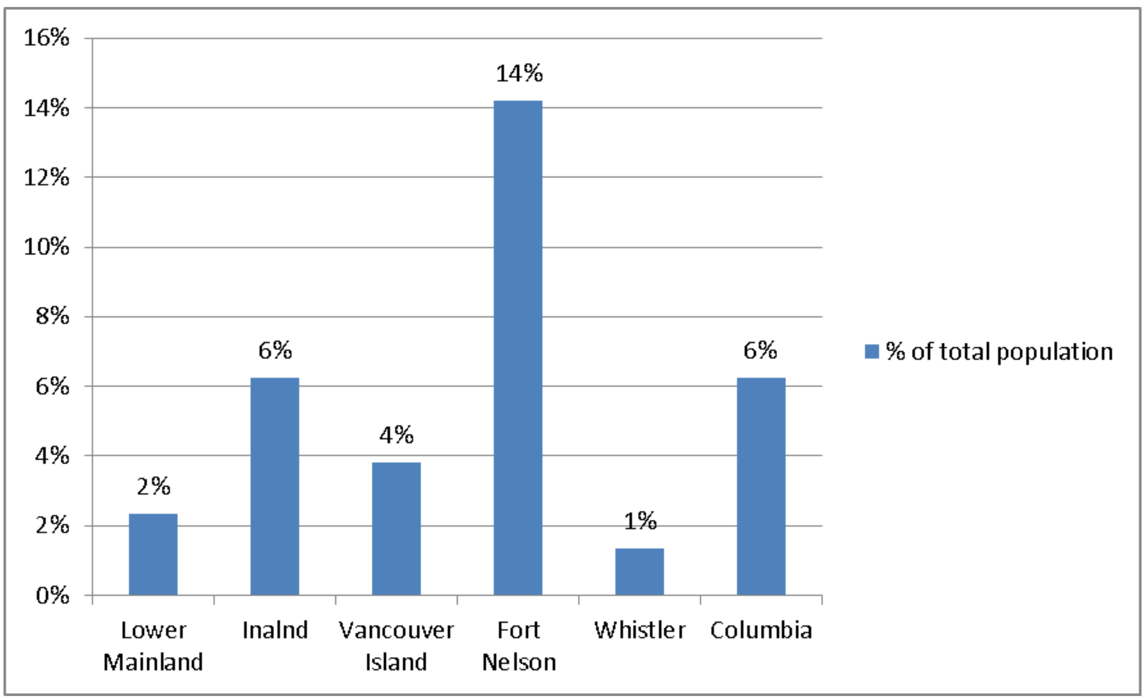
157.1.5 The proportion of First Nations people to the total population in each service region.

Response:

The percentage of First Nations people among the total population in each service territory was obtained through the 2006 Census data and is provided in the figure below. The FEU have selected specific regional districts to act as proxies for the FEU's service territory.[118]

'Aboriginal Identity' in the census study refers to those persons who reported identifying with at least one Aboriginal group, that is, North American Indian, Métis or Inuit, and/or those who reported being a Treaty Indian or a Registered Indian, as defined by the Indian Act of Canada, and/or those who reported they were members of an Indian band or First Nation.

Figure: The Proportion of People with Aboriginal Identity to the Total Population in Each FEU Service Region.



[118] The Lower Mainland service territory comprises the Fraser Valley and Greater Vancouver Regional Districts. The Vancouver Island service territory includes the Capital and Nanaimo Regional Districts, the Inland region is represented by the Central Okanagan and Fraser-Fort George Regional Districts, and the Columbia region is represented by the East Kootenay Regional District. Where Fort Nelson and Whistler could be segregated they were, and where they could not be separated from their regional districts, they were respectively represented by the Northern Rockies and Squamish-Lillooet Regional Districts.

158.0 Reference: Regional Characteristics

Exhibit B-3-1, Appendix G-10, pp. 5-1, 13-4 to 13-6

Residential End Use Survey - Residential Uses of Natural Gas

Tables 13-4, 13-5, 13-6, 13-7 and 13-8 of Appendix G-10 present estimates of consumption of natural gas by end use for residential customers in FEI Lower Mainland, FEI Interior, FEVI, FEW and FEFN, respectively.

158.1 Please prepare a bar chart showing the portion (in percent) of residential demand in each region (FEI Lower Mainland, FEI Interior, FEVI, FEW and FEFN) that serves the following: (i) primary space heating, (ii) domestic water heating, and (iii) other residential requirements.

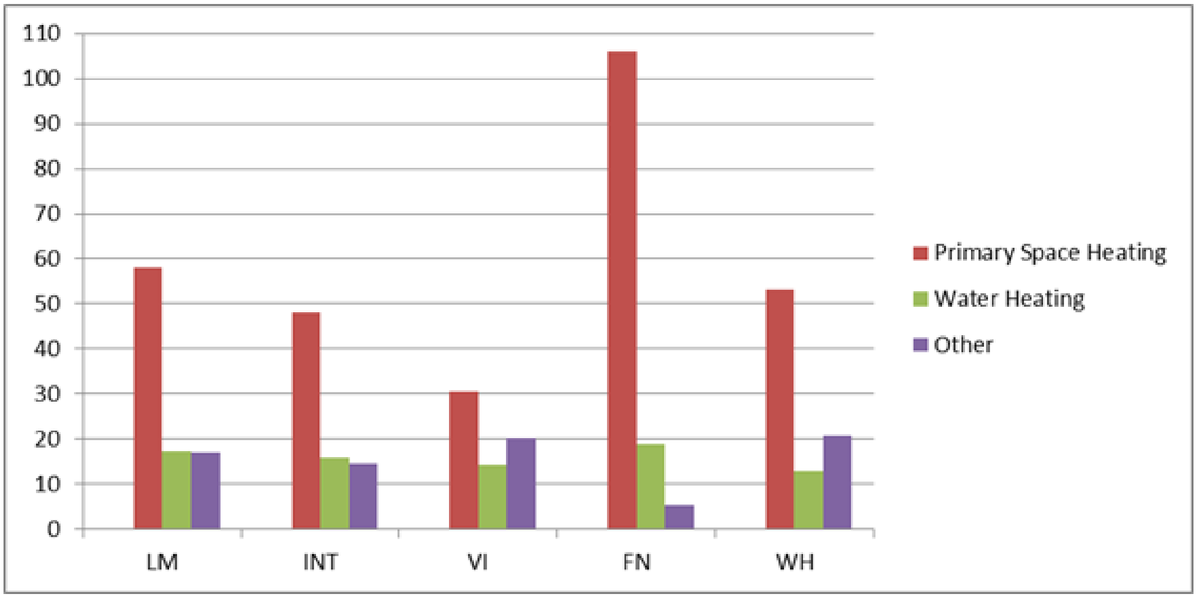
Response:

The following summary provides an analysis of regional variation in household gas consumption associated with space, hot water and other end uses.

Heating Requirements

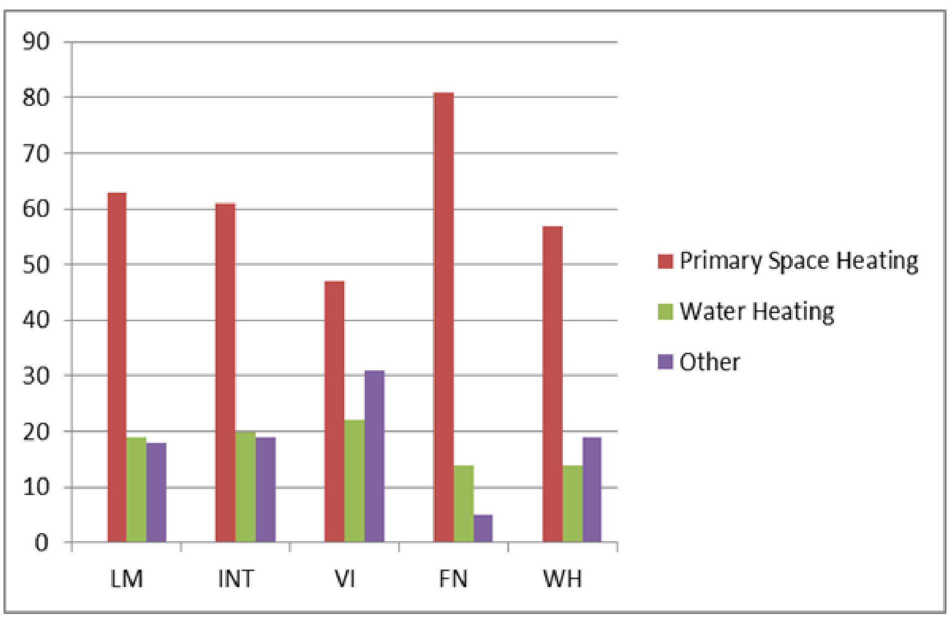
Primary space heating is the largest single component of residential demand in all five regions. However, there are regional variations in the amount attributable to primary space heating both in terms of GJs consumed and as a proportion of overall consumption. It ranges from a high of 106 GJs per year in Fort Nelson, which represents about 80% of the region's overall gas consumption, to a low of 30 GJs in Vancouver Island (47%). For the other regions, the proportion of gas used for primary space heating consumption is fairly consistent: Whistler, 53.2GJs (58%); Lower Mainland – 58GJs (63%), and Interior – 48 GJs (61%). This information is depicted in **Error! Reference source not found.** below.

Figure 1: Residential Natural Gas Consumption (GJs) by End Use and Region[119]



As a percentage of overall household use, natural gas consumption by region is depicted in **Error! Reference source not found.** below.

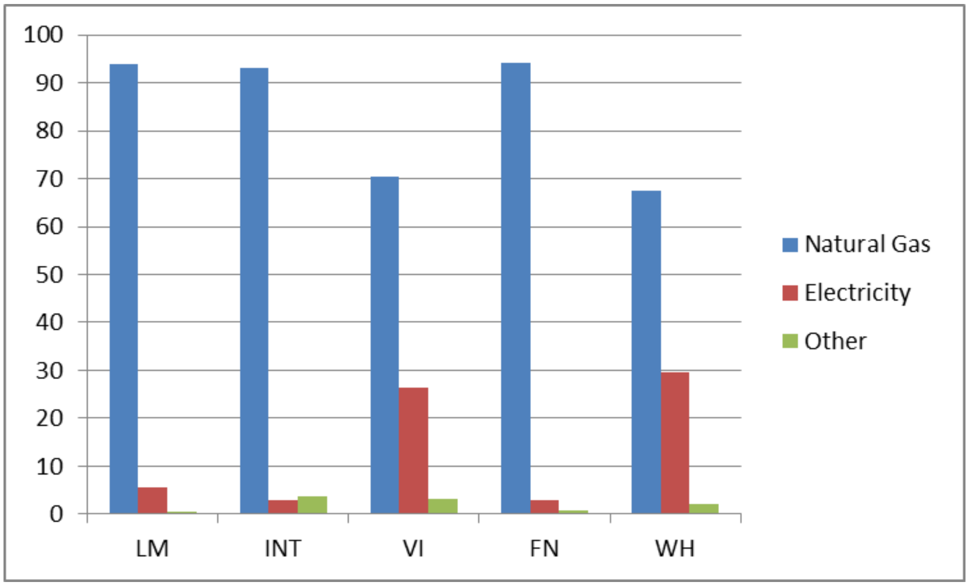
Figure 2: Percentage of Residential Natural Gas Consumption by End Use[120]



[119] Terasen Gas Residential End use Study (2008)
[120] Ibid

Figure 3 shows the percentage of natural gas customers who use natural gas as their primary heating fuel.

Figure 3: Primary Space Heating Fuel of FortisBC natural gas customers by Region (%)121

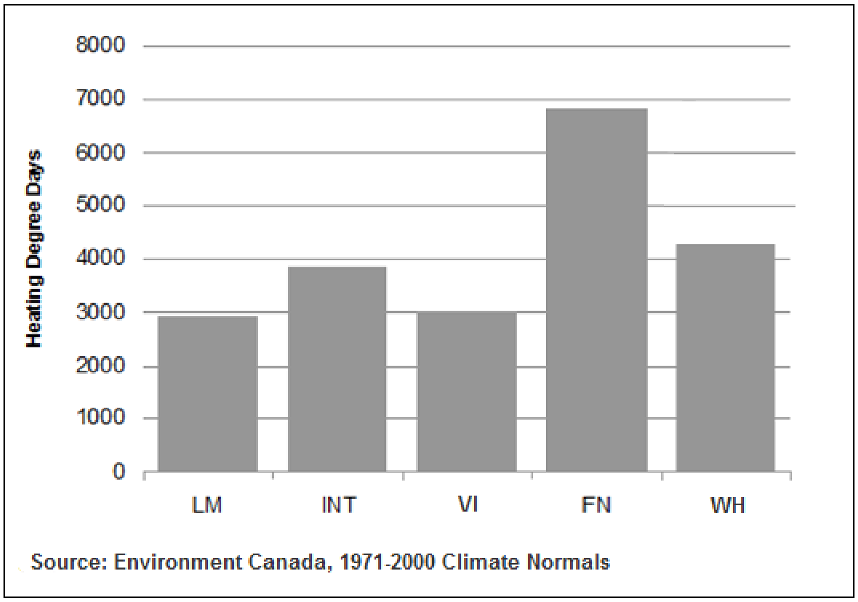


Regional variation in gas consumption is due mainly to (1) temperature differences (see **Error! Reference source not found.**); (2) the percentage of homes that use natural gas as their primary heating fuel (See Figure 3); (3) the percentage of homes in each area that have supplementary heat sources; and lastly (4) construction differences.

Gas consumption in Whistler is impacted by the amount of time that the property is occupied. Lower adoption of natural gas space heating in Whistler and on Vancouver Island likely reflects the relatively recent introduction of the fuel to each region.

[121] Ibid

Figure 4: Typical Annual Heating Degree Days by Region122



Heating requirements have a tremendous influence on overall household gas requirements. For example, 94% of Fort Nelson, Lower Mainland and Interior customers use natural gas as their primary heating fuel, whereas only 70% (70.4%) do on Vancouver Island (Figure 3). In addition, even where Vancouver Island customers use natural gas as their primary fuel, they are less likely to use furnaces or boilers than other areas and have a greater incidence of using natural gas fireplaces as their heating source. Therefore, the amount of gas used per customer on Vancouver Island for space heating is lower.

The difference between primary space heating demand in the Lower Mainland and the Interior is partially explained by higher levels of wall and ceiling insulation, more energy efficient windows and exterior doors in Interior homes. Interior customers are also more diligent about maintaining draft proofing measures such as weather stripping and caulking.

Hot Water

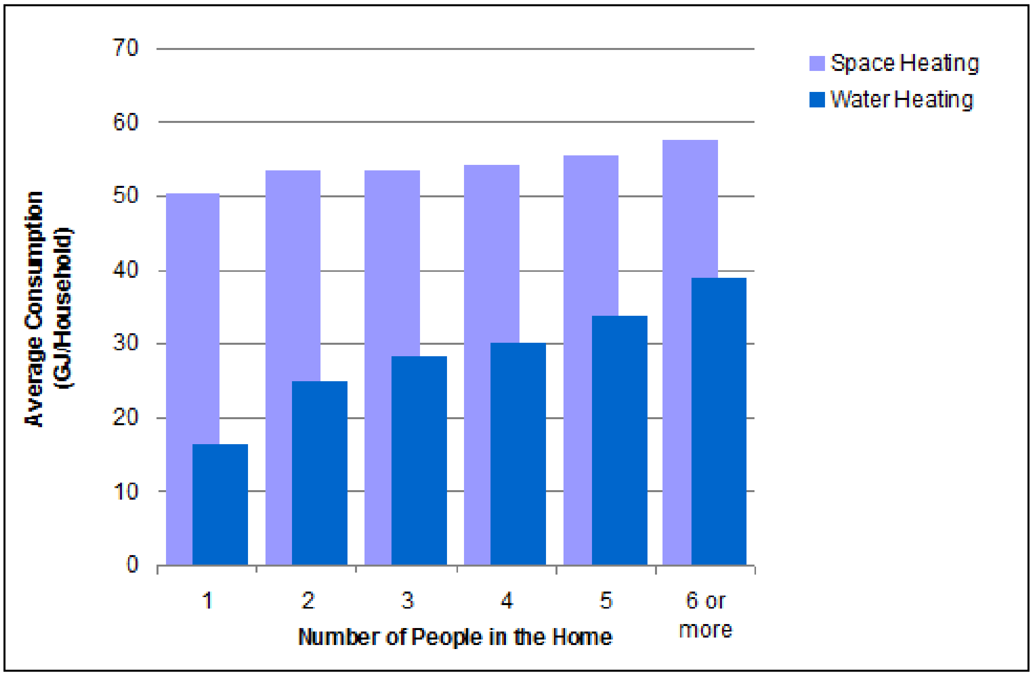
The regional variation in natural gas consumption for domestic hot water (DHW) is small. Variation ranges from a high of 18.8GJs (14% of overall consumption) in Fort Nelson to a low of 12.8 GJs (14%) in Whistler. For the other regions the proportion of gas used for DHW is fairly consistent: Vancouver Island - 14.4GJs (22%); Lower Mainland – 17.2GJs (19%), and Interior – 16GJs (20%).

[122] Environment Canada, 1971-2000 Climate Normals

Demand is driven by the number of occupants and the percentage of homes using natural gas for DHW. In the case of Whistler, the amount of time that the property is occupied is a contributing factor. Forty-three percent of Whistler customers report using electricity to heat their DHW. On Vancouver Island, about twenty percent use electricity, whereas in the Lower Mainland, Interior and Fort Nelson approximately one-in-ten customers have electric DHW.

The number of household occupants also influences demand for DHW (See **Error! Reference source not found.**). This correlation is observed by comparing the lower average number of household occupants in the Interior (2.43 residents per dwelling) and Vancouver Island (2.39), with the Lower Mainland (3.01).

Figure 5: Gas Consumption by Number of People in the Home123



Other End Uses

The regional variation in natural gas consumption for other end uses reflects the different rates of penetration of end uses in each region. Other end use consumption ranges from a high of 25.4GJs (28% of overall consumption) in Whistler to a low of 5.4 GJs (4%) in Fort Nelson. Other end use consumption in Vancouver Island is in line with Whistler 20GJs (31%). The other two regions, including the Lower Mainland 16.9GJs (18%) and Interior 14.4GJs (18%), reveal virtually identical consumption patterns for other end uses.

[123] Terasen Gas Residential End use Study (2008)

More Whistler customers use piped gas for BBQs (42.8%), have gas ranges (30%) and use gas to heat hot tubs than in other regions. In Vancouver Island, supplementary heating is the primary driver of other end use consumption.

Conclusion

In summation, overall the Interior and Lower Mainland show relatively similar patterns of usage. While the Interior has a lower overall consumption, the relative proportion of consumption for each end use is practically identical. Fort Nelson consumption patterns are heavily influenced by weather and their northern locale drives increased space heating demands. Whistler is impacted by weather, but also occupancy levels. Vancouver Island reveals a more varied mixture of heating fuels that reflects the more recent introduction of natural gas to the region.

158.2 Prepare a chart similar to the one prepared in response to the previous question but in terms of GJs per year required to serve each end use requirement.

Response:

Please refer to the response to BCUC IR 1.158.1.

158.3 From the data on the amount of residential demand serving end use requirements other than space and domestic water heating, and from the FEU's data on the frequency distribution of residential consumption per customer, what portion of residential customers in each region (FEI Lower Mainland, FEI Interior, FEVI, FEW and FEFN) can be considered to be using natural gas solely for applications other than space or domestic water heating? (In other words, if X gigajoules of the average annual residential consumption in Whistler is for applications other than space or domestic water heating, then what portion of Whistler residential customers have an annual consumption below X gigajoules?)

Response:

Results from the 2008 Residential End Use Study (Figure 1: Dwelling with no gas space or DHW) show that only 3.3% of FEU customers use natural gas (or piped propane) exclusively for purposes other than primary space heating and domestic hot water. Figure 1 provides a regional breakdown.

Figure 1: Dwelling with no gas space or DHW

	LM	INT	VI	FN	WH	2008 Overall
Unweighted base	578	730	566	138	209	2221
All Dwellings: No gas space heat or gas DWH (%)	2.5	2.6	9.7	2.2	26.2	3.3

Figure 2 (Customers with Annual Consumption Lower than 20GJs) is based on 2011 actual consumption and provides the percentages of customers who have levels of consumption that suggest they do not have gas as their primary space heating fuel or for DHW. The consumption pattern matches the pattern in Figure 1. However, this approach does not account for energy use patterns nor does it account for housing type. It also does not distinguish between different end uses that have a similar consumption. For example, a single person with gas fueled DHW and someone who uses gas exclusively to heat their hot tub and has no other gas end uses may have the same level of consumption.

Figure 2: Customers with Annual Consumption Lower than 20GJs

	Annual Estimated Consumption (GJs)			Cumulative percentage of customers by region			
	Space Heating	Water Heating	Other End Uses	5 GJs/Year	10 GJs/Year	15 GJs/Year	20 GJs/Year
Lower Mainland	58	17.2	**16.9**	2.23	3.8	5.6	7.5
Interior	48	16	**14.4**	1.66	2.88	4.4	6.1
Vancouver Island	30.4	14.4	**20**	5.8	10.3	15.9	21.7
Fort Nelson	106	18.8	**5.4**	0.7	0.8	0.9	1.2
Whistler	53.2	12.8	**25.4**	7.4	12.1	18.9	25.8

158.4 Table 5-1 of Appendix G-10 shows the main space heating fuel for each region. Please prepare a bar chart showing the portion (in percent) of residential customers in each region (FEI Lower Mainland, FEI Interior, FEVI, FEW and FEFN) that (i) use natural gas as their primary space heating fuel, (ii) use electricity as their primary space heating fuel, and (iii) use a fuel other than natural gas or electricity.

Response:

Please refer to the response to BCUC IR 1.158.1.